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**FINANCING ALTERNATIVES AND INCENTIVES FOR
SOLAR THERMAL CENTRAL RECEIVER SYSTEMS**

By
Peter B. Bos

June 1982

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**Polydyne, Inc.
Menlo Park, California**

U.S. Department of Energy

Solar Energy

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FOR SOLAR THERMAL CENTRAL RECEIVER SYSTEMS**

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June 1982

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ABSTRACT

As a result of various recently enacted incentive and regulatory legislation combined with the new administration policy and budgetary guidelines, the commercialization of solar thermal central receiver systems will involve financing alternatives other than conventional utility financing. This study was conducted to identify these potential financing alternatives and the associated requirements and impacts on the Department of Energy program.

Based upon this analysis, it is concluded that the current alternative financing window is extremely short (through 1985), and that an extension or at the least a gradual phasing out, of the solar tax credits is necessary for the successful transfer of the central receiver technology to the private sector. Furthermore, throughout this time period, continued government support of the R&D activities is necessary to provide the necessary confidence in this technology for the private (financial) sector to underwrite this technology transfer.

Consequently, even though the central receiver technology shows high promise for replacing a significant fraction of the oil/gas-fired utility industry peaking and intermediate generation, the current readiness status of this technology still requires further direct and indirect government support for a successful technology transfer. The direct government research and development support will provide the basis for technological readiness and confidence, whereas the indirect tax incentive support serves to underwrite the extraordinary risks associated with the technology transfer.

These support requirements need only be limited to and decreasing during this technology transfer phase, since as the systems approach successful full-scale commercialization, the extraordinary risks will be gradually eliminated. At the time of commercialization the system's value should be on a par with the installed system's cost.

SECTION 1

INTRODUCTION

This report evaluates the new administration government policy and budgetary guidelines as these impact on the solar thermal central receiver systems development and commercialization.

As a result of various tax incentive and regulatory legislation, the financial alternatives for commercialization of solar technologies are significantly enhanced. However, the time frame for these incentives and associated intermediary financing arrangements is quite limited in duration (1985). At the same time the proposed reduction in federal R&D program support severely undermines the technological readiness and associated investor confidence in these new alternative energy technologies.

Consequently, this report addresses the requirements for successful technology transfer as perceived by the financial or private sector, and the necessary related government involvement. This involvement by the federal and local governments is examined in terms of direct research and development (R&D) support and indirect support in terms of underwriting of the extraordinary risks associated with new technology transfer by means of tax incentives.

In this context this report describes the requirements for successful solar thermal central receiver technology transfer and the impact on the Department of Energy (DOE) program strategy.

SECTION 2

GOVERNMENT POLICY AND BUDGETARY GUIDELINES

Significant changes have taken place recently in government policy with regard to development support for renewable energy technology. Prior to Fiscal Year 1981, the government policy for solar energy was guided by the Solar Energy Research, Development and Demonstration Act of 1974. This policy in essence had as its goals to "pursue research of solar energy for our national needs" and "to develop and demonstrate practical means on a commercial scale". The associated DOE program activities were (1) to conduct research and development to establish component and subsystem technical feasibility and readiness for several technology options, and (2) to build demonstration plants to establish system feasibility and readiness.

Subsequently, the Domestic Policy Review of solar energy was initiated in 1978, which identified the potential of solar energy as an important U.S. energy supply with significant advantages over other conventional energy resources (such as environmental quality and oil import replacements). Furthermore, it identified the potential of solar energy resources for making a significant energy contribution by the year 2000.

The emphasis of the current administration as described in the National Energy Policy Plan clearly is for the private sector to assume the responsibility for technology transfer of the renewable energy resources previously underwritten by the government.

Furthermore, as described in the House Report "Energy and Water Development Appropriation Bill," the government policy is to "restructure technology programs so as

to emphasize longer-term, high-risk but potentially high-payoff research and development".

Commensurate with this plan, the administration has provided for significant tax incentives and has removed many barriers which previously prevented the free market system from operating effectively.

This report describes and analyzes the impact of these various incentive and regulatory policies in terms of their sufficiency to effect the continuation of the viable solar technologies. In this context, the requirements of and the impact on the DOE programs and an associated strategy are discussed.

To place this study in perspective, it is necessary to describe the various incentive and regulatory policies as these pertain to the solar energy technologies. The important question to be answered is whether these incentives are sufficient for the successful technology transfer of the Solar Thermal Central Receiver concept from the present level of development to full commercial reality.

SECTION 3

FEDERAL AND STATE TAX INCENTIVES AND REGULATORY LEGISLATION

A number of important incentive and regulatory pieces of legislation have recently been enacted which have significant bearing on the potential for solar technology commercialization. These legislative acts are summarized in Table 3.1. This legislation has provided a short-term market opportunity window for renewable energy technologies. Consequently, it is impabove the regular 10% investment tax credit). Thus non-residential investors (small power producers) of solar or wind property will be eligible for the regular 10% business investment tax credit and a 15% federal solar energy tax credit. Prior to assessment of the financing alternatives and incentives, it is important to describe these various legislative acts in terms of their respective impact on the solar energy resources development and technology transfer.

Public Utilities Regulatory Policy Act (PURPA), 1978

The **Public Utilities Regulatory Policy Act (PURPA)**¹ exempts non-utility small power producers of certain types of power plants, including renewable energy resources, from the Public Utilities Holding Act if the size is less than 30 MW and any fossil fuel consumption produces less than 25% of the total energy output. Accordingly, electric generating systems which qualify are not classified as public utility property, and thus are exempt from State and Federal electric utility regulation.

In addition, the Federal Energy Regulatory Commission (FERC) regulations implementing PURPA provide for the sale of electricity from qualifying facilities at rates based on the purchasing utility's avoided cost, rather than the producer's cost of service. Thus this act insures that the qualifying facilities will not be considered public utility property and will be eligible for the tax credits and shortened depreciation period provided for in the tax incentive legislation discussed below. This new legal framework provides the basis for market entry of non-regulated intermediaries between the hardware manufacturers, the risk-averse public utilities, and the cost-averse Public Utility Commissions.

Table 3-1 Federal Tax Incentives and Regulatory Legislation

Public Utilities Regulatory Policy Act (PURPA), 1978

- o Small, renewable energy sources (<30 MW) exemption from Public Utilities Holding Act
- o Mandated purchase of energy at avoided costs

Energy Tax Act (ETA), 1978

Crude Oil Windfall Profits Tax Act, 1980

- o 15% additional investment tax credit for wind and solar systems installed prior to December 31, 1985
- o Utility companies ineligible for these tax credits

Economic Recovery Tax Act (ERTA), 1981

- o Accelerated Cost Recovery System (ACRS)
 - o Elimination of the at-risk provision for special energy property (provides for non-recourse debt financing)
 - o 25% tax credit for increased R&D expenditures
-

Energy Tax Act (ETA), 1978 and Crude Oil Windfall Profits Tax Act (COWPTA), 1980²

Under this legislation, certain non-utility owned alternative energy properties, including solar and wind, are eligible for a supplemental investment tax credit of 15% (over and above the regular 10% investment tax credit). Thus non-residential investors (small power producers) of solar or wind property will be eligible for the regular 10% business investment tax credit and a 15% energy tax credit on the basis of capital cost. This is particularly advantageous to solar and wind technologies where the initial capital cost is very high and the operational cost is relatively low. This credit has no limit; however, it is scheduled to expire on December 31, 1985, and does not provide for an extension for affirmative commitments beyond this time limit for solar and wind systems.

This Act incorporates provisions against "double-dipping", which means that the tax credits cannot be taken if the financing is obtained from non-taxable grants or subsidized loans. However, loan guarantees and state tax credits do not reduce the energy tax credits.

Specifically, public utilities are ineligible for these energy tax credits (including systems leased to utilities). This provides venture capital groups a decisive advantage over utilities in financing these renewable energy projects during the time period that these incentives are operative.

Economic Recovery Tax Act (ERTA), 1981

The **Economic Recovery Tax Act of 1981³** significantly changed the federal income taxation of business and individuals. Many of these changes have a direct effect on the tax treatment of renewable energy projects. In general, these changes were designed to encourage investments (1) by reducing the personal income tax rates and the maximum tax bracket, and (2) by accelerating and simplifying the depreciation deductions.

The **Economic Recovery Tax Act** created the **Accelerated Cost Recovery System (ACRS)** for property placed in service after 1980. Generally, the statutory recovery periods for depreciation are now shorter than the previous Asset Depreciation Range (ADR) depreciation system. Under the ACRS, the cost of tangible business property is

recovered over a period of three, five, ten, or fifteen years, depending upon the type of property involved. The cost of property in each category may be recovered under the statutory schedule, which concentrates deductions in the early years of the period. In the alternative, taxpayers may elect to stretch out their deductions by using the straight line depreciation method over the recovery period or over specified longer periods.

Under the ACRS, the three-year category includes property used in connection with research and experimentation. The ten-year category includes capital investments for which the guideline life was twelve and one half years or less, and the fifteen-year category includes property for which the guideline life was more than twelve and one half years. The five-year category includes any property that is not included in the three, ten, or fifteen-year categories. **Most non-utility owned renewable energy projects will most likely be classified as five-year property.**⁴

Special rules govern the depreciation of public utility property. Public utility property is ineligible for accelerated depreciation under ACRS if the taxpayer does not use a normalization method of accounting*. Even if a normalization method of accounting is used, the cost of public utility property may have to be recovered over a longer time period than would apply to non-utility property. Under ACRS, the recovery period for public utility property (other than real property improvements) is 10 years for property which had a guideline life under the ADR system of 18 to 25 years, and 15 years for property which had a guideline life of 25 years or more. **Utility financed and owned renewable energy projects are projected to be classified as ten-year property for ACRS purposes.**⁵

Thus, since the tax treatment of non-utility property is more favorable than utility-owned property, the importance of solar or wind energy projects satisfying the

* For electric utility regulatory purposes there are two methods of handling deferred taxes, "flow through" and "normalization". In the flow-through method the tax deferrals are flowed through immediately either to the ratepayers through a decrease in rates or to the equity holders through an increase in equity return. In the normalization method, deferred taxes are accumulated in a reserve account and used as a source of internally generated cash, along with retained equity earnings and depreciation, to pay for new investment items.

ownership conditions avoiding classification as utility property under PURPA is underscored.

Furthermore, the **Energy Recovery Tax Act of 1981** provides for exemption of the **"at-risk"** provision for special energy property. Previously, a private investor could only take, for tax purposes, a cumulative deduction from income up to the amount of money at risk in a venture. No further losses could be deducted until such time as the investment began to show net positive taxable income. **The exemption of the "at-risk" provision allows an equity investor in a leveraged investment to claim the full tax benefits based upon the total cost of the project, even with a non-recourse loan* and when the lender is a related party, providing that the investor's equity is at least 25% of the cost, and the debt financing payments are level.**

Exemption of special energy property encourages the risk capitalist to increase leverage (i.e., debt-to-equity ratio) of a project by securing the maximum amount of non-recourse debt financing, if possible. However, with regard to solar projects, this may be difficult to obtain in practice since the uncertain value of solar plants may not provide sufficient collateral. The provision that the investor can borrow from a related party is very important in this regard. As a result, for a high risk technology such as the early solar facilities, the lender need not be a conventional source, such as a bank or an insurance company, but can be an interested or related party such as the product manufacturer.

The **'safe harbor'** provision currently allows the sale of the tax credits and depreciation. Thus a company with a small taxable base or with limited tax liabilities can sell the facilities to an organization that is able to absorb these tax credits and depreciation and then lease these facilities back at reasonable rates.

