AUGUST 19[illegible]

Advanced Energy Systems Division

ROBINS AIR FORCE BASE SOLAR COGENERATION FACILITY FINAL REPORT VOLUME I

Prepared For
THE UNITED STATES DEPARTMENT OF ENERGY
Contract No. DE-AC03-81SF11494

Westinghouse Electric Corporation
Advanced Energy Systems Division
P.O. Box 10864
Pittsburgh, Pennsylvania 15236

NOTICE

AESD-TME-3114

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1.0 EXECUTIVE SUMMARY

1.1 PROJECT SUMMARY

The principal objective of the Robins Air Force Base Solar Cogeneration Conceptual Design Program is to develop a conceptual design and cost estimate for a demonstration solar facility to generate electricity and deliver process steam to the existing base distribution systems. The facility is to have the potential for construction and operation by 1986, make use of existing solar thermal technology and provide the best economics for the overall application.

Specific objectives are to 1) prepare a Solar Cogeneration Facility Specification, 2) select a preferred facility configuration and prepare a conceptual design, 3) establish the performance and economic attractiveness of the facility, and 4) prepare a development plan for a demonstration program at Robins Air Force Base.

The Westinghouse Advanced Energy Systems Division with the support of Heery and Heery, Inc., Foster Wheeler Solar Development Corporation, the U.S. Air Force Logistics Command, and Georgia Power Company has selected a conceptual design for a solar cogeneration facility that utilizes the latest DOE central receiver technology, effectively utilizes the energy collected in the application, operates base loaded every sunny day of the year, and is applicable to innumerable industrial and military facilities throughout the country.

An artist's concept for the solar cogeneration facility is shown in Figure 1.1-1. The cogeneration concept utilizes central receiver technology and consists of the installation of a solar collector field, a central receiver (boiler), a turbine-generator for electric power production, and associated feedwater and steam piping, and the integration of electrical and steam hardware with existing Air Force Base services and control systems. The ability to operate the existing boiler and electrical distribution systems without solar facility operation is retained, thus providing full normal

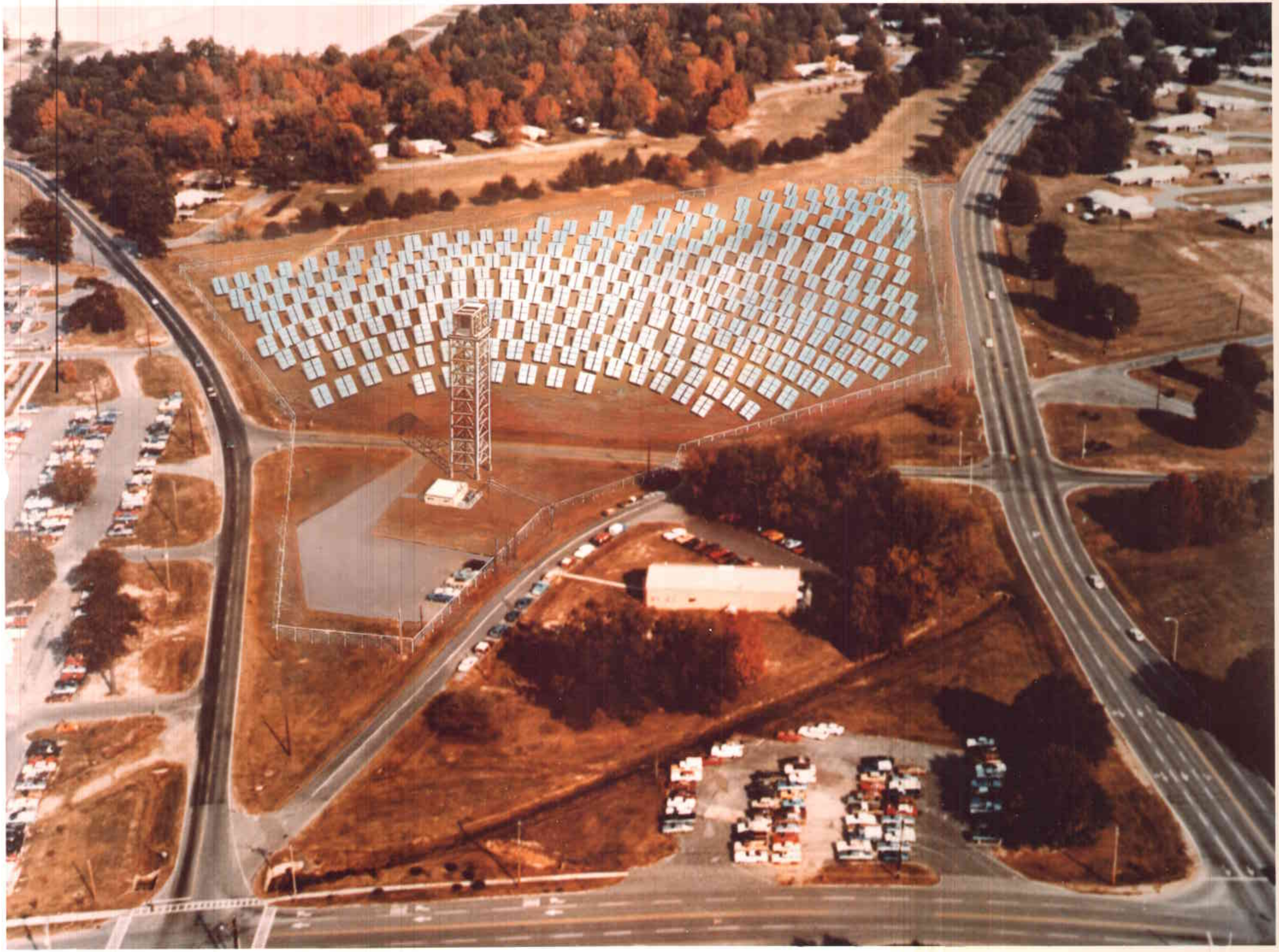


Figure 1.1-1. Robins Air Force Base Solar Cogeneration Facility

service during periods of inclement weather or at night. The normal operating mode uses 100 percent of the available solar energy to displace both purchased electricity and gas/oil for steam production.

A review of the industrial process steam usage in the United States and the potential for economical cogeneration assisted in the selection of the concept which would predominately serve a baseload process steam need with electrical generation in a topping cycle mode. The review indicated that there are widespread industrial as well as military applications wherein a steady usage of 862-1000 kPa (125-145 psia) steam is required in conjunction with electrical needs. The United States Air Force Logistics Command, headquartered at Wright-Patterson Air Force Base, Ohio is responsible for a large number of bases which require this type of application. They have been a major participant in this program. Robins Air Force Base, Georgia, one of several major logistics centers under the command of Wright-Patterson, provides the site specific application, necessary support facilities, and substantial personnel services to support the program.

Robins Air Force Base was selected for a variety of reasons:

- United States Air Force Commitment to Renewable Energy
  The Air Force Logistics Command has been actively involved in the pursuit of applications for all of the renewable energy sources. They are leading all of the other services in this pursuit and are totally committed to the success of this program.

- Constant Year Round Thermal and Electrical Energy Demand
  Projected steam requirements vary from 10,909kg/h to 22,100kg/h of steam for every hour of the year which provides a constant demand for effective annual usage of solar energy. Site electrical demand is significantly greater than provided by this application, therefore, all electricity generated is to be consumed on site.

- Excellent Solar Characteristics
  Robins is in a zone of good solar insolation with little cloud cover and therefore will provide an excellent basis for verification of solar energy usage.

- Wide Spread Market Potential
  The site energy demand characteristics are typical of four other Air Force bases and a large spectrum of industrial sites with an estimated 200,000 boilers in range of 0.4 to 1.9 MW_t.

- Stable Energy Demand
  The substantial energy conservation measures which have been previously employed at Robins and the planned construction of buildings to be served by Steam Plant No. 4 result in a forecasted thermal demand assuring full utilization of the output of the solar facility.

- No Institutional or Environmental Constraints
  There are no institutional or regulatory constraints for use of land for solar cogeneration. Environmental assessments of surrounding land indicate that no known constraints exist.

An available and conveniently located site, shown on Fig. 1.4-3, has been established adjacent to Seventh Street between "B" Street and Robins Parkway ("E" Street) for installation of the facility. This location is adjacent to electrical distribution lines to which the electrical power will be delivered and in the proximity of Steam Plant No. 4 to which the process steam will be delivered.

The solar facility thermal rating was selected to serve the planned steam demand upon Steam Plant No. 4 in 1986 when the facility is operated in parallel of one or more boilers at their minimum practical level to satisfy that demand. With this basis, the electrical output is a small fraction of load in the distribution network into which the electrical output is delivered. This choice results in that maximum use of the solar facility equipment allowed by meteorological conditions.

The development plan provides for orderly execution of the steps required to proceed for this conceptual design through the first one of twenty five years of operation by the user (USAF). These steps are: Advanced Conceptual Design; Preliminary and Detail Design; Procurement; Construction and Checkout; and Startup, Performance Validation and Monitoring of Operation. The planned schedule presumes start of advanced conceptual design in October 1981 and culminates with completion of one year of operation by early 1987.

The plan embodies a unique sharing of costs between the DOE and the USAF with full benefits accruing to each organization. This result is achieved through defining the roles and responsibilities of DOE and USAF to produce a rational sharing of resource investment and risk while avoiding burdensome or complicated financial interactions. Specifically this plan presumes that DOE will provide all design and capital investments while the USAF will provide all services for making the site ready for construction and all normal, planned operating and maintenance costs after completion of construction. Finally, the information and experience of building and operating this demonstration facility are fully available not only to each participant but to all industry through DOE information dissemination policies and practices.

The capital cost to DOE using the above share plan is in 1980 dollars (excluding one-time engineering costs) while the USAF costs for accommodating the solar facility site and operating and maintaining the facility for twenty five years is in 1980 dollars. The economic assessment of the solar facility was based on the methodology and economic assumptions defined by the USAF for the Energy Conservation Investment Program (ECIP). This approach is basically a present worth analysis of nonrecurring capital cost, recurring operating and maintenance costs, and recurring benefits of the direct reduced energy usage. On a total investment basis, i.e., summing the DOE and USAF costs, and assuming a 0.85 learning curve, the benefit/cost ratio exceeds 1.0 after only 35 installations assuming the ECIP guideline fuel escalation rate of 8 percent above the general inflation rate. This drops to 3 installations at 12 percent fuel escalation rate above the general inflation rate.

This opportunity to demonstrate solar cogeneration should be exploited now.

1.2 INTRODUCTION

The development of solar thermal power system technology is an important and necessary outgrowth of the United States' desire to reduce its usage of conventional oil and natural gas fuels in the generation of electrical, mechanical, or thermal energy. The U.S. Department of Energy (DOE) Solar

Thermal Program has the overall goal of providing the technological and industrial base that is required to support the commercialization of promising solar thermal technologies. Solar displacement of existing gas and oil fuel usage utilizing the central receiver concept has been identified as the most promising near-term application of this technology.

The Robins Air Force Base (RAFB) Solar Program was funded by DOE for the period of December 1, 1980 to August 31, 1981. The principal objective was to develop a conceptual design and cost estimate for a solar cogeneration facility that has the potential for construction and operation by 1986, makes use of available solar thermal technology, and provides the best economics for this application.

An artist's concept for the solar cogeneration facility is shown in Figure 1.1-1. The cogeneration concept utilizes central receiver technology and consists of the installation of a solar collector field, a central receiver (boiler), a turbine-generator for electric power production, and associated feedwater and steam piping, and the integration of electrical and steam hardware with existing Air Force Base services and control systems. The ability to operate the existing boiler and electrical distribution systems without solar facility operation is retained, thus providing full normal service during periods of inclement weather or at night. The normal operating mode uses 100 percent of the available solar energy to displace both purchased electricity and gas/oil for steam production.

The Solar Cogeneration Program objectives were accomplished using a work breakdown structure defining seven major tasks as follows:

Task 1100 - Solar Cogeneration Facility Specification
Task 1200 - Selection of Site-Specific Facility Configuration
Task 1300 - Facility Conceptual Design
Task 1400 - Facility Performance Estimates
Task 1500 - Facility Cost Estimates and Economic Analysis
Task 1600 - Development Plan
Task 1700 - Program Plan and Management

Westinghouse Electric Corporation, Advanced Energy Systems Division, as prime contractor, had overall responsibility for conducting the conceptual design program including program definition, cost, and schedular control, and interface definition both between project participants and between the solar facility and the Air Force Base. In addition, Westinghouse retained responsibility for project integration and systems engineering, solar facility and system design and analysis, economic impacts and assessments, safety evaluations, and program planning for the demonstration phases of the project. Westinghouse was supported directly by two major subcontractors: Heery and Heery, Inc. (H&H) and Foster Wheeler Solar Development Corporation (FWSDC).

H&H provided architect/engineer services that included the conceptual design of the site, arrangements, balance of facility component design, cost estimating in support of economic analyses and construction planning for the subsequent demonstration program.

FWSDC provided the design of the receiver system and associated controls, including performance analysis, cost estimating in support of the economic analyses and construction planning of this system for the subsequent demonstration program.

The above design team was vigorously supported by the United States Air Force personnel at Wright-Patterson Logistics Command and at Robins Air Force Base, who provided major assistance in integrating the solar facility into the base operations, provided base related operating and meterological data, and assisted in identifying and defining institutional, environmental, and safety considerations. This study could not have been successfully completed without the aggressive owner support and cooperation received from the Air Force.

In addition, the design team was assisted by Georgia Power Company in fiscal and technical matters related to the electrical generator to electrical distribution system interface.

DOE, as project funding agent, provided contractual and technical program guidance. Contractual communication was through DOE's San Francisco Operations Office (DOE-SAN) and technical guidance was provided by Sandia National Laboratories, Livermore as well as DOE-SAN. The programmatic and technical experience of these organizations with respect to solar power generation was recognized and utilized by Westinghouse in the course of accomplishing this program.

1.3 FACILITY DESCRIPTION

Robins Air Force Base is located at 32° 36' north latitude and 83° 36' west longitude, close to the geographic center of Georgia. Situated east of the City of Warner Robins in Houston County, it is approximately 37 km (23 mi) south of Macon. The site is at the foothills of the Piedmont Plateau and is at an elevation of 93 m (305 ft) above mean sea level.

The climate is generally quite mild and is not given to severe storms. However, tornados, hail, and snow storms have been experienced. Hurricanes and storms from both the Atlantic Ocean and the Gulf of Mexico have dissipated to rainstorms by the time they reach the Robins area.

The proposed solar cogeneration site is located in the southern portion of the Base. The heliostat field will encompass approximately 62,730 m^2 (15.5 acres) and is bounded on the east, south and west by paved roads and on the north by a portion of a golf course. The land is unused and flat (a 3.0 m (10 ft) declination in elevation at the south end). The tower supporting the central receiver will be located at the southern end of the collector field near the northwest corner of the existing Band Building, Building 760.

Steam Plant No. 4, Building 644, is approximately 305 m (1,000 ft) from the solar site. The entire thermal output of the solar facility will be piped into this steam system. A 12.6 kV power line is located within 31 m (100 feet) of the facility. It is planned to feed the entire electrical output of the solar cogeneration system into this line, displacing a portion of the electricity that would have to be purchased from the Georgia Power Company.

The intent of the solar cogeneration facility is to generate a sufficient quantity of steam to displace one of four fossil fuel fired boilers in Steam Plant No. 4 during periods of adequate insolation. The steam plant houses four natural gas/fuel oil fired water tube type steam generators with a combined capacity of 42,700 kg/h (94,000 lb/h). Steam generated at 0.96 MPa (140 psia) serves 30 diversified military and industrial facilities including a hospital, dormatory complex, avionics center, electronic shops, and warehouses. The steam loads include space heating, domestic hot water generation, sterilization, absorption cooling, and process requirements. The primary usage is space heating which is evidenced by the present (1980) winter peak demand at approximately 19,430 kg/h (42,800 lb/h). This steam demand is presently met by operating two of the four boilers on a rotating basis.

Three programmed building expansions have been identified. These additions will increase the peak winter demand in 1986 to approximately 22,180 kg/h (48,900 lb/h). This peak corresponds to a maximum monthly average projected steam demand of 18,800 kg/h (41,500 lb/h) during January.

The electrical needs of the base's industrial areas are currently being met by the Georgia Power Company through a 20 MW substation. The substation has two 10 MW transformers, each capable of carrying the connected electrical load. The load always exceeds one megawatt and the distribution system is capable of accepting the full electrical output from the solar cogeneration facility. Distribution is at 12.6 kV with transformation to lower voltages occurring at each building or group of buildings.

An existing energy monitoring and control system (EMCS) will be interfaced to both the solar facility and steam plant to allow for monitoring transitions of steam and power.

1.4 CONCEPTUAL DESIGN DESCRIPTION

Several unique design features distinguish the RAFB Solar Cogeneration Facility as an ideal solar thermal demonstration project. These include the use of water-steam receiver technology based on conventional drum-type natural circulation boiler experience, close proximity of the facility site to existing steam and electrical distribution systems, a simple control system that utilizes conventional equipment, and service to electrical and steam loads that ensure immediate use of all collected solar energy.

The baseline solar cogeneration facility design is made up of five major systems: the Collector System, Receiver System, Master Control System, Electrical Power Generating System, and the Balance of Facility. A schematic system level diagram of the solar facility is presented in Figure 1.4-1, Schematic System Level Diagram of Solar Cogeneration Facility at Robins Air Force Base. This figure clearly depicts the relationships of the major system components to one another within the facility and to the existing Robins Air Force Base steam plant and electrical distribution system.

The preferred configuration shown schematically on Figure 1.4-1 utilizes water-steam receiver technology to provide main steam at 6.0 MPa/400°C (865 psia, 750°F) to a commercial single stage turbine generator, which discharges steam at 1.06 MPa/186°C (153 psia, 366°F) to the existing steam distribution system served by Steam Plant #4 on the Robins Air Force Base. The electrical power is fed into the existing 12.6 kV electric distribution line. Important project and design information is summarized in Table 1.4-1, Conceptual Design Summary Table.

The principal solar facility/existing plant interfaces consist of (1) steam piping connection between the solar facility turbine discharge pipe and the Steam Plant No. 4 header piping, (2) piping connection between the Steam Plant No. 4 feed system and the solar feed system, (3) control interface between the solar facility and existing Steam Plant No. 4, and (4) electrical interface between the solar facility turbine generator and the existing 12.6 kV distribution trunk. Desuperheating of the turbine discharge steam and pressure control on the discharge header ensure that temperatures and pressures are maintained within existing system operating limits. Solar generated steam displaces fossil generated steam whenever available, with fossil generated

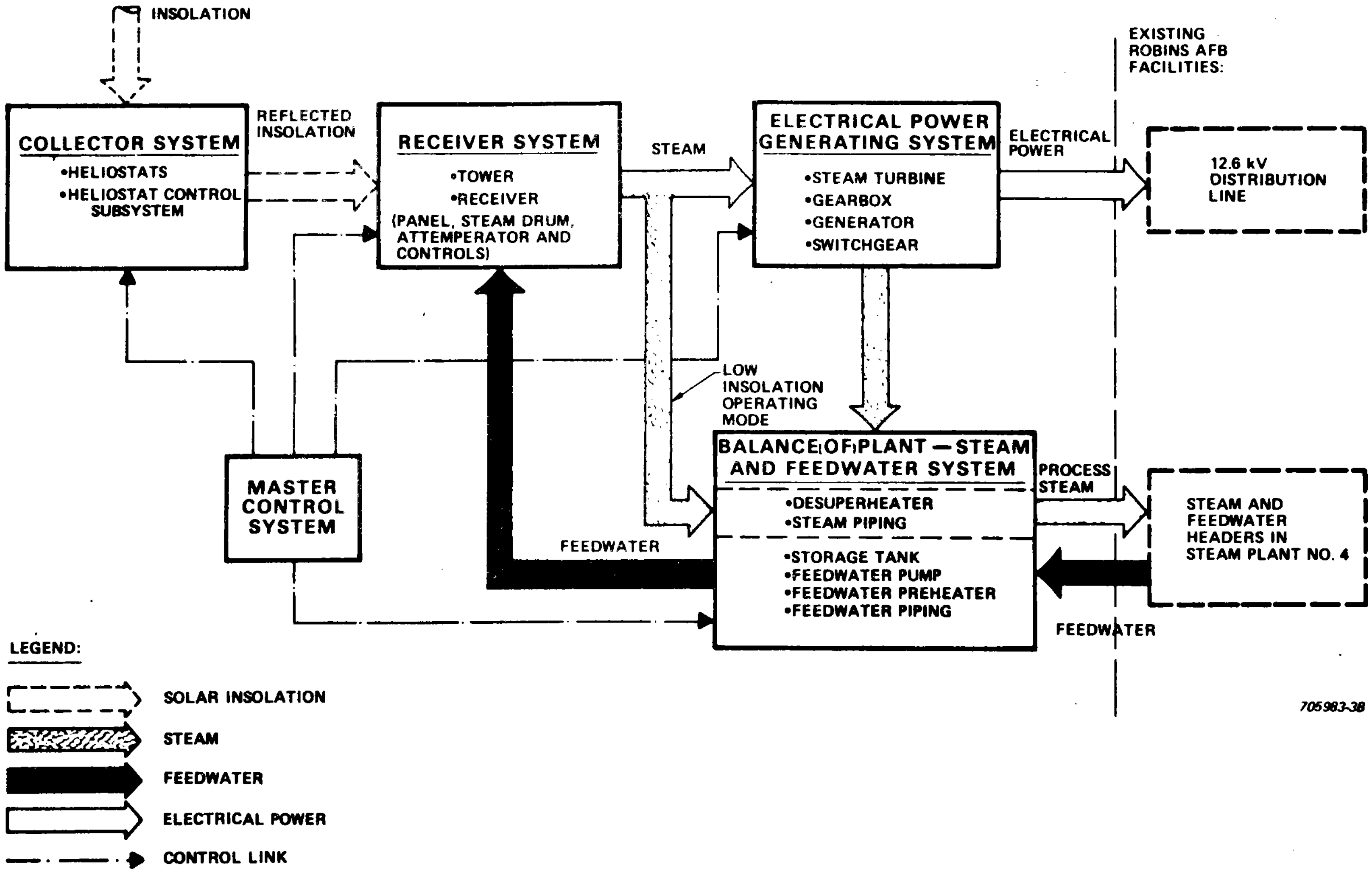


Figure 1.4-1. Schematic System Level Diagram of Solar Cogeneration Facility at Robins Air Force Base

TABLE 1.4-1: CONCEPTUAL DESIGN SUMMARY

1. Prime Contractor: Westinghouse Electric Corporation
   Advanced Energy Systems Division
   R. W. Devlin, Project Manager

2. Major Subcontractors: Heery & Heery, Inc.
   R. D. Yelvington
   Foster Wheeler Solar Development Corporation
   S. F. Wu

3. Site Location: Robins Air Force Base
   Warner Robins, GA

4. Facility Characteristics:
   a. Turbine type - Commercial high backpressure
   b. Turbine inlet temperature and pressure - 400°C 6.0 MPa (750°F, 865 psia)
   c. Turbine outlet temperature and pressure - 186°C, 1.07 MPa (366°F, 155 psia)
   d. Process fluid - steam - Building and Industrial Processes
   e. Process fluid temperature and pressure - 178°C, 0.96 MPa (353°F, 140 psia)

5. Design Point (Noon Winter Solstice): 10.04 MW_t to Receiver Panel

6. Receiver:
   a. Receiver fluid - water/steam
   b. Configuration - flat panel, 8.78 m wide x 8.25 m high (28.8 ft x 27.1 ft)
   c. Type - natural recirculation boiler section, with preheater and superheater sections
   d. Elements - preheater, boiler, superheater, and drum
   e. Temperature (receiver fluid output) - 410°C (770°F)
   f. Pressure (receiver fluid output) - 6.1 MPa (890 psia)

7. Collector Field:
   a. Number of heliostats - 251
   b. Mirror reflective area per heliostat - 52.77 m^2 (568 ft^2)
   c. Cost - \$/m^2 installed - \$260.00 (1980\$)

d. Type - Second Generation

e. Field Configuration - north

f. Total mirror reflective area - 13,245 m^2 (142,516 ft^2)

g. Total collector field area - 62,730 m^2 (15.5 acres)

8. Storage: None

9. Construction Cost:

   a. Total Construction Cost - including all capital, startup, and checkout costs but excluding O & M - (1980 $)

10. Construction Time: 41 months

11. Solar Facility Contribution at Design Point:

    a. Receiver Output - 8.84 MW_t
    Percent of the sum of Steam Plant No. 4
    complex peak thermal load and base complex electrical load (35%)

    b. Electrical power - .678 MW_e
    Percent of base complex
    electrical power 6.7%

    c. Mechanical power - MW_m and percent of total complex
    mechanical power - 0

    d. Process power - 7.92 MW_t
    Percent of Steam Plant No. 4 complex peak
    process thermal load - 55%

12. Solar Facility Contribution, annual:

    a. Receiver output - 10,870 MWh_t
    Percent of the sum of Steam Plant No. 4
    complex thermal load and base complex electrical load - 6.0%

    b. Electrical energy - 616 MWh_e
    Percent of base complex
    electrical energy - 0.7%

c. Mechanical energy - MWh_m and percent of total complex mechanical energy - 0

d. Process energy - 9583 MWh_t
Percent of Steam Plant No. 4 complex process thermal load - 10.4%

13. Solar Fraction:
   a. Design Point - 0.35
   b. Annual - 0.06

14. Annual Fossil Energy Saved: 8286 barrels of crude oil at 5.80×10^6 Btu/barrel -

15. Type of Fuel displaced: natural gas/oil

16. Ratio of $\frac{\text{Annual Energy Produced:}}{\text{Total mirror area}}$ $\frac{MWh_t}{m^2}$ - 0.82

17. Ratio of $\frac{\text{Capital Cost}}{\text{Annual Displaced Fuel}}$:

18. Site insolation (direct normal):
   a. Design point - 950 W/m^2
   b. Annual average - 4.57 KWh/m^2-day -
   c. Annual average with insulation greater than 250 W/m^2 = 4.25 kWh/m^2 - day (250 W/m^2 is the approximate value required to overcome losses, this value varies with time of day and time of year).
   d. Source - weather tape for Atlanta, GA - SOLMET

19. Cogeneration Utilization Efficiency (CUE) - 75.5%

steam supplying any demand in excess of the solar facility output. Similarly, the solar electrical output displaces power normally purchased from Georgia Power with all solar capacity being used for this purpose.

The feedwater supplied from the existing plant is fed into a level controlled surge tank for subsequent use in the solar facility. This method renders the feed control system for solar operation almost independent of the existing feed controls.

Figures 1.4-2 and 1.4-3 show the site arrangement of the preferred configuration. The heliostat field is located north of the receiver tower. The tower is located to best utilize the existing land area available for the collector field. Traffic now served by Seventh Street, part of a golf fairway and a temporary building used for band functions will be displaced to provide space for the solar facility.

The collector field consists of a fan shaped array of 251 heliostats on 62,730 m^2 (15.5 acres) of land. The heliostats employed are nominal second generation heliostats with characteristics as defined by Sandia National Laboratories, Livermore at the start of the conceptual design program. This heliostat is a single pedestal design which has a glass reflective area of 52.77 m^2 (568 ft^2), an aspect ratio of 1.0, and carries 12 mirror modules of size 1.22 m x 3.66 m (4 ft x 12 ft) each. This heliostat concept was selected as representative of the class of configurations that will be available in 1985 for solar cogeneration applications.

The receiver of the Receiver System provides a means of transferring the incident radiant flux energy from the collector system into superheated steam. The receiver subsystem consists of one vertical panel of tubes to intercept the radiant flux reflected from the collector system, a single tower structure to support the receiver, and associated steam drum and piping. The external central receiver concept is based on the water/steam central receiver technology being developed by DOE. The receiver also includes the valves and

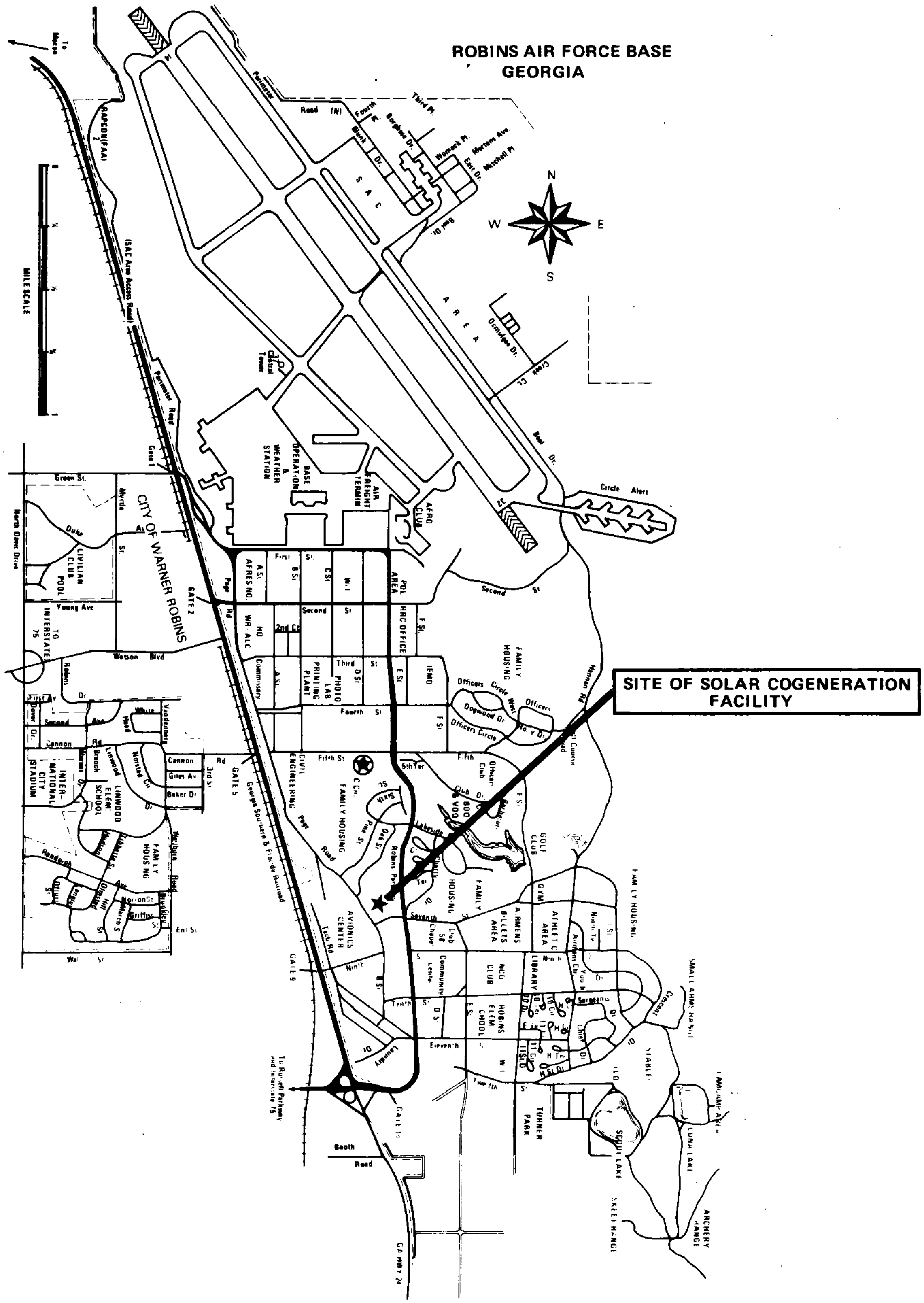


Figure 1.4-2. Location of Solar Cogeneration Facility on Robins Air Force Base

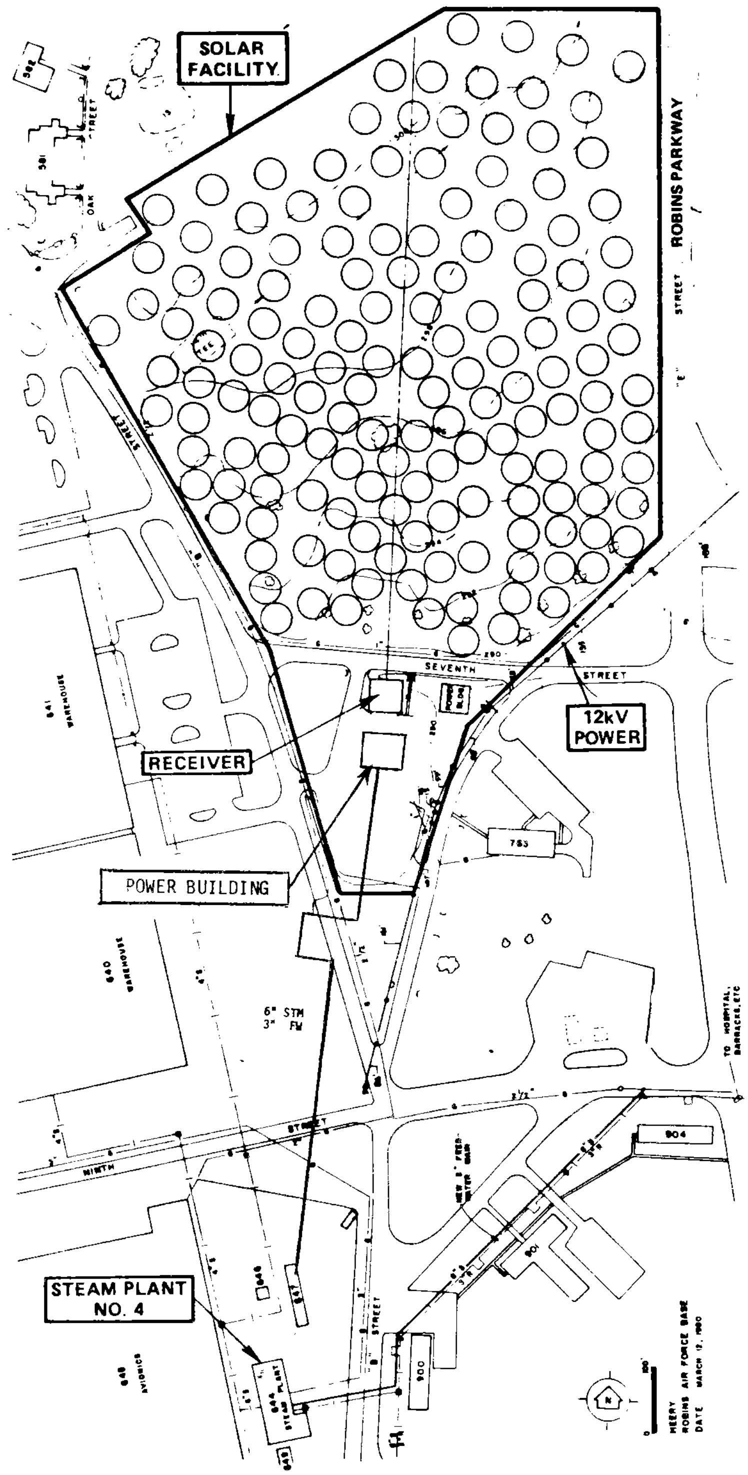


Figure 1.4-3. Site Plot Plan for Solar Cogeneration Facility on Robins Air Force Base

control system necessary to regulate flow, temperature, and pressure; and the required control system components necessary for safe and efficient operation, startup, shutdown, and standby.

The Master Control System is used to sense, detect, monitor, and control all parameters necessary to ensure safe and proper operation of the entire integrated solar cogeneration facility. The control system consists of computers, peripheral equipment, control and display consoles, control interfaces, data acquisition equipment and software.

The Electrical Power Generating System (EPGS) provides the means for converting to electrical power the thermal output from the receiver. The output from the EPGS is regulated for integration into the Robins Air Force Base electrical distribution network. The EPGS consists of the turbine generator and switchgear required to interface the electrical output of the solar facility to the base distribution system.

1.5 SOLAR COGENERATION FACILITY PERFORMANCE

The Solar Cogeneration Facility at Robins Air Force Base can produce electric power and process steam from solar energy over a broad range of loads. In this cycle, feedwater is received from the existing base feed system associated with Steam Plant No. 4. High pressure superheated steam is generated in the solar receiver and delivered to a turbine at 6.0 MPa/400°C (865 psia, 750°F) for the production of electricity. After expansion through this turbine to a pressure of 1.07 MPa (155 psia) the steam is delivered, after piping loss, to the base Steam Plant No. 4 distribution system at 0.93 MPa (140 psia).

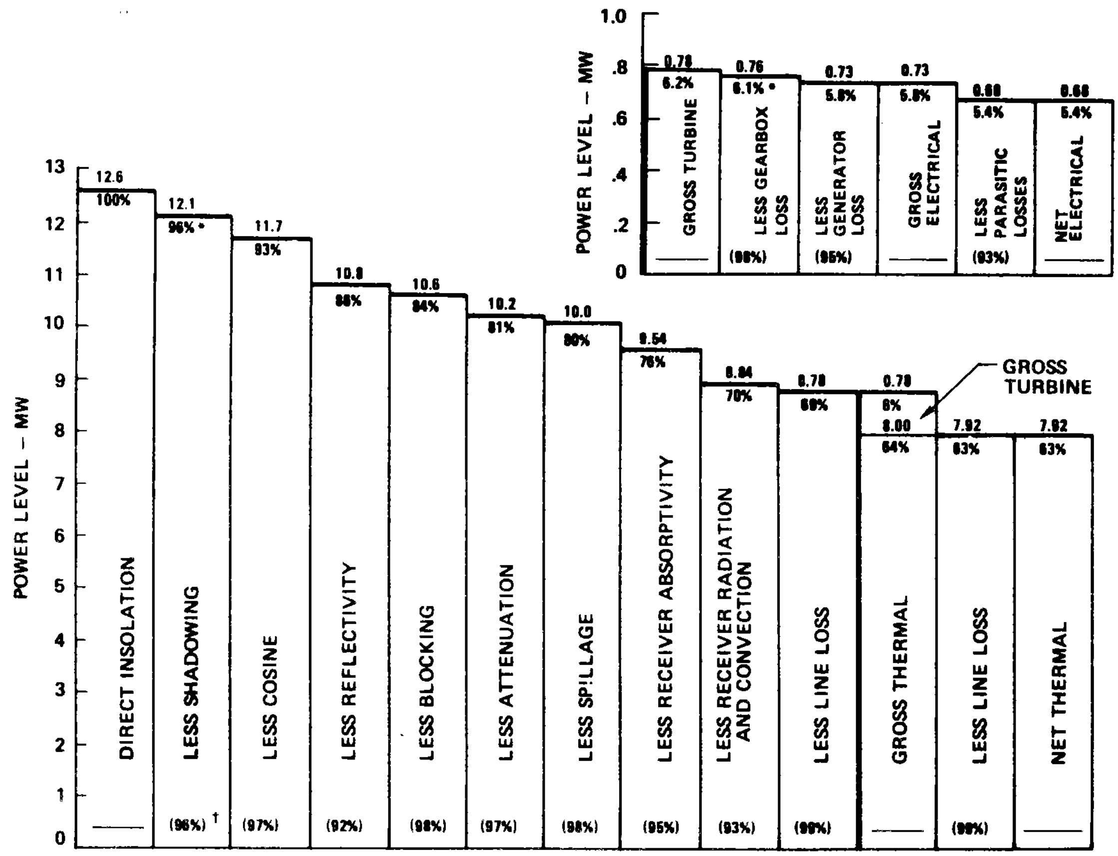
The solar cogeneration facility operates in parallel with one or more of the four fossil boilers in Steam Plant No.4 to satisfy the steam demand. The collector field and receiver are sized so that during spring and fall months (the time of lowest steam demand), the total of the steam produced from solar energy in full sunshine and the steam produced by one fossil boiler at its lowest efficient operating level ($\sim$ 20 percent of rated) will meet the anticipated steam demand. At times when either the solar insolation is reduced or the steam demand is greater, the operating level of the fossil boiler (or boilers) is increased so that the steam demand is satisfied. This plan of operation ensures that 100 percent of the solar energy which is meteorologically available is used to displace fossil fuel. Stated conversely, the installed solar equipment can be utilized to the maximum benefit that the weather allows. The operation of at least one fossil boiler is required to satisfy the steam load. The solar facility so sized can produce 678 kW_e and 7.92 MW_t in the form of 11,820 kg/h (26,010 lb/h) of 1.07 MPa (155 psia) discharge steam at noon winter solstice based upon an insolation of 950W/m^2.

The solar facility performance characteristics are summarized in Table 1.5-1 for the noon winter solstice design point. Figure 1.5-1 is a stair-step power efficiency diagram at the design point which identifies the various components and their respective efficiencies which contribute to the overall facility power output. Figure 1.5-2 is a similar stair-step energy efficiency diagram for the typical meteorological year (annual).

The dynamic response characteristics of the solar facility, its systems and components and the fossil boiler were evaluated to establish that startup/shutdown and cloud transients pose no design or operating problem and so the combined solar/fossil/steam distribution arrangement can be operated without requiring a thermal storage system to buffer the solar generated transients.

TABLE 1.5-1: SOLAR COGENERATION FACILITY CHARACTERISTICS

• Collector System	
- Heliostat Type	Typical 2nd Generation
- Field Configuration	North Field
- Field area	62,730 m^2 (15.5 acres)
- Number of heliostats	251
• Receiver System	
- Receiver type	External Natural Circulation, rectangular external panel configuration
- Receiver size	8.78 m wide by 8.25 m high
• Tower Height	60 m (Receiver centerline)
• Electrical Generation System	
- Cycle	Commercial type backpressure turbine
- Turbine expansion efficiency	61%
- Turbine inlet	6.0 MPa, 400°C
- Turbine exhaust	1.07 MPa, 177°C



* XX% - Net efficiency at each point in conversion process.

†(XX%) - Efficiency of each conversion step.

Figure 1.5-1. Power Efficiency Diagram for Noon Winter Solstice

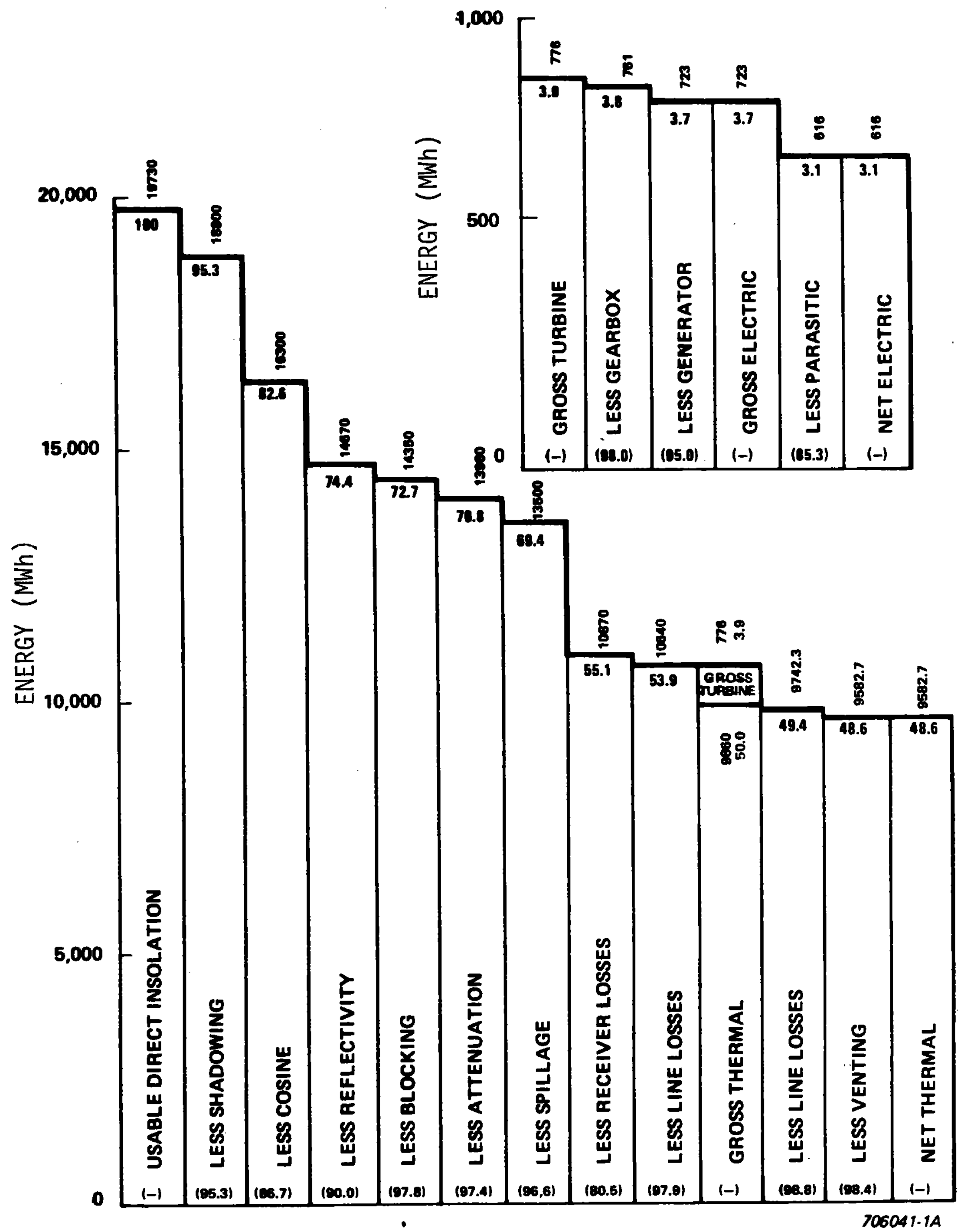


Figure 1.5-2. Energy Efficiency Chart - Annual Average

1.6 ECONOMIC FINDINGS

The economic assessment of the solar facility was based on the methodology and economic assumptions defined in the USAF Energy Conservation Investment Program (ECIP). This approach is basically a present worth analysis of non-recurring captial costs, recurring operating and maintenance costs, and recurring benefits due to reduced energy usage.

In performing this economic assessment, eight scenarios were evaluated to portray the economic worth under different economic assumptions. These eight scenarios were structured as follows:

- Scenario A - A base case evaluation using the ECIP economic parameters and the capital, O&M, and engineering cost estimates for the first facility.
- Scenario B - The same as Scenario A except that the DOE capital costs have been removed; thus, this assessment represents the Owner's (USAF) economic view of the facility.
- Scenario C - The same as Scenario A except that the Owner and O&M costs have been removed; thus, this assessment represents the DOE's economic view of the facility.
- Scenario D - The same as Scenario A except that the capital costs were reduced to correspond to the fiftieth installation for a 0.85 learning curve and the one-time design engineering costs were removed.
- Scenario E - The same as Scenario A except that the capital costs were reduced to correspond to the three-hundredth installation for a 0.85 learning curve and the one-time design engineering costs were removed.
- Scenario F - The same as Scenario A except that the natural gas and oil escalation rates were increased by two percent over the Scenario A values (sixteen percent instead of fourteen percent).
- Scenario G - The same as Scenario A except that the natural gas and oil escalation rates were increased by four percent over the Scenario A values (eighteen percent instead of fourteen percent).
- Scenario H - The same as Scenario A except that the 1981 costs for natural gas were set identical to the 1981 costs for oil, on an equivalent energy basis.

For the above economic scenarios, the results were:

Economic Scenario and Description	Benefit/Cost Ratio	Payback Period (Years)
A - Base (ECIP)	0.32	67
B - USAF View	8.2	4.2
C - DOE View	0.33	26
D - 50th Installation	0.97	27
E - 300th Installation	1.48	18
F - 16%/yr. Fuel Escalation	0.54	67
G - 18%/yr. Fuel Escalation	0.54	67
H - Natural Gas Costs Equal Oil Costs	0.90	17

In summary, the Westinghouse Design team and the U.S. Air Force believe that considerable technological advances in solar energy systems could be obtained from the installation and operation of the solar cogeneration facility at Robins Air Force Base with, what is considered to be, a modest capital investment.

1.7 DEVELOPMENT PLAN

The overall objective of the Solar Thermal Repowering Program is to provide demonstration plants that serve to reduce the uncertainty associated with the design, performance, operation, maintenance, cost, and safety of a new technology. User risks associated with the uncertainty in each of these areas must be reduced considerably before plants can be financed entirely on a commercial basis. The cogeneration facility described in this conceptual design report is to be located on RAFB and uniquely serves the overall objective. The construction and operation of the facility will provide firm data thereby leading to the elimination of uncertainties and promoting further applications.

The steps required to proceed from the conceptual design through one year of operations by the user (USAF) are: Preliminary and Detail Design; Procurement; Construction and Checkout; and Startup, Performance Validation and Monitoring of Operation. Figure 1.7-1 shows the major milestones to be achieved in support of the overall objective. This schedule presumes start of contract in October 1982 and culminates with the completion of one year of operation in 1987.

The design, procurement, fabrication, and erection of the receiver represent the critical path for this program. An expedited schedule could shorten the time to completion. The desirability of earlier completion would naturally be addressed as part of further contract negotiations.

Construction work is planned to start at the site in August 1984, with initial operation by the RAFB personnel in March 1986. Owner preparation work will be furnished prior to start of construction.

The roles and responsibilities of DOE and USAF have been defined to produce a rational sharing of resource investment and risk while avoiding burdensome or complicated financial interactions. Specifically this plan presumes that DOE will provide all design and capital investments while the USAF will provide all services for making the site ready for construction and all normal, planned operating and maintenance costs after completion of construction. The expenditures schedule for each participant is shown in Table 1.7-1.

TABLE 1.7-1: EXPENDITURES SCHEDULE
(Millions of Dollars) (1981 $)

	TOTAL	FISCAL YEAR (OCTOBER 1 THROUGH SEPTEMBER 30) 1983	1984	1985	1986	1987 to 2011
Capital Costs (DOE)	7.34	0.02	0.59	5.65	1.08	0
User Costs (USAF) - Installation	0.5	0.1	0.3	0.1	0	0
User Costs (USAF) - O & M	4.2	0	0	0	0.1	4.1

The experience gained from these cooperative efforts of DOE and USAF can be promulgated to support other solar thermal applications. Transferring this experience to other potential industrial and military uses will be a prime objective of this program.

1.8 SITE OWNER'S ASSESSMENT

1.8.1 ENDORSEMENT OF PROJECT RESULTS

The United States Air Force has for many years recognized the importance of energy conservation and the application of innovative and latest state of the art energy technology. Considerable attention has been focused on facility energy which accounts for approximately 29 percent of the total energy used by the Air Force. For installation operations, average annual energy use per gross square foot of floor area is to be reduced 20 percent in existing buildings and 45 percent in new buildings by FY 1985 as measured from the FY 1975 usage level; and, in existing buildings, energy-conservation retrofits are to be installed by 1990 and consumption of petroleum-based fuels reduced by 30 percent. Alternative energy sources are to provide, by FY 1985, at least 10 percent of the energy used in Air Force installations, and renewable energy

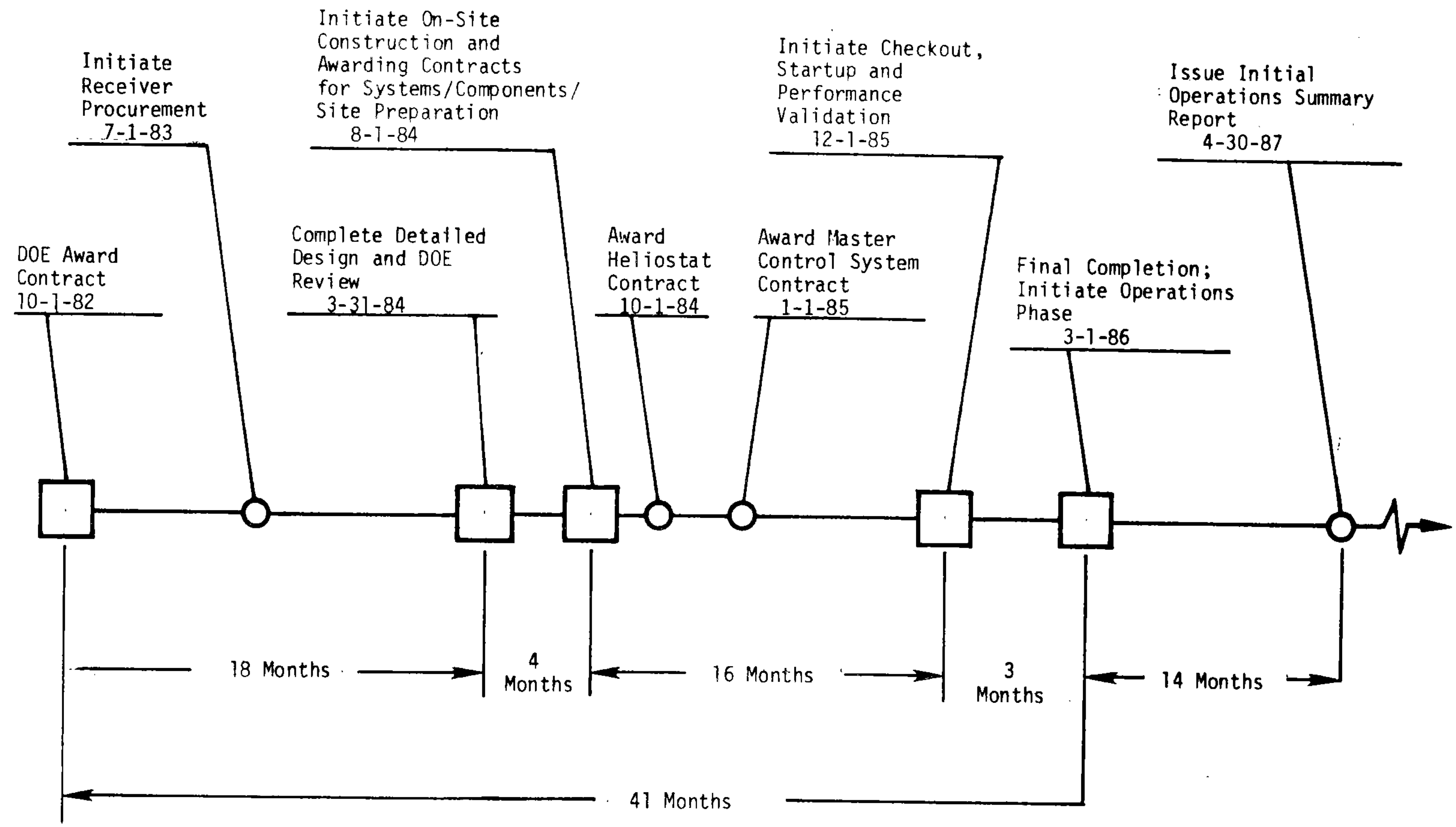


Figure 1.7-1. Major Milestones and Schedule for Design, Construction, Startup, and Initial Operation of Robins AFB Solar Cogeneration Facility

sources, at least 1 percent; energy consumption levels are to be identified and monitored through metering and energy audit/survey programs; and potential energy conservation measures are to be identified.

The solar cogeneration facility at Robins Air Force Base will assist the Air Force in meeting these goals.

To this end, Robins Air Force Base and the Air Force Logistics Command are prepared to support the solar cogeneration facility by:

a. Providing sufficient land area for the collector field and tower

b. Closing Seventh Street between "B" Street and Robins Parkway

c. Providing additional land area for the collector field currently utilized for the 14th tee of the golf course

d. Considering the proper course of action for the acquisition, use, or elimination of Building No. 760 (the Band Building)

e. Approving the removal of the trees in and at the sides of the collector field

Long range plans for Robins anticipate an expansion of facilities in the area of the solar cogeneration facility. This will increase the process steam load for Steam Plant No. 4. The solar cogeneration facility would provide relief for these additional load requirements.

The above endorsement is consistent with the understandings and agreements reached between Westinghouse and Air Force personnel during the first meeting at Robins in January 1981, at the "User Review of Site Specific Configuration" meeting held on 11 March 1981 at Robins and the "Mid-term Review" meeting held at Robins on 30 April - 1 May, 1981.

1.8.2 ROBINS AIR FORCE BASE BENEFITS FROM THE SOLAR COGENERATION FACILITY

Located in the heart of middle Georgia, Robins Air Force Base, is the home of the Warner Robins Air Logistics Center (WR-ALC) one of five Air Force Logistics Command (AFLC) industrial-logistics complexes in the U.S. Warner Robins ALC ensures the readiness of operational forces by providing worldwide logistics management for over 40 major weapons systems, including the C-141 and C-130 cargo aircraft, helicopters, various missiles, the F-15 Air Superiority Fighter and over 190,000 items used on every aircraft in the Air Force inventory. Warner Robins ALC is also the Avionics Center for the Air Force, and the Air Force technology repair center for gyros, airborne electronic equipment, life support systems, and propellers. Headquarters, Air Force Reserve, the Strategic Air Command 19th Bombardment Wing and various Air Force tenant organizations are also located at this 8,855 acre installation, which employs nearly 15,000 civilian employees and is the largest industrial complex in Georgia. The large work force, highly specialized equipment and industrial processes, and extensive facilities make Robins AFB one of the largest and most important concentrations of Air Force resources in the United States.

As a major logistics installation, Robins Air Force Base depends heavily upon energy in quantity to accomplish its immense logistics mission. For years, AFLC activities like WR-ALC have increasingly relied upon a plentiful supply of low cost energy to service a variety of Air Force logistics needs. Management action has been particularly intense during the past decade to increase system effectiveness and work force productivity by exploiting new mechanized methods, system automation, and high-technology concepts. This trend has been exemplified at Robins by the employment of modern metal cutting, forming and heat-treatment maintenance facilities, new mechanized material handling systems, and the extensive use of environmentally-controlled areas for computer data processing, airborne electronic component repair, corrosion control work, and other functions. The result has been an era of enchanced productivity and operational responsiveness, accompanied by an increased reliance upon the energy "factor of production."

Energy-intensive AFLC activities have been severely affected by the nationwide energy cost-supply problem. The decline in domestic oil and natural gas production, complicated by the growing national dependence upon unreliable, high-priced foreign energy sources, has had a pronounced impact on the Air Force activities as well as private industry. Costs have climbed steeply since the early seventies for electric power, fuel oil, and natural gas, with the cost growth expected to continue in the future. Vigorous energy conservation measures have been effective in most cases in reducing energy consumption. Total energy costs have risen, nevertheless, because of increases in utility rates.

Robins AFB and other Air Force activities are responding to today's energy challenge with emphasis on improved energy effectiveness on several fronts. A number of specific programs are under way to carry out Executive Order 12003, which requires a 20 percent reduction in energy in existing facilities by 1985.

Building Energy Technical Surveys (BETS)

Robins was one of the first Air Force installations to implement building energy audits using a computer simulation model, which resulted in Military Construction Program actions in FY 80, 81, and 82. Projects in this context include conventional energy savings measures, such as adding insulation, storm windows, etc., as well as technical improvements in heating and cooling systems. Improvements to 30 buildings, costing $1.5 million, have been awarded to date. Energy conservation improvements in 16 other buildings are now under design.

Energy Monitoring and Control System (EMCS)

The EMCS is the latest state of the art in centralized computer control of utilities energy consumption. Construction now under way will complete connection of the EMCS to all major Robins facilities. The system allows central control for manual and programmed turn-off and turn-on of air conditioning, heating and other equipment. The EMCS also provides monitoring of steam pressure, chilled water temperature, room temperature, air flow, metering capability, and preventative maintenance information. The EMCS will play a major role in meeting energy goals at Robins.

Energy Curtailment Contengency Plan

To prepare for the increasing threat of energy shortages, Robins developed and published in April 1980 a comprehensive energy curtailment contingency plan to deal with possible energy shortage scenarios.

Industrial Solar Applications

A solar energy system to purify aircraft fuel tank purge fluid was locally designed and installed in 1977 as one of the first industrial solar applications in the Air Force. Prior to the installation of this system, purge fluid (a high flash point oil which is used to "wash out" aircraft fuel tanks to reduce explosion hazards) became contaminated with more flammable aircraft fuel after repeated use, and the flash point would drop below the minimum safety level. This contaminated fluid was then sold for a fraction of its original cost. With the solar system, the purge fluid is now reclaimed and purified for repeated use. The purge fluid is purified by flowing through the solar panels for heating and then to an aeration tank where the more volatile fuel components are evaporated off and condensed for other uses. The project paid for itself the first year and at current purge fluid prices now saves the taxpayer over $41,000 per year. In addition to this project, Robins AFB recently completed construction of a $1.0 million solar energy system for the aircraft corrosion control facility. The system utilizes 1,580 m^2 (17,000 ft^2) of flat-plate collectors to produce 60-82°C (140-180°F) water, which in conjunction with a 473 m^3 (125,000 gallon) storage tank, is used for aircraft corrosion treatment of C-130, C-141 and F-15 aircraft. The system will supply virtually 100 percent of the 12 million liters (3.2 million gallons) of hot water required annually for these aircraft.

Energy policy at Robins AFB and with AFLC, as exemplified in the above initiatives and other actions, is to support national energy objectives by becoming more energy efficient, reducing dependance on critical fuels and by shifting to alternative sources. The Westinghouse proposed Solar Cogeneration Facility will make a major contribution to the base energy program by reducing base reliance on nonrenewable energy sources. This application of advanced energy technology will also be of considerable value to the direct logistics mission of the base by servicing the south end of the base and particularly the Directorate of Maintenance Avionics Centers in Buildings 640 and 645, the Base Hospital and Robins Community Center. Maintenance facilities in the vicinity of the proposed solar site operate five days per week, three shifts per day, and weekends during the day shift. The weekend work is required for performance of scheduled avionics work load with existing equipment and facilities. This tends to spread out our energy utilization and will enable the proposed solar facility to fully contribute at all periods of energy generation. The electrical power generation will be especially beneficial because of the consistently growing peak demand. Based on previous experience with solar energy, base officials, including the using activity and the Base Civil Engineering organization, are very enthusiastic about developing and implementing a solar cogeneration application. There is no doubt that the solar cogeneration facility will assist Robins in the long range AFLC goal to be energy self-sufficient for the industrial processes by the year 2000.

1.8.3 COMMENTS ON OPERATION, SAFETY, AND ENVIRONMENTAL IMPACTS AND BENEFITS

RAFB and Air Force Logistics Command personnel have maintained an intimate knowledge of the conceptual design of the cogeneration facility with a continual surveillance of the compatibility of the design with existing operating staff capabilities, safety considerations for the facility and its interaction with the utilization of the surrounding areas, and the environmental benefits and/or impacts.

During the execution of this design RAFB personnel have reviewed and influenced the content of the facility specification with respect to safety requirements, reviewed the tower location and height in relation to similar structures (water towers) and existing flight paths, provided local data for the environmental criteria section for the Facility Specification and advised on specific actions to initiate environmental deliberations. Based upon the above actions, the user is confident that appropriate actions have been taken for the conceptual design phase and that the proper background has been established to expect success from on-going work relative to operational, safety and environmental issues.

1.8.4 COMMENTS ON PROJECT DEVELOPMENT PLAN AND SCHEDULE

The development plan presented in Section 7.0 of this report has been reviewed by the user to determine whether the role assigned to the user is desirable within the context of the total plan. The roles, authority and responsibilities as outlined in that section are endorsed by the Air Force Logistics Command and RAFB as a desirable arrangement worthy of support. The owner costs associated with accepting that user role are also agreeable to the Air Force Logistics Command. The schedule for operation in 1986 is deemed satisfactory although an expedited schedule would be preferred by the user. Earlier operation can be achieved either of, or a combination of, two ways. First, a contract start date prior to October 1982 would improve the operation date on a day for day basis. Second, an implementation of a "fast-track" schedule in which aggressive early committments to long-lead procurement items are pursued could shorten the design and construction period by an estimated six to nine months. Efforts to achieve these improvements is desirable.

2.0 INTRODUCTION

This report covers work performed for the Department of Energy (DOE) for a program entitled "Design of a Solar Central Receiver System Integrated with a Cogeneration Facility." The period of performance was December 1, 1980 to August 31, 1981. Tne programmatic data pertaining to tnis contract are:

Contract Number	DE-AC03-81SF11494
Contract Amount	$540,704
Prime Contractor	Westinghouse Electric Corporation Advanced Energy Systems Division P. O. Box 10864 Pittsburgh, PA 15236
Principle Investigator	Robert W. Devlin (412-892-5600)

The conceptual design developed during this program for solar cogeneration at the Robins Air Force Base is technically feasible for project implementation by 1986. This concept uses conventional water/steam technology familiar to Robins operating personnel. The design and user team participants are convinced that demonstration of this technology not only meets the program objectives but is in total consonance with the continuing United States Air Force objective of establishing and installing alternate energy sources through the year 2000.

2.1 STUDY OBJECTIVE

The principle objective of this study was to develop a conceptual design, including performance and cost estimates, for a solar cogeneration facility to displace fossil fuel and purchased electricity at the Robins Air Force Base with potential for construction by 1986. The design objective is to make best use of existing solar technology compatible with base operating experience and to provide the best economics for this application. Specific tasks in support of these objectives were 1) to prepare a facility (overall system) specification for the solar facility, 2) to select a preferred configuration and prepare a conceptual design, 3) to establish the performance and economic merit of the facility, and 4) to prepare a development plan leading to construction and operation of a demonstration facility by 1986.

2.2 TECHNICAL APPROACH AND SITE SELECTION

The technical approach for the study, including a description of each task, is described in Section 2.2.1. The rationale for selecting Robins Air Force Base is discussed in Section 2.2.2.

2.2.1 TECHNICAL APPROACH

The Robins Air Force Base Solar Cogeneration Program was divided into seven major tasks:

Task 1 - Solar Cogeneration Facility (Overall System) Specification
Task 2 - Selection of Site-Specific Facility Configuration
Task 3 - Facility Conceptual Design
Task 4 - Facility Performance Estimates
Task 5 - Facility Cost Estimates and Economic Analysis
Task 6 - Development Plan
Task 7 - Program Plan and Management

The Westinghouse Team approach to accomplish the program was based upon two concepts: (1) using high caliber technical personnel with directly applicable experience in solar applications, and (2) implementing effective schedule and cost control measures on a task-by-task basis.

The foundation of the program was Task 2 - Selection of a Site-Specific System Configuration complemented by Task 1 - Facility (Overall System) Specification that is designed to guide the performance of all subsequent tasks.

2.2.2 SELECTION OF ROBINS AIR FORCE BASE FOR SOLAR COGENERATION

A review of the industrial process steam usage in the United States and the potential for economical cogeneration assisted the Westinghouse Team in the selection of a concept which would predominately serve a baseload process steam need with electrical generation in a topping cycle mode. The review indicated that there are widespread industrial as well as military applications wherein a steady usage of 862-1000 kPa (125-145 psia) steam is required in conjunction with electrical needs. The United States Air Force Logsitics Command, headquartered at Wright-Patterson Air Force Base, Ohio is responsible for a large number of bases which require this type of application. They were a major participant in this program. Robins Air Force Base, Georgia, one of several major Logistics Centers under the command of Wright-Patterson, provides the site specific application, necessary support facilities, and substantial personnel services to support the program.

Robins Air Force Base was selected for a variety of reasons:

- United States Air Force Commitment to Renewable Energy
  The Air Force Logistics Command has been actively involved in the pursuit of applications for all of the renewable energy sources. They are leading all of the other services in this pursuit and are totally committed to the success of this program.

- Constant year round thermal and electrical energy demand
  Considering planned expansion, the thermal requirements on Steam Plant No. 4 on the base vary from 10,909 kg/h (24,050 lb/h) to 22,100 kg/h (48,800 lb/h) of steam for every hour of the year which provides a constant demand for effective annual usage of solar energy. Site electrical demand is significantly greater than provided by this application, therefore, all electricity generated is expected to be consumed on site.

- Excellent solar characteristics
  Robins is in a zone of good solar insolation with little cloud cover and therefore will provide an excellent basis for verification of solar energy usage.

- Wide spread market potential
  The site energy demand characteristics are typical of numerous military bases and a large spectrum of industrial sites.

- <u>Stable energy demand</u>
  Substantial energy conservation measures have been employed at Robins and facility additions are planned; therefore, no reduction in thermal demand is forecasted assuring full utilization of the output of the Solar System.

- <u>No institutional or environmental constraints</u>
  There are no institutional or regulatory constraints for use of land for solar cogeneration. Environmental assessments of surrounding land indicate that no known constraints exist.

The Georgia Power Company offers support services for electrical interfaces and will enter into the necessary agreements for electrical power transfer between its network and the base generating facility.

The Westinghouse Team has outstanding qualifications, experience, and capabilities to ensure the successful demonstration of the solar cogeneration at Robins Air Force Base.

- Each participant is actively engaged in the development and application of solar technology.

- Each participant has successfully been involved in efforts equivalent to the proposed scope of work and has extensive experience for the conceptual design and evaluation of solar cogeneration systems.

- The Westinghouse Team members are experienced suppliers of hardware and services for innovative industrial/military development projects, including prior work conducted at Robins Air Force Base by Heery and Heery.

This project team was supported by Wright-Patterson and Robins Air Force Base who have strong, long standing interests in energy conservation. The Air Force has instituted several energy conservation projects at Robins. Robins personnel supplied site interface data, energy utilization data, weather data and potential military market data in support of this program. The Georgia Power Company has developed a nationally recognized posture for support of innovative energy conservation measures employing solar energy and is fully committed to this program at Robins, one of its largest electrical customers.

In keeping with the DOE Solar Cogeneration Program objectives, a concept has been selected which utilizes the latest in DOE developed central receiver technology. The concept makes the most efficient use possible of the solar facility in that all of the energy collected is utilized in the application; no thermal storage is required; the system operates base-loaded every sunny day of the year, and the application is equivalent to innumerable industrial and military needs throughout the country yielding vast commercial potential.

In summary, the technical considerations of the application, the sincere user interest, and the proven team compatibility and cooperation dictate the choice of Robins Air Force Base as the proper site selection.

2.3 SITE LOCATION

Robins Air Force Base is located in Houston County east of the City of Warner Robins in Central Georgia. Robins AFB is 37 km (20 miles) south of Macon, Georgia.

Latitude and longitude is N32° 36', W83° 36', respectively. Elevation is 93 m (306 ft) above mean sea level.

The collector field and receiver tower are located in a largely unused grassed area adjacent to an industrial area of the base.

The specific heliostat field is bounded on the west by "B" Street, on the south by Seventh Street, on the north by a portion of a base golf course and on the east by Robins Parkway. The heliostat field contains 62,730 m^2 (15.5 acres).

The central receiver tower location is just beyond the northwest corner of Building 760, the Band Building, which is a single story wood frame structure with concrete slab on ground construction.

The site is within 305 m (1000 feet) of a base steam plant, which can receive the entire solar derived thermal output, and within 31 m (100 feet) of a 12.6 kV power line, which can receive the entire solar derived electrical output.

The site is presently bounded by sanitary sewers, storm sewers, natural gas lines, television, telephone and other communication lines, as well as central district steam and electrical power.

This Robins site is typical of many military and industrial sites that are located in or near areas that are well developed, and where land space for heliostat fields is limited. This particular application clearly demonstrates the capability of effective utilization of solar energy in a community/ industrial location.

2.4 SITE GEOGRAPHY

Robins Air Force Base is located at the northern border of the coastal plains, at the foot of the Piedmont Plateau. The topography is generally flat, but well drained and not subject to flooding.

The soil is composed of sand and a sand-clay material. The water table is expected to be at least 3.0 m (10 ft) below grade. Soil borings for adjacent structures have been provided by the Base. Foundation design for the tower, power building and heliostat supports will be based on a geotechnical analysis, to be performed in a subsequent work order. The site selected for the heliostat field has a favorable slope of 3.0 m (10 ft) to the south and a cross slope of 1.8 m (6 ft) from west to east.

2.5 CLIMATE

Located very near the geographical center of Georgia, RAFB is well situated to escape rigorous climatic extremes. The climate is a blend of the maritime and continental types. Rarely does either dominate for long unbroken periods. The prevailing northwesterly winds of winter and early spring are frequently superseded by southerly flows of warm, moist tropical air. The southern extremity of the Appalachians presents an effective barrier to the rapid flow of cold air in winter. In summertime the prevailing southerlies frequently give way to the drier westerly and northerly winds. In short, the climate is truly equable.

Typical monthly meteorological data (National Oceanic and Atmospheric Adminstrations (NOAA)) are presented in Table 2.5-1. The NOAA annual weather data shows an average temperature of 18.4°C (65.1°F), average precipitation of 1.1 m (44.5 inches) and average sunshine of 2810 hours.

Severe storms are infrequent in this locality. There have been few tornadoes, the most recent on May 21, 1955. Thunderstorms occur on approximately two days out of five from June through August. Occasionally, thunderstorms are accompanied by severe squalls, but property damage from this cause has been heavy in only a few instances. As RAFB is some 200 miles from both the Atlantic and Gulf of Mexico, hurricanes offer no direct threat, and secondary effects are generally milder than those produced by the heavier thunderstorms. Property damage of a minor nature occurs occasionally due to gale force winds and heavy rainfall.

Snow occurs at some time during most winters, but amounts of snow are usually quite small as evidenced by only 6 days with one inch or more of snowfall in the 25-year period 1949-1973. However, on rare occasions heavy snow does occur in this area. The two heaviest snowstorms (24-hour amounts) on record are 0.2m (6.9 in.) in February 1914 and 0.4m (16.5 in.) in February 1973.

During the accomplishment of Task 2 of the contract (Selection of Site Specific Configuration), detailed hour-by-hour insolation data was not available for the RAFB location. The insolation data used during this phase was that for the Shenandoah Total Energy System site, located in Shenandoah, Ga, about 80 km (50 mi) northwest of Warner Robins. Table 2.5-2 presents the data. This information was then transformed from hours into days at a typical insolation level, and used as the insolation data for the Annual Integrated Energy Performance Model (Appendix E). For the conceptual design phase, an hour-by-hour insolation data tape (SOLMET form) has been obtained for Atlanta, Georgia. Since this location is about 110 km (70 miles) northwest of Warner Robins, a comparison was made between the minutes of sunshine for the Warner Robins weather station and from the SOLMET weather tape. This data is presented in Table 2.5-3. Considering the two different data sources and the

TABLE 2.5-1: TYPICAL WEATHER DATA FOR MACON/WARNER-ROBINS, GA.

Month	Percent Sunshine	Max. Avg. Temp. °C	Min. Avg. Temp. °C	Mean Wind Speed kph	Relative Humidity Percent @ 0700	Relative Humidity Percent @ 1300
Jan.	54	15	3	13.5	83	59
Feb.	58	16	4	14.5	83	53
Mar.	62	20	7	15.0	85	52
Apr.	69	26	12	14.2	86	48
May	70	30	16	12.4	88	52
June	69	33	19	11.7	87	53
July	64	33	22	11.1	90	58
Aug.	69	33	21	10.4	92	59
Sep.	62	30	18	11.4	93	59
Oct.	69	26	12	11.1	88	51
Nov.	63	20	6	11.7	86	52
Dec.	56	15	3	12.4	84	56

TABLE 2.5-2: SHENANDOAH STE PROJECT WEATHER DATA

Insolation Level (W/m^2)	No. of Hours
0-50	1241
50-100	241
100-150	196
150-200	157
200-250	143
250-300	136
300-350	140
350-400	117
400-450	141
450-500	161
500-550	145
550-600	157
600-650	176
650-700	179
700-750	185
750-800	178
800-850	186
850-900	205
900-950	176
950-1000	115
1000-1050	5

TABLE 2.5-3: COMPARISON OF WARNER ROBINS AND ATLANTA (SOLMET) WEATHER DATA

Month	Max. Minutes of Sunshine	Minutes of Sunshine: Warner Robins	Minutes of Sunshine: SOLMET	% Difference from Warner Robins
Jan.	19,116	10,323	9,580	-7
Feb.	19,207	11,140	12,403	+11
Mar.	22,292	13,821	14,930	+8
Apr.	23,386	16,136	16,030	-1
May	25,744	18,121	17,323	-4
June	25,681	17,720	15,479	-13
July	26,156	16,740	16,561	-1
Aug.	24,795	17,104	15,955	-7
Sep.	22,262	13,802	14,717	+6
Oct.	21,144	14,589	16,408	+12
Nov.	18,889	11,900	13,360	+12
Dec.	18,676	10,458	12,023	+15

normal variations in the weather, there is a good comparison between the different weather station locations. As a further comparison, the SOLMET data was compared to the Shenandoah data used during Phase 2 of the project. As shown in Figure 2.5-1, the two sources compare very favorably. Therefore, the SOLMET data for Atlanta adequately predicts the typical weather for the Warner Robins location.