With regard to the **'safe-harbor'** provision, any loan must be a level payment loan; otherwise the tax credits are subject to recapture. Furthermore, the borrower's at-risk percentage declines to 20% and the level payment requirements is eliminated when the non-recourse loan is provided by an unrelated lender. Because of this extremely

* A non-recourse loan is a loan secured only by the asset being financed. The lender has no recourse to the borrower in case of default.

favorable tax treatment, some of these provisions, especially the sale of these credits under the 'safe-harbor' provision, are currently under review.

The **Economic Recovery Tax Act** furthermore provides significant incentives for increased research and development by means of a **research tax credit**. This research tax credit can be used to reduce the federal income tax liability. The credit is figured on the amount of research expenses incurred during the tax year that are more than the average of these expenses during a base period. The credit is limited to 25% of this amount. The base period is generally the last three tax years before the tax year for which the credit is taken. This tax credit cannot reduce the tax liability below zero, but unused credit can be carried back 3 years and forward 15 years. The two general kind of expenses that qualify for the credit are:

1. In-house research expenses
2. Contract research expenses

In-house research expenses can include employee wages, supplies used for research, and amounts paid others for rights to use personal property for research. Contract research expenses are amounts paid others to perform research.

In summary, the interaction of the **Public Utility Regulatory Policies Act (PURPA)**, the **Crude Oil Windfall Profit Tax Act (COWPTA)** and the **Economic Recovery Tax Act (ERTA)** present significant benefits to and thus incentives for intermediary or third-party financing of solar projects.

State Tax Incentives

In addition to these federal tax incentives, individual states provide for different incentives to include provisions for income tax credit deductions, accelerated depreciation, property tax exemptions, and sales tax exemptions⁶ (Table 3-2). The specific incentives vary from state to state.

A summary of these various state tax incentives for non-residential uses of solar energy is shown in Table 3-3, which was derived from the Solar Data Bank Report.⁷ Since the guidelines provided in this table are in summary form only, and considering the complexity of the individual state laws, the details regarding a specific state incentive program should be obtained directly from the specific state.

Table 3-2 State Tax Incentives and Regulatory Legislation

- o Income tax credits or deductions
 - o Provisions for accelerated depreciation
 - o Property tax exemption
 - o Sales or use tax exemption
-

Table 3-3 Tax Incentives for Commercial Solar Applications

State	Property Tax Exemption	Income Tax Incentive	Sales Tax Exemption
Alabama	no	no	no
Alaska	no	35% credit	not applicable
Arizona	exemption	election of 35% credit or 36 month depreciation	exemption
Arkansas	no	100% deduction	no
California	no	election of 25% tax credit or depreciation over 12 to 60 months	no
Colorado	exemption	30% credit; \$3000 maximum	no
Connecticut	local option	no	exemption
Delaware	no	no	not applicable
Florida	exemption	no	exemption
Georgia	local option	no	refund
Hawaii	exemption	10% credit	no
Idaho	no	no	no
Illinois	exemption	no	no
Indiana	exemption	25% credit; \$10,000 maximum	no
Iowa	exemption	no	no
Kansas	exemption	30% credit with \$4500 maximum; 60 month depreciation	no
Kentucky	no	no	no
Louisiana	no	no	no
Maine	exemption	20% credit; \$100 maximum	refund
Maryland	exemption statewide; credits at local option	no	no
Massachusetts	exemption	100% deduction	no
Michigan	exemption	no	exemption
Minnesota	exemption	no	no
Mississippi	no	no	no

State	Property Tax Exemption	Income Tax Incentive	Sales Tax Exemption
Montana	exemption	no	not applicable
Nebraska	no	no	refund
Nevada	no	no	no
New Hampshire	local option	no	not applicable
New Jersey	exemption	no	exemption
New Mexico	no	no	no
New York	exemption	no	no
N. Carolina	exemption	25% credit; \$1000 maximum	no
N. Dakota	exemption	5% credit for each of 2 years	no
Ohio	exemption	10% credit against corporate franchise tax; 10% for individuals and partnerships (\$1000 maximum)	exemption
Oklahoma	no	15% credit	no
Oregon	exemption	35% corporate tax credit	not applicable
Pennsylvania	no	no	no
Rhode Island	exemption; local option on any locally imposed tax	10% credit; \$1500 maximum	refund
S. Carolina	no	25% credit; \$1000 maximum	no
S. Dakota	partial credit	no	no
Tennessee	exemption	no	no
Texas	exemption	60 month depreciation for corporations	exemption
Utah	no	10% credit; \$3000 maximum	no
Vermont	local option	25% credit; \$3000 maximum	no
Virginia	local option	no	no
Washington	exemption	no	no
W. Virginia	no	no	no
Wisconsin	exemption	no	no
Wyoming	no	no	no

Source: Reference 7

Some of the more favorable states with regard to special solar legislation are California and Arizona, which have large tax income credits with no limit on the amount eligible for these credits. Other favorable states with regard to tax benefits without dollar limitations are Arkansas, Hawaii, Massachusetts, North Dakota, Ohio, Oklahoma and Oregon. All other states impose a dollar amount limitation on the tax credits provided, and their tax incentives are thus of limited benefits to large scale projects.

In California, solar electric systems are eligible for a 25% state energy tax credit in addition to the federal tax credits. No limit is associated with this tax credit which is independent of the federal tax credits taken, other than the fact that state taxes are deductible from federal taxation. For corporations in California with a federal marginal tax rate of 46%, this reduces the 25% state tax credit to an effective 13.5%.

However, combined with the federal 10% investment tax credit and 15% energy tax credit, this amounts to an effective tax credit of 38.5%! Furthermore, in California, the remaining 75% of solar system cost can be depreciated on a double-declining basis over a three-year period for state income tax purposes. Currently, California state credits are available for solar systems installed on or before December 31, 1983, thus providing a very small time window for large-scale solar systems. Even though the eligibility time period for these solar credits has been extended in the past, the potential for extension beyond 1983 is uncertain.

In Arizona the state tax credit is 35% of the cost of a solar energy system until the end of 1983. Most importantly, rather than an abrupt discontinuation, after 1983 the percentage tax credit decreases by 5% per year until the tax credit expires on December 31, 1989. Excess credit may be carried forward for a period of 3 years. The time scale and gradual reduction of the Arizona tax credits are very much in line with the projected technology transfer for some of the more economically viable solar technologies, such as the solar thermal central receiver concept. Alternatively, the solar system can be depreciated over a period of 3 years. In addition, the state exempts solar systems from property taxation and from sales and excise taxes through December 31, 1989.

Summary

The federal and state incentives provided serve to underwrite the extraordinary risks* associated with the solar technology development and commercialization. However, in spite of this risk underwriting by the government, these current tax and regulatory provisions are not without risks. The Federal energy tax credits require that the property be installed and operating by December 31, 1985 (various states sooner than this time period). Thereafter, absence of this important incentive reduces the value and thus the potential selling price of solar systems significantly. It is questionable how many fully integrated solar systems can be fully tested, manufactured and installed prior to the 1986 deadline. The source of the borrowed funds in a highly leveraged project will look for an ironclad source of debt servicing regardless of the profitability and performance of the project, which may require significant recourse loans on the part of the owner, performance warranties from the manufacturers and possibly take or pay contracts** from the utilities. Other issues relate to the stabilization of fossil fuel prices, the reduction of the maximum income tax rate on individuals and land, and transmission line availability.

The U.S. Treasury Department recently made a review of the energy tax credits. However, Congress expressed its continued support of these incentives by circulating resolutions in both the House and Senate that strongly advised the Administration against any possible changes.

In conclusion, this section describes the legislation pertaining to alternatives to the usual federal budget outlays for the commercialization of solar energy technologies by:

1. Providing incentives to R&D limited partnerships or corporations, by means of favorable R&D tax credits, for investment in the alternative energy technologies research, development and demonstration phases, and

* risks in excess of the normal business risks normally taken by the industrial sector.

** In a 'take or pay' contract the buyer pays for a contracted amount of output regardless of delivery. In a 'take and pay' contract the buyer is only committed to purchase the amount actually delivered.

2. Creating the potential for financial intermediaries (solar management companies/limited partnerships) to take maximum advantage of the existing supply-side economic incentives (ACRS and investment tax credits) and alternative energy tax credits.

The former provides for the incentives to carry out advanced R&D, whereas the latter stimulates the technology transfer or commercialization of these technologies. This latter opportunity can only be exercised once sufficient research, development and demonstration phases of a technology have been successfully completed.

Consequently, manufacturers in conjunction with venture capitalists have been provided a potential investment opportunity where the high risks are compensated with attractive economic returns. Already several wind, solar thermal, photovoltaic, cogeneration, and small-scale hydroelectric projects are currently funded using this approach. Whether these incentives will be sufficient both in time and magnitude to accomplish the desired commercialization of the solar thermal central receiver technology is examined in the following sections.

SECTION 4

STUDY ASSUMPTIONS AND INPUTS

Before embarking on the various financing alternatives, it is important to summarize the various underlying economic and financial parameters, and to describe the financial methodology used in the following sections.

Economic and Financial Parameters

The economic and financial parameters used in this study are shown in Table 4-1. A long-term inflation rate of 8.5% was assumed in this analysis. These data are consistent with the EPRI Technical Assessment Guide (1981.)⁵ All subsequent derived financial parameters and escalation rates reflect these basic assumptions. **Because the analysis is performed in terms of real rather than inflated prices, the results of the study are largely independent of the details of the assumed inflation rate.** The real escalation of fuel prices is also taken from the Technical Assessment Guide. However, this document was prepared in late 1981, prior to the present short term stabilization of oil prices. Nevertheless, the depletable nature of oil resources is expected to result in a long-term real price escalation. The range of 2% to 3% long-term average real oil price escalation rate used in this study as recommended by EPRI and others (including the World Bank) seems reasonable in terms of historical price increase experience.

The **levelized fixed charge rate (FCR)** was calculated using the referenced methodology.⁸ The FCR was calculated incorporating the latest tax laws including the new schedules for accelerated depreciation, tax incentives for conventional and alternative energy systems, etc. Since California represents a unique market in terms of the value of alternative generating technologies, this region was treated separately to permit incorporation of the California tax incentives for renewables into the analysis, as shown in Table 4-2.

For utility-owned systems, a 10-year ACRS (Accelerated Cost Recovery System) has been assumed even though no ruling has yet been made by the IRS regarding solar or wind systems.⁵ For the intermediary financed cases a 5-year ACRS was used.⁴

Table 4-1 Economic and Financial Parameters

General Economic Assumptions

Rate of Inflation (Long-term basis)	8.5%
Capital costs escalation rate	8.5%
Operation and maintenance costs escalation	8.5%
Fuel escalation rates (above inflation)	2% - 3%

Financial Parameters*

Cost of capital (after taxes)	12.5%
Marginal corporate income tax rate (Federal)	46.0%
Investment tax credits	10.0%
Solar energy tax credits (through 1985)	15.0%
Other taxes (percentage of capital cost)	1.0% - 2.0%
Insurance rates (percent of capital cost)	0.25%
Operating life	30 years
Accelerated Cost Recovery (ACRS)	5-10 years
Levelized fixed charge rates:	
o Utility	17.5% - 18.5%
o Intermediary	11.5% - 15%

*California region treated separately (Table 4-2)

Table 4-2 Levelized Fixed Charge Rates for Utility and Intermediary Financing in California

Utility Financing Through 1984	Intermediary Financing Through 1983	Intermediary Financing 1985
-FCR-	-FCR-	-FCR-
DEPR LIFE=? 10.00	DEPR LIFE=? 5.00	DEPR LIFE=? 5.00
OPER LIFE=? 30.00	OPER LIFE=? 20.00	OPER LIFE=? 20.00
COST OF CAP=? 12.50	COST OF CAP=? 12.50	COST OF CAP=? 12.50
TAX RATE=? 51.18	TAX RATE=? 51.18	TAX RATE=? 51.18
INV TX CR=? 10.00	INV TX CR=? 10.00	INV TX CR=? 10.00
EN TX CR=? -3.173 *	EN TX CR=? 15.00	EN TX CR=? 15.00
OTHER TX=? 1.00	13.50	-3.173 *
INS RATE=? .50	-3.173 *	11.83
ACRS CH? Y **	25.33	OTHER TX=? 1.00
ACRS: YR1=? 8.20	OTHER TX=? 1.00	INS RATE=? .50
ACRS: YR2=? 13.60	INS RATE=? .50	ACRS CH? Y **
ACRS: YR3=? 11.00	ACRS CH? Y **	ACRS: YR1=? 19.55
ACRS: YR4=? 10.00	ACRS: YR1=? 10.54	ACRS: YR2=? 32.36
ACRS: YR5=? 10.00	ACRS: YR2=? 21.46	ACRS: YR3=? 24.49
ACRS: YR6=? 10.00	ACRS: YR3=? 19.72	ACRS: YR4=? 15.73
ACRS: YR7=? 9.10	ACRS: YR4=? 16.07	ACRS: YR5=? 7.07
ACRS: YR8=? 9.10	ACRS: YR5=? 18.87	FCR: 12.85
ACRS: YR9=? 9.10	FCR: 9.73	
ACRS: YR10=? 9.10		
FCR: 18.44		

* California Sales Tax effect Net of Federal Taxes

** Combined Federal and State Depreciation.

Several of the key economic, financial, operational and systems parameters were varied parametrically in this study, to show the effect of these parameters on the results obtained.

Cost of Capital

The **cost of capital** was determined for both the utility ownership and intermediary financing cases as shown in Table 4-3⁹. For the case of utility ownership, the figures shown are representative of a cross section of U.S. utilities (Standard and Poors, Value Line), albeit modified somewhat to reflect the long-term economic outlook. In the case of intermediary financing, a 25% equity-75% debt financing ratio was assumed to accommodate high leverage financing while maintaining the minimum equity required to take advantage of the various tax credits. This 25% equity position is required to take advantage of both the California and Federal tax incentive legislation.

The derived after-tax cost of capital is 12.5%, for both cases, and reflects the general rate of inflation of 8.5%. Therefore, in real terms, the cost of capital is approximately 4%. It is an interesting coincidence that the after-tax cost of capital is the same for both utility and intermediary financing, even though the individual financing ratios and costs are quite different for the two cases. This is largely coincidental, however.

These financial and economic parameters are varied parametrically in this report to assess the sensitivity or impact of these variables upon the result.

Rate of Return (Modified)

Because of the nature of the cash flows associated with Intermediary financing, which includes both positive and negative cash flows, a **Modified Internal Rate Of Return (MIRR)*** method was used throughout this report. In this method, all positive cash flows are assumed to be reinvested at a **"risk rate"**, which is the required return on recent investments of similar risk, whereas the negative cash flows are discounted at a **"safe rate"**, which reflects the rates of returns earned on liquid investments, such as government securities.

Table 4-3

Cost of Capital*

FINANCING	COST OF CAPITAL		RATIO	WEIGHTED COST
	Before Tax	After Tax		After Tax
UTILITY				
Equity	18%	18%	0.40	7.2%
Preferred Stock	16%	16%	0.10	1.6%
Debt	15%	7.5%	0.50	3.7%
TOTAL				12.5%
INTERMEDIARY				
Equity	20%	20%	0.25	5.0%
Debt	15-20%	7.5-10%	0.75	5.6-7.5%
TOTAL				10.6-12.5%

* Rate of inflation: 8.5% per year

The Modified Internal Rate of Return method is one of several internal rate of return (IRR) alternatives which avoids the drawbacks of the traditional IRR technique. This method of analysis avoids the pitfalls of the discounting of future negative cash flows at large discount rates and extremely high reinvestment rates of early large positive cash flows, resulting in unrealistic high internal rates of return. As a side benefit, the MIRR avoids the problem of multiple solutions associated with conventional internal rate of return calculations involving positive and negative cash flows.

Because of the unproven nature of the solar technologies, a **risk rate of 20 percent** after taxes was specified in the following analyses, which is commensurate with rates of returns required by investors for the projects with similar associated risks. The **safe rate**, used for discounting the negative cash flows encountered in highly levered intermediary financing arrangements, is assumed equal to that earned on cash equivalents of U.S. Treasury Bills or 12 percent (**6% after taxes**).

Insolation Characteristics

The solar insolation pertaining to the various potential solar system regions is shown in Table 4-4 in terms of total annual solar input. These data represent the latest information available from Sandia National Laboratories¹⁰ (1979) and incorporate significant changes over previously available data bases.

In particular, the Sandia data for direct beam radiation in regions C and D are substantially lower than previously estimated. These low values essentially preclude the Southeastern and Northeastern U.S. regions (C and D, respectively) from serious consideration as potential solar thermal central receiver markets. Only regions A and B, corresponding to the Western and Southwestern U.S. have sufficiently high levels of direct insolation for potentially significant market penetration of the solar thermal central receiver systems.

* Also called Financial Management Rate of Return (FMRR)

Table 4-4 Insolation Characteristics of the Solar Markets¹ (kW-hr/m²-year)

<u>MARKET AREA</u>	<u>SOLAR THERMAL CENTRAL RECEIVER SYSTEMS²</u>
Region A Inyokern, CA	2,546
Region B Phoenix, AZ	2,529
Region C Miami, FL	1,389
Region D Boston, MA	1,197

¹ Source: E. Boes (1979), Sandia National Laboratories, Albuquerque, NM

² Direct beam radiation, 2-axis tracking

SECTION 5

FINANCING ALTERNATIVES AND INCENTIVES

As a direct result of the various tax incentives and regulatory legislation provisions discussed in the previous section, the financing alternatives for solar facilities have been greatly enhanced. The combination of the **Public Utility Regulatory Policies Act of 1978**, the **Crude Oil Windfall Profit Tax of 1980**, and the **Economic Recovery Tax Act of 1981** effectively makes non-utility or third-party ownership of solar plants significantly more attractive than utility ownership. This comes about because several of these tax incentive and regulatory provisions cannot be utilized by the regulated utility companies.

In addition, the utility industry is subject to considerable regulatory and capital financing constraints, and thus financing and construction of new generating facilities in general have been very expensive and time consuming. This financing will be even more difficult for the capital intensive and largely unproven solar technologies. The inherent incremental capacity additions and associated cash flow requirements, possible due to the modularity of the various solar technologies, ameliorate somewhat the capital incentive nature of such facilities, by reducing the Allowance-for-Funds-During-Construction (AFDC) and excess reserve requirements. These benefits make solar technologies attractive with regard to utility expansion planning. **However, the utility industry by its very nature provides for the reliable delivery of electric power and typically is not involved directly in the development of the underlying technologies.**

Consequently, this section will explore some of the potential financial alternatives in relationship to the development and commercialization of the solar technologies, and specifically, with regard to the solar thermal central receiver concept.

These financial alternatives must be viewed in combination with the investment decision. This latter **investment decision** is based upon various factors, including: (1) economic considerations, notably, the ability of the project to generate desirable cash flows, (2) technical considerations including, low operating and maintenance costs,

reliability in operation and long system lifetimes, and (3) other considerations, including manufacturers' warranties, legal and environmental constraints and compatibility with user needs and business strategy.

The **financing decision** focuses upon the best financing mix or capital structure commensurate with the associated business risks such as to maximize the value of the investment in relationship to the overall portfolio of assets.

In the case of intermediary financing, the interrelationship between the investment and financing decision is less clearly defined, since the user and owner of the asset are frequently separated. It must be emphasized that the technical and economic shortcomings of a particular investment cannot be overcome by the financial considerations and benefits associated with the investment alone! Especially with regard to the associated tax benefits, care must be taken that the investment has economic substance; otherwise the Internal Revenue Service may challenge the validity of the entire venture.¹¹

Following is a discussion of the most important generic alternative financing structures, and the associated potential government participation. Obviously, the specific arrangements can have many variations and become quite complex. This study therefore only addresses the generic structures.

The central issues for each of these financing alternatives are:

- (1) What financial alternative arrangements are most suitable for the solar technologies, in relation to the various legislation and the manufacturers and users interests and requirements?
- (2) How do these financial arrangements benefit the development and transfer of the solar technologies in general and the solar thermal central receiver concept in particular?
- (3) What are the requirements other than the favorable tax and regulatory laws for these financial alternatives to effectively participate in this process?

- (4) Are the various Federal and State legislative and regulatory incentives sufficient in scope and time period to permit the technology transfer to occur?
- (5) What are the roles and strategy of the Department of Energy Program commensurate with these financing alternatives?

Potential Solar Electric Power Systems California Market Penetration

California presently offers a unique market for grid-connected solar electric technologies. Thus, the initial market penetration for solar thermal central receiver systems is assumed to occur in California as a result of a combination of highly favorable conditions.

Specific market advantages of California include high insolation levels, high fuel prices and significant State tax incentives for renewables. California provides an **additional 25 percent State tax credit** and also permits **double declining depreciation of the remaining 75 percent over 3 years**. It also has a favorable political and regulatory climate as well as solar-oriented and experienced utilities. However, the California special tax incentives are currently scheduled to expire at the end of 1983.

Consequently, the following intermediary financing analyses assume conditions typical of California. Subsequently, the impact of changing these various assumptions was assessed by parametrically varying selected key parameters.

Utility or User Financing

As was mentioned earlier direct financing of solar technologies during the early commercialization phase by the utility incentives is unlikely. This risk aversion also includes debt surrogates such as take or pay contracts.

However, to establish the basis for economic comparisons, and to cover the solar technology financing subsequent to the risky technology transfer time period and special tax incentive availability, the allowable or break-even cost for solar thermal central receiver plants was calculated, using traditional utility financing.⁸

The economic, financial, operational and technical parameters corresponding to this direct utility financed solar thermal central receiver plant are summarized in Table 5-1. As can be seen, the base case assumes installation in California, after the state energy tax credits have expired. The 6-cents/kWh (1982 dollars) busbar cost corresponds to an oil price delivered to the utility of \$ 6/MBtu (at a heat rate of 10,000 Btu/kWh) or \$ 34.80/bbl., assuming no capacity credit for the solar plant. The busbar cost escalation is governed by oil price escalation, which is assumed at 2%/year real (10.67%/year apparent) over the long-term.⁵

The financial parameters all reflect the basic 8.5%/year inflation rate assumed, and thus are considered in real terms. The cost of capital of 12.5% (after taxes) and the associated fixed charge rate of 18.5% reflect this basic inflation rate.

The fixed charge rate was computed using the methodology described in Reference 8, with changes made to reflect the new ERTA ACRS (depreciation) on treatment, assuming a 10-year ACRS tax life for utility-owned renewables (EPRI Technical Assessment Guide⁵), and adjusted to include straight-line state income tax depreciation. Also included in the fixed charge rate is the combined Federal and State marginal tax rate of 51.18%, the general investment tax credit of 10%; a sales tax of 6.5% (3.2% net of Federal taxes), property taxes of 1%, and insurance costs of 0.25%/year.

The capacity factor of 30% assumes a Rankine cycle central receiver plant with 3-hour storage and 6.9 kWh/m²-day annual average direct insolation typical of Inyokern California.¹² Operating and maintenance costs are assumed at \$25/kW-year with an escalation rate of 8.5%/yr.^{5,12}

The resulting allowable central receiver plant cost is **\$2424/kW(pk)** (1982\$) for this utility financed case.