Table 2.5-4 lists a summary of the direct normal insolation from the SOLMET weather tape. Days with insufficient insolation are defined as days that have direct normal insolation which never exceeds 250 W/m^2. The value of 250 W/m^2 direct normal insolation is chosen as representative of the minimum insolation required for facility operation because about 250 W/m^2 direct normal insolation is necessary to meet the thermal losses of the cogeneration facility.

TABLE 2.5-4: SUMMARY OF SOLMET DIRECT NORMAL INSOLATION DATA

Total direct normal insolation	1668.4 kWh/m^2
Direct normal insolation greater than 250W/m^2	1550.3 kWh/m^2
Hours of direct normal insolation	4283 hours
Hours of direct normal insolation greater than 250 W/m^2	2406 hours
Number of days with insufficient insolation	53 days
Frequency of insufficient insolation days	
a) single day	26
b) 2 days in a row	9
c) 3 days in a row	3

2.6 EXISTING PLANT DESCRIPTION

Steam Plant No. 4 houses four water tube type boilers capable of producing 965 kPa (140 psia) saturated steam for distribution to a variety of comfort conditioning, hot water heating, and industrial process functions. There are, at present, approximately 30 different facilities served by this boiler plant. The steam distribution system is not interconnected with any other steam distribution system on the Base.

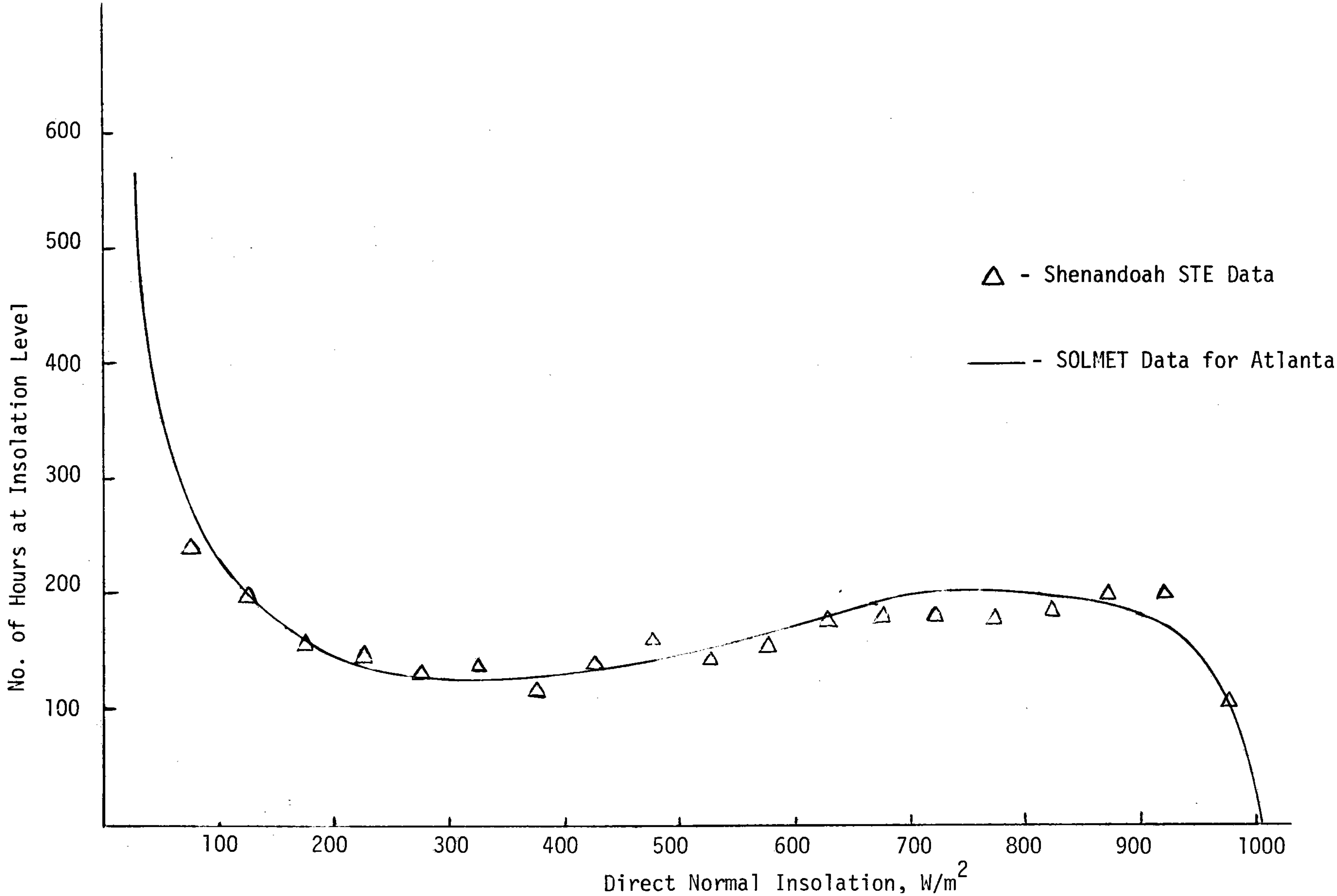


Figure 2.5-1 Comparison of Shenandoah and Atlanta (SOLMET) Weather Data

The steam plant contains a deaerating feedwater heater, steam turbine driven and electric motor driven feedwater pumps, chemical treatment system with monitoring devices, and steam flow recording meters. The plant utilizes natural gas fuel with oil backup.

The steam plant presently serves 30 diversified military and industrial buildings. The major steam temperature 177°C, 931 kPa (350°F, 135 psia) loads are:

	Steam Flow Rate	Power MW_t
Avionics Complex;	8,796 kg/h (19,363 lbs/h)	5.90
Dormitory Complex;	4,435 kg/h (9,763 lbs/h)	2.97
Aircraft Repairs;	1,450 kg/h (3,192 lbs/h)	0.97
Hospital;	1,139 kg/h (2,508 lbs/h)	0.76
Other;	3,580 kg/h (7,974 lbs/h)	2.43
Total	19,400 kg/h (42,800 lbs/h)	13.03

The steam loads include space heating, domestic hot water generation, sterilizers, absorption cooling, industrial steam process, makeup air tempering, and steam humidification.

Steam Plant No. 4 was built about 1955. Boiler No. 1 was replaced in 1970. Boilers No. 2 and No. 3 were installed in 1975. Boiler No. 4 is the only original boiler and it was converted from coal to gas/oil.

Boilers No. 2 and 3 are operated most of the time and are parallel controlled by a master steam pressure controller on the steam header. The steam turbine driven feedwater pump operates continuously and supplies a feedwater header. Turbine backpressure (exhaust) steam is piped into the deaerating feedwater heater. Each boiler has a modulating feedwater valve, positioned by a water level controller in its respective drum, and continuously receives deaerated feedwater.

Steam Plant No. 4 is ideally suited to receive and distribute the entire thermal output of the solar plant. The four boilers are very responsive to changes in header pressure and ramp up or down in less than 60 seconds as large loads on the piping systems are started up or shut down. The fossil boiler will respond to satisfy the steam load under transient solar conditions.

The industrial area of Robins Air Force Base is served by Georgia Power Company from a 20 MW substation, consisting of two 10 MW transformers, either of which can carry the entire connected electrical load. The load is carried 24 hours a day, 365 days a year and always exceeds one megawatt.

The electrical load is distributed at 12.6 kV. Transformers are provided at each building or group of buildings.

The entire electrical output from the solar plan can be assimilated and distributed by the existing electrical distribution system.

2.7 EXISTING PLANT PERFORMANCE

The existing Steam Plant No. 4 consists of four gas/oil fired, 0.97 MPa (140 psia) water tube steam boilers with a total rated capacity of 42,700 kg/h (94,000 lbs/h). The buildings connected to the plant have a maximum 1980 winter steam load of 19,400 kg/h (42,800 lbs/h). The maximum winter load is presently projected to increase to 22,200 kg/h (48,900 lbs/h) when three identified programmed buildings are connected. The January 1986 monthly <u>average</u> daylight projected load is 18,800 kg/h (41,500 lbs/h).

The steam demand has been increasing, reflecting the growth pattern of the base. Future expansion is towards the southern end of the facilities. The load on Steam Plant No. 4 has grown steadily for the past six years although the rate of growth has slowed somewhat during the past three years. The 1975 annual production was approximately 71 million kg (156 million lbs) of steam; during 1980 the production was almost 80 million kg (177 million lbs). The steam demand imposed on the plant is such that it can be met by operating only two of the four boilers, holding the remaining two in reserve. It is the operating procedure of the plant personnel to rotate the firing schedules so that all the boilers are exercised.

The four boilers are capable of dual fuel firing. The primary fuel is natural gas purchased from the Atlanta Gas Light Company on an interruptible basis. The back-up fuel is No. 2 fuel oil and is procured from local suppliers. The fuel oil is burned during those periods when the natural gas supply is curtailed. The number of interruptions has decreased from a high of 110 during 1977 to only 12 in 1980. In 1977 natural gas represented 70 percent of the energy input to the boiler plant; in 1980 the percentage had increased to 97 percent. The total plant operates at an average annual efficiency in the 78 percent to 83 percent range.

The shape of the steam demand profile of the load projection for 1986 was derived from historical data supplied by the Base Civil Engineering Division. The data was in the form of individual boiler charts which recorded the instantaneous steam demand and stack gas temperature for each operating boiler. Only the steam demand during the 0700 to 1700 time interval, corresponding to the hours of solar operation, was utilized in the development of the shape of the curves. Representative boiler charts for typical weekdays and weekends for winter, spring, summer, and fall may be found in Appendix F as Figures F-1 thru F-4.

The information from the present steam demand profiles and the programmed building expansions was assimilated into a series of steam demand profiles for 1986, when the facility is expected to be in operation. The curves, presented in Appendix F, as Figures F-5 thru F-16, show average weekday and weekend demand profiles for each month of the year. These curves were derived by averaging the steam demand at each hour of the day over the month's weekdays or weekend days. The daily curves show that the load remains quite constant throughout the period that the solar cogeneration facility operates. A summary curve, Figure 2.7-1, representing the annualized load lines for 1979 historical data and the 1986 projections clearly depict the characteristics of the yearly

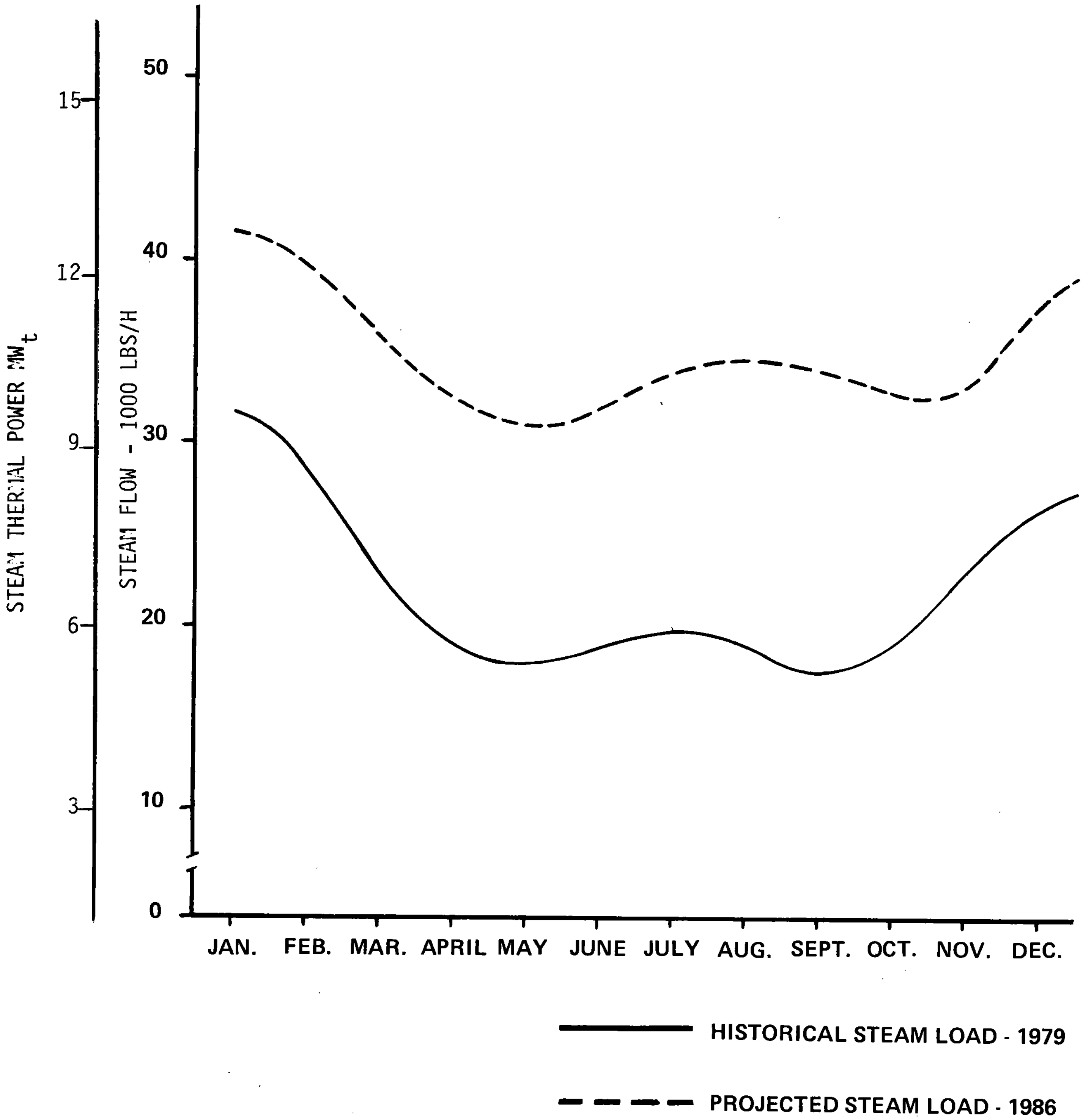


Figure 2.7-1. Steam Load on Steam Plant No. 4, Monthly Average

steam demand. There is a significant decrease in steam demand during the spring and autumn "swing" seasons and a noticeable increase in steam demand during the latter part of the summer. This increased demand is attributable to the heavy dependence on steam powered absorption chillers for space conditioning. Upon the completion of the three programmed building expansions, the projected 1986 maximum steam demand will be approximately 22,200 kg/h (48,800 lbs/h).

Operating and maintenance costs for the current RAFB installation, without the addition of the solar facility, are estimated to include replacement of one or more of the existing boilers within the next 25 years. The major impact of the solar facility upon the planned O&M of the existing installation would be the elimination of one boiler replacement due to reduced fossil boiler operating time after the solar facility is installed.

2.8 PROJECT ORGANIZATION

The Westinghouse team provided an organization that was carefully assembled to ensure successful completion of this project. Figure 2.8-1 shows the project organization chart. The Advanced Energy Systems Division of the Westinghouse Electric Corporation was the prime contractor and provided project management, systems design and integration. Two subcontractors with which Westinghouse has worked before on numerous solar and other projects rounded out the design team. Heery & Heery, Inc. an Atlanta, GA based architect/ engineering firm with vast experience in energy related projects provided A/E services. Having many years of energy related A/E experience, Heery & Heery served in a similar role with Westinghouse of the Ft. Hood Solar Total Energy Project as well as site interface services with Westinghouse on the Shenandoah Total Energy Project. Foster Wheeler Development Corporation provided the solar receiver design, drawing on their abundant experience in the DOE Central Receiver Program as well as years of experience in high technology nuclear and fossil steam generation. Mechanical Technology, Inc. provided consultation on advanced turbine technology regarding the most efficient small turbine for this application. The United States Air Force Logistics Command Office of DCS/Engineering and Services provided the user interface. Headquartered at

PROJECT ORGANIZATION

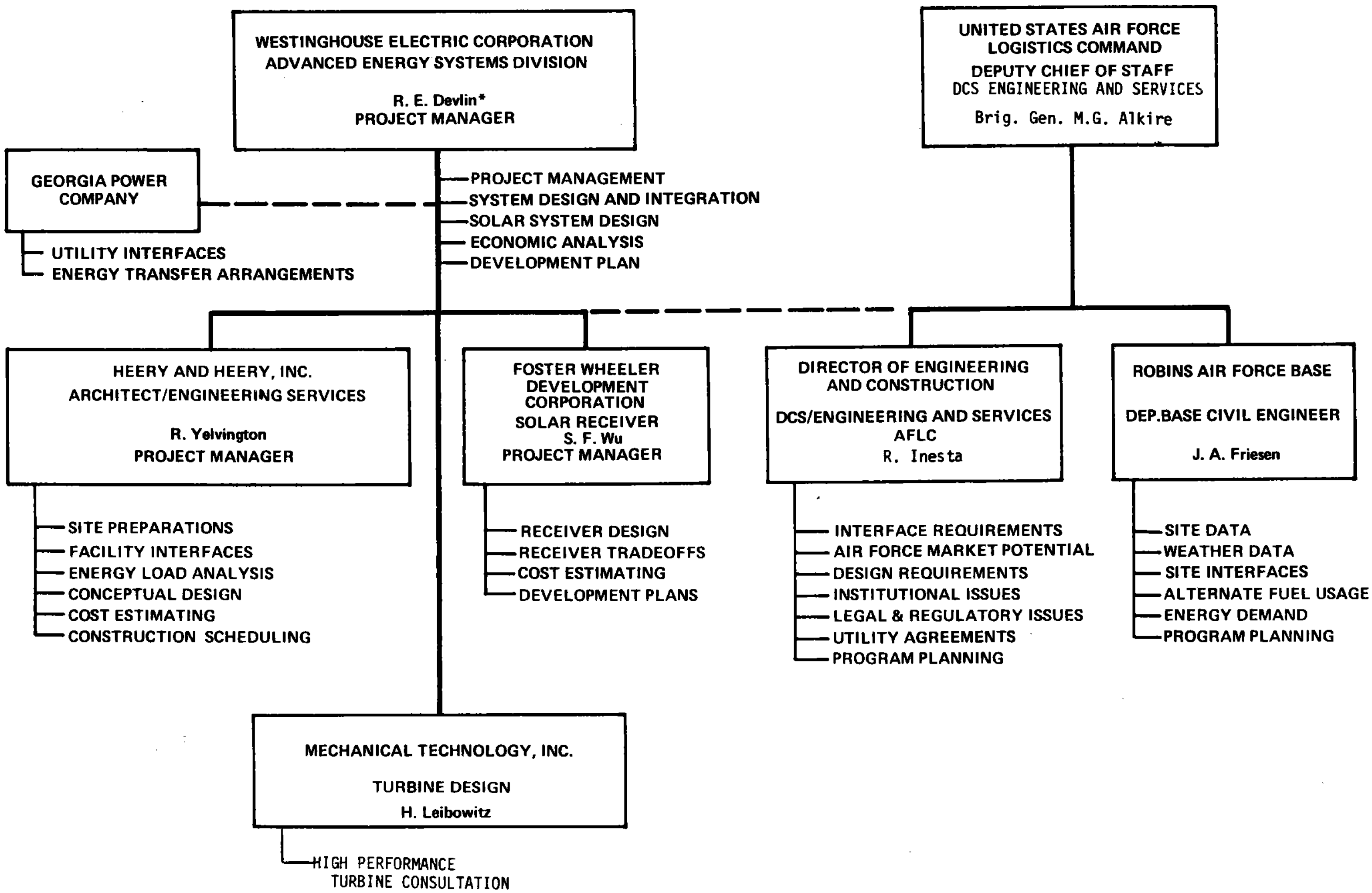


Figure 2.8-1. Westinghouse Solar Cogeneration Facility Project Team

Wright-Patterson Air Force Base, Ohio, this command is responsible for seven logistics commands located at six Air Force Bases throughout the country. Robins Air Force Base, Georgia was selected by the Air Force and the design team as the site specific application. Robins Air Force Base provided a specific site and application meeting overall Air Force needs (market potential) and base specific requirements. Robins personnel furnished site data. In addition, Air Force input included legal, regulatory, and institutional requirements and planning input for overall program implementation. These inputs were coordinated through the Air Force headquarters personnel. This has assured applicability to all Air Force installations as well as Robins AFB. The Georgia Power Company supplies electricity to the base. The on-site electrical distribution system belongs to the Air Force. Since the base electrical demand is so large relative to the output of the cogeneration facility, no electricity will be transferred back to the Georgia Power grid as a result of operation of the cogeneration facility. However, power interactions between the base system and the power company have been addressed in the design of the facility. This assures that all interfaces as well as institutional and regulatory issues have been addressed during the course of the project.

2.9 FINAL REPORT ORGANIZATION

The remainder of this report is written to follow the flow of the study results from the initial Baseline Configuration, to the Preferred Configuration, the Conceptual Design, the Economic Assessment, and through to the Development Plan for the Robins Air Force Base Solar Cogeneration Facility.

Section 3 of this report documents the methodology and trade iterations used by the Westinghouse team to modify its original Baseline Configuration of the facility into the selected Preferred Configuration.

Sections 4 and 5 of this report describe the conceptual design of the facility and the systems contained therein. Facility configuration, performance, capital and operation and maintenance costs, safety, environmental, institutional and regulatory considerations are addressed in Section 4. More detailed descriptions of systems such as the collector field, receiver, electric power generation, and balance of facility are addressed in Section 5.

Section 6 presents the scenarios and economic analyses performed along with an assessment of the sensitivity of the results to variations in assumed parameter values.

Section 7 contains a development plan for on-going final design, construction, startup and operations, which if implemented, results in an operating facility in 1986. The roles of the U.S. Air Force, Department of Energy and design organizations are discussed.

The completed Facility Specification is included in Appendix A. The body of this report refers to this facility specification where appropriate for those supporting details of data addressed and highlighted herein.

3.0 SELECTION OF PREFERRED COGENERATION FACILITY

The preferred cogeneration facility configuration was selected as Task 2 of the conceptual design study. This section of the report summarizes the evaluation of alternative configurations considered to have potential for improving the facility value. Section 3.1 presents the alternatives evaluated, Section 3.2 presents the selected configuration, Section 3.3 identifies the receiver technology, and Sections 3.4 through 3.12 address individual evaluations which were conducted.

3.1 INTRODUCTION

The baseline facility configuration at the start of Task 2 is summarized in Table 3.1-1 along with the proposal configuration. The differences observed on this table derive from the change in heliostat unit from the Westinghouse Second Generation design to a "generic" Second Generation design.

The following questions were addressed in Task 2 to arrive at the preferred system configuration.

1) Does expansion of the land area assigned to collector field or relocation of the receiver tower improve the economic value of the facility? (Section 3.5)

2) Does an increase or decrease in receiver height above ground improve the economic value of the facility? (Section 3.6)

3) Does selective canting of each heliostat to correspond to its slant range distance in the field improve the economic value of the facility? (Section 3.7)

4) Does inclining the receiver panel off vertical improve the economic value of the facility? (Section 3.8)

TABLE 3.1-1: FACILITY COMPARISON

ITEM	PROPOSAL	BASELINE FOR TRADE STUDIES
-Noon Winter Solstice		
Thermal Rating - MW_t	8.4	10.7
Steam Production - kg/h	9290 (20,500 lb/h)	14,140 (31,200 lb/h)
Electric Output (kW_e)	750	1148
-Steam Conditions		
Pressure MPa	5.9 (850 psia)	5.9 (850 psia)
Temperature (°C)	400 (750°F)	400 (750°F)
-Heliostats		
Unit Area - m^2	81.8 (880 ft^2)	52.8 (568 ft^2)
Number	151	266
-Tower Height - m	60 (200 ft)	60 (200 ft)
-Turbine Type	MTI	MTI

5) Does utilization of a commercial turbine instead of a high performance turbine improve the economic value of the facility? (Section 3.9)

6) Do increases in turbine inlet steam pressure or temperature improve the economic value of the facility? (Section 3.10)

7) Would a reduction in the base steam operating pressure at certain times of the year be a practical way to improve the economic value of the facility? (Section 3.11)

8) Is thermal storage necessary to provide a buffer against thermal transients induced by cloud transients from the solar facility components? (Section 3.12)

The selection process, in any case, followed a straightforward evaluation method. This method consisted of the following steps and criteria:

a) Establish that the change under consideration does or does not violate a technical requirement or limit,

b) Estimate the change in annual energy quantity delivered to the base,

c) Estimate the annual economic value of the change in energy quantity delivered to the base,

d) Estimate the capital cost change of the facility in providing the changed configuration,

e) Compare the economic value change to the capital cost change,

f) Evaluate the community/operational consequences of the changed facility compared to the baseline facility, and

g) Accept or reject the change under consideration.

A logic diagram of this process is shown on Figure 3.1-1. The detailed evaluations are presented in Sections 3.5 through 3.12.

3.2 SOLAR COGENERATION FACILITY CONFIGURATION

The main purpose of the solar cogeneration facility was to utilize the insolation incident on a specific land area to create useful thermal and electrical energy to displace that produced either off the base or via fossil fuel by facilities on the base. A facility concept was developed that would accomplish this at the lowest cost/value ratio. This configuration is indicated in Figure 3.2-1.

The land area available for placement of the heliostat field is shown in Figure 3.2-2. Preliminary calculations using the MIRVAL computer code indicate that the facility thermal output rating would be on the order of 10 MW. This relatively low power level indicated that the facility should be kept as simple as possible if it was to have any economic value. Therefore, it was decided early on that the working fluid would be water/steam and that the solar receiver would be an exposed, flat-panel type with a single drum and a natural circulation steam generator. The cogeneration facility would use a nonextracting, high back pressure turbine, with a single feedwater heater and a closed storage tank. Feedwater for the facility would be obtained from the existing Steam Plant No. 4, thereby eliminating the need for any additional condensers or feedwater makeup or treatment equipment.

Since the turbine back pressure is relatively high (1.07 MPa, 155 psia), it was desirable to utilize a steam turbine with as high an efficiency as possible. One of the more promising alternatives was a derivative of the high-speed, high efficiency unit developed for the Shenandoah Total Energy System by Mechanical Technologies, Inc. (MTI) However, the use of the MTI configuration could require a significant development effort, due to the cogeneration facility for Robins Air Force Base possibly producing higher steam turbine flows than the Shenandoah design can handle. Therefore, it was decided that an alternative to the MTI turbine should be evaluated. This alternative would be an

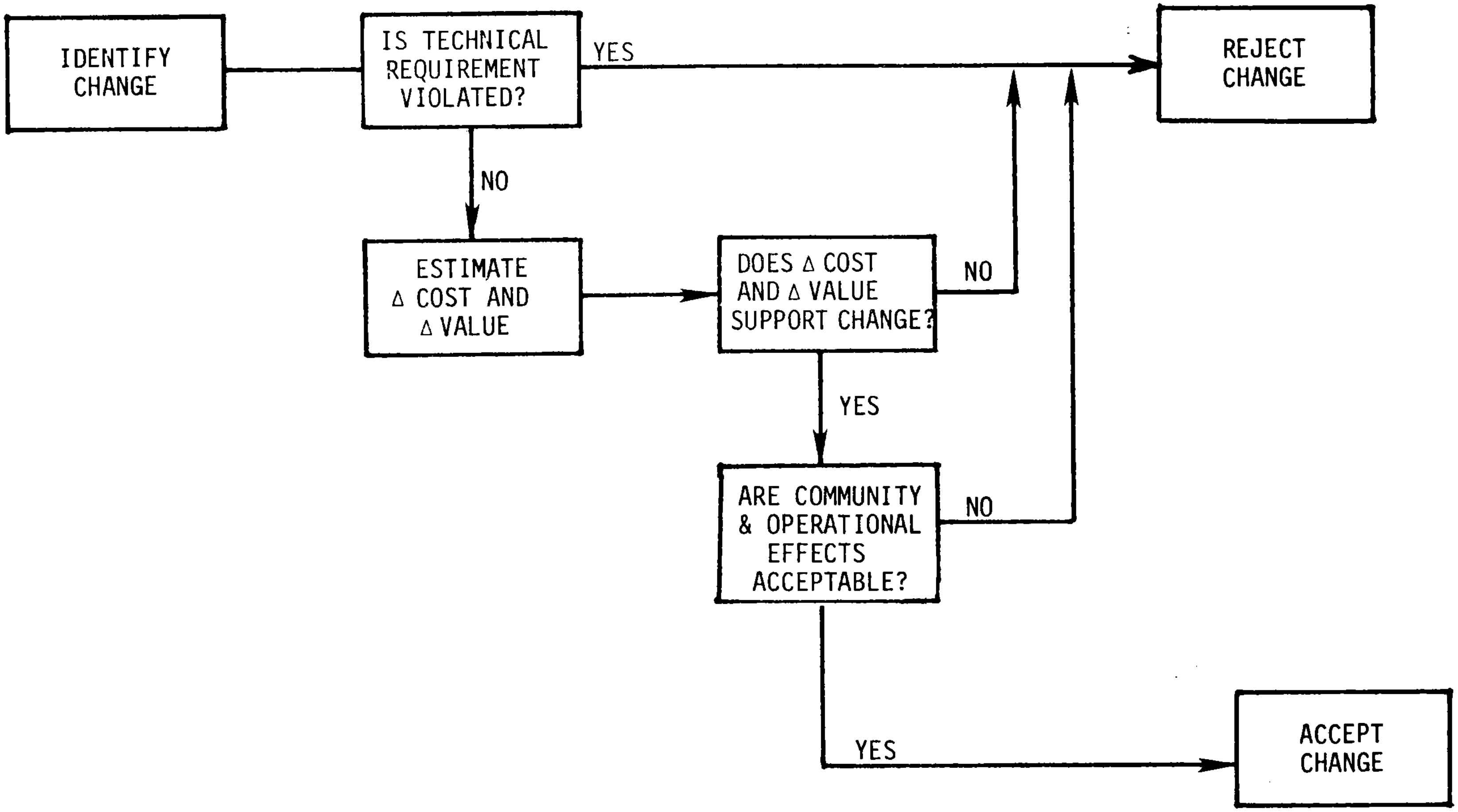


Figure 3.1-1. Preferred Configuration Selection Logic Diagram

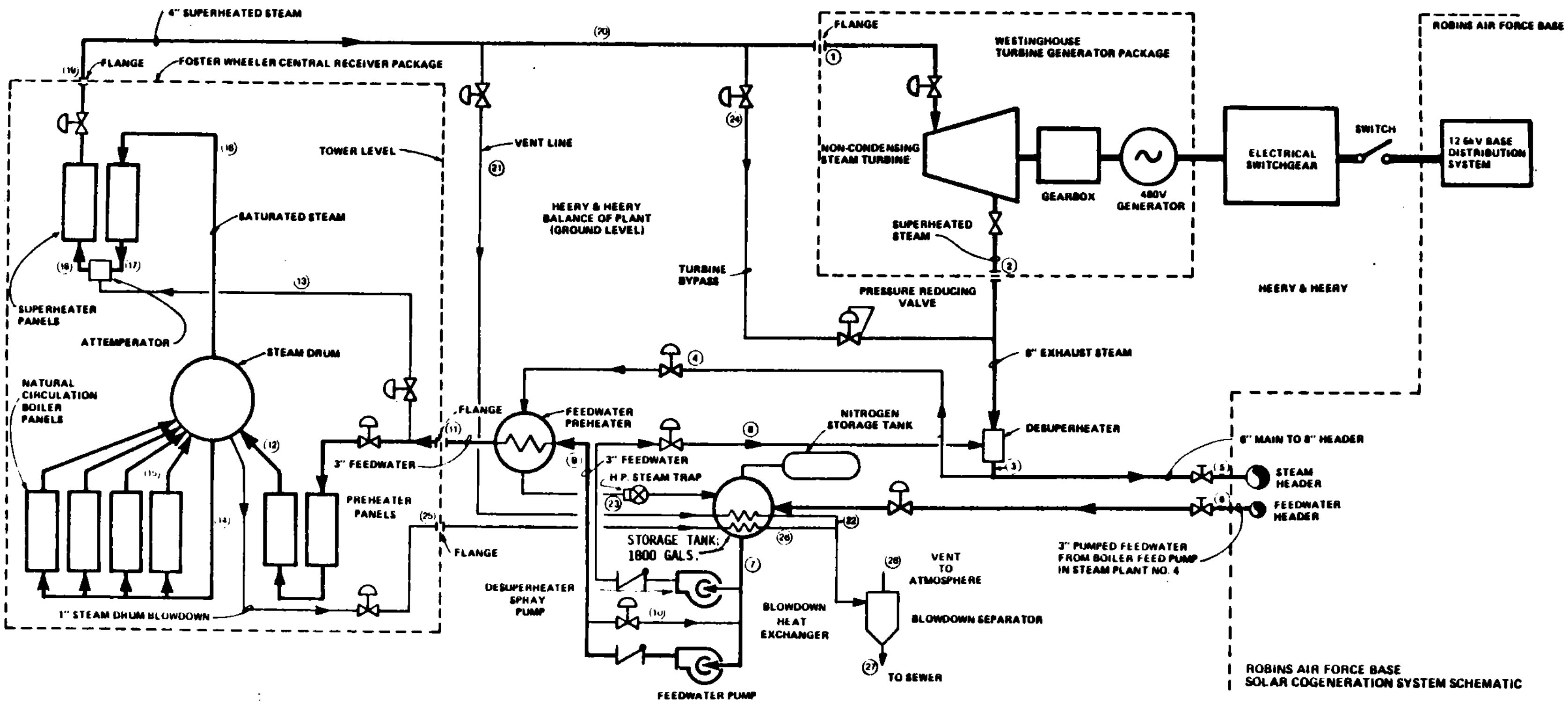


Figure 3.2-1. Solar Facility Configuration

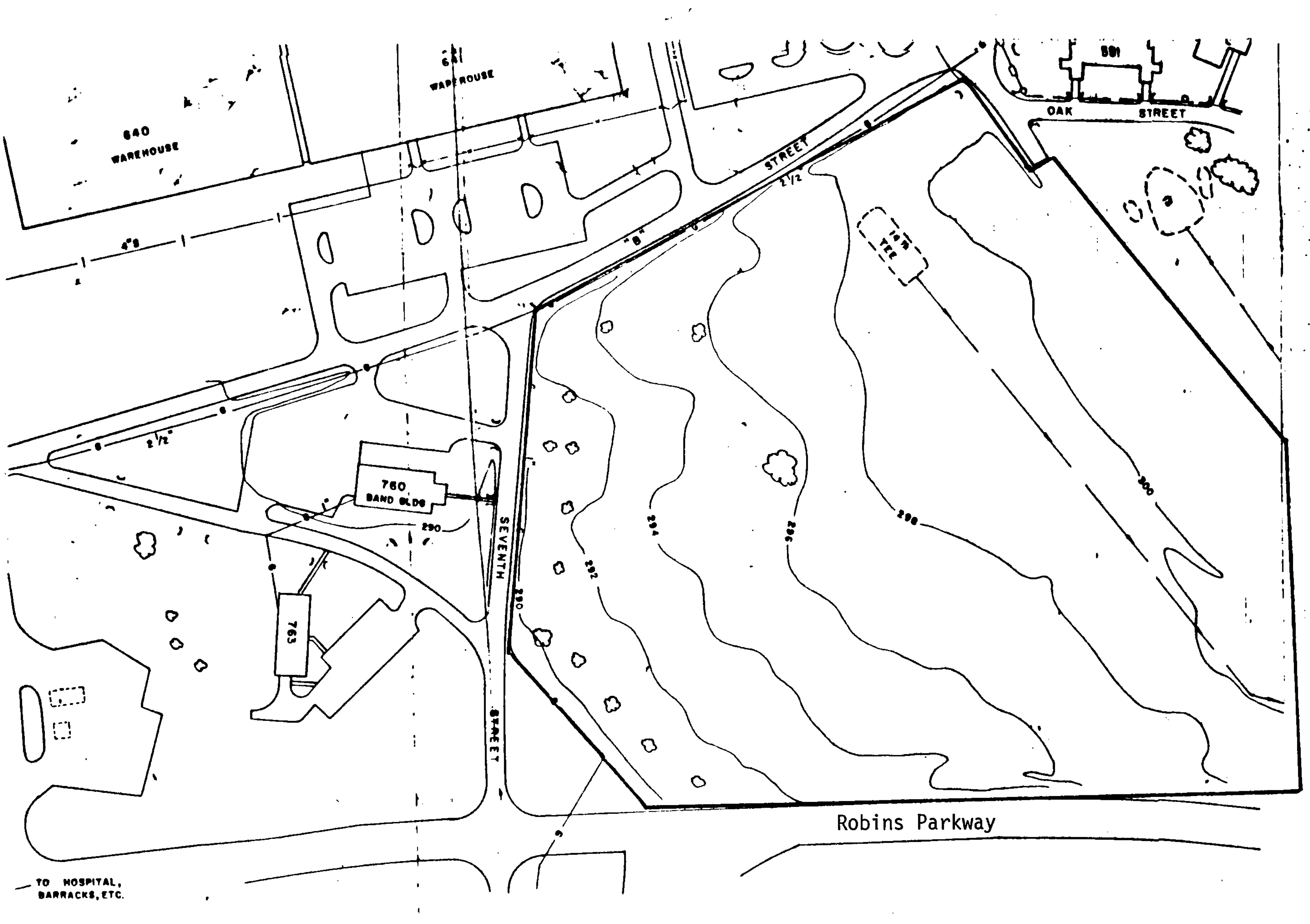


Figure 3.2-2. Site Identified for Location of Cogeneration Facility

off-the-shelf industrial high back pressure unit already widely used in industry. While the efficiencies of these units are significantly lower than the MTI unit (on the order of 50 percent vs. 70 percent for the MTI design), their lower cost could result in an actual economic savings over the life of the cogeneration facility.

Thermal storage is frequently incorporated in a solar facility as a means of avoiding plant outages during cloud transients (short term storage, usually designated buffer storage) or to extend the operating time of the plant to periods when there is little or no insolation (at night or poor insolation daylight periods).

Consideration was given to the use of thermal storage in this facility to extend the operating time. The steam load displaceable by solar energy i.e. the steam demand after reduction of the quantity of steam generated by the fossil boilers at their minimum effective operating level, ranges from about 10,700 kg/h to 15,700 kg/h (23,500 lb/h to 34,500 lb/h) depending upon the time of year. Furthermore, depending upon the tower height and corresponding number of heliostats, the solar facility would supply 8400 kg/h to 13,900 kg/h (18,000 lb/h to 31,000 lb/h) at the design point. This means that, over the range of tower heights considered, the facility steam production would be less than the "displaceable" steam load over much of the year even if the tallest tower were installed. Obviously thermal storage would be usable for collecting "excess" energy only when the steam demand is lower than the steam generating capability of the solar facility, i.e. those days when the steam demand is on the low end of its range and the solar insolation is simultaneously on the high end of its range. It is estimated that even for the highest tower under consideration, an ideal storage system would extend the facility operating time about 60 hours per year. The extra cost of providing the thermal storage system and the larger facility (80m tower) compared to providing a nominal size facility (60m) exceeds the value of the extra useful energy achievable. Hence, the most economical alternative for this facility is to select the size (tower height) for which all the solar energy is used to directly displace fossil derived energy. Therefore thermal storage is not advisable for this application to extend operating time.

Buffer storage is generally incorporated to avoid cloud transients from causing excessive thermal transients resulting in facility outages. For the solar cogeneration facility, the most critical item would be the steam turbine. However, as will be discussed in section 3.4, the steam turbine type that will be incorporated in the conceptual design is a commercial off-the-shelf industrial unit. These turbines are inherently rugged, and can be started quickly and easily when cold. Since the cogeneration facility supplies only a small portion of the plant electrical energy (about 650 kW out of 10 MW), there is little danger of power outages. Also, at least one of the fossil boilers would always be kept on line and could easily pick up the load if the solar cogeneration facility had to be shut down. Therefore, there is no need for buffer storage to mitigate thermal transients. Since neither extended operations nor thermal transient considerations warrant the inclusion of thermal storage, no storage system is included in this facility.

3.3 TECHNOLOGY

Water/steam was chosen as the receiver working fluid because of the simple interface with the existing steam plant. Direct use of the superheated steam produced by the proposed cogeneration facility eliminates the need for intermediate heat exchangers, pumps, additional controls, and other auxiliary equipment. Water, even treated boiler-quality feedwater, is inexpensive and readily available at the existing steam plant. Since only moderate steam pressure and temperature is required and no thermal storage is needed, there are no advantages to the use of an intermediate fluid loop.

The selected receiver concept is an exposed flat-panel type, natural circulation steam generator with separate preheater and superheater circuits.

Previous receiver studies conducted as part of the industrial retrofit project (Provident Refinery) indicated that the levelized energy cost of a flat-panel receiver was virtually the same as that of a cavity-type receiver. The difference was well within the boundaries of the cost and analytical assumptions made. The exposed, vertical, flat-panel configuration was chosen for this facility, however, because of its simplicity in surface arrangement and structural assembly. It is also easily adapted to the heat flux levels on the active energy-absorption surfaces resulting from the proposed heliostat layout.

Natural circulation has a history of high reliability in fossil-fueled boilers. Much experience exists regarding the design, construction, and operation of this type of boiler at the pressure and temperature considered for this installation. Natural circulation eliminates capital and maintenance costs and power consumption associated with a forced-circulation pump, and avoids the serious consequences of a pump or power failure. The boiler circuitry of a natural circulation receiver is inherently self-compensating for energy input variations with both time and location in the receiver. On the other hand, in a once-through design, a complicated valving and control system would be required to adjust the flows among the circuits, to compensate for these variations. A natural-circulation receiver is also relatively tolerant of impure feedwater because of its large tubes, large water inventory, and drum blow-down capability. In addition, previous testing of natural circulation solar receivers with 1 MW_t and 5 MW_t capacities has demonstrated their thermal/ hydraulic stability and ease of control under steady state and transient conditions.

3.4 DETERMINATION OF FACILITY SIZE

With the facility configuration defined as described in Section 3.2, it was required that the facility be sized to result in the most favorable economic benefit. The purpose of the cogeneration facility is to displace as much as possible of the steam generated by Steam Plant No. 4, and the electricity consumed on the base that is generated by the Georgia Power Company. When sizing the facility, the facility steam and electrical output must be matched to the base steam and electrical requirements. Too small a facility will result in little economic benefit in terms of displaced fossil fuel, while too large a facility will result in an oversizing, with it operating at part capacity for a significant portion of the year. The method chosen to define the conceptual facility size was to calculate the annual steam and electrical production and the facility capital costs for a number of different facility concepts, sizes, and base steam loads. By obtaining a cost/benefit ratio for each particular concept, the facility size can be defined that would result in the highest economic value for a specific base steam load.

The results of the trade studies presented in Sections 3.5 through 3.12 were used to revise the baseline facility configuration to be used for the calculation of a size of the facility. The revised baseline configuration is as follows:

- Heliostat field size of 62,730 m^2 (15.5 acres) - Section 3.5
- Heliostats to all use same canting angles - Section 3.7
- Receiver to be oriented vertically with no inclination - Section 3.8
- Commercially available industrial high backpressure turbine to be used - Section 3.9
- Steam conditions of 400°C, 5.9 MPa (750°F, 850 psia) at the turbine inlet and 0.93 MPa (135 psia) at the turbine exit selected - Section 3.10 (Some Economic analyses described in this section were performed for 10.3 MPa turbine inlet pressure but calculations indicated that the same optimum plant size occurs for 5.9 MPa inlet pressure)
- No variation in turbine exit pressure between summer and winter operation - Section 3.11
- No buffer storage - Section 3.12

The two variables considered in the determination of the facility size were the Steam Plant No. 4 steam demands and the range of tower heights of 40 to 80 meters. This range of tower heights results in a range of 184 to 308 heliostats in the available field area and a range of 9.7 to 13.5 MW of thermal power incident on the receiver at the design point.

The steam loads initially used for the evaluation of the size of the facility were those that were met by the base Steam Plant No. 4 for the year 1979. These are shown as a solid line in Figure 3.4-1. However, Steam Plant No. 4 must be kept on-line at a standby flow in order that the plant steam load is

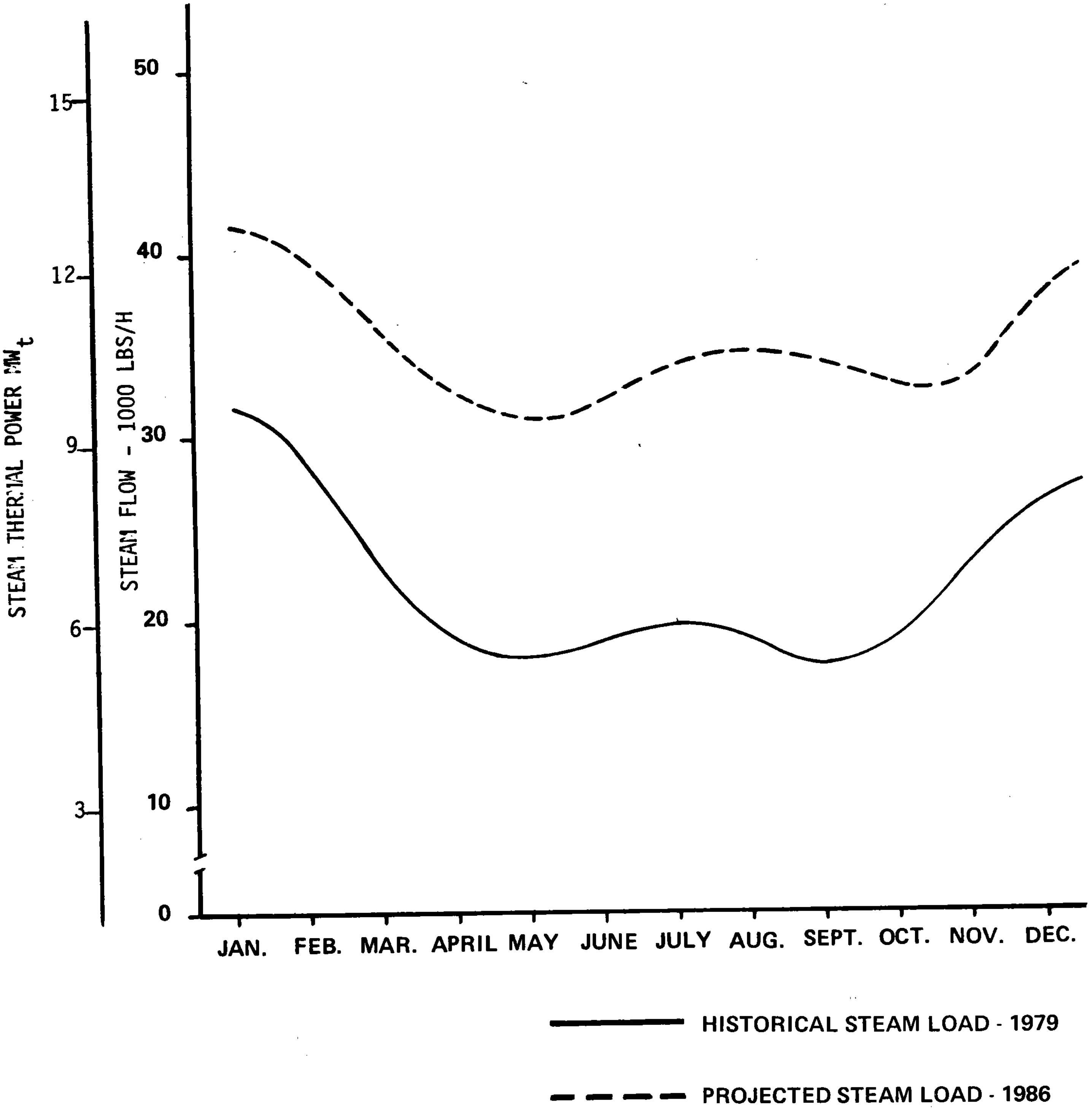


Figure 3.4-1 Steam Load on Steam Plant No. 4, Monthly Average

always met if there is a sudden outage of the solar cogeneration facility. Also, Steam Plant No. 4 must supply any of the steam load that cannot be met by the cogeneration facility (on poor insolation days and/or peak load days). This standby condition of the boilers is generally 20 to 25 percent of the rated capacity of the boiler, or about 2300 kg/h (5000 lb/h).

Therefore, the maximum steam production rate from the solar cogeneration facility which can be utilized is the actual load minus about 2300 kg/h (5000 lb/h). For the purposes of determining the facility size, it was assumed that on those days when the facility was able to produce more steam than the base could use, the number of the heliostats in use would be controlled to match the steam production with the base steam requirements.

A second mode analyzed was to assume that the base could always use all of the steam produced by the facility. This would be the case if the steam demand were increased by at least a factor of two over that described as a solid line in Figure 3.4-1. This would be possible if the solar cogeneration facility was coupled to other steam loads besides just those presently met by Steam Plant No. 4.

The two cases described above, together with a third case where it is assumed that the cogeneration facility should meet the entire 1979 Steam Plant No. 4 load (no fossil standby assumed) were used to develop the facility size.

The Annual Integration Performance Model (Appendix E) was used to calculate the annual electrical and useful steam production for each of the three facility sizes. In addition, the three separate steam demand cases (Steam Plant No. 4 minus 2300 kg/h (5000 lb/h), total Steam Plant No. 4, and an effectively infinite load) were analyzed separately.

For the three facility sizes (i.e., tower heights and resulting number of heliostats deployed in the field area) considered, the receiver incident power was then calculated by the MIRVAL code. These results are given in Appendix C. The net thermal input to the receiver was calculated by assuming that about 95 percent of the total energy hitting an infinite plane at the receiver location actually hits the receiver. The convection, conduction, and radiation losses were then estimated to be 5 percent of the design point receiver incident power. The design point turbine flow was calculated based upon the desired turbine inlet conditions and a feedwater temperature of 174°C (345°F). This value was obtained by assuming the feedwater heater can heat the water to within 3°C (5°F) of the saturation temperature of the steam entering the heater. These design point flows are stated in Appendix D for the four different turbine types and conditions and the three facility sizes. With the turbine design point calculated, the turbine part-load profiles (kilowatts generated and exhaust enthalpy vs. turbine flow) were determined. These were then inputted to the Annual Integration Performance Model. The month-by-month average steam loads were also inputted into the model. The annual integrated performance of the specific facility (steam sent to base and net electrical energy produced) was then calculated. To determine the economic benefit of the facility, it was calculated from recent RAFB utility price data, that each kilogram of 140 psia saturated steam delivered to the complex by the facility results in 1.32¢ savings in fossil fuel, and that each kilowatt-hour of electricity generated by the facility was worth 3.533¢.

Table 3.4-1 summarizes the annual facility performance and economic benefits for the three facility sizes, and three separate steam demands. Similar calculations are shown for the MTI turbine and two additional inlet conditions for the commercial industrial turbine. These economic benefits were used for the determination of the turbine type and inlet conditions described in Section 3.9 and 3.10, and are included here for comparison purposes.

Using the facility costs described in detail in Appendix D, Table 3.4-2 summarizes the cost-to-benefit ratios for the various facility sizes and steam demands. Additional data was calculated for a facility utilizing 50 meter and a 70 meter tower heights to better show the variation in cost-to-benefit ratio with tower height. By normalizing the cost-to-benefit data (making the 50 meter "reduced demand value" equal 1.0), Figure 3.4-2 can be obtained for the three steam demands.

TABLE 3.4-1: ANNUAL STEAM AND ELECTRICAL PRODUCTION FOR VARIOUS FACILITY SIZES AND TURBINES

	ANNUAL STEAM DELIVERED TO BASE		ANNUAL ELECTRICITY DELIVERED TO BASE			
	kg $\times 10^6$	Dollar Value $\times 10^5$	MWh Gross	MWh Net	Net Dollar Value $\times 10^5$	Total Dollar Value $\times 10^5$
I. Steam Plant No. 4 Demand						
a) Commercial Turbine 10,340 kPa, 400°C						
40 m	9.305	1.228	540	470	0.166	1.394
60 m	12.650	1.670	790	700	0.247	1.917
80 m	13.750	1.815	810	720	0.254	2.069
b) MTI Turbine 10,340 kPa, 400°C						
60 m	12.127	1.615	1160	1070	0.378	1.993
c) Commercial Turbine 7585 kPa, 400°C						
60 m	12.971	1.712	640	570	0.205	1.917
d) Commercial Turbine 5860 kPa, 400°C						
60 m	13.154	1.736	510	450	0.160	1.896
II. Use All Steam Produced						
a) Commercial Turbine 10,340 kPa, 400°C						
40 m	9.625	1.271	570	500	0.177	1.448
60 m	14.758	1.948	980	880	0.311	2.359
80 m	17.371	2.293	1140	1020	0.360	2.653

TABLE 3.4-1: ANNUAL STEAM AND ELECTRICAL PRODUCTION FOR VARIOUS FACILITY SIZES AND TURBINES (CONT'D)

	ANNUAL STEAM DELIVERED TO BASE		ANNUAL ELECTRICITY DELIVERED TO BASE			
	kg $\times 10^6$	Dollar Value $\times 10^5$	MWh Gross	MWh Net	Net Dollar Value $\times 10^5$	Total Dollar Value $\times 10^5$
b) MTI Turbine 10,340 kPa, 400°C						
60 m	13.750	1.815	1390	1290	0.456	2.271
c) Commercial Turbine 7585, kPa, 400°C						
60 m	15.125	1.997	910	830	0.293	2.290
d) Commercial Turbine 5860 kPa, 400°C						
60 m	15.584	2.057	670	620	0.225	2.282
III. Reduced Steam Plant No. 4 Demand						
a) Commercial Turbine 5860 kPa, 400°C						
40 m	8.024	1.059	490	430	0.151	1.210
60 m	10.109	1.334	680	590	0.208	1.542
80 m	10.351	1.366	685	595	0.210	1.516

TABLE 3.4-2: FACILITY SIZE ECONOMICS

	Facility Cost $\$ \times 10^6$	Capital Charge $\$ \times 10^5$	Economic Benefit $\$ \times 10^5$	Normalized Cost/Benefit Ratio
I. Steam Plant No. 4 Demand				
40 m	5.974	7.617	1.394	1.098
50 m	6.871	8.760	1.760	1.000
60 m	7.639	9.740	1.917	1.021
70 m	8.192	10.445	2.020	1.039
80 m	8.535	10.882	2.069	1.057
II. Use All Steam Produced				
40 m	5.974	7.617	1.448	1.057
50 m	6.871	8.760	1.900	0.926
60 m	7.639	9.740	2.259	0.855
70 m	8.192	10.445	2.520	0.834
80 m	8.535	10.882	2.653	0.824
III. Reduced Demand				
40 m	5.974	7.617	1.210	1.265
50 m	6.871	8.760	1.420	1.240
60 m	7.639	9.740	1.542	1.269
70 m	8.192	10.445	1.570	1.337
80 m	8.535	10.882	1.576	1.387

Facility parametrics done using commercial turbine, 10,340 kPa, 400°C (1500 psia, 750°F) inlet.

Cost/benefit values normalized to Steam Plant No. 4 demand for a 50 meter tower height.

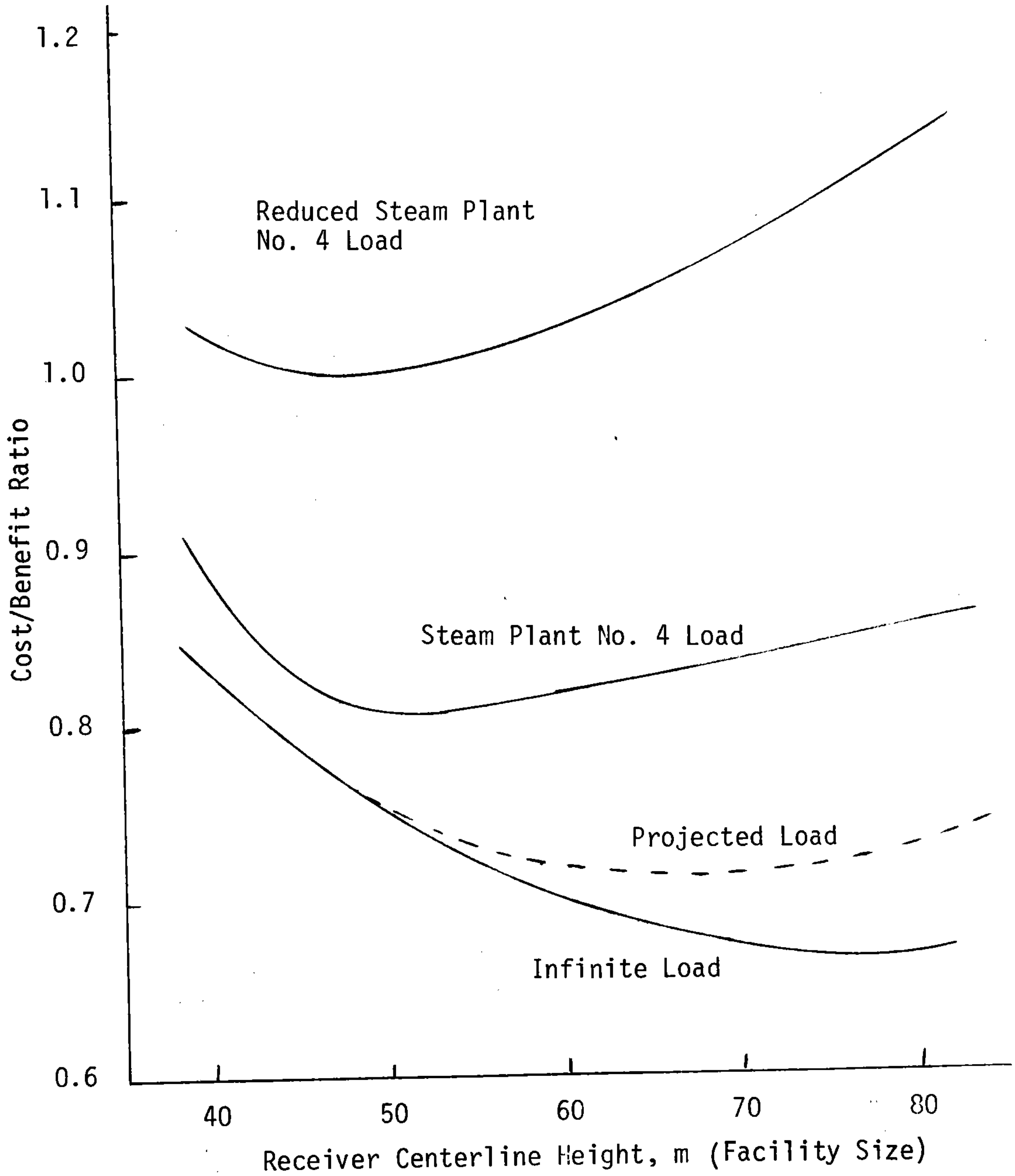


Figure 3.4-2. Facility Cost/Benefit Ratio vs. Size and Steam Load

Figure 3.4-2 indicates that the most economical facility size is a strong function of the steam demand, as expected. For the reduced steam load, the most cost effective facility size would be the 50 meter case. If the steam load was increased by about 2900 kg/h (5000 lb/h), thereby being equivalent to the total production from Steam Plant No. 4, the most beneficial facility size would increase to the equivalent of about a 53 meter tower. For an infinite load, which would roughly correspond to at least doubling the Steam Plant No. 4 demand, the most cost effective facility size would increase to about 75 meters. Also, as the steam demand is increased the greater is the payoff from the optimal facility for that demand. Therefore, there is a strong impetus to determine the expected steam demand in 1986 to properly size the facility.

This information was passed on to the Air Force, and it was determined that there will be additional buildings added to Robins Air Force Base by 1986, and that these new buildings would be coupled to Steam Plant No. 4 (and hence the solar cogeneration facility). This would increase the total steam demand to the dotted line shown on Figure 3.4-1. With this new steam demand, from the economic analyses using the three previous demand curves, the optimum facility would be to utilize approximately a 60 meter tower. Since the cost-to-benefit ratio is fairly flat between 60 and 70 meters, there is little economic incentive to tie up the added capital cost into the larger facility. Therefore, it was decided to select the 60 meter tower for the conceptual design.

This tower size, together with detailed heliostat field boundaries allowing for right-of-ways, resulted in placement of 251 heliostats in the available land area. Further details on the conceptual design are described in Section 4.

3.5 HELIOSTAT FIELD SIZE AND ORIENTATION

The proposed site for the solar cogeneration facility is shown in Figure 3.5-1. This open area is bounded by "B" Street and Robins Parkway in the east-west direction, and Seventh Street and the golf course in a north-south direction. Of the land available on the base for the location of a heliostat field, this one appeared to be most suitable for the following reasons:

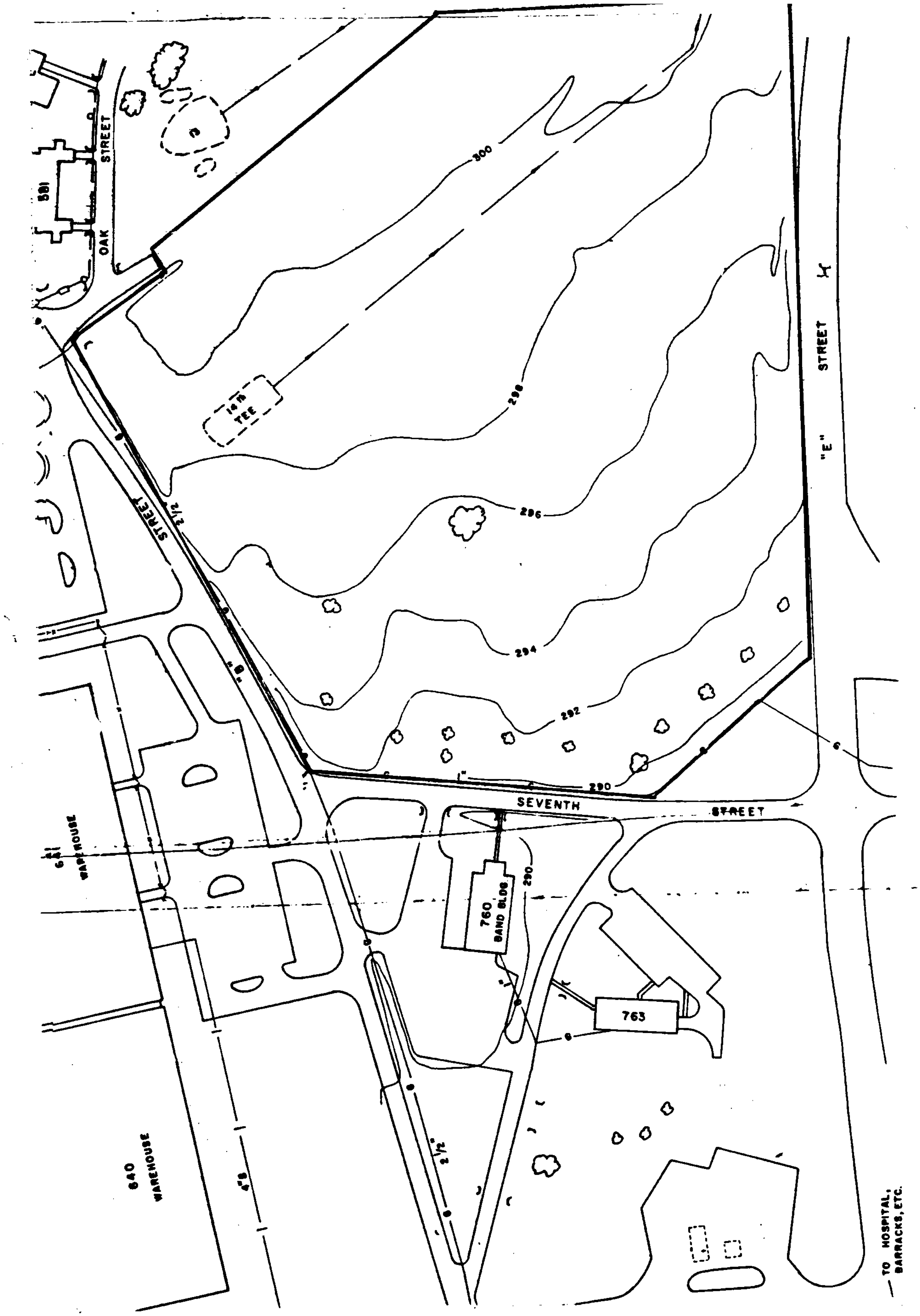


Figure 3.5-1. Site Identified for Location of Cogeneration Facility

- Land layout allowed for the use of a north-facing receiver and a generally symmetrical field about the north-south axis

- The land is fairly flat and open, minimizing the amount of clearing and grading that would be required

- The site is close to Steam Plant Number 4, which eases the piping runs needed to tie the solar cogeneration facility into the base

- The site is served by a segment of the 12.6 kV distribution system of adequate size.

Following site selection, a series of trade studies was performed utilzing cost/performance curves to determine the effect of the tower location, tower height, and the heliostat field size and geometry, upon the net useful energy generated.

The heliostat was chosen early in the plant conceptual design study as being a second generation design. The heliostat configuration is shown in Figure 3.5-2, while the characteristics are described in Table 3.5-1. Briefly, the heliostat is a two-axis tracking unit made up of twelve mirror modules (two horizontal and six vertical). The modules are flat, and can be canted for any slant range.

The land area chosen as a baseline for the analysis is the area of 15 acres chosen for the proposal. The receiver tower location would be just north of the band building. One major site impact of this choice is the elimination of the 14th tee and part of the 14th fairway of the base golf course. This was done with the full approval of the Air Force.

With the baseline field, a total of 266 second generation type heliostats are able to be placed in a radial stagger arrangement in the field. Figure 3.5-3 shows the location of the individual heliostats in the proposed field. This deployment results in a total of 10.7 MW of thermal energy incident on a plane 11.7 m wide by 9.9 m high at the receiver location at a noon winter solstice insolation condition of 950 W/m^2. This is approximately 97 percent of the total energy that could possibly be captured by a solar receiver.

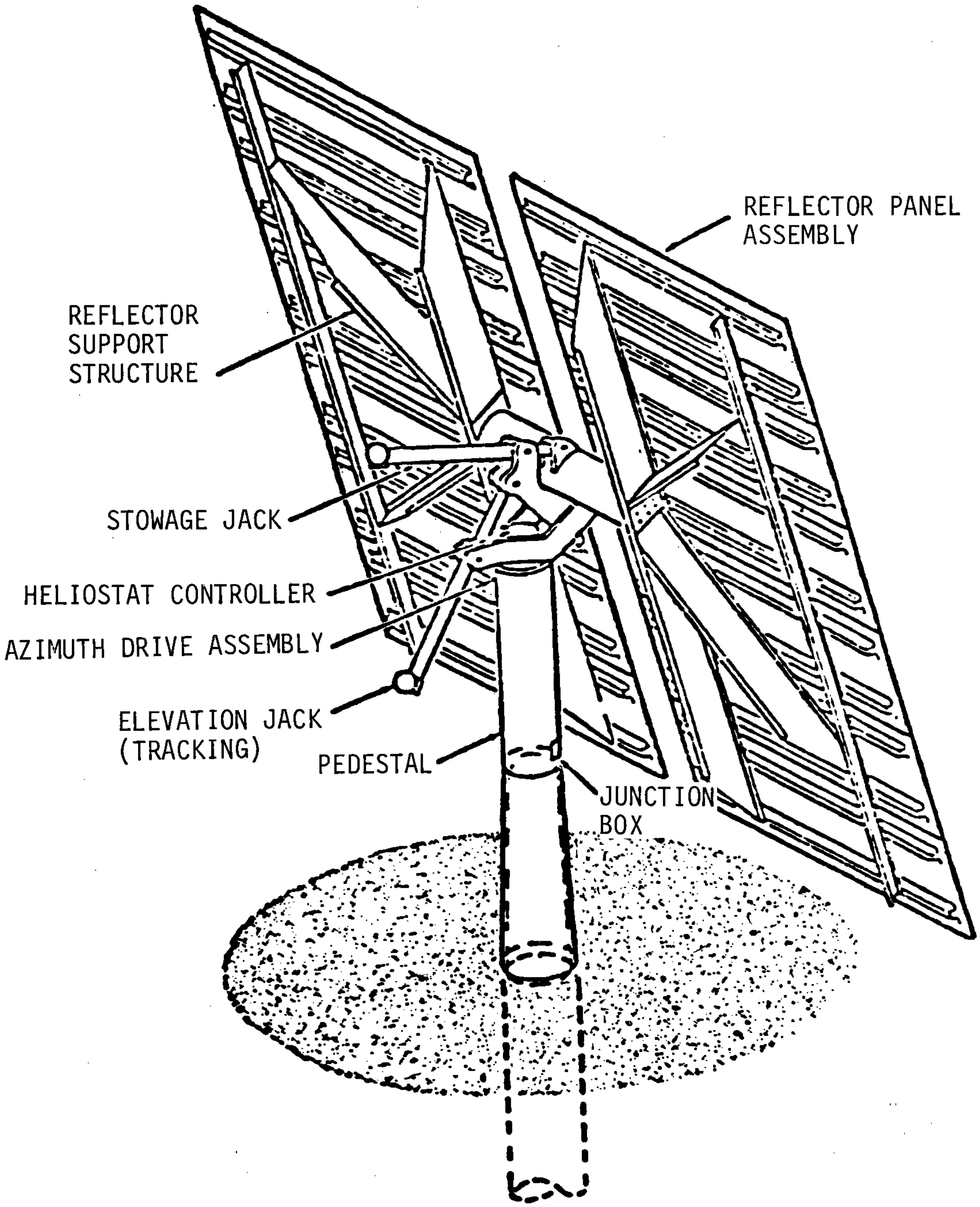


Figure 3.5-2. Generic Heliostat Configuration

TABLE 3.5-1: GENERIC HELIOSTAT CHARACTERIZATION

Mirror module size	1.22 m x 3.66 m (4 ft x 12 ft)
Mirror module reflective area	4.40 m^2 (47.34 ft^2)
No. of mirror moduls per heliostat (2 horizontal, 6 vertical)	12
Total miror module area/heliostat	53.51 m^2 (576 ft^2)
Heliostat dimensions	7.39 m wide x 7.44 m high (24 ft 3 in x 24 ft 5 in)
Heliostat area	55.01 m^2 (592.1 ft^2)
Total reflective area	52.77 m^2 (568.02 ft^2)
% Reflective area $\left(\frac{\text{Total reflective area}}{\text{Heliostat area}}\right)$	96%
Mirror reflectivity clean (annual average)	92% (90%)
Heliostat 1 - standard deviation angular errors for pointing	0.75 milliradians each axis
Surface normal 1 - standard deviation errors	1 milliradian each axis
Minimum distance center to center (heliostat spacing)	10.79 m (35.4 ft)
Height of elevation axis centerline	4.04 m (13 ft 3 in)

Mirror modules canted to focus the sun's rays for
for the most remote heliostat (slant range of 328.4 m)
Mirrors are flat (32°F to 120°F ambient temperature)

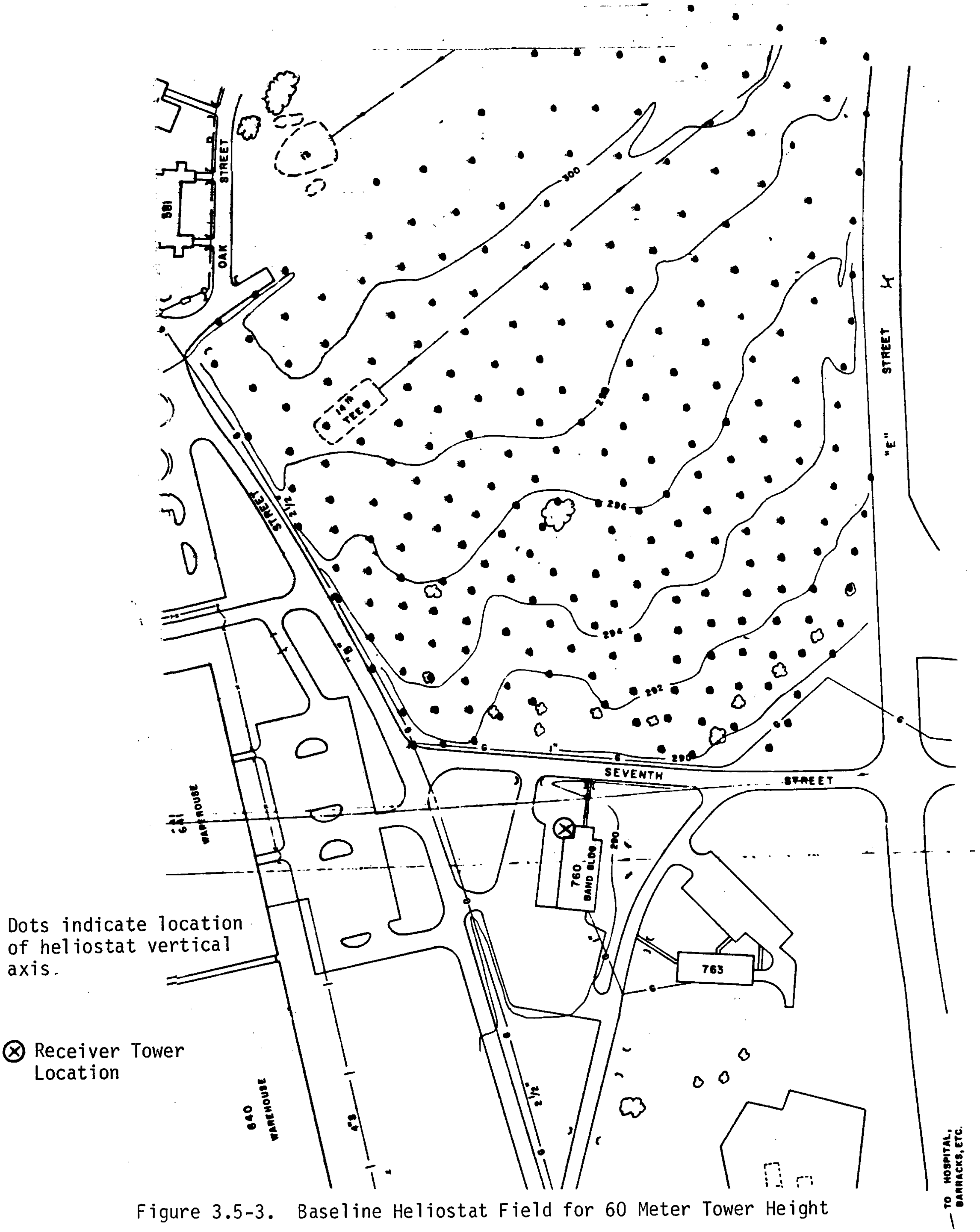


Figure 3.5-3. Baseline Heliostat Field for 60 Meter Tower Height

A range of tower heights between 40 m and 80 m was chosen for analysis as described in Section 3.6.1. For each tower height a heliostat field was configured in a manner to minimize the effects of the heliostat shadowing and blocking, and to maximize the number that can be placed in a given area. Figure 3.5-4 indicates the effect of the tower height on the number of heliostats that can be placed in the baseline field and on the solar energy incident on the baseline receiver (11.7 m wide by 9.9 m high) at noon winter solstice.

With the thermal power from the baseline field calculated, a series of parametric analyses was done to determine the effect of changes in the field area and receiver tower location on the incident energy impinging upon the receiver. Figure 3.5-5 shows the different field sizes and tower locations considered.

In all of the parametric analyses on the heliostat field size, it was decided to use the tower height and receiver size that were generated in the proposal concept. These were a height of 60 meters from the ground to the receiver centerline and a receiver size of 11.7 m wide by 9.9 m high. The receiver size would not be materially impacted by the relatively small changes possible in the field size with the proposed site, and the results obtained using a 60 meter tower would be valid for any proposed tower height.

- Configuration 1 - moving the tower to the bottom of the triangular area formed by the two intersecting streets east and west of the band building, and using all of the area north of the tower for heliostats.
- Configuration 2 - decreasing the field size so as to avoid removing the 14th tee and shortening the 14th fairway.
- Configuration 3 - increasing the field size to encompass the green on the 13th hole.
- Configuration 4 - increasing the field size by expanding to the east over and past "E" Street. The field expansion was taken out to about 120 meters east of the street.

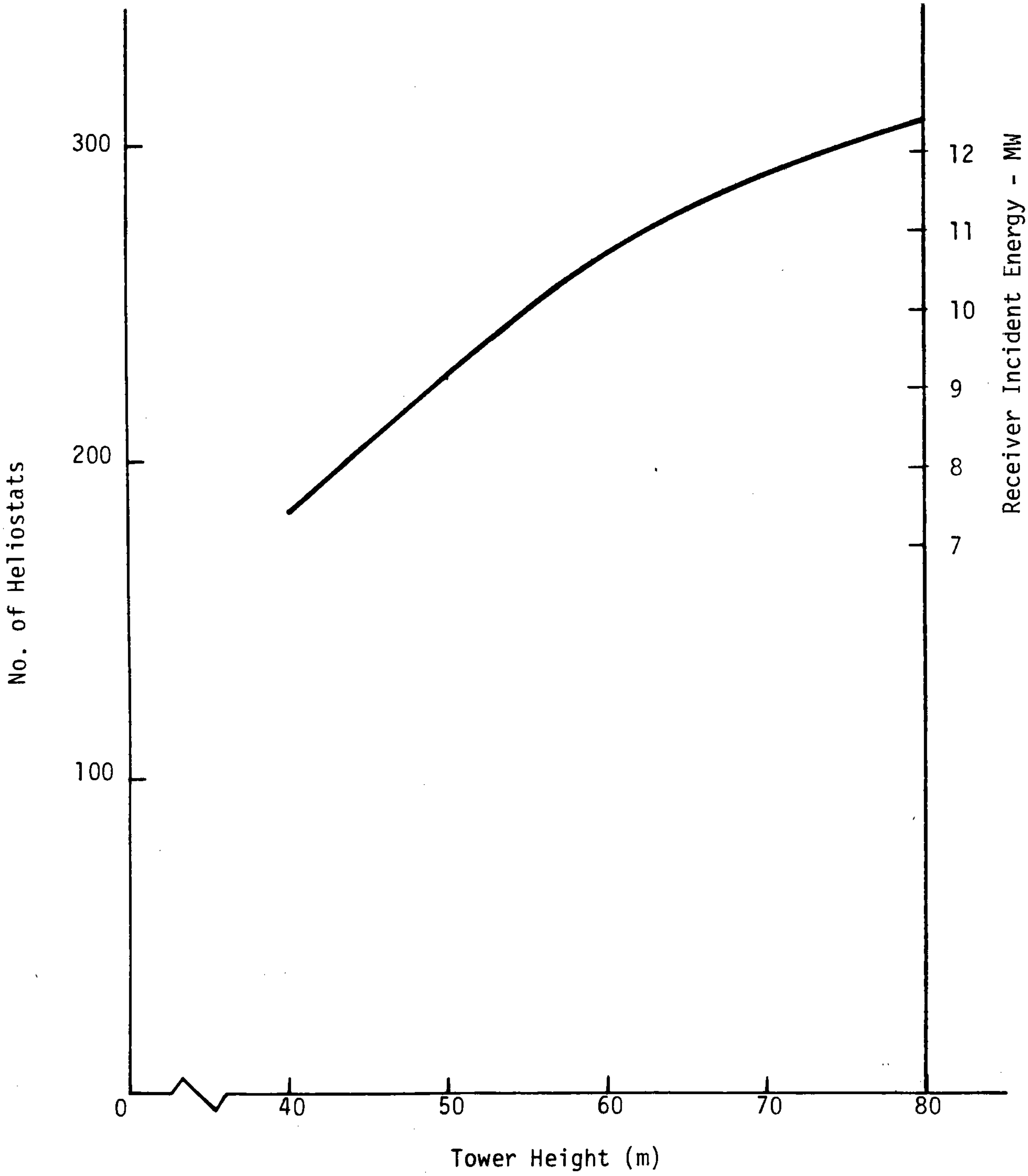


Figure 3.5-4. Effect of Tower Height on Number of Heliostats and Receiver Incident Energy

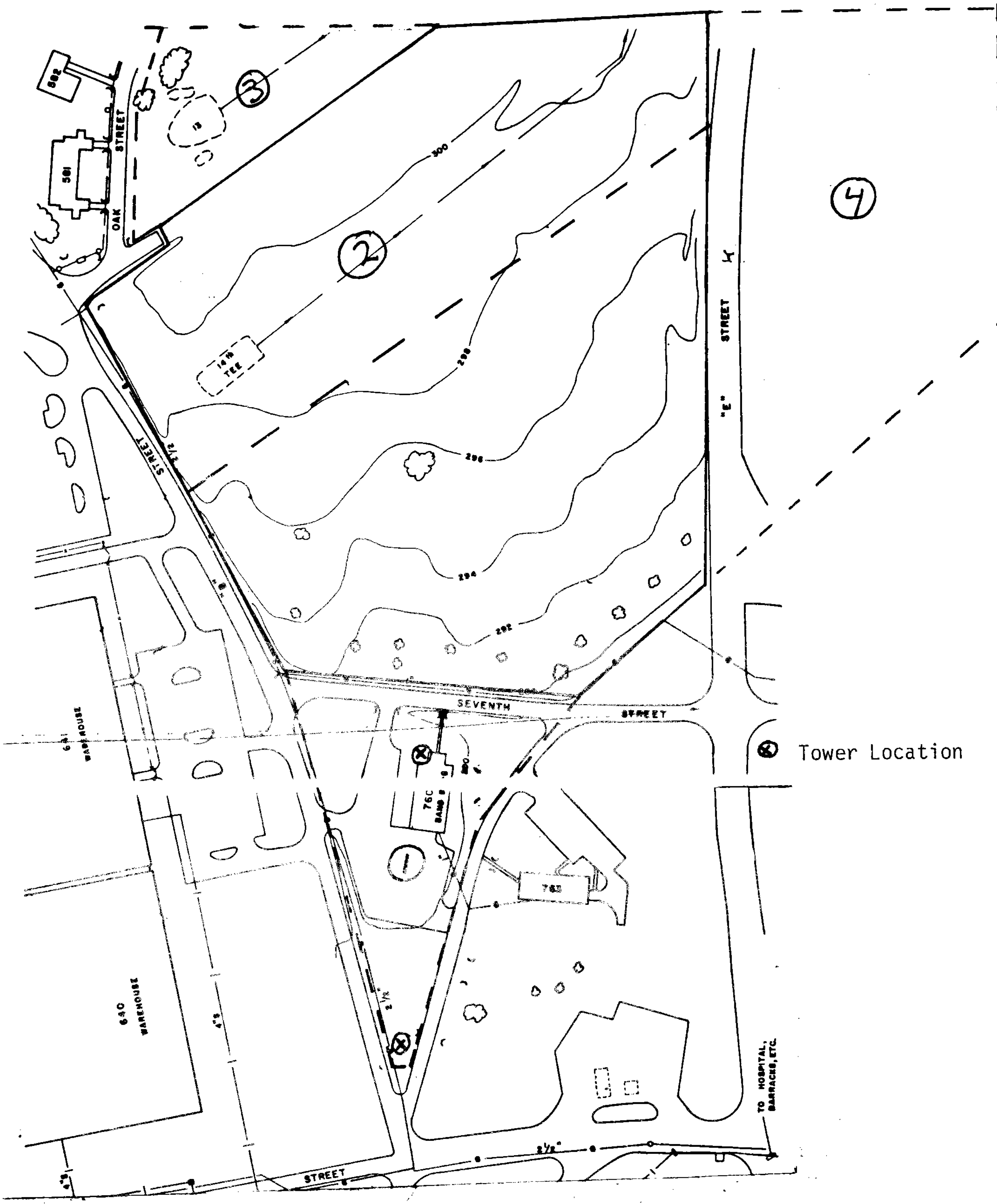


Figure 3.5-5. Variations in Heliostat Field Area Considered for Analysis

TABLE 3.5-2: EFFECT OF VARYING FIELD SIZE

Base: 60 m tower, 266 heliostats, incident power of 10.7 MW_t at noon winter solstice

Area Variance*	Number of Heliostats	Variation in Number of Heliostats from Base
1. Move tower to bottom of triangular field	240	-10
2. Reduce field to keep 14th tee	195	-25
3. Expand field to eliminate 13th green	282	+5
4. Expand field to east street	335	+26

*For location and size of area variances, see Figure 3.5-5.

A summary of the effect on the receiver power of the various heliostat fields is given in Table 3.5-2 For each of these fields, heliostats were configured in a radial staggered pattern in order to maximize the solar energy utilization. This maximizing process is a tradeoff betweeen the degree of parking of heliostats possible into a given area and the amount of shadowing and blocking that occurs between heliostats.

For configuration 1, the receiver tower was moved south into the apex of the triangular area. The band building and Seventh Street would be eliminated and the entire additional area between the two intersecting streets forming the apex would be available for the placement of more heliostats. For this field, the number of heliostats that could be located in the field would be approximately 240 (for a 60 meter tower height), a decrease of 6 percent from the 266 heliostats for the baseline configuration. Also, a check was made for an 80 meter tower height in this configuration to ensure that the result is not tower height dependent. With a tower height of 80 meters in this configuration, the number of heliostats that could be located in the field would be approximately 275, a decrease of 8 percent from the 308 heliostats for the baseline configuration. Therefore, over the range of tower heights of interest, even though the total field area increases, the narrowness of the additional area below Seventh Street allows for only a few additional heliostats, while the greater radial distance from Seventh Street to the base of the receiver tower causes a wider spacing between the heliostats fewer heliostats can be placed in this area resulting in a net loss in the total number that can be placed into the Configuration 1 field compared to the baseline field. Therefore, the Configuration 1 field is clearly not recommended.

Configuration 2 was chosen as a possibility in case it were strongly desirable not to infringe on the existing golf course. For this case, the border of the heliostat field was extended along a line parallel to and 50 m south of the normal direction of the 14th fairway. For this case, the loss of part of the 14th fairway for heliostat placement reduces the number of heliostats that can be placed in the field to 195, a reduction of about 25 percent from the baseline configuration. This large reduction would severely impact the value received from the cogeneration facility. In order to gain back the energy lost due to the reduction in field area, the tower height would have to be increased from 60 to over 90 meters. This would result in a large cost increase over the baseline concept. Also, there would be a non symmetry around the north-south axis (more heliostats to the east). The peak loads are in the winter, and the heaviest loads at this time occur in the morning. For this reason, and the increased tower height necessary to regain the power lost due to the reduced field area, the Configuration 2 field is not recommended.

Configuration 3 was chosen as a possibility only if it would be beneficial to move the green on the 13th hole. While the movement of a tee is fairly easy, the reconstruction of a green together with surrounding sandtraps is a relatively complicated affair, and usually a year or more is required before the green is fully in condition. By using the area presently allocated to the 13th hole green, the number of heliostats that could be placed in the entire field would be about 282, a net increase of about 6 percent over the baseline value of 266. A similar sort of effect could be achieved by increasing the tower height from 60 meters to about 66 meters and keeping the baseline field size. Recognizing the difficulties inherent in the construction of a golf course green, it is recommended that the 13th green should not be eliminated.

Configuration 4 was identified as being the only possible way to dramatically and efficiently increase the field area. Further expansion directly north would not be profitable, due to the large radial spacing required between heliostat rows due to shadowing and blocking effects. The area to the west of "B" and Oak Streets is a developed residential housing district. Southward expansion would be fruitless with the rectangular receiver concept being used. Therefore, the open area to the east of "E" Street was the only alternative. Configuration 4 resulted in the expansion of the field to the limits shown on Figure 3.5-5. This allows 335 heliostats to be placed in the total land area, an increase of about 26 percent over the baseline concept. However, this would require major reconstruction at the site. "E" Street is a major thoroughfare through the base, and is a large four-lane road. Since it is generally accepted practice not to allow the general public to have ready access through a heliostat field, this road would have to be closed and tben rebuilt to bypass the field. This would be a major and costly endeavor, and would not be justified by the possible benefits of a larger field. In addition, preliminary analyses seem to indicate that the use of the baseline field would allow the solar cogeneration facility to meet the peak steam demand of the loads connected to Steam Plant Number 4 for all times except during the two peak winter months. Therefore, there is no justification for increasing the field size beyond the 62,730 m^2 (15.5 acres) identified in the proposal and used as a baseline.

3.6 TOWER HEIGHT TRADE STUDY

3.6.1 RANGE OF TOWER HEIGHTS

The baseline facility utilized a receiver located 60 m (200 ft.) above ground level and a collector field as shown on Figure 3.6-1. It was recognized at the start of the trade studies that a range of power levels must be investigated in arriving at a preferred facility configuration. For this reason, an evaluation of energy collection with various tower heights was conducted for the fixed baseline collector field size. Analyses were conducted using the MIRVAL code over a range of tower heights from 40 m (133 ft) to 80 m (267 ft). The results are shown in Table 3.6-1.

TABLE 3.6-1: POWER LEVEL VARIATION WITH TOWER HEIGHT

TOWER HT. - Meters	NO. OF HELIOSTATS	RECEIVER PLANE POWER (MW_t)
40	184	7.4
50	226	9.1
60	266	10.7
70	291	11.7
80	308	12.4

These data show that for the fixed field size a 1/3 decrease in tower height from the 60 meter base height results in a 31 percent decrease in number of

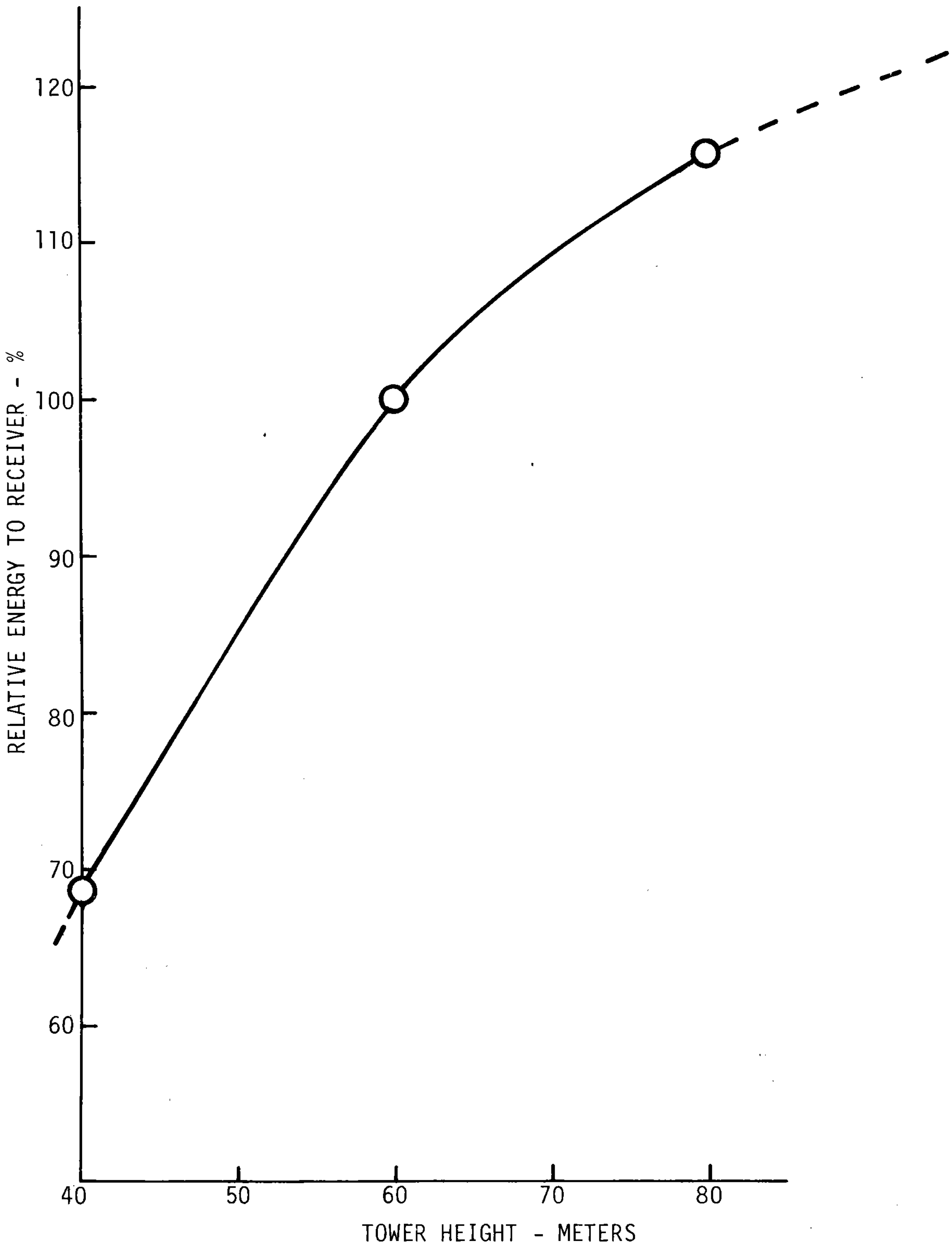


Figure 3.6-1. Relative Power to Receiver vs Tower Height

heliostats; a 1/3 increase results in a 16 percent increase in number of heliostats. The energy delivered to the receiver changes by the corresponding percentage in each case. These results are plotted in Figure 3.6-1 for reference and use in later evaluations.

3.6.2 TOWER HEIGHT COST ESTIMATES

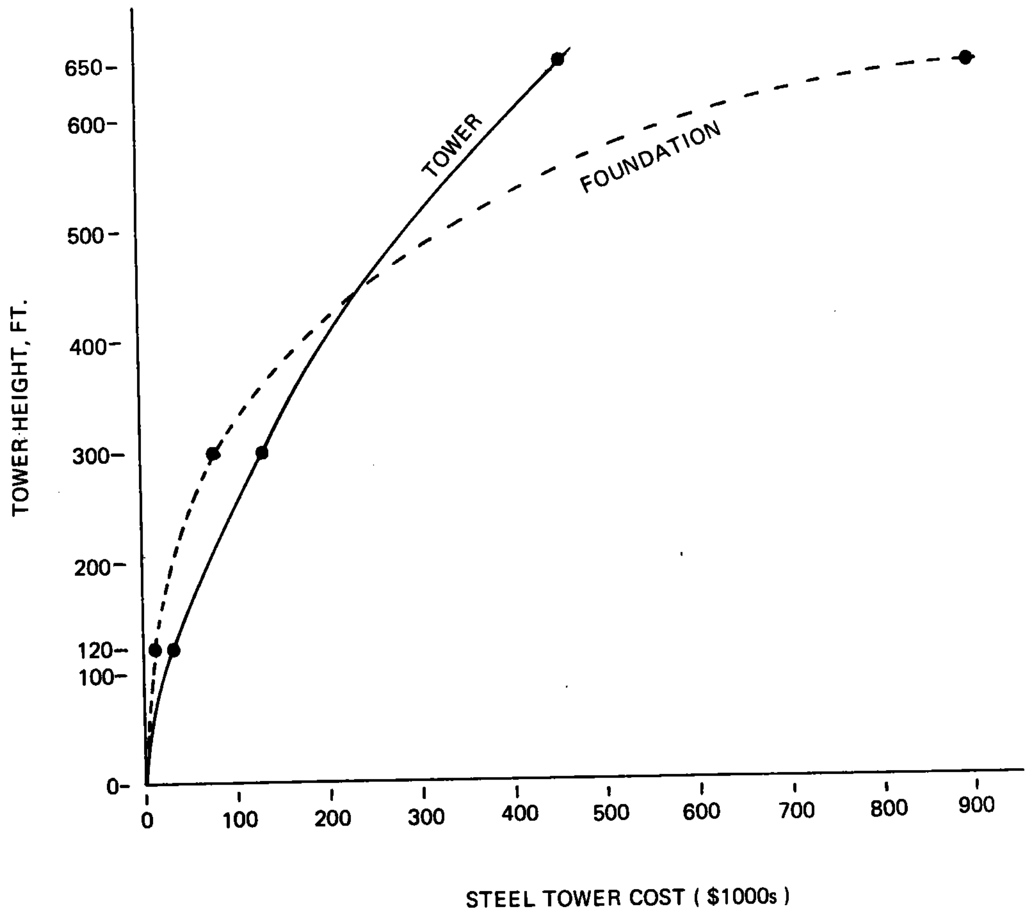
The Sterns-Roger solar central receiver studies for towers (Sandia C-21560 June 1979) were utilized to develop a comparative cost model based on 40, 60, and 80 meter (131 ft, 197 ft, and 262 ft) tower heights.

The Sterns-Roger data for a 90,900 kg (200 KIP), 0.05g ground acceleration, and 31 m/s (70 mph) wind in 37 m (120 ft), 91 m (300 ft), and 198 m (650 ft) configurations was utilized. The Robins conditions are 52,730 kg (116 KIP), 0.05g ground acceleration, and 40 m/s (90 mph) wind. Assumptions permitted the substitution of 90,900 kg (200 KIP) and 31 m/s (70 mph) to equate 52,730 kg (116 KIP) and 40 m/s (90 mph). Figure 3.6-2 depicts a tower cost curve and foundation cost curve in 1979 dollars.

The Sterns-Roger report also considered the diameter across flats at the top and bottom. The study models utilized in Figure 3.6-3 were based on 6.1, 9.1, and 13.7 meter (20, 30, and 45 ft) average diameters compared to a 12 m (40 ft) size for Robins. The increase was used to factor the weight of the bracing in Figure 3.6-4.

Column weight for the Sterns-Roger models was based on a 90,900 kg (200 KIP) receiver plus nominal bracing weight; the Robins 52,730 kg (116 KIP) load plus greater bracing weights is approximately the same. Figure 3.6-5 shows the column weight.

The combined bracing and column weights are shown on Figure 3.6-6 and are multiplied by the cost per ton of a similar Sterns-Roger model. The resultant is the tower cost.



DATA EXTRACTED FROM TABLE 1, PAGE 2-2 *
200 KIP LOAD, .05 GROUND ACCELERATION, 70 MPH
4 KSF SOIL (EXCEPT 650 ft. = 12 KIPS)

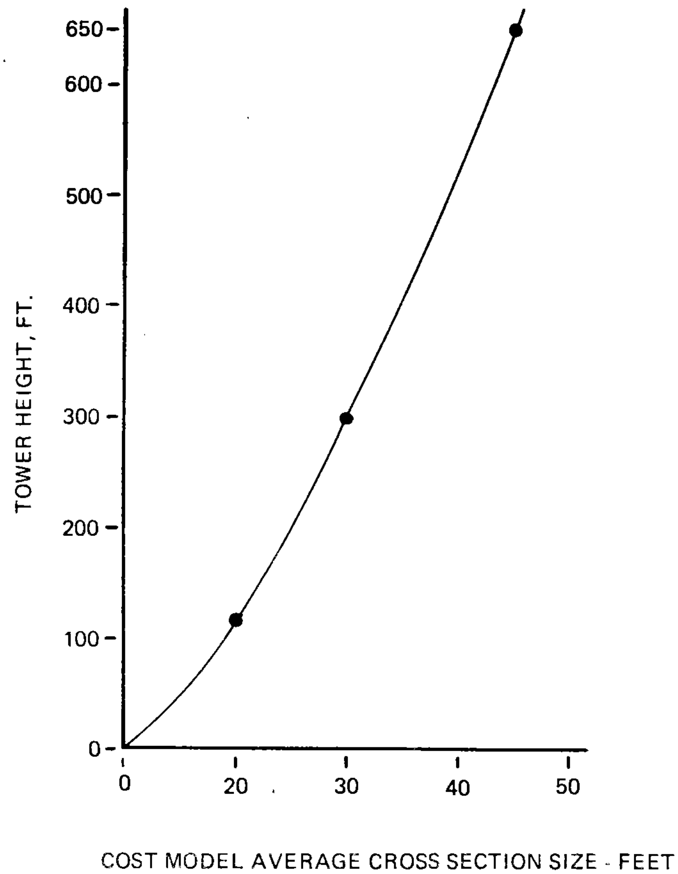
COL.	HEIGHT	TOP	BASE	(AVG)
30	120′	20′	20′	20′
1	300′	20′	40′	30′
3	650′	30′	60′	45′

ASSUMPTIONS, 116 KIP VS 200 KIP = 90 MPH VS 70 MPH

HEIGHT, M.	HEIGHT, FT.	TOWER	BASE	TOTAL (1979$)
40	131	$ 37,000	$ 11,000	$ 48,000
60	196	$ 62,000	$ 39,000	$ 101,000
80	262	$ 100,000	$ 60,000	$ 160,000

* ALL DATA EXTRACTED FROM TOWER COST DATA FROM SOLAR CENTRAL RECEIVER STUDIES, STERNS- ROGER / SANDIA C- 21560, JUNE '79

Figure 3.6-2. Comparative Steel Tower Cost Analyses

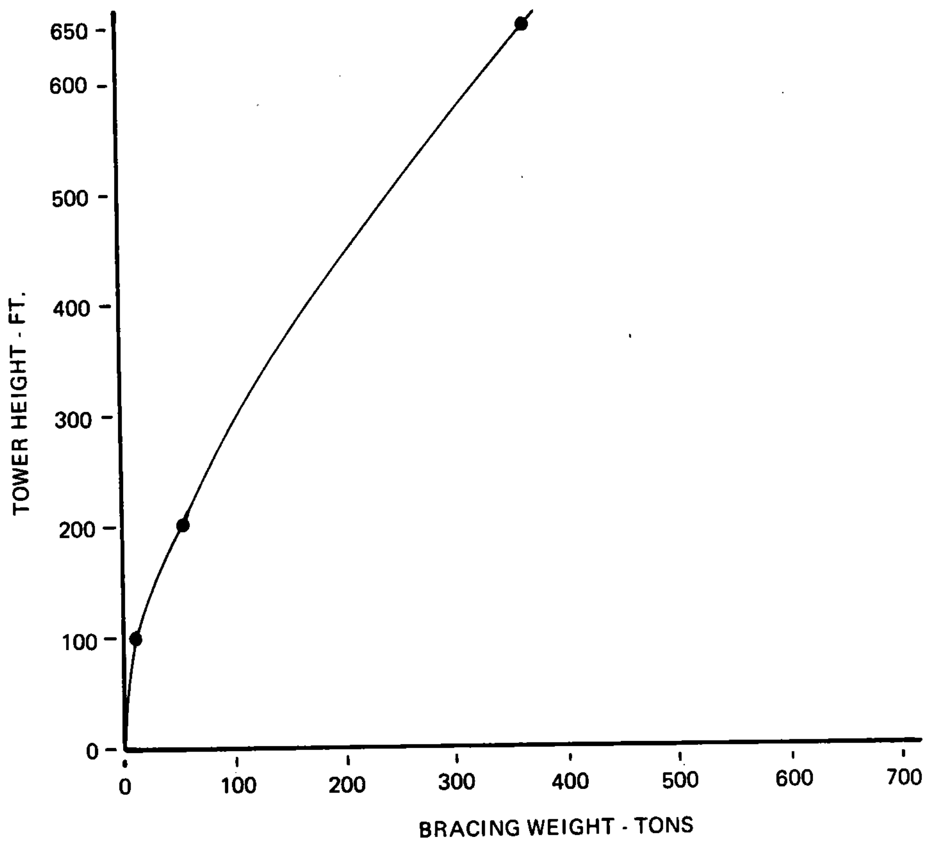


HEIGHT, M.	HEIGHT, FT.	SIZE	REQUIRED*	INCREASE
40	131	22′	40′	1.82
60	196	25½′	40′	1.57
80	262	28½′	40′	1.40

* CONVERT TO 40′ x 40′ TOP, 40′ x 40′ BASE TOWER

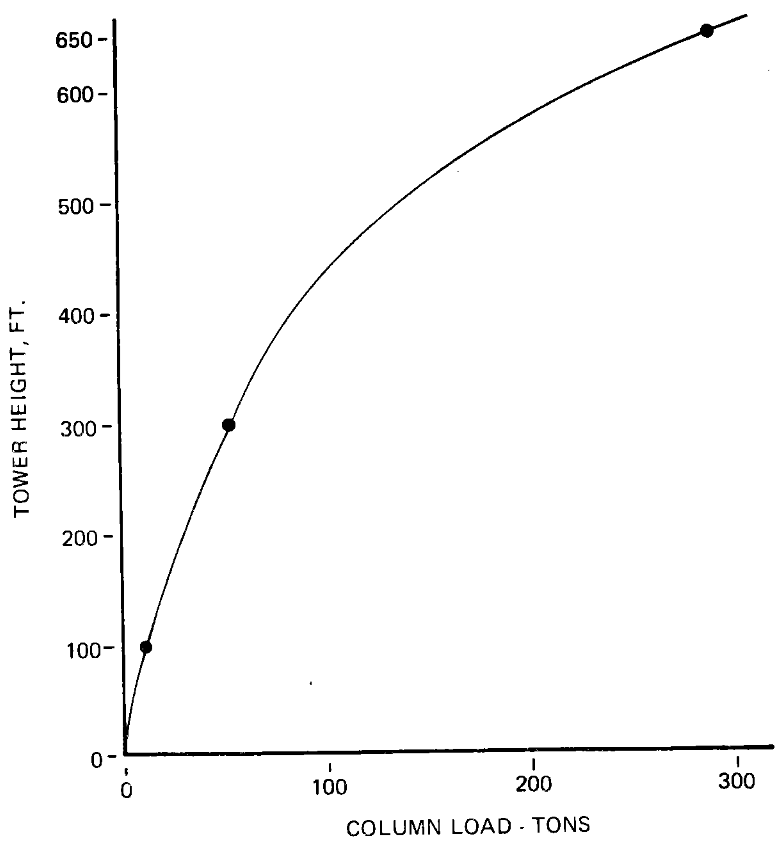
Figure 3.6-3. Average Size Across Tower Flats

USING 40' x 40' AVERAGE CROSS SECTION, USE SAME SIZE COLUMNS, BUT LONGER HORIZONTAL AND VERTICAL BRACING. DATA IS FOR FACTORING BRACING ONLY.



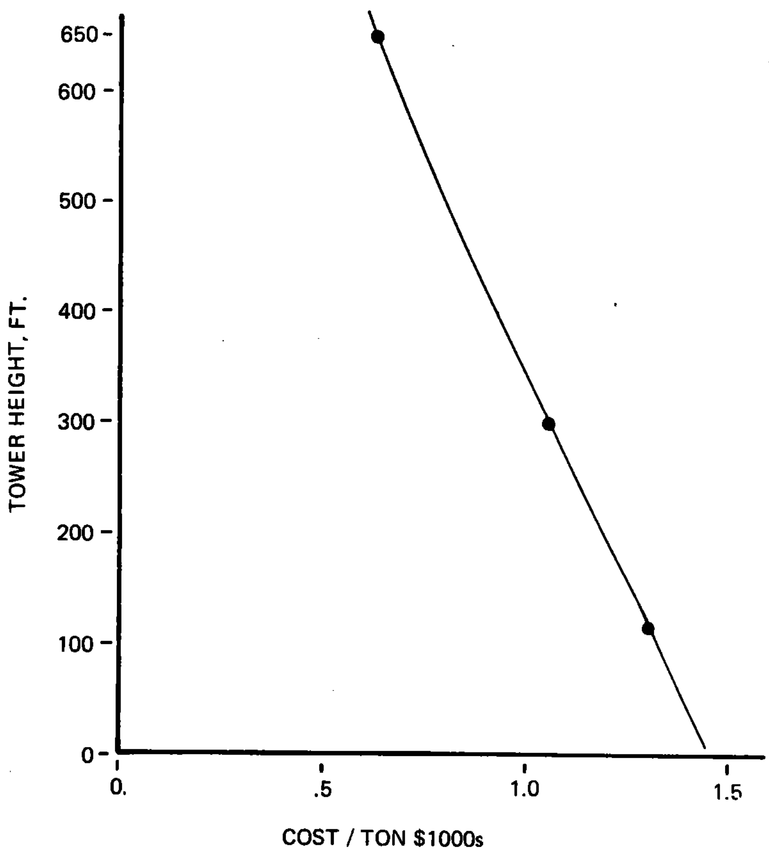
HEIGHT, M.	HEIGHT, FT.	WEIGHT	SIZE C. F.		WEIGHT (BRACING)
40	131	15 TONS	x 1.82	=	27.3 TONS
60	196	30 TONS	x 1.57	=	47.1 TONS
80	262	52 TONS	x 1.40	=	72.8 TONS

Figure 3.6-4. Bracing Weights Curves



HEIGHT, M.	HEIGHT, FT.	COLUMN WEIGHT
40	131	10 TONS
60	196	20 TONS
80	262	35 TONS

Figure 3.6-5. Column Weight



COMBINED WEIGHT - BRACING AND COLUMNS

HEIGHT, M.	BRACING*		COL.		TOTAL	x	$/TON	=	TOTAL COST $
40	27.3 TONS	+	10	=	37.3	x	1250	=	46,625
60	47.1		20		67.1	x	1180	=	79,178
80	72.8		35		107.8	x	1100	=	$118,580

*40′ x 40′

Figure 3.6-6. Column and Bracing Cost Curve

The foundation cost from Figure 3.6-2 is added to the tower cost from the same figure to arrive at the tower/foundation costs shown in Figure 3.6-7.

Figure 3.6-8 shows cost curves for stairs and elevators extracted from the Sterns-Rogers Report, and pro rata costs for 40, 60, and 80 meter towers, fixed costs for beacons, lighting, and a 12 x 12 meter (40 ft x 40 ft) platform are added to arrive at total accessory costs.

Figure 3.6-9 combines tower and base and accessories costs and escalates costs and cost differentials from 1979 to 1984.

The comparative tower cost curves generated were analyzed simultaneously with energy collection curves from the number of heliostats that could be effectively packed into the collector field, all contingent on allowable net thermal output.

3.7 HELIOSTAT CANTING INVESTIGATION

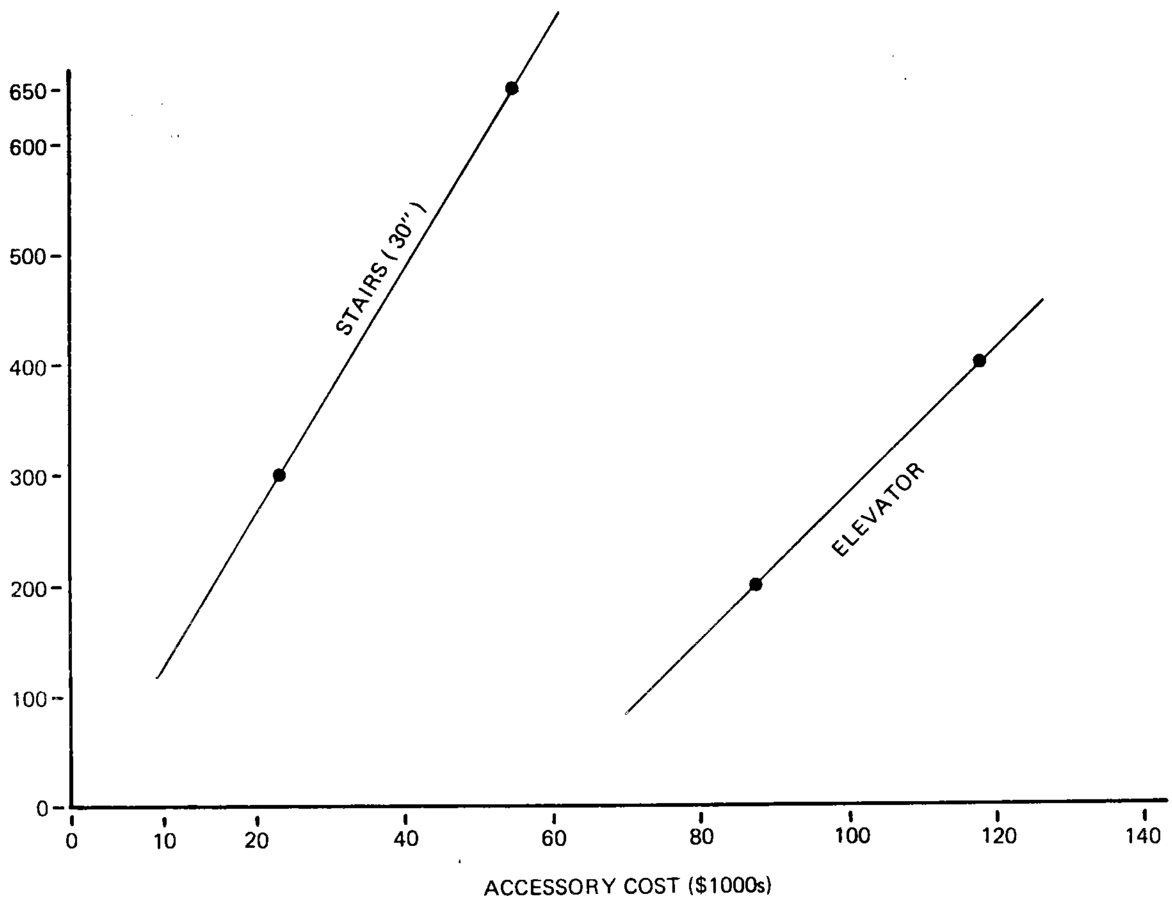
The baseline configuration utilizes a heliostat field in which each heliostat is "canted" for the maximum slant range in the field. The resultant beam size at the receiver dictates the receiver panel size so that about 95 percent of the reflected energy is intercepted. The question arose as to whether selective canting of heliostats according to their individual slant ranges would reduce the beam size and permit a smaller receiver panel size. It was recognized that any change to decrease the beam size would imply an increase in peak heat flux at the center of the receiver panel. Hence the question was: Does selective canting of heliostats in this application permit significant reduction in receiver panel dimensions without incurring excessive peak heat flux?

The conclusion reached is that the peak heat flux increases to unacceptable levels without a significant reduction in panel size. Therefore, the preferred facility maintains the baseline configuration in which the mirror panels on each heliostat are "canted" to the radius of curvature dictated by the most remote heliostat in the field.

TOTAL COST ($1000s)

HEIGHT, M.	HEIGHT, FT.	TOWER	FOUNDATION	TOTAL COST
40	131	$ 46.6	$ 13	$ 59.6
60	196	$ 79.2	$ 40	$ 119.2
80	262	$ 118.6	$ 75	$ 193.6

Figure 3.6-7. Combined Tower and Foundation Cost



TOTAL TOWER ACCESSORY COST - $1000s

HEIGHT, M.	HEIGHT, FT.	ELEVATOR	BEACON LIGHTING	30" W STAIRS	LIGHTNING	40' x 40' PLATFORM	ACC. TOTAL
40	131	$80	$89	$10	$15	$48	$242
60	196	$88	$89	$15	$16	$48	$256
80	262	$97	$89	$22	$17	$48	$273

Figure 3.6-8. Cost of Accessories

TOTAL TOWER COST ($1000s)

HEIGHT, M.	TOWER + BASE	ACC.	TOTAL
40	$ 59.6	$242	$301.6
60	$119.2	$256	$375.2
80	$193.6	$273	$466.6

(IN 1979 DOLLARS)

BASELINE	60 M. TOWER	$375,200
	- 40 M. TOWER	301,600
REDUCTION, 40 M.		-($73,600)
	80 M. TOWER	$466,600
BASELINE	60 M.	375,200
ADDITION, 80 M.		+$91,400

	'79	'80	'81	'82	'83	'84
$\Delta$$ DEDUCT 40 M.	73.6	81.0	89.1	97.9	107.8	118.5
BASELINE 60 M.	375.2	412.7	454.0	499.0	549.3	604.3
$\Delta$$ ADD FOR 80 M.	91.4	100.5	110.6	121.7	133.8	147.2

COST DIFFERENTIALS IN &1000s AT 10% ESCALATION

Figure 3.6-9. Tower Cost Summary

The investigation utilized a combination of MIRVAL and simplified closed form estimates of the beam size. The analyses were conducted primarily at noon winter solstice with simple assessments of other times of the year to confirm that the noon winter solstice comparison is generally applicable.

The beam size results are portrayed on Figure 3.7-1. This figure portrays the fraction of the receiver incident energy which occurs inside a distance "X" from the panel center as a function of that distance "X." Four curves are shown as follows:

Curve 1 This curve is taken from a MIRVAL analysis of the baseline field.

Curve 2 This curve is derived by use of the Coddington equations with parameters chosen to agree with the MIRVAL analysis in the vicinity of X = 2. The canting strategy is that used in the MIRVAL analysis.

Curve 3 This curve is derived by use of the Coddington equations with each of five field segments canted at the slant range at the center of that field segment.

Curve 4 This curve is derived from curves 1 and 3 by attaching the MIRVAL tail from 1 to the basic curve of 3. This is therefore our best estimate of the energy distribution for a field of selectively canted heliostats.

A perusal of the curves indicates that for a panel size to intercept in the vicinity of 95 percent of the beam energy, the panel could be about 1 to 1-1/4 meters smaller for a field of selectively canted heliostats than for the same field of uniformly canted heliostats. However, the peak heat flux must be acceptable.

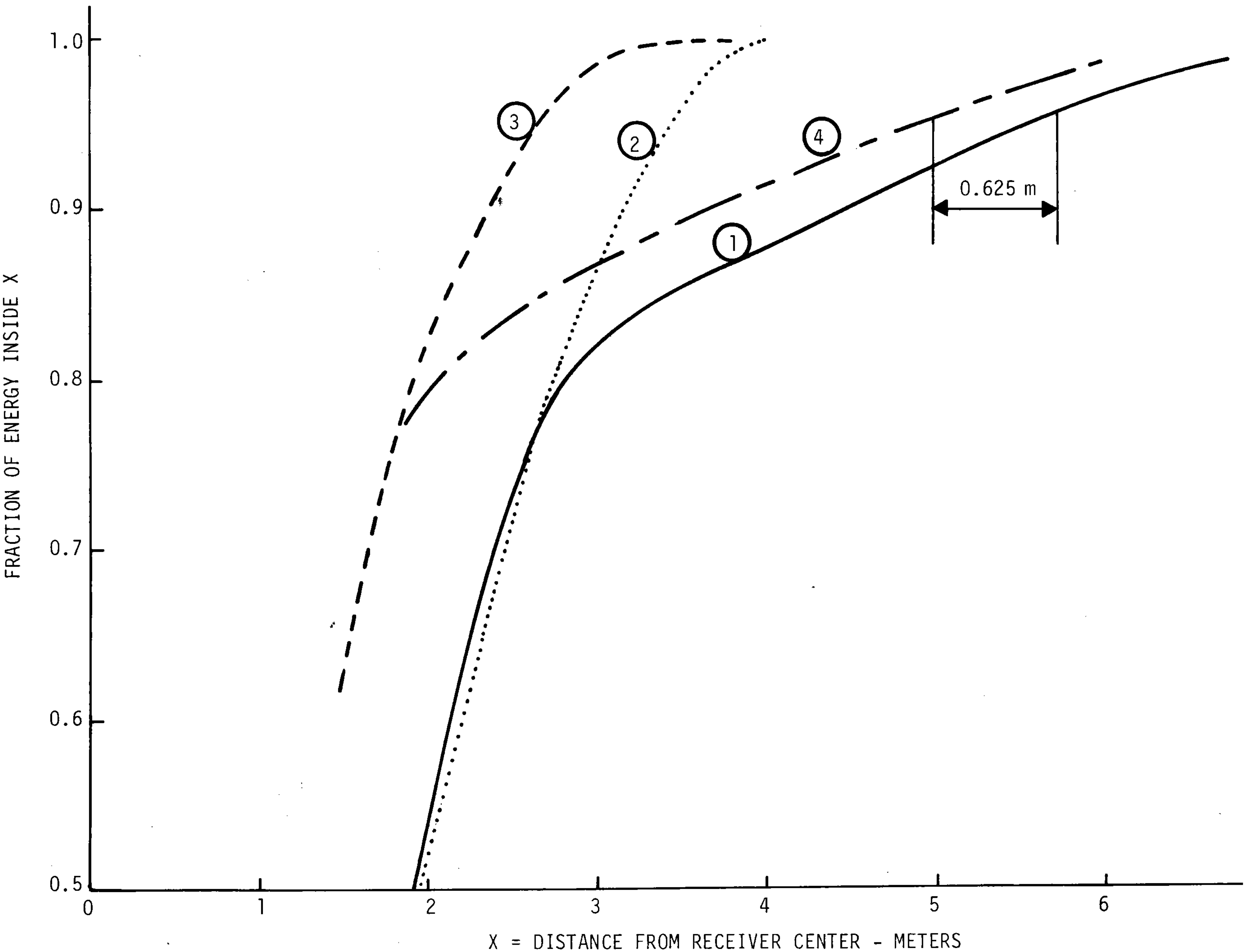


Figure 3.7-1. Estimated Integrated Receiver Energy Distribution Inside Radius, X

The peak heat fluxes for these cases were therefore estimated. This was done using the Coddington equations, as before, along with the MIRVAL solution. The results are portrayed on Table 3.7-1.

TABLE 3.7-1: Receiver Peak Heat Flux Estimates

BASIS OF ESTIMATE	VALUE (MW/m^2)
MIRVAL (curve 1, Fig. 3.7-1)	0.68
Curve 2, Fig. 3.7-1)	0.69
Curve 3, Fig. 3.7-1)	1.36

The limiting value is near .68 MW/m^2. The results for the selectively canted case, the curve 3 case, shows that the improved focusing of the "closer in" parts of the field increase the peak heat flux to excessive values without a commensurate improvement in total energy collection for a given size receiver. Therefore the selectively canted case is eliminated from further consideration.

3.8 EFFECT OF RECEIVER INCLINATION

The baseline configuration utilizes a receiver concept in which the receiver panel is oriented in a vertical plane. For this orientation and the baseline heliostat field, the angle between a line normal to the receiver panel and the direction of incident energy from the individual heliostats varies from approximately 60° to approximately 10° depending upon the heliostat location in the field. The associated effective target "height" presented to the incoming energy beams therefore varies from about .50 to .98 times the actual receiver panel height. The question arose as to whether a significant improvement in energy collection could be achieved by "inclining" the receiver panel to present a target more nearly "normal" to the incoming beams. It is recognized that the cost of the receiver would be increased by the structural complications associated with providing an "inclined" panel. The question then is: Does provision of an inclined receiver panel rather than a vertical panel result in improved cost of energy collection in this application?

The conclusion reached is that the cost of providing the inclined panel exceeds the benefits to be derived therefrom. Therefore, the preferred system utilizes a vertically oriented receiver panel.

The investigation utilized a MIRVAL analysis of the baseline field to establish the energy distribution in which the panel is located and assessments were made of the intercepted energy for a fixed panel size of different orientations. The assessment was made at noon winter solstice but energy distribution variations through the year are judged not to be great enough to influence the conclusion.

The basic geometry of the field and receiver panel is shown on Figure 3.8-1. The range of angles between the panel normal and the reflected beams is from 60° for innermost heliostats to 10° for outermost heliostats.

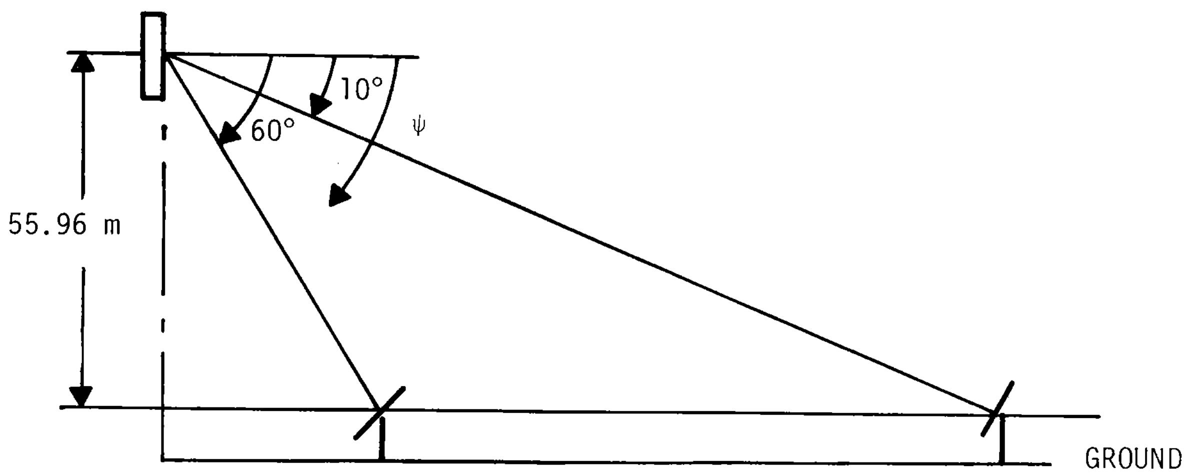


Figure 3.8-1. Schematic Field/Receiver Geometry

The effective target height as presented to the heliostats can be estimated as:

$$\overline{\text{Cos }\Psi} = \sum_{i=1}^{N} \frac{N_i \text{ Cos } \Psi_i}{N_T}$$

where N_i is the number of heliostats with angle Ψ_i. Formulation of this quantity for the baseline case yields

$$\overline{\text{Cos }\Psi_b} = .907$$

Now, rotating the receiver panel from the vertical plane by an angle τ changes the range of incident angles changes for 60° to 10° to a range $(60 - \tau)°$ to $(10 - \tau)°$.

The average cosine of the angle of incidence then can be formulated for a tilt angle τ as

$$\overline{\text{Cos }\psi\ (\tau)} = \sum_{i=1}^{N} \frac{N_i\ [\text{Cos }(\Psi_i - \tau)}{N_T}$$

This latter quantity depends upon τ as shown below:

τ	$\overline{\text{Cos }\Psi}$
18°	.983
20°	.986
23°	.987
26°	.985
28°	.983

This table shows that the largest average cosine (and hence largest target presented to the whole field) occurs when τ = 23°, and Cos Ψ (23°) = .987 as contrasted to a vertical panel value Cos Ψ (0°) = .907.

For a panel height of approximately 8.0 meters, a value close to the baseline receiver height, the effective target height presented to the field is

$$\overline{h}\ (o) = 7.25 \text{ meters}$$

$$\overline{h}\ (23) = 7.89 \text{ meters}$$

The relative energy collected for these two orientations therefore can be evaluated by comparing the energy intercepted by a panel of height 7.25 meters with the energy intercepted by a panel of height 7.89 meters for a given beam produced by the field of heliostats. The comparison is drawn on Figure 3.8-2 which shows the energy distribution for a MIRVAL analysis of the field. This data shows that a tilted receiver panel of a given size in this application could collect about 1 percent more energy than a vertical panel of the same size. Considering this assessment further, it is apparent that the same effective target size can be achieved by increasing the height of the panel rather than titling the existing panel. The required increase would be 7.8 percent; that is, in this application the same energy collection improvement over the baseline can be achieved by either (1) tilt the given panel by 23° off vertical or (2) increase the height of the panel by 7.8 percent and leaving it in a vertical orientation.

The question now is one of which method of accomplishing the same purpose would be preferable. We have concluded that increased length is preferable to a tilted panel for the following reasons:

1) No new parts or labor is introduced because only modest increases in sizes of existing parts are involved (e.g. longer tubes, risers and downcomer pipes).

2) No structural loading complications are introduced by overhung loads.

3) The tilted case would introduce a higher peak heat flux and this parameter is designed to its acceptable limit in the vertical orientation.

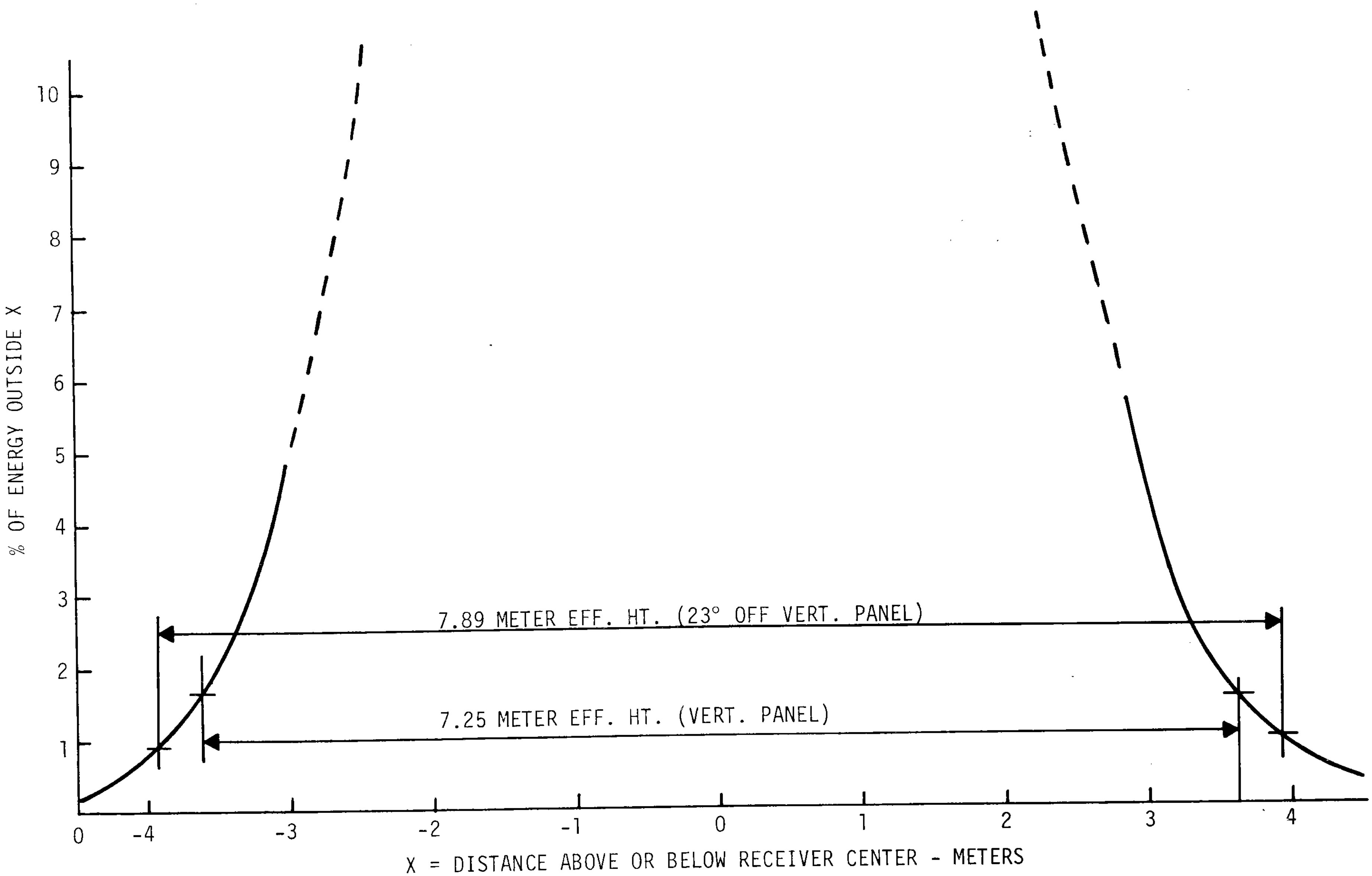


Figure 3.8-2. Estimate of Integrated Receiver Energy Distribution Along a Vertical Line

Therefore the tilted panel configuration is eliminated from further consideration.

3.9 STEAM TURBINE TYPE TRADE STUDY

In the development and selection of a site specific configuration for a solar cogeneration facility at Robins Air Force Base, as required in Task 2, several trade studies were completed on the steam turbine and on the steam inlet and exit conditions for the turbine. These efforts were performed prior to the initiation of a detailed development and analysis of a conceptual design for the cogeneration facility. The trade studies to select the type of steam turbine to be used for generating electricity are summarized in this section. Presented below in Section 3.10 is a summary of the trade studies completed on the steam inlet pressure and temperature conditions for the turbine. The analytical results on a reduced turbine discharge (exhaust) pressure for summer operation, when the process steam requirements are reduced, is discussed in Section 3.11. Detailed results on all three of these types of trade studies are included in Appendix D.

The baseline steam turbine which was proposed utilized the technology previously developed by Mechanical Technology, Inc. (MTI) for the Shenandoah project. This MTI turbine is a high efficiency, high speed turbine which was designed, developed, and planned for use in the Solar Total Energy - Large Scale Experiment (STE-LSE) program at Shenandoah. Two different modifications of this high performance MTI turbine were considered for the cogeneration facility. The reference configuration as submitted in the proposal replaced the low pressure turbine designed for Shenandoah with a second high pressure unit. By enlarging the nozzle area and redesigning the pinion shaft for the increased power requirements, a dual high pressure stage turbine could be utilized for the facility. The net electrical power that could be delivered to Robins Air Force Base, as discussed in the proposal, was approximately 750 kW at noon winter solstice. This electrical output power was based on a flow rate to the turbine of approximately 4290 kg/h (20,500 lb/h) of superheated steam at an inlet pressure of 5.86 MPa (850 psia) and an inlet temperature of 399°C (750°F), as well as a turbine exit pressure of 0.931 MPa (135 psia).

As part of the system size trade studies, tower heights of 40, 60, and 80 meter (131, 197, and 262 ft) were being evaluated. For these tower heights and the corresponding thermal power input to the receiver fluid, a maximum flow rate of up to 16,920 kg/h (37,300 lb/h) was considered. Accordingly, a modified high performance, higher power MTI turbine, with the attendant higher values of expansion efficiency and net turbine and gearbox efficiency, was evaluated. The performance capabilities of this modified MTI turbine at various inlet pressures and temperatures, with an electrical output power of up to approximately 1700 kW, were established in discussions with personnel from MTI (Reference 3.9-1*). Thus, the performance of a modified version of the MTI turbine submitted in the proposal was analyzed during these trade studies. Turbine expansion efficiencies of 78 percent at full flow conditions are considered feasible. The basic cost of this modified MTI turbine was estimated to be $1,200,000. (Reference 3.9-1). The primary reason for selecting the MTI turbine for the initially proposed configuration was to provide more electrical power from the steam turbine generator and thereby meet the desired electrical energy to thermal energy ratio of greater than 10 percent.

Since the high performance MTI turbine was known to be in a class by itself in terms of efficiencies, it was decided to compare the performance and cost of an MTI turbine with the performance and cost of a typical commercial turbine in this cogeneration facility. The expansion efficiency for a typical commercial turbine is approximately 61 percent and the basic cost for the turbine generator unit is approximately $125,000. Thus, it was considered prudent to reinvestigate whether it is cost effective to use the MTI turbine for this cogeneration application, since the electrical output power is only approximately 10 percent of the thermal output power of the facility.

As part of these turbine trade studies, 10 different steam turbines were initially considered and analyzed. One typical commercial turbine was selected

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* Reference 3.9-1 Personal communication, H. Leibowitz (MTI), January 30 and February 9, 1981.

for detailed evaluation and for performance comparisons with the modified MTI turbine. More than 40 cases on the performance capabilities of the turbines were analyzed. These analyses included: a) both full load and part load performance to account for the variations in solar insolation at different times of the day and days of the year, b) different tower heights and corresponding thermal powers into the receiver fluid for the selected fixed collector field land area, c) variations on inlet pressure and inlet temperature, and d) two different turbine discharge (exhaust) pressures. The objective of these turbine trade studies was to estimate and compare the variations in plant capital cost and the annual value produced, both from electrical power generation and process steam generation, with the high performance MTI turbine and with the typical commercial turbine.

Based on the Collector (Heliostat) Field Trade Study results and the Solar Facility Size results discussed above in Sections 3.5 and 3.4, 266 heliostats were placed in the collector field land area with a receiver centerline height of 60 meters (197 ft). The MIRVAL computer program was used to determine the thermal power transmitted from the collector field to the receiver. For this baseline case, 10.7 MW of thermal power was incident on the receiver plane at noon winter solstice. Accounting for both spillage and convection and radiation thermal losses from the receiver surface, 90 percent of this thermal power (9.65 MW) was assumed to be transferred to the receiver fluid (water/steam).

Initially, performance comparisons between the MTI and commercial turbines were completed for a turbine inlet pressure of 10.34 MPa (1500 psia) and an inlet temperature of 399°C (750°F). Considering the pressure and thermal losses in the piping from the receiver to the turbine, the receiver outlet pressure and temperature were estimated to be 10.5 MPa (1525 psia) and 410°C (770°F), respectively. The feedwater inlet temperature to the receiver was assumed to be 174°C (345°F). For these receiver inlet and exit conditions, the flow rate through the receiver and the turbine was computed to be 14,620 kg/h (32,200 lb/h).

With this full power design flow rate, the above mentioned turbine inlet pressure and temperature, and a turbine exhaust pressure of 0.93 MPa (135 psia), as well as accounting for the turbine expansion, net turbine, gearbox, and generator efficiencies, 1400 kW of electrical power is produced by the MTI turbine. For the same flow rate, inlet and exit pressure, and inlet temperature, the electrical output power from a typical commercial turbine is 982 kW. Also, the part load performance, i.e., reduced flow at the same inlet and exit pressures and inlet temperature, was evaluated for both turbines.

Shown in Figure 3.9-1 is a comparison of the electrical output power as a function of flow rate for the MTI turbine and a typical commercial turbine. Note that significantly more electrical power is produced, as expected, by the high performance (high efficiency) MTI turbine than that produced by the commercial turbine.

Downstream of the turbine, approximately 16 percent of the turbine flow is diverted to the feedwater heater in the cogeneration facility. Therefore, the process steam flow was assumed to be $\sim$ 84 percent of the turbine flow rate at all power levels. Considering the enthalpy of the steam at the turbine exhaust, 8.04 MW_t (27.4 x 10^6 Btu/h) of process steam thermal power is produced downstream of the MTI turbine at the design point (full power) turbine flow rate of 14,620 kg/h (32,200 lb/h). Since the commercial turbine generator produces less electrical power than the MTI turbine, more thermal power for process steam is available because of the higher turbine exit enthalpy. Thus, 8.33 MW (28.4 x 10^6 Btu/h) of process steam thermal power is produced at the design point with the commercial turbine.

Shown in Figure 3.9-2 are the process steam thermal output powers as a function of flow rate for the MTI and commercial turbines. Note that the process steam output power with the commercial turbine is somewhat higher than that with the MTI turbine. This improved process steam performance partially mitigates the loss in electrical performance shown in Figure 3.9-1.

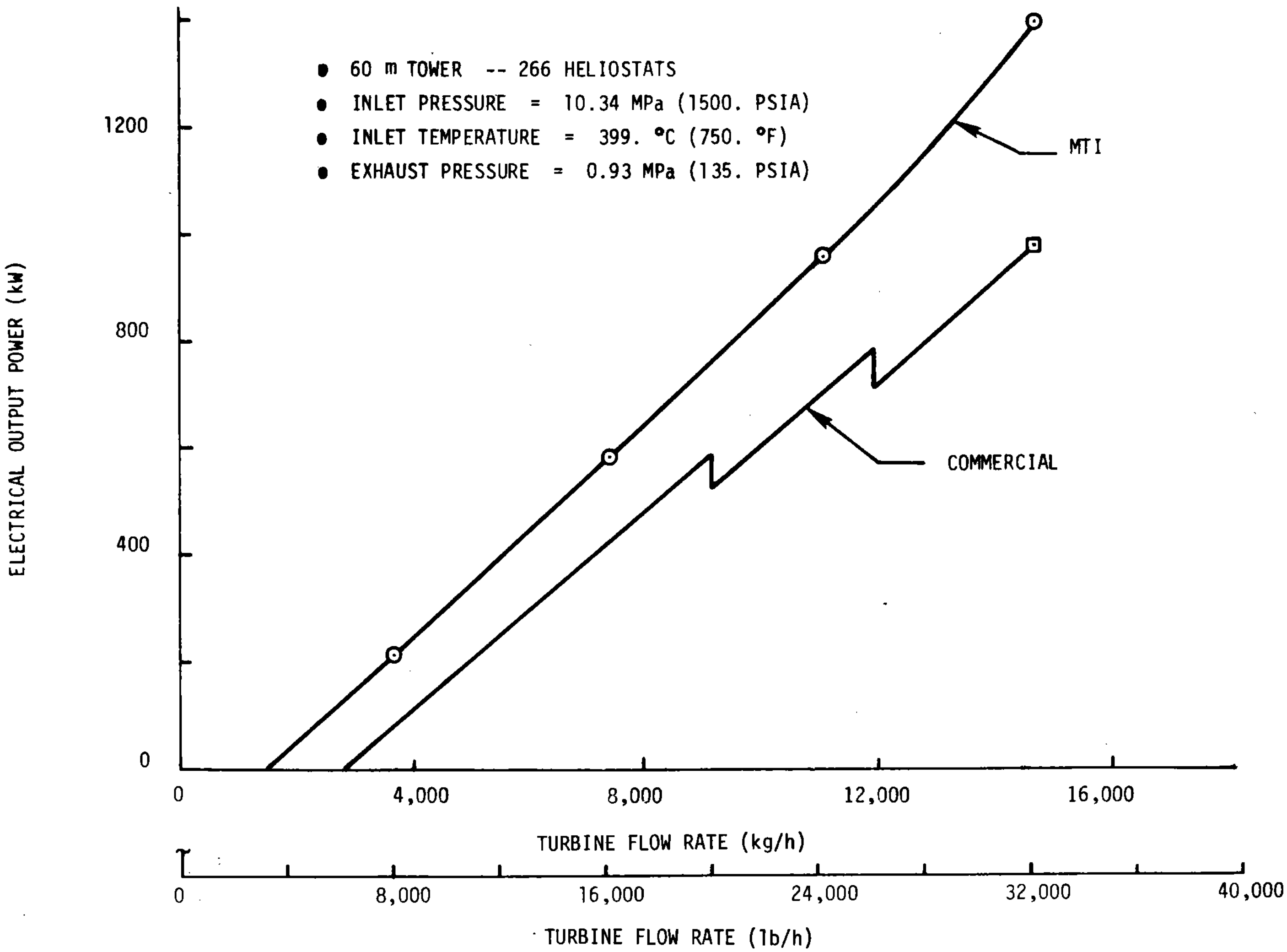


Figure 3.9-1. Electrical Output Power as a Function of Turbine Flow Rate for MTI and Commercial Turbines

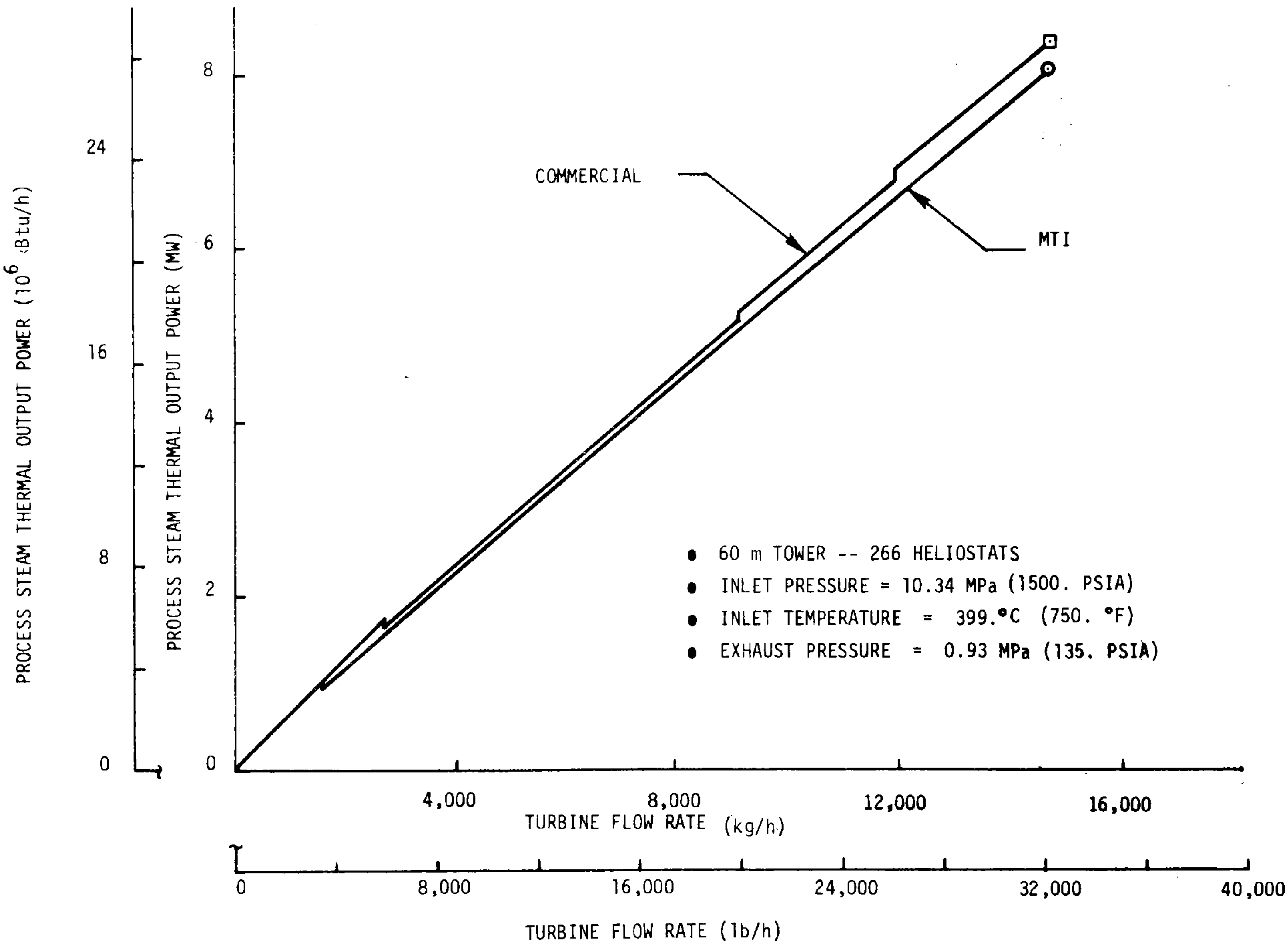


Figure 3.9-2. Process Steam Thermal Output Power as a Function of Turbine Flow Rate for MTI and Commercial Turbines

Comparisons were drawn on the cost, annual output, and economic value for the high performance MTI turbine and the commercial turbine so as to select one of the turbines for the Robins AFB cogeneration facility. Shown in Table 3.9-1 are these comparisons for the two turbines. These results were based on a 60 m (197 ft) tower, a steam inlet temperature and pressure of 399°C (750°F) and 10.34 MPa (1500 psia), respectively, and the Robins AFB Steam Plant No. 4 steam demand curves. As discussed above, the basic cost of the MTI turbine (including the gear box, electrical generator, and controls) is estimated to be $1,200,000 (in 1981 $). Similarly, the cost of a typical commercial turbine for this application is approximately $125,000. Thus, the difference in capital cost for the two turbines was estimated to be $1,075,000. The electrical power to thermal power ratio at the noon winter solstice design point, i.e., at the maximum turbine flow rate values in Figure 3.9-1 and 3.9-2, was computed to be 17.4 percent and 11.8 percent for the MTI and commercial turbines, respectively.

The magnitude of the solar insolation incident on the collector field and the thermal power transferred into the receiver fluid varies for each hour of the day and for each day of the year. This variation in solar insolation, including the effects of partly cloudy conditions, results in different electrical output powers and process steam output powers throughout the year. By maintaining the turbine inlet pressure and temperature at their controlled values, the variation in thermal power at the receiver is accommodated by varying the flow rate through the receiver and turbine. As shown in Figure 3.9-1, the electrical output power from the MTI turbine is approximately 950 kW for a part power flow rate of 10,870 kg/h (24,000 lb/h). A process steam thermal power of approximately 6 MW (20,500 Btu/h) is produced downstream of the MTI turbine at the same turbine flow rate, as shown in Figure 3.9-2.

By integrating the electrical and process steam output powers for each hour of the day over the entire year, the net annual electrical and process steam (energy) outputs were calculated. These results were evaluated by using the Cogeneration Facility Annual Integration Performance Model discussed in Appendix E. A summary of the analytical results derived is given in

Section 3.4, System Size. As shown in Table 3.9-1, 1070 MWh of net annual electrical energy are produced by the MTI turbine. Also, 12.2×10^6 kg (26.9×10^6 lbs) of process steam, i.e. 8190 MWh_t, are produced each year with an MTI turbine in the cogeneration facility. The net annual electrical energy to thermal (process steam) energy ratio for the MTI turbine was computed to be 13.0% (see Table 3.9-1). The corresponding values of net annual output of electrical energy and process steam and the electrical energy to thermal energy ratio for the commercial turbine are presented in Table 3.9-1. Note that the significant reduction in electrical energy produced by the commercial turbine (700 MWh versus 1070 MWh) is partially mitigated by an increase in the amount of process steam available downstream of the turbine.

The net annual economic value (in 1981 $) of the electrical energy and the process steam energy provided by/with the MTI and commercial turbines is also shown in Table 3.9-1. These economic values were based on the current (1981) rates which Robins Air Force Base paid for their electrical power and for the fuel used in their boilers to produce process steam, i.e., $0.03533/kWh for electricity and about $0.006/lb of process steam. Note that the estimated $13,100 increase ($37,800 minus $24,700) in annual economic value for the electrical energy provided by the MTI turbine (compared to that produced by the commercial turbine) is partially counterbalanced by a decrease in net annual economic value for the process steam of about $5,500 ($167,000 minus $161,500). Thus, the difference in net annual economic value between the two turbines is about $7,600 (see Table 3.9-1). By simply multiplying this value by 25, the difference in total economic value for a 25 year period was approximated as $190,000. In other words, the use of an MTI turbine in the Robins AFB solar cogeneration facility produces $190,000 more economic value in 25 years than the typical commercial turbine.

By comparing this difference in total economic value with the difference in cost of the two turbines (see Table 3.9-1), one clearly concludes that the application of a high performance MTI turbine in this cogeneration facility is not cost effective. Therefore, a commercial steam turbine generator has been selected for this facility.