Alternatively the utility industry could establish an independent entity for the purpose of financing a specific solar technology, similar to the project type previously deployed for certain nuclear plants. The financing is typically achieved by means of a significant amount of debt financing with the plant itself serving as collateral and the cash flows generated by the plant providing the debt servicing. However, since both the cash flows

Table 5-1 Utility Financing - Solar Thermal Central Receiver Plant
(1982\$)

Parameter	Value
Inflation	8.5 %/year
Marginal Federal Tax Rate	46.0 %
Marginal State Tax Rate	9.6 % (California)
Combined Marginal Tax Rate	51.18 %
Investment Tax Credit	10.0 %
Federal Energy Tax Credit	---
State Energy Tax Credit	---
Property Tax	1.0 %/year
Sales Tax	6.5 %
Depreciation	ACRS
Tax Life	10 years
Cost of Capital	12.4 % (after taxes)
Fixed Charge Rate	18.5%
Plant Size	100 MW(pk)
Year of Installation	1985/86
Base Year Dollars	1982
Operational Plant Life	30 years
Capacity Factor	30 %
Capital Cost Escalation	8.5 %/year
Busbar Energy Cost	\$ 0.06 /kW-hr
Avoided Cost Escalation	10.67 %/year (2.00 % real)
O&M Costs	\$ 25/kW-yr
O&M Escalation	8.5 %/year
Insurance Costs	0.25 % of plant cost
Allowable Price	\$ 2424/KW(pk) installed

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Investment Tax Credit	10.0 %
Federal Energy Tax Credit	---
State Energy Tax Credit	---
Property Tax	1.0 %/year
Sales Tax	6.5 %
Depreciation	ACRS
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O&M Escalation	8.5 %/year
Insurance Costs	0.25 % of plant cost
Allowable Price	\$ 2424/KW(pk) installed

generated and the collateral value of early solar plants are uncertain, the associated assessment by the lending institutions will preclude this type of financing. Furthermore, solar plants financed by the utility companies in this manner are still classified as public utilities and are thus subject to regulation which precludes specification under PURPA and thus allowance under COWPA for the additional 15% energy tax credit. This latter exclusion makes the financing by intermediary organizations significantly more attractive during the technology transfer period than by direct or indirect utility financing.

Another possibility for utility participation would be leasing the solar facility from an intermediary purchaser (**purchase-lease option**). This option has several advantages to the utility over direct purchasing to include being able to pass along the tax credits to a lessor under ERTA and in return potentially realize improved cash flow benefits. These include reduced lease payments, as well as improved balance sheet treatment. However, solar systems do not qualify for the additional 15% alternative energy tax credit if they are leased to public utilities.

Consequently, the direct or indirect financing of solar systems by the electric utility companies does not appear to be a very likely situation in the near-term technology transfer time period.

Consequently, the remainder of this report will deal with those financial options that can best benefit from all the various tax incentives available, and thus lend themselves to intermediary or third-party financing during the technology transfer time period that these incentives are available.

R&D Limited Partnerships

The funding for research and development of new solar technologies can benefit from the specific tax incentive legislation enacted. The ERTA 1981 provides for a 25% R&D tax credit, providing the R&D expenses incurred during a given tax year are more than the average of these expenses during a base period (generally the last three years prior to the year in which the credit is taken).

As a result of this legislation, the limited partnership structure can provide for all or part of the required R&D financing. The generic structure of the R&D limited partnership is shown in Figure 5-1. In general, the general partner is the manufacturer or corporation with the specific research and development needs. The limited partners provide for all or part of the financing in return for the tax benefits, royalties, and potential future capital appreciation by means of future equity participation as a result of the potential option of royalty conversion into equity. The limited partnership participation can further be enhanced by leveraging the equity financing with debt financing. Because of the inherent risks associated with most R&D, the lender may require loan guarantees from either or both the general and limited partners. Also as a result of the complicated legislation concerning such financial arrangements, the R&D limited partnership must be structured with great caution.

Besides the indirect participation of the government by means of tax credits, the government can directly participate, through the Department of Energy, by jointly funding (cost-sharing) specific research and development of high risk, high pay-off solar technology concepts, or indirectly by providing loan guarantees. This will significantly reduce the risk exposure to the limited partners. At the same time, the Department of Energy is leveraging its constrained budget resources into longer-term, high-risk but potentially high pay-off research and development, commensurate with the new government policy guidelines. This direct participation by the government is especially important for the long-range technology proof-of-concept type research and development preceding the commercialization of a specific technology.

Also important is a liberal policy of the government with respect to patent rights, thus providing incentives to industry undertaking the expensive R&D for developing new concepts, thereby facilitating the technology development and subsequent transfer process.

Manufacturer Financing (Sale-leaseback)

Because of the direct economic interest of the manufacturers of solar technologies, there is a strong interest on their part to arrange for the required financing, directly or indirectly, and sell the power under a long-term contract to the end-user (utility). Typically, the end-user may or may not be interested in participating in the financing of

Figure 5-1

R&D LIMITED PARTNERSHIP STRUCTURE

the project. Since electric utility companies cannot take advantage of the energy tax credits, combined with their current financing problems, an avoided cost power purchase agreement with a subsequent option to purchase the facility may be quite attractive to a utility.

The manufacturer in financing a solar project can benefit in various ways:

- (1) By providing a market for its products,
- (2) By having control over the design, costs and production write-offs, assuming vertical integration,
- (3) By making use of the various tax credits available (directly or indirectly).

The manufacturers have both direct and indirect financing options available. Under the **direct financing**, the manufacturer builds, finances and owns the solar plant directly, thereby assuring a ready market while taking advantage of the various tax incentives available. The manufacturer enters into a long-term contract with the electric utility company to purchase the energy generated at or near avoided cost as established under PURPA legislation. In this agreement, the utility may provide the site, interconnects and operating and maintenance for the plant.

However, in the direct financing approach the manufacturer assumes all the business and financial risks associated with new technology commercialization as well as the immediate impact of this risk exposure on the valuation of the company. The effect of leveraging by means of debt financing of part of the required funding further aggravates this risk exposure. In order to be able to take these risks, the manufacturer must be a large, profitable and diversified company with large cash flows and high tax liabilities, or be a subsidiary of such a company.

Typically, since most solar companies do not fall in the above category and even when they do, they are not inclined to assume all the risks associated with a full-scale solar project. This is especially true when the solar project is large and expensive, as is the case with solar thermal central receiver plants, which makes the total risk exposure quite large.

In this case, the manufacturer can sell the tax credits associated with the project under a **sale-leaseback** arrangement. Under this arrangement the manufacturer, often in conjunction with an architect-engineering firm, builds the solar facility and enters into a long-term energy purchase agreement with the local electric utility company, essentially similar as under the direct financing approach.

However, the manufacturer arranges for the financing with an intermediary or third-party by selling the solar facility to this intermediary and then leasing the facility back. This way the intermediary can take full advantage of the various tax incentives associated with the project, under the 'safe-harbor' provisions of the Economic Recovery Tax Act, while providing attractive leasing terms to the manufacturer.

Such a typical indirect sale-leaseback financing arrangement is shown in Figure 5-2. As shown, the intermediary structure can be organized as a general or limited partnership, where the general partner(s) can be a corporation(s). This partnership will receive lease payments from the manufacturer in return for providing the project financing. To minimize the financial and technical risks associated with the project, the intermediary may require various performance guarantees and equipment warranties.

Furthermore, the intermediary can leverage its financial position by arranging for debt financing, as long as it maintains the minimum 25 percent equity position as required by the ERTA. The ability of the intermediary to provide the debt servicing will determine the interest rates associated with this debt financing.

This risk is minimized by the various debt guarantees provided to the lender, as well as the soundness of the solar facility to serve as security or collateral. This ability of the solar facility to provide sufficient collateral may be insufficient, especially in the beginning, when the facilities are new and unproven. Consequently, the intermediary (or manufacturer) must typically provide debt service guarantees other than plant collateral.

In the case where the intermediary is a limited partnership, the various tax benefits and cash flows are passed along to the limited partners in return for providing the equity financing (and debt guarantees). The general partner takes the various risks and

Figure 5-2

SALE/LEASE BACK STRUCTURE

5-11

provides for the general management and financial arrangements of the facility in return for a management fee.

Obviously, the interests of the various parties are to earn as high a return with as low a risk exposure as possible. Fortunately, with the Federal tax incentives available through 1985, the financial returns for such a sale-leaseback arrangement can be quite attractive for all parties involved. The lender can obtain attractive rates commensurate with the risks for providing the debt financing. The manufacturer has a ready market for its solar products, without having to provide all the financing or assume all the associated risks. The architect-engineering firm gets its fees in addition to gaining valuable experience in the design and construction of the new solar technologies. The utility is provided the electric power generated at acceptable costs, while it gains operating experience with the new technologies at no inherent risk. Finally, the intermediary organization for arranging the financing can earn a substantial return on the equity provided.

This can be readily ascertained from the financial analyses associated with the sale-leaseback intermediary financing shown in Tables 5-2 and 5-3. The analysis in Table 5-2 was conducted for a facility constructed and financed in California prior to December 31, 1983, thereby being able to take full advantage of both the federal and state tax incentives, and Table 5-3 shows the results of the financing assuming no state tax incentives through December 31, 1985 with only federal tax incentives available.

As can be seen, these analyses assumed a 5-year project period with 25/75 percent equity/debt financing. Non-recourse financing was assumed for this analysis, which may be difficult to obtain in practice without some additional concessions or without further investor confidence in this technology as a result of additional demonstrations. **Most importantly, this intermediary analysis was conducted for a non-dimensional plant price, which means that the results are applicable for any plant cost regardless of the amount of energy produced (\$1000/kW in 1982 \$, actual price is any multiple of this figure)!** Furthermore, at the end of the 5-year period, it was assumed conservatively that the plant was sold back to the manufacturer for one dollar. Because of the limitation in scope of this study and the large variability in the specific conditions associated with the individual manufacturers, this analysis only addresses the third-

Table 5-2 Sale/Leaseback with Federal and California Energy Tax Credits (1983)
(Non-Dimensional)

Electric Power Plant Financial Analysis

Description:

Syst. Description

System Size 1 MW
Operational year 1983
Base Year Dollar 1982
Inflation 8.50 %/yr
Type Financing SI-lease

Variables:

Project Period 5 years
System Price 1000 \$base/kw
Interconnect Cost 0 \$base/kw
Price Escalation 8.5 %/yr
Capacity Factor 30 %
Avoided Cost 0 \$base/kwh
Revenue Escalation 10.67 %/yr
Lease Payments 0 \$oper/yr
Lease Escalation 0 %/yr
Fixed O&M 0 \$base/kw-yr
Var O&M Costs 0 \$base/kwh
O&M Escalation 8.5 %/yr
Insurance Costs .25 % of price
Property Taxes 1 % of price
Sales Taxes 6.5 % of price
Marginal Tax Rate 51.18 %
Invest. Tax Rate 10 % in yr0 0 % in yr1
Energy Tax Rate 28.5 % in yr0 0 % in yr1
Debt % of Capital 75 %
Cost of Equity 20 %/yr
Loan Interest 15 %/yr
Loan Term 5 years

Safe Rate of Retrn 6 %/yr
Depreciation rates 18.54 21.46 19.72 18.87 18.87 0

Electric Power Plant Financial Analysis								Sale Leaseback				
CASH FLOW STATEMENT (\$1000)												
Year	Revenue	Lease Expense	O&M Expense	Insur Cost	Property Sls Tax	Interest Expense	Deprec. Expense	Taxable Income	Income Tax	Princ. Payment	Tax Credits	Cash Flow AT
1983	-271(invest)		0		71		201	-272	-139		418	215
1984	0	243	0	3	11	122	233	-126	-64	121	0	51
1985	0	243	0	3	11	104	214	-89	-45	139	0	32
1986	0	243	0	3	11	83	205	-59	-30	160	0	16
1987	0	243	0	3	11	59	205	-33	-18	184	0	4
1988	0	243	0	3	11	32	0	198	101	211	0	-115
1989	0(sale)					0		0	0	0		0
FV of return		724.0951	PV of investment			86	Modif IRR		53.24	Cost	1000	