TABLE 3.9-1: COMPARISONS OF COST, ANNUAL OUTPUT, AND ECONOMIC VALUE FOR MTI AND COMMERCIAL TURBINES

STEAM TURBINE:*	MTI		COMMERCIAL
COST (1981 $)	$1,200,000		$125,000
DIFFERENCE IN COST		$1,075,000	
DESIGN POINT ELECTRICAL POWER TO THERMAL POWER RATIO (PERCENT)	17.4		11.8

STEAM TURBINE:*	MTI		COMMERCIAL
NET ANNUAL OUTPUT:			
o MWh electrical	1070		700
o kg (lbs) of process steam	12.2×10^6 (26.9×10^6)		12.6×10^6 (27.8×10^6)
o electrical energy to thermal energy ratio (percent)	13.0		8.2
NET ANNUAL ECONOMIC VALUE (1981 $):			
o electrical	$ 37,800		$ 24,700
o process steam	161,500		167,000
o total	$199,300		$191,700
DIFFERENCE IN NET ANNUAL ECONOMIC VALUE (1981 $):		$ 7,600	
DIFFERENCE IN TOTAL ECONOMIC VALUE FOR 25 YEARS (1981 $):		$190,000	
CONCLUSION:		SELECT COMMERCIAL TURBINE	

*BASED ON 60m TOWER AND STEAM INLET TEMPERATURE AND PRESSURE CONDITIONS OF 399°C (750°F) AND 10.34 MPa (1500 PSIA) [BOILER PLANT NO. 4 DEMAND CURVES].

Having selected a commercial turbine, one should also note that the commercial turbine has the following additional features (benefits): a) it is a proven "off-the-shelf" system, b) several manufacturers of commercial turbines are available, c) the performance capabilities of commercial turbines have been demonstrated through many years of experience, and d) the commercial turbine is relatively easy to operate and maintain and has a high reliability. On the other hand, the high performance, high speed MTI turbine in the size required for this facility is considered to be a developmental type turbine for which the performance, reliability, and ease of operation and maintenance remain to be demonstrated. Finally, by using a commercial turbine, the Robins AFB solar cogeneration team have provided a straightforward engineering approach to the design of the facility and thereby minimized the number of developmental components/systems in that facility.

In addition to the results presented above for the MTI and commercial turbines with a 60 m tower height (and the corresponding number of heliostats in the collector field and thermal power into the receiver fluid), steam turbine generator performance capabilities for both turbines were analyzed for tower heights of 40 and 80 meters (131 and 262 ft). Detailed results on these performance analyses and comparisons are presented in Appendix D.

3.10 STEAM CONDITION TRADE STUDIES

Having selected a typical commercial turbine in lieu of the proposed high performance MTI turbine for the cogeneration facility (see Section 3.9), a series of trade studies was performed to select the turbine inlet conditions, i.e., the inlet temperature and pressure, for this commercial turbine. The originally proposed (baseline) turbine inlet conditions were: a) an inlet temperature of 399°C (750°F) and b) an inlet pressure of 5.86 MPa (850 psia). The baseline steam turbine exit (exhaust) pressure was 0.93 MPa (135 psia). This relatively high turbine back pressure was dictated by the process steam requirements downstream of the turbine.

Qualitatively, for fixed values of inlet and exhaust pressure, the electrical output power from a turbine generator can be increased by increasing the turbine inlet temperature, due to better thermodynamic cycle efficiency. Similarly, for fixed values of turbine inlet temperature and exhaust pressure, increasing the turbine inlet pressure will yield more mechanical work out of the turbine and hence produce more electrical power. Counterbalancing (at least partially) these increases in electrical output power from the turbine were several system tradeoffs which needed to be considered and evaluated.

The system tradeoffs on increasing the inlet temperature were: a) the costs of the steam piping, turbine and receiver are increased and b) the thermal losses from the receiver surface (both convection and radiation losses) and from the steam piping are increased. In addition, a Class IV commercial turbine has a maximum temperature capability of 399°C (750°F). Higher class commercial turbines which can operate at temperatures up to and above 510°C (950°F) are readily available, particularly in the multi-MW and multi-hundred MW sizes. Attendant with these higher class turbines are several material and component design changes which result in higher costs. The system tradeoff on increasing the turbine inlet pressure is that the costs for the receiver and for the steam and feedwater piping are increased.

In addition to the above qualitative considerations for the system tradeoffs on increasing the temperature and/or pressure at the turbine inlet to produce more electrical power, one needs to recognize that the electrical power produced by the cogeneration facility, as well as the integration of this power over the entire year (.i.e., the electrical energy produced in MWh), represents only about 10 percent of the thermal process steam power (or energy) produced by the facility. Also, when the electrical power and net annual electrical energy are increased for a fixed tower height, as discussed above in Section 3.9 (see Figures 3.9-1 and -2 and Table 3.9-1), this improved electrical performance by the turbine is partially mitigated by a corresponding loss in thermal power and annual thermal output energy from the process steam downstream of the turbine.

Referring to the net annual electrical energy output from the MTI turbine and the commercial turbine (see Table 3.9-1), note that a 53 percent increase in electrical energy produced (1070 MWh versus 700 MWh) only provides approximately $7,600 of additional net annual economic value. Even though these results were for two different types of turbines with different performance characteristics, the qualitative conclusion which can be drawn from the results presented in Table 3.9-1 is still germane.

In summary, when comparative trade study results on turbine and process steam performance for the cogeneration facility are analyzed, there is little significance to the increase in electrical output power and energy which would be produced by an increase in turbine inlet temperature, since most of this improved performance will be counterbalanced by a loss in process steam output power and annual energy. Similarly, as one anticipates a significant decrease in electrical output power and energy by decreasing the turbine inlet pressure, these decreases will at least be partially mitigated by a significant increase in the process steam thermal power and energy.

For these trade studies, the temperature of the steam at the turbine inlet was investigated from 399°C (750°F) to 482°C (900°F). The variations in capital cost, net annual output, and net annual economic value were determined and compared for these conditions. For the pressure trade studies, the steam pressure at the turbine inlet was varied from 5.86 MPa (850 psia) to 10.34 MPa (1500 psia). The performance of the turbine was evaluated for three inlet pressures and comparisons were drawn on the total facility (capital) costs and the economic values for these conditions. Further details on the performance of the commercial turbine under these various conditions are provided in Appendix D. Also, the performance capabilities and analyses of the high performance MTI turbine at various temperatures and pressures are presented in Appendix D.

3.10.1 TURBINE INLET TEMPERATURE

Shown in Table 3.10-1 are comparisons of the predicted values of the total capital cost, net annual output, and annual economic value for a cogeneration facility with a commercial turbine at two inlet temperatures: 399°C (750°F) and 482°C (900°F). These analytical results and estimates were based on a 60 meter (197 ft) tower, a turbine inlet pressure of 10.34 MPa (1500 psia), and the Robins AFB Steam Plant No. 4 steam demand curves. The baseline turbine inlet temperature which was originally proposed was 399°C (750°F).

The first entries in Table 3.10-1 are estimated values, in 1981 $, for the total capital cost of the cogeneration facility with a commercial turbine operating at the two inlet temperatures. These costs are revised estimates from those submitted in the proposal, particularly for those components and systems which were being evaluated as part of the turbine, steam condition, field size, tower height, and receiver system trade studies. The breakdown of these total facility costs (i.e., the estimated costs of the components and systems in accordance with the appropriate cost code categories) to support these cost estimates have been provided in Appendix D. The values presented for total costs should not be considered as absolute, but rather as relative, since the detailed conceptual design of the facility (Task 3) has just been initiated. Moreover, the detailed estimates of the cost of the facility are reserved for Task 5, which is not scheduled to begin until May, 1981.

The difference in total capital cost of the facility for the two turbine inlet temperatures was estimated to be $112,000. This cost differential between a facility with a turbine inlet temperature of 399°C (750°F) and one with an inlet temperature of 482°C (900°F) is considered to be a reasonably accurate estimate which represents the additional cost expected to be incurred for the steam piping, turbine, etc. at the higher temperature.

Based on the Collector Field Trade Study and System Size results discussed above in Sections 3.5 and 3.4, respectively, 266 heliostats were placed in the collector field land area with a receiver centerline height of 60 meter (197 ft). For these conditions, 9.65 MW of thermal power is transferred to the receiver fluid (see Section 3.9). By considering the pressure and thermal losses in the piping from the receiver to the turbine, and assumed values for the feedwater inlet temperature and pressure (similar to those developed above

TABLE 3.10-1: COMPARISONS OF TOTAL FACILITY COST, ANNUAL OUTPUT, AND ECONOMIC VALUE FOR COMMERCIAL TURBINE AT TWO INLET TEMPERATURES

TURBINE INLET TEMPERATURE, °C (°F)	399 (750)		482 (900)
TOTAL FACILITY (CAPITAL) COST* (1981 $)	$7,949,000		$8,061,000
DIFFERENCE IN COST		$112,000	
NET ANNUAL OUTPUT*			
o MWh ELECTRICAL	700		746
o kg (LBS) OF PROCESS STEAM	12.6×10^6 (27.8×10^6)		12.5×10^6 (27.6×10^6)
o ELECTRICAL ENERGY TO THERMAL ENERGY RATIO (PERCENT)	8.2		8.8
NET ANNUAL ECONOMIC VALUE (1981 $)			
o ELECTRICAL	$ 24,700		$ 26,400
o PROCESS STEAM	167,000		165,500
o TOTAL	$191,700		$191,900
RECOMMENDATION ON INLET TEMPERATURE FOR STARTING CONCEPTUAL DESIGN:		399°C (750°F)	

*BASED ON 60 m TOWER AND 10.34 MPa (1500 PSIA) TURBINE INLET PRESSURE [STEAM PLANT NO. 4 DEMAND CURVES].

in Section 3.9), the flow rate through the receiver and through the turbine was computed to be 4.06 kg/s (32,200 lb/h) and 3.70 kg/s (29,400 lb/h) for turbine inlet temperatures of 399°C (750°F) and 482°C (900°F), respectively.

The solar insolation incident on the collector field and the thermal power transmitted to the receiver varies for each hour of the day and for each day of the year. This variation in solar insolation, including the effects of partly cloudy or hazy conditions, produces variable electrical output powers and process steam output powers throughout the year. By maintaining the turbine inlet pressure and temperature at their controlled values, the variation in thermal power transferred to the receiver fluid is accommodated by varying the flow rate through the receiver and turbine. The full power and part power electrical and process steam performances of the facility with the commercial turbine at an inlet temperature of 399°C (750°F) were discussed above in Section 3.9 and shown in Figures 3.9-1 and 3.9-2.

By integrating the electrical and process steam output powers for each hour of the day over the entire year, the net annual electrical and process steam energy outputs were calculated. These results were evaluated by using the Cogeneration Facility Annual Integration Performance Model discussed in Appendix E. The net annual output from, and the net annual economic value of, the cogeneration facility with a commercial turbine operating at the two different inlet temperatures are shown in Table 3.10-1. Thus, 700 MWh of net annual electrical energy are produced by the commercial turbine at an inlet temperature of 399°C (750°F). Also, 12.6 X 10^6 kg (27.8 x 10^6 lbs) of process steam, i.e. 8460 MWh of thermal energy, are produced each year by the facility with a commercial turbine at the above inlet temperature.

The performance of the modified MTI turbine at the two inlet temperatures and at varying flow rates was analyzed and compared. From the performance results of the MTI turbine at full power (full flow) conditions with an inlet temperature of 399°C (750°F) 1400 kW of electrical power are produced. At an inlet temperature of 482°C (900°F), the electrical power produced by the MTI turbine is 1492 kW at full flow. Thus, by increasing the inlet temperature from the baseline value to 482°C (900°F), approximately 6.6 percent more electrical power can be generated by a turbine at full flow. Similar percentage increases in electrical power are produced by the various part flow (part power) conditions. Further details on the performance of the MTI turbine at the two turbine inlet temperatures are provided in Appendix D.

As discussed above in Section 3.9 and shown in Figure 3.9-1, the electrical output power from the commercial turbine is approximately 982 kW for a turbine inlet temperature of 399°C (750°F). With an inlet temperature of 482°C (900°F), the electrical output from the commercial turbine was estimated to be 1046 kW. Shown in Figure 3.10-1 is a comparison of the electrical output power as a function of flow rate for a commercial turbine at these two inlet temperatures. The results presented for an inlet temperature of 399°C (750°F) are the same as those shown in Figure 3.9-1. The performance curve shown in Figure 3.10-1 for an inlet temperature of 482°C (900°F) is an estimated performance profile as inferred from the MTI turbine results. The increase in turbine inlet temperature to 482°C (900°F) was assumed to yield approximately 6.6 percent more electrical power over the entire range of turbine flow rates. Thus, the net annual electrical energy output for the commercial turbine at an inlet temperature of 482°C (900°F) was estimated to be 746 MWh, as shown in Table 3.10-1.

The increase in net annual electrical energy produced by the turbine when the inlet temperature is increased from 399°C (750°F) to 482°C (900°F) is counterbalanced by a reduction in annual thermal output energy from the process steam downstream of the turbine. From the results presented in Table 3.10-2 on net annual output of electrical and process steam energy for the commercial turbine at three inlet pressures (which is discussed below in Section 3.10.2), a difference of 130 MWh (700 MWhs minus 570 MWh) of net annual electrical energy is produced between a turbine operating at an inlet pressure of 7.58 MPa (1100 psia) and one at a pressure of 10.34 MPa (1500 psia). This decrease in electrical energy as the pressure is decreased is offset by an increase in the

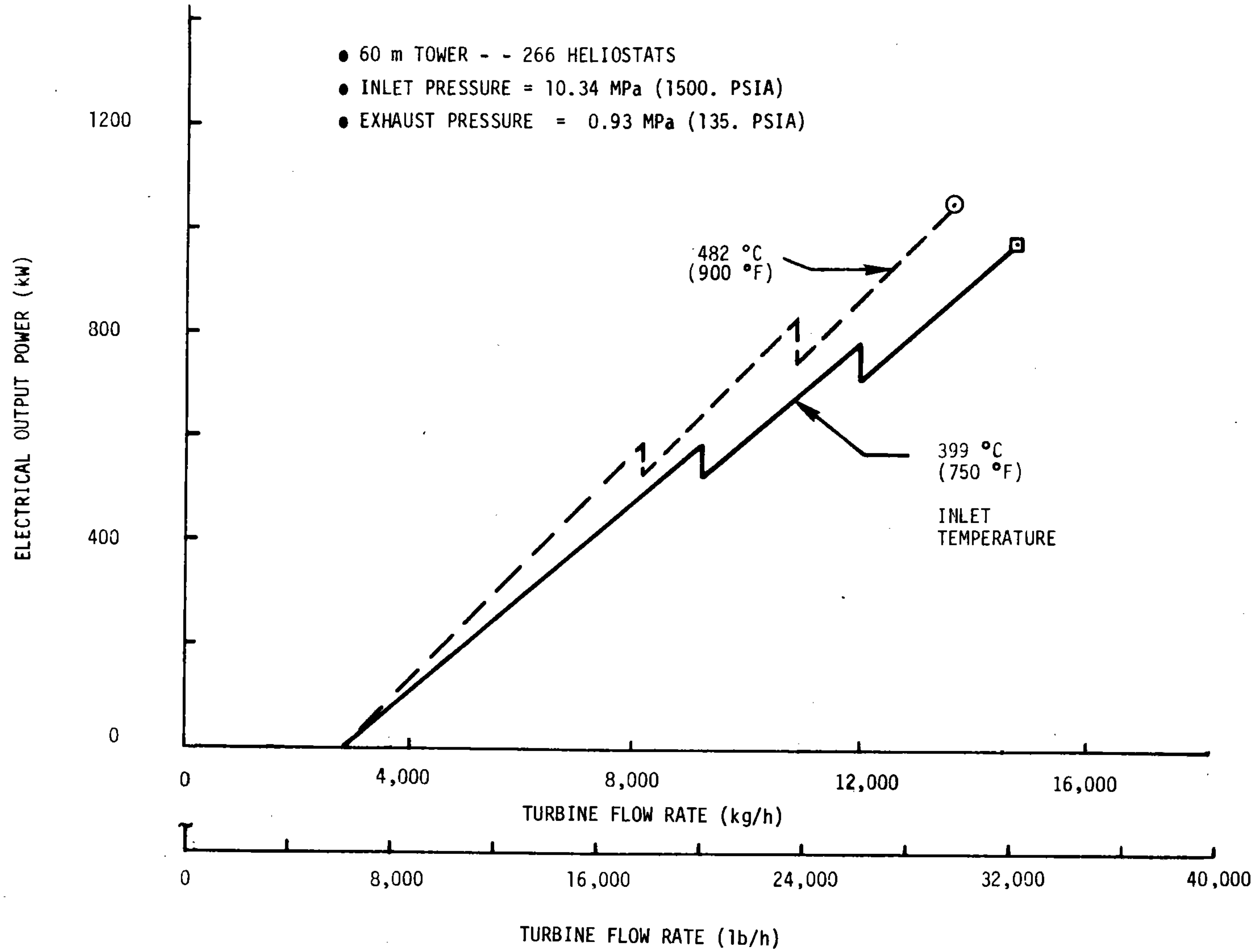


Figure 3.10-1. Electrical Output Power as a Function of Flow Rate for Commercial Turbine at Two Inlet Temperatures

process steam produced, i.e., 0.4 x 10^6 kg (13.0 x 10^6 minus 12.6 x 10^6 kg) more steam is produced at the lower pressure. Therefore, a 46 MWh (746 minus 700 MWh) increase in electrical energy (see Table 3.10-1) as the turbine inlet temperature is increased from 399°C (750°F) to 482°C (900°F) would result in decreasing the annual process steam produced from 12.6 x 10^6 kg (27.8 x 10^6 lbs) to 12.5 x 10^6 kg (27.6 x 10^6 lbs), as shown in Table 3.10-1.

From these results, the net annual electrical energy to thermal (process steam) energy ratio was computed to be 8.2 percent and 8.8 percent for turbine inlet temperatures of 399°C (750°F) and 482°C (900°F), respectively. The net annual economic value (in 1981 $) of the electrical energy and process steam energy produced with a commercial turbine operating at the two inlet temperatures is also shown in Table 3.10-1. These economic values were based on the current (1980) rates which Robins Air Force Base paid for their electrical power and for the fuel used in their boilers to produce process steam, i.e., $0.03533/kWh for electricity and about $ 0.006/lb of process steam. Note that the total net annual economic value for the two inlet temperatures is almost identical, i.e., the increase in value of the electrical energy produced as the inlet temperature is increased is almost totally offset by the decrease in economic value of the process steam.

Since the difference in total annual economic value for operating the facility with a commercial turbine at the two inlet temperatures is very small, and since the total capital cost with a turbine inlet temperature of 482°C (900°F) is $112,000 higher than the cost with an inlet temperature of 399°C (750°F), as shown in Table 3.10-1, one clearly concludes that the design of the facility at the higher inlet temperature is not cost effective. Therefore, the recommended turbine inlet temperature for starting the conceptual design of the facility is 399°C (750°F).

3.10.2 TURBINE INLET PRESSURE

Trade studies were completed on the effects of varying the turbine inlet pressure and how these pressures affected the total capital cost, net annual output, and net annual economic value of the facility. For these trade studies, the steam pressure at the turbine inlet was varied from 5.86 MPa (850 psia) to 10.34 MPa (1500 psia). Both turbine performance and process steam performance were evaluated for three pressures within this range.

Shown in Figure 3.10-2 is a comparison of the electrical output power as a function of turbine flow rate for a commercial turbine at inlet pressures of: 10.34 MPa (1500 psia), 7.58 MPa (1100 psia), and 5.86 MPa (850 psia). These results were based on a 60 m (197 ft) tower, 266 heliostats in the collector field, and 9.65 MW of thermal power transferred to the receiver fluid at the noon winter solstice design point. Also, the turbine inlet temperature was held fixed at 399°C (750°F) and the turbine exhaust pressure was taken as 0.93 MPa (135 psia).

Accounting for the pressure and thermal losses in the piping from the receiver to the turbine, and taking assumed values for the feedwater inlet temperature and pressure (similar to those discussed in Section 3.9), the flow rate through the receiver and through the turbine was computed to be 14,620 kg/h (32,200 lb/h) for an inlet pressure of 10.34 MPa (1500 psia). Similarly, for turbine inlet pressures of 7.58 MPa (1100 psia) and 5.86 MPa (850 psia), the turbine flow rate was determined as 14,290 kg/h (31,500 lb/h) and 14,110 kg/h (31,100 lb/h), respectively. At these design flow rates for the three pressures, 982 kW, 922 kW, and 831 kW of electrical output power are produced by the turbine (see Figure 3.10-2).

The thermal power transmitted to the receiver varies for each hour of the day throughout the year, based on the solar insolation incident on the collector field. These variations in solar insolation and thermal power at the receiver are accommodated by varying the flow rate through the receiver and turbine, while the turbine inlet temperature and pressure are held constant. Therefore, the part power (part flow) performance of the turbine was required so that the total annual electrical energy produced by the turbine could be calculated. The part power performance of the commercial turbine at each of the three pressures is also depicted in Figure 3.10-2.

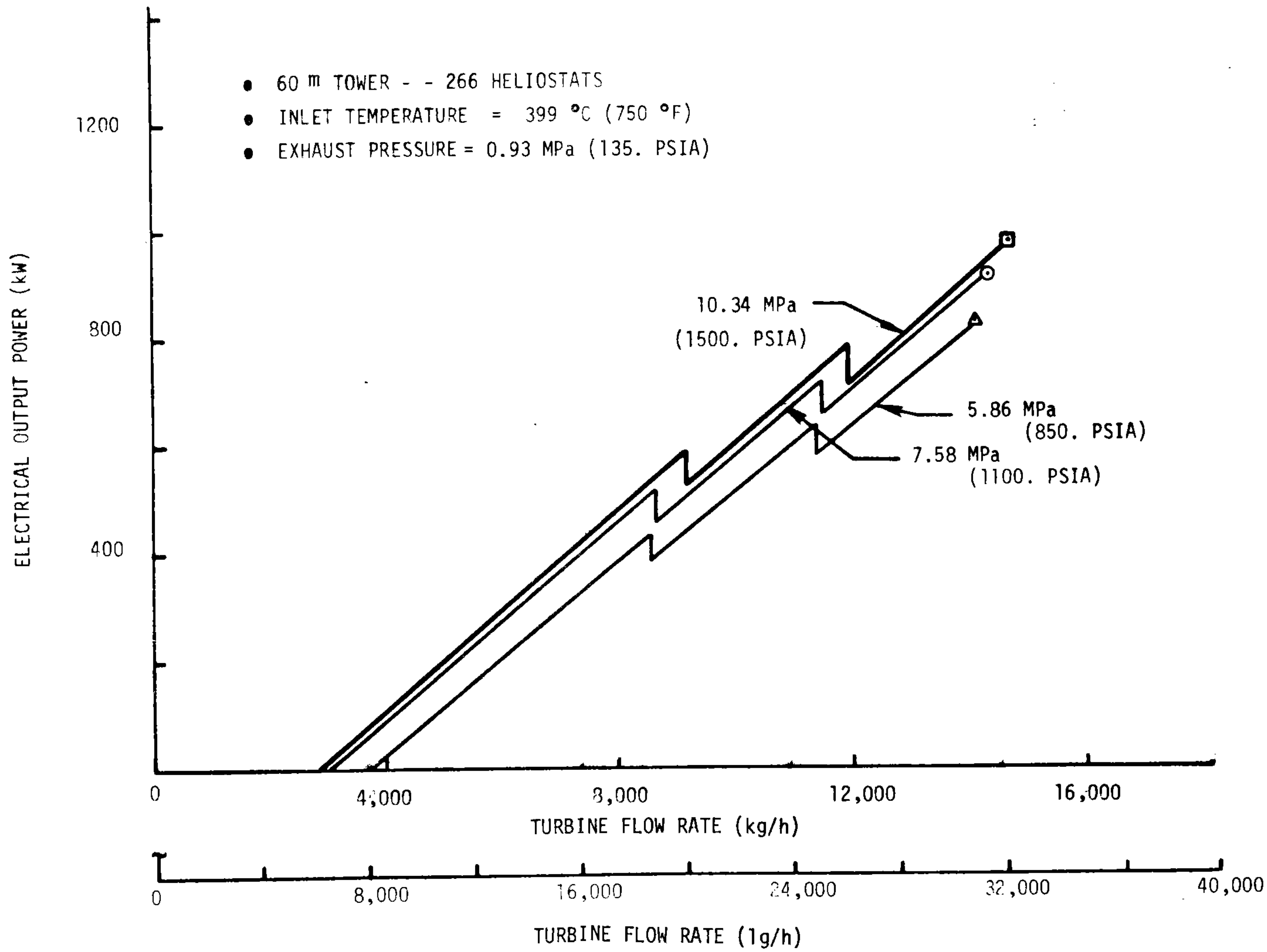


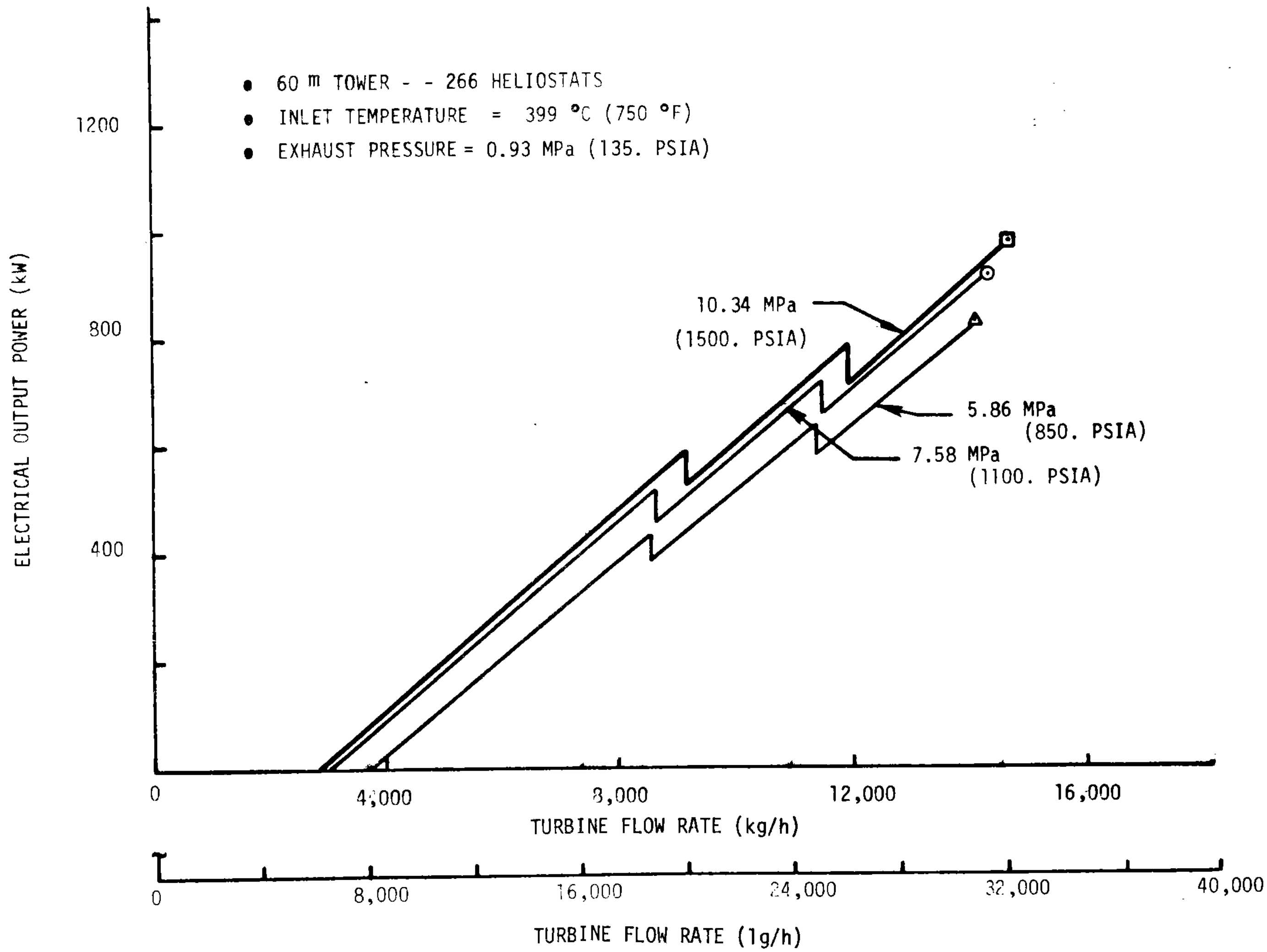
Figure 3.10-2. Electrical Output Power as a Function of Flow Rate for Commercial Turbine at Three Inlet Pressures

Downstream of the turbine, part of the turbine flow rate is diverted to the feedwater heater. The balance of the turbine flow is used for process steam. Depending upon the thermal power at the receiver, the electrical power produced by the turbine, and the exit enthalpy of the steam from the turbine, varying levels of process steam thermal power are produced. At the noon winter solstice design point, approximately 8.33 MW_t (28.4 x 10^6 Btu/h) of process steam thermal output power are produced downstream of the turbine with an inlet pressure of 10.34 MPa (1500 psia).

Similarly, for turbine inlet pressures of 7.58 MPa (1100 psia) and 5.86 MPa (850 psia), approximately 8.40 MW_t (28.6 x 10^6 Btu/h) and 8.47 MW_t(28.9 x 10^6 Btu/h), respectively, of process steam thermal output power are produced at the design point. Note that as the inlet pressure is decreased, the process steam thermal output power increases. Thus, the decrease in electrical output power from the turbine (see Figure 3.10-2) as the inlet pressure is decreased is at least partially mitigated by an increase in the process steam thermal output power.

Presented in Table 3.10-2 are comparisons of the total capital cost, net annual output, and annual economic value for the facility with a commercial turbine at the three inlet pressures investigated. These results were based on a 60 m (197 ft) tower, a turbine inlet temperature of 399°C (750°F), and the Robins AFB Steam Plant number 4 steam demand curves. The baseline turbine inlet pressure as submitted in the proposal was 5.86 MPa (850 psia).

Shown initially in Table 3.10-2 are estimated values, in 1981 $, for the total capital cost of the facility with a commercial turbine operating at the three inlet pressures. These costs are revised estimates from those submitted in the proposal, particularly for those components and systems which were being evaluated as part of the turbine, steam condition, field size, tower height, and receiver system trade studies. The breakdown of these total facility costs, in accordance with the appropriate cost code categories, to support these estimates have been provided in Appendix D. The total cost values shown should not be considered as absolute, but rather as relative, since the



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Downstream of the turbine, part of the turbine flow rate is diverted to the feedwater heater. The balance of the turbine flow is used for process steam. Depending upon the thermal power at the receiver, the electrical power produced by the turbine, and the exit enthalpy of the steam from the turbine, varying levels of process steam thermal power are produced. At the noon winter solstice design point, approximately 8.33 MW_t (28.4 x 10^6 Btu/h) of process steam thermal output power are produced downstream of the turbine with an inlet pressure of 10.34 MPa (1500 psia).

Similarly, for turbine inlet pressures of 7.58 MPa (1100 psia) and 5.86 MPa (850 psia), approximately 8.40 MW_t (28.6 x 10^6 Btu/h) and 8.47 MW_t(28.9 x 10^6 Btu/h), respectively, of process steam thermal output power are produced at the design point. Note that as the inlet pressure is decreased, the process steam thermal output power increases. Thus, the decrease in electrical output power from the turbine (see Figure 3.10-2) as the inlet pressure is decreased is at least partially mitigated by an increase in the process steam thermal output power.

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TABLE 3.10-2: COMPARISONS OF TOTAL FACILITY COST, ANNUAL OUTPUT, AND ECONOMIC VALUE FOR COMMERCIAL TURBINE AT THREE INLET PRESSURES

TURBINE INLET PRESSURE, MPa (psia)	5.86 (850)		7.58 (1100)		10.34 (1500)
TOTAL FACILITY (CAPITAL) COST* (1981 $)	$7,639,000		$7,770,000		$7,949,000
DIFFERENCE IN COST:		$131,000		$179,000	
DESIGN POINT ELECTRICAL POWER TO THERMAL POWER RATIO (PERCENT)	9.8		11.0		11.8
NET ANNUAL OUTPUT					
o MWh ELECTRICAL	450		570		700
o kg (lbs) OF PROCESS STEAM	13.2×10^6 (28.9×10^6)		13.0×10^6 (28.5×10^6)		12.6×10^6 (27.8×10^6)
o ELECTRICAL ENERGY TO THERMAL ENERGY RATIO (PERCENT)	5.1		6.5		8.2
NET ANNUAL ECONOMIC VALUE (1981 $)					
o ELECTRICAL	$ 15,900		$ 20,100		$ 24,700
o PROCESS STEAM	173,600		171,200		167,000
o TOTAL	$189,500		$191,300		$191,700

RECOMMENDATION ON INLET PRESSURE FOR STARTING CONCEPTUAL DESIGN: 5.86 MPa (850 PSIA)

*BASED ON 60 m TOWER AND 399°C (750°F) TURBINE INLET TEMPERATURE (STEAM PLANT NO. 4 DEMAND CURVES) detailed conceptual design of the facility (Task 3) had just been initiated. Moreover, the detailed estimates of the cost of the facility were reserved for Task 5, which was not begun until May, 1981.

The differences in the total capital cost of the facility between the two higher turbine inlet pressures and the two lower inlet pressures are also shown in the Table 3.10-2. Thus, by decreasing the turbine inlet pressure from 10.34 MPa (1500 psia) to 7.58 MPa (1100 psia), the total capital cost of the facility can be decreased by $179,000. These cost differentials shown are considered to be reasonably accurate estimates which adequately represent the additional cost expected to be incurred for the receiver and for the steam and feedwater piping at the higher operating pressures.

Based on the analytical results for the electrical output power and process steam thermal output power at the noon winter solstice design point, the electrical power to thermal power ratio was calculated to be 11.8, 11.0, and 9.8 percent for the three turbine inlet pressures of 10.34 MPa (1500 psia), 7.58 MPa (1100 psia), and 5.86 MPa (850 psia), respectively. These values are also shown in Table 3.10-2.

By integrating the electrical and process steam output powers for each hour of the day and each day of the year, the net annual electrical and process steam energy outputs were determined, as discussed in Section 3.4, System Size. The net annual output from, and the net annual economic value of, the cogeneration facility with a commercial turbine operating at the three different inlet pressures are shown in Table 3.10-2. For a turbine inlet pressure of 5.86 MPa (850 psia), approximately 450 MWh of net annual electrical energy are produced. Downstream of the turbine, 13.2 x 10^6 kg (28.9 x 10^6 lbs) of net annual process steam, i.e. 8800 MWh of thermal energy, are provided. Note that as the turbine inlet pressure is decreased, the annual electrical energy produced by the turbine decreases significantly. These losses in electrical energy output are at least partially mitigated by an increase in the amount of process steam produced. Note also that the electrical energy to thermal energy ratio changes from approximately 8.2 to 5.1 percent as the inlet pressure is decreased to 5.86 MPa (850 psia).

Also presented in Table 3.10-2 are the net annual economic values (in 1981 $) of the electrical energy and process steam energy produced with the commercial turbine at the three inlet pressures. The economic value for the electrical energy produced was based on the current (1980) rate paid by Robins AFB to the Georgia Power Company. Also, the annual economic values for the process steam produced downstream of the turbine were based on the 1980 rates which Robins AFB paid for the fuel which was used to produce process steam in their boilers. As the turbine inlet pressure is decreased, the significant reduction in annual economic value of electrical energy is almost completely counter-balanced by the increases in the economic value of process steam from the facility.

By comparing the total capital cost estimates of the facility for a turbine operating at the three inlet pressures with the annual economic values, (see Table 3.10-2), the following conclusion was drawn: the operation at the two higher inlet pressures is not cost effective. Therefore, a turbine inlet pressure of 5.86 MPa (850 psia) is recommended for starting the conceptual design of this facility.

3.10.3 SUMMARY

Trade studies have been completed on the steam inlet and exit conditions for a commercial turbine being proposed for the Robins Air Force Base solar cogeneration facility. For these trade studies, the temperature of the steam at the turbine inlet was investigated from 399°C (750°F) to 482°C (900°F). From the results, the recommended turbine inlet temperature is 399°C (750°F). This conclusion was drawn from comparisons of the total capital cost and net annual economic value of the facility with a commercial turbine at the two inlet temperatures (see Table 3.10-1).

For the pressure trade studies, the performance of the cogeneration facility was analyzed while the steam pressure at the turbine inlet was varied from 5.86 MPa (850 psia) to 10.34 MPa (1500 psia). Both turbine performance and process steam performance were evaluated for three inlet pressures. The total capital cost, net annual output of electrical energy and process steam energy, and the annual economic value of these energies for each condition was estimated and compared. From the results (see Table 3.10-2), the recommended inlet pressure for the commercial turbine is 5.86 MPa (850 psia).

One additional steam condition trade study was performed in which consideration was given to reducing the turbine exhaust pressure and, in turn, the Steam Plant No. 4 steam pressure for summer operation. This reduced back pressure would enhance the solar electrical energy production during those times of the year when the process steam demand flow rate is reduced. The results of this trade study are discussed below in Section 3.11, Reduced Turbine Discharge Pressure for Summer Operation.

3.11 REDUCED TURBINE DISCHARGE PRESSURE FOR SUMMER OPERATION

The normal operating pressure on the Steam Plant No. 4 steam header is 0.96 MPa (140 psia). This pressure is the discharge pressure from the turbine driving the electric generator to provide the electrical part of the cogenerated energy. Because the turbine output is improved by lower discharge pressure the question arose as to whether the facility economic value would be improved by operating the base steam distribution system at reduced pressure during summer months when the steam demand is low relative to the winter months.

An estimate of the change in economic value of the energy produced resulted in an increase of less than $1,235 per year. On the negative side, there are two factors which outweigh this small advantage. First, a change in operating procedures would be required with coincident costs of training and increased potential for operating error. Second, and more important, an absorption chiller serving the avionics building would not function adequately at reduced pressure. Modifications to circumvent these adverse conditions would not be cost effective in view of the small benefit. Therefore, the idea of reduced base steam pressure during part of the year was rejected.

3.12 THERMAL STORAGE

The question of whether the inclusion of a thermal storage system in this facility was addressed in the selection of the preferred site specific configuration. There are two aspects to this question which can be addressed separately. These are: 1) Is thermal storage required to mitigate against thermal transients induced by solar insolation changes during cloud passage? 2) Is thermal storage advisable to extend the period of solar facility operation beyond the daylight hours? These are addressed separately.

3.12.1 STORAGE FOR "BUFFERING" TRANSIENTS

The operation of the solar facility during intermittent cloudy days will result in thermal transients emanating from cloud passage. These transients would be potentially threatening if either the solar components were compromised by their occurrence or if the base steam demand were interrupted by their occurrence.

A review of the solar facility component ability to withstand the induced transients without damage has shown that there is no requirement for thermal storage from this view.

A review of the ability of the fossil boilers to undergo changes in firing rate sufficient to offset the changes in solar insolation without excessive header steam pressure variation has shown there is no requirement for thermal storage from this view either.

Therefore, there is no need for "buffer" thermal storage in this facility and any expenditure for it is not warranted from these considerations.

3.12.2 STORAGE FOR "EXTENDED OPERATION"

Having eliminated the use of thermal storage for buffering thermal transients, the question remained as to whether storage for extended operation is desirable from economic or demonstration considerations. The ability to utilize such a storage system requires that periods of operation occur during which the solar energy collection exceeds the steam demand so that the excess can be stored for later use. In this application, the constraint on the solar collector land area and the existence of a specific steam demand interact to limit the excess energy collection available for storage.

As described in section 3.6, the available land area can be used with various receiver heights to achieve different energy collection rates at the design insolation level of 950 W/m^2. The data is summarized as:

Tower Height	Steam Delivered to Base System
60 m (197 ft)	12,053 kg/h (26,518 lb/h)
70 m (230 ft)	13,117 kg/h (28,858 lb/h)
80 m (262 ft)	13,945 kg/h (30,678 lb/h)

A review of the anticipated useful steam demand from the solar facility shows that only in certain months of the year is the demand less than these values. Also, the solar data indicates that the solar insolation is great enough to produce an excess of steam only a fraction of the time during these months. Further, the energy value achievable through storage depends upon the size of the installed storage system as does the cost of the system.

The economic assessment of a storage system was therefore conducted as follows:

1) Choose a tower height
2) Choose a thermal storage system size
3) Estimate the value of the annual stored energy
4) Estimate the annualized capital cost for the selected size storage system based upon the configuration on Fig. 3.12-1.

The results of the analysis are shown on Figure 3.12-2 for sizes from 3 MW_t to 20 MW_t and for receiver heights of 60 and 80 meters (197 and 262 ft) above ground. This figure shows that the annualized cost based upon 12 percent discount factor and 25 year life always exceeds the annual value of the extra collectable energy afforded by storage. Therefore there is not an economic incentive, per se, for including thermal storage in this facility.

The operational or demonstration advantages of including a thermal storage system involve considerations beyond this one facility. The decision to

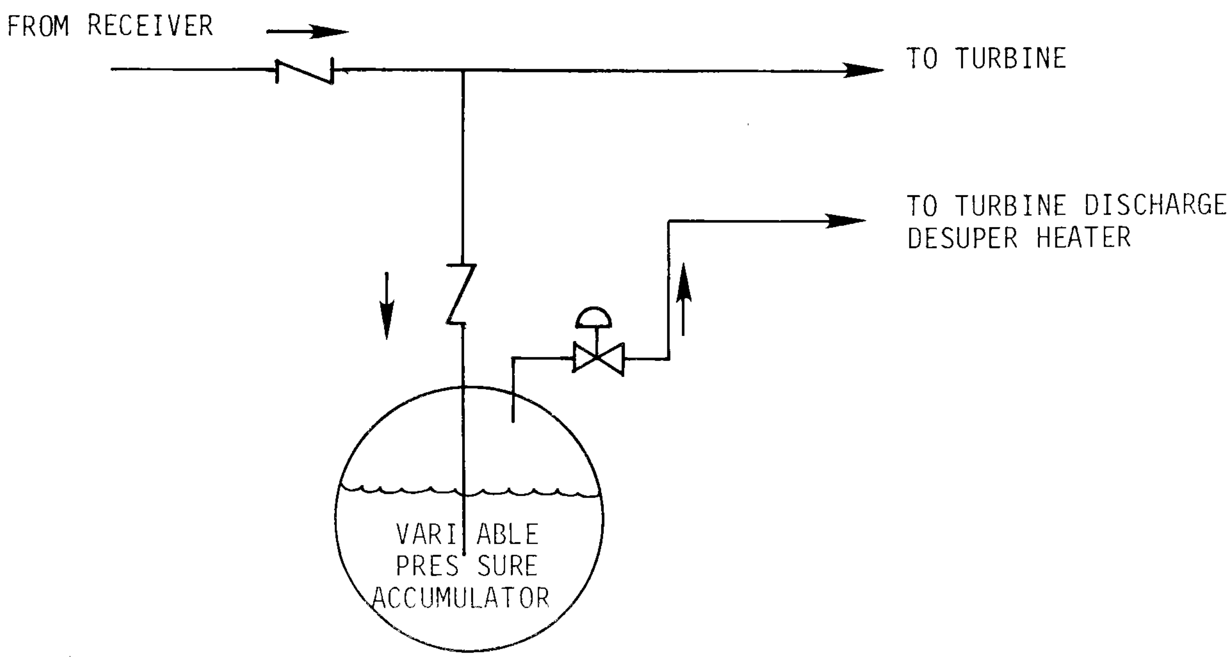


Figure 3.12-1. Thermal Storage Schematic

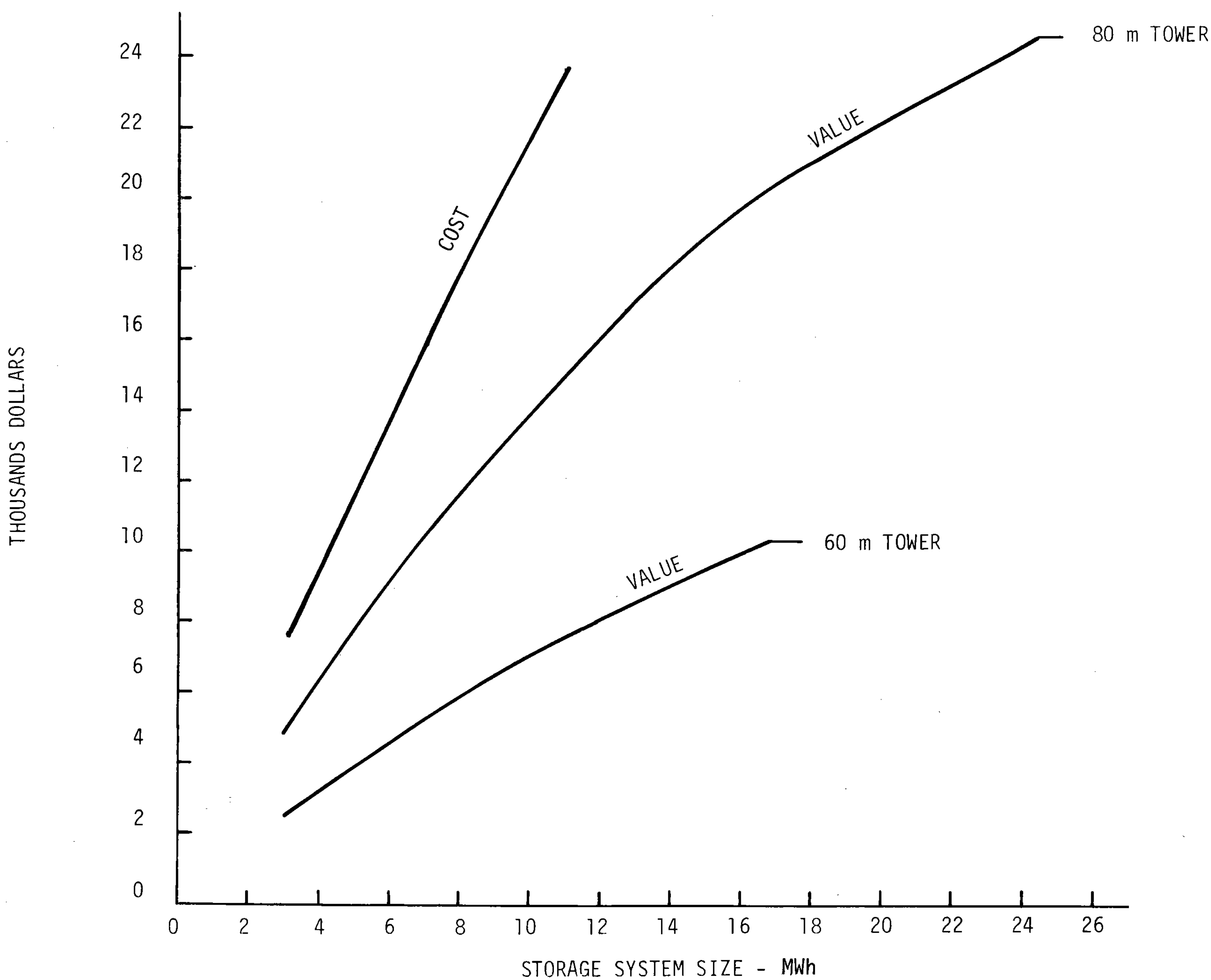


Figure 3.12-2. Annualized Cost and Value of Thermal Storage

include such a system would result in the following impacts upon the site specific configuration or facility operation:

1. A perturbation to either the facility size (increase) or to the operating scenario (decrease in the 100 percent direct output usage during adequate insolation) would be required to provide energy for storage during part of the time.

2. Under the latter case, (decrease in direct usage of output) the value of the energy collected would be decreased due to the introduction of increased thermal losses and decreased "available" energy by use of the storage system.

For this specific application, the capital cost increase or energy value decrease are not warranted or needed and hence thermal storage is not included in the selected configuration.

4.0 CONCEPTUAL DESIGN

This section provides a description of the solar facility. Discussions include system level functional requirements, design, operation, performance, cost, safety, environmental, institutional, and regulatory considerations.

Unique aspects of the RAFB Cogeneration Facility include the use of water/steam receiver technology utilizing conventional drum-type boiler technology, location of receiver tower and heliostat field within an industrial/community environment, use of conventional control philosophy, and operation by military/civilian technicians.

4.1 SOLAR COGENERATION FACILITY DESCRIPTION

Based upon the tradeoff studies described in Sections 3.5 through 3.12, and on the plant sizing analysis described in Section 3.4, a solar cogeneration facility was designed that would most economically meet the expected steam demands of Steam Plant No. 4 at Robins Air Force Base. A schematic system level diagram of the conceptual design of the RAFB solar cogeneration facility is given in Figure 4.1-1A. The facility consists of a Collector System, a Receiver System, an Electrical Power Generating System, the Balance of Plant - Steam and Feedwater System, and a Master Control System. Also shown are the interfaces with the existing Steam Plant and Base Grid at RAFB. The proposed configuration utilizes a water-steam receiver to provide steam at 5.96 MPa/400°C (865 psia/750°F) to a single-stage turbine-generator, which then discharges steam to the existing steam plant distribution system. The electrical power is fed into the existing 12.6 kV distribution line.

A schematic flow diagram of the facility configuration is shown in Figure 4.1-1. This layout includes all the major components of the facility except for the individual heliostats and other components of the Collector System, the receiver tower of the Receiver System and the Master Control System.

Output Power at Noon Winter Solstice Design Point: 678 kW_e and 7.92 MW_t (Process Steam)

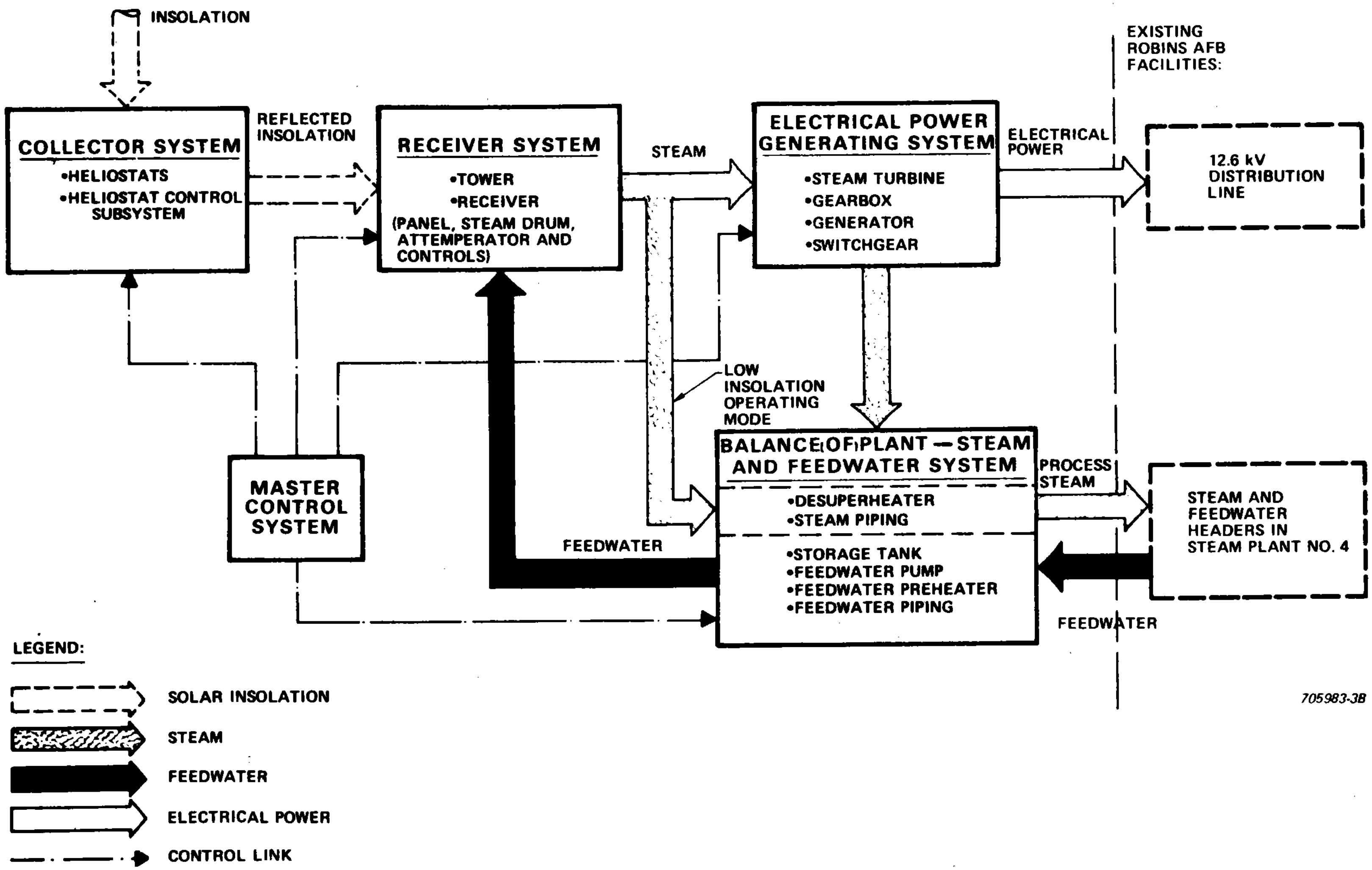


Figure 4.1-1A. Schematic System Level Diagram of Solar Cogeneration Facility at Robins Air Force Base

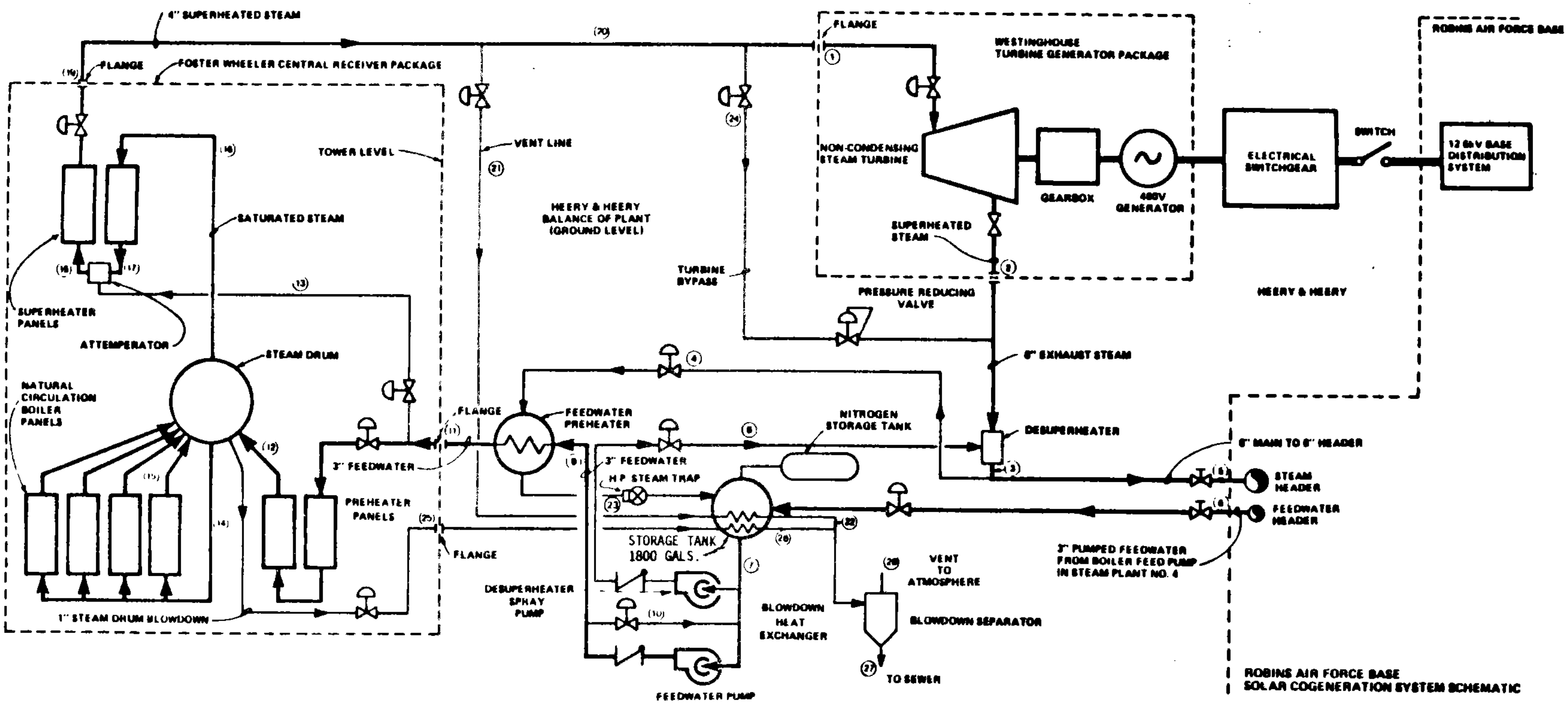


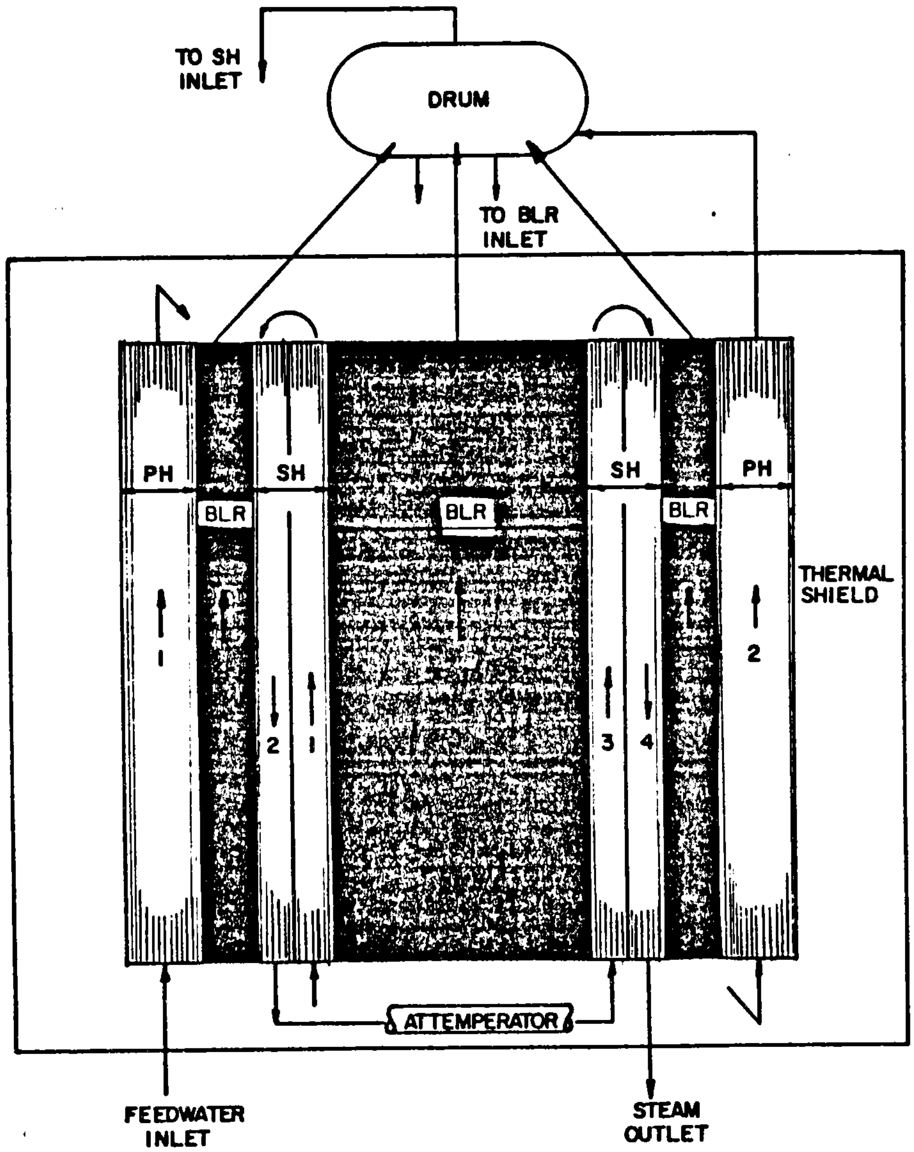
Figure 4.1-1. Solar Cogeneration Facility Configuration

The facility size used during the selection of the preferred cogeneration facility contained 266 of the Sandia second-generation heliostats focusing onto a rectangular solar receiver with dimensions of 11.7 m wide by 9.9 m high. This resulted in a net power of 10.7 MW on the receiver plane at the design point of noon winter solstice. Since then, the heliostat field boundaries have been defined in more detail, and about 6 meters (20 feet) of clearance was allowed between the various streets and the start of the heliostat field. This resulted in a total of 251 heliostats that can be placed in the field. Also, it was determined that the outer regions of the receiver do not contribute significantly to the energy collection, but are significant thermal loss paths due to convection, conduction, and radiation from their surfaces. Therefore, the conceptual design utilizes a receiver size of 8.78 m wide by 8.25 m high. The net result was 10.05 MW of energy impinging on the receiver surface at noon winter solstice.

The receiver is a single drum, natural circulation configuration, shown schematically in Figure 4.1-2. The central portion of the receiver is lined with vertical boiler tubes and four separate superheater passes. A spray attemperator is located between the second and third superheater panels to control the receiver exit temperature.

The steam turbine to be used in the conceptual design will be a single stage, commercially available unit. While the final selection of the steam turbine has not been made, preliminary scoping studies tend to indicate that it will be a single stage machine operating in the 5000-8000 rpm range.

Block valves (i.e., automatic hand valves) will be used to open and close nozzle chambers around the turbine inlet. This is done to avoid much of the steam throttling that would be required at part load if no block valves were used. A speed reduction gearbox will be used to drive a synchronous generator. Bypass lines will be incorporated around the turbine to allow for facility operation when the turbine cannot be operated (facility startup and low insolation times).



PH = PREHEATER PANELS
BLR = BOILER PANELS
SH = SUPERHEATER PANELS
PASSES ARE NUMBERED IN THE SEQUENCE OF FLOW

Figure 4.1-2. Conceptual Arrangement of Receiver Configuration

A spray desuperheater is provided in the turbine exit piping to reduce the steam conditions to close to saturation to provide compatibility with the demand loads and the steam being supplied by Steam Plant No. 4. The water for desuperheating will be piped from a desuperheating pump which is piped in parallel with the main feedwater pump.

The triplex feedwater pump will be driven by a variable speed, direct current motor.

A 6.82 m^3 (1800 gallon) storage tank will be used as a condensate storage and mixing tank. The tank will be pressurized to 827 kPa (120 psia) by a nitrogen supply, thereby avoiding air entrainment in the feedwater. The dearated condensate from Steam Plant No. 4, the drain flow from the feedwater heater, and the feedwater pump bypass flow will all be piped into the tank. Some fluid heatup will be provided by heat transfer from the hot blowdown flow through a simple heat exchanger inside the tank.

The storage tank is supplied condensate from the existing Steam Plant No. 4 feedwater system. The effluent from that existing water treatment system is not of a quality for use in the solar facility. The Air Force is committed to upgrade that system to meet the solar requirements prior to the completion of the facility.

The feedwater heater is of a straightforward multi-pass design widely used by utilities and industry. Desuperheated steam at 1048 kPa (152 psia) will be condensed, with the latent heat being transferred to the feedwater. A terminal temperature difference (saturated steam temperature minus feedwater exit temperature) of 3C° (5F°) is standard performance obtainable by these units.

The tie-in to the existing steam plant distribution system is accomplished with a 0.2 m (6 in.) steam line which delivers the thermal output of the solar facility to the base steam system. The existing pressure controller at Steam Plant No. 4 maintains 862 kPa (140 psia) in the steam plant header by varying the boiler firing rate. This control system will accomodate receipt of the solar facility process steam by reducing the fossil steam production to maintain pressure.

4.2 FUNCTIONAL REQUIREMENTS

The RAFB Solar Cogeneration Facility shall be designed to meet the performance requirements delineated in Section 3.0, Requirements, of the Robins Air Force Base Solar Cogeneration Facility (Overall System) Specification included as Appendix A. Also, the facility shall be designed in accordance with several performance requirements which are specified in Section 4.0, Environmental Criteria, of the Facility Specification, Appendix A. The solar cogeneration facility shall be designed to operate in parallel with the existing gas/oil fired boilers. The solar system shall be designed to operate during various modes including startup, normal operation, and shutdown.

The facility shall be designed for a 25 year service life with no major component replacement required and deliver 10.05 MW_t to the receiver panel at noon winter solstice. Further details on the facility design life are presented in Section 3.10, Service Life, of the Facility Specification in Appendix A.

Incorporated in the design are instrumentation and control systems to assure that allowable ramp rates on the receiver and allowable turndown ratios on the boiler(s) are not exceeded. Methods of control shall include attemperation, flow rate through the receiver, and defocusing of the heliostats. Sufficient instrumentation shall be provided to monitor flow, pressure, and temperature throughout the system and to monitor the defocusing of heliostats. The requirements for instrumentation shall encompass not only sensing for control purposes but also provide sufficient diagnostic information for measuring performance to fulfill the requirements of the user (Air Force) agency.

A Master Control System shall be utilized to monitor sensors and to provide proper control of all central mechanisms to meet all system response criteria. This system shall:

- Provide automated control of solar cogeneration facility with operator override capability

- Maintain design simplicity utilizing standard control practices and simple, well defined interfaces between new and existing control systems

- Provide cost effective design through selection of off-the-shelf equipment, modularity, and selection of generically similar equipment

4.3 DESIGN AND OPERATING CHARACTERISTICS

The Robins Air Force Base Solar Cogeneration Facility uses a water/steam receiver and steam turbine configuration. Utilizing a north heliostat field and single tower, with the receiver tower located adjacent to the turbine building, the preferred configuration offers a simple cogeneration design.

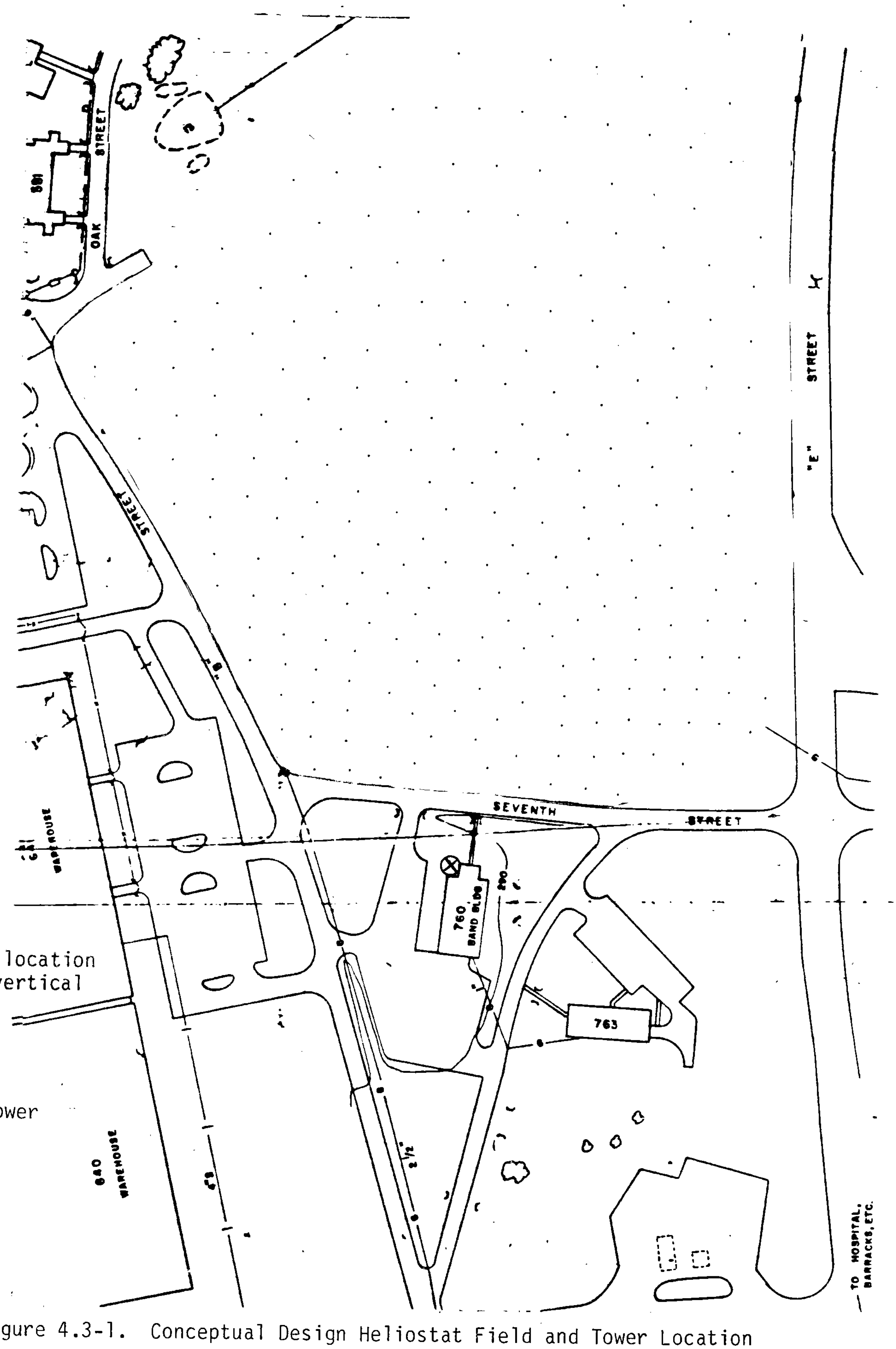
The solar receiver operates in parallel with the existing fossil boiler(s). Superheat steam temperature is controlled primarily by attemperation. Operation of the fossil boiler(s) is necessary since the solar facility at most can supply approximately 70 percent of the projected steam load.

4.3.1 FACILITY ARRANGEMENT

Figure 4.3-1 is a plot plan showing the approximate location of the tower and heliostat field.

4.3.2 DESIGN CHARACTERISTICS

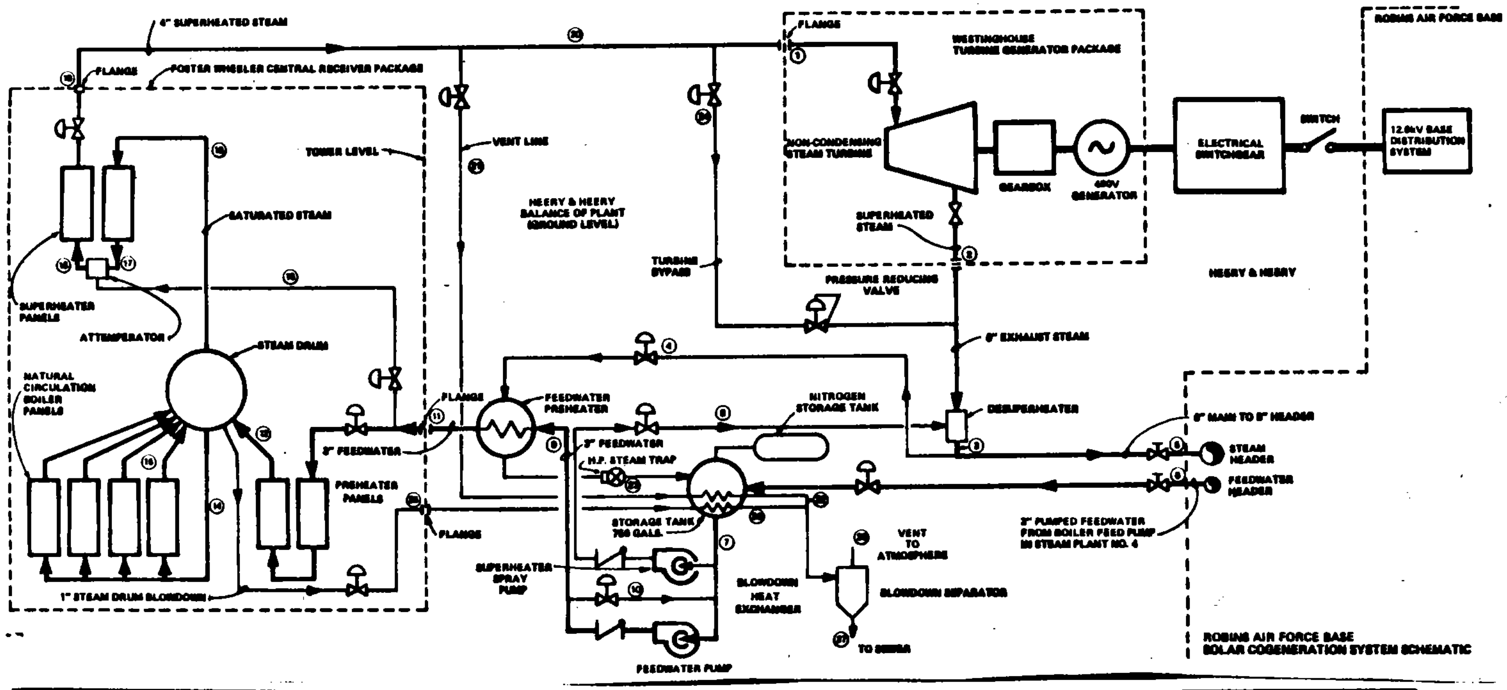
Design characteristics of the solar cogeneration facility are summarized in Table 1.4-1. A statepoint flow diagram of the facility is shown in Figure 4.3-2. For normal facility operation, condensate water enters the facility from the Steam Plant No. 4 feedwater header, and is supplied to a 6.81 m^3 (1800 gallon) storage/mixing tank. Here it is mixed with the condensate from the steam feedwater heater and the feedwater pump bypass flow. The blowdown flow from the steam drum (about 0.5 percent of the receiver exit steam flow is required to control water quality) passes through a heat exchanger in the storage tank, then is sent to a steam separator and vented to the atmosphere. The condensate leaves the storage tank and is supplied to the



Dots indicate location of heliostat vertical axis.

⊗ Receiver Tower Location

Figure 4.3-1. Conceptual Design Heliostat Field and Tower Location



		1	2	3	4	5	6	7	8	9	10	11	12	13	14
FLOW	kg/s	3.605	3.605	3.868	0.591	3.277	3.295	3.886	0.263	3.623		3.623	3.333	0.272	61.05
	lb/hr	28610	28610	30700	4690	28010	26150	30845	2090	28755		28755	26450	2.160	485000
PRESSURE	kPa	5962	1068	1055	1048	985	896	827	1379	8582		7858	7033	6757	6964
	psia	865	155	153	152	140	130	120	200	1245		1140	1020	980	1010
TEMP	C	400	259	186	186	179	83	99	99	101		179	196	178	280
	F	750	498	366	366	354	180	209	210	214		353	384	353	536
ENTHALPY	kJ/kg	3172	2956	2784	2784	2773	344	414	411	423		753	832	753	1234
	Btu/lb	1365	1272	1198	1198	1193	148	178	177	182		324	358	324	531
FLUID		STEAM	STEAM	STEAM	STEAM	STEAM	F.W.	F.W.	WATER	F.W.		F.W.	F.W.	F.W.	F.W.

		15	16	17	18	19	20	21	22	23	24	25	26	27	28
FLOW	kg/s	61.05	3.333	3.333	3.605	3.605	3.605			0.591		0.018	0.018	0.018	0.0004
	lb/hr	485000	26450	26450	28610	28610	28610			4690		145	145	142	3
PRESSURE	kPa	6964	6964	6660	6620	6135	6031			1034		7169	7444	103	103
	psia	1010	1010	966	960	890	875			150		1040	1080	15	15
TEMP	C	285	285	365	316	410	400			180		287	106	100	100
	F	545	545	690	600	770	750			356		548	220	212	212
ENTHALPY	kJ/kg	1350	2770	3068	2710	3198	3172			762		1269	437	418	2673
	Btu/lb	581	1192	1320	1166	1376	1365			328		546	188	180	1159
FLUID			STEAM	STEAM	STEAM	STEAM	STEAM			COND.		WATER	WATER	COND.	STEAM

Figure 4.3-2. Conceptual Design Facility Flow Diagram and State Points

feedwater pump. The high pressure water is then sent to the feedwater heater. Part of the feedwater flow is sent to the spray desuperheater by the superheater pump, which is used to desuperheat the turbine exit steam to close to the saturation temperature. The feedwater then passes through the feedwater heater, where it is heated by condensing steam supplied from the flow downstream of the desuperheater. The feedwater flow then is piped to the receiver, where it passes through a preheated panel prior to entering the steam drum. The receiver steam generator is a natural circulation boiler. A steam separator in the drum is used to separate the saturated vapor and liquid. The saturated steam then leaves the drum, and passes through four superheat panels arranged in series. A spray attemperator is used between the second and third superheater pass to control the receiver steam exit temperature, with the attemperating water being obtained from the feedwater supply. Superheated steam at the desired conditions then leaves the receiver and is piped to the turbine.

If the insolation is insufficient to operate the turbine (low insolation or during startup) the steam bypasses the turbine, is sent through a pressure reducing valve, and is piped the turbine exhaust header. The steam then passes through the desuperheater. Part of the desuperheated steam is used for the feedwater heater. The remainder is then piped to the steam header in Steam Plant No. 4, where the connection is made between the base and the cogeneration facility.

4.3.3 OPERATIONAL CHARACTERISTICS

The primary function of the Solar Cogeneration Facility is to supply electrical power and process steam to produce fossil fuel savings at Robins Air Force Base. Figure 3.2-1 is a simplified flow schematic showing the solar facility flow paths to and from the unit.

Table 4.3-1 is a brief summary of the design/operating characteristics of the facility. Table 4.3-2 is a summary of the power utilization of the facility. Briefly, out of 12.1 MW incident on the heliostat surface area, 0.678 MW of electricity is generated and 7.92 MW of thermal energy is transferred to the base. Further details on the power utilization are given in Section 4.5.

TABLE 4.3-1 DESIGN/OPERATING CHARACTERISTICS AND DESIGN POINT CONDITIONS

Heliostats

Type - Second Generation

Size - 7.44 m high by 7.39 m wide (24.4 ft by 24.25 ft)

Mirror Reflective Area - 52.77 m^2 (568 ft^2)

Field Configuration - North

Number of Heliostats - 251

Receiver

Type-Flat panel, single drum, natural circulation, separate preheater, boiler and superheater panels

Size - 8.78 m wide by 8.25 m high (28.8 ft by 27.1 ft)

Incident Power - 10.04 MW at noon winter solstice

Peak Receiver heat flux - 0.633 MW/m^2 (200,000 $Btu/h\text{-}ft^2$)

Receiver thermal efficiency - 89%

Steam drum pressure - 6.96 MPa (1010 psia)

Receiver exit steam conditions - 410°C, 6.140 MPa (770°F, 890 psia)

Tower

Type - Steel, rectangular cross section

Height - 60 m (197 ft), ground to receiver center

Turbine

Type - Commercial, noncondensing single stage

Turbine flow - 12,977 kg/h (28,610 lb/h)

Inlet conditions - 400°C, 6.0 MPa (750°F, 865 psia)

Exit conditions - 259°C, 1.07 MPa (498°F, 155 psia)

Net electrical production - 678 kW

TABLE 4.3-1 DESIGN/OPERATING CHARACTERISTICS AND DESIGN POINT CONDITIONS (CONT'D)

Desuperheater

Type - Water spray

Steam exit conditions - 186°C, 1.055 MPa (366°F, 153 psia)

Steam flow to base - 11,820 kg/h (26,010 lb/h)

Feedwater Pump

Type - Positive displacement Triplex

Pump drive - Electric motor, belt drive

Flow - 13,043 kg/h (28,755 lb/h)

Pump head - 834 m (2737 ft)

Pump work - 34.8 kW (46.6 Hp)

Feedwater Heater

Type - Shell and tube

Steam supply - 1.05 MPa (152 psia)

Feedwater exit temperature - 178°C (353°F)

Shell design pressure - 1.83 MPa (265 psia)

Tube design pressure - 10.47 MPa (1515 psia)

TABLE 4.3-2 POWER UTILIZATION AT DESIGN POINT

Incident on heliostat surface area - 12.1 MW_t

Reflected by heliostats - 10.85 MW_t

Incident on receiver - 10.04 MW_t

Transferred to working fluid - 8.84 MW_t

Produced electrical - 0.678 MW_e

Produced, useful thermal - 7.92 MW_t

The operation of the system is automatic during most operational modes. The operational modes should not pose any operational problems to plant personnel that cannot be addressed within their experience and training.

The solar cogeneration control system allows daily cycling of the unit and utilizes solar energy for generation of electrical power and process steam. The master control system shall control the solar system in a safe and reliable condition under all modes of operation.

4.3.3.1 OPERATIONAL MODES

The master control system allows the operator to select one of two plant operating modes: a turbine following mode, or process steam mode.

With clear day insolation available, the operator may select the turbine following mode of operation. The receiver and the collector systems are automatically controlled to maximize thermal energy output from the solar facility. The turbine inlet control valves are automatically positioned to maintain stable steam conditions at the turbine inlet by responding to whatever steam flow is made available.

When meteorological conditions are unstable such that cloud shadows could be expected to completely cover the heliostat field for significant periods of time, the process steam mode may be selected. Steam of lower pressure and temperature than that produced during the turbine following mode is generated in the receiver. This steam then bypasses the turbine, is desuperheated and directed to the steam header. This operational mode allows use of the facility during partly cloudy periods without multiple starts and synchronization of the turbine generator.

4.3.3.2 OPERATING CONTROL PHILOSOPHY

The controls for the major facility systems and overall facility control are incorporated in a centralized, minicomputer-based Master Control System (MCS). A centralized MCS has the following advantages:

- Reduces the number of interfaces with other control systems, thus simplifying plant design, operation, maintenance, and personnel training
- Enhances system response by reducing communication problems
- Provides flexibility for control system design
- Is easy to reconfigure
- Provides a comprehensive operator/process interface

The plant can be operated at no less than three levels (automatic, semiautomatic and manual) of control with the operator's responsibilities varying with each level.

In the automatic level, the MCS provides overall facility control and system integration and coordination. The MCS provides safe and reliable operation of the plant by evaluating many environmental, system, and component variables, characteristics, and responses. The operator simply monitors the performance and status of the facility systems and components.

In the semiautomatic level, the MCS automatically controls each system with the operator providing the supervisory control and system integration/

coordination function. The operator accomplishes this by adjusting the setpoints on the system master control stations or initiates control logic sequences associated with the individual systems.

In the manual level the portion of the emergency trip and interlock system necessary for operating/equipment safety employs solid-state logic and functions automatically at all levels of control.

4.4 SITE REQUIREMENTS

The steam load studies indicate that the steam flow requirements projected to approximately 11,350 kg/h (25,000 lbs/h), can be met with a heliostat field of 50,000 m^2 (12.4 acres) to 65,000 m^2 (16 acres) depending on the packing and tower height.

The electrical load studies indicate that the power generated can range from 0.25 MW to 2.0 MW with no adverse effects. The power generation, in this study, becomes an economic factor and a byproduct of the available steam flow.

The site also requires an accessible, but secure, area be provided for a central receiver tower and power plant structure. This area must be within a reasonable distance of the field and in the proximity of a steam main and power line.

The 3 meter (10 ft) declination in the field elevation to the south is fortuitous since this, in effect, adds 3 meters to the effective tower height.

This particular site meets all of the criteria for solar cogeneration and can utilize all of the daytime thermal and electrical power generated.

The existing facility requires relatively minor modifications to accept and distribute both thermal and electrical power.

Solar steam will simply displace fossil steam when introduced into the steam distribution system. The existing deaerator/feedwater system will automatically direct feedwater to the solar surge tank in response to the surge tank liquid level control.

Generated power introduced into the 12.6 kV distribution system will simply reduce the substation load, and thereby reduce both electrical demand and metered consumption.

An existing Energy Monitoring and Control System (EMCS) can be used to monitor the solar cogeneration facility.

A master site plan is included in Appendix B showing existing conditions.

The solar cogeneration facility utilizes the readily available site utility interfaces: water, sanitary sewer, storm sewer, electrical power, telephone, steam, feedwater, and EMCS.

4.5 FACILITY PERFORMANCE

For the design point of noon winter solstice, 10.04 MW_t of thermal power are incident on the receiver plane. This translates into 0.678 MW of electricity being supplied to the base, and about 11,800 kg/h (26,010 lb/h) of steam being supplied to the steam header in Steam Plant No. 4, i.e., 7.92 MW of thermal power. For a typical meteorological year, Figure 4.5-1 shows the step-by-step efficiency diagram for the cogeneration facility.

A computer model (RAFBSCPI) outlined in Appendix G was developed to integrate the hour-by-hour, steady-state performance of the final cogeneration facility for a typical year. RAFBCPI was used to calculate the performance for several system and heliostat availabilities. While the system availability was held at 98 or 100 percent, the heliostat availability was varied from 95, 98 and 100 percent. The best case, 100 percent system and heliostat availability, produced 14.2 x 10^6 kg (31.3 x 10^6 lbs) of steam and 616.3 MWh_e for the base. The effective annual fossil energy replaced for the best case was 8286 barrels of oil. For comparison, the case with 98 percent system and heliostat availability produced about 13.7 x 10^6 kg (30.1 x 10^6 pounds) of steam and about 585.1 MWh_e which corresponds to approximately 7945 effective barrels of oil. A summary of results is listed in Table 4.5-1, and a plot of barrels of oil versus availability is shown in Figure 4.5-2. The number of effective barrels of oil replaced increased about 2 percent when the system availability was raised from 98 percent to 100 percent. The barrels of oil replaced increased by 4 percent when the heliostat availability was raised from 95 percent to 98 percent, and by about 2 percent when the heliostat availability was raised from 98 percent to 100 percent. For the annual average at 100 percent availability, Figure 4.5-3 shows a step-by-step efficiency diagram for the cogeneration facility. Table 4.5-2 shows the month-by-month and total annual steam and electrical production for 100 percent system and heliostat availability.

The Cogeneration Utilization Efficiency (CUE) is an indication of the energy conversion efficiency of the facility. For this facility, it can be written as:

$$CUE = \frac{MWh_e + MWh_t}{MWh}$$

where:

MWh_e = Net annual electrical energy to base

MWh_t = Net annual thermal energy to base

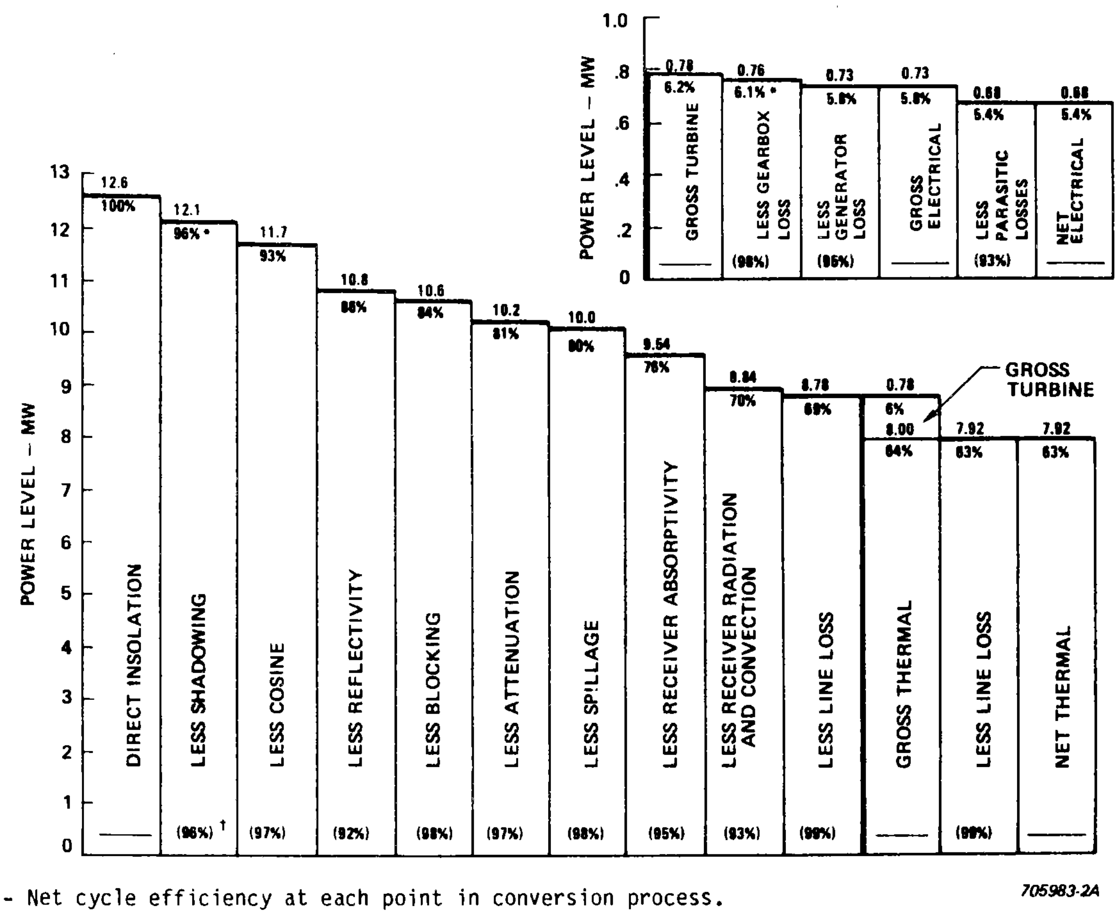
MWh = total annual energy input to facility, i.e. total energy impinging on the receiver.

Taking the energy input to be that impinging on the receiver, the CUE for this facility would be:

MWH_e = 616

MWh_t = 9,583

MWh = 13,502



* XX% - Net cycle efficiency at each point in conversion process.

†(XX%) - Efficiency of each conversion step.

Figure 4.5-1. Power Efficiency Chart - Design Point

TABLE 4.5-1: PERFORMANCE INTEGRATION RESULTS

System Availability	Heliostat Availability	Process Steam Produced (10^6 lb)	Steam Vented (10^5 lb)	Energy of Process Steam MWh_t	Energy of Net Electric MWh_e	Annual Energy Produced MWh_t	Annual Energy Displaced MWh_t	Annual Energy Produced per Mirror Area MWh_t/m^2	Overall Solar System Performance Efficiency	Annual Thermal Solar Fraction	Annual Energy into Receiver Fluid MWh_t	Usable Energy Incident on Receiver MWh_t	Effective Annual Fossil Energy Replaced (barrels of oil)
1.0	.95	29.3	3.7	8974.5	557.4	10142.1	13119.1	.766	.951	.098	10142.1	12749.3	7719.9
	.95	29.4	3.7	8993.2	559.1	10162.5	13148.5	.767	.951	.098	10162.5	12771.0	7737.2
	.98	30.6	4.6	9353.7	593.3	10592.8	13715.6	.800	.952	.102	10592.8	13215.7	8070.9
	.98	30.6	4.5	9362.7	593.9	10598.6	13728.8	.800	.952	.102	10598.6	13222.7	8078.7
	1.0	31.3	5.2	9582.7	616.3	10867.8	14080.2	.821	.953	.104	10867.8	13501.6	8285.5
.98	.95	28.9	4.0	8836.9	551.1	9999.4	12925.7	.755	.951	.096	9999.4	12563.2	7606.1
	.95	28.9	4.9	8834.3	552.3	10025.8	12926.4	.757	.951	.096	10025.8	12596.9	7606.5
	.95	29.0	3.9	8869.8	553.0	10030.8	12973.4	.757	.951	.097	10030.8	12599.4	7634.2
	.98	30.0	5.3	9179.2	584.6	10421.7	13467.7	.787	.952	.100	10421.7	13007.3	7925.0
	.98	30.2	3.8	9231.7	585.6	10430.7	13536.8	.788	.952	.100	10430.7	13015.2	7965.7
	1.0	30.7	5.2	9381.1	603.6	10643.7	13784.8	.804	.953	.102	10643.7	13234.2	8111.7
	1.0	30.6	5.8	9374.4	604.3	10656.4	13778.8	.805	.953	.102	10656.4	13248.0	8108.1

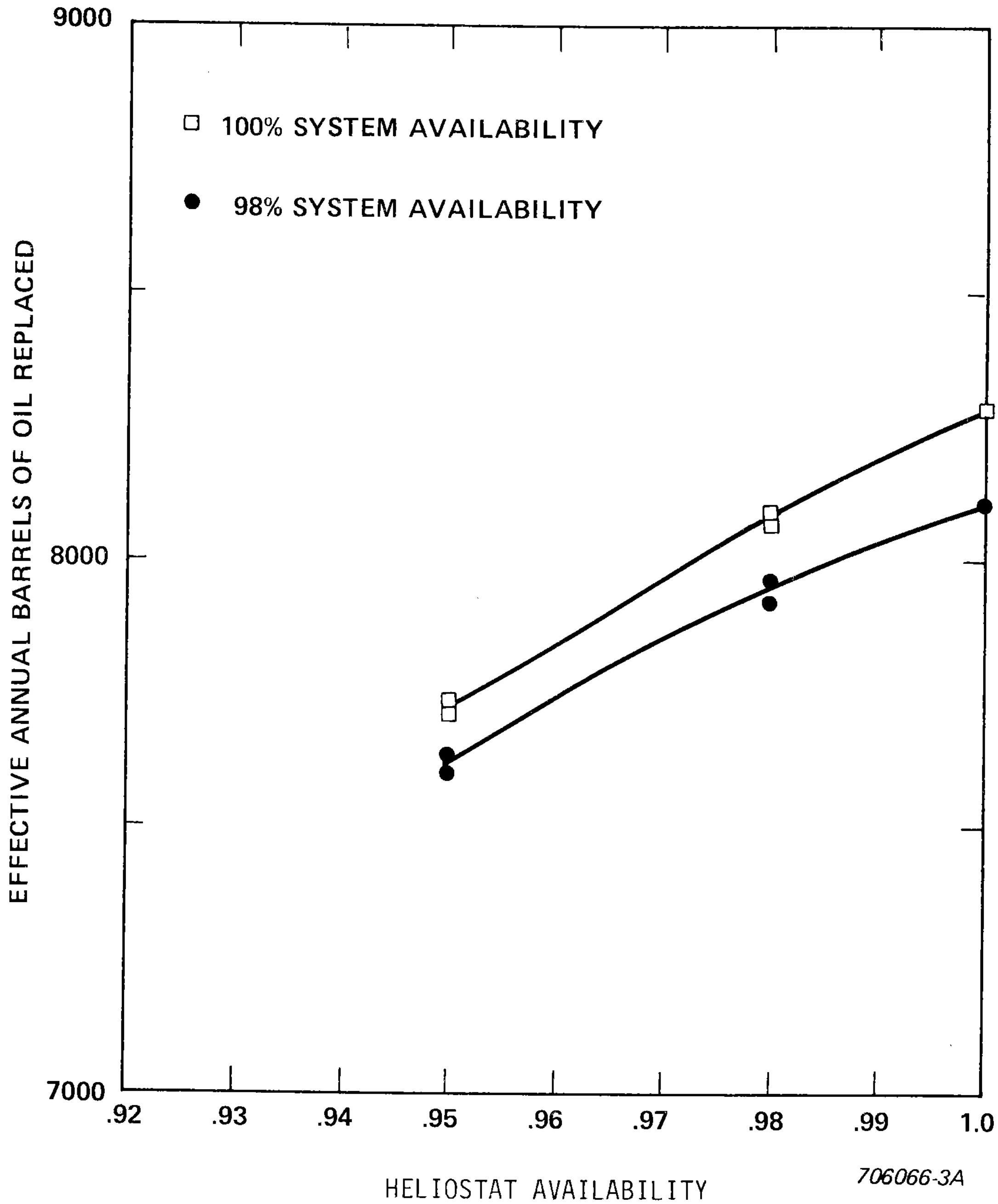


Figure 4.5-2. Effective Annual Fossil Fuel Replaced vs. System and Heliostat Availability

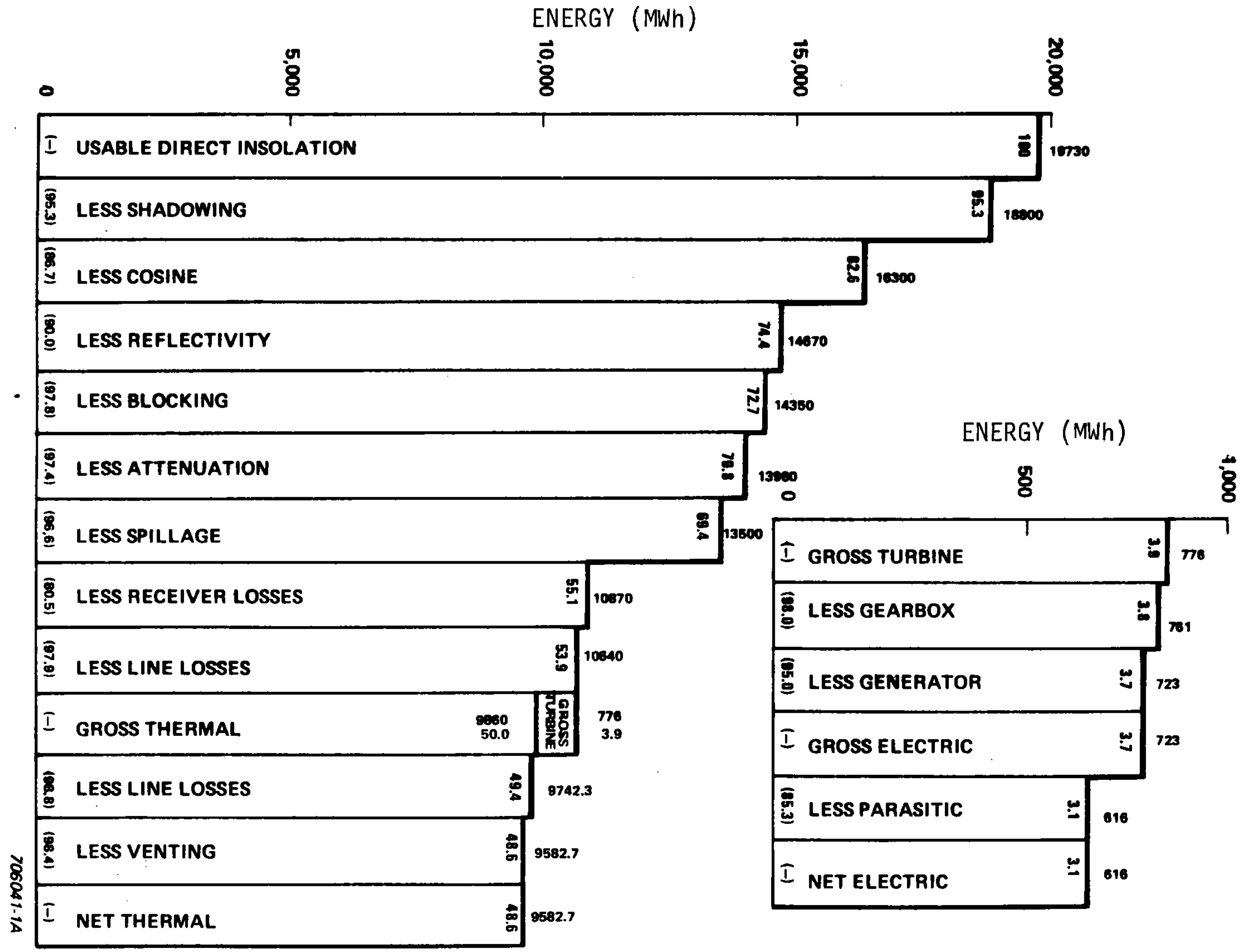


Figure 4.5-3. Energy Efficiency Chart - Annual Average

TABLE 4.5-2: MONTHLY FACILITY STEAM AND ELECTRICAL ENERGY PRODUCTION
100% FACILITY AND HELIOSTAT AVAILABILITY

Month	Process Steam			Electrical Energy
	(Gg)	(millions of pounds)	Thermal Energy MWh_t	(MWh)
January	.771	1.701	521	31.8
February	1.108	2.444	748	50.3
March	1.252	2.761	845	54.6
April	1.319	2.909	890	58.3
May	1.225	2.701	827	51.9
June	1.103	2.433	745	39.7
July	1.291	2.848	872	52.6
August	1.264	2.788	853	50.6
September	1.265	2.790	854	53.5
October	1.432	3.157	966	67.0
November	1.195	2.635	806	63.2
December	.975	2.150	658	42.8
Total	14.200	31.316	9583	616.3

*Based on SOLMET weather tape for Atlanta, GA for a typical meteorological year.

$$\text{CUE} = \frac{616 + 9583}{13{,}502} = 75.5\%$$

4.6 ENERGY LOAD PROFILE

The Robins Solar cogeneration facility is designed to produce electricity and steam for use on the base. The dispatching of the energy from the cogeneration facility to the base will be identical during summer and winter, since the only ties to the base are at the steam header in Steam Plant No. 4, and at the base electrical substation. The electrical energy demand is always at least ten times greater than the design point facility electrical production, so the facility will only reduce slightly the total plant electrical load.

The shape of the steam demand profile of the load projection for 1986 was derived from individual boiler charts supplied by the Base Civil Engineering Division. Only the steam demand during the 0700 to 1700 time interval, corresponding to the hours of solar operation, was utilized in the development of the shape of the curves. Representative boiler charts were evaluated for a typical weekday and a typical weekend day for each month of the year.

The present steam demand profiles and the programmed building expansions were used to develop steam demand profiles for 1986, when the cogeneration facility is expected to be in operation. Curves were prepared for a typical weekday and weekend demand profile for each month of the year (Appendix F). The loads remain quite constant throughout the day. The upper curve given in Figure 4.6-1, representing the monthly average load for the 1986 projection, depict the characteristics of the yearly steam demand. Note that the peak loads are in the winter and that the steam demand decreases during the spring and fall. Also, the increase in steam demand during the summer results from the steam-powered absorption chillers for space conditioning. Upon the completion of the three programmed building expansions, the projected 1986 maximum steam demand(x) will be approximately 22,200 kg/h (48,800 lbs/h). By inspection of Figure 4.6-1, the maximum value of the monthly average projected steam demand is 18,800 kg/h (41,500 lbs/h).

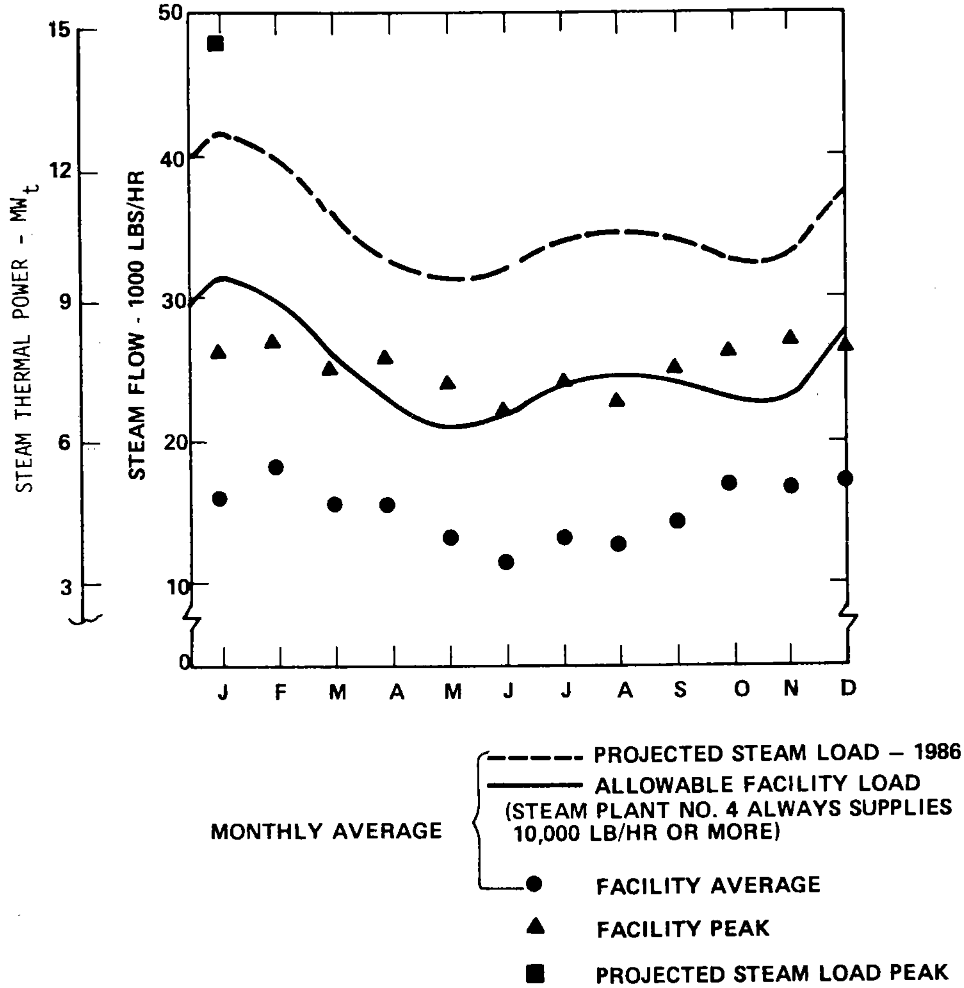


Figure 4.6-1. Existing (1979) and Projected (1986) Steam Demand Profiles

There are only a few hours during the year when the facility output would be greater than the allowable facility load. RAFBCPI (Appendix G) annual calculation indicates that only less than two percent of the total process steam that could be created would not be useable, assuming that all heliostats are available. This loss is shown in Figure 4.5-3 in the venting block.

Table 4.6-1 summarizes, for a typical good insolation day, the distribution of steam production between Steam Plant No. 4 and the cogeneration facility, as well as the net electrical production or consumption by the cogeneration facility. During the night, the entire steam demand is met by Steam Plant No. 4, while some electricity is supplied to the cogeneration facility for standby operations (500 W) and trace heating (when ambient temperature drops below 2°C (350°F) trace heaters are turned on to prevent the exposed receiver panels from freezing 15 kW is the average power consumed by these heaters). When the sun is above the 15° altitude angle, the heliostats can be brought on line, and the insolation focused on the receiver. The facility can then be brought up to temperature, and the turbine can be brought on line. The steam produced by the facility can be sent to the steam header in Steam Plant No. 4, and the fossil boilers' generation can be reduced as the facility picks up the majority of the load. At the end of the day, when the insolation is insufficient to operate the facility, the heliostats can be stowed, the facility brought into a shutdown mode, and the fossil boilers can be used to meet the load.

TABLE 4.6-1 DAILY ENERGY SUMMARY (Typical Winter Day - December 7)

Hour	Direct Insolation (W/m^2)	Steam Flow, kg/hr Receiver	Demand Flow	To Meet Demand	Net Electrical kW
1	0.0	0.0	16776	0.0	-15.5
2	0.0	0.0	16776	0.0	-15.5
3	0.0	0.0	16776	0.0	-15.5
4	0.0	0.0	16776	0.0	-15.5
5	0.0	0.0	16776	0.0	-15.5
6	0.0	0.0	16776	0.0	-15.5
7	0.0	0.0	17728	0.0	-15.5
8	233.9	0.0	17728	0.0	-28.6
9	696.4	2523	17411	2331	-20.3
10	903.6	10349	17048	9475	444.0
11	956.1	12032	16867	10939	594.0
12	975.6	12921	16821	11713	674.0
13	969.7	12833	16731	11636	666.0
14	949.7	11940	16595	10859	586.0
15	891.1	10181	16413	9329	429
16	704.4	2573	16232	2381	-20.5
17	199.2	0.0	16005	0.0	-0.5
18	0.0	0.0	16776	0.0	-0.5
19	0.0	0.0	16776	0.0	-0.5
20	0.0	0.0	16776	0.0	-0.5
21	0.0	0.0	16776	0.0	-0.5
22	0.0	0.0	16776	0.0	-0.5
23	0.0	0.0	16776	0.0	-0.5
24	0.0	0.0	16776	0.0	-0.5

4.7 CAPITAL COST SUMMARY FOR PROJECT

The capital cost estimate for the RAFB Solar Cogeneration Facility is summarized in Table 4.7-1. The costs shown include the direct costs, indirect (engineering and project management) and owner's costs, but excludes one time engineering costs. The backup for calculating the direct costs for each subsystem is presented in Appendix A (System Requirements Specification). The basis for each of the costs other than direct cost is discussed in this section. A definition of cost accounts included in the direct cost estimate and described in Appendix A is presented in Table 4.7-2.

The total estimated construction and related costs for the solar facility is \$11,614,374 in 1981 dollars. This estimate is based on an assumed installed collector field cost of \$260/m^2, including foundations, field wiring, installation, and the delivered cost of collector equipment. The total cost is based on the engineering and construction schedule discussed in Section 7.0, requiring approximately 18 months of engineering overlapping 20 months of construction, and 3 months for checkout and startup, a total of 41 months.

4.7.1 DIRECT COSTS

The total direct costs estimated for this project are \$6,852,048 million. Direct costs are defined as the present day (1981) material and labor costs associated with the delivery and installation of each subsystem identified in the conceptual design.

The approach utilized to estimate direct costs involves the development of engineering data; preparation of equipment lists or descriptions of groups of equipment or subsystems; the accumulation of data for materials costs, based on similar estimates for other projects, information provided by equipment vendors, and published data; the development of estimates for labor associated with installation of each subsystem or major piece of equipment based on experience with similar installations; and the application of labor rates representative of the Warner Robins area. Figure 4.7-1 shows typical cost account boundries for the receiver and for the turbine generator.

TABLE 4.7-1: CONSTRUCTION COST ESTIMATE SUMMARY
(In 1981 Dollars)

Account/Description	
5000 Facility Cost	
5100 Site Improvements	$ 197,308
5200 Administrative Areas	$ 63,973
5300 Collector System	$3,492,163
5400 Receiver System	$1,918,871
5500 Master Control System	$ 386,000
5600 Non-Solar (Fossil) Energy System	N/A
5700 Energy Storage System	N/A
5800 Electric Power Generating System	$ 229,754
5900 Balance of Facility-Steam & Feedwater System	$ 563,979
Total Direct Cost	$6,852,048
Indirect Costs	$ 413,423
Total Direct and Indirect Costs	$7,265,471
Engineering	$1,999,160
Total Field and Office Costs	$9,264,631
Fee and G & A	$1,816,368
Georgia Power Co. Allowance*	$ 75,000
Owner's Costs	$ 458,375
Total	$11,614,374

* one time connection fee

TABLE 4.7-2: CONSTRUCTION COST CODES

Solar Cogeneration Facility Capital Investment Cost

5000 Facility Cost

- 5100 Site Improvements
  NOTE: Required land for Project to be provided by owner
  - 5110 General Site preparation (e.g., grading, water supply modifications, roads, landscaping, etc.)
- 5200 Administrative Areas (Operations, Security, Storage and Maintenance)
- 5300 Collector System
- 5400 Receiver System
- 5500 Master Control System
- 5600 Non-Solar (Fossil) Energy System (Not Applicable)
- 5700 Energy Storage System (Not Applicable)
- 5800 Electrical Power Generating System
- 5900 Balance of Facility - Steam and Feedwater System

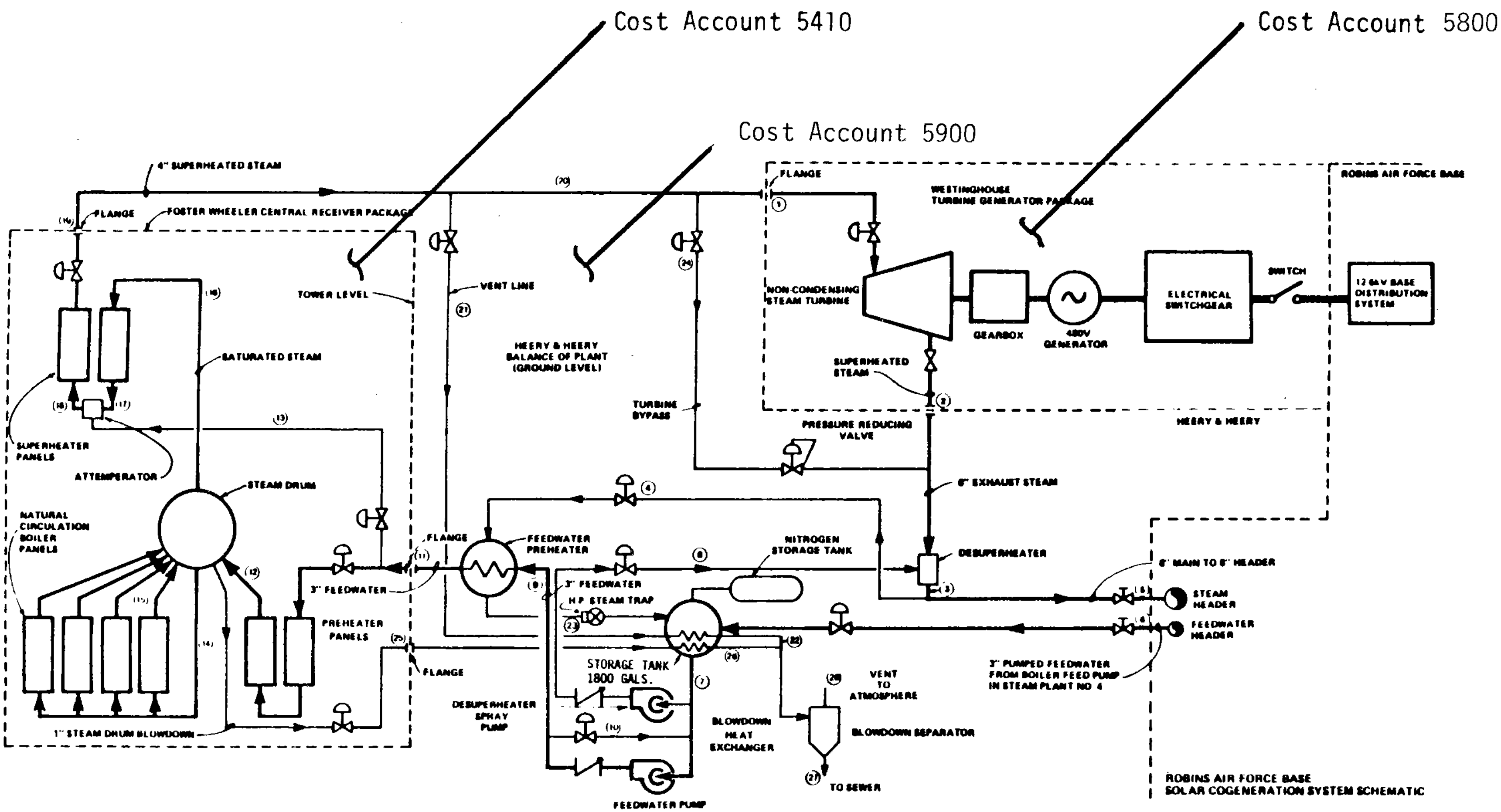


Figure 4.7-1. Cost Account Boundaries Solar Cogeneration Facility

4.7.2 INDIRECT COSTS

Indirect costs primarily include the cost of engineering and design work in support of construction. These indirect costs are estimated at 6 percent of the total direct costs. This percentage was based on estimates of engineering labor developed for most of the expected engineering and design effort. The total estimated indirect cost is approximately $2,229,791 in 1981 dollars including fee and G&A.

One time engineering costs provide for the development of detailed engineering information; preparation of drawings, equipment lists, and specifications; procurement of subcontractors and major pieces of equipment; development of detailed cost and scheduling information; and project management.

4.7.3 OWNER'S COSTS

Owner's costs estimated for this project are approximately $458,375 in 1981 dollars. A breakdown of the owner's costs is presented in Table 4.7-3.

4.8 OPERATING AND MAINTENANCE COSTS AND CONSIDERATIONS

4.8.1 GENERAL

Whenever insolation conditions are satisfactory the solar cogeneration facility is to be operational, as discussed in earlier sections of the report. This requires the facility to be aligned and prepared to accept insolation between 0700 and 1700 solar time, approximately, throughout the year.

It is intended that operational and maintenance programs for the solar cogeneration facility should supplement the existing program for Steam Plant No. 4 and be wholly integrated within an overall scheme for both facilities. Such an approach will maximize the utilization efficiency of the combined facility and minimize the additional cost of operational and maintenance functions.

TABLE 4.7-3 OWNER'S COST SUMMARY
(1981 Dollars)

a.	Land and land rights and cost of Right of Ways; 15.5 acres $3250/acre:	$50,375
b.	Landscaping to rework areas surrounding site:	$10,000
c.	Relocation of fourteenth tee of golf course:	$15,000
d.	Traffic studies related to closing off 7th streets:	$5,000
e.	Archaeological search for artifacts, if required:	$5,000
f.	Other environmental studies required for permits:	$10,000
g.	Public relations activities (both local and regional):	$5,000
h.	Coordination of installation of piping connections in Steam Plant No. 4 and any utility relocations:	$10,000
i.	Owner's managerial, engineering, accounting, labor relations, general services, estimating, planning, coordination and other base services directly related to the project:	$20,000
j.	Cost for RAFB EMCS:	$4,000
k.	Present value of Building No. 760 Band Building:	$154,000
l.	Miscellaneous, e.g. gate access control communication, relocation of outdoor use of land area displaced by tower and power building)	$40,000
m.	Repair deaereator and chemical treatment of boiler water.	$130,000
	TOTAL:	$458,375

Steam Plant No. 4 operates continuously and is currently manned on a three shift system. Each shift has two boiler plant operators on duty and the hours are arranged from 0000-0800, 0800-1600, 1600-2400. A maintenance crew for mechanical activities is attached to the plant and normally works from 0730-1615 each day. Electrical and instrument control technicians are available from support departments on base as needed.

It is recommended that the existing structure be supplemented as necessary to expand the program for an integrated operation and maintenance task.

4.8.2 OPERATIONS

The solar cogeneration facility will be manned by operational personnel continuously during the hours of effective insolation. In addition manning will be required for a period before and after the insolation period in order that start up, shut down and secure procedures can be effectively carried out. The approximate daily operational manning period will vary between 12.5 hours at summer solstice to 10.0 hours at winter solstice.

In Table 4.8-1, the operating cost category OM 100 includes the cost of wages for additional plant operating personnel, the cost of operating consumables and other fixed charges.

The number of boiler plant operators currently assigned to Steam Plant No. 4 would be increased in order that the integrated facility will be fully manned at all times. Salaries and overhead for the additional operators are estimated to be about $33,000 per year.

An allowance of $15,000 is included for supplies consumed in the solar cogeneration facility on a regular basis, such as makeup water, water treatment chemicals, cleaning supplies, paint, lubricants, etc.

Other fixed charges include items such as insurance, wastewater disposal, etc. An allowance of $12,000 is included to cover these costs.

TABLE 4.8-1

ANNUAL PLANT OPERATING AND MAINTENANCE COSTS
(IN 1981 DOLLARS)

OM 100	Operating Cost (110 + 120 + 130)			$ 60,000
	OM 110	Operating Personnel		33,000
	OM 120	Operating Consumables		15,000
	OM 130	Other Fixed Charge Rate		12,000
OM 200	Maintenance Material Cost (210 + 220 + 230)			38,198
	OM 210	Spare Parts (211 thru 215)		20,452
		OM 211	Turbine and Elec. Plant	1,628
		OM 212	Collector Equipment	13,824
		OM 213	Receiver Equipment	5,000
		OM 214	Thermal Storage Equipment	--
		OM 215	Fossil Boiler Equipment	--
	OM 220	Material for Repair		17,746
	OM 230	Other		
OM 300	Maintenance Labor Cost (310 + 320)			68,240
	OM 310	Scheduled Maintenance		34,120
	OM 320	Corrective Maintenance		34,120
		TOTAL (100 + 200 + 300)		$166,438

Total cost for OM 100 operating cost is approximately.

4.8.3 MAINTENANCE

Maintenance functions on the solar cogeneration facility will normally be carried out during periods when the facility is non-operational, that is during early morning or the evening.

Days on which no insolation is possible due to cloud cover can be utilized for maintenance functions.

For purposes of planning maintenance requirements, it is convenient to divide the equipment forming the solar cogeneration facility into four components: These are:

1. Heliostat field
2. Receiver
3. Turbine, generator and master control
4. Balance of facility.

A brief discussion of each of these components follows.

1. Heliostat field. Scheduled maintenance is limited to mirror washing, inspection of the heliostat assemblies and computer maintenance. Mirror washing is a necessity because foreign particulates degrade the mirrors reflective efficiency. Frequency of washing will be between three and twelve times per year depending upon the actual particulate density. In calculating the maintenance cost we have allowed for mirror washing to be carried out at monthly intervals.

   Inspection will be conducted annually to determine reflective surface damage, oil leaks, corrosion, vegetation growth, and other factors affecting heliostat performance.

Computer maintenance is best performed by the manufacturer under a service contract.

Unscheduled field maintenance will be initiated as a result of the field inspection and/or alarm message data on the control console. The nature of the defect will be determined and the repair technique and format adjusted to the situation (repair at site, refurbished by supplier or replaced).

Components of the heliostat system which may require maintenance on an unscheduled basis include the heliostat controller, combination heliostat field controller and heliostat controller, encoders, gear motors and drive mechanism seals. Each of these are readily accessible and can be replaced at the pedestal.

Mirror assemblies, if damaged beyond efficient reflectivity, will be removed and replaced with stocked spares at the pedestal. A stock of spare units will enable an entire heliostat to be removed and replaced in the event of severe mechanical damage.

2. Receiver. The receiver control system and operating modes proposed allow for operation with a minimum of direct operator involvement. Operating personnel can devote their attention to monitoring the system, identifying problems, and performing preventive maintenance. We anticipate that the receiver system can be run by one operator after the initial start-up and checkout phases are complete.

Routine maintenance on the receiver should be minimal because there are few moving parts. Scheduled maintenance is expected to consist of replacing gaskets on drum manways, resetting and testing safety relief valves, and possibly performing a corrosion test. Overnight shutdown affords time for repacking and resetting of valves that can be isolated from receiver pressure. With proper feedwater conditioning, acid cleaning of the boiler will be required at intervals of not less than 3 to 5 years, based on previous experience with fossil-fueled boilers operating under similar conditions. Routine inspection of the absorptive coating on the receiver active surfaces will be made. Reprinting of these surfaces will be performed if required.

Since the receiver is similar to a fossil-fueled boiler in design,, arrangement, and materials, repairs can be made using techniques familiar to operators of conventional steam generators. Easy access is provided to the rear of the receiver and to the receiver headers and riser tubes. Access to the front is from a platform suspended from the top of the receiver structure. No special jigs, tools, or lifting devices are needed for receiver maintenance, and no unusual skills are required of the maintenance personnel--only the usual skills of machinists, welders, pipefitters, riggers, electricians, and technicians on the staff of the facility.

3. Turbine, generator and master control. The turbine/generator has a high reliability and will not normally require, at intervals of less than 10 years, any major maintenance involving removal/replacement of rotor, buckets, diaphragms, bearings, seals, valve or governing mechanisms. Such major maintenance, if needed, should be performed under the supervision of the manufacturer's representative.

   The routine inspection and maintenance for the turbine generator consist of the following items:

   - Inspect and clean, if necessary, the steam inlet strainer after the first day and first week of operation and annually therafter
   - Clean and lubricate external pivots of governor system; replenish lubricant in lever system bearings once per month
   - Check oil level in hydraulic governor system once per month
   - Check out over-speed trip on the turbine once per month; clean and lubricate, if required, outside moving parts of over-speed trip control

- Test oil neutralization number, flash point, viscosity, etc. (every six months)

- Maintain oil levels, as required, in turbine bearing reservoir, speed reducer gear box, generator bearing reservoir (if required)

The master control maintenance shall be covered by a service contract for the computer equipment. All instrumentation equipment including cabling and connectors will be periodically inspected. Any unsatisfactory conditions would be subject to immediate maintenance. Each instrumentation and control item or channel will be periodically recalibrated.

4. Balance of facility. The equipment to be installed in the solar plant building is of similar type to the conventional equipment installed in Steam Plant No. 4, and comprises pumping units, heat exchangers, pneumatically operated control valves and manually operated valves. Much of the equipment operates at higher pressure and temperatures than the integrated conventional steam plant, but the skills required of maintenance personnel are the norm for staff engaged in power plant operation. The manufacturers of the individual components will be required to provide detailed maintenance recommendations for the equipment supplied to the project, which will be incorporated into the plant schedules.

Maintenance material and labor costs are also contained in Table 4.8-1 under headings OM 200 and OM 300. Each of the four categories was considered separately.

Heliostat annual maintenance and estimated repair costs were based upon the criteria contained in Detailed Design Report MCR-80-1396A entitled "Second Generation Heliostat Development." This indicates that maintenance and repair costs calculated from statistical reliability, actual life and test data amount to 0.91 percent of the installed cost of heliostat equipment, or $31,775.

Receiver maintenance and repair cost is assumed to be $58,240.

Maintenance and repair costs for turbine generator and master control gear are $9,375.

Estimated maintenance and repair costs for the balance of facility are based upon judgement and experience of historical costs associated with similar equipment in steam raising plants. An allowance has been made for adding additional craftsmen to the existing maintenance crew and the cost of their salaries and overheads has been apportioned between heliostat and balance of facility equipment. An allowance for replacement spare parts for each item of equipment is included in OM 220. This element is based upon specific recommendations by manufacturers of the equipment envisaged for this application.

Except as outlined above, cost distribution per O&M accounts has been carried out utilizing the following assumptions.

60/40 material/labor split for all maintenance.

50/50 split between OM 210 (spare parts) and OM 220 (material for repairs).

No items appylying to OM 230 (other).

50/50 split between scheduled and corrective labor in OM 300.

Total annual maintenance material and labor cost is approximately $166,438.

4.8.4 EXTENDED LIFE CYCLE OF FOSSIL FUEL BOILER

Steam generated by the solar cogeneration facility which is distributed through the system currently served by Steam Plant Number 4 will correspondingly reduce the steam demand upon the fossil fuelled boilers. (Currently boiler numbers 2 and 3 operate for approximately 90 percent of the time partly at full capacity.) The reduction in demand will extend the life cycle of these boilers by approximately 10 percent by reducing the hours operated at full capacity. Each is rated at 24,000 lbs. per hour and has an expected life of 25 years. The estimated cost of each boiler is $240,000.

Cost savings per year from reduced operation of two boilers is, therefore, $240,000 x 10% x 2 divided by 25 = $1,920 per year.

4.9 SUPPORTING FACILITY AND SYSTEM ANALYSES

In the development of a conceptual design for the RAFB Solar Cogeneration Facility, several supporting facility and system analyses have been initiated or performed. Some of these efforts to support the design have only been completed to the preliminary assessment stage. In these cases, the additional efforts to be accomplished during the Preliminary and Detailed Design and Construction Phases of the project have been considered and/or identified.

Presented in Section 4.9.1 are discussions of the Safety Considerations for this facility. This section covers the normal, industrial type Health and Safety aspects during the construction, checkout and operation of the facility (Subsection 4.9.1.1). Also included in Section 4.9.1 are discussions of Facility Safety (4.9.1.2). These safety evaluations treat the major efforts which have been or will need to be considered regarding the design features and procedures unique to the operation of a solar cogeneration facility, as well as the unique safety aspects of the collector, receiver and master control systems.

Given below in Section 4.9.2, entitled Environmental Considerations, are the results of the preliminary environmental impact/benefit efforts which have been performed during the conceptual design. Also included are the planned areas of investigation which will need to be evaluated when an environmental impact estimate is prepared for the project. This estimate will also treat the environmental benefits from the operation of the facility.

A review of the Institutional, Regulatory, and Other Considerations was initiated during this conceptual design. These included the potential barriers to the construction/operation of a solar facility at Robins AFB. These considerations are presented in Section 4.9.3.

Section 4.9.4, Overall Logistic and Service Considerations, presents preliminary conceptual design information on: Reliability/Availability (Subsection 4.9.4.1), Maintainability (4.9.4.2), Producibility (4.9.4.3), Installation (4.9.4.4) and Logistic Support (Subsection 4.9.4.5).

4.9.1 SAFETY CONSIDERATIONS

A number of reports have been issued that address the safety aspects that are unique to the application of a solar central receiver power system such as this solar facility at Robins AFB. Among these are three reports that dealt with the 5 MW_t Central Receiver Test Facility (CRTF) which was constructed at the Sandia National Laboratories in Albuquerque, New Mexico.* The tower, heliostat field and control building for this test facility covers approximately 40,470 m^2 (10 acres) of land. The height of the tower is 60 meters (197 ft) and the heliostat collector field contains up to 366 heliostats. Several prototype heliostats and types of central receivers located at the top of the tower have been and are being evaluated at this facility.

Several safety aspects of this facility were discussed in the MITRE Report (Ref. 4.9-1)*. These included: a) the requirements for fire protection and b) the potential glare from the heliostat mirrors and its effect on the pilots that take off and land aircraft at the two airports that border the Sandia facility: Kirtland Air Force Base and the Albuquerque Municipal Airport. Because the CRTF heliostats are individually focused onto the receiver at the top of the tower, each one at a different angle, their effect on a pilot's

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* References

4.9-1: S. Haus, L. Duncan, P. Alkon and J. Pratt, the MITRE Corporation, "Preliminary Environmental Assessment Concerning the Construction and Operation of a 5-MW Solar Thermal Central Receiver Test Facility," MITRE Working Paper 11290, November, 1975.

4.9-2: T. D. Brumleve, Sandia National Laboratories, Livermore, "Eye Hazard and Glint Evaluation for the 5-MW_t Solar Thermal Test Facility," SAND 76-8022, May, 1977.

4.9-3: L. L. Young, III, "Solar Energy Research at Sandia Laboratories and Its Effects on Health and Safety", SAND 77-1412, October 1977.

vision was expected to be slight, similar to flying across the choppy water of a lake. The Martin-Marietta heliostat design for the CRTF consists of 25 individual facets or mirrors to produce the 37 m^2 of reflective surface and each of these facets are slightly dished and can be individually focused.

An additional consideration with regard to the air traffic in the Sandia area was the 60 meters (197 ft) tall tower. This consideration was reviewed for the Robins AFB solar cogeneration facility for two reasons: (1) the tower height for the RAFB solar facility is also 60 meters (197 ft) tall (to the center of the receiver) and (2) the CRTF is located in close proximity to the Kirtland Air Force Base (and Albuquerque International Airport) runways and therefore is directly applicable to Robins AFB. Since the CRTF tower needed to conform to FAA regulations for aircraft safety, any danger was expected to be minimal. Moreover, the tower location has been noted on the pilot's instrument approach plates (Jepson Charts for civilian aircraft and the DOD "Flight Instrument Approach Procedures and Airfield Diagrams" for militray aircraft) for Albuquerque so that all aircraft can avoid it. Some minor thermal turbulence has also been created by the heat plume (thermal convection losses from the receiver surface) rising from the tower. The combination of these three potential safety impacts (glare, obstruction and turbulence) on air traffic, particularly for small aircraft, required that consideration be given to possible modifications in the flight paths over the Sandia National Laboratories, Albuquerque area. Similar solar reflectance/ tower height/heat plume assessments will be required in the development of a solar cogeneration facility at Robins AFB. These assessments will be performed during the Design Phase of the project.

Significant efforts were performed in assessing the eye hazards and evaluating the glint aspects in the development of the 5 MW_t CRTF (Ref. 4.9-2). Potential eye hazards associated with concentrated reflected light (solar reflectance hazards) were evaluated. Specific light intensities and hazardous ranges of single and multiple coincident heliostat beams were assessed for conditions at both ground level and in the air space above the facility. The possible long-range and short-range distractive effects of reflected beams were also considered. Certain beam control modifications needed to be incorporated into the design so as to minimize the altitude at which over-flying aircraft could encounter unsafe levels and these were described. Recommendations were made in Reference 4.9-2 with respect to the 5 MW_t CRTF for further evaluation of the intensity excursions during fail-safe shutdown situations and for specific experiments which could be used to verify analytical models and to assess the distractive glint effects.

Excerpts from some of the conclusions drawn in Reference 4.9-2, along with additional specific notations which apply, in general, to a solar cogeneration facility at Robins AFB are as follows:

- With regard to the application of the 25 faceted heliostat design by Martin-Marietta at the CRTF, the reflected beam from any single heliostat with a focal length shorter than about 260 m constitutes a potential eye hazard that extends for a comparatively short distance on either side of its focal point. This hazard zone is generally confined to 20-30 meters on either side of the focal point with the shorter focal length beams being the most hazardous. Similar assessments will need to be made when one considers the potential eye hazards of the latest Second Generation Heliostat designs which are being or have been developed. For the conceptual design of the RAFB solar facility, a "Generic" Second Generation Heliostat design has been evaluated.

- Specific beam control measures needed to be incorporated as a result of possible multiple beam intensities so as to minimize the altitude at which over-flying aircraft might encounter eye hazards. These efforts were designed to effectively preclude intensities greater than one sun and thereby prevent unsafe retinal irradiances at altitudes greater than about 200 m during normal operations.

- Although, during certain types of fail-safe shutdown, the potential for momentary excursions of greater than one-sun intensity may extend to several hundred meters, these types of failures were considered to be very rare.

- Based on the Martin-Marietta cavity receiver for the CRTF, the reflected light from diffuse surfaces located in the focal zone does not appear to present a hazard except in controlled areas near the top of the tower. Further consideration of this aspect will need to be performed for the receiver design to be employed at the RAFB solar cogeneration facility, as being designed by Foster Wheeler Solar Development Corporation.

- The potential fire hazard which might exist for the shorter focal length heliostats needs to be evaluated for the conditions in which the beams might impinge on a combustible material.

A preliminary review of the safety considerations that are unique to the conceptual design of the RAFB solar cogeneration facility has been completed.

4.9.1.1 HEALTH AND SAFETY

One of the developmental aspects of the Supporting Facility and System Analyses for a solar cogeneration facility at Robins AFB is a safety evaluation on the application of a solar central receiver/heliostat collector field design for the facility. Several safety considerations are unique to a solar central receiver thermal power system design. Presented below in Subsection 4.9.1.2 are discussions of Facility Safety. That section covers those aspects of the solar facility which are unique to this application. Other health and safety considerations are relevant to normal industrial practice in the construction and operation of this facility. These health and safety aspects are discussed in this section.

In performing a review of the Health and Safety considerations for this design, several types of safety hazards have been identified. These include: solar reflectance; working fluid (steam and hot water); electrical; mechanical; maintenance; and malfunction hazards. In addition, several other potential problems have been considered in the health and safety aspects of this solar facility and these include a) the use of a 70 meter (228 ft) tall tower and receiver and the associated safety of the operating, testing and maintenance personnel in the performance of their normal functions and b) the use of guard rails and other safety hardware (e.g., designing the tower to ensure that personnel located on the tower cannot fall off from the tower).

These potentially hazardous conditions in the operation of this facility can be precluded by designing with sound engineering practices and judgement. Each of these aspects have been investigated in a preliminary nature for this solar cogeneration facility. Specific details on one of these potential normal Health and Safety hazards, namely the Working Fluid (steam and hot water) harzards, for this facility are summarized below. In most cases, possible causes for the hazardous conditions have been outlined. Some of the specific corrective actions which will be pursued to mitigate the severity or frequency of occurrence, or to eliminate the hazard entirely, have been identified. A more complete health and safety assessment of the RAFB solar cogeneration facility is planned during the Design and Construction Phases of this project. This assessment will be based on the final design of the facility as well as on the specific components selected for the facility and will include results on the electrical, mechanical, maintenance and malfunction hazards.

Prior to summarizing the results on the safety hazards and their resolution, and in developing an approach towards assessing the Health and Safety aspects of this facility, the following subjects have been considered (as discussed below): a) the objectives of the health and safety program, including the unique safety considerations for the solar facility, b) the applicable standards, codes and design guidelines and c) the definition of a recommended set of safety related categories to be utilized in the safety analyses to be performed during the Design and Construction Phases.

The conclusions drawn from a preliminary review of the health and safety considerations during the conceptual design study are: a) several hazards, causes of potential hazards and corrective actions have been identified and b) all potential problems are amenable to solution.

GENERAL SAFETY REQUIREMENTS

As delineated in Section A.3.13 of Appendix A [Robins Air Force Base Solar Cogeneration Facility Specification] the Westinghouse design team will be establishing a tailored facility safety program beginning at the start of the Design Phase and continuing throughout the Construction and Operations Phases (including the facility's 25 year service life). This safety program will establish administrative and technical means by which mishap prevention requirements and policies are planned, managed and implemented into the solar facility project. The purpose of the safety program is to identify significant mishap risks and define methods to cope effectively with those risks within project cost, schedule, performance and technical acceptability parameters.

A facility safety review board will be named to ensure, to the maximum extent practical, the inherent safety of the facility and its systems through the use of appropriate design features and qualified components. These features will be subjected to analyses to provide a thorough review of their compatibility with the maintenance, test, and operation of the facility. The design features will be reviewed to minimize the probability of safety degradation because of human error. Particular attention will be paid to the facility and systems design, as well as interfaces, to ensure detection of impending hazardous conditions in sufficient time to complete automatic or manual control actions.

The facility safety organization/review board will: a) conduct safety hazards analyses of the integrated facility and its operation, as well as the interfaces with the existing Steam Plant and electrical distribution system, including all support equipment, b) provide an assessment of the mishap risk presented by various normal and emergency operations of the facility and its interfaces for both normal and contingency conditions, and c) ensure that major subcontractors conduct appropriate analyses and provide data suitable for incorporation into the facility safety analysis program.

The above general safety requirements may need to be augmented/complemented by the performance of a Failure Modes and Effects Analysis (FMEA). This FMEA could be performed on all mechanical, thermal, hydraulic and electrical systems and components of the facility, including the heliostats and heliostat control system of the Collector System. The FMEA could be used to identify the critical failure modes that might be hazardous to life, result in injury or cause major damage to the solar facility. In coordinating the efforts of the facility safety organization/review board with the potential FMEA efforts, additional requirements for health and safety may need to be factored into the design. These requirements would be applicable to the design of the components and subsystems of the Collector, Receiver, Electrical Power Generating, Master Control System, as well as the Balance of the Facility and the steam, feed-water, and electrical interfaces.

The overall health and safety design requirements for the solar cogeneration facility are as follows:

- Implement a safety program which reviews all mechanical, thermal, hydraulic, and electrical components and subsystems and which identifies, evaluates, and either eliminates or controls all undesirable hazards with the potential to: injure personnel, visitors, or the general public; damage the facility; or cause loss of program objectives.
- The safety design cirteria shall be that no major damage, or personnel, visitor, or general public hazard should occur because of a single point failure or a single failure following an undetected failure.
- Develop a safety shutdown system capability in the Master Control System and the heliostat control system which monitors specific parameters, i.e., temperatures, pressures, and flow rates at various locations throughout the facility and the maximum flux on the receiver surface.

OBJECTIVES

Health and Safety must be considered and appropriate procedures, and design features developed and implemented during the design, construction, and operations phases of this project. Therefore, the facility must be designed to fulfill the following objectives:

- Protect the health and insure the safety of the general public.
- Protect the health and insure the safety of the Robins AFB civilian and military personnel and visitors to the solar cogeneration facility.
- Protect the health and insure the safety of the construction, testing, operating, and maintenance personnel for the facility.
- Protect the health and/or insure the safety of the living environment (birds, animals, other wildlife, trees, shrubs, grass, etc.).
- Maintain the quality of the natural environment by minimizing or eliminating the pollution or contamination of the surrounding land, water, and air.

The first three objectives deal directly with health and safety and will be the primary goals of this effort. The last two objectives (environmental health, safety, and quality) deal indirectly with health and safety. Any impacts to the quality (or health and safety) of the natural (or living) environment identified will need to be evaluated further as part of the environmental assessment. The above criteria, possibly complemented by others yet to be identified, will be the Health and Safety objectives in future phases of this solar cogeneration facility project.

DESIGN GUIDELINES

Numerous standards and codes, laws and regulations, design guidelines and requirements, and other publications and documents are applicable to the industrial type Health and Safety and the unique Solar Facility Safety aspects of a solar cogeneration facility at Robins AFB. Several of these design guidelines are delineated in Section A.2.0, References, of the Robins AFB Facility Specification (Appendix A). Additional design guideline/requirement references for health and safety are being considered for inclusion in the Facility Specification. These additional references (which have not been cited in this final report or in Appendix A) will be reviewed and evaluated during the Design Phase to determine which ones are directly applicable to this solar facility. Special attention will be devoted to the design and operation of the Collector System and the receiver because of their relatively less mature technologies.

The design and operation of the Electrical Power Generating System, the Balance of the Facility, and the Master Control System and the design of the tower and the interfacing components will be based on more mature technology. Accordingly, the applicable codes, standards, regulations, etc. now available for these components and systems will be complied with during the Design, Construction and Operations Phases. These same codes and standards, appropriately applied, will serve to insure a safe design of the Collector System and the receiver.

During the design phase, the Westinghouse team plans to review and utilize, where appropriate, the safety assessments/analyses which have been performed by other solar central receiver design contractors. These include the industrial contractors for the Solar Hybrid Repowering and Solar Cogeneration Facility Conceptual Design Projects which have been (or are being) completed. In addition, the safety assessments performed for the Solar Total Energy -- Large Scale Experiment Nos. 1 and 2 (for Fort Hood and Shenandoah) will be reviewed to insure that all of the design criteria and safety analyses previously documented on various types of solar hazards have been considered. Extensive expertise has been developed on the safety of various solar systems by individuals at the Sandia National Laboratories, Albuquerque and the Sandia National Laboratories, Livermore. Those efforts will be reviewed and incorporated, where appropriate, into the safety analyses for the Robins AFB solar facility. Finally, several safety analyses/assessments have been (or are being) completed for the 5 MW_t CRTF in Albuquerque and the 10 MW_e Central Receiver Pilot Plant near Barstow, CA and these will be factored into the design.

Several Sandia National Laboratories, Albuquerque and contractor reports on collectors, test facilities, total energy systems, solar irrigation and technology development and testing have been issued over the past several years. These programs include the Solar Total Energy System Test Facility (STESTF) and Solar Collector Module Test Facility at the Sandia National Laboratories, Albuquerque, the Solar Irrigation Projects near Willard, New Mexico and Coolidge, Arizona, and supportive technology development and testing at Sandia National Laboratories, Albuquerque . The field experience gained in the parabolic trough area, although not directly applicable to the heliostat Collector System and Central Receiver Solar Thermal Power System area, will provide additional background information and knowledge for the design of the solar cogeneration facility.

All of the above mentioned standards, codes, design guidelines, etc. will be utilized as the controlling design, health, safety and solar facility safety guidelines and requirements during future phases of the RAFB solar cogeneration facility project, as appropriate.

SAFETY HAZARD CATEGORY DEFINITIONS

The conventional definitions by which possible hazardous conditions will be categorized for severity during the design phase of this project are as follows:

- Category I - Safety Catastrophic. Condition(s) such that environment, personnel error, design characteristics, procedural deficiencies, or system or component malfunction will cause death or multiple injuries to personnel
- Category II - Safety Critical. Condition(s) such that environment, personnel error, design characteristics, procedural deficiencies, or system or component malfunction will cause major personnel injury, or will result in a hazard requiring immediate action to preclude major personnel injury
- Category III - Safety Marginal. Condition(s) such that environment, personnel error, design characteristics, procedural deficiencies, or system or component malfunction will cause minor injuries to personnel
- Category IV - Safety Negligible. Condition(s) such that environment, personnel error, design characteristics, procedural deficiencies, or system or component malfunction will probably not cause personnel injury

WORKING FLUID HAZARDS

The working fluids to be used in the solar facility are a) the high temperature and high pressure [6.14 MPa (890 psia)/410°C (770°F)] steam being supplied from the receiver to the steam turbine of the Electrical Power Generating System (EPGS), b) the process steam discharged from the turbine at a lower temperature and pressure, as it is transported through the piping and components of the Balance of the Facility to the steam header in Steam Plant No. 4 and c) the hot water transported from the feedwater header in Steam Plant No. 4 through various components of the feedwater system of the Balance of the Facility. The potential hazards associated with each of these fluids are discussed below.

High temperature/high pressure and intermediate temperature/intermediate pressure steam is generated/transported/utilized in various components and piping from the receiver, through the turbine and on to the steam header in Steam Plant No. 4. The maximum pressure of the feedwater at the feedwater pump exit is 8.58 MPa (1245 psia).

A few steam and hot water hazards are associated with the piping; the preheater, boiler, and superheater in the receiver; and the turbine, pumps and other components of the facility. These hazards are easily controlled based on mature technology, since several codes and standards are now available for the use of steam and hot water at these conditions. Thus, the piping and associated components will be designed to fulfill the appropriate standards and codes which pertain to the use of steam and hot water and to pressurized components and systems of the facility mentioned above under Design Guidelines.

Based on the above, several different types of hazards exist with the use of steam and hot water in the facility. A burn hazard (scalding) could exist if personnel were to come into direct contact with steam or hot water which has leaked, sprayed, or spilled from the facility. This leakage or spillage could result from the rupture of components or piping or from the relatively normal leakage around glands, rotary shafts, at the pumps, etc.

Another potential hot water burn type hazard exists when personnel could come into direct contact with exposed steam and hot water piping and components [up to $\sim$ 410°C (770°F)]. Since steam is used throughout the existing Robins AFB distribution systems and extensive experience in the normal use of steam is available, these steam and hot water hazards are not considered to be extraordinary. Moreover, thermal insulation will be used to minimize the potential for direct contact with piping and/or components of the steam and hot water systems.

4.9.1.2 FACILITY SAFETY

This section reviews the unique safety considerations/hazards associated with locating a solar cogeneration facility near the existing Steam Plant No. 4 on Robins AFB. These "solar" hazards are primarily related to the use of a tall central receiver tower and a large heliostat collector field. Specific restrictions are imposed by FAA regulations on the construction of a tall (receiver) tower. The heliostat collector field poses a significant safety consideration with respect to both the general public and to the operating personnel, when one considers the potential solar reflectance hazards resulting from the operation of the facility.

UNIQUE SAFETY CONSIDERATIONS

Several unique safety considerations for the design, construction, and operation of the solar cogeneration facility have been reviewed with the engineers and personnel from Robins Air Force Base. These safety aspects in the application of a solar facility at Robins AFB have included the following: a) a review of the traffic patterns for the Air Force and military aircraft which take off from and land at Robins Air Force Base and the associated proximity of these traffic patterns to the solar cogeneration facility site, b) a review of the safety activities which were performed by the Air Force flight safety officer at Kirtland Air Force Base in Albuquerque, New Mexico during his earlier assessments of flight safety and commercial air traffic safety at the Albuquerque Airport/Kirtland Air Force Base with respect to the 5 MW_t Central Receiver Test Facility (CRTF), and c) the relationship between the air traffic patterns at Robins AFB, the location of the receiver tower for the solar facility and the locations and heights of the two water towers which are located on Robins AFB.

The runways at Robins AFB are Runway 32 for landing or taking off in a northwesterly direction and Runway 14 for landing and taking off in a southeasterly direction (see Figure 1.4-2). The receiver and tower for the solar facility will be located $\sim$ 2600 meters (8530 ft), at an angle of 198 degrees clockwise from due north, from the southeast end of Runway 32.

The two water towers on Robins AFB are located closer to the northwest/south-east runway centerline extension (flight path) for the Air Force Base. Hence, these water towers will be much more visible to the Air Force pilots in their flight patterns near the Base. The height of the water tower closest to the runway is 48 meters (157 ft) above ground elevation and this tower is located southwest of the touchdown (landing) point (numerals 32) for Runway 32. This water tower is approximately 1160 meters (3800 ft) from the touchdown point on Runway 32. The other water tower located on Robins AFB has a height of 45 meters (148 ft) above ground elevation. The ground elevations of these two towers are close to the elevation of the receiver tower for the solar facility. The height of the top of the tower for the solar facility is 69.3 meters (227 ft), which is only ~ 21 meters (70 ft) taller than one of the water towers. Thus, the Westinghouse design team and the Robins AFB Civil Engineering Squadron, Safety and Flight Safety personnel have determined that the close proximity of the solar receiver tower and its height are of no concern for the takeoff and landing of Air Force aircraft at Robins AFB.

The landing and takeoff patterns from Runway 32 and Runway 14 have been reviewed. The landing pattern is such that all aircraft (other than light aircraft, such as those used by the local flying [Aero] club, or helicopters) which arrive at Robins AFB (when not performing a "straight in" approach) complete their upwind/crosswind leg, downwind leg, and base leg of their approach patterns to insure that their aircraft are never flying over the main residential area of Robins AFB. This means that aircraft which are landing on Runway 14 (in a southeasterly direction) will perform a "left hand" traffic pattern, i.e., their aircraft will fly over the nonresidential area at Robins AFB (northeast of the field - see Figure 1.4-2). For runway 32, a "right hand" traffic pattern is followed, which again precludes their flying directly over the major portions of the facilities and residences at Robins AFB. In light of the above and since the proposed receiver/tower for the solar facility is located southwest of the runway and near the residential area, all aircraft will have no reason to be anywhere near the solar tower or the above mentioned water towers. All light aircraft, such as those used by the local flying (Aero) club, and all helicopters traffic patterns are to be revised, as discussed in Section 4.9.3 below.

Additional discussions (and coordination efforts) were held (performed) as part of the conceptual design of the solar facility, both in person and via other communications, with Robins AFB cognizant personnel. These discussions were focused on the normal health and safety, flight safety and unique safety aspects of the solar cogeneration facility. The Westinghouse design team and the appropriate Robins AFB personnel have determined that they envision no significant safety impacts from the design, construction and operation of the solar facility at the proposed location on Robins AFB.

SOLAR REFLECTANCE HAZARDS

Several different hazardous conditions could result from the effects of concentrated solar insolation or reflectance from individual or multiple heliostats in the Collector System. Thus, a potential safety hazard associated with the solar cogeneration facility site could stem from emergency or accidential misdirected solar radiation. This invisible concentrated and focused solar radiation can potentially cause fires and burns as well as create glare problems. At the focal point, there is a concentrated beam of focused radiation. Beyond the focal point, this beam becomes increasingly dispersed and eventually becomes more diffuse than the original solar radiation. Thus, there is a range around the focal point where the beam is concentrated to a degree to present potential safety hazards. These include potential fires, burns, and glare.

A potentially severe eye hazard exists for those personnel located near the focal point of several heliostats during periods of sunshine. Depending upon the concentration ratio for these heliostats and the eye location, temporary "flash" blindness or permanent blindness (from the burn damage to the choroid and retina of the eye) could occur. A glare hazard may also exist when personnel are located in or near the collector field. As discussed above, a glint or glare hazard is also a safety consideration to the general public outside and above the boundaries of the solar cogeneration facility, e.g., along Robins Parkway ("E" Street) and "B" Street.

TABLE 4.3-1 DESIGN/OPERATING CHARACTERISTICS AND DESIGN POINT CONDITIONS (CONT'D)

Desuperheater

Type - Water spray
Steam exit conditions - 186°C, 1.055 MPa (366°F, 153 psia)
Steam flow to base - 11,820 kg/h (26,010 lb/h)

Feedwater Pump

Type - Positive displacement Triplex
Pump drive - Electric motor, belt drive
Flow - 13,043 kg/h (28,755 lb/h)
Pump head - 834 m (2737 ft)
Pump work - 34.8 kW (46.6 Hp)

Feedwater Heater

Type - Shell and tube
Steam supply - 1.05 MPa (152 psia)
Feedwater exit temperature - 178°C (353°F)
Shell design pressure - 1.83 MPa (265 psia)
Tube design pressure - 10.47 MPa (1515 psia)

TABLE 4.3-2 POWER UTILIZATION AT DESIGN POINT

Incident on heliostat surface area - 12.1 MW_t

Reflected by heliostats - 10.85 MW_t

Incident on receiver - 10.04 MW_t

Transferred to working fluid - 8.84 MW_t

Produced electrical - 0.678 MW_e

Produced, useful thermal - 7.92 MW_t

The operation of the system is automatic during most operational modes. The operational modes should not pose any operational problems to plant personnel that cannot be addressed within their experience and training.