Table 5-3 Sale/Leaseback with Federal and California Energy Tax Credits (1983)
(Non-Dimensional)

Electric Power Plant Financial Analysis

Description:

Syst. Description
System Size 1 MW
Operational year 1985
Base Year Dollar 1982
Inflation 8.50 %/yr
Type Financing SI-lease

Variables:

Project Period 5 years
System Price 1000 \$base/kw
Interconnect Cost 0 \$base/kw
Price Escalation 8.5 %/yr
Capacity Factor 30 %
Avoided Cost 0 \$base/kwh
Revenue Escalation 10.67 %/yr
Lease Payments 0 \$oper/yr
Lease Escalation 0 %/yr
Fixed O&M 0 \$base/kw-yr
Var O&M Costs 0 \$base/kwh
O&M Escalation 8.5 %/yr
Insurance Costs .25 % of price
Property Taxes 1 % of price
Sales Taxes 6.5 % of price
Marginal Tax Rate 51.18 %
Invest. Int Rate 10 % in yr0 0 % in yrf
Energy Tax Rate 15 % in yr0 0 % in yrf
Debt % of Capital 75 %
Cost of Equity 20 %/yr
Loan Interest 15 %/yr
Loan Term 5 years

Safe Rate of Retrn 6 %/yr
Depreciation rates 19.55 32.36 24.49 15.73 7.87 0

Salvage Value 0 base\$/kw

Electric Power Plant Financial Analysis										Sale Leaseback			
CASH FLOW STATEMENT (\$1000)													
Year	Revenue	Lease Expense	O&M Expense	Insur Cost	Property Tax	Interest Expense	Deprec. Expense	Taxable Income	Income Tax	Princ. Payment	Tax Credits	Cash Flow AT	
1985	-319(invest)		0		83		230	-333	-170		319	87	
1986	0	286	0	3	13	144	413	-287	-147	142	0	131	
1987	0	286	0	3	13	122	313	-165	-85	163	0	69	
1988	0	286	0	3	13	98	201	-29	-15	188	0	-1	
1989	0	286	0	3	13	70	101	100	51	216	0	-67	
1990	0	286	0	3	13	37	0	233	119	249	0	-135	
1991	0(sale)					0		0	0	0		0	
FV of return	607.5311				PV of investment	155		Modif IRR		31.44	Cost	1000	

party financing arrangement, and does not include the manufacturers' financial analyses.

The federal investment and energy tax credits of 10 and 15 percent were included for both cases, as well as the 25 percent (13.5 percent after federal taxes) California energy tax credit in the first case. Also included was an adjustment of the 6.5 percent (3.172% after taxes) California sales tax on the facility. All cases incorporate the combined federal and state (California) depreciation schedules (weighted) appropriate for the year of installation, as well as the combined marginal corporate income tax rate of 51.18%. Furthermore, except where noted, the tax credits and sales taxes are accounted for in the year of installation (year 0).

Prior to and through 1983, the 5-year federal ACRS schedule was adjusted to account for the California state income tax solar plant depreciation, which corresponds to a double-declining balance schedule for the remaining 75 percent of the plant cost after the tax credit. After 1983 a sum-of-the-years depreciation schedule was assumed for the California income tax calculations. Annual expenses correspond to a 1 percent annual property tax assessment and a 0.25 percent insurance rate. Finally, the lease payments were assumed equal to the debt service payments.

Using the modified internal rate of return (MIRR) approach previously described, combined with a safe rate of 6 percent and a risk rate of return of 20 percent after taxes, the MIRR for the sale-leaseback intermediary financing are 27.3 percent and 19.3 percent after taxes for the 1985 and 1983 (including California tax credits) cases, respectively, independent of the price paid for the solar facility or the revenues derived from electric energy sales. Corporations or wealthy investors, making regular withholding tax payments, can immediately realize these tax credits by reducing their withholding taxes accordingly during year 0. This effectively increases the MIRR substantially to 53.2% and 31.4%, respectively, for these cases as shown in Tables 5-2 and 5-3. The actual MIRR for various investors lies somewhere in between these numbers.

This is a very high rate of return as compared with the associated risks (greater than the 20 percent risk rate specified), and is a **direct result of the combination of federal**

and state tax incentives provided. Without these incentives, this type of intermediary financing is no longer attractive, as shown in Table 5-4.

Consequently, this example shows the importance of the government underwriting of the extraordinary risks associated with the transfer of the new energy resource technologies by providing the indirect program support in the form of tax incentives.

The results of these analyses are summarized in Table 5-5 for the various cases analyzed. The effects of the various tax credits can clearly be seen from this table. The elimination of both the federal and state tax credits in 1986 and beyond, as currently scheduled, no longer makes the financing of solar facilities attractive to intermediary financed sale/leaseback arrangements. (MIRR of is much less than the required risk rate of 20%.) The elimination of the California solar energy tax credits after 1983 makes the sale/leaseback financing by intermediaries somewhat less attractive, especially if the tax credits cannot be taken in the year of installation (year 0).

Consequently, the financial window provided by the tax incentives (through 1985) is rather short in relationship to the current development status of the solar thermal central receiver technology. An extension and subsequent gradual decrease of these tax incentives through at least 1990 will be necessary to effect the successful transfer of this (and other) solar technology.

Table 5-4 Sale/Leaseback Without Energy Tax Credits (1986)
(Non-Dimensional)

Electric Power Plant Financial Analysis

Description:

Syst. Description
System Size 1 MW
Operational year 1986
Base Year Dollar 1982
Inflation 8.50 %/yr
Type Financing SI-lease

Variables:

Project Period 5 years
System Price 1000 \$base/kw
Interconnect Cost 0 \$base/kw
Price Escalation 8.5 %/yr
Capacity Factor 30 %
Avoided Cost 0 \$base/kwh
Revenue Escalation 10.67 %/yr
Lease Payments 0 \$oper/yr
Lease Escalation 0 %/yr
Fixed O&M 0 \$base/kw-yr
Var O&M Costs 0 \$base/kwh
O&M Escalation 8.5 %/yr
Insurance Costs .25 % of price
Property Taxes 1 % of price
Sales Taxes 6.5 % of price
Marginal Tax Rate 51.18 %
Invest. Tax Rate 10 % in yr0 0 % in yr1
Energy Tax Rate 0 % in yr0 0 % in yr1
Debt % of Capital 75 %
Cost of Equity 20 %/yr
Loan Interest 15 %/yr
Loan Term 5 years

Safe Rate of Retrn 6 %/yr
Depreciation rates 21.35 31.46 23.59 15.73 7.87 0

Salvage Value 0 base\$/kw

Electric Power Plant Financial Analysis									Sale Leaseback			
CASH FLOW STATEMENT (\$1000)												
Year	Revenue	Lease Expense	O&M Expense	Insur Cost	Property Sls Tax	Interest Expense	Deprec. Expense	Taxable Income	Income Tax	Princ. Payement	Tax Credits	Cash Flow AT
1986	-346(invest)		0		90		296	-386	-198		139	-100
1987	0	310	0	3	14	156	436	-299	-153	154	0	136
1988	0	310	0	3	14	133	327	-167	-85	177	0	68
1989	0	310	0	3	14	106	218	-31	-16	204	0	-1
1990	0	310	0	3	14	76	109	108	55	234	0	-73
1991	0	310	0	3	14	40	0	252	129	270	0	-146
1992	0(sale)					0		0	0	0		0
FV of return	399.2914			PV of investment		268	Modif IRR		8.27	Cost		1000

**Table 5-5 Sale-Leaseback Intermediary Financing¹
Modified Internal Rate of Return**

Investment Tax Credit	Energy Tax Credit		Expiration Date	MIRR (Percent) ³ After Taxes	
				Year 0	Year 1
Federal 10%	Fed & State ²	28.5%	12/31/83	53.2%	27.3%
Federal 10%	Federal	15.0%	12/31/85	31.4%	19.3%
Federal 10%	Federal	0.0%	unknown	8.3%	8.6%

¹ Lease Payments equal to Debt Servicing Payments

² California

³ Independent of System Price or Energy Revenues.
Risk Rate - 20% after taxes; Safe Rate - 6% after taxes

Intermediary Financing

Because of the high technological and financial risks associated with the commercialization of new, as yet unproven, solar technologies, manufacturers frequently cannot or will not take all the risks themselves.

Fortunately, because of the various tax incentives and regulatory legislative provisions discussed previously, the various incentives provided make it attractive for intermediaries or third parties to assume the associated risks (especially through 1985).

The most common structure for intermediary financing is a general or limited partnership. In contrast to a corporation, where tax credits and/or losses do not directly flow through to shareholders, a partnership can pass on the tax credits and/or losses from its activities to the partners. Furthermore, in a limited partnership, the limited partners are not personally liable for the financial liabilities of the partnership beyond the amount invested. Thus, a limited partnership provides (high income) taxpayers the opportunity to incur high initial tax deductions often in excess of the amount invested in the partnership, and at the same time benefit from the tax credits provided, without incurring personal financial liability beyond the amount invested.

Consequently, most intermediary financing arrangements or tax shelters are limited partnerships. This gives the general partner the management control of the activity, while providing a tax shelter without personal liability or responsibility of the operation for the limited partners.

A potential structure of a limited partnership is shown in Figure 5-3 in which the partners only contribute part of the required funding, and the remaining financing is provided through 'non-recourse' loans (i.e., loans for which the partners bear no liability for repayment). Such 'non-recourse' borrowing is made possible for solar projects by the Economic Recovery Act of 1981 which exempts the renewable energy properties that qualify for the energy investment tax credits from the 'at-risk' limitations.

Without this exception, the deductions of the partners would be limited to the amount 'at-risk' in the venture, thus restricting the use of 'non-recourse' financing.

However, in practice, the partnership may still have to provide for loan guarantees in order to secure debt financing at reasonable rates, since the inherent value assessment of the early unproven solar plants most likely is insufficient to serve as sufficient collateral.

The general partner can be structured as a corporation to include entrepreneurs, manufacturers and users (utilities). To facilitate the financing, the general partner as an intermediary must contract with the various parties and secure the various guarantees and warranties associated with purchase and installation of the equipment. Furthermore, the general partner must make long-term lease or power purchase agreements with the end-user or utility company. For the venture to be successful, each party to the venture must obtain the required returns commensurate with the associated risks. Limited partnerships are attractive tax shelters for individuals in high tax brackets.

With regard to the financing of solar thermal central receiver projects, the tax shelter arises from the combinations of highly leveraged financing (debt/equity of 75/25) and tax incentives available, to include the 15% federal solar energy tax credit in addition to the regular 10% investment tax credit, a 5-year ACRS depreciation of the plant assets, various state tax incentives, and large interest deductions.

Risks and Benefits of the Various Parties

The risks and returns for the various parties involved in the intermediary financing arrangements will vary substantially, depending upon the negotiation terms and subsequent contractual relationships. Obviously, each party will attempt to realize the highest returns with the lowest possible risk exposure. However, typically the negotiations will balance the risks commensurate with the returns for each of the parties involved.

Manufacturer

The manufacturer, possibly in conjunction with an architect/engineering firm, will provide for turnkey installation of the solar facility at a fixed price. Furthermore, the manufacturer may be required to provide for specific product warranties and service

contracts for specified time periods, as well as insurance protection against major catastrophies.

The benefits to the manufacturer clearly are the establishment of production capability with an early share of the solar system market. During the early years (through 1985), the extraordinary risks associated with this early market penetration are underwritten to a large extent by the energy tax credits available. The intermediary financing made possible by these tax credits thus provides for the sale of systems and equipment at prices substantially above the basic intrinsic value, which is commensurate with the high initial start-up costs associated with new technology development and commercialization.

The risks to the manufacturer associated with structure are cost overruns with regard to fixed price and extraordinary expenses in connection with the warranties and guarantees provided. Furthermore, major equipment failures and repairs as well as excessive servicing needs are major risk factors.

Architect/Engineer

The benefits for the architect/engineering firm are firsthand experience with the installation of new technology systems, which will provide an early market advantage over other A&E firms. The fees associated with these services will be commensurate with other projects, consequently, the benefits are substantial. The risks are cost overruns associated with fixed price fees (not if on a percentage basis) and warranties provided regarding the services performed associated with the untried new solar technologies.

Intermediary - General Partners

The primary role of the intermediary general partners is to organize the entire project and arrange for the contractual terms between the various parties involved. Thus, the general partners must bring together the manufacturer, architect/engineering firm, utility company (user) and the financial participants (equity underwriters and lenders) of the project. Subsequently, the intermediary general partners must provide the overall technical and financial management of the solar facility.

As can be seen from Figure 5-3, the contractual arrangements are numerous and complex, requiring multifaceted knowledge and negotiating skills. The benefits are many, to include management fees, potential royalty payments, and high return on equity due to very good cash flows as a result of the many tax incentives provided.

The general partners do assume the risks associated with the project that are not contractually covered by the other participants, or those arising from contractual defaults. Also the general partners must provide for the front money to organize and complete negotiations of the project, which obviously is at risk (but which may subsequently be shared by the limited partners).

Intermediary - Limited Partners

The intermediary limited partners provide for the majority of equity funding of the project, as well as potential debt service guarantees or collateral in case of highly leveraged financing. The limited partners do not participate in the management of the project, and their liability or risk is limited to the equity funds and debt guarantees provided.

The benefits consist of high after-tax equity returns due to the flow-through of the various tax incentives associated with the project (Tax shelter). The major risk of the limited partners is associated with mismanagement of the project, debt guarantees, major unexpected failures of the system, or unforeseen changes in the tax, regulatory or market areas.

Lender

The lender provides the debt financing for the project and receives a rate of interest commensurate with the risk taken. These risks are highest for non-recourse financing without debt guarantees, since the collateral value of the solar plant is uncertain. Consequently, the lender may require certain debt guarantees to lower the risk exposure in return for reduced interest charges.

Utility Company or User

Under PURPA legislation, the utility industry must purchase the electric energy generated by the solar facility at avoided cost. Even without this legislation, the utility benefits by this intermediary financing approach by having electric power available

without the associated capital investment requirements. During this period of high financing costs, especially in view of the capital intensive nature of solar plants, the utility industry is thus provided with firsthand experience with solar plant development and operation without the commensurate risks of financing the facility. Furthermore, the utility typically has the option to purchase the facility at the end of the project period at fair market value or below. This latter value will be substantially below the initial price of the facility, especially during the early technology transfer phase. Finally, the utility benefits indirectly by participation in solar projects from a public relations (and PUC) point of view.

In a typical arrangement, the utility may provide the plant site, grid interface, and potentially the operation and maintenance requirements in return for electric energy purchases at attractive rates below avoided costs. The risks to the utility company associated with the intermediary financed project are minimal, unless the utility sponsors the project by providing services below cost or purchasing power in excess of the avoided costs.

Economic Analysis of Intermediary Financing

To demonstrate the economic benefits of intermediary or third-party financing of commercial solar projects, the breakeven installed price was calculated based upon providing a **modified internal rate of return (MIRR) of 20 percent (after taxes)**. As explained previously, this methodology was selected to properly account for the various large positive and negative cash flows that occur throughout the project period. The positive cash flows are assumed to be reinvested at an equivalent risk rate (after taxes), whereas the negative cash flows are discounted at a safe rate (after taxes), which is equivalent to the rate of return of liquid investments.

The various assumptions describing the economic, financial, operational and systems parameters for the base case are shown in Table 5-6. In the subsequent section, each of the key variables was varied parametrically to provide insight into the sensitivity of these parameters upon the results obtained for the base case.

These results can then be compared with the traditional utility financing to show the impact of the various tax and regulatory legislation and the associated potential intermediary financing on the solar technology transfer.

As mentioned before, the base case is assumed to be a plant sited in the high insolation regions of California, with start of operations on or before December 31, 1985. This solar thermal central receiver plant will thus experience the benefits of high insolation and high displaced fuel values, and thus attractive avoided cost contracts. For the base case an avoided cost of \$0.06/kWh (1982\$) or 60 mills/kWh is assumed, corresponding to \$6.00/MBtu (at 10,000 Btu/kWh heat rate) or \$34.80/bbl of oil equivalent, with a real escalation rate of 2% per annum.

Furthermore, the intermediary financing could benefit from the very favorable state tax incentives if extended beyond December 31, 1983 (not included in the base case).

As can be seen, all the financial and economic parameters reflect the basic inflation rate assumption of 8.5%/year., and are similar to the previously described utility financed case (Table 5-1).

The differences are that the Federal (and possibly State) energy tax credits can be utilized by the intermediary financing syndicate, as well as the shorter 5-year ACRS plant depreciation for Federal income tax purposes (and potentially a 3-year double-declining depreciation of the remaining 75% (after tax credit) plant costs for State income tax purposes).

The intermediary financing is highly leveraged (debt/equity ratio-75/25) with a loan interest of 15% and a 20 year term. A 20-year project term is also assumed, which is long for intermediary financing arrangements. The 25% equity is the minimum equity investment as required under the safe-harbor provisions ERTA.

To make the investment attractive for intermediary financing, a required equity rate of return equal to other investment opportunities of similar risk must be provided. This required risk rate is assumed to be 20%/year (after taxes), which constitute the reinvestment rate of all positive cash flows. The negative cash flows are discounted at

Table 5-6 Intermediary Financing, Solar Thermal Central Receiver Plant
(1982\$)

Parameter	Value
Inflation	8.5%/year
Marginal Fed. Tax Rate	46.0%
Marginal State Tax Rate	9.6%
Combined Marginal Tax Rate	51.18%
Investment Tax Credit	10.0%
Fed. Energy Tax Credit	15.0%
State Energy Tax Credit	0%
Property Tax	1.0%/year
Sales Tax	6.5%
Depreciation	ACRS
Tax Life	5 years
Required Risk Rate of Return	20%/year (after tax)
Safe Rate	6%/year (after tax)
Plant Size	25 MW
Year of Installation	1985
Base Year Dollars	1982
Project Life	20 years
Debit/Equity Ratio	75/25
Cost of Equity	20%/year (after tax)
Loan Interest	15%/year
Loan Term	20 years
Capacity Factor	30%
Capital Cost Escalation	8.5%/year
Avoided Cost Rate	\$0.06/kWh
Avoided Cost Escalation	10.67%/year (2% real)
O&M Costs	\$25/kW-year
O&M Escalation	8.5%/year
Insurance Costs	0.25%
Resale/Salvage Value	0
Allowable Price	\$4100 /kW(pk) installed.

a safe rate similar to the yield of U.S. Treasury Bills or 6% per year after taxes (12% before taxes).

The allowable installed solar thermal central receiver plant price is calculated at the required modified internal rate of return of 20% (after tax). For the base case, the allowable installed price is \$4100/kW(pk). The details of the cash flows calculated for the base case are shown in Table 5-7. As can be seen, the net present value of these cash flows is zero when discounting the positive cash flows at the risk rate and the negative cash flows at the safe rate.

It should be noted that the tax credits and first year depreciation are taken by the investors in the year of installation (1985). This reflects the ability of high tax bracket investors to reduce their periodic withholding tax payments by these amounts prior to the year in which the return is filed. If these tax credits were taken during the first year of operation, the allowable installed price would be reduced to \$3,309.

The allowable installed price of \$4100/kW(pk) for the intermediary financing case is much higher than for the previously determined utility financed \$2424/kW(pk) base case. The difference is a result of the favorable tax treatment provided to the intermediary financing organization. Actually, the difference would be even more dramatic if the project life time was equal to the utility systems life time of 30 years, as will be shown in the following sensitivity analysis.

Table 5-7 Intermediary Financing - Base Case

Electric Power Plant Financial Analysis

Description:

Syst. Description Base Case
System Size 25 MW
Operational year 1985
Base Year Dollar 1982
Inflation 8.50 %/yr
Type Financing Intermed

Variables:

Project Period 20 years
Syst. Price range 4000 — 4200 \$base/kw
Interconnect Cost 0 \$base/kw
Price Escalation 8.5 %/yr
Capacity Factor 30 %
Avoided Cost .06 \$base/kwh
Revenue Escalation 10.67 %/yr
Lease Payments 0 \$oper/yr
Lease Escalation 0 %/yr
Fixed O&M 25 \$base/kw-yr
Var O&M Costs 0 \$base/kwh
O&M Escalation 8.5 %/yr
Insurance Costs .25 % of price
Property Taxes 1 % of price
Sales Taxes 6.5 % of price
Marginal Tax Rate 51.18 %
Invest. Tax Rate 10 % in yr0 0 % in yr1
Energy Tax Rate 15 % in yr0 0 % in yr1
Debt % of Capital 75 %
Cost of Equity 20 %/yr
Loan Interest 15 %/yr
Loan Term 20 years
Safe Rate of Retrn 6 %/yr
Depreciation rates 19.35 32.36 24.49 15.73 7.87
Salvage Value 0 \$base/kw

Electric Power Plant Financial Analysis Base Case												
CASH FLOW STATEMENT (\$1000)												
Year	Revenue	Lease Expense	O&M Expense	Insur Cost	Property Tax	Interest Expense	Deprec. Expense	Taxable Income	Income Tax	Princ. Payment	Tax Credits	Cash Flow AT
1985	-32733(Invest)	0	0	8511	1309	14730	42370	-34108	-17456		32733	8946
1986	5343	0	798	327	1309	14730	42370	-34191	-27735	959	0	14955
1987	5913	0	866	327	1309	14586	32065	-43241	-22131	1102	0	9853
1988	6544	0	940	327	1309	14421	20596	-31049	-15891	1268	0	4170
1989	7243	0	1020	327	1309	14231	10304	-19949	-10210	1458	0	-892
1990	8015	0	1106	327	1309	14012	0	-8739	-4475	1677	0	-5943
1991	8871	0	1200	327	1309	13760	0	-7727	-3985	1928	0	-5700
1992	9817	0	1302	327	1309	13471	0	-6593	-3374	2217	0	-5456
1993	10865	0	1413	327	1309	13139	0	-5324	-2725	2530	0	-5149
1994	12024	0	1533	327	1309	12756	0	-3902	-1997	2932	0	-4817
1995	13307	0	1664	327	1309	12316	0	-2310	-1182	3372	0	-4500
1996	14727	0	1805	327	1309	11811	0	-525	-269	3878	0	-4134
1997	16298	0	1958	327	1309	11229	0	1474	754	4460	0	-3740
1998	18037	0	2125	327	1309	10560	0	3716	1902	5129	0	-3315
1999	19962	0	2305	327	1309	9791	0	6229	3188	5898	0	-2857
2000	22091	0	2501	327	1309	8906	0	9048	4631	6783	0	-2366
2001	24449	0	2714	327	1309	7889	0	12209	6249	7800	0	-1839
2002	27057	0	2945	327	1309	6719	0	15757	8065	8970	0	-1277
2003	29944	0	3195	327	1309	5373	0	19740	10103	10315	0	-679
2004	33139	0	3467	327	1309	3826	0	24210	12391	11863	0	-43
2005	36675	0	3761	327	1309	2046	0	29231	14960	13642	0	629
2006	0(sale)					0		0	0	0		0
FV of return	1176202.			PV of investment	30680		Modif IRR		20.00		Cost	4100

SECTION 6

SENSITIVITY ANALYSIS

To measure the impact of changes in the key assumptions, a sensitivity analysis was performed for the intermediary financing case. In this analysis the key financial and technical (operational) parameters were varied over a broad range to determine the resulting changes in the allowable installed systems price, while maintaining the required modified rate of return at 20 percent after taxes. The results are summarized in the following tables with the base case denoted by bold print.