The solar cogeneration control system allows daily cycling of the unit and utilizes solar energy for generation of electrical power and process steam. The master control system shall control the solar system in a safe and reliable condition under all modes of operation.

4.3.3.1 OPERATIONAL MODES

The master control system allows the operator to select one of two plant operating modes: a turbine following mode, or process steam mode.

With clear day insolation available, the operator may select the turbine following mode of operation. The receiver and the collector systems are automatically controlled to maximize thermal energy output from the solar facility. The turbine inlet control valves are automatically positioned to maintain stable steam conditions at the turbine inlet by responding to whatever steam flow is made available.

When meteorological conditions are unstable such that cloud shadows could be expected to completely cover the heliostat field for significant periods of time, the process steam mode may be selected. Steam of lower pressure and temperature than that produced during the turbine following mode is generated in the receiver. This steam then bypasses the turbine, is desuperheated and directed to the steam header. This operational mode allows use of the facility during partly cloudy periods without multiple starts and synchronization of the turbine generator.

4.3.3.2 OPERATING CONTROL PHILOSOPHY

The controls for the major facility systems and overall facility control are incorporated in a centralized, minicomputer-based Master Control System (MCS). A centralized MCS has the following advantages:

- Reduces the number of interfaces with other control systems, thus simplifying plant design, operation, maintenance, and personnel training
- Enhances system response by reducing communication problems
- Provides flexibility for control system design
- Is easy to reconfigure
- Provides a comprehensive operator/process interface

The plant can be operated at no less than three levels (automatic, semiautomatic and manual) of control with the operator's responsibilities varying with each level.

In the automatic level, the MCS provides overall facility control and system integration and coordination. The MCS provides safe and reliable operation of the plant by evaluating many environmental, system, and component variables, characteristics, and responses. The operator simply monitors the performance and status of the facility systems and components.

In the semiautomatic level, the MCS automatically controls each system with the operator providing the supervisory control and system integration/

coordination function. The operator accomplishes this by adjusting the setpoints on the system master control stations or initiates control logic sequences associated with the individual systems.

In the manual level the portion of the emergency trip and interlock system necessary for operating/equipment safety employs solid-state logic and functions automatically at all levels of control.

4.4 SITE REQUIREMENTS

The steam load studies indicate that the steam flow requirements projected to approximately 11,350 kg/h (25,000 lbs/h), can be met with a heliostat field of 50,000 m^2 (12.4 acres) to 65,000 m^2 (16 acres) depending on the packing and tower height.

The electrical load studies indicate that the power generated can range from 0.25 MW to 2.0 MW with no adverse effects. The power generation, in this study, becomes an economic factor and a byproduct of the available steam flow.

The site also requires an accessible, but secure, area be provided for a central receiver tower and power plant structure. This area must be within a reasonable distance of the field and in the proximity of a steam main and power line.

The 3 meter (10 ft) declination in the field elevation to the south is fortuitous since this, in effect, adds 3 meters to the effective tower height.

This particular site meets all of the criteria for solar cogeneration and can utilize all of the daytime thermal and electrical power generated.

The existing facility requires relatively minor modifications to accept and distribute both thermal and electrical power.

Solar steam will simply displace fossil steam when introduced into the steam distribution system. The existing deaerator/feedwater system will automatically direct feedwater to the solar surge tank in response to the surge tank liquid level control.

Generated power introduced into the 12.6 kV distribution system will simply reduce the substation load, and thereby reduce both electrical demand and metered consumption.

An existing Energy Monitoring and Control System (EMCS) can be used to monitor the solar cogeneration facility.

A master site plan is included in Appendix B showing existing conditions.

The solar cogeneration facility utilizes the readily available site utility interfaces: water, sanitary sewer, storm sewer, electrical power, telephone, steam, feedwater, and EMCS.

4.5 FACILITY PERFORMANCE

For the design point of noon winter solstice, 10.04 MW_t of thermal power are incident on the receiver plane. This translates into 0.678 MW of electricity being supplied to the base, and about 11,800 kg/h (26,010 lb/h) of steam being supplied to the steam header in Steam Plant No. 4, i.e., 7.92 MW of thermal power. For a typical meteorological year, Figure 4.5-1 shows the step-by-step efficiency diagram for the cogeneration facility.

A computer model (RAFBSCPI) outlined in Appendix G was developed to integrate the hour-by-hour, steady-state performance of the final cogeneration facility for a typical year. RAFBCPI was used to calculate the performance for several system and heliostat availabilities. While the system availability was held at 98 or 100 percent, the heliostat availability was varied from 95, 98 and 100 percent. The best case, 100 percent system and heliostat availability, produced 14.2×10^6 kg (31.3×10^6 lbs) of steam and 616.3 MWh_e for the base. The effective annual fossil energy replaced for the best case was 8286 barrels of oil. For comparison, the case with 98 percent system and heliostat availability produced about 13.7×10^6 kg (30.1×10^6 pounds) of steam and about 585.1 MWh_e which corresponds to approximately 7945 effective barrels of oil. A summary of results is listed in Table 4.5-1, and a plot of barrels of oil versus availability is shown in Figure 4.5-2. The number of effective barrels of oil replaced increased about 2 percent when the system availability was raised from 98 percent to 100 percent. The barrels of oil replaced increased by 4 percent when the heliostat availability was raised from 95 percent to 98 percent, and by about 2 percent when the heliostat availability was raised from 98 percent to 100 percent. For the annual average at 100 percent availability, Figure 4.5-3 shows a step-by-step efficiency diagram for the cogeneration facility. Table 4.5-2 shows the month-by-month and total annual steam and electrical production for 100 percent system and heliostat availability.

The Cogeneration Utilization Efficiency (CUE) is an indication of the energy conversion efficiency of the facility. For this facility, it can be written as:

$$CUE = \frac{MWh_e + MWh_t}{MWh}$$

where:

MWh_e = Net annual electrical energy to base

MWh_t = Net annual thermal energy to base

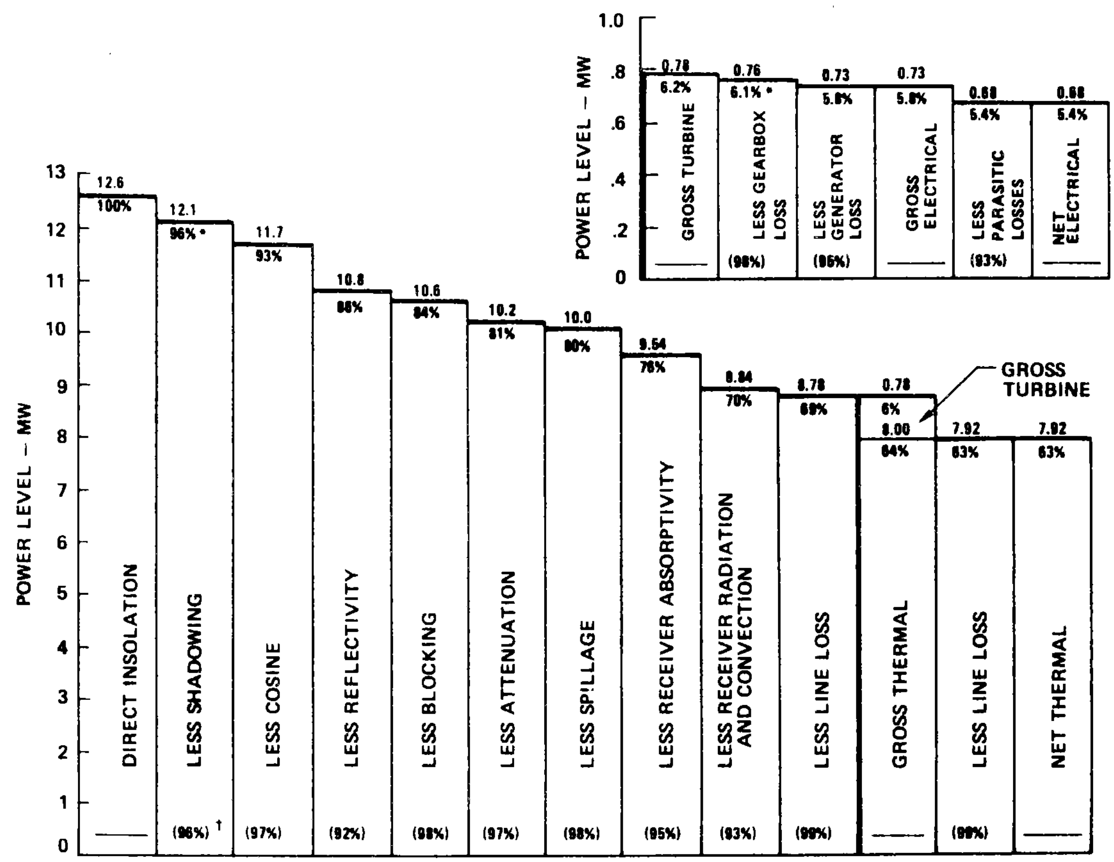
MWh = total annual energy input to facility, i.e. total energy impinging on the receiver.

Taking the energy input to be that impinging on the receiver, the CUE for this facility would be:

MWH_e = 616

MWh_t = 9,583

MWh = 13,502



* XX% - Net cycle efficiency at each point in conversion process.

†(XX%) - Efficiency of each conversion step.

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Figure 4.5-1. Power Efficiency Chart - Design Point

TABLE 4.5-1: PERFORMANCE INTEGRATION RESULTS

System Availability	Heliostat Availability	Process Steam Produced (10^6 lb)	Steam Vented (10^5 lb)	Energy of Process Steam MWh_t	Energy of Net Electric MWh_e	Annual Energy Produced MWh_t	Annual Energy Displaced MWh_t	Annual Energy Produced per Mirror Area MWh_t/m^2	Overall Solar System Performance Efficiency	Annual Thermal Solar Fraction	Annual Energy into Receiver Fluid MWh_t	Usable Energy Incident on Receiver MWh_t	Effective Annual Fossil Energy Replaced (barrels of oil)
	.95	29.3	3.7	8974.5	557.4	10142.1	13119.1	.766	.951	.098	10142.1	12749.3	7719.9
	.95	29.4	3.7	8993.2	559.1	10162.5	13148.5	.767	.951	.098	10162.5	12771.0	7737.2
1.0	.98	30.6	4.6	9353.7	593.3	10592.8	13715.6	.800	.952	.102	10592.8	13215.7	8070.9
	.98	30.6	4.5	9362.7	593.9	10598.6	13728.8	.800	.952	.102	10598.6	13222.7	8078.7
	1.0	31.3	5.2	9582.7	616.3	10867.8	14080.2	.821	.953	.104	10867.8	13501.6	8285.5
	.95	28.9	4.0	8836.9	551.1	9999.4	12925.7	.755	.951	.096	9999.4	12563.2	7606.1
	.95	28.9	4.9	8834.3	552.3	10025.8	12926.4	.757	.951	.096	10025.8	12596.9	7606.5
.98	.95	29.0	3.9	8869.8	553.0	10030.8	12973.4	.757	.951	.097	10030.8	12599.4	7634.2
	.98	30.0	5.3	9179.2	584.6	10421.7	13467.7	.787	.952	.100	10421.7	13007.3	7925.0
	.98	30.2	3.8	9231.7	585.6	10430.7	13536.8	.788	.952	.100	10430.7	13015.2	7965.7
	1.0	30.7	5.2	9381.1	603.6	10643.7	13784.8	.804	.953	.102	10643.7	13234.2	8111.7
	1.0	30.6	5.8	9374.4	604.3	10656.4	13778.8	.805	.953	.102	10656.4	13248.0	8108.1

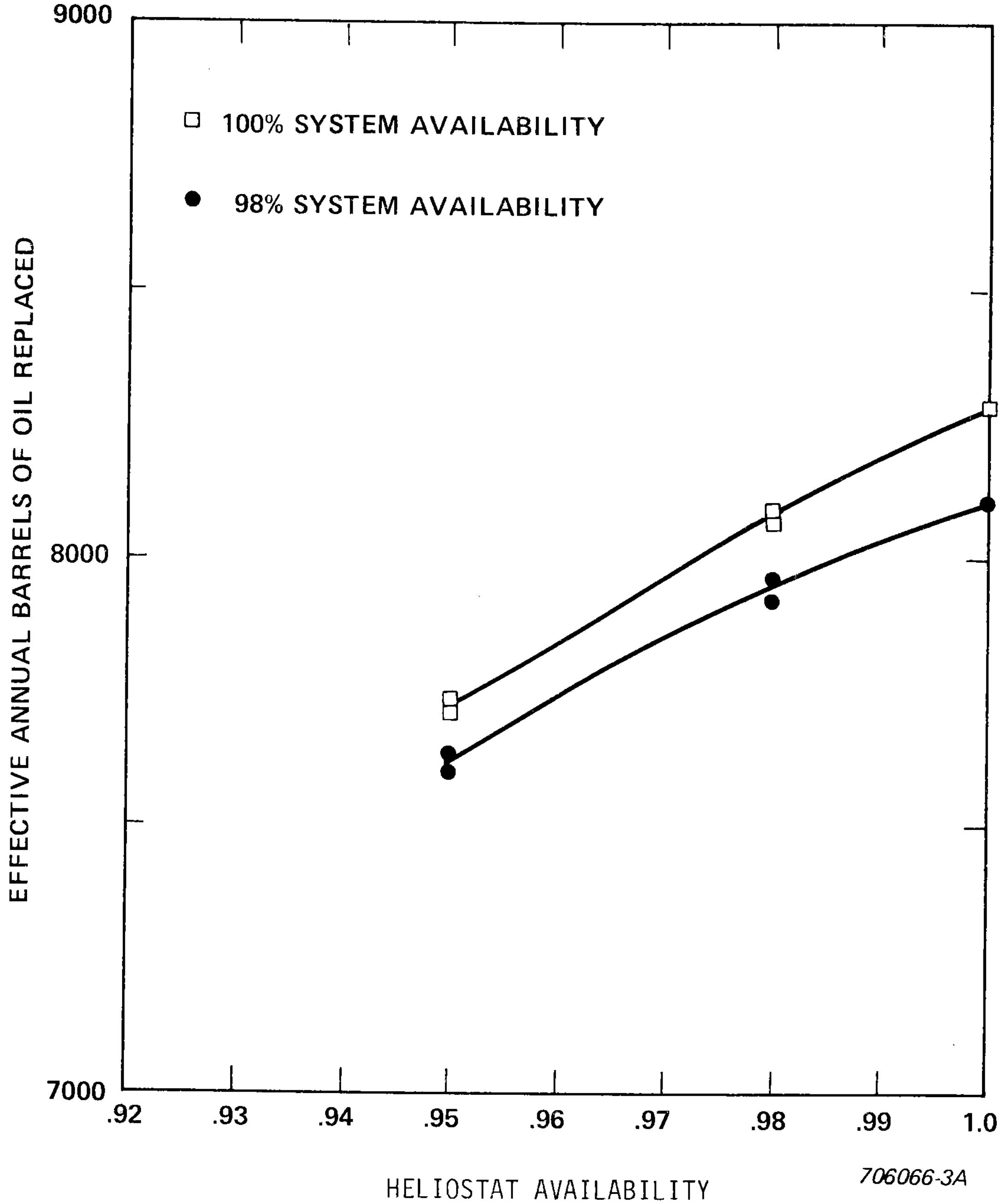

Figure 4.5-2. Effective Annual Fossil Fuel Replaced vs. System and Heliostat Availability

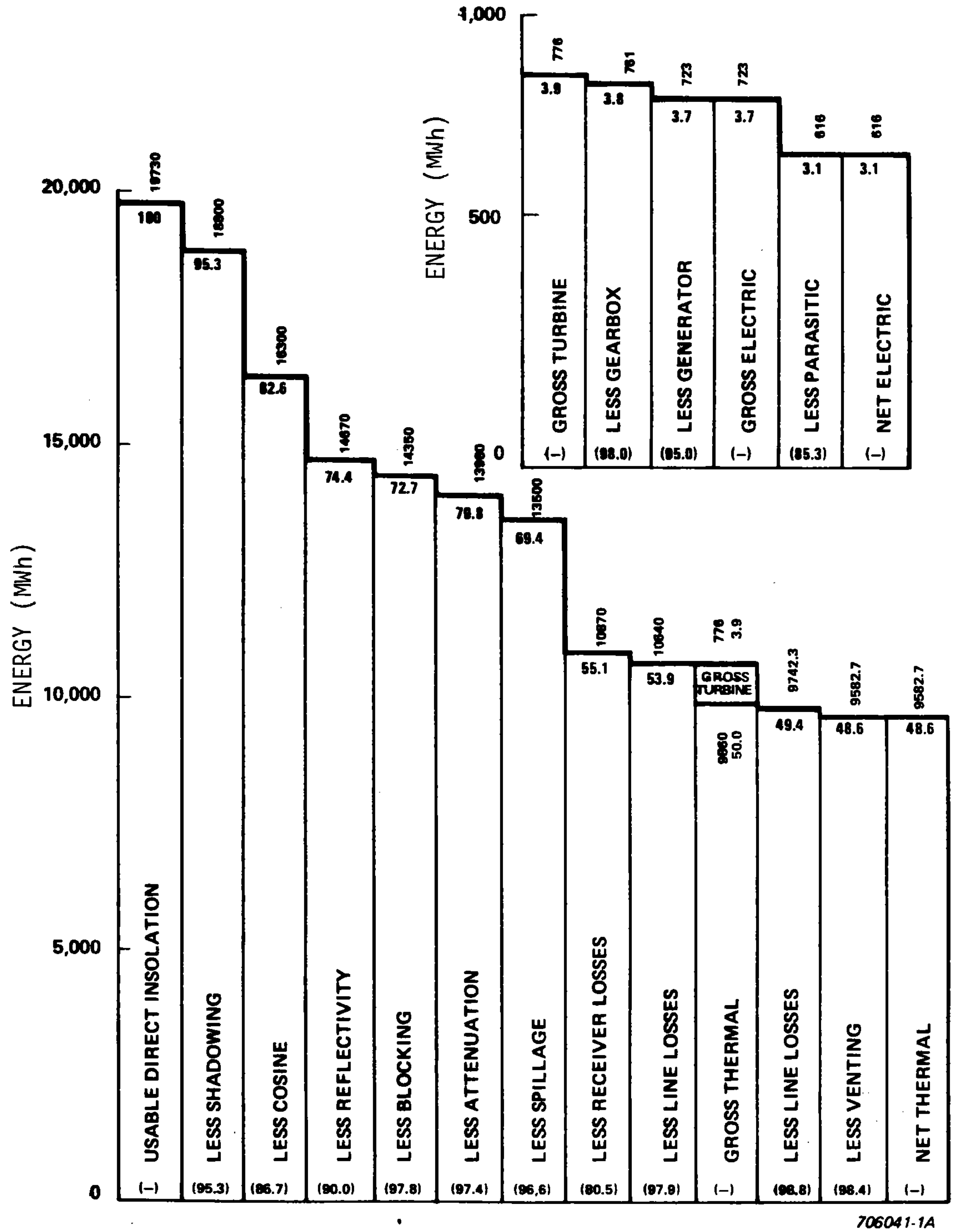

Figure 4.5-3. Energy Efficiency Chart - Annual Average

TABLE 4.5-2: MONTHLY FACILITY STEAM AND ELECTRICAL ENERGY PRODUCTION 100% FACILITY AND HELIOSTAT AVAILABILITY

Month	Process Steam (Gg)	Process Steam (millions of pounds)	Process Steam Thermal Energy MWh_t	Electrical Energy (MWh)
January	.771	1.701	521	31.8
February	1.108	2.444	748	50.3
March	1.252	2.761	845	54.6
April	1.319	2.909	890	58.3
May	1.225	2.701	827	51.9
June	1.103	2.433	745	39.7
July	1.291	2.848	872	52.6
August	1.264	2.788	853	50.6
September	1.265	2.790	854	53.5
October	1.432	3.157	966	67.0
November	1.195	2.635	806	63.2
December	.975	2.150	658	42.8
Total	14.200	31.316	9583	616.3

*Based on SOLMET weather tape for Atlanta, GA for a typical meteorological year.

$$CUE = \frac{616 + 9583}{13,502} = 75.5\%$$

4.6 ENERGY LOAD PROFILE

The Robins Solar cogeneration facility is designed to produce electricity and steam for use on the base. The dispatching of the energy from the cogeneration facility to the base will be identical during summer and winter, since the only ties to the base are at the steam header in Steam Plant No. 4, and at the base electrical substation. The electrical energy demand is always at least ten times greater than the design point facility electrical production, so the facility will only reduce slightly the total plant electrical load.

The shape of the steam demand profile of the load projection for 1986 was derived from individual boiler charts supplied by the Base Civil Engineering Division. Only the steam demand during the 0700 to 1700 time interval, corresponding to the hours of solar operation, was utilized in the development of the shape of the curves. Representative boiler charts were evaluated for a typical weekday and a typical weekend day for each month of the year.

The present steam demand profiles and the programmed building expansions were used to develop steam demand profiles for 1986, when the cogeneration facility is expected to be in operation. Curves were prepared for a typical weekday and weekend demand profile for each month of the year (Appendix F). The loads remain quite constant throughout the day. The upper curve given in Figure 4.6-1, representing the monthly average load for the 1986 projection, depict the characteristics of the yearly steam demand. Note that the peak loads are in the winter and that the steam demand decreases during the spring and fall. Also, the increase in steam demand during the summer results from the steam-powered absorption chillers for space conditioning. Upon the completion of the three programmed building expansions, the projected 1986 maximum steam demand(x) will be approximately 22,200 kg/h (48,800 lbs/h). By inspection of Figure 4.6-1, the maximum value of the monthly <u>average</u> projected steam demand is 18,800 kg/h (41,500 lbs/h).

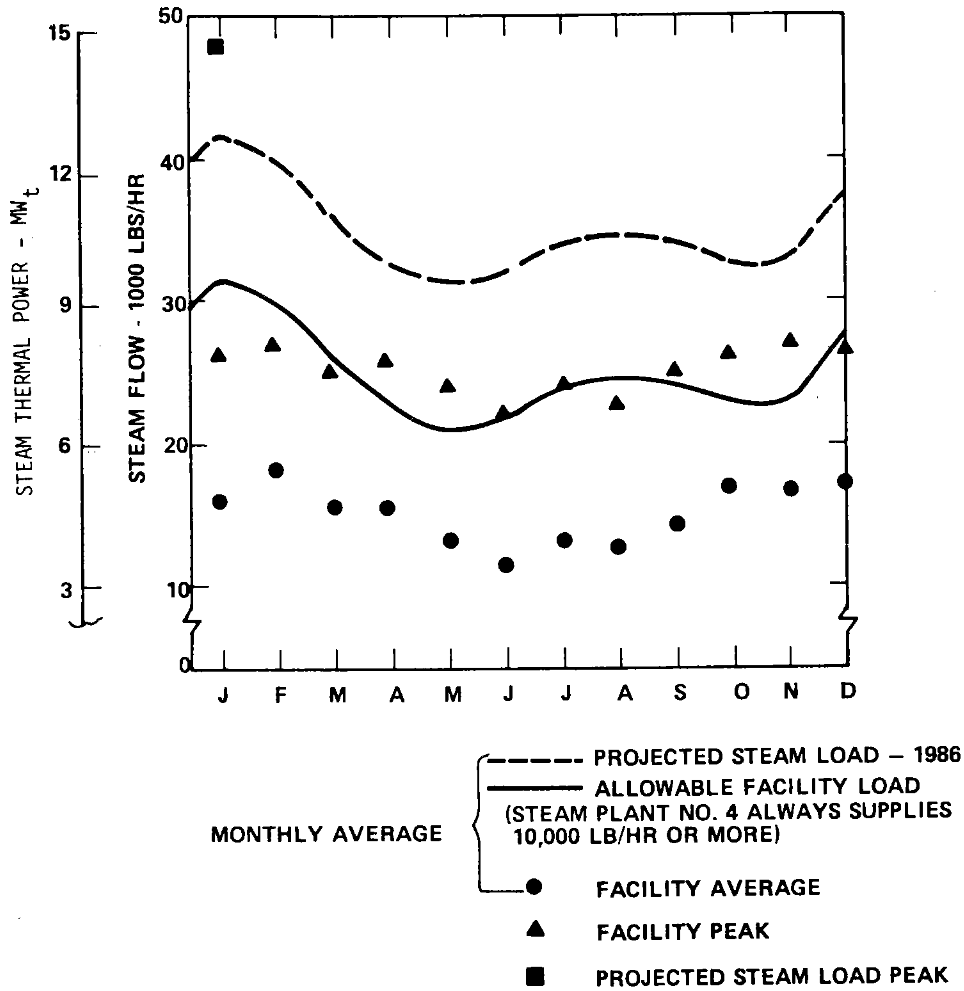

Figure 4.6-1. Existing (1979) and Projected (1986) Steam Demand Profiles

There are only a few hours during the year when the facility output would be greater than the allowable facility load. RAFBCPI (Appendix G) annual calculation indicates that only less than two percent of the total process steam that could be created would not be useable, assuming that all heliostats are available. This loss is shown in Figure 4.5-3 in the venting block.

Table 4.6-1 summarizes, for a typical good insolation day, the distribution of steam production between Steam Plant No. 4 and the cogeneration facility, as well as the net electrical production or consumption by the cogeneration facility. During the night, the entire steam demand is met by Steam Plant No. 4, while some electricity is supplied to the cogeneration facility for standby operations (500 W) and trace heating (when ambient temperature drops below 2°C (350°F) trace heaters are turned on to prevent the exposed receiver panels from freezing 15 kW is the average power consumed by these heaters). When the sun is above the 15° altitude angle, the heliostats can be brought on line, and the insolation focused on the receiver. The facility can then be brought up to temperature, and the turbine can be brought on line. The steam produced by the facility can be sent to the steam header in Steam Plant No. 4, and the fossil boilers' generation can be reduced as the facility picks up the majority of the load. At the end of the day, when the insolation is insufficient to operate the facility, the heliostats can be stowed, the facility brought into a shutdown mode, and the fossil boilers can be used to meet the load.

TABLE 4.6-1 DAILY ENERGY SUMMARY (Typical Winter Day - December 7)

Hour	Direct Insolation (W/m^2)	Steam Flow, kg/hr			Net Electrical kW
		Receiver	Demand Flow	To Meet Demand	
1	0.0	0.0	16776	0.0	-15.5
2	0.0	0.0	16776	0.0	-15.5
3	0.0	0.0	16776	0.0	-15.5
4	0.0	0.0	16776	0.0	-15.5
5	0.0	0.0	16776	0.0	-15.5
6	0.0	0.0	16776	0.0	-15.5
7	0.0	0.0	17728	0.0	-15.5
8	233.9	0.0	17728	0.0	-28.6
9	696.4	2523	17411	2331	-20.3
10	903.6	10349	17048	9475	444.0
11	956.1	12032	16867	10939	594.0
12	975.6	12921	16821	11713	674.0
13	969.7	12833	16731	11636	666.0
14	949.7	11940	16595	10859	586.0
15	891.1	10181	16413	9329	429
16	704.4	2573	16232	2381	-20.5
17	199.2	0.0	16005	0.0	-0.5
18	0.0	0.0	16776	0.0	-0.5
19	0.0	0.0	16776	0.0	-0.5
20	0.0	0.0	16776	0.0	-0.5
21	0.0	0.0	16776	0.0	-0.5
22	0.0	0.0	16776	0.0	-0.5
23	0.0	0.0	16776	0.0	-0.5
24	0.0	0.0	16776	0.0	-0.5

4.7 CAPITAL COST SUMMARY FOR PROJECT

The capital cost estimate for the RAFB Solar Cogeneration Facility is summarized in Table 4.7-1. The costs shown include the direct costs, indirect (engineering and project management) and owner's costs, but excludes one time engineering costs. The backup for calculating the direct costs for each subsystem is presented in Appendix A (System Requirements Specification). The basis for each of the costs other than direct cost is discussed in this section. A definition of cost accounts included in the direct cost estimate and described in Appendix A is presented in Table 4.7-2.

The total estimated construction and related costs for the solar facility is \$11,614,374 in 1981 dollars. This estimate is based on an assumed installed collector field cost of \$260/m^2, including foundations, field wiring, installation, and the delivered cost of collector equipment. The total cost is based on the engineering and construction schedule discussed in Section 7.0, requiring approximately 18 months of engineering overlapping 20 months of construction, and 3 months for checkout and startup, a total of 41 months.

4.7.1 DIRECT COSTS

The total direct costs estimated for this project are \$6,852,048 million. Direct costs are defined as the present day (1981) material and labor costs associated with the delivery and installation of each subsystem identified in the conceptual design.

The approach utilized to estimate direct costs involves the development of engineering data; preparation of equipment lists or descriptions of groups of equipment or subsystems; the accumulation of data for materials costs, based on similar estimates for other projects, information provided by equipment vendors, and published data; the development of estimates for labor associated with installation of each subsystem or major piece of equipment based on experience with similar installations; and the application of labor rates representative of the Warner Robins area. Figure 4.7-1 shows typical cost account boundries for the receiver and for the turbine generator.

TABLE 4.7-1: CONSTRUCTION COST ESTIMATE SUMMARY
(In 1981 Dollars)

Account/Description	
5000 Facility Cost	
5100 Site Improvements	$ 197,308
5200 Administrative Areas	$ 63,973
5300 Collector System	$3,492,163
5400 Receiver System	$1,918,871
5500 Master Control System	$ 386,000
5600 Non-Solar (Fossil) Energy System	N/A
5700 Energy Storage System	N/A
5800 Electric Power Generating System	$ 229,754
5900 Balance of Facility-Steam & Feedwater System	$ 563,979
Total Direct Cost	$6,852,048
Indirect Costs	$ 413,423
Total Direct and Indirect Costs	$7,265,471
Engineering	$1,999,160
Total Field and Office Costs	$9,264,631
Fee and G & A	$1,816,368
Georgia Power Co. Allowance*	$ 75,000
Owner's Costs	$ 458,375
Total	$11,614,374

* one time connection fee

TABLE 4.7-2: CONSTRUCTION COST CODES

Solar Cogeneration Facility Capital Investment Cost

5000 Facility Cost

- 5100 Site Improvements
  NOTE: Required land for Project to be provided by owner
  - 5110 General Site preparation (e.g., grading, water supply modifications, roads, landscaping, etc.)
- 5200 Administrative Areas (Operations, Security, Storage and Maintenance)
- 5300 Collector System
- 5400 Receiver System
- 5500 Master Control System
- 5600 Non-Solar (Fossil) Energy System (Not Applicable)
- 5700 Energy Storage System (Not Applicable)
- 5800 Electrical Power Generating System
- 5900 Balance of Facility - Steam and Feedwater System

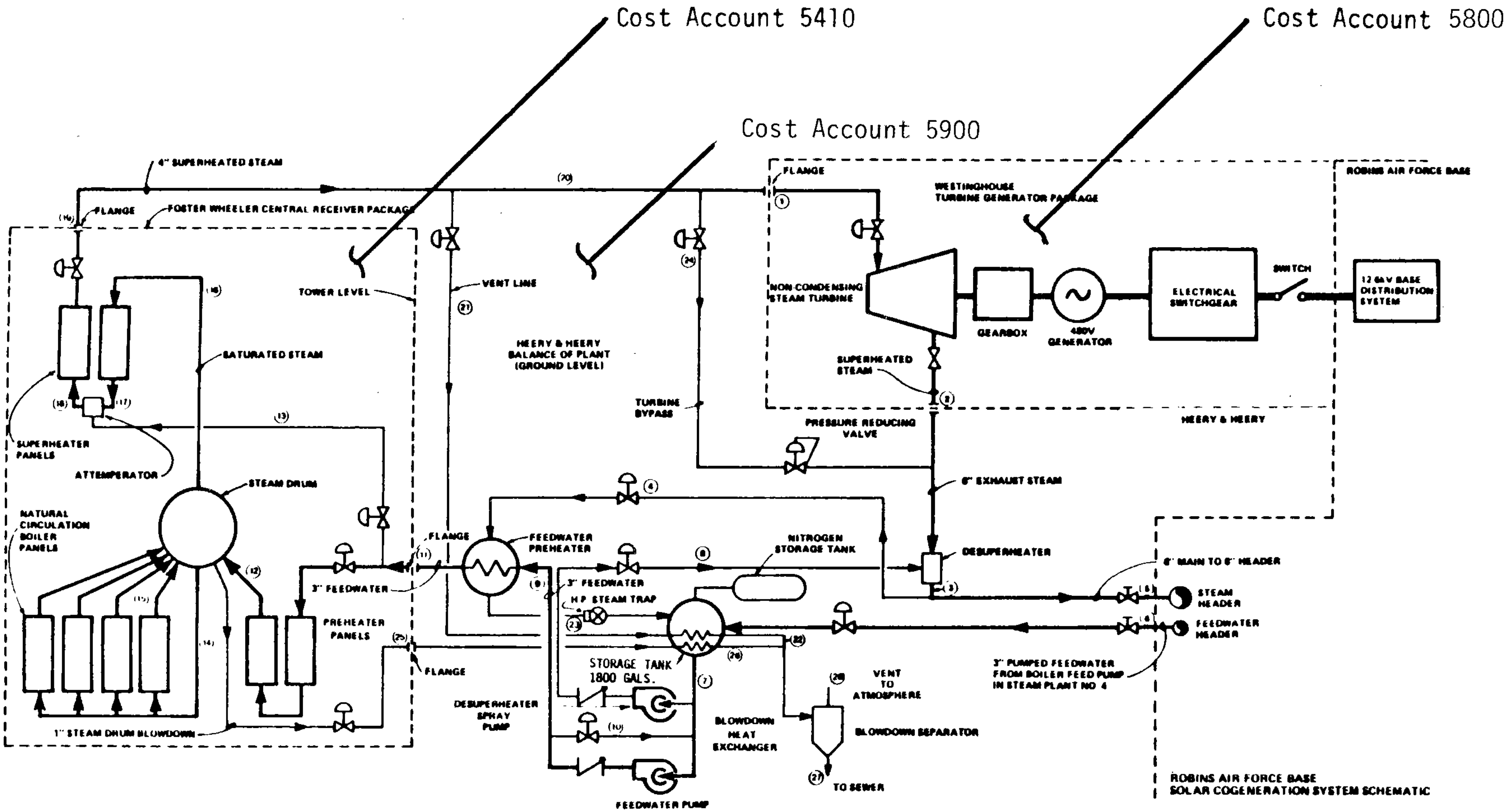

Figure 4.7-1. Cost Account Boundaries Solar Cogeneration Facility

4.7.2 INDIRECT COSTS

Indirect costs primarily include the cost of engineering and design work in support of construction. These indirect costs are estimated at 6 percent of the total direct costs. This percentage was based on estimates of engineering labor developed for most of the expected engineering and design effort. The total estimated indirect cost is approximately $2,229,791 in 1981 dollars including fee and G&A.

One time engineering costs provide for the development of detailed engineering information; preparation of drawings, equipment lists, and specifications; procurement of subcontractors and major pieces of equipment; development of detailed cost and scheduling information; and project management.

4.7.3 OWNER'S COSTS

Owner's costs estimated for this project are approximately $458,375 in 1981 dollars. A breakdown of the owner's costs is presented in Table 4.7-3.

4.8 OPERATING AND MAINTENANCE COSTS AND CONSIDERATIONS

4.8.1 GENERAL

Whenever insolation conditions are satisfactory the solar cogeneration facility is to be operational, as discussed in earlier sections of the report. This requires the facility to be aligned and prepared to accept insolation between 0700 and 1700 solar time, approximately, throughout the year.

It is intended that operational and maintenance programs for the solar cogeneration facility should supplement the existing program for Steam Plant No. 4 and be wholly integrated within an overall scheme for both facilities. Such an approach will maximize the utilization efficiency of the combined facility and minimize the additional cost of operational and maintenance functions.

TABLE 4.7-3 OWNER'S COST SUMMARY
(1981 Dollars)

a.	Land and land rights and cost of Right of Ways; 15.5 acres $3250/acre:	$50,375
b.	Landscaping to rework areas surrounding site:	$10,000
c.	Relocation of fourteenth tee of golf course:	$15,000
d.	Traffic studies related to closing off 7th streets:	$5,000
e.	Archaeological search for artifacts, if required:	$5,000
f.	Other environmental studies required for permits:	$10,000
g.	Public relations activities (both local and regional):	$5,000
h.	Coordination of installation of piping connections in Steam Plant No. 4 and any utility relocations:	$10,000
i.	Owner's managerial, engineering, accounting, labor relations, general services, estimating, planning, coordination and other base services directly related to the project:	$20,000
j.	Cost for RAFB EMCS:	$4,000
k.	Present value of Building No. 760 Band Building:	$154,000
l.	Miscellaneous, e.g. gate access control communication, relocation of outdoor use of land area displaced by tower and power building)	$40,000
m.	Repair deaereator and chemical treatment of boiler water.	$130,000
	TOTAL:	$458,375

Steam Plant No. 4 operates continuously and is currently manned on a three shift system. Each shift has two boiler plant operators on duty and the hours are arranged from 0000-0800, 0800-1600, 1600-2400. A maintenance crew for mechanical activities is attached to the plant and normally works from 0730-1615 each day. Electrical and instrument control technicians are available from support departments on base as needed.

It is recommended that the existing structure be supplemented as necessary to expand the program for an integrated operation and maintenance task.

4.8.2 OPERATIONS

The solar cogeneration facility will be manned by operational personnel continuously during the hours of effective insolation. In addition manning will be required for a period before and after the insolation period in order that start up, shut down and secure procedures can be effectively carried out. The approximate daily operational manning period will vary between 12.5 hours at summer solstice to 10.0 hours at winter solstice.

In Table 4.8-1, the operating cost category OM 100 includes the cost of wages for additional plant operating personnel, the cost of operating consumables and other fixed charges.

The number of boiler plant operators currently assigned to Steam Plant No. 4 would be increased in order that the integrated facility will be fully manned at all times. Salaries and overhead for the additional operators are estimated to be about $33,000 per year.

An allowance of $15,000 is included for supplies consumed in the solar cogeneration facility on a regular basis, such as makeup water, water treatment chemicals, cleaning supplies, paint, lubricants, etc.

Other fixed charges include items such as insurance, wastewater disposal, etc. An allowance of $12,000 is included to cover these costs.

TABLE 4.8-1

ANNUAL PLANT OPERATING AND MAINTENANCE COSTS
(IN 1981 DOLLARS)

OM 100	Operating Cost (110 + 120 + 130)			$ 60,000
	OM 110	Operating Personnel		33,000
	OM 120	Operating Consumables		15,000
	OM 130	Other Fixed Charge Rate		12,000
OM 200	Maintenance Material Cost (210 + 220 + 230)			38,198
	OM 210	Spare Parts (211 thru 215)		20,452
		OM 211	Turbine and Elec. Plant	1,628
		OM 212	Collector Equipment	13,824
		OM 213	Receiver Equipment	5,000
		OM 214	Thermal Storage Equipment	--
		OM 215	Fossil Boiler Equipment	--
	OM 220	Material for Repair		17,746
	OM 230	Other		
OM 300	Maintenance Labor Cost (310 + 320)			68,240
	OM 310	Scheduled Maintenance		34,120
	OM 320	Corrective Maintenance		34,120
		TOTAL (100 + 200 + 300)		$166,438

Total cost for OM 100 operating cost is approximately.

4.8.3 MAINTENANCE

Maintenance functions on the solar cogeneration facility will normally be carried out during periods when the facility is non-operational, that is during early morning or the evening.

Days on which no insolation is possible due to cloud cover can be utilized for maintenance functions.

For purposes of planning maintenance requirements, it is convenient to divide the equipment forming the solar cogeneration facility into four components: These are:

1. Heliostat field
2. Receiver
3. Turbine, generator and master control
4. Balance of facility.

A brief discussion of each of these components follows.

1. Heliostat field. Scheduled maintenance is limited to mirror washing, inspection of the heliostat assemblies and computer maintenance. Mirror washing is a necessity because foreign particulates degrade the mirrors reflective efficiency. Frequency of washing will be between three and twelve times per year depending upon the actual particulate density. In calculating the maintenance cost we have allowed for mirror washing to be carried out at monthly intervals.

   Inspection will be conducted annually to determine reflective surface damage, oil leaks, corrosion, vegetation growth, and other factors affecting heliostat performance.

Computer maintenance is best performed by the manufacturer under a service contract.

Unscheduled field maintenance will be initiated as a result of the field inspection and/or alarm message data on the control console. The nature of the defect will be determined and the repair technique and format adjusted to the situation (repair at site, refurbished by supplier or replaced).

Components of the heliostat system which may require maintenance on an unscheduled basis include the heliostat controller, combination heliostat field controller and heliostat controller, encoders, gear motors and drive mechanism seals. Each of these are readily accessible and can be replaced at the pedestal.

Mirror assemblies, if damaged beyond efficient reflectivity, will be removed and replaced with stocked spares at the pedestal. A stock of spare units will enable an entire heliostat to be removed and replaced in the event of severe mechanical damage.

2. Receiver. The receiver control system and operating modes proposed allow for operation with a minimum of direct operator involvement. Operating personnel can devote their attention to monitoring the system, identifying problems, and performing preventive maintenance. We anticipate that the receiver system can be run by one operator after the initial start-up and checkout phases are complete.

   Routine maintenance on the receiver should be minimal because there are few moving parts. Scheduled maintenance is expected to consist of replacing gaskets on drum manways, resetting and testing safety relief valves, and possibly performing a corrosion test. Overnight shutdown affords time for repacking and resetting of valves that can be isolated from receiver pressure. With proper feedwater conditioning, acid cleaning of the boiler will be required at intervals of not less than 3 to 5 years, based on previous experience with fossil-fueled boilers operating under similar conditions. Routine inspection of the absorptive coating on the receiver active surfaces will be made. Reprinting of these surfaces will be performed if required.

Since the receiver is similar to a fossil-fueled boiler in design,, arrangement, and materials, repairs can be made using techniques familiar to operators of conventional steam generators. Easy access is provided to the rear of the receiver and to the receiver headers and riser tubes. Access to the front is from a platform suspended from the top of the receiver structure. No special jigs, tools, or lifting devices are needed for receiver maintenance, and no unusual skills are required of the maintenance personnel--only the usual skills of machinists, welders, pipefitters, riggers, electricians, and technicians on the staff of the facility.

3. Turbine, generator and master control. The turbine/generator has a high reliability and will not normally require, at intervals of less than 10 years, any major maintenance involving removal/replacement of rotor, buckets, diaphragms, bearings, seals, valve or governing mechanisms. Such major maintenance, if needed, should be performed under the supervision of the manufacturer's representative.

   The routine inspection and maintenance for the turbine generator consist of the following items:

   - Inspect and clean, if necessary, the steam inlet strainer after the first day and first week of operation and annually therafter
   - Clean and lubricate external pivots of governor system; replenish lubricant in lever system bearings once per month
   - Check oil level in hydraulic governor system once per month
   - Check out over-speed trip on the turbine once per month; clean and lubricate, if required, outside moving parts of over-speed trip control

- Test oil neutralization number, flash point, viscosity, etc. (every six months)

- Maintain oil levels, as required, in turbine bearing reservoir, speed reducer gear box, generator bearing reservoir (if required)

The master control maintenance shall be covered by a service contract for the computer equipment. All instrumentation equipment including cabling and connectors will be periodically inspected. Any unsatisfactory conditions would be subject to immediate maintenance. Each instrumentation and control item or channel will be periodically recalibrated.

4. Balance of facility. The equipment to be installed in the solar plant building is of similar type to the conventional equipment installed in Steam Plant No. 4, and comprises pumping units, heat exchangers, pneumatically operated control valves and manually operated valves. Much of the equipment operates at higher pressure and temperatures than the integrated conventional steam plant, but the skills required of maintenance personnel are the norm for staff engaged in power plant operation. The manufacturers of the individual components will be required to provide detailed maintenance recommendations for the equipment supplied to the project, which will be incorporated into the plant schedules.

Maintenance material and labor costs are also contained in Table 4.8-1 under headings OM 200 and OM 300. Each of the four categories was considered separately.

Heliostat annual maintenance and estimated repair costs were based upon the criteria contained in Detailed Design Report MCR-80-1396A entitled "Second Generation Heliostat Development." This indicates that maintenance and repair costs calculated from statistical reliability, actual life and test data amount to 0.91 percent of the installed cost of heliostat equipment, or $31,775.

Receiver maintenance and repair cost is assumed to be $58,240.

Maintenance and repair costs for turbine generator and master control gear are $9,375.

Estimated maintenance and repair costs for the balance of facility are based upon judgement and experience of historical costs associated with similar equipment in steam raising plants. An allowance has been made for adding additional craftsmen to the existing maintenance crew and the cost of their salaries and overheads has been apportioned between heliostat and balance of facility equipment. An allowance for replacement spare parts for each item of equipment is included in OM 220. This element is based upon specific recommendations by manufacturers of the equipment envisaged for this application.

Except as outlined above, cost distribution per O&M accounts has been carried out utilizing the following assumptions.

60/40 material/labor split for all maintenance.

50/50 split between OM 210 (spare parts) and OM 220 (material for repairs).

No items appylying to OM 230 (other).

50/50 split between scheduled and corrective labor in OM 300.

Total annual maintenance material and labor cost is approximately $166,438.

4.8.4 EXTENDED LIFE CYCLE OF FOSSIL FUEL BOILER

Steam generated by the solar cogeneration facility which is distributed through the system currently served by Steam Plant Number 4 will correspondingly reduce the steam demand upon the fossil fuelled boilers. (Currently boiler numbers 2 and 3 operate for approximately 90 percent of the time partly at full capacity.) The reduction in demand will extend the life cycle of these boilers by approximately 10 percent by reducing the hours operated at full capacity. Each is rated at 24,000 lbs. per hour and has an expected life of 25 years. The estimated cost of each boiler is $240,000.

Cost savings per year from reduced operation of two boilers is, therefore, $240,000 x 10% x 2 divided by 25 = $1,920 per year.

4.9 SUPPORTING FACILITY AND SYSTEM ANALYSES

In the development of a conceptual design for the RAFB Solar Cogeneration Facility, several supporting facility and system analyses have been initiated or performed. Some of these efforts to support the design have only been completed to the preliminary assessment stage. In these cases, the additional efforts to be accomplished during the Preliminary and Detailed Design and Construction Phases of the project have been considered and/or identified.

Presented in Section 4.9.1 are discussions of the Safety Considerations for this facility. This section covers the normal, industrial type Health and Safety aspects during the construction, checkout and operation of the facility (Subsection 4.9.1.1). Also included in Section 4.9.1 are discussions of Facility Safety (4.9.1.2). These safety evaluations treat the major efforts which have been or will need to be considered regarding the design features and procedures unique to the operation of a solar cogeneration facility, as well as the unique safety aspects of the collector, receiver and master control systems.

Given below in Section 4.9.2, entitled Environmental Considerations, are the results of the preliminary environmental impact/benefit efforts which have been performed during the conceptual design. Also included are the planned areas of investigation which will need to be evaluated when an environmental impact estimate is prepared for the project. This estimate will also treat the environmental benefits from the operation of the facility.

A review of the Institutional, Regulatory, and Other Considerations was initiated during this conceptual design. These included the potential barriers to the construction/operation of a solar facility at Robins AFB. These considerations are presented in Section 4.9.3.

Section 4.9.4, Overall Logistic and Service Considerations, presents preliminary conceptual design information on: Reliability/Availability (Subsection 4.9.4.1), Maintainability (4.9.4.2), Producibility (4.9.4.3), Installation (4.9.4.4) and Logistic Support (Subsection 4.9.4.5).

4.9.1 SAFETY CONSIDERATIONS

A number of reports have been issued that address the safety aspects that are unique to the application of a solar central receiver power system such as this solar facility at Robins AFB. Among these are three reports that dealt with the 5 MW_t Central Receiver Test Facility (CRTF) which was constructed at the Sandia National Laboratories in Albuquerque, New Mexico.* The tower, heliostat field and control building for this test facility covers approximately 40,470 m^2 (10 acres) of land. The height of the tower is 60 meters (197 ft) and the heliostat collector field contains up to 366 heliostats. Several prototype heliostats and types of central receivers located at the top of the tower have been and are being evaluated at this facility.

Several safety aspects of this facility were discussed in the MITRE Report (Ref. 4.9-1)*. These included: a) the requirements for fire protection and b) the potential glare from the heliostat mirrors and its effect on the pilots that take off and land aircraft at the two airports that border the Sandia facility: Kirtland Air Force Base and the Albuquerque Municipal Airport. Because the CRTF heliostats are individually focused onto the receiver at the top of the tower, each one at a different angle, their effect on a pilot's

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* References

4.9-1: S. Haus, L. Duncan, P. Alkon and J. Pratt, the MITRE Corporation, "Preliminary Environmental Assessment Concerning the Construction and Operation of a 5-MW Solar Thermal Central Receiver Test Facility," MITRE Working Paper 11290, November, 1975.

4.9-2: T. D. Brumleve, Sandia National Laboratories, Livermore, "Eye Hazard and Glint Evaluation for the 5-MW_t Solar Thermal Test Facility," SAND 76-8022, May, 1977.

4.9-3: L. L. Young, III, "Solar Energy Research at Sandia Laboratories and Its Effects on Health and Safety", SAND 77-1412, October 1977.

vision was expected to be slight, similar to flying across the choppy water of a lake. The Martin-Marietta heliostat design for the CRTF consists of 25 individual facets or mirrors to produce the 37 m^2 of reflective surface and each of these facets are slightly dished and can be individually focused.

An additional consideration with regard to the air traffic in the Sandia area was the 60 meters (197 ft) tall tower. This consideration was reviewed for the Robins AFB solar cogeneration facility for two reasons: (1) the tower height for the RAFB solar facility is also 60 meters (197 ft) tall (to the center of the receiver) and (2) the CRTF is located in close proximity to the Kirtland Air Force Base (and Albuquerque International Airport) runways and therefore is directly applicable to Robins AFB. Since the CRTF tower needed to conform to FAA regulations for aircraft safety, any danger was expected to be minimal. Moreover, the tower location has been noted on the pilot's instrument approach plates (Jepson Charts for civilian aircraft and the DOD "Flight Instrument Approach Procedures and Airfield Diagrams" for militray aircraft) for Albuquerque so that all aircraft can avoid it. Some minor thermal turbulence has also been created by the heat plume (thermal convection losses from the receiver surface) rising from the tower. The combination of these three potential safety impacts (glare, obstruction and turbulence) on air traffic, particularly for small aircraft, required that consideration be given to possible modifications in the flight paths over the Sandia National Laboratories, Albuquerque area. Similar solar reflectance/ tower height/heat plume assessments will be required in the development of a solar cogeneration facility at Robins AFB. These assessments will be performed during the Design Phase of the project.

Significant efforts were performed in assessing the eye hazards and evaluating the glint aspects in the development of the 5 MW_t CRTF (Ref. 4.9-2). Potential eye hazards associated with concentrated reflected light (solar reflectance hazards) were evaluated. Specific light intensities and hazardous ranges of single and multiple coincident heliostat beams were assessed for conditions at both ground level and in the air space above the facility. The possible long-range and short-range distractive effects of reflected beams were also considered. Certain beam control modifications needed to be incorporated into the design so as to minimize the altitude at which over-flying aircraft could encounter unsafe levels and these were described. Recommendations were made in Reference 4.9-2 with respect to the 5 MW_t CRTF for further evaluation of the intensity excursions during fail-safe shutdown situations and for specific experiments which could be used to verify analytical models and to assess the distractive glint effects.

Excerpts from some of the conclusions drawn in Reference 4.9-2, along with additional specific notations which apply, in general, to a solar cogeneration facility at Robins AFB are as follows:

- With regard to the application of the 25 faceted heliostat design by Martin-Marietta at the CRTF, the reflected beam from any single heliostat with a focal length shorter than about 260 m constitutes a potential eye hazard that extends for a comparatively short distance on either side of its focal point. This hazard zone is generally confined to 20-30 meters on either side of the focal point with the shorter focal length beams being the most hazardous. Similar assessments will need to be made when one considers the potential eye hazards of the latest Second Generation Heliostat designs which are being or have been developed. For the conceptual design of the RAFB solar facility, a "Generic" Second Generation Heliostat design has been evaluated.

- Specific beam control measures needed to be incorporated as a result of possible multiple beam intensities so as to minimize the altitude at which over-flying aircraft might encounter eye hazards. These efforts were designed to effectively preclude intensities greater than one sun and thereby prevent unsafe retinal irradiances at altitudes greater than about 200 m during normal operations.

- Although, during certain types of fail-safe shutdown, the potential for momentary excursions of greater than one-sun intensity may extend to several hundred meters, these types of failures were considered to be very rare.

- Based on the Martin-Marietta cavity receiver for the CRTF, the reflected light from diffuse surfaces located in the focal zone does not appear to present a hazard except in controlled areas near the top of the tower. Further consideration of this aspect will need to be performed for the receiver design to be employed at the RAFB solar cogeneration facility, as being designed by Foster Wheeler Solar Development Corporation.

- The potential fire hazard which might exist for the shorter focal length heliostats needs to be evaluated for the conditions in which the beams might impinge on a combustible material.

A preliminary review of the safety considerations that are unique to the conceptual design of the RAFB solar cogeneration facility has been completed.

4.9.1.1 HEALTH AND SAFETY

One of the developmental aspects of the Supporting Facility and System Analyses for a solar cogeneration facility at Robins AFB is a safety evaluation on the application of a solar central receiver/heliostat collector field design for the facility. Several safety considerations are unique to a solar central receiver thermal power system design. Presented below in Subsection 4.9.1.2 are discussions of Facility Safety. That section covers those aspects of the solar facility which are unique to this application. Other health and safety considerations are relevant to normal industrial practice in the construction and operation of this facility. These health and safety aspects are discussed in this section.

In performing a review of the Health and Safety considerations for this design, several types of safety hazards have been identified. These include: solar reflectance; working fluid (steam and hot water); electrical; mechanical; maintenance; and malfunction hazards. In addition, several other potential problems have been considered in the health and safety aspects of this solar facility and these include a) the use of a 70 meter (228 ft) tall tower and receiver and the associated safety of the operating, testing and maintenance personnel in the performance of their normal functions and b) the use of guard rails and other safety hardware (e.g., designing the tower to ensure that personnel located on the tower cannot fall off from the tower).

These potentially hazardous conditions in the operation of this facility can be precluded by designing with sound engineering practices and judgement. Each of these aspects have been investigated in a preliminary nature for this solar cogeneration facility. Specific details on one of these potential normal Health and Safety hazards, namely the Working Fluid (steam and hot water) harzards, for this facility are summarized below. In most cases, possible causes for the hazardous conditions have been outlined. Some of the specific corrective actions which will be pursued to mitigate the severity or frequency of occurrence, or to eliminate the hazard entirely, have been identified. A more complete health and safety assessment of the RAFB solar cogeneration facility is planned during the Design and Construction Phases of this project. This assessment will be based on the final design of the facility as well as on the specific components selected for the facility and will include results on the electrical, mechanical, maintenance and malfunction hazards.

Prior to summarizing the results on the safety hazards and their resolution, and in developing an approach towards assessing the Health and Safety aspects of this facility, the following subjects have been considered (as discussed below): a) the objectives of the health and safety program, including the unique safety considerations for the solar facility, b) the applicable standards, codes and design guidelines and c) the definition of a recommended set of safety related categories to be utilized in the safety analyses to be performed during the Design and Construction Phases.

The conclusions drawn from a preliminary review of the health and safety considerations during the conceptual design study are: a) several hazards, causes of potential hazards and corrective actions have been identified and b) all potential problems are amenable to solution.

GENERAL SAFETY REQUIREMENTS

As delineated in Section A.3.13 of Appendix A [Robins Air Force Base Solar Cogeneration Facility Specification] the Westinghouse design team will be establishing a tailored facility safety program beginning at the start of the Design Phase and continuing throughout the Construction and Operations Phases (including the facility's 25 year service life). This safety program will establish administrative and technical means by which mishap prevention requirements and policies are planned, managed and implemented into the solar facility project. The purpose of the safety program is to identify significant mishap risks and define methods to cope effectively with those risks within project cost, schedule, performance and technical acceptability parameters.

A facility safety review board will be named to ensure, to the maximum extent practical, the inherent safety of the facility and its systems through the use of appropriate design features and qualified components. These features will be subjected to analyses to provide a thorough review of their compatibility with the maintenance, test, and operation of the facility. The design features will be reviewed to minimize the probability of safety degradation because of human error. Particular attention will be paid to the facility and systems design, as well as interfaces, to ensure detection of impending hazardous conditions in sufficient time to complete automatic or manual control actions.

The facility safety organization/review board will: a) conduct safety hazards analyses of the integrated facility and its operation, as well as the interfaces with the existing Steam Plant and electrical distribution system, including all support equipment, b) provide an assessment of the mishap risk presented by various normal and emergency operations of the facility and its interfaces for both normal and contingency conditions, and c) ensure that major subcontractors conduct appropriate analyses and provide data suitable for incorporation into the facility safety analysis program.

The above general safety requirements may need to be augmented/complemented by the performance of a Failure Modes and Effects Analysis (FMEA). This FMEA could be performed on all mechanical, thermal, hydraulic and electrical systems and components of the facility, including the heliostats and heliostat control system of the Collector System. The FMEA could be used to identify the critical failure modes that might be hazardous to life, result in injury or cause major damage to the solar facility. In coordinating the efforts of the facility safety organization/review board with the potential FMEA efforts, additional requirements for health and safety may need to be factored into the design. These requirements would be applicable to the design of the components and subsystems of the Collector, Receiver, Electrical Power Generating, Master Control System, as well as the Balance of the Facility and the steam, feed-water, and electrical interfaces.

The overall health and safety design requirements for the solar cogeneration facility are as follows:

- Implement a safety program which reviews all mechanical, thermal, hydraulic, and electrical components and subsystems and which identifies, evaluates, and either eliminates or controls all undesirable hazards with the potential to: injure personnel, visitors, or the general public; damage the facility; or cause loss of program objectives.
- The safety design cirteria shall be that no major damage, or personnel, visitor, or general public hazard should occur because of a single point failure or a single failure following an undetected failure.
- Develop a safety shutdown system capability in the Master Control System and the heliostat control system which monitors specific parameters, i.e., temperatures, pressures, and flow rates at various locations throughout the facility and the maximum flux on the receiver surface.

OBJECTIVES

Health and Safety must be considered and appropriate procedures, and design features developed and implemented during the design, construction, and operations phases of this project. Therefore, the facility must be designed to fulfill the following objectives:

- Protect the health and insure the safety of the general public.
- Protect the health and insure the safety of the Robins AFB civilian and military personnel and visitors to the solar cogeneration facility.
- Protect the health and insure the safety of the construction, testing, operating, and maintenance personnel for the facility.
- Protect the health and/or insure the safety of the living environment (birds, animals, other wildlife, trees, shrubs, grass, etc.).
- Maintain the quality of the natural environment by minimizing or eliminating the pollution or contamination of the surrounding land, water, and air.

The first three objectives deal directly with health and safety and will be the primary goals of this effort. The last two objectives (environmental health, safety, and quality) deal indirectly with health and safety. Any impacts to the quality (or health and safety) of the natural (or living) environment identified will need to be evaluated further as part of the environmental assessment. The above criteria, possibly complemented by others yet to be identified, will be the Health and Safety objectives in future phases of this solar cogeneration facility project.

DESIGN GUIDELINES

Numerous standards and codes, laws and regulations, design guidelines and requirements, and other publications and documents are applicable to the industrial type Health and Safety and the unique Solar Facility Safety aspects of a solar cogeneration facility at Robins AFB. Several of these design guidelines are delineated in Section A.2.0, References, of the Robins AFB Facility Specification (Appendix A). Additional design guideline/requirement references for health and safety are being considered for inclusion in the Facility Specification. These additional references (which have not been cited in this final report or in Appendix A) will be reviewed and evaluated during the Design Phase to determine which ones are directly applicable to this solar facility. Special attention will be devoted to the design and operation of the Collector System and the receiver because of their relatively less mature technologies.

The design and operation of the Electrical Power Generating System, the Balance of the Facility, and the Master Control System and the design of the tower and the interfacing components will be based on more mature technology. Accordingly, the applicable codes, standards, regulations, etc. now available for these components and systems will be complied with during the Design, Construction and Operations Phases. These same codes and standards, appropriately applied, will serve to insure a safe design of the Collector System and the receiver.

During the design phase, the Westinghouse team plans to review and utilize, where appropriate, the safety assessments/analyses which have been performed by other solar central receiver design contractors. These include the industrial contractors for the Solar Hybrid Repowering and Solar Cogeneration Facility Conceptual Design Projects which have been (or are being) completed. In addition, the safety assessments performed for the Solar Total Energy -- Large Scale Experiment Nos. 1 and 2 (for Fort Hood and Shenandoah) will be reviewed to insure that all of the design criteria and safety analyses previously documented on various types of solar hazards have been considered. Extensive expertise has been developed on the safety of various solar systems by individuals at the Sandia National Laboratories, Albuquerque and the Sandia National Laboratories, Livermore. Those efforts will be reviewed and incorporated, where appropriate, into the safety analyses for the Robins AFB solar facility. Finally, several safety analyses/assessments have been (or are being) completed for the 5 MW_t CRTF in Albuquerque and the 10 MW_e Central Receiver Pilot Plant near Barstow, CA and these will be factored into the design.

Several Sandia National Laboratories, Albuquerque and contractor reports on collectors, test facilities, total energy systems, solar irrigation and technology development and testing have been issued over the past several years. These programs include the Solar Total Energy System Test Facility (STESTF) and Solar Collector Module Test Facility at the Sandia National Laboratories, Albuquerque, the Solar Irrigation Projects near Willard, New Mexico and Coolidge, Arizona, and supportive technology development and testing at Sandia National Laboratories, Albuquerque . The field experience gained in the parabolic trough area, although not directly applicable to the heliostat Collector System and Central Receiver Solar Thermal Power System area, will provide additional background information and knowledge for the design of the solar cogeneration facility.

All of the above mentioned standards, codes, design guidelines, etc. will be utilized as the controlling design, health, safety and solar facility safety guidelines and requirements during future phases of the RAFB solar cogeneration facility project, as appropriate.

SAFETY HAZARD CATEGORY DEFINITIONS

The conventional definitions by which possible hazardous conditions will be categorized for severity during the design phase of this project are as follows:

- Category I - Safety Catastrophic. Condition(s) such that environment, personnel error, design characteristics, procedural deficiencies, or system or component malfunction will cause death or multiple injuries to personnel
- Category II - Safety Critical. Condition(s) such that environment, personnel error, design characteristics, procedural deficiencies, or system or component malfunction will cause major personnel injury, or will result in a hazard requiring immediate action to preclude major personnel injury
- Category III - Safety Marginal. Condition(s) such that environment, personnel error, design characteristics, procedural deficiencies, or system or component malfunction will cause minor injuries to personnel
- Category IV - Safety Negligible. Condition(s) such that environment, personnel error, design characteristics, procedural deficiencies, or system or component malfunction will probably not cause personnel injury

WORKING FLUID HAZARDS

The working fluids to be used in the solar facility are a) the high temperature and high pressure [6.14 MPa (890 psia)/410°C (770°F)] steam being supplied from the receiver to the steam turbine of the Electrical Power Generating System (EPGS), b) the process steam discharged from the turbine at a lower temperature and pressure, as it is transported through the piping and components of the Balance of the Facility to the steam header in Steam Plant No. 4 and c) the hot water transported from the feedwater header in Steam Plant No. 4 through various components of the feedwater system of the Balance of the Facility. The potential hazards associated with each of these fluids are discussed below.

High temperature/high pressure and intermediate temperature/intermediate pressure steam is generated/transported/utilized in various components and piping from the receiver, through the turbine and on to the steam header in Steam Plant No. 4. The maximum pressure of the feedwater at the feedwater pump exit is 8.58 MPa (1245 psia).

A few steam and hot water hazards are associated with the piping; the preheater, boiler, and superheater in the receiver; and the turbine, pumps and other components of the facility. These hazards are easily controlled based on mature technology, since several codes and standards are now available for the use of steam and hot water at these conditions. Thus, the piping and associated components will be designed to fulfill the appropriate standards and codes which pertain to the use of steam and hot water and to pressurized components and systems of the facility mentioned above under Design Guidelines.

Based on the above, several different types of hazards exist with the use of steam and hot water in the facility. A burn hazard (scalding) could exist if personnel were to come into direct contact with steam or hot water which has leaked, sprayed, or spilled from the facility. This leakage or spillage could result from the rupture of components or piping or from the relatively normal leakage around glands, rotary shafts, at the pumps, etc.

Another potential hot water burn type hazard exists when personnel could come into direct contact with exposed steam and hot water piping and components [up to $\sim$ 410°C (770°F)]. Since steam is used throughout the existing Robins AFB distribution systems and extensive experience in the normal use of steam is available, these steam and hot water hazards are not considered to be extraordinary. Moreover, thermal insulation will be used to minimize the potential for direct contact with piping and/or components of the steam and hot water systems.

4.9.1.2 FACILITY SAFETY

This section reviews the unique safety considerations/hazards associated with locating a solar cogeneration facility near the existing Steam Plant No. 4 on Robins AFB. These "solar" hazards are primarily related to the use of a tall central receiver tower and a large heliostat collector field. Specific restrictions are imposed by FAA regulations on the construction of a tall (receiver) tower. The heliostat collector field poses a significant safety consideration with respect to both the general public and to the operating personnel, when one considers the potential solar reflectance hazards resulting from the operation of the facility.

UNIQUE SAFETY CONSIDERATIONS

Several unique safety considerations for the design, construction, and operation of the solar cogeneration facility have been reviewed with the engineers and personnel from Robins Air Force Base. These safety aspects in the application of a solar facility at Robins AFB have included the following: a) a review of the traffic patterns for the Air Force and military aircraft which take off from and land at Robins Air Force Base and the associated proximity of these traffic patterns to the solar cogeneration facility site, b) a review of the safety activities which were performed by the Air Force flight safety officer at Kirtland Air Force Base in Albuquerque, New Mexico during his earlier assessments of flight safety and commercial air traffic safety at the Albuquerque Airport/Kirtland Air Force Base with respect to the 5 MW_t Central Receiver Test Facility (CRTF), and c) the relationship between the air traffic patterns at Robins AFB, the location of the receiver tower for the solar facility and the locations and heights of the two water towers which are located on Robins AFB.

The runways at Robins AFB are Runway 32 for landing or taking off in a northwesterly direction and Runway 14 for landing and taking off in a southeasterly direction (see Figure 1.4-2). The receiver and tower for the solar facility will be located $\sim$ 2600 meters (8530 ft), at an angle of 198 degrees clockwise from due north, from the southeast end of Runway 32.

The two water towers on Robins AFB are located closer to the northwest/southeast runway centerline extension (flight path) for the Air Force Base. Hence, these water towers will be much more visible to the Air Force pilots in their flight patterns near the Base. The height of the water tower closest to the runway is 48 meters (157 ft) above ground elevation and this tower is located southwest of the touchdown (landing) point (numerals 32) for Runway 32. This water tower is approximately 1160 meters (3800 ft) from the touchdown point on Runway 32. The other water tower located on Robins AFB has a height of 45 meters (148 ft) above ground elevation. The ground elevations of these two towers are close to the elevation of the receiver tower for the solar facility. The height of the top of the tower for the solar facility is 69.3 meters (227 ft), which is only $\sim$ 21 meters (70 ft) taller than one of the water towers. Thus, the Westinghouse design team and the Robins AFB Civil Engineering Squadron, Safety and Flight Safety personnel have determined that the close proximity of the solar receiver tower and its height are of no concern for the takeoff and landing of Air Force aircraft at Robins AFB.

The landing and takeoff patterns from Runway 32 and Runway 14 have been reviewed. The landing pattern is such that all aircraft (other than light aircraft, such as those used by the local flying [Aero] club, or helicopters) which arrive at Robins AFB (when not performing a "straight in" approach) complete their upwind/crosswind leg, downwind leg, and base leg of their approach patterns to insure that their aircraft are never flying over the main residential area of Robins AFB. This means that aircraft which are landing on Runway 14 (in a southeasterly direction) will perform a "left hand" traffic pattern, i.e., their aircraft will fly over the nonresidential area at Robins AFB (northeast of the field - see Figure 1.4-2). For runway 32, a "right hand" traffic pattern is followed, which again precludes their flying directly over the major portions of the facilities and residences at Robins AFB. In light of the above and since the proposed receiver/tower for the solar facility is located southwest of the runway and near the residential area, all aircraft will have no reason to be anywhere near the solar tower or the above mentioned water towers. All light aircraft, such as those used by the local flying (Aero) club, and all helicopters traffic patterns are to be revised, as discussed in Section 4.9.3 below.

Additional discussions (and coordination efforts) were held (performed) as part of the conceptual design of the solar facility, both in person and via other communications, with Robins AFB cognizant personnel. These discussions were focused on the normal health and safety, flight safety and unique safety aspects of the solar cogeneration facility. The Westinghouse design team and the appropriate Robins AFB personnel have determined that they envision no significant safety impacts from the design, construction and operation of the solar facility at the proposed location on Robins AFB.

SOLAR REFLECTANCE HAZARDS

Several different hazardous conditions could result from the effects of concentrated solar insolation or reflectance from individual or multiple heliostats in the Collector System. Thus, a potential safety hazard associated with the solar cogeneration facility site could stem from emergency or accidential misdirected solar radiation. This invisible concentrated and focused solar radiation can potentially cause fires and burns as well as create glare problems. At the focal point, there is a concentrated beam of focused radiation. Beyond the focal point, this beam becomes increasingly dispersed and eventually becomes more diffuse than the original solar radiation. Thus, there is a range around the focal point where the beam is concentrated to a degree to present potential safety hazards. These include potential fires, burns, and glare.

A potentially severe eye hazard exists for those personnel located near the focal point of several heliostats during periods of sunshine. Depending upon the concentration ratio for these heliostats and the eye location, temporary "flash" blindness or permanent blindness (from the burn damage to the choroid and retina of the eye) could occur. A glare hazard may also exist when personnel are located in or near the collector field. As discussed above, a glint or glare hazard is also a safety consideration to the general public outside and above the boundaries of the solar cogeneration facility, e.g., along Robins Parkway ("E" Street) and "B" Street.

The skin hazard (concentrated sunburn) is also a consideration for the design of this solar cogeneration facility. Although the above-mentioned eye hazard is more critical, serious burns from concentrated insolation (reflectance) could occur near the focal point. However, multiple sun intensities would be sufficiently uncomfortable on the skin that evasive action would probably be taken immediately. Skin or eye hazards to the living environment, like that to a bird flying at or near the focal point of the heliostats for the Collector System, is an additional consideration. While not as hazardous as burns or fire, glare is a potential problem resulting form misaligned or even properly aligned heliostats. This is due to its ability to impact both on-site and off-site receptors as well as those in overflying military or civilian aircraft. The intensity of this glare will be a function of the distance of the receptor from the heliostat field or individual heliostats producing the glare. As this distance increases, the intensity of the glare decreases.

Nuisance glare and glint caused by reflected sunlight from the heliostats may affect nearby residents; Air Force, helicopter, and small aircraft pilots and passengers; and pedestrians or vehicular traffic near the solar facility. Several studies have been conducted previously which describe the potential environmental and safety hazards that exist for solar central receiver facilities. One of the safety considerations most frequently cited is variously termed distractive glint, nuisance glare, misdirected light, or spurious reflections. These can result from normal operation of the facility, from misaligned heliostats, or during mirror washing operations. The impact can range from nuisance glare and temporary blindness to serious skin burns and permanent eye damage, depending on the proximity and length of exposure. The occurence of these impacts will depend upon the proximity of the field to residences and traffic corridors, upon the terrain, and upon the presence of other structures within the line of sight, as well as the orientation of the heliostats. Several mitigating measures can be taken when proven necessary that will eliminate or reduce these potential hazards or annoyances. For example fencing or vegetative screening can be used to surround the heliostat collector field to prevent nuisance glare or glint to residents and motorists.

Potential safety hazards exist for Air Force and other aircraft pilots and Air Force or airline passengers due to glint and glare from the heliostats and the 70 meters (228 ft) height of the receiver and tower. Several evaluations of flight paths, aircraft altitudes, types and sizes of aircraft, and air traffic volumes near the site of the solar facility at Robins AFB have been made to determine the probability and severity of these potential impacts. Control measures to protect pilots and air travelers from glint include the use of exclusion zones for aircraft and beam control techniques. These control measures can be determined and easily resolved in cooperation with FAA authorities.

Most of the above solar reflectance hazards are of concern primarily to the construction, testing, operating, and maintenance personnel, and to the visitors, authorized or unauthorized, to the solar cogeneration facility. Techniques which might be (or are being) used in the design of the RAFB solar facility to eliminate, reduce the frequency of, or mitigate the severity of, some of these potential hazards include: the use of fencing to enclose the collector field; requiring eye protection, protective clothing, and/or gloves when working near the heliostat collector field or the receiver at the top of the tower; proper instruction of operating, testing, and maintenance personnel on the methods to avoid these hazards; proper design of the controls for the Collector System (particularly for quick and safe emergency shutdown conditions); all potentially combustible materials will be stored in places inaccessible to misdirected radiation; and the use of safety and warning devices or signs.

4.9.2 ENVIRONMENTAL CONSIDERATIONS

4.9.2.1 INTRODUCTION

Extensive environmental consideration efforts and/or the determination of the environmental impact requirements/assessments have been performed for several Solar Central Receiver Thermal Power Systems. These include environmental impact/benefit assessments and/or estimates for the 5 MW_t Central Receiver Test Facility (CRTF) in Albuquerque, N.M., and for the 10 MW_e Central

Receiver Pilot Plant near Barstow, California. In conjunction with the environmental impact assessment efforts for the Barstow Pilot Plant and other solar systems, several reports have been issued by the University of California, Los Angeles, on the environmental effects of Solar Thermal Power Systems, e.g., References 4.9-4 and 4.9-5.* As part of these environmental studies, the prior environmental/ecological conditions at the Barstow site were established. The intent was to insure that subsequent to the construction, operation, decommissioning, and disassembly of the Barstow Plant, the site will be restored to the condition in which it existed prior to breaking ground. Reference 4.9-4 documents these initial conditions for that site. Other environmental considerations and potential environmental impacts of solar central receiver systems are discussed in Reference 4.9-5.

4.9.2.2 ENVIRONMENTAL IMPACT/BENEFIT ESTIMATES

Several discussions and meetings were held with appropriate Robins AFB personnel, including individuals from the Civil Engineering Squadron, on the environmental considerations for this solar cogeneration facility. These discussions have established the methods by which the Westinghouse design team and the Air Force intend to pursue the environmental impact/benefit estimates for this facility. At the initiation of the Preliminary Design Phase for this project, Westinghouse AESD and the Air Force Logistics Command, in conjunction with Robins AFB personnel, will prepare and submit Air Force Form Nos. 813 and 814. These forms are entitled "Request for Environmental Impact Analysis" and Preliminary Environmental Survey", respectively. A.F. Form 813 will be completed by the Westinghouse AESD, the Air Force Logistics Command at Wright - Patterson Air Force Base, Ohio, and the Civil Engineering Squadron at Robins Air Force Base for study and review by the Robins AFB Environmental Protection

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* Reference 4.9-4: "Ecological Baseline Studies at the Site of the Barstow 10 MW_e Pilot Solar Thermal Power System," UCLA 12/1223, November 1979.