As was mentioned previously, these results are independent of the rate of inflation assumed, since all the financial parameters, such as the cost of capital, rate of return, and various escalation rates, are expressed in real terms relative to the general rate of inflation indicated. Thus, when the general rate of inflation comes down from the 8.5 percent level assumed, all of the financial parameters are adjusted accordingly, thereby making the results independent of the assumed rate of inflation.

Energy Tax Credit Effect

Since the basis for intermediary financing resides in the energy tax incentives provided, it is illustrative to look at the effect of these energy tax credits upon the allowable installed price. These energy tax credits are in addition to the regular 10% investment tax credit. Furthermore, as was discussed previously, several states have provisions for additional state energy tax credits. As was mentioned, the 25% state tax credit combined with high avoided costs and insulation levels make California a very attractive initial market for early solar systems.

These effects are shown in Table 6-1, which incorporates three distinct cases: (1) without energy tax credits, which under present legislation would occur after 1985; (2) with only the federal 15% energy tax credit, which currently in California would exist after 1983 and through 1985; and (3) the case with 28.5% combined net federal and California energy tax credit, which currently includes the period through 1983 in California.

Table 6-1 Energy Tax Credit Effect (1982 \$), Solar Thermal Central Receiver

Year	Investment Tax Credit	Energy Tax Credit	Installed Price - \$/kWpk	
			Year 0	Year 1
1986	10%	0%	2871	2385
1985	10%	15%	4100	3309
1983	10%	28.5%	5534	4254

**Table 6-2 MIRR Risk Rate and Safe Rate Effect, Solar Thermal Central Receiver
(1982\$)**

Risk Rate	Safe Rate	Installed Price - \$kWpk
15%	6%	4201
20%	6%	4100
20%	12%	6091

As can be seen from this table, the effect of tax credit on allowable installed systems installed cost is very large. Actually, with somewhat higher overall tax credits, the allowable installed price becomes extremely large.

Obviously, since the utility industry cannot take advantage of this tax shelter while under PURPA legislation they must purchase the energy generated at avoided cost, the intermediary financing approach provides a very attractive structure for underwriting the technology transfer of the emerging solar technologies.

The impact of taking the tax credits and the first year of depreciation (ACRS) by the investors in the year of installation (year 0) as compared to during the first year of operation (year 1) is also indicated. This effect is large, and reflects the ability of corporations or high tax bracket investors to be able to realize the tax incentives benefits by reducing their periodic withholding tax deposits immediately after the start of operations rather than at the end of their tax year. Actually, the allowable installed systems price lies somewhere in between the year 0 and 1 figures shown, depending upon the individual investor circumstances.

MIRR Risk Rate and Safe Rate Effects

As explained previously, the MIRR methodology is used to determine the allowable installed solar systems prices for the intermediary financing. This requires inputs regarding the rates of return to appropriately deal with the large positive and negative cash flows, the risk rate and safe rate of return, respectively, associated with this type of financing.

The after-tax risk rate of 20% for the base case reflects the rate of return earned on projects incurring similar risks, whereas the after-tax safe rate of 6% reflects the net return on highly liquid and low risk investments such as treasury bills. The modified after-tax internal rate of return associated with the allowable installed system cost is equal to the required risk rate of return of 20%.

The impact of changing these rates is shown in Table 6-2. As can be seen, the sensitivity of the safe rate is quite large as compared to variations in the risk rate of

return. Consequently, intermediary financing structures with a high safe rate will permit associated high allowable installed systems costs.

Loan Interest and Financial Leverage Effects

One of the key features associated with intermediary financing and use of tax credits is the potential for high leverage provided by the ERTA legislation for solar systems. By exempting the solar systems from the 'at risk' provision, the intermediary financing can be highly leveraged without losing the tax benefits*. The effects of this leveraging and the interest rates associated with the debt financing are shown in Table 6-3.

Obviously, the lower the interest rate, the more attractive the financing, and thus the higher the allowable installed systems price. The actual interest rate is determined by the nature of the debt financing, the associated technical and economic risks, and the financial risk due to leverage. A recourse loan based upon collateral or debt guarantees by the intermediary investors will result in lower rates as compared with non-recourse financing.

The financial leverage increases the risk exposure and thus will typically result in higher interest rates for the debt financing, all other factors equal. The lower the technical risks associated with the project, such as provided by equipment warranties or performance guarantees, as well as improved maturity of the technology, will translate into reduced interest rates.

As can be seen, the effect of leverage on allowable systems price is quite large. Thus intermediary financing will benefit from the highest possible leverage (25% equity/75% debt), and lowest possible interest rate financing.

Project Life, Loan Term, and Resale Value Effects

As mentioned above, the intermediary financing base case assumes a project life of 20 years as compared to the system operational life of 30 years assumed for utility financing. On the other hand, the project times associated with most limited partnerships are typically shorter than 20 years.

* As long as the equity is at least 25 percent

Table 6-3 Loan Interest and Financing Leverage Effects (\$/kWpk - 1982\$)

Loan Interest Rate	Debt/Equity (percentage)				
	75/25	67/33	50/50	25/75	0/100
12.5%	4910				
15.0%	4100	4068	3623	2182	1455
17.5%	3485				
20.0%	2987				

Consequently, it is of interest to assess the effect of assumed project life on the results. Like real estate syndicates, the facility is assumed to have a resale value for the shorter project periods. These variations are shown in Table 6-4, which shows allowable installed systems price as a function of both project life and resale value (in 1982\$).

As can be seen, the longer project lives result in significant increased allowable systems prices. Even with the high resale value associated with the 5-year project period, the shorter lifetimes and associated shorter loan periods and higher debt service payments during the early years of the project, significantly reduces the early year cash flows. This can also clearly be seen from the cases with loan terms shorter than the project terms. Clearly, from a financial viewpoint, the longer the project term and associated loan terms, the more favorable the investment becomes. (However, the associated technical and financial risks are higher).

The salvage value for the longer term projects has only minor effect on the overall results, since these values are relatively small, and (if smaller than the original price) are taxed at ordinary income rates. The resulting cash flow is then further discounted over the large time period.

Avoided Cost and Associated Escalation Effects

The avoided cost paid by the California electric utilities for the electric energy generated is closely related to the price of oil. (These costs are updated quarterly by these utilities in California.)^{13,14} Obviously, since the price paid for oil by the utilities constitutes the basis for the revenues generated, both the oil price and the associated oil price escalation have significant impact on the results. The impact of these factors is shown in Table 6-5 by varying both the avoided cost values and the associated escalation rates.

In other southwestern U.S. states such as Arizona, the avoided costs are based upon a combination of oil and coal prices, resulting in lower avoided costs there. The underlying reason is that these utilities are summer peaking, and thus the solar systems displace oil during the summer only, while the rest of the year they displace lower cost coal. The result is a much lower allowable solar systems value or price in the

Table 6-4 Project Life, Loan Term and Resale Value Effects (1982 \$)

Project Life (Years)	Loan Term (Years)	Resale Value \$/kW(Pk)-1982\$	Installed Price \$/kW(pk)
30	30	0	6047
30	20	0	4280
20	20	0	4100
20	15	0	3037
20	10	0	2283
20	5	0	1880
10	10	0	1846
10	10	1000	2125
10	5	1000	1701
5	5	1000	1483
5	5	2000	2007

southwestern U.S. than for California, in spite of the high solar insolation prevalent there. This is a major reason for projecting California as the first significant solar systems market.

Obviously the higher the avoided cost and escalation, the higher the allowable solar systems installed price. The base case of 60 mills/kWh for avoided cost reflects a 1982 delivered oil price to the utility of approximately \$35/bbl (1982\$), assuming a heat rate of 10,000 BTU/kWh and no capacity credit for the solar facility.^{5,13} A 2% real oil price escalation over the long-term is assumed as the base case for avoided cost, which reflects the depletable nature of oil and corresponds to the lower value suggested by the EPRI Technical Assessment Guide.⁵

Because of a recent decline in oil prices, with subsequent leveling of these prices, the special case of 90 mills/kWh and 0% real escalation is shown. This latter case reflects an actual case being considered by the California PUC with the utility paying a level avoided cost of 90 mills/kWh, which is currently higher than the actual avoided cost.¹⁴ A special account is debited by this difference, which places a lien on the property. When the avoided costs subsequently exceed the 90 mills/kWh, the account is credited with the difference until the account is zero, after which time the utility pays the actual avoided cost. If the account is not reduced to zero during the project life, the utility can exercise the lien against the solar facility.

Capacity Factor Effect

The effect of capacity factor on the allowable system cost is shown in Table 6-5 to permit evaluation of solar systems with and without storage in different regional utility grids.

Solar system load following capability and storage improve the allowable cost in two ways: (1) by increasing the amount of energy generated over time or capacity factor, and (2) by increasing the avoided cost revenues as a result of enhanced capacity displacement values. The former effect is shown in Table 6-6, whereas the latter effect can be deduced from Table 6-5. As can be seen, the effect of capacity factor is significant, especially when combined with larger avoided cost revenues due to enhanced capacity credit.

Table 6-5 Avoided Cost and Associated Escalation Effects (1982 \$)

Avoided Cost (mills/kW-hr)	Avoided Cost Escalation Rate - Apparent ¹ (Real)			
	8.50 % (0%)	9.60 % (1%)	10.67 % (2%)	11.75 % (3%)
50			3322	
60	2992	3521	4100	4729
70			4878	
80			5659	
90	4770		6437	

¹ Inflation Rate = 8.5 %/year

Table 6-6 Capacity Factor Effect (1982 \$)

Capacity Factor	Installed Price - \$/kW(pk)
0.20	2542
0.25	3321
0.30	4100

Operating and Maintenance (O&M) Costs and Escalation Effects

System operating and maintenance costs constitute the other operating parameter. Since only limited operating experience exists for this parameter, the sensitivity of these costs and associated escalation assumptions are shown in Table 6-7. Most of the solar thermal central receiver O&M costs are related to plant size and thus are fixed. However, Rankine cycle systems with storage may incur a small energy dependent or variable O&M component. The effect of both fixed and variable O&M are included in this table.

The base case numbers correspond to the EPRI Technical Assessment Guide,⁵ whereas the variations cover the uncertainties associated with this parameter. Again, the effect of O&M costs on allowable systems cost are significant, whereas the effect of O&M escalation is somewhat smaller.

Property Tax and Insurance Rate Effects

Even though some states exempt their solar facilities from property tax assessment, property taxes typically constitute a county tax revenue and thus are normally to be considered an operating expense. In California, this tax rate is specified statewide at approximately 1% of plant cost as a result of Proposition 13 legislation, and solar plants are not exempt from this tax (base case).

The typical range of this property tax for various states is from 1 to 2%, and its effect on allowable systems cost is shown in Table 6-8.

Also shown in this table is the effect of insurance rates on the allowable cost for a range of typical insurance rate values. Since both property taxes and insurance rates are assessed against plant cost, these rates have identical impacts on the allowable systems cost.

Sales Tax Effect

Another burden imposed upon the solar facility is the sales tax, which is collected at the time of purchase. This tax inherently is a state tax and, consequently, varies from

Table 6-7 O&M and Associated Escalation Rate Effects (1982 \$)

O & M Costs		O & M Escalation ¹		
Fixed (\$/kW-yr)	Variable (Mills/kW-hr)	8.5 %	9.5 %	10.5 %
15	0	4329		
25	0	4100	4027	3945
25	1	4040		
35	0	3871		
45	0	3640		

¹ Inflation Rate = 8.5 % per Year

Table 6-8 Property Tax and Insurance Rate Effects (1982 \$)

Property Tax Rate ¹	Insurance Rate ¹	Installed Price - \$/kW(pk)
1 %	0.25 %	4100
2 %	0.25 %	3671
1 %	0.50 %	3986

¹ Percent of installed price, paid annually

state to state, with potential small local county or city variations. For the base case considered (California), the sales tax generally is 6.5% of the plant cost, and solar plants are not exempted from this tax.

Other states either have no sales tax or exempt solar facilities from this tax. Table 6-9 shows the effect of sales tax exemption which is significant (for California this 6.5% tax rate is equivalent to a negative tax credit after Federal taxes of 3.173%).

Combined Federal and State Marginal Income Tax Rate Effect

Most states impose their own income taxes on corporations and individuals. Typically these income taxes are progressive and thus similar in principle to the federal income taxes. Consequently, the marginal tax rates should be used for financial analysis. Furthermore, since state taxes are deductible from the federal income tax assessments, the combined federal and state marginal income tax rate must be determined.

The combined marginal rate is:

$$T_C = T_f + T_s - T_f T_s$$

where:

T_C = Combined marginal tax rate

T_f = Federal marginal tax rate

T_s = State marginal tax rate

For the base case, the federal corporate marginal tax rate is 46% and the California corporate marginal tax rate is 9.6%. This results in a 51.18% combined marginal income tax rate for projects built and financed in California.

The effect of changing this parameter is shown in Table 6-10. Contrary to intuition, the effect of reducing the combined marginal income tax rate is to reduce the allowable system price. This result is due to the very large tax credits available both at the federal and state levels. (Tax shelter)

Table 6-9 Sales Tax Effect

Sales Tax	Installed Price - \$/kW(pk)
0 %	4390
6.5 %	4100

Table 6-10 Combined Federal and State Marginal Income Tax Effect

Marginal Income Tax Rate	Installed Price-\$/kW(pk)
50.00 %	3989
51.18 %	4100

SECTION 7

SOLAR THERMAL ELECTRIC MARKET PENETRATION

The market penetration of solar thermal central receiver systems is determined by the relative costs and values to the users of these systems. Because of the intermittent nature of the insolation, coupled with the capital intensive nature of solar plants in general, the penetration of these solar systems is limited to approximately 5 to 10 percent of the utility installed capacity. Beyond this penetration, the value of solar systems decreases rapidly due to displacement of lower priced fuels and lower capacity displacement values based upon the established loss-of-load requirements. At this penetration the solar market is still very large.

Furthermore, the geographical area amenable to solar thermal central receiver applications is limited, due to the combination of direct insolation availability and displaced fuel prices, to the western and southwestern United States.¹⁰ Consequently, the **potential** market for solar thermal central receiver systems is determined by 5-10 percent penetration of approximately 32 percent of the U.S. newly installed capacity additions and a fraction of the replacement market or repowering of oil fired conventional generation.^{15,16} This potential market is indicated in Figure 7-1 and Table 7-1 by regions A and B. As mentioned previously, California represents an attractive initial market for solar systems. This potential California market (submarket of Region A) is quite large as shown in Tables 7-1 and 7-2.

The **projected** market penetration of these potential markets can be described by the logistics function. The reasons for this are discussed in the references 17,18,19. Consequently, only the results of this analysis are shown in this report. The projected market penetration scenario for the solar thermal central receiver technology is determined by a variety of technical and economic factors and market infrastructure. The previously described tax incentives and financing arrangements are only some of these factors.

In general, these tax incentives coupled with projected low or optimistic systems costs will result in a high or optimistic market penetration scenario. Vice versa, a high

POTENTIAL SOLAR ELECTRIC MARKET REGIONS

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Figure 7-1

Table 7-1 **Potential U.S. Solar Systems Utility Market**
MW(pk) Per Year

Market	1980	1985	1990	1995	2000
California (1%)	33	43	51	63	78
California (5%)	167	213	255	315	388
Region A	330	410	490	610	750
Region B	480	580	660	820	1010
Total	810	990	1150	1430	1760

▫ California is part of Region A

Table 7-2

**POTENTIAL SOLAR ELECTRIC POWER SYSTEMS
MARKET PENETRATION FOR CALIFORNIA
MW(PK) PER YEAR**

<i>Utility Penetration</i>	<i>Year</i>				
	<i>1980</i>	<i>1985</i>	<i>1990</i>	<i>1995</i>	<i>2000</i>
1%	33	43	51	63	78
5%	167	213	255	315	388

Market Advantages of California

- High insolation levels
- High Fuel Prices
- Significant State tax incentives

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penetration scenario will result in lower systems costs due to the increased experience or learning curve effects. To bound the problem, optimistic, pessimistic and expected solar thermal central receiver market penetration scenarios are defined in Table 7-3 corresponding to optimistic, pessimistic and expected cost projections. The corresponding logistic function take-over periods and penetration dates are tabulated in Table 7-4.²²

Applying these penetration scenarios to the potential solar thermal central receiver market results in the **projected** markets, corresponding to the optimistic, pessimistic and expected cost and penetration scenarios, shown in Table 7-5 in terms of capacity additions per year and cumulative capacity. These projected market penetrations in turn determine the production rates and cumulative production of the solar plant subsystems, such as heliostats as shown in Table 7-6, which in turn define the projected costs as a function of time, corresponding to the optimistic, pessimistic and expected scenarios. Even though the scope of this study precludes a detailed cost analysis of solar thermal central receiver systems, a typical experience cost curve for one major cost component, heliostats, is shown in Figure 7-2.²⁰

A cursory review of the projected systems costs by 1985, corresponding to the various scenarios, indicates that the energy tax credit window (1985) is extremely small to permit successful transfer of this technology. The abrupt ending of this energy tax credit after 1985 by itself undermines the effectiveness of this incentive for successful transfer of this technology, because of the perceived risks by investors regarding the possibility of not completing the facility in time to receive the benefits of this tax credit. In addition, the California tax credits are scheduled to expire after 1983 without any 'grandfather' clause provisions.

Consequently, a preliminary conclusion of this study is that even though the energy tax credits as currently defined are quite substantial in magnitude, they are potentially insufficient in time to underwrite the extraordinary risks associated with a successful solar thermal central receiver technology transfer.

Table 7-3 Convolution Matrix for Cost Estimation

Scenario	System Performance	Projected Market Penetration	Expected Installed Costs ¹	Contingencies
Optimistic	High Estimate	High (Optimistic)	Low Estimate	Low (Project only)
Expected	Medium Estimate	Medium/Low (Expected)	Medium Estimate	Medium (Project only)
Pessimistic	Low Estimate	Very Low (Pessimistic)	High Estimate	High (Project only)

¹ Based on Experience Curve

**Table 7-4 Projected Solar Systems Market Penetration Logistic Penetration
Analysis, Solar Thermal Central Receiver Systems**

HIGH (OPTIMISTIC) SCENARIO

Take-Over Period	
1% - 99%	26 years
10% - 90%	13 years
Penetration Date	
1%	1982/3
50%	1996

INTERMEDIATE (EXPECTED) SCENARIO

Take-Over Period	
1% - 99%	40 years
10% - 90%	20 years
Penetration Date	
1%	1983/4
50%	2004

LOW (PESSIMISTIC) SCENARIO

Take-Over Period	
1% - 99%	54 years
10% - 90%	27 years
Penetration Date	
1%	1984/5
50%	2013

Table 7-5 Solar Thermal Central Receiver Electric Systems
Projected U.S. Utility Market Penetration
 MW(pk)/Year or MW(pk)

	1980	1985	1990	1995	2000
High Penetration - Annual	4	23	136	591	1,400
High Penetration - Cumulative	10	73	460	2,300	7,650
Intermediate Penetration - Annual	4	15	52	173	516
Intermediate Penetration - Cumulative	10	63	230	800	2,560
Low Penetration - Annual	4	10	27	72	190
Low Penetration - Cumulative	10	50	145	400	1,070

**Table 7-6 Projected Heliostate Production Rates and Cumulative Production Solar Thermal
Central Receiver Systems With Alternative Market Penetration Scenarios**

	1980	1985	1990	1995	2000
High Penetration - Annual Rate	600	4,000	22,500	100,000	250,000
High Penetration - Cumulative	2,000	12,500	75,000	400,000	1,275,000
Intermediate Penetration - Annual Rate	600	2,500	10,000	30,000	100,000
Intermediate Penetration - Cumulative	2,000	10,000	40,000	135,000	425,000
Low Penetration - Annual Rate	600	1,500	5,000	12,500	35,000
Low Penetration - Cumulative	2,000	8,000	25,000	70,000	175,000

HELIOSTAT & PARABOLIC DISH INSTALLED PRICE ESTIMATES BASED ON LEARNING CURVE EXPERIENCE & DETAILED PRICE ESTIMATES

Figure 7-2

As noted previously in this report, the successful transfer of the solar thermal central receiver technology can be significantly enhanced by factors relating to the technical and financial risks associated with commercialization.

The **financial risks** can be reduced by the indirect underwriting of the extraordinary risks associated with each phase of the technology development and transfer by means of various tax incentive and regulatory legislation. These various RD&D phases and associated illustrative costs are shown in Figure 7-3.

The **extraordinary risk** exposure associated with the various phases of research, development and demonstration are schematically shown in Figure 7-4 as a percentage of the project cost. This extraordinary risk exposure is the difference between the actual project cost and the project value as determined from discounting the projected tangible and intangible benefits associated with the project or technology at a discount rate corresponding to the cost of capital commensurate with normal business and financial risks. Thus the technology transfer process can be significantly aided by the aforementioned underwriting of these extraordinary risks by means of various tax incentives.

By definition the **successful** commercialization of a technology will gradually reduce the percentage of this extraordinary risk underwriting with each phase of development and demonstration to zero, as shown in Figure 7-4. For economically non-viable technologies the value will always be less than the costs, and thus will require continual subsidies. Consequently, the tax incentives should be configured such that they provide for sufficient extraordinary risk underwriting throughout the various phases of RD&D, which means a gradual reduction or tapering of these incentives until the projected time of commercialization. This will eliminate those non-viable technologies which still require subsidies after this time period, and thus provide a mechanism for commercializing only those technologies that are economically viable.

The **technical risks** associated with the technology can be reduced by an effective solar thermal RD&D program. The area where the DOE program can provide significant inputs consists of defining an RD&D program that will enhance the **technology confidence**, and thereby reducing the technical risks associated with the central receiver technology as perceived by the financial or investor community.

Figure 7-3

**RELATIVE COSTS ASSOCIATED WITH VARIOUS
PHASES OF RESEARCH, DEVELOPMENT AND DEMONSTRATIONS**

7-12

Figure 7-4

EXTRA-ORDINARY RISK EXPOSURE ASSOCIATED WITH VARIOUS PHASES OF RESEARCH, DEVELOPMENT AND DEMONSTRATIONS

*Computed at normal business risk.

An effective RD&D program aimed at reducing the technical risks will significantly assist the technology transfer by providing better systems definitions and costs reflecting actual hardware demonstrations, as well as lowering the investor-perceived risk assessment and related financing costs associated with the early solar thermal central receiver projects. As was shown in Sections 5 and 6, the lowered risks and commensurate lower financing costs will increase the allowable installed systems price, thereby facilitating the technology transfer process.

Furthermore, DOE can assist in lowering the financing costs associated with the technology transfer by providing loan guarantees for the leveraged intermediary financing arrangements. From a utility or user viewpoint, the availability of plants and thus the reliability (scheduled and unscheduled outages) are important and should be explicitly addressed in subsequent demonstrations.

In summary, an effective RD&D program aimed at increasing the technology confidence by minimizing the perceived technical (and financial) risks to the potential investors is extremely important for the achievement of a successful technology transfer. This observation also reflects the opinions expressed by the various interested parties participating in the recent Solar Thermal Technology Evaluation and Program Workshop held at the Electric Power Research Institute²¹.

APPENDIX A

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