Reference 4.9-5: Baldwin, J. H., et. al., "Community Applications of Small Scale Solar Thermal Energy Systems," UCLA 12/1279, February 1981.

Committee. Some of the information required on this form will be completed in detail. This includes a description of the proposed action and alternatives and the purpose of and the need for the action. The essence of this action is to enable an early determination of the potential for significant environmental impact of the proposed project for management consideration in relation to overall project decisions in accordance with the National Energy Policy Act (NEPA). Partially completed copies of Air Force Forms 813 and 814 have been received from Robins AFB for our information, review, and completion. Westinghouse AESD plans to complete these forms and return them to Robins AFB for their review and action during the Design Phase of the project. After these forms are submitted, Robins AFB Civil Engineering will proceed with a preliminary environmental survey for the facility.

The above limited documentation will permit the cognizant environmental planning personnel at Robins AFB to make an early determination whether the proposed solar facility qualifies for a CATegory EXclusion (CATEX) approval condition. If not, Westinghouse AESD and Robins AFB personnel will proceed with an environmental analysis which, under the Air Force's Environmental Impact Analysis Process, will result in either a Finding Of No Significant Impact (FONSI) or an Environmental Impact Statement (EIS) requiring a complete environmental impact/benefit assessment, with the attendant Environmental Impact Statement and public hearings to ascertain whether or not the facility can be constructed and operated. It is probable that the Category Exclusion (CATEX) criteria will be fulfilled, since a few environmental benefits will be realized by the installation and operation of this facility with no known significant environmental impacts.

The conceptual design of the solar cogeneration facility has been studied to determine the potential for adverse or beneficial impacts to the surrounding environment. The preliminary environmental considerations have included a review of some of the existing environmental impact information prepared for similar solar central receiver designs and configurations. From these initial environmental impact considerations, it appears that there will be no major adverse environmental impacts resulting from the construction and operation of the facility. One beneficial impact will be the reduction in the amount of emissions released to the air as a result of the decreased consumption of natural gas/oil by Steam Plant No. 4, as the solar facility displaces part of the daytime steam loads.

The environmental impact aspects which may need to be addressed during the Design Phase include a description of the site from a environmental viewpoint, the environmental impacts of construction, and the adverse or beneficial environmental impacts of operating the facility. In the event that a complete environmental impact assessment and an Environmental Impact Statement are required, efforts will be performed to determine the biological, socioeconomic, physical, and human environment aspects in the construction and operation of the facility.

4.9.3 INSTITUTIONAL, REGULATORY AND OTHER CONSIDERATIONS

1. The local flying club and the helicopter flight approach patterns will be modified to avoid the receiver tower; RAFB will originate a directive.

2. The 14th tee of the golf course will be relocated to accommodate the heliostat field; RAFB will originate a directive.

3. Paving of the heliostat field increases the storm water run off rate from 0.85 m^3/s (30 CFS) to 2.83 m^3/s (100 CFS) under 100 year storm conditions. The run off will be collected and directed to the storm sewer.

4. The design engineers in the 2853 Civil Engineering Squadron (CES), must approve the electrical switchgear design and utility connections.

5. Georgia Power Company will require reimbursement for installation and maintenance of safety devices at their substations.

6. A Purchased Power Agreement must be contracted for between Georgia Power Company and RAFB subject to review by the Federal Energy Regulatory Commission.

4.9.4 OVERALL LOGISTIC AND SERVICE CONSIDERATIONS

4.9.4.1 RELIABILITY/AVAILABILITY

The RAFB Solar Cogeneration Facility is designed with the goal of achieving an operating life of 25 years with normal maintenance.

The Solar Cogeneration Facility will draw electrical power from the Georgia Power grid for startup, shutdown, standby and emergency conditions, as well as for process steam only operating conditions and during nightime.

Forced (unscheduled) outage rates will be kept at a minimum by:

a) Designing for reliability,

b) Assuring craftsmanship and quality in construction, assembly, and installation,

c) Maintaining the facility in accordance with a maintenance program and associated procedures to be defined and prepared during the design and construction phases,

d) Employing properly trained and experienced operating and maintenance personnel,

e) Providing an adequate stock of spare parts and assuring fast delivery from vendors of those parts not normally stocked.

4.9.4.2 MAINTAINABILITY

Maintainability has been and will be an important consideration in the selection of equipment. Accessibility, working area, and space requirements for assembly/disassembly have been considered and provided for in the layout designs. Components of the systems subject to wear, damage, and potential maintenance, such as electronic units, motors, drives, supporting wheels, gears, actuators, valves, etc. will be easily reached, serviced, or replaced. A minimum of special tools and equipment will be necessary for maintaining the facility.

4.9.4.3 PRODUCIBILITY

The design represents a mature technology which has evolved over the past several years of application and experience in solar central receiver thermal power systems. The pieces of equipment which make up the facility, including the collector system (heliostats), receiver system (receiver and tower), balance of the facility, and the control and monitoring devices of the master control system will be designed and built using conventional materials and well established design, manufacturing, and construction techniques.

4.9.4.4 INSTALLATION

Installation of the equipment, components, subsystems, and systems of the facility will be accomplished by the use of conventional techniques and tools. Also, methods and means of assuring and monitoring quality during the installation process will be devised and implemented.

4.9.4.5 LOGISTIC SUPPORT

It is recommended that the logistic support requirements of the solar cogeneration facility be integrated into the present logistics systems being utilized at RAFB. This way, the solar cogeneration facility will benefit from the inherent advantages of being part of a highly sophisticated and proven inventory control, order processing, shipping, receiving, and distribution system.

5.0 SYSTEM CHARACTERISTICS

This section describes design, functional requirements and operating characteristics which influence cost or performance for each of the following major systems.

- Collector
- Receiver/Tower
- Master Control
- Electric Power Generation
- Facility Steam and Feedwater

The actual cost estimates for construction, operation and maintenance for each of the major systems are not discussed in this section of the report, because the detail for costing is very adequately presented in Tables 4.7-1 and 4.7-3 as well as Appendix A.

5.1 COLLECTOR SYSTEM

The collector system is comprised of the heliostats, the heliostat control system and the field layout. This system was designed with 251 heliostats to provide optimum field layout consistent with the following constraints and conditions.

- land availability of 15.5 acres
- receiver tower height of 60 meters (196.8 ft) to receiver panel centerline
- shading and blocking of 6 percent at the design point
- sun position at or greater than 0.26 rad (15°) above horizon at any time of year
- heliostat performance as specified in Collector Subsystem Specification A10772 Issue D

The collector system's function is to provide the means for redirecting the direct solar energy to impinge on the receiver panel, and it functions as appropriate for all steady state modes of plant operation. This includes the capability of controlling the number of heliostats in the tracking mode so as to vary the redirected energy on the receiver between zero and the maximum achievable level with step changes no larger than ten percent of the design value of collector field output.

Heliostat orientation will be available to the Master Control System at all times. Collector field control is directed by a computer referred to as the Master Control System (MCS). This controller initiates operational mode commands to the Heliostat Field Controller(s) (HFC), addresses commands to HFC groups or individual Heliostat Controller(s) (HC), and provides a reference time base to lower tier control modules in the field.

The requirements for design and performance of individual heliostats have been established in "Collector Subsystem Specification A10772, Issue D" by Sandia National Laboratories (Livermore, California) for the Second Generation Heliostat program. The heliostats developed in that program and/or the requirements pertaining thereto will apply to the heliostats employed in this facility except as follows: 1) the performance specified in Section 3.2.1 of A10772 may be traded-off relative to this specific facility application to achieve collector system cost reductions only through coordination with and approval of the United States Air Force Logistics Command Engineering Services Division, 2) delete paragraph 3.2.2d, 3) paragraph 3.4.4 format - replace "Southern California Edison and Sandia" with United States Air Force Logistics command," 4) paragraphs 4.1 and 4.2 - change "Sandia" to "USAF Logistics Command", 5) Figure 3, page 20 - delete Beam Characterization System block, 6) Appendix 1, Environmental Conditions, entry 3.5: Earthquake - change "Seismic Zone 3 (Uniform Building Code)" to read "Seismic Zone 1 (Uniform Building Code)," and 7) Appendix 1 Section 3.6: Soil Properties - delete existing data and replace with corresponding data to be supplied with purchase order.

As designed, the collector system redirects 10.0 MW of solar energy to impinge on the receiver panel 8.78 m wide x 8.25 m high (28.8 ft x 27.1 ft) at noon winter solstice with a direct normal insolation value of 950 W/m^2.

The total construction cost of collector system including heliostats, foundations, wiring and controls is taken as $\$260/m^2$ for a total of 3,492,163 in 1981 dollars.

5.2 RECEIVER SYSTEM

The receiver system includes the support tower, the central receiver that intercepts the reflected sunlight from the heliostat field, and all of the related piping, valves and instrumentations for regulating steam and condensate flow between the central receiver and the power generation building.

5.2.1 RECEIVER TOWER

The tower supporting the central receiver will be the dominant component of the solar cogeneration facility. The structure will be approximately 54 meters (178 ft) high and will be located at the southern part of the tract of land dedicated to the solar facility.

5.2.1.1 FUNCTIONAL REQUIREMENTS

The primary function of the tower is to support the central receiver in the optimum position to collect the reflected sunlight from the heliostat field. Additionally the tower will perform several other important functions. It will provide safe access by maintenance personnel to the receiver for periodic maintenance. The tower structure will provide space for and include provisions for supporting the steam and condensate piping between the receiver and the power generation building. It also provides support for the elevator and stairwell to the receiver platform. The tower must further provide a rigid support for the receiver during periods of heavy winds or earthquake loading, and yet be sufficiently flexible to allow the unit to expand thermally while in operation.

5.2.1.2 DESIGN CONSIDERATIONS

The conceptual tower design took into consideration the worst case situations for the following five factors:

1) Wind,
2) Earthquakes,
3) Lightning,
4) Reflected solar radiation, and
5) Fire.

Wind. The maximum wind velocity under operating conditions is 13.4 m/sec (44 ft/sec); the maximum survival velocity is 40.2 m/sec (132 ft/sec). Wind velocities are measured at a height of 9.1 meters (30 ft) above ground level. While the survival wind velocity was considered as a potential governing criterion in the design of the tower, the maximum operating wind velocity was specified to guarantee that the swaying experienced by the tower from vortex shedding would be left within acceptable limits, approximately 0.12m (5 in.) during operation.

Earthquakes. The receiver tower must be designed to maintain its structural integrity in the event of an earthquake. To assure this the conceptual tower was designed around a hypothetical earthquake the magnitude of which may be expected in the vicinity of Robins Air Force Base. The middle Georgia region is categorized as Seismic Zone No. 1 by the Uniform Building Code. The earthquake requirements of the solar cogeneration facility are similar to that of an industrial plant.

Subsequent detailed design and analysis of the tower will comply with the requirements of various national building codes and standards. The maximum survival ground acceleration for both horizontal and vertical directions was to be 0.05 Gs.

Lightning. A grounding system is provided to protect the cogeneration facility against faults in electrical equipment, static electricity, and lightning. The grounding system consists of a series of deep ground wells interconnected with #4/0 AWG direct buried base copper wire. This will form an overall ground grid electrically bonding the heliostat and electrical power generating system grounding systems with the towers grounding system.

Protection of the tower from direct lightning strikes will be provided by four metal air terminals located on top of the structure. The air terminals will be directly attached to the tower framing which is connected to the grounding grid described in the previous paragraph. All equipment and metal structures will also be bonded to the ground grid system to reduce the potential for side flashing.

Reflected Solar Radiation. Because of the inherent tolerances in the individual heliostat focusing controls, the collector structure, and the tower structure, it is safe to assume that some portion of the reflected solar radiation will spill over the central receiver collector surface and fall on the surrounding structure during normal operation. The maximum flux levels resulting from the reflected radiation are not expected to exceed 35.4 kW/m^2 (11,250 Btu/h ft^2). The conceptual design has not determined the amount or duration of stray reflected radiation, but it seems reasonable to assume that some sort of protection for the tower top mounted systems will be required.

Fire. The probability of a fire at the tower is low due to a minimum of combustible materials. Typical materials which could be a source of fire include paints on the structure and lubricants for gears, winches, and the elevator.

Access to the cogeneration facility will be limited during the hours of operation. Consequently only minimal fire protection equipment will be required at the top of the tower. Fire protection needs will be adequately met with portable fire extinguishers. Adequate fire exits and egress are provided in the stairwells, landings, and catwalks in the vicinity of the receiver elevations in compliance with NFPA guidelines.

5.2.1.3 STRUCTURAL CONSIDERATIONS

The tower structure will be designed to support the platform and the receiver footprint. The receiver assembly will consist of four structural columns on a 6.1 m x 3.7 m (20 ft x 12 ft) "foot print". The loading points of 17,917 kg (39.5 KIPS) and 11,748 kg (25.9 KIPS) will be carried by structural beams at the top of the tower proper.

Openings will be provided in the platform to accommodate a Champion Hoist Co 454 kg (1000 lb) passenger-tool rack and pinion elevator with 10 hp motor, and for a stairway.

Structural rigidity will be incorporated into the tower structure to limit wind sway to 0.12 m (5 in.) on an east-west axis and 0.3 m (12 in.) on a less critical north south axis during a 13.4 m/sec (30 mph) wind. The "sail" effect will be much greater on the north-south axis.

Foster Wheeler proposes to utilize construction cranes to elevate major components. Final assembly of small parts will be done on temporary catwalks and by utilizing the elevator when ready.

No permanent hoisting equipment is integrated into the tower design, partly because the superstructure (receiver) caps the tower proper. The adjacency of the tower to a paved street will facilitate access by a RAFB (or rental) crane for future replacement of any component weighing several thousand pounds. Foster Wheeler may elect to provide a temporary winch beam to lift certain components during assembly.

The tower structure will enclose the elevator and stairway openings with structural beams in a manner that these structures form part of the membrane effect. Stair landings will occur at bracing points. The entire tower will be primed and painted.

Structural members near the top of the tower will be protected by thermal shielding to ensure against thermal degradation of strength.

5.2.1.4 ARCHITECTURAL CONSIDERATIONS

The central receiver tower will be constructed of standard shape structural steel, square in plan, of approximate dimensions 11 meters x 11 meters (36 ft x 36 ft) and 60 meters (197 ft) high to the centerline of the central receiver. Ground anchorage for the tower will be accomplished with concrete piers (steel reinforced) on concrete spread footings.

Access to the top tower level from ground level will be accomplished by both a 434 kg (1000 lb.) capacity rack and pinion personnel hoist and by an open steel stairway at the tower center.

5.2.2 CENTRAL RECEIVER

The selected receiver concept is an exposed flat-panel type, natural-circulation steam generator with separate preheater and superheater circuits. The elevation and plan views of the receiver are given in Figure 5.2-1. The whole receiver panel is positioned vertically and faces a north heliostat field.

5.2.2.1 FUNCTIONAL REQUIREMENTS

The receiver unit provides a means of transferring the incident solar radiation from the collector system into water/steam and producing superheated steam suitable for use in the Robins AFB cogeneration facility. The design life of the receiver is 25 years. Appropriate ASME boiler codes and design standards will be followed in the receiver design. All structures and supports will be designed for the anticipated dead, wind, and seismic loads.

The receiver is sized to produce 13,210 kg/h (29,130 lb/h) of superheated steam at a pressure of 6,137 kPa (890 psia) and a temperature of 410°C (770°F), with a thermal output of 8.98 MW (30.7 x 10^6 Btu/h). This thermal rating corresponds to the design point condition that is based on a direct normal insolation of 950 W/m^2 (301 Btu/h x ft^2) at noon winter solstice with 251 heliostats. The key requirements that directly guide design of the receiver are summarized in Table 5.2-1.

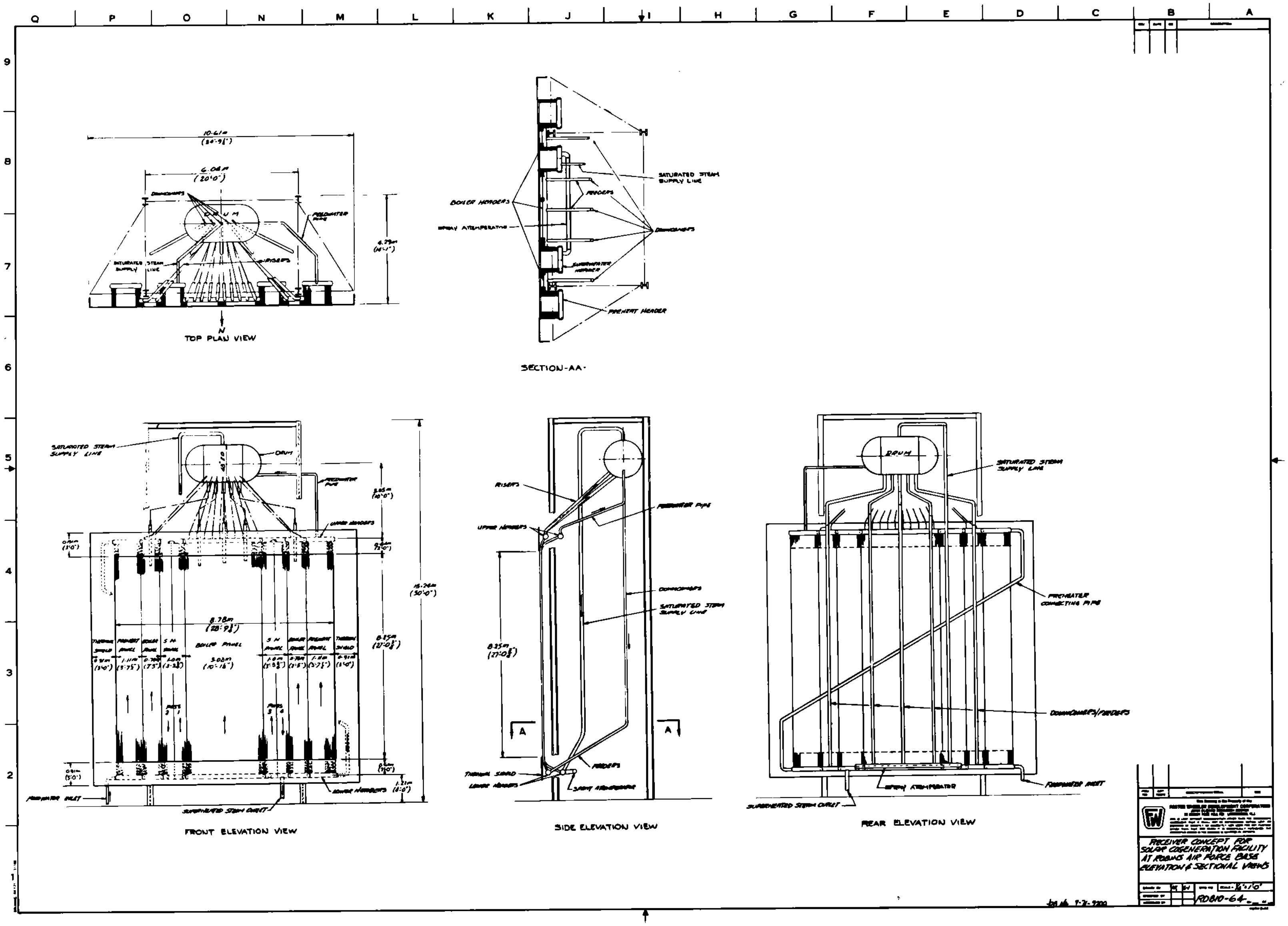

Figure 5.2-1. Elevation and Plan Views of the Receiver

Table 5.2-1: SUMMARY OF RECEIVER REQUIREMENTS

Design Point	:	Noon, Winter Solstice
Thermal Output	:	8.98 MW (30.7 x 10^6 Btu/h)
Steam Outlet Conditions		
Temperature	:	410°C (770°F)
Pressure	:	6,140 kPa (890 psia)
Flow Rate	:	13,210 kg/h (29,130 lb/h)
Feedwater Conditions		
Temperature	:	178°C (352°F)
Pressure	:	7,650 kPa (1110 psia)
Flow Rate	:	13,280 kg/h (29,280 lb/h)
Drum Operating Pressure	:	6,960 kPa (1010 psia)
Drum Continuous Blowdown	:	70 kg/h (150 lb/h)
Superheater Duty	:	1.59 MW (5.4 x 10^6 Btu/h)
Environments		
Ambient Average Temperature Range	:	3 to 33°C (37 to 91°F)
Survival Wind Speed	:	40 m/s (90 mph) at 10 m (30 ft) elevation
Seismic Zone	:	UBC Zone 1

An accurate prediction of heat flux patterns on the receiver surface, particularly the magnitude and location of peak heat fluxes, is vital to the proper design of the receiver. The maximum heat flux shall not exceed 0.69 MW/m^2 (220,000 Btu/h ft^2) for boiler panels, 0.47 MW/m^2 (150,000 Btu/h ft^2) for superheater panels, and 0.35 MW/m^2 (110,000 Btu/h ft^2) for preheater panels. The active receiver surface is 8.78 m (28.8 ft) wide by 8.25 m (27.1 ft) high. These dimensions and the heat-flux distribution maps described in Appendix C were used as bases for the conceptual design of the receiver.

The feedwater to the receiver should be of high quality to minimize the possibility of internal boiler corrosion and tube deposits. Tube deposits can lead to tube failures, particularly at the high heat-flux levels considered in this design. The concentration of impurities in the boiler water can be limited by continuous blowdown from the drum. Blowdown rate equal to 0.5 percent of output steam flow was chosen for the conceptual design. The maximum limits on critical impurities in the feedwater as well as in the boiler water are specified in Appendix A, System Specification.

5.2.2.2 DESIGN DESCRIPTION

Figure 5.2-1 shows an active receiver surface which measures 8.78 meters (28.8 ft) in width and 8.25 meters (27.1 ft) in height and it is framed by stainless steel thermal shields 0.91 meters (3 ft) wide on each side. The allocation of preheater, boiler and superheater surfaces are also illustrated is this view. The central portion of the receiver surface is lined with boiler tubes. Two superheater panels are sandwiched by this central panel and two side boiler panels. The remaining outside surface is covered by preheater panels, one on each side. All panels are made of tubes that are joined along their length by continuous-weld integral fins to form vertical flat Monowalls™. Carbon steel (SA-210 A1) tubes of 50.8 mm (2.0 in.) and 25.4 mm (1.0 in.) O.D. were selected for the boiler and preheater panels respectively, and 25.4 mm (1.0 in.) O.D. stainless steel (SA-213 TP304H) tubes for the superheater panels. A fin width of 6.4 mm (0.25 in.) was used for all tube sizes. The schematic flow diagram is shown in Figure 5.2-9.

receiver is shown in Figure 5.2-2. It consists of four support columns interconnected to form a structural-steel framework. The dimensions between the centerlines of these columns are 6.1 meters (20 ft) wide and 3.66 meters (12 ft) deep. The steam drum is hung from the top beams by U-bolt hangers. The upper headers of receiver panels are hung from the supports attached to the top front beam as shown in the top plan view of this figure. The panels are held in position and braced at the back against thermal stress and wind and seismic loads by means of buckstays that connect the panels with the support structure at different elevations. The back surfaces of the panels, as well as drum, headers and piping, are insulated to reduce thermal losses to the environment. The shaded areas shown in Figure 5.2-2 depict the enclosure arrangement for drum, risers and headers. Since the front surfaces of the panels are exposed to the ambient condition, heat tracing elements are installed at the back surfaces to keep the panels above freezing during overnight receiver shutdown. There are platforms with ladders at the top of tower and at the drum level for easy inspection and maintenance.

5.2.2.3 DESIGN AND ANALYSIS CONSIDERATIONS

a. Thermal/Hydraulic - Detailed thermal/hydraulic design and analyses were performed for the selected receiver concept. The results obtained for the key receiver components are described as follows.

   Surface Allocation - The active surface of the receiver must be correctly proportioned between superheater and boiler/preheater sections so that the designed superheater outlet conditions can be obtained. The approach to the surface allocation is summarized as follows:

   - To locate the superheater surfaces as far away from the high heat-flux zones as possible
   - To assure that the incident power absorbed by the superheater surfaces meets the duty requirement for different time points during the year
   - To check whether the remaining surfaces are adequate for natural circulation or not

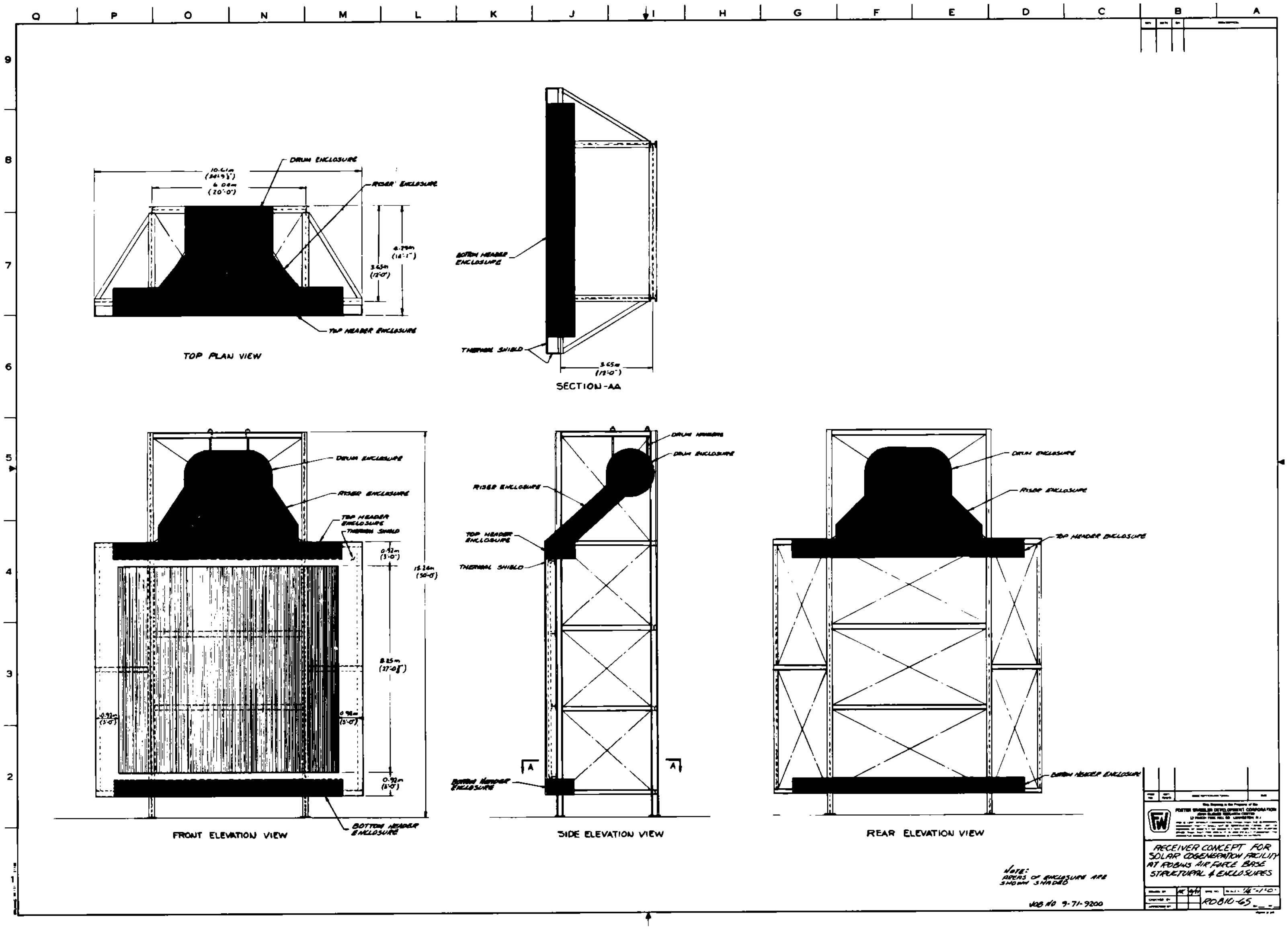

Figure 5.2-2. Structural Support and Enclosure Concept for the Receiver

- To cover the low heat absorption zones where natural circulation is difficult by preheater panels.

At the design point condition, the superheater section requires approximately 18 percent of the total thermal duty. The surface allocation selected was described in the preceding section. For this surface arrangement, the proportion of the total absorbed power by each superheater pass was calculated and the total of all superheater passes was summed up for three typical time points during the year. The results are shown in Table 5.2.2. As can be seem from this table, the superheater surface was purposely oversized to accommodate the possible power shift away from the superheater during other insolation conditions without degrading the superheater outlet temperature. The excess thermal power can be offset by spray attemperation.

Preheater - At the design point condition, preheater surfaces absorb approximately 3 percent of the total power. Feedwater is preheated from 178°C (352°F) to 196°C (384°F). The maximum heat flux falling on the preheater is 0.054 MW/m^2 (17,000 Btu/h ft^2) which is well within the allowable limit for the preheater design.

Boiler - The selected receiver concept uses the natural circulation principle. In a natural-circulation system, the rate of flow that can be produced is governed by flow resistances and differences in density between the downcomer circuits and the upward heated circuits. Control of these resistances enables the designer to apportion an adequate flow of water to parallel circuits. For the circulation analysis, the boiler section was divided into three circuits. After several repetitive calculations, during which changes were made to the number and size of tubes, downcomer/feeders and risers in the individual circuits, an acceptable arrangement was obtained. The numbers and sizes of the selected boiler circuits are given in Table 5.2-3.

Table 5.2-2 Absorbed Power Proportions on Superheater Passes

Day of year	Time of Day	% of Total Absorbed Power on Superheater Passes				
		Pass 1	Pass 2	Pass 3	Pass 4	Total
Day 172 (Summer Solstice)	0618	5.5	3.0	6.7	3.9	19.1
	0830	6.5	4.1	6.5	4.4	21.5
Day 355 (Winter Solstice)	1200	6.8	5.0	6.6	5.0	23.4

Table 5.2-3 Summary of Boiler Circuitry

Size / Circuit Description	No. of Downcomer/ Feeders	No. of Tubes	No. of Risers
	114.3 mm O.D. (4.5 in O.D.)	50.8 mm O.D. (2 in O.D.)	76.2 mm O.D. (3 in O.D.)
Central Panel	3	54	10
Side Panel, East	1	13	2
Side Panel, West	1	13	2
Total	5	80	14

The predicted boiler circulation results at the design point condition, noon winter solstice, are summarized in Table 5.2-4. The ratio of the total circulating flow rate to the total steam generating rate (overall circulation ratio) is found to be 18.3. To assess the part-load circulation performance, calculations were also made at the median and minimum operating conditions. The median condition is a representative operating point which has about 70 percent of the design-point power incident on the receiver. The minimum condition has about 21 percent of design-point power input. The steam-generating rate and the circulation ratio are presented in Figure 5.2-3 as functions of the power incident on the receiver. The velocities entering boiler tubes at the high absorption (central panel) and low absorption (side panels) regions are also shown in this figure. Evaluation of these results indicated that all circuits satisfy the circulation design criteria imposed on the entrance velocity, steam quality and absorbed heat flux.

Superheater - The selected superheater arrangement consists of four vertical passes in series with a spray attemperator located between Passes 2 and 3. Each pass is made of sixteen (16) stainless steel tubes of 25.4 mm (1.0 in) O.D. on 31.8 mm (1.25 in) centers. Temperatures of the steam and tube wall along the length were calculated for the design point heat flux conditions. In calculating these temperatures, the following heat flux conditions and flow imbalance effects were considered.

- Tube metal temperature based on the incident heat flux values
- Steam temperature based on the absorbed heat flux values
- Heat flux variation among tubes of the same pass
- Flow imbalance because of manufacturing variations in tubewall thickness (+10%, -0% on minimum wall).

The results are shown in Figure 5.2-4. The maximum mean metal temperature was based on the worst combination of heat flux and flow conditions (i.e., the highest heat flux and lowest flow among the tubes of the same pass).

TABLE 5.2-4 Boiler Circulation Characteristics at Design Point

Circuit Description	Circulating Flow kg/h (lb/h)	Velocity Entering m/s (ft/s)	Exit Quality % by Wt.	Steam Generated kg/h (lb/h)
Central Panel	170,000 (375,000)	0.82 (2.7)	6.5	11,120 (24,520)
Side Panel, East	24,950 (55,000)	0.52 (1.7)	1.8	440 (965)
Side Panel, West	24,950 (55,000)	0.52 (1.7)	1.8	440 (965)

Total Circulation Rate = 219,800 kg/h (0.485 x 10^6 lb/h)

Steam Generation Rate = 12,000 kg/h (26,450 lb/h)

Drum Pressure = 6964 kpa (1010 psia)

Overall Exit Quality, % by Wt = 5.5

Overall Circulation Ratio = 18.3

Heat Input Condition: Noon, Winter Solstice

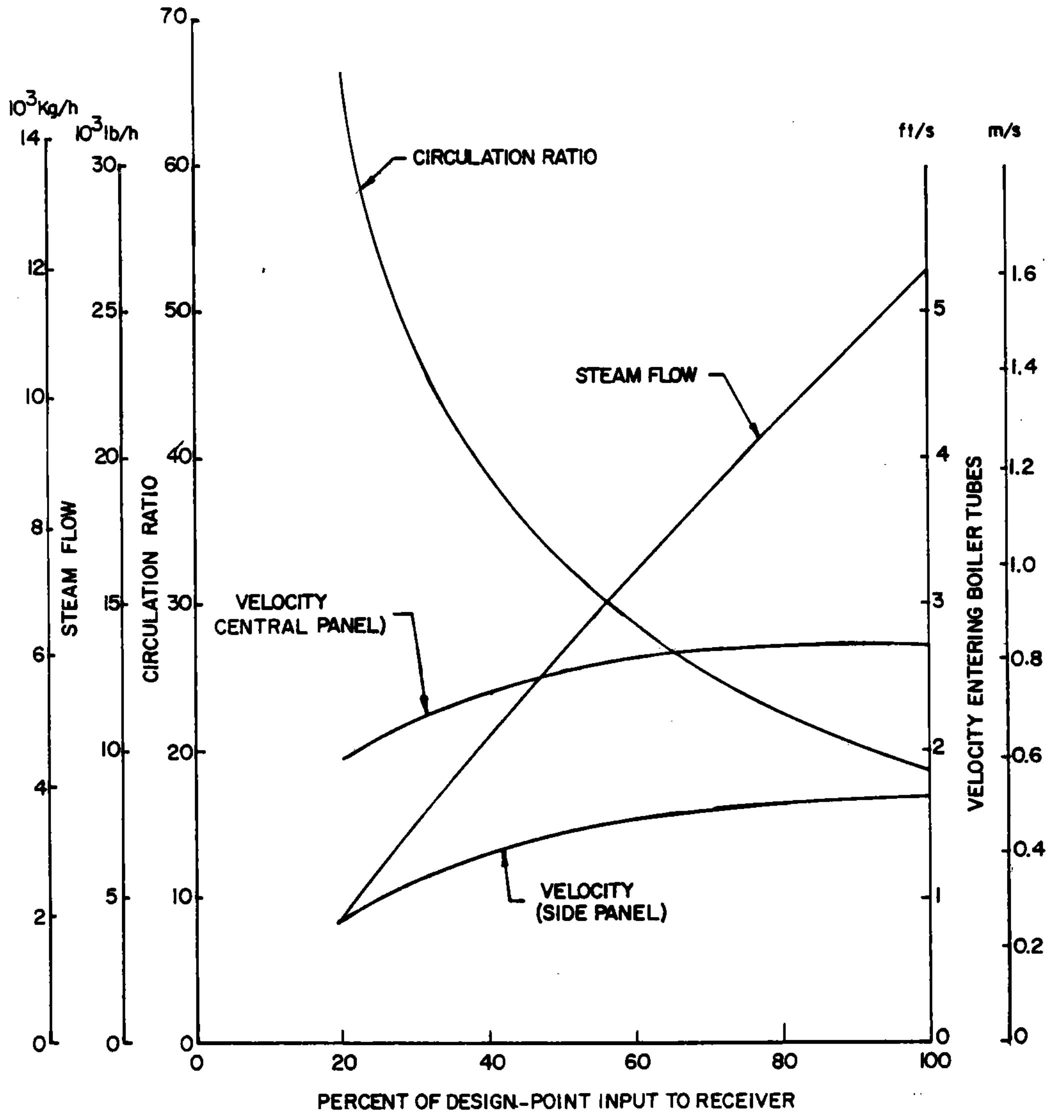

Figure 5.2-3. Boiler Circulation Characteristics at Different Heat Input Conditions

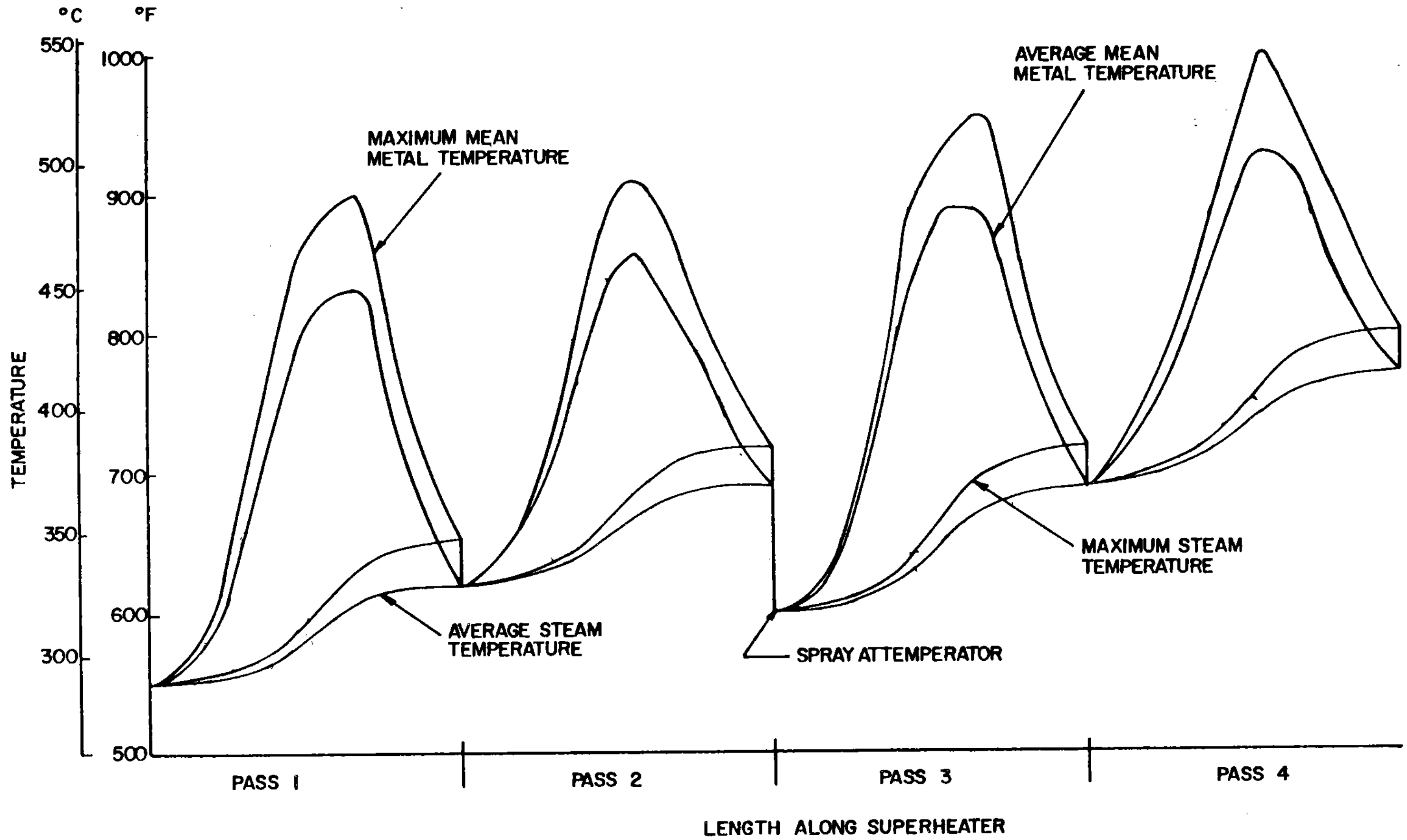

Figure 5.2-4. Tube Wall and Steam Temperature Along the Length of Superheater

The mass velocities, average heat transfer film coefficients and pressure drops for all superheater passes at the design point condition are listed in Table 5.2-5. The total pressure drop across the superheater, including those for connecting pipe and attemperator, was predicted as 827 kPa (120 psi).

b. Structural Design and Analysis - In order to ensure the structural integrity of the receiver during its 25-year lifetime, a stress analysis of the receiver components was performed. The resulting stresses and strains were evaluated using the criteria set forth in the ASME Boiler and Pressure Vessel Codes and other applicable standards.

The structural design requirements of the receiver can be placed into two categories. First is the area of concern relating to internal pressure and temperature distribution. The second refers to external influences such as wind and seismic loading.

Pressure Parts: This section describes the structural analysis and design of the receiver panels and other pressure components such as risers, feeders, downcomers, headers and the drum. The methods used in structural analysis, the computer programs, the criteria used in the evaluation and the important results are described as follows:

Applicable Codes and Standards: The requirements of the ASME Boiler and Pressure Vessel Code, Section I are fully met in the receiver design. Fatigue and creep-fatigue interactions are important failure modes in the receiver design. However, Section I has no criteria to evaluate these failure modes. Hence, Section I is supplemented by using the fatigue curves of Section VIII, Division 2 in the sub-creep regime. The evlevated temperature fatigue curves of Code Case N-47 of the ASME Boiler Code, Section III are used wherever the temperatures excced those given in Section VIII. The Interim Structural Design Standard prepared by Foster Wheeler for Sandia Laboratories (1) is also used as a guideline in this design.

Table 5.2-5 Supherheater Performance Characteristics at Design Point

Superheater Pass No.	Mass Velocity 10^6 kg/h-m^2 (10^6 lb/h-ft^2)	Heat Transfer Coefficient W/m^2°C (Btu/h-ft^2-°F)	Pressure Drop kPa (psi)
1	3.447 (0.706)	4260 (750)	152 (22)
2	3.447 (0.706)	3975 (700)	193 (28)
3	3.589 (0.735)	4145 (730)	241 (35)
4	3.589 (0.735)	4030 (710)	241 (35)

(ii) Superheater Panel: One of the critical components (in terms of structural integrity and fatigue life) in the receiver is the superheater panel. The superheater panel is composed of 25.4 mm (1.0 in.) O. D., 3.76 mm (0.148 in.) minimum wall, stainless steel (Type 304) tubes on 31.75 mm (1.25 in.) centers using Monowall^{TM} construction in which the tubes are joined together along their length by continuously welded integral fins to form a flat panel.

The temperature distribution and stress distribution were determined by using the finite element program ANSYS (2). Because of symmetry only one-half of the tube and the fin was analyzed. This half was modeled by a fine mesh consisting of 116 isoparametric elements. Generalized plane strain conditions were assumed in the tube. It has been shown that in a panel supported by multiple buckstays this model would predict the stresses accurately. Generalized plane strain analysis was done by first performing a plane strain analysis and then relaxing the axial forces at the ends. A postprocessor computer program called FINTUBE, developed by Foster Wheeler, was used to do this relaxation of end forces and to calculate the bending stresses as well as peak stresses.

The temperature and stress distributions for a typical steady state condition are shown in Figures 5.2-5 and 5.2-6. The parameters used in the analysis are as follows:

Heat Flux q = 0.366 MW/m^2 (116,000 Btu/h-ft^2)

Film Coefficient h = 3.98 kW/m^2-°C (700 Btu/h-ft^2-°F)

Thermal Conductivity k = 22.63 W/m-°C (13.08 Btu/h-ft-°F)

Fluid Temperature T_f = 343°C (650°F)

Coefficient of Thermal Expansion = 18.54 x 10^{-6}/°C (10.3 x 10^{-6}/°F)

Modulus of Elasticity E = 1.555 x 10^5 MPa (22.55 x 10^6 psi)

Poisson's Ratio = 0.3046

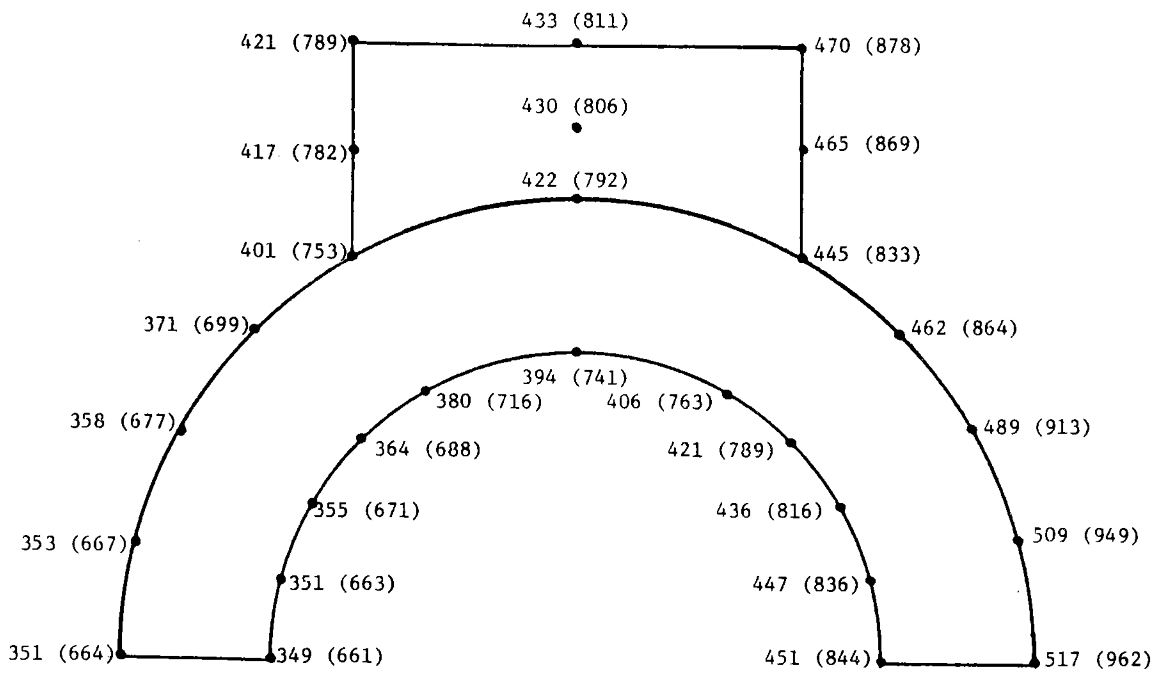

Figure 5.2-5. Typical Temperature Distributions in Superheater Tube

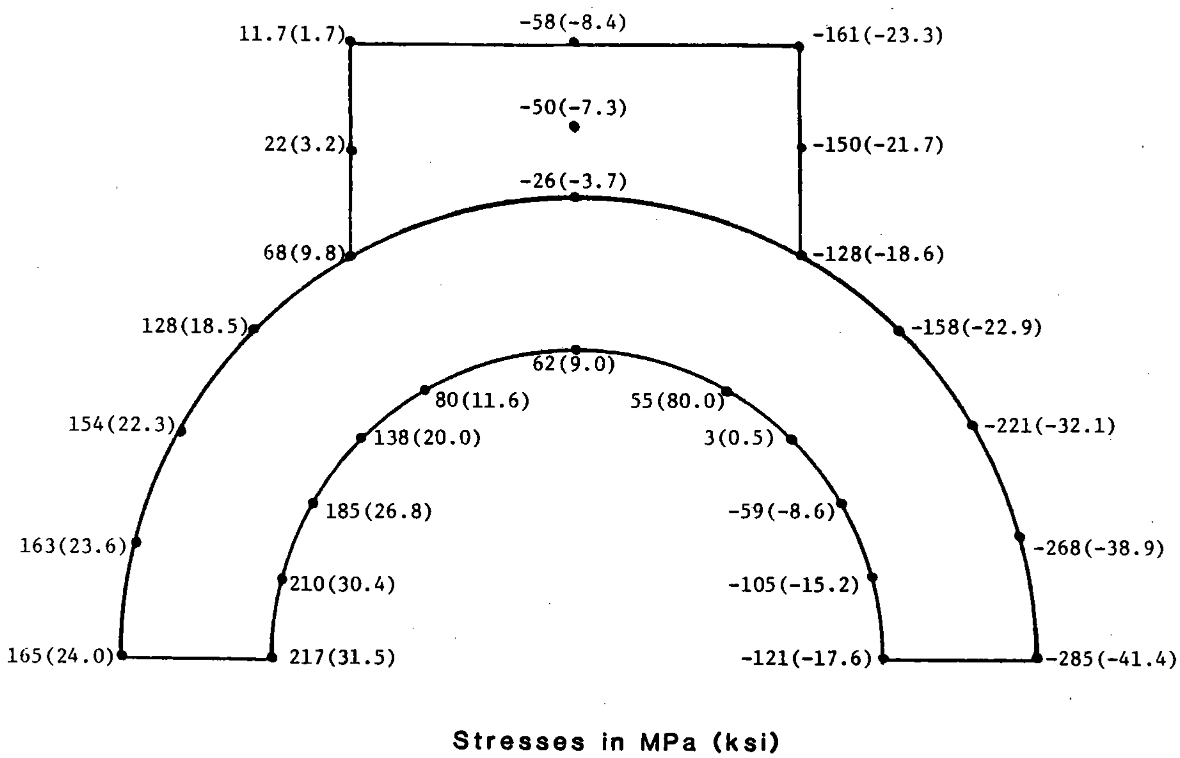

Figure 5.2-6. Typical Axial Stress Distributions in Superheater Tube

The stresses and strains obtained in this analysis were evaluated using the following criteria:

- Limit the primary stresses due to pressure to the allowable stresses given in ASME Code Section I.
- Limit the primary plus secondary stresses (thermal stresses) to twice the yield stress or 3 x S_m.
- Evaluate the fatigue life using Section VIII Division 2 for temperatures below creep range. For temperatures in the creep range use the fatigue curves of Code Case N-47.

Using this approach it was found that the superheater panels have a fatigue life of 75,000 cycles.

The receiver is assumed to undergo 10,000 diurnal startup and shutdown cycles (including cold startups) during its 25-year life. In addition, it is assumed that it will be subjected to 2,500 startup-shutdown cycles due to cloud cover. It is recognized that there may be many more cloud fluctuations which do not warrant shutdown. These fluctuations would cause stress cycling in the receiver. However, the stress excursions in these cycles would not be high and are not expected to affect the life of the receiver panels significantly in view of the considerable margin in the fatigue life (75,000 cycles). A more thorough study is required to determine the effect of cloud coverages on the receiver cycle life. It will also be necessary to develop a set of guidelines which the plant operator can use in deciding whether or not to shutdown.

(iii) Boiler Parts: Thermal stress analysis of the boiler panels was done using the finite element program ANSYS. A fatigue analysis was done using the fatigue curves of the ASME Code Section VIII Division 2. It was found that the boiler panels have a fatigue life in excess of 100,000 cycles.

(iv) Other Pressure Parts: Other pressure parts such as the downcomer, headers, feeders and risers, drum, etc. were sized according to the requirements of ASME Code Section I.

Support Structure Design: The general arrangement of the support structure is shown in Figure 5.2-2. The support structure consists of 4 columns interconnected by beams and braces. The loadings considered in the design of the support structure are as follows:

- Dead Load: For the first iteration the dead load was assumed to be 60,000 kg (132.3 kips)
- Wind Load: The survival wind speed is 40 m/s (90 mph) at a reference height of 10 meters (30 ft). The corresponding wind pressure at the centerline of the receiver is estimated as 2.16 kPa (45 psf) according to ANSI A58.1 (3). The operational wind load considered was the one corresponding to a wind speed of 6.67 m/s (15 mph) at the reference height.
- Seismic Load: Uniform Building Code Zone 1 values were used in the design.

The support structure was designed to withstand the above loads and other applicable loads such as snow, rain, ice, etc. It should be pointed out that the support structure design is somewhat preliminary and not every member was individually sized. There is room for further optimization and possible reduction in the weight of the support structure.

REFERENCES:

(1) I. Berman, et. al, "An Interim Structural Design Standard for Solar Energy Applications," Report No. SAND-79-8183, Sandia Laboratories, Livermore, April 1979.

(2) ANSYS Engineering Analysis System User's Manaul. Swanson Analysis Systems, Incorporated, 1974.

(3) ANSI A58.1-1972. Building Code Requirements for Minimum Design Loads in Building and Other Structures.

5.2.2.4 PERFORMANCE ESTIMATES

Receiver performance evaluations conducted included calculations of thermal losses at different operating conditions and estimates of receiver cooldown rates during overnight shutdown period.

a. Thermal Losses - With spillage loss accounted for separately, thermal losses from the receiver consist of reflection, reradiation, convection, and conduction. The reflection loss amounts to 5 percent of the incident energy, based on a solar absorptivity of 0.95 for the Pyromark black absorber coating. To calculate the other losses, the preheater, boiler, and superheater panels were simulated by simplified analytical models. Computer program SINDA was used to perform the calculations with the following relevant input data:

Surface absorptivity	=	0.95
Average wind velocity	=	4.7 m/s (15 ft/sec) at receiver elevation
Insulation thickness	=	102 mm (4 in)
Average ambient temperature	=	10°C (50°F)

The results for the design point (noon, winter solstice) condition are summarized in Table 5.2-6. As shown in the table, there is a total of 10.05 MW power incident on the active receiver surface and a net of 8.98 MW is absorbed by the receiver working fluid. This results in a receiver thermal efficiency (excluding spillage) of approximately 89 percent.

Calculations of thermal losses were also made for the median and minimum operating conditions. The median operating condition is a representative point which has about 7 MW of power incident on the receiver. Approximately half of the annual operating hours will have insolation greater than this point. At the minimum operating condition the incident power on receiver is about 2.15 MW. The results obtained for these two conditions along with that for the design point are shown in Figure 5.2-7. The receiver thermal efficiency (excluding spillage) decreases as the heat input to the receiver decreases. At the median and minimum operating conditions the efficiency drops to 86 percent and 69 percent respectively.

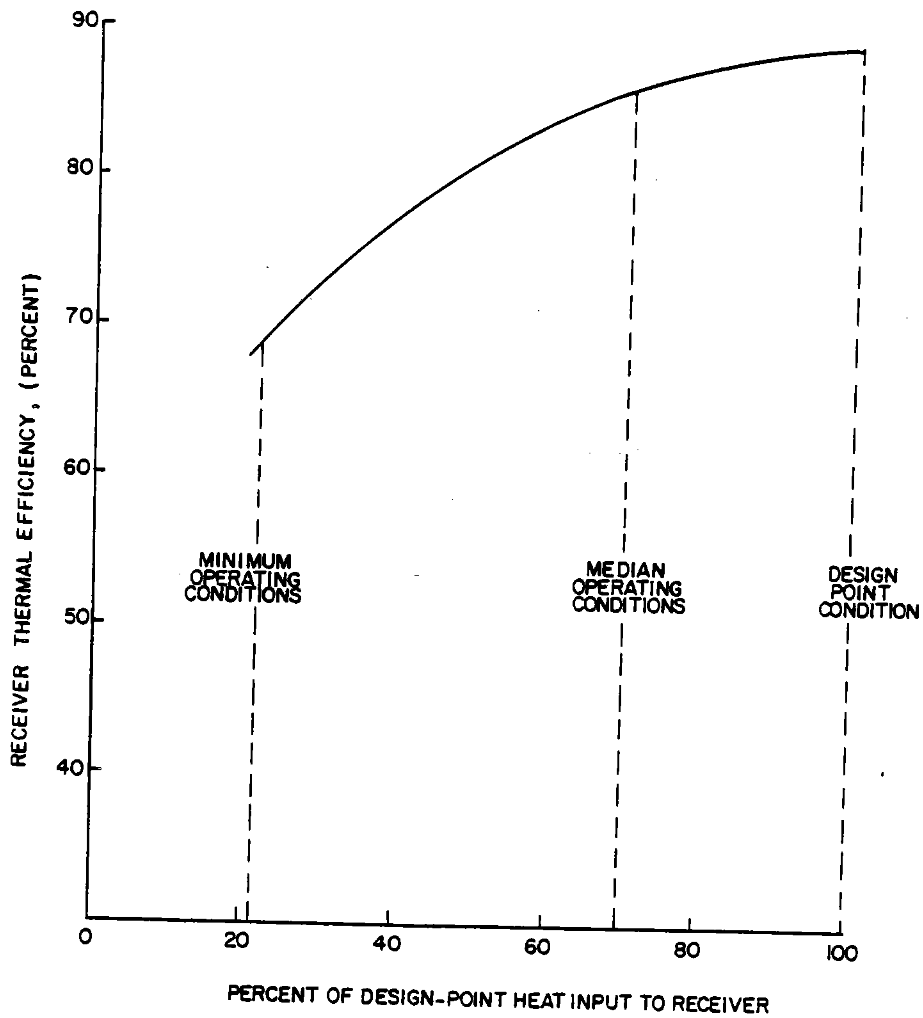

Figure 5.2-7. Receiver Thermal Efficiency at Different Heat Input Conditions

Table 5.2-6 Summary of Receiver Thermal Losses at Design Point

	Power MW	Percent of Total Incident Power
Total Incident to Active Surface	10.05	100
Loss by Reflection	0.5	5
Loss by Reradiation	0.25	2.5
Loss by Convection	0.3	3.0
Loss by Conduction	0.02	0.2
Net Absorbed by Receiver	8.98	89.3

b. <u>Overnight Cooldown</u> - The receiver pressure parts are fully insulated except the front surfaces of receiver panels are exposed to the ambient condition. To determine the overnight cooldown rate of the receiver, heat losses from the receiver components during the overnight shutdown period were estimated. Transient computer models were made to simulate the exposed tube panels and other insulated pressure parts. The following conditions were assumed for the calculation:

Wind velocity	=	4.7 m/s (15 ft/sec) at receiver elevation
Ambient temperature	=	3°C (37°F)
Initial temperature	=	188°C (370°F) for preheater panels
	=	427°C (800°F) for superheater panels
	=	288°C (550°F) for boiler panels and other pressure parts
Insulation thickness	=	102 mm (4 in.) for tubes, panels, drum, and header and piping enclosures
	=	51 mm (2 in.) for downcomers.

For a 14-hour shutdown period, the total heat loss from the receiver was estimated to be 0.73 MWh_t. The cooldown rates of the receiver components during this period are shown in Figure 5.2-8. The results indicated that the exposed receiver panels, particularly superheater and preheater panels, cool down much faster than other fully insulated pressure parts do. For the average panel temperature to drop to, for instance, 100°C (212°F), it would take superheater and preheater panels each approximately 0.3 hours and boiler panel 3.1 hours.

Heating elements are installed between the back surfaces of panels and insulation. For preliminary cost estimating, the heat tracing system was sized to maintain panel temperature above freezing during overnight shutdown.

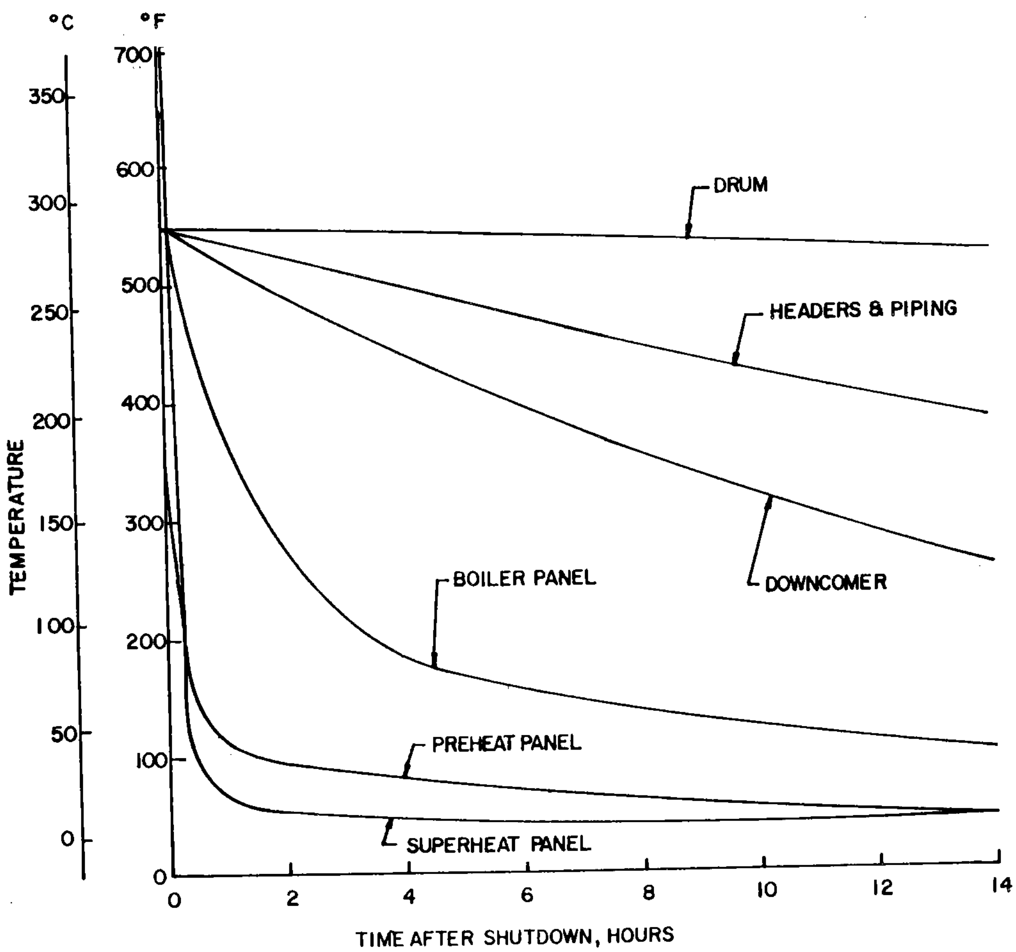

Figure 5.2-8. Overnight Cooldown Rates of Receiver Components

5.2.2.5 OPERATING AND CONTROL CHARACTERISTICS

The receiver control consists of an outlet pressure regulator, a feedwater regulator, a steam temperature regulator, and a startup flow regulator. A schematic flow diagram illustrating the essential instrumentation, valving, and controls of the receiver is shown in Figure 5.2-9.

During normal operation, receiver outlet steam pressure is regulated by the turbine inlet control valve or turbine bypass valve. The startup flow regulator is activated only during the startup periods in order to bring up drum pressure at an optimum rate. When the full superheater outlet pressure is reached, the startup control system will be deactivated and the outlet pressure will be regulated in the same manner as that during normal operation.

Feedwater flow is controlled by a conventional three-element feedwater regulator of the type used on fossil-fueled drum-type boilers. This regulator is responsive to drum water level, steam flow and feedwater flow. Through the control logic, the steam flow signal is algebraically summed with the feedwater flow signal. The difference between the flows is used as a feed-forward signal through a proportioning level controller to regulate the feedwater supply valve in anticipation of drum-level variations. A signal from the drum-level transmitter also feeds into the level controller, where it is compared with the drum level set point to generate a signal that causes the level controller to modulate the feedwater valve and restore drum level to the set point. The modulation of the feedwater valve, resulting from combined effects of level and flow signals, maintains a constant drum level during wide and rapid load changes.

The superheater outlet steam temperature is controlled by an attemperator located between superheater passes 2 and 3. In the attemperator, feedwater is sprayed into the superheated steam and evaporated, thus lowering the steam temperature. The control logic in the steam temperature regulator adjusts and monitors the spray flow to achieve the desired superheater outlet temperature. Pressure sensed at the outlet of the attemperator is used in the control logic

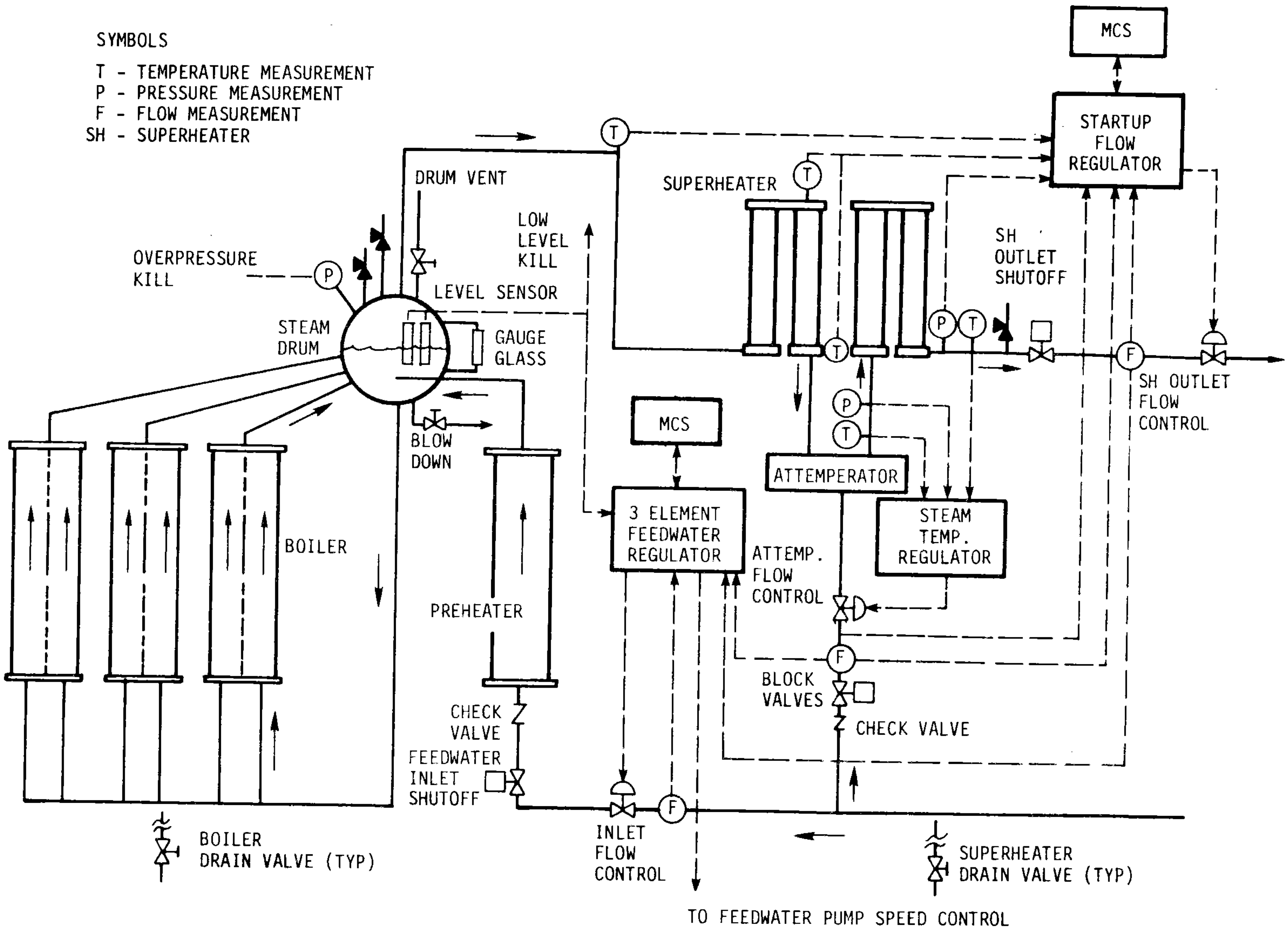

Figure 5.2-9. Schematic Flow and Control Diagram of the Receiver

to determine the saturation temperature at this point. Maximum spray flow is limited so that the steam temperature leaving the attemperator will not fall below 11.1°C (20°F) above saturation.

Since the receiver must be started up at least once a day, the startup must be automated to bring the receiver on line in a minimum time consistant with safe operation. The fundamental requirement during startup is to maintain sufficient steam flow through the superheater during the pressure ramp-up to keep superheater tube temperatures and front-to-back tube-wall temperature differences within safe limits. The startup flow regulator, shown in Figure 5.2-9, controls flow through the superheater by modulating a valve in the superheater outlet line. Inputs to the regulator are signals of steam flow, attemperator water flow, saturation temperature at the drum, steam temperature rise across a selected superheater pass and superheater outlet steam pressure. The control system operates in response to a startup function which relates the acceptable drum water temperature rise to the instantaneous heat absorbed and the drum water temperature. This startup function can be generated by an analytical computer model simulating the anticipated startups. The actual operation of this control system will have to be tuned during preliminary operation of the receiver.

During overnight shutdown heat tracing elements on the back of the receiver panels are used to keep the panels from freezing. Temperature sensors are strategically located on the back of panels to activate and monitor the tracing heaters.

All receiver controls can be operated either in a fully automatic mode or by manual override at the operator's discretion. Sensors are provided to activate alarms so that the operators can defocus the heliostats in the event of high superheater outlet steam temperature, high drum pressure, or low water level in the drum.

5.2.2.6 WEIGHT AND COST ESTIMATES

The weights of key components of the selected receiver design were calculated. Table 5.2-7 summarizes the weights and materials for these components. The

Table 5.2-7 Summary of Material and Estimated Weight of the Receiver

	Material	Weight, kg x 10^3 ($lb \times 10^3$)	
1. Pressure Parts			
Preheater Panels	SA-210 A-1	1.9 (4 1)	
Preheater Headers	SA-106 C	0.1 (0.2)	
Steam Drum	SA-516 Gr 70	6.2 (13.8)	
Downcomer	SA-106 C	1.3 (2.9)	
Boiler Panels	SA-210 A-1	4.4 (9.6)	
Boiler Headers	SA-106 C	0.4 (0.9)	
Risers	SA-210 A-1	0.4 (0.8)	
Supherheater Panels	SA-213 TP 304H	1.5 (3.3)	
Superheater Headers	SA-335 P-2	0.2 (0.5)	
Connecting Piping	SA-106 C	0.7 (1.6)	
Subtotal Pressure Parts			17.1 (37.7)
2. Enclosure and Shields			
Casing Plates & Stiffeners	Carbon Steel	6.2 (13.6)	
Thermal Shield	SA-240 304	0.9 (1.9)	
Insulation	Mineral Wool	2.8 (6.3)	
Lagging	Aluminium	1.3 (2.8)	
Subtotal Insulation & Shield			11.2 (24.6)
3. Structural Steel	Carbon Steel		17.5 (38.5)
4. Platform & Ladders	Carbon Steel		3.6 (8.0)
5. Miscellaneous Accessories			4.5 (10.0)
Total Receiver Dry Weight			53.9 (118.8)
Contained Water Weight at 15.6° (60°F)			5.4 (12.0)
Total Estimated Weight			59.3 (130.8)

whole receiver unit weighs 53,900 kg (118,800 lb) empty, and 59,300 kg (130,800 lb) filled with water. The cost estimate of this receiver was based on the receiver conceptual arrangement drawings, design information, list of materials, estimated weights and site location. Costs of shop fabrication, and general accessories, as well as home-office expenditures, were estimated by Foster Wheeler Energy Corporation's (FWEC) Equipment Estimating Department. Field erection cost was estimated by FWEC's Construction Department. Standard commercial estimating methods were used for these estimates. The total construction cost of the receiver alone, not including support tower or the tower steam/feed piping, in 1981 dollars is approximately $1.58 million. The tower cost is 334,321 and the Total Receiver System cost is 1,918,871.

5.3 MASTER CONTROL SYSTEM (MCS)

The solar cogeneration facility will provide at noon winter solstice about 7 percent of the substation average electrical power demand of 10 MW_e and about 70 percent of the Steam Plant No. 4 projected average thermal steam load of 4.7 kg/s (37,500 lb/h). The solar facility operates in parallel with the electrical and steam systems, in effect reducing the loads on the present energy systems. Therefore, the control systems and operating procedures used on the present equipment will not require modification. The fossil boiler(s) will control the steam header pressure, as the boiler(s) do now, and the turbine throttle valve and automatic hand valves will be controlled to maintain the set pressure at the inlet to the throttle valve.

The Master Control System (MCS) consists of computer equipment, peripherals and associated software designed to enable supervision and control of the overall solar cogeneration facility operation. The MCS is also used to acquire, store and evaluate facility operating data. Each individual system in the facility implements its own control and data acquisition. The purpose of the MCS is to integrate and coordinate the operation of all the facility components and provide a single entry point for operator intervention in any phase and at any level of the unit control scheme.

A block diagram of the overall facility control configuration is shown in Figure 5.3-1. The MCS is essentially made up by the Control Computer, associated keyboards, CRTs, consoles, and storage devices. Each of the facility systems is independent in that it can operate without the MCS if necessary for any reason. Facility operation without the MCS does, however, have limitations imposed by the absence of coordination of all system performances.

5.3.1 FUNCTIONAL REQUIREMENTS

The MCS shall control the solar cogeneration facility in a safe and reliable condition under all modes of operation. The MCS shall permit the operator to select the facility operating mode. The MCS shall operate the facility under all conditions including startup, shutdown, transient, steady state, and emergency operation.

5.3.1.1 DESIGN CRITERIA

In order to satisfy the general design requirements, the MCS shall meet the following design criteria:

High Availability

- High component/circuit reliablity employing the lastest solid-state technology ahd conservative designs.
- Modular architecture to enhance fault detection and maintenance.
- Self-diagnostic capability wherever possible.

Comprehensive Operator/Facility Interface

- CRT displays shall provide for the following:
    - process monitoring
    - trouble identification
    - operator guidance
    - interactive communications
    - status information
    - historical review

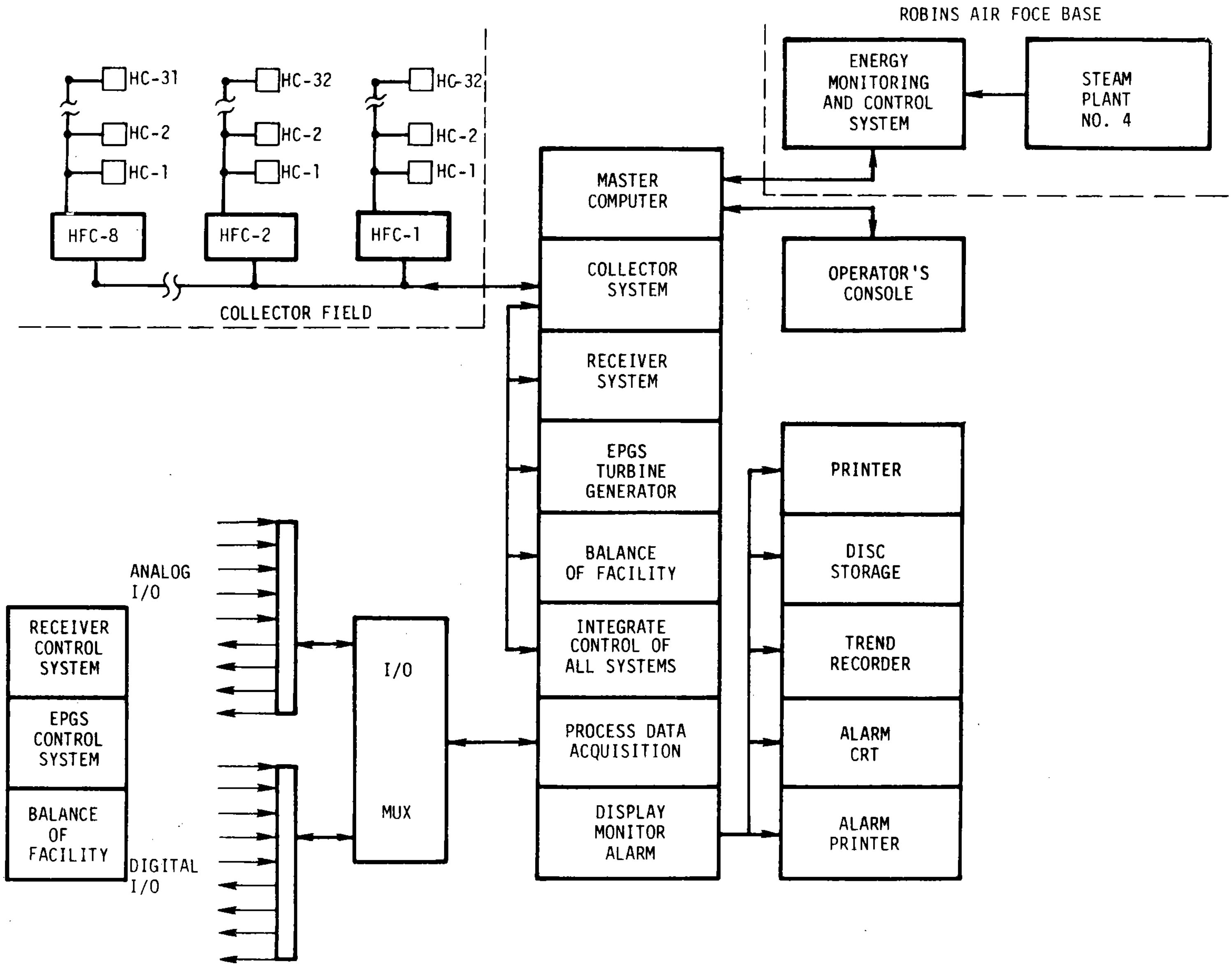

Figure 5.3-1. Master Control System

- Main control board with conventional displays, control stations, alarms, etc. shall provide the operator with a familiar operation/process interface.

Flexibility

- All control logic functions and control algorithms shall be implemented in direct digital control (DDC) software. The system shall be programmed in a computer language which allows changes to be made simply and quickly.

System Modifications

- Existing control systems will be modified only where necessary.

5.3.1.2 DESIGN PHILOSOPHY

The controls for the major facility systems and overall facility control are incorporated in a centralized, minicomputer-based MCS. A centralized MCS has the following advantages:

- Reduces the number of interfaces with other control systems, thus simplifying facility design, operation, maintenance, and personnel training
- Enhances system response by reducing communication problems
- Provides flexibility for control system design
- Is easy to reconfigure
- Provides a comprehensive operator/process interface

5.3.2 MASTER COMPUTER SYSTEM

The purpose of the master computer is to integrate, supervise, and coordinate the operation of all major systems of solar cogeneration facility including:

- Collector System
- Receiver System
- Turbine Generator

- Balance of Facility
- Transmit conditions to the base EMCS and receive status of Steam Plant No. 4

5.3.2.1 CONTROL LEVELS

The plant can be operated in any one of three levels of control with the operator's responsibilities varying with each level.

AUTOMATIC

At this level the MCS is providing overall plant control and system integration and coordination. The MCS provides safe and reliable operation of the plant by evaluating many environmental, system, and component variables, characteristics, and responses. The operator simply monitors the performance and status of the facility systems, and components.

SEMIAUTOMATIC

At this level the MCS automatically controls each system with the operator providing the supervisory control and subsystem integration/coordination function. The operator accomplishes this by adjusting the setpoints on the system master control stations or initiates control logic sequences associated with the individual systems.

MANUAL

The portion of the emergency trip and interlock system necessary for operating equipment safety employs solid-state logic and functions automatically at all levels of control.

5.3.3 COLLECTOR CONTROLS

The collector controls are composed of the following major components:

- Heliostat Controllers (HC)
- Heliostat Field Controllers (HFC)

The design for the collector field controls is based on reliable and currently available hardware through a three-level distributed computer system network. The heliostat controls use an open-loop sun-tracking concept with an accurate encoding resolution of elevation and azimuth positions. Position command is closed loop calculated by the microprocessor that directs the controller to keep the position error at zero based on encoder feedback.

A block diagram in Figure 5.3-1 depicts the collector control configuration.

5.3.3.1 HELIOSTAT CONTROLLER (HC)

Each heliostat has one 16-bit microprocessor that is the heart of the heliostat controller (HC). The microprocessor is a single chip device with programmable or erasable and programmable read only memory (PROM or EPROM) as well as random access memory (RAM). Additional components of the HC include the communication programmable control chips and various interface/line driver elements. The HC receives azimuth and elevation angles from the heliostat position encoders and then delivers appropriate signals to the azimuth and elevation drive motors for the required pointing angles. Heliostat control commands and sun vectors are recieved from the respective heliostat field controller (HFC). The HC delivers requested data to the HFC upon command.

5.3.3.2 HELIOSTAT FIELD CONTROLLER (HFC)

The HFC handles a subfield of 31 or 32 HCs by means of a single serial communication line composed of twisted shielded pair operating at 9,600 bauds. All HCs are "multidropped" from the same line that can be as long as 3,050 meters (10,000 ft) without requiring communication modems.

The heliostat field contains 251 heliostats which are controlled by eight HFCs. Each HFC, in turn, is "multidropped" from a single twisted pair operating at 9,600 bauds that links it to the MCS.

The HFC computer hardware is similar to the HC hardware. The only differences are a larger random access memory (RAM) and the existence of a bubble (nonvolatile) memory unit at the HFC. Two serial communication I/O ports enable command linkages to all HCs and the MCS interface unit, respectively.

In order to further increase the flexibility of the collector array, the control system is designed to operate without the MCS with respect to the main modes of operation. The MCS is needed only to coordinate certain maintenance operations and to update or modify the normal control sequence for the field, subfield, or single heliostat as desired by the operator.

5.3.3.3 COLLECTOR CONTROL OPERATION

All the detailed control algorithms for operation of the heliostats during the various modes are stored in the bubble memory of the HFC. The execution of these algorithms is controlled by loading them from the bubble memory into the RAM section. It is possible to modify or update the routines from the MCS by downloading new routines through the same communication network utilized for control of the array. The status of each heliostat or set of heliostats is available at all times at the request of the MCS operator. The HC has the necessary software, stored in the programmable read only memory (PROM) of the microprocessor chip, to execute any command.

The heliostat control arrangement is designed to achieve the intended performance at all levels with very little human intervention. All the modes of operation, including startup, normal tracking, synthetic tracking, maintenance, shutdown, emergency operation, and contingency operation, can be selected by a single operator by controlling the execution of the appropriate instructions or set of routines, which are permanently stored, they can be modified or updated at any time using the standard computer system software without affecting the hardware. Provisions are included, however, to enable manual intervention in any function by the operator.

One of the principal concerns associated with the design of the operations control strategy is to minimize the impact of malfunctions, occurring at any level, on the performance of the components not directly affected by the malfunction. Abnormal conditions are relayed through the communication network to the MCS.

5.3.4 RECEIVER CONTROL

The purpose of the receiver controllers during normal operation are to maintain superheat steam temperature within specified limits, and to maintain drum level through the feedwater control system.

Process measurements are transmitted to the MCS for processing according to the control algorithms programmed into the MCS. The output from the control algorithms forms the demand signal (superheat steam temperature) which is transmitted to the receiver controller.

5.3.4.1 PROCESS OVERVIEW

Figure 5.3-2 shows a simplified flow diagram of the solar receiver indicating the locations of the control valves and measurements. Feedwater flow to the receiver is provided by a solar feedwater pump. Feedwater flow is controlled by a variable speed feedwater pump and a single flow control valve. Attemperation is used to control superheat steam temperature.

5.3.4.2 SOLAR RECEIVER SUPERHEAT STEAM TEMPERATURE CONTROL

An attemperator is located between the primary and secondary superheater section. The secondary superheater outlet temperature is compared to a MCS or operator-selected setpoint and the resulting error signal generates the attemperating water demand signal. A block valve associated with the attemperator control valve is interlocked to close whenever its control valve is demanded to close.

5.3.4.3 SOLAR FEEDWATER CONTROL

The feedwater flow required to maintain proper drum level is controlled using a three-element feedwater control system (see Figure 5.3-2).

Measured steam flow is one element that is used to establish feedwater flow demand. The measured drum level is compared to a setpoint in the controller which is used to correct the feedwater flow demand. The corrected demand

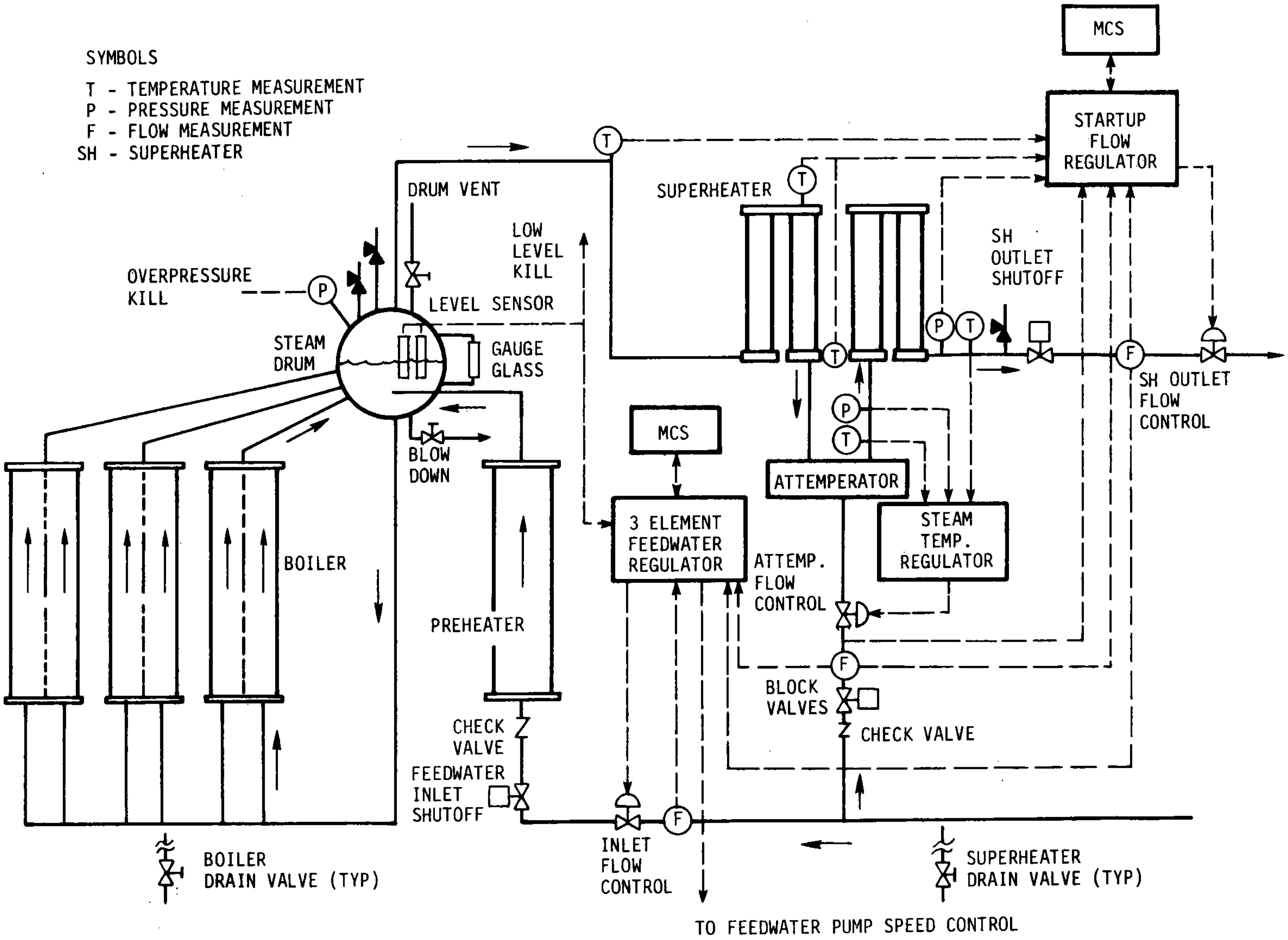

Figure 5.3-2. Schematic Flow and Control Diagram of the Receiver

signal is compared to measured flow and applied to a proportional plus integral controller to demand the speed of the feedwater pump.

During startup and shutdown when there is little or no steam flow from the receiver, a single element feedwater flow control based on drum level is used.

5.3.5 FOSSIL BOILER CONTROL

The existing fossil-fueled boilers and associated boiler controls have adequate response to offset solar cloud transients, such that the present controllers will not require modification.

5.3.6 BALANCE OF FACILITY (BOF)

The following comprise the BOF equipment:

- Feedwater Pump
- Feedwater Preheater
- Desuperheater Pump
- Heater Drains
- Turbine Auxiliaries
- Fire Protection
- Service Water System
- Environmental Systems

All the above systems are interfaced with and monitored by the MCS. Information from components of the BOF communicate with the MCS through its I/O system.

5.3.7 TURBINE GENERATOR CONTROL

The turbine control system receives analog and digital information from turbine sensors and control mode and setpoint data from the MCS. The turbine control system controls the turbine governor valve, automatic hand valves, and the turbine bypass valve. The turbine controls include an inlet pressure controller, a speed controller, an automatic startup controller, and an automatic synchronizing control system.

- Inlet Pressure Controllers: Steam flow through the turbine is controlling by the governor valve to maintain a setpoint turbine inlet pressure.

- Speed Control: Steam flow through the turbine is regulated by the governor valve to maintain the demand turbine speed.

- Bypass Control: A turbine bypass valve and pressure reducing station is provided for use during facility startup and shutdown. They are also used to provide steam for thermal loads if the turbine generator is inoperative and in the process steam mode.

- Automatic Startup: A control system that automatically starts the turbine generator, including venting and draining, and brings it up to operating speed.

- Automatic Synchronization: A control system that adjusts the turbine generator speed to match generator frequency and phase angle to that of the utility grid and then automatically connects the generator output to the grid.

5.3.8 INSTRUMENTATION

Electronic process measurement transmitters are used to process measurements required by the solar cogeneration facility. These transmitters are field rack mounted where feasible and measure the different parameters associated with the cogeneration facility as part of the MCS. The major parameters measured by the instruments are:

- Pressure and Differential Pressure

- Temperature

- Flow

- Level
- Volt
- Ampere
- Frequency

The transmitters are of a simplified and compact design with external span and zero adjustment, with modular construction and plug-in circuit board to aid troubleshooting and reduce parts inventory.

Solid-state strip chart recorders driven by the computer are mounted on the main control board to record and trend any abnormal condition encountered during load excursions, transients, and system failures.

The cost of the MCS, including the hardware and software but not including the collector system controls, the receiver controls, the EPGS controls or the Balance of Facility Controls is estimated to be 386,000 in 1981 dollars.

5.4 ELECTRICAL POWER GENERATION SYSTEM (EPGS)

Electrical power is required to align the heliostat collectors and to operate the steam turbine auxiliary equipment in order to commence operation of the electrical generating system. This power, referred to elsewhere as "Start Up Power", will be available from the existing Robins Air Force Base electrical distribution system. When the turbine generator is operating the net power produced by the solar cogeneration facility will be supplied to the base distribution system.

5.4.1 TURBINE GENERATOR

The turbine generator package consists of a single-stage noncondensing turbine connected to the generator through speed reducing gears. The turbine has two automatic hand valves for efficient operation at partial load. It also includes piping, valves, controls, lube system and instrumentation necessary for its operation. The turbine is sized for a steam flow of 3.605 kg/s (28610 lb/h) at 5.96 MPa (865 psia) and 400°C (750°F) inlet conditions, exhausting to a 1.07 MPa (155 psia) back pressure.

The generator rating is 1000 kVA at 80 percent power factor. The generator produces 3 phase, 60 cycle, 480 volts electricity and is air cooled. The turbine generator controls include a turbine inlet pressure controller, a speed controller, an automatic startup controller, an automatic synchronizing control system, and a turbine protection system.

5.4.1.1 FUNCTIONAL REQUIREMENTS

The functional requirements of the turbine generator are as follows:

- Receive steam at flow rates, temperature, and pressures as defined in Section 4.3.2 (State Point 1)
- Produce 725 kW of electricity as measured at the generator output terminals
- Supply steam to the desuperheater at flow rates, temperatures and pressures as defined in Section 4.3.2 (State Point 2)
- Receive startup, control setpoint and shutdown commands from the master control system
- Transmit data on operating parameters (temperatures, pressures, turbine speed, etc.) to the master control system

5.4.1.2 DESIGN

Standard single stage turbines are divided into classes on the basis of maximum operating steam pressure and temperature. The rated design turbine inlet conditions of 5.96 MPa (865 psia) and 400°C (750°F) produce a requirement for a class lV turbine. The steam turbine shall meet the API 611 standard for general purpose turbines.

The generator is a 4 pole, 1800 rpm, 1000 kVA machine. The air cooled generator produces 480 volts, 3 phase, 60 cycle electricity.

The turbine generator set shall be a complete assembly, such that the turbine, gear, generator and accessories shall be assembled on a steel bedplate, tested, and shipped as a unit, thus facilitating installation on the foundation.

5.4.1.3 OPERATING CHARACTERISTICS

Although the facility has two normal operational modes: the turbine following mode and the process steam mode, the turbine generator has only one normal operational mode since in the process steam mode the turbine is bypassed. In the turbine following mode the turbine inlet governor valve and the automatic hand valves are positioned to maintain stable steam conditions at the turbine inlet by responding to whatever steam flow is available.

The turbine generator set is designed to meet the following rated operating conditions:

Flow Rate	3.605 kg/s (28610 lb/h)
Steam Inlet Temperature	400°C (750°F)
Steam Inlet Pressure	5.96 MPa (865 psia)
Steam Outlet Pressure	1.07 MPa (155 psia)

At rated conditions the generator output is 725 kW (gross).

5.4.1.4 PERFORMANCE ESTIMATES

The following turbine generator performance estimates are based on the Westinghouse EH-125 model turbine and the performance is typical of single stage turbines of this size and class.

In the turbine following operational mode the setpoint for the steam temperature leaving the solar receiver is 410°C (770°F). There is a thermal loss in the piping from the receiver to the turbine, such that at rated flow there is a 10°C (18°F) drop in the steam temperature. Since the thermal loss, in this operational mode, is almost independent of flow rate, the temperature drop increases as flow rate decreases. This effect is shown in Figure 5.4-1. The pressure loss in the pipeline from the turbine exhaust to the steam header in Steam Plant No. 4 is 100 kPa (15 psi) at rated flow conditions. At minimum flow the pressure loss in this line is less than 4 kPa (0.5 psi). Therefore in the turbine following mode, the turbine experiences a constant inlet pressure, a variable inlet temperature and a variable exhaust pressure with changes in flow rate.

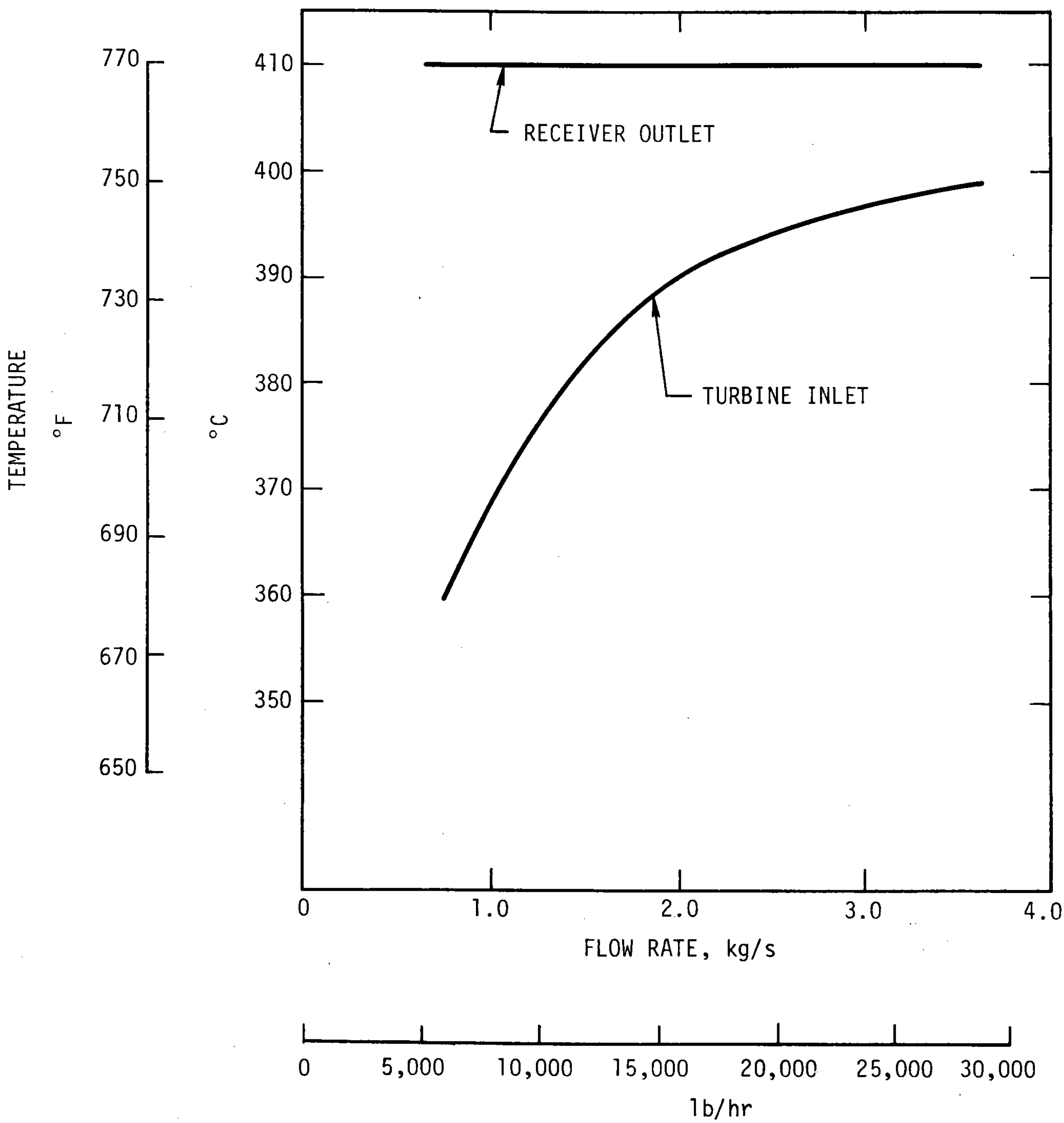

Figure 5.4-1. Effect of Thermal Loss on Turbine Inlet Temperature

Shown in Figure 5.4-2 is the output power of the turbine and generator as a function of flow rate. Most turbine manufacturers offer two "hand" (can be automatically activated) valves on turbines of this size. The "hand" valves are used to control the number of nozzle groups used to accommodate a partial load point. By eliminating throttling of the steam, the "hand" valves provide lower steam rates when the turbine is operating at partial load conditions as shown in the figure. The turbine exhaust enthalpy as a function of flow rate is shown in Figure 5.4-3. The effect of the "hand" valves on the exit steam enthalpy show as the step changes at flow rates of approximately 2.0 and 3.0 kg/s.

5.4.2 ELECTRICAL SWITCHGEAR

A schematic representation of the solar cogeneration facility switchgear is presented in Appendix A, A.5-3. The main switchgear will be supplied with power from both the turbine generator and, through a reversible electric meter, the base distribution system. All of the electrical loads associated with the facility will be supplied through the switchgear located in the Power Building.

The major auxiliary loads served by the switchgear include the lighting panels for both the control building and the receiver tower, the heliostats and their controls, the electric motor driven feedwater pump, the power building, HVAC system, and the solar cogeneration system control panel.

Operation of the electrical system will be closely coordinated with the Georgia Power Company for synchronization, phase control, fault protection, safety interlocks, and metering and monitoring while operating in the turbine following mode.

5.4.2.1 SYSTEM OPERATION

This section describes the sequence of operations required to bring the solar facility on line.

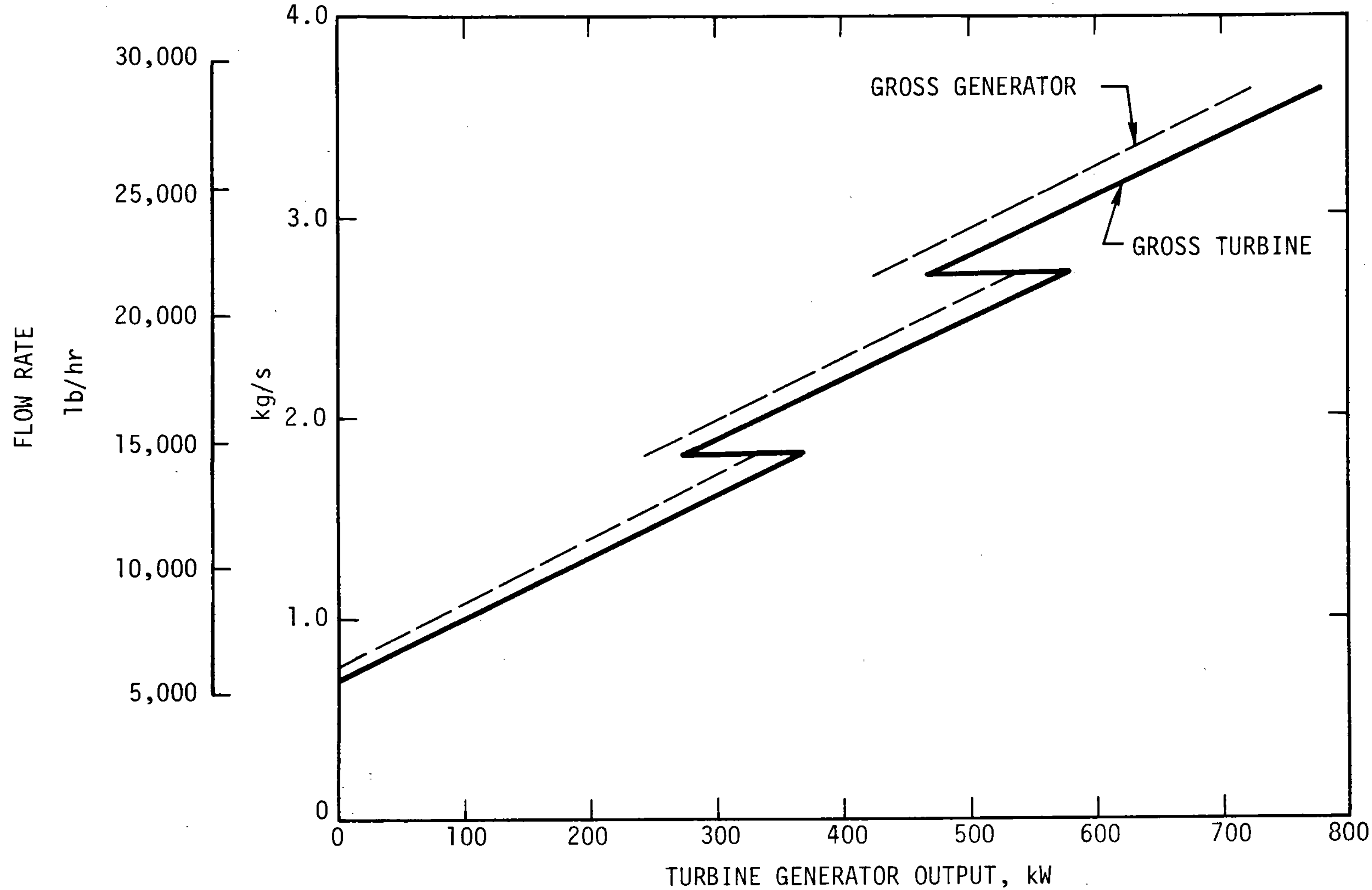

Figure 5.4-2. Turbine Generator Output Power Versus Turbine Flow Rate

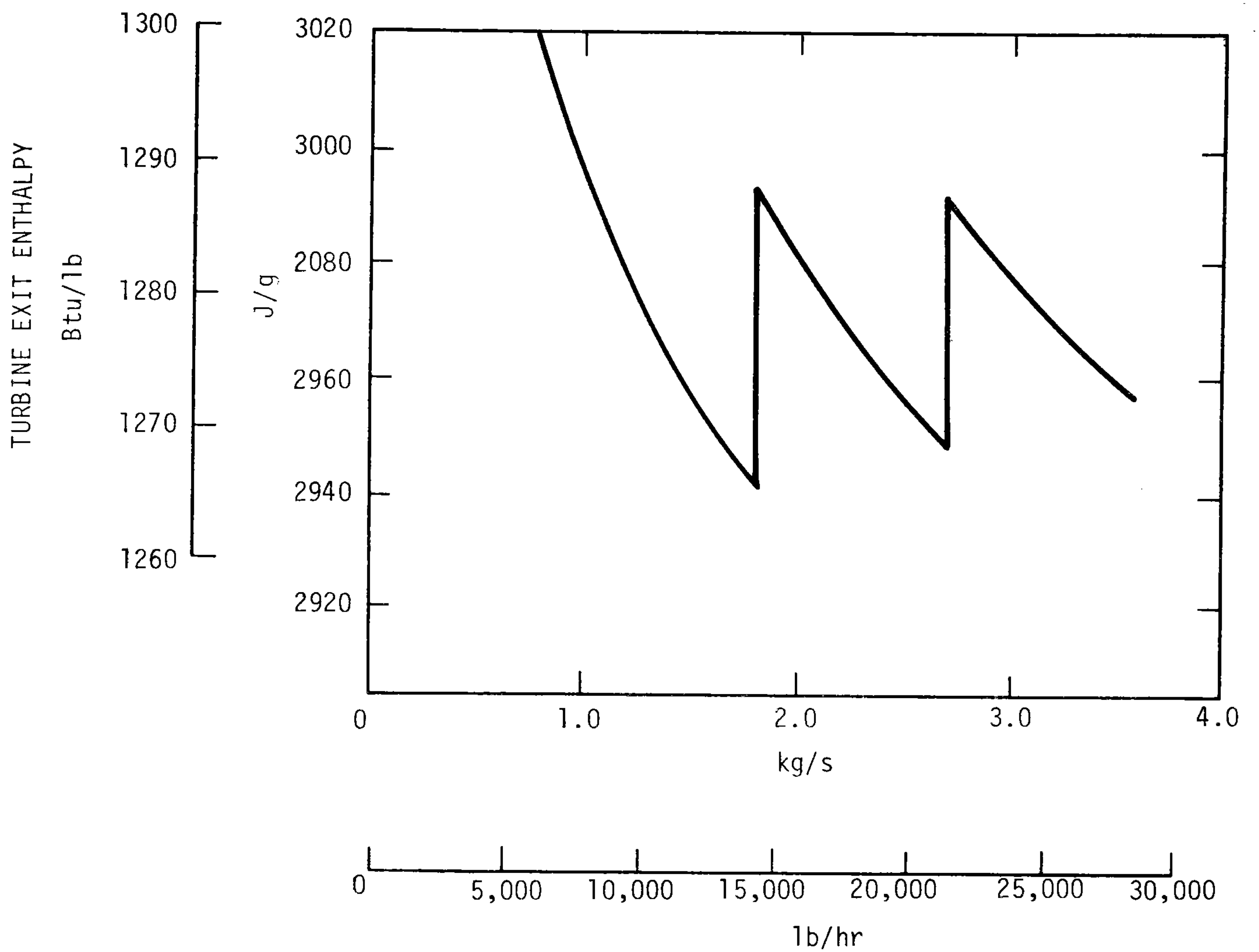

Figure 5.4-3. Turbine Exhaust Enthalpy Versus Flow Rate

TABLE 5.4-1: TURBINE GENERATOR COMPONENT LIST

- Turbine
- Gear Reducer
- Generator
- Turbine Bypass Control System
- Automatic Synchronization System
- Turbine Protection System
- Generator Protection System
- Turbine Control System
- Automatic Startup System
- Thermal Insulation

Base supplied power is required to bring the cogeneration facility on line. The EPGS switchgear is energized by closing the circuit breaker from the 12.6 kV base distribution system. This provides the system startup power. This breaker may be closed only when one of the following conditions is met:

(1) Three phase voltage must be available from the base distribution system and no voltage is present on the bus of the EPGS switchgear, or

(2) Three phase voltage is available on the bus of the EPGS switchgear and is synchronized with the three phase voltage of the base system.

The circuit breaker cannot be closed without three phase voltage at the connection to the base system.

Once the central receiver boiler has developed operating pressure the steam turbine may be started and the generator accelerated to rated speed and voltage. Upon attainment of these conditions the generator may be connected to the EPGS switchgear by means of a synchronizer-controlled circuit breaker. This circuit breaker can be closed only when the generator is producing three phase voltage at the same value and in the same phase with the Base distribution system. The closure of the generator can be initiated and, as synchronizing conditions are fulfilled, the circuit breaker connecting the generator to the EPGS switchgear will close. The production of electrical power from the generator will be increased by increasing the steam flow to the turbine until either the desired generator output is reached or all available steam is being used.

At this time the EPGS is producing a quantity of electricity sufficient to power its auxiliaries and deliver excess power into the Base distribution system. A reversible electrical meter will record the net kWh delivered to the Base electrical system.

A power sensor will be installed in the EPGS switchgear at the point where the cogeneration system switchgear connects with the Base distribution system.

This sensor will be set to open the breaker connecting the switchgear to the Base system in the event that EPGS output exceeds a predetermined set point. Exceeding this setpoint will be an indication that the portion of the Base system to which the EPGS is connected is not receiving power from the Georgia Power Company source. The EPGS is, therefore, connected to loads in excess of its capacity and is energizing lines which may be considered by line repair crews to be de-energized, resulting in a hazardous situation for these personnel.

The EPGS switchgear will contain under-frequency sensors which will be activated when the generator circuit breaker is closed. A reduction in frequency below a predetermined set point will also indicate that the portion of the Base distribution system to which the EPGS is connected has become disconnected from the Georgia Power Company source. The under-frequency sensor will cause the circuit breaker connecting the EPGS to the Base to open, isolating the EPGS from the rest of the Base loads.

A conventional backup system is judged at this conceptual design stage to be not necessary due to the reliability of the Georgia Power Company. However, a battery pack backup system will be provided for the computer operation.

The cost of the EPGS including the turbine generator and associated controls, the electrical switchgear and transformer is estimated to be $229,754 in 1981 dollars.

5.5 BALANCE OF FACILITY

The balance of facility includes the feedwater piping from the connections at Steam Plant No. 4 to the receiver inlet connection at the top of the tower and the steam piping from the receiver outlet connection at the top of the tower to the turbine inlet and from the turbine outlet to Steam Plant No. 4. It also includes blow down, vent and by-pass piping, the desuperheating at the turbine outlet, the feedwater surge tank, pumps, heating equipment, and valves including associated control equipment. The power building structure is not assigned to the Balance of Facility nor are other site preparations.

5.5.1 PIPING INTERFACE WITH STEAM PLANT NO. 4

The solar facility is connected to the existing Steam Plant No. 4 with two underground mains. One of these shall be a 15.25 cm (6 in.) pipe which shall convey either solar generated steam to the steam header in the Steam Plant No. 4, or steam from Steam Plant No. 4 to the Solar Facility during the feedwater and turbine warm-up periods. The other pipe shall be a 7.62 cm (3 in.) feedwater line which shall convey deaerated feedwater to the surge tank in the Solar Facility from Steam Plant No. 4.

The 15.24 cm (6 in.) underground steam line originates inside a pit in the Solar Power Generating facility and shall follow the shortest possible route to the northeast corner of Steam Plant No. 4 where it terminates and enters the Steam Plant building and hence connect to the 15.24 cm (6 in.) steam line coming out of Boiler No. 1 just before it joins the 25.40 cm (10 in.) steam header. The 7.62 cm (3 in.) feedwater line follows the same underground route from the Solar Generating Facility to the Steam Plant No. 4. After it enters Steam Plant No. 4, it connects with the 10.16 cm (4 in.) feedwater line coming out of the feedwater pumps.

Solar generated steam leaves the Solar Facility at a pressure of 965 kPa (140 psia) and a temperature of 185°C (366°F). Feedwater enters the solar facility at a pressure of 896 kPa (130 psia) and a temperature of 82°C (180°F). Carbon steel pipe is used for both the steam and feedwater interface between the Solar Facility and Steam Plant No. 4. Expansion loops are provided as necessary.

5.5.1.1 CONTROL INTERFACE

In this solar cogeneration facility, the solar boiler shall function as Boiler No. 5 of Steam Plant No. 4. It shall be connected in parallel with the other four boilers. When sunlight is available, the solar boiler shall be base-loaded and the steam plant boilers shall make up the difference. Since the capacity of the solar boiler varies with available sunlight, pressure control on the steam header shall modulate the gas fired boilers to maintain pressure and compensate for solar steam. When solar generated steam is available, it shall have direct access to the steam header in Steam Plant No. 4 without passing through any control valves.

The quantity of feedwater to be drawn by the Solar Steam Generating Facility shall be controlled by a float actuated modulating valve which shall maintain approximately 15 minutes supply of water (3.41 m^3 - 900 gallons) in the surge tank at all times. When the float control in the surge tank opens the feedwater level control valve, it shall also send a signal to the feedwater pumps in Steam Plant No. 4 to start running, unless they are already running.

5.5.1.2 FEEDWATER QUALITY

The maximum limits on critical impurities in the feedwater are:

Oxygen	:	0.007 ppm
Silica	:	0.02 ppm
Iron	:	0.01 ppm
Copper	:	0.05 ppm
Hydrazine	:	0.02 ppm
Total Hardness	:	0
Organics	:	0
pH	:	8.5 - 9.2

It has been determined that, at present, Steam Plant No. 4 feedwater does not meet a majority of the limits given above. It shall, therefore, be necessary to repair the water treatment equipment at RAFB before the solar facility is functional. The owner has agreed to conduct this repair as part of his costs.

The concentration of impurities in the solar boiler water shall also be limited by continuous blowing from the drum. The maximum limits on critical impurities in the boiler water shall be:

Total Dissolved Solids	:	1000 ppm
Silica	:	5 ppm

5.5.2 FEEDWATER PUMP

The boiler feed pump is situated between the feedwater surge tank and the feedwater preheater. It serves to increase the boiler feedwater pressure from 896 kPa (130 psia) in the surge tank to approximately 8,721 kPa (1,265 psia) entering the feedwater preheater. The pump will have a capacity of 14.3 m^3/h (60 gpm) at a maximum speed of 490 rev./min.

5.5.2.1 PUMP CHARACTERISTICS

The pump is a positive displacement type horizontal triplex pump driven by an electric motor. This type of pump is suitable for low flow rate, high pressure applications and maintains a high efficiency throughout a wide range of operations.

To take up irregularities and to induce uniform flow in the suction and discharge lines of the triplex pump, pulsation dampener will be employed. The feedwater storage tank serves as the pulsation dampener on the pump suction line. On the high pressure pump discharge line a dampener with a diaphragm or bladder will be used.

5.5.2.2 PUMP CONTROL

The triplex feedwater pump will be driven by a variable speed, direct current motor.

Flow control will be accomplished by varying the speed of the pump with a signal from the steam drum level control and by bypassing a portion of the feedwater flow through a pressure relief valve. The use of the bypass line will be limited to those flow conditions beyond the control capability of the variable speed electric motor.

5.5.3 HEAT EXCHANGERS

There are three heat exchanger: the feedwater preheater, one located inside the feedwater storage tank for the vent line, and one located in the feedwater storage tank for drum blowdown.

5.5.3.1 FEEDWATER PREHEATER

The feedwater preheater is a simple shell and tube type heat exchanger located between the discharge of the boiler feedwater pumps and the preheater panels of the central receiver. The heat exchanger shell will contain the steam with boiler feedwater on the tube side.

The purpose of the feedwater preheater is to boost the temperature of the boiler feedwater from Steam Plant No. 4 from 101°C (213°F) as it leaves the boiler feed pump to approximately 178°C (353°F) entering the central receiver preheat panels.

Steam can be supplied to the preheater from two sources, depending upon the mode of operation of the solar cogeneration facility. Under startup conditions steam will be supplied by the underground steam line from Steam Plant No. 4. As the facility makes the transition into full operating mode the preheating steam will be taken from a point just downstream of the turbine exhaust steam desuperheater. A turbine bypass line is provided should the turbine be off-line to allow the cogeneration facility to continue operation.

The heat exchangers rated heat transfer is 4,290 MJ/h (4.070 x 10^6 Btu/h). Minimum and rated flows for both steam and feedwater through the unit are presented in the table below.

Tube (Feedwater)	Mininum	Rated
Flow	1,366 kg/h (3,005 lbs/h)	13,309 kg/h (29,280 lbs/h)
Pressure (inlet)	8,583 kPa (1,245 psia)	8,583 kPa (1,245 psia)
Pressure drop across coil	-	21 kpa (3 psi)
Temperature (inlet)	98°C (209°F)	101°C (213°F)
Temperature (outlet)	178°C (352°F)	178°C (352°F)
Shell (Steam)		
Flow	232 kg/h (510 lbs/h)	2,195 kg/h (4,830 lbs/h)
Pressure (inlet)	965 kPa (140 psia)	1,048 kPa (152 psia)
Temperature (inlet)	186°C (366°F)	186°C (366°F)

The feedwater preheater shell and bonnet will be constructed of carbon steel in accordance with ASME standards for unfired pressure vessels. The tube bundle will be type 90-10 copper nickel alloy. The individual tubes will have an outside diameter of approximately 19mm (0.75 in.). Design pressures are 1,482 kPa (215 psia) and 10,447 kPa (1515 psia) for the shell and tubes respectively. Steam and condensate piping connections to the shell will be flanged ASA 150 fittings, 76mm (3 in.) for the steam and 25mm (1 in.) for the condensate. Feedwater inlet and outlet connections will be by 5mm (2 in.) flanged ASA 900 fittings.

5.5.3.2 FEEDWATER SURGE TANK

The feedwater storage tank serves to provide a surge capacity for the condensate from Steam Plant No. 4. The 76 mm (3 in.) feedwater line from the existing plant discharges into the 6.82 m^3 (1800 gallon) tank. The feedwater pump takes its suction from the surge tank. At rated conditions the tank will experience a flow of 12,120 kg/h (26,664 lbs/h) of feedwater from Steam Plant No. 4 The feedwater will be at a pressure of 896 kPa (130 psia) and a temperature of 82°C (180°F).

The continuous blowdown line from the central receiver steam drum is routed through the surge tank. A small heat exchanger in the tank serves to recover heat from the blow down to preheat the condensate as well as to reduce the volume of flash steam. After the heat exchanger the blowdown is piped to a blowdown separator and ultimately the cogeneration facility vent and drain. Condensate from the feedwater preheater is piped through a high pressure steam trap and discharged into the surge tank.

The feedwater surge tank is equipped with a system for providing a nitrogen blanket above the water level. The pressure within the storage vessel will be maintained at approximately 896 kPa (130 psia) by this equipment.

5.5.3.3 DESUPERHEATER

A steam conditioning system consisting of a desuperheater and a desuperheater spray pump located prior to the injection of the solar derived steam into the base steam distribution system and the solar cogeneration facility feedwater preheater. The desuperheater will moderate the temperature of the steam supplied to the base and the preheater to prevent thermal shock and control system imbalances.

A small spray pump, taking its suction from the feedwater storage tank, will provide a continuous flow to the desuperheater. The pump will operate at constant speed; control of the flow will be accomplished by a throttle valve and by recirculating a portion of the flow back to the pump by means of a pressure relief valve. The condensate from the pump will be supplied to the desuperheater at 517 kPa (75 psi) above the steam pressure.

The desuperheater will operate under three distinct conditions: normal operation with exhaust steam coming out of the steam turbine, a reduced steam flow warm-up period with the turbine bypassed, and full rated flow with the turbine bypassed.

5.5.4 POWER GENERATION BUILDING

Superheated steam generated by the solar receiver shall be used to operate the turbine-generator in the power generation building which shall be located immediately behind the solar tower. The power generation building shall house the balance of plant equipment, the electrical switchgear and a control room for the heliostat control computers and the master control system. The power generation building shall be a simple rectangular shaped building with internal dimensions of 12.2 meters (40 ft) by 9.8 meters (32 ft). Due to the fact that part of the internal space shall be taken up by the control room, toilet and lab sink, the remaining open area space shall be 101 m^2 (1087 ft^2).

The control room area shall be 12.8 m^2 (138 ft^2). The control room shall have a separate and low ceiling so that air conditioning equipment for the control room area can be located above the ceiling. The control room shall have direct access to the outside and access to the equipment area. It shall have one window facing the outside and one window facing the equipment area. Access to the toilet shall be from inside the control room only. A laboratory type sink shall be located in the equipment area adjacent to the control building. There shall also be direct access to the outside from the power equipment area through a 3.1 meters (10 ft) wide rolling type overhead door.

5.5.4.1 MECHANICAL EQUIPMENT GENERAL ARRANGEMENT

The mechanical equipment shall be located in the power generation building in a manner to allow the most efficient use of the space. Basically, the equipment which processes the feedwater from Steam Plant No. 4 shall be arranged on one side of the floor, and the equipment which processes the superheated steam coming from the tower shall be on the other side of the floor. This type of arrangement shall result in the minimum amount of piping runs and shall offer a clear aisle down the middle of the floor through which equipment can be moved to the 3.1 meters (10 ft) wide door, if necessary. The layout shall also provide sufficient working space and easy access to the equipment for maintenance purposes. In this regard, sufficient space to pull tubes shall be provided as well as lay down space.

5.5.4.2 ARCHITECTURAL CONSIDERATIONS

The power generation building located adjacent to the receiver tower will be a functional basic structure used to house the mechanical operations and controls of the solar generation facility. The building will be constructed of concrete block walls on continuous spread footing concrete floor slab and roof structure of steel joists with metal decking, rigid insulation, and a built-up roof. The roof structure will be slightly sloped for water drainage to gutters and downspouts on either side of the building. The overall exterior dimensions of 13.8 meters (45 ft 4 in.) by 10.4 meters (34 ft) produce a gross building area of approximately 143 m^2 (1541 ft^2).

Enclosed within the structure are the control room, 13.6 m^2 (146 ft^2), housing the central receiver monitoring equipment, adjoining lavatory, 2 m^2 (20 ft^2), and the equipment room, 106 m^2 (1146 ft^2), housing mechanical equipment for solar facility operation.

The control room is directly accessible from the exterior and will also have direct access to the equipment room, both will also have direct access to the equipment room, both physically and visually. The control room as well as the toilet room will be comfort conditioned from an HVAC unit located above the control room ceiling. The toilet area for use of control room personnel will include a lavatory and water closet.

The cost of the Balance of Facility including the feedwater and steam piping between the Steam Plant No. 4 and the EPGS, between the EPGS and the receiver at the top of the tower, all associated pumps, heaters, valves and controls but not including the Power Building structure, is $569,979 in 1981 dollars.

6.0 ECONOMIC ANALYSIS

6.1 METHOD

The economic assessment was based on the methodology and economic assumptions defined by the USAF for the Energy Conservation Investment Program (ECIP). This approach is basically a present worth analysis of nonrecurring capital costs, recurring operating and maintenance costs, and recurring benefits due to reduced energy usage.

Specifically, the economic justification for use of solar energy in place of conventional fuels for process heat generation at the Robins Air Force Base is evaluated by a direct comparison of the cost associated with solar energy application and the equivalent fuel cost savings in conventional fuels. The cost of process heat generation is made up of the cost of fuels, operating and maintenance costs and the capital charge for plant investment. Since installation of the solar energy system does not decrease the capacity requirement for the existing process heat generation facilities, the net effect of using a solar system for process heat generation will be solely in the reduced consumption of conventional fuels, a reduced demand for electricity and reduced O&M costs. Thus profitability of the solar energy system can be determined by comparing the cost of solar energy with the cost savings from the reduction of fuel consumption and the electrical power purchased, and the reduced current O&M costs over the life of the project.

The parameters incorporated in the economic analysis are as follows:

- Capital investment
- General inflation rate
- Fuel escalation rate above general inflation rate
- Present electricity cost
- Present cost of fuels
- Annual O&M expenses
- Project life

To evaluate the potential worth of this demonstration project financial options were considered as well as the sensitivity to variations in key assumptions such as the fuel escalation rate. A total of eight economic scenarios (Scenario A through H on Table 6.1-1) were defined for this evaluation. Scenario A considers the economic benefit potential for the initial demonstration facility with consideration given to the capital costs, operating and maintenance cost, and the value of energy savings. Scenario B considers the potential economic benefit from the view point of the Air Force assuming that DOE funds the total capital cost. In this case the Air Force realizes the benefit of fuel and electrical savings at the expense of operating and maintenance costs. Scenario C considers the economics from the viewpoint of the DOE assuming that the Air Force funds the operating and maintenance costs. In this case the DOE realizes the benefit of fuel and electrical cost savings at the expense of the capital investment. Scenarios D and E consider the total economic potential of this facility for a production run of 50 and 300 units respectively. Scenarios F and G consider the economics of the facility as a first prototype but with higher natural gas and oil escalation rates than the Energy Conservation Investment Program rates of Scenario A. Finally, Scenario H takes into account the possibility of natural gas de-regulation and equates the natural gas and oil costs in \$/MBtu.

6.2 ASSUMPTIONS AND RATIONALE

6.2.1 ECIP GUIDELINES

The economic assessment of the solar cogeneration facility was based on the assumptions shown on Table 6.2-1 which are consistent with the ECIP guidelines.

6.2.2 PROJECT START DATE

The project was assumed to startup in 1986.

6.2.3 FUEL/ENERGY COSTS

The fuel energy costs were based on actual Robins Air Force Base costs escalated to 1985 per Table 6.2-1 escalation rates. These 1985 costs are as follows:

TABLE 6.1-1: ECONOMIC SCENARIOS (1981)

	A	B	C	D	E	F	G	H
Life (years)	25	Same as A	Same as A	Same as A	Same as A	Same as A	Same as A	Same as A
Starting Year	1986	Same as A	Same as A	Same as A	Same as A	Same as A	Same as A	Same as A
Capital Costs (1981)	7,340,471	0	Same as A	2,933,252	1,926,874	Same as A	Same as A	Same as A
Owner Costs (1981)	458,375	Same as A	0	183,166	120,323	Same as A	Same as A	Same as A
O & M Costs (1981)	166,438	Same as A	0	Same as A	Same as A	Same as A	Same as A	Same as A
Fuel/Energy Costs								
Elec. ($/MBTU) (1981)	3.04	Same as A	Same as A	Same as A	Same as A	Same as A	Same as A	Same as A
Nat. Gas ($/MBTU) (1981)	2.99	Same as A	Same as A	Same as A	Same as A	Same as A	Same as A	8.80
Oil ($MBTU) (1981)	8.80	Same as A	Same as A	Same as A	Same as A	Same as A	Same as A	Same as A
Fuel/Energy Saving								
Elec. (kwh/yr)	616,300	Same as A	Same as A	Same as A	Same as A	Same as A	Same as A	Same as A
Nat. Gas (Ft^3/yr)	41,624,854	Same as A	Same as A	Same as A	Same as A	Same as A	Same as A	Same as A
Oil (gal/yr)	37,585	Same as A	Same as A	Same as A	Same as A	Same as A	Same as A	Same as A
Present Worth								
Discount Rate (%/yr)	10	Same as A	Same as A	Same as A	Same as A	Same as A	Same as A	Same as A
Fuel/Energy Escalation								
Elec (%/yr)	13	Same as A	Same as A	Same as A	Same as A	Same as A	Same as A	Same as A
Nat. Gas (%/yr)	14	Same as A	Same as A	Same as A	Same as A	Same as A	Same as A	Same as A
Oil (%/yr)	14	Same as A	Same as A	Same as A	Same as A	Same as A	Same as A	Same as A
Fuel/Energy Differential Escalation								
Elec (%/yr)	7	Same as A	Same as A	Same as A	Same as A	Same as A	Same as A	Same as A
Nat. Gas (%/yr)	8	Same as A	Same as A	Same as A	Same as A	10	12	Same as A
Oil (%/yr)	8	Same as A	Same as A	Same as A	Same as A	10	12	Same as A
Capital Escalation (%/yr)	6	Same as A	Same as A	Same as A	Same as A	Same as A	Same as A	Same as A
O & M Escalation (%/yr)	5.6	Same as A	Same as A	Same as A	Same as A	Same as A	Same as A	Same as A

TABLE 6.2-1: ECONOMIC ASSUMPTIONS PER ECIP GUIDELINES

Life - Solar Installation - 25 years

Discount Factor - 10%

ESCALATION RATES FOR EXTENDING $ VALUES TO REFERENCE YEAR

(%)

	FY 78	FY 79	FY 80	FY 81	FY 82	FY 83
Capital plus Construction	8.0	7.0	6.5	6.0	6.0	6.0
O&M	7.1	6.4	6.2	5.6	5.6	5.6
Electricity	16	16	16	13	13	13
Coal	10	10	10	10	10	10
Oil	16	16	16	14	14	14
Natural Gas	15	15	15	14	14	14

LONG-TERM REAL DIFFERENTIAL ESCALATION RATES

O&M	0.0%
Coal	5.0%
Oil	8.0%
Natural Gas	8.0%
Electricity	7.0%

ENERGY CONVERSIONS

Electricity	11,600 Btu/kWh
Oil	138,700 Btu/gal
Gas	1,030 Btu/ft^3

	$/MBtu
Electricity	4.96
Natural Gas	5.05
Fuel Oil	14.86

6.2.4 ANNUAL FUEL/ENERGY SAVINGS

The estimated production/saving of electricity from the facility is as follows:

Electricity	616,300 kWh/yr

Total thermal output was estimated for the facility to be equivalent to 8,286 barrels of oil. Using the approximate 10.8 percent thermal energy of oil to natural gas ratio for Robins Air Force Base the energy savings for natural gas and oil are as follows:

Natural gas	41,624,854 ft^3/yr
Oil	37,585 gal/yr

6.2.5 CAPITAL COSTS

Capital costs were based on those described in paragraph 4.7 which include direct costs, indirect costs, and owner's costs expressed in 1981 dollars. These capital costs were escalated to 1985 using the Table 6.2-1 values. Total capital costs in 1985 dollars is $12,138,986, excluding one time engineering costs (Table 6.3-1, item 1.d - item 1.b).

6.2.6 O&M COSTS

O&M costs were based on those described in paragraph 4.8 which includes annual operating costs, maintenance material costs, and labor costs in 1981 dollars. These O&M costs were escalated to 1985 using Table 6.2-1 values. Total annual O&M costs in 1985 dollars is $206,970.

6.2.7 REDUCED O&M COSTS ON EXISTING BOILER FACILITY

Reduced O&M costs on the existing boiler facility is described in paragraph 4.8 in 1981 dollars. Using the escalation values from Table 6.2-1 brings the reduced O&M costs to $2,387 in 1985 dollars.

6.2.8 ELIMINATION OF ONE BOILER REPLACEMENT IN EXISTING FACILITY

It was assumed that the addition of the solar facility would eliminate one boiler replacement of 16 years in the existing facility. The boiler was estimated to cost $389,800 in 1979 dollars. Escalated to 1985 dollars this represents as savings of $560,790.

6.3 RESULTS AND CONCLUSIONS

As stated earlier the economic value of the Robins Air Force Base solar cogeneration facility was determined using the ECIP methodology as delineated in paragraph 6.1. Since there are many potential applications of this facility, the 50th and 300th installations were studied. These results are contained in paragraph 6.3.1 which discusses scenario's A, D, and E.

In order to fully appreciate this project from the Air Force point of view, the economics of the facility was determined with all capital costs removed since they would be provided by the DOE. This view is contained in paragraph 6.3.2 which discusses Scenario B.

Taking into account the location of the facility on Air Force Base and the accessibility of manpower, lead to the determination of the economics of the facility from a DOE point of view including one-time engineering costs but in which all operation and maintenance costs and owners' costs were removed and were assumed to be provided by the Air Force. Paragraph 6.3.3 contains these results in a discussion of Scenario C.

Because of the uncertainty of the rate of inflation of natural gas and oil over and above the general inflation rate, it was decided to determine the economics of the facility taking into account 10 and 12 percent differential inflation rates as compared to the ECIP rates of 8 percent for natural gas and oil. These results are contained in paragraph 6.3.4 which discusses Scenario F and G.

Due to the possibility of de-regulation of natural gas it was decided to investigate the case where natural gas costs equal that of oil on a $/MBtu basis. These results are contained in paragraph 6.3.5.

Finally, paragraph 6.3.6 summarizes the economic evaluations for all the Scenarios considered.

6.3.1 PROTOTYPE, 50th and 300th INSTALLATIONS ECONOMICS (SCENARIOS A, D, and E)

Scenarios D and E are identical to Scenario A except that the capital costs were estimated to be approximately 40 and 26 percent respectively taking into account an 0.85 learning factor. Further, Scenarios D and E do not include first time engineering costs.

The summary of results of the economic analysis for the prototype facility (Scenario A), the 50th installation (Scenario D) and the 300th installation (Scenario E) are found in Tables 6.3-1, 6.3-4, and 6.3-5, respectively and in Figure 6.3-1.

Figure 6.3-1 is a plot of the Discounted Benefit/Cost Ratio and the Payback Period vs. Number of Units. It can be seen from the plot that the benefit/cost ratio goes from approximately 0.32 for the prototype to 1.5 for the 300th unit. The benefit/cost ratio exceeds 1.0 after the installation of the 65th unit. The payback period decreases from approximately 67 years for the prototype to approximately 17 years for the 300th unit.

6.3.2 AIR FORCE ECONOMIC VIEW (SCENARIO B)

Scenario B is identical to Scenario A except that the capital costs are eliminated, thereby, permitting economic analysis of the Air Force investment (i.e. owners' costs and O&M costs) which has the full advantage of the DOE investment. Table 6.3-2 summarizes the results of the economic analysis. The benefit/cost ratio was determined to be approximately 8.2 with a payback period of about 4 years.

6.3.3 DOE ECONOMIC VIEW (SCENARIO C)

Scenario C is identical to Scenario A except the owners' costs and O&M costs are eliminated which, as stated earlier, will be provided by the Air Force.

TABLE 6.3-1: ECIP ECONOMIC ANALYSIS SUMMARY
(SCENARIO A)

Location: Robin Air Force Base FY 1985
Project: Solar Cogeneration Facility

Economic Life: 25 Yrs. Date Prepared: 1981 Prepared by D. W. Miller

COSTS

1. Non-recurring Initial Capital Costs:
   a. CWE $ 9,323,926
   b. Design $ 2,523,893
   c. Indirect $ 2,815,060
   d. Total $14,662,879

BENEFITS

2. (i) Recurring Benefit/Cost Differential Othern than Energy:
   a. Annual Labor Decrease (+)/Increase (-) $ 2,387 /Yr.
   b. Annual Material Decrease (+)/Increase (-) $ - /Yr.
   c. Other Annual Decrease (+)/Increase (-) $ -206,970/Yr.
   d. Total Costs $ -204,583
   e. 10% Discount Factor $ 9.524
   f. Discounted Energy Benefit/Cost (d x e) $-1,948,449
   (ii) Non-recurring Benefit/Cost Differential Other than Energy:
   g. Annual Material Decrease (+)/Increase (-) $ 560,790
   h. 10% Discount Factor 0.228
   i. Discounted Benefit/Cost (g x h) $ 127,860
   j. Total Benefit/Cost Differential Other than Energy (f + i) $-1,820,589
3. Recurring Energy Benefit/Costs:
   a. Type of Fuel: Electricity
      (1) Annual Energy Decrease (+)/Increase (-) 7,149 MBTU
      (2) Cost Per MBTU $ 4.96/MBTU
      (3) Annual Dollar Decrease/Increase [(1) x (2)] $ 35,459/Yr.
      (4) Differential Escalation Rate (7 %) Factor 18.049
      (5) Discounted Dollar Decrease/Increase [(3) x (4)] $ 640,000
   b. Type of Fuel: Natural Gas
      (1) Annual Energy Decrease (+)/Increase (-) 42,874 MBTU
      (2) Cost per MBTU $ 5.05 /MBTU
      (3) Annual Dollar Decrease/Increase [(1) x (2)] $ 216,514 /Yr.
      (4) Differential Escalation Rate (8 %) Factor 20.05
      (5) Discounted Dollar Decrease/Increase [(3) x (4)] $ 4,341,106
   c. Type of Fuel: Oil
      (1) Annual Energy Decrease (+)/Increase (-) 5,213 MBTU
      (2) Cost per MBTU $ 14.86 /MBTU
      (3) Annual Dollar Decrease/Increase [(1) x (2)] $ 77,465 /Yr.
      (4) Differential Escalation Rate (8 %) Factor 20.05
      (5) Discounted Dollar Decrease/Increase [(3) x (4)] $ 1,553,173
   d. Type of Fuel: ____
      (1) Annual Energy Decrease (+)/Increase (-) MBTU
      (2) Cost per MBTU $ /MBTU
      (3) Annual Dollar Decrease/Increase [(1) x (2)] $ /Yr.
      (4) Differential Esclation Rate (___%) Factor
      (5) Discounted Dollar Decrease/Increase [(3) x (4)] $
   e. Discounted Energy Benefits [3a(5)+3b(5)+3c(5)+3d(5)] $ 6,534,279
4. Total Benefits (Sum 2j + 3e) $ 4,713,690
5. Discounted Benefit/Cost Ratio (Line 4 ÷ Line 1d) $ 0.32
6. Total Annual Energy Savings [3a(1)+3b(1)+3c(1)+3d(1)] 55,236 MBTU
7. E/C Ratio (Line 6 ÷ Line 1a/1000) 5.92
8. Annual Dollar Savings [2d+3a(3)+3b(3)+3c(3)+3d(3)] $ 138,941
9. Pay-Back Period [(Line 1a - Salvage) ÷ Line 8] 67.1 Yrs.

TABLE 6.3-2: ECIP ECONOMIC ANALYSIS SUMMARY

(SCENARIO B)

Location: Robin Air Force Base FY 1985

Project: Solar Cogeneration Facility

Economic Life: 25 Yrs. Date Prepared: 1981 Prepared by D. W. Miller

COSTS

1. Non-recurring Initial Capital Costs:	
a. CWE	$ 578,688
b. Design	$
c.	$
d. Total	$ 578,688
BENEFITS	
2. (i) Recurring Benefit/Cost Differential Othern than Energy:	
a. Annual Labor Decrease (+)/Increase (-)	$ 2,387 /Yr.
b. Annual Material Decrease (+)/Increase (-)	$ - /Yr.
c. Other Annual Decrease (+)/Increase (-)	$ -206,970 /Yr.
d. Total Costs	$ -204,583
e. 10% Discount Factor	$ 9.524
f. Discounted Energy Benefit/Cost (d x e)	$ -1,948,449
(ii) Non-recurring Benefit/Cost Differential Other than Energy:	
g. Annual Material Decrease (+)/Increase (-)	$ 560,790
h. 10% Discount Factor	0.228
i. Discounted Benefit/Cost (g x h)	$ 127,860
j. Total Benefit/Cost Differential Other than Energy (f + i)	$-1,820,589
3. Recurring Energy Benefit/Costs:	
a. Type of Fuel: Electricity	
(1) Annual Energy Decrease (+)/Increase (-)	7,149 MBTU
(2) Cost Per MBTU	$ 4.96 /MBTU
(3) Annual Dollar Decrease/Increase [(1) x (2)]	$ 35,459 /Yr.
(4) Differential Escalation Rate (7 %) Factor	18.049
(5) Discounted Dollar Decrease/Increase [(3) x (4)]	$ 640,000
b. Type of Fuel: Natural Gas	
(1) Annual Energy Decrease (+)/Increase (-)	42,874 MBTU
(2) Cost per MBTU	$ 5.05 /MBTU
(3) Annual Dollar Decrease/Increase [(1) x (2)]	$ 216,514 /Yr.
(4) Differential Escalation Rate (8 %) Factor	20.05
(5) Discounted Dollar Decrease/Increase [(3) x (4)]	$4,341,106
c. Type of Fuel: Oil	
(1) Annual Energy Decrease (+)/Increase (-)	5,213 MBTU
(2) Cost per MBTU	$ 14.86 /MBTU
(3) Annual Dollar Decrease/Increase [(1) x (2)]	$ 77,465 /Yr.
(4) Differential Escalation Rate (8 %) Factor	20.05
(5) Discounted Dollar Decrease/Increase [(3) x (4)]	$1,553,173
d. Type of Fuel:	
(1) Annual Energy Decrease (+)/Increase (-)	MBTU
(2) Cost per MBTU	$ /MBTU
(3) Annual Dollar Decrease/Increase [(1) x (2)]	$ /Yr.
(4) Differential Esclation Rate (%) Factor	
(5) Discounted Dollar Decrease/Increase [(3) x (4)]	$
e. Discounted Energy Benefits [3a(5)+3b(5)+3c(5)+3d(5)]	$6,534,279
4. Total Benefits (Sum 2j + 3e)	$4,713,690
5. Discounted Benefit/Cost Ratio (Line 4 ÷ Line 1d)	$ 8.15
6. Total Annual Energy Savings [3a(1)+3b(1)+3c(1)+3d(1)]	55,523 MBTU
7. E/C Ratio (Line 6 ÷ Line 1a/1000)	95.5
8. Annual Dollar Savings [2d+3a(3)+3b(3)+3c(3)+3d(3)]	$ 138,941
9. Pay-Back Period [(Line 1a - Salvage) ÷ Line 8]	4.16 Yrs.

TABLE 6.3-3: ECIP ECONOMIC ANALYSIS SUMMARY
(SCENARIO C)

Location: Robin Air Force Base FY 1985
Project: Solar Cogeneration Facility

Economic Life: 25 Yrs. Date Prepared: 1981 Prepared by D. W. Miller

COSTS	
1. Non-recurring Initial Capital Costs:	
a. CWE	$8,745,239
b. Design	$2,523,893
c. Indirect	$2,815,060
d. Total	$14,084,192
BENEFITS	
2. (i) Recurring Benefit/Cost Differential Othern than Energy:	
a. Annual Labor Decrease (+)/Increase (-)	$ - /Yr.
b. Annual Material Decrease (+)/Increase (-)	$ /Yr.
c. Other Annual Decrease (+)/Increase (-)	$ - /Yr.
d. Total Costs	$ -
e. 10% Discount Factor	$ 9.524
f. Discounted Energy Benefit/Cost (d x e)	$ -
(ii) Non-recurring Benefit/Cost Differential Other than Energy:	
g. Annual Material Decrease (+)/Increase (-)	$ 560,790
h. 10% Discount Factor	0.228
i. Discounted Benefit/Cost (g x h)	$ 127,860
j. Total Benefit/Cost Differential Other than Energy (f + i)	$ 127,860
3. Recurring Energy Benefit/Costs:	
a. Type of Fuel: Electricity	
(1) Annual Energy Decrease (+)/Increase (-)	7,149 MBTU
(2) Cost Per MBTU	$ 4.96 /MBTU
(3) Annual Dollar Decrease/Increase [(1) x (2)]	$ 35,459 /Yr.
(4) Differential Escalation Rate (7 %) Factor	18.049
(5) Discounted Dollar Decrease/Increase [(3) x (4)]	$ 640,000
b. Type of Fuel: Natural Gas	
(1) Annual Energy Decrease (+)/Increase (-)	42,874 MBTU
(2) Cost per MBTU	$ 5.05 /MBTU
(3) Annual Dollar Decrease/Increase [(1) x (2)]	$ 216,514 /Yr.
(4) Differential Escalation Rate (8 %) Factor	20.05
(5) Discounted Dollar Decrease/Increase [(3) x (4)]	$4,341,106
c. Type of Fuel: Oil	
(1) Annual Energy Decrease (+)/Increase (-)	5,213 MBTU
(2) Cost per MBTU	$ 14.86 /MBTU
(3) Annual Dollar Decrease/Increase [(1) x (2)]	$ 77,465 /Yr.
(4) Differential Escalation Rate (8 %) Factor	20.05
(5) Discounted Dollar Decrease/Increase [(3) x (4)]	$1,553,173
d. Type of Fuel:	
(1) Annual Energy Decrease (+)/Increase (-)	MBTU
(2) Cost per MBTU	$ /MBTU
(3) Annual Dollar Decrease/Increase [(1) x (2)]	$ /Yr.
(4) Differential Esclation Rate (%) Factor	
(5) Discounted Dollar Decrease/Increase [(3) x (4)]	$
e. Discounted Energy Benefits [3a(5)+3b(5)+3c(5)+3d(5)]	$ 6,534,279
4. Total Benefits (Sum 2j + 3e)	$ 4,713,690
5. Discounted Benefit/Cost Ratio (Line 4 ÷ Line 1d)	$ 0.33
6. Total Annual Energy Savings [3a(1)+3b(1)+3c(1)+3d(1)]	55,236 MBTU
7. E/C Ratio (Line 6 ÷ Line 1a/1000)	6.32
8. Annual Dollar Savings [2d+3a(3)+3b(3)+3c(3)+3d(3)]	$ 343,524
9. Pay-Back Period [(Line 1a - Salvage) ÷ Line 8]	25.5 Yrs.

TABLE 6.3-4: ECIP ECONOMIC ANALYSIS SUMMARY
(SCENARIO D)

Location: Robin Air Force Base FY 1985
Project: Solar Cogeneration Facility

Economic Life: 25 Yrs. Date Prepared: 1981 Prepared by D. W. Miller

COSTS		
1.	Non-recurring Initial Capital Costs:	
	a. CWE	$ 3,725,811
	b. Design	$
	c. Indirect	$ 1,124,898
	d. Total	$4,850,709
BENEFITS		
2. (i)	Recurring Benefit/Cost Differential Othern than Energy:	
	a. Annual Labor Decrease (+)/Increase (-)	$ 2,387 /Yr.
	b. Annual Material Decrease (+)/Increase (-)	$ - /Yr.
	c. Other Annual Decrease (+)/Increase (-)	$ -206,970 /Yr.
	d. Total Costs	$ -204,583
	e. 10% Discount Factor	$ 9,524
	f. Discounted Energy Benefit/Cost (d x e)	$ -1,948,449
(ii)	Non-recurring Benefit/Cost Differential Other than Energy:	
	g. Annual Material Decrease (+)/Increase (-)	$ 560,790
	h. 10% Discount Factor	0.228
	i. Discounted Benefit/Cost (g x h)	$ 127,860
	j. Total Benefit/Cost Differential Other than Energy (f + i)	$-1,820,589
3.	Recurring Energy Benefit/Costs:	
	a. Type of Fuel: Electricity	
	(1) Annual Energy Decrease (+)/Increase (-)	7,149 MBTU
	(2) Cost Per MBTU	$ 4.96/MBTU
	(3) Annual Dollar Decrease/Increase [(1) x (2)]	$ 35,459/Yr.
	(4) Differential Escalation Rate (7 %) Factor	18.049
	(5) Discounted Dollar Decrease/Increase [(3) x (4)]	$ 640,000
	b. Type of Fuel: Natural Gas	
	(1) Annual Energy Decrease (+)/Increase (-)	42,874 MBTU
	(2) Cost per MBTU	$ 5.05 /MBTU
	(3) Annual Dollar Decrease/Increase [(1) x (2)]	$ 2,165,141 /Yr.
	(4) Differential Escalation Rate (8 %) Factor	20.05
	(5) Discounted Dollar Decrease/Increase [(3) x (4)]	$ 4,341,106
	c. Type of Fuel: Oil	
	(1) Annual Energy Decrease (+)/Increase (-)	5,213 MBTU
	(2) Cost per MBTU	$ 14.86 /MBTU
	(3) Annual Dollar Decrease/Increase [(1) x (2)]	$ 77,465 /Yr.
	(4) Differential Escalation Rate (8 %) Factor	20.05
	(5) Discounted Dollar Decrease/Increase [(3) x (4)]	$ 1,553,173
	d. Type of Fuel:	
	(1) Annual Energy Decrease (+)/Increase (-)	MBTU
	(2) Cost per MBTU	$ /MBTU
	(3) Annual Dollar Decrease/Increase [(1) x (2)]	$ /Yr.
	(4) Differential Esclation Rate (%) Factor	
	(5) Discounted Dollar Decrease/Increase [(3) x (4)]	$
	e. Discounted Energy Benefits [3a(5)+3b(5)+3c(5)+3d(5)]	$ 6,534,279
4.	Total Benefits (Sum 2j + 3e)	$ 4,713,690
5.	Discounted Benefit/Cost Ratio (Line 4 ÷ Line 1d)	$ 0.97
6.	Total Annual Energy Savings [3a(1)+3b(1)+3c(1)+3d(1)]	55,236 MBTU
7.	E/C Ratio (Line 6 ÷ Line 1a/1000)	14.8
8.	Annual Dollar Savings [2d+3a(3)+3b(3)+3c(3)+3d(3)]	$ 138,941
9.	Pay-Back Period [(Line 1a - Salvage) ÷ Line 8]	26.8 Yrs.

TABLE 6.3-5 ECIP ECONOMIC ANALYSIS SUMMARY

(SCENARIO E)

Location: Robin Air Force Base FY 1985

Project: Solar Cogeneration Facility

Economic Life: 25 Yrs. Date Prepared: 1981 Prepared by D. W. Miller

COSTS	
1. Non-recurring Initial Capital Costs:	
a. CWE	$ 2,447,531
b. Design	$
c. Indirect	$ 738,933
d. Total	$3,186,464
BENEFITS	
2. (i) Recurring Benefit/Cost Differential Othern than Energy:	
a. Annual Labor Decrease (+)/Increase (-)	$ 2,387 /Yr.
b. Annual Material Decrease (+)/Increase (-)	$ - /Yr.
c. Other Annual Decrease (+)/Increase (-)	$ -206,970 /Yr.
d. Total Costs	$ -204,583
e. 10% Discount Factor	$ 9.524
f. Discounted Energy Benefit/Cost (d x e)	$ -1,948,449
(ii) Non-recurring Benefit/Cost Differential Other than Energy:	
g. Annual Material Decrease (+)/Increase (-)	$ 560,790
h. 10% Discount Factor	0.228
i. Discounted Benefit/Cost (g x h)	$ 127,860
j. Total Benefit/Cost Differential Other than Energy (f + i)	$-1,820,589
3. Recurring Energy Benefit/Costs:	
a. Type of Fuel: Electricity	
(1) Annual Energy Decrease (+)/Increase (-)	7,149 MBTU
(2) Cost Per MBTU	$ 4.96 /MBTU
(3) Annual Dollar Decrease/Increase [(1) x (2)]	$ 35,459 /Yr.
(4) Differential Escalation Rate (7 %) Factor	18.049
(5) Discounted Dollar Decrease/Increase [(3) x (4)]	$ 640,000
b. Type of Fuel: Natural Gas	
(1) Annual Energy Decrease (+)/Increase (-)	42,874 MBTU
(2) Cost per MBTU	$ 5.05 /MBTU
(3) Annual Dollar Decrease/Increase [(1) x (2)]	$ 216,514 /Yr.
(4) Differential Escalation Rate (8 %) Factor	20.05
(5) Discounted Dollar Decrease/Increase [(3) x (4)]	$ 4,341,106
c. Type of Fuel: Oil	
(1) Annual Energy Decrease (+)/Increase (-)	5,213 MBTU
(2) Cost per MBTU	$ 14.86 /MBTU
(3) Annual Dollar Decrease/Increase [(1) x (2)]	$ 77,465 /Yr.
(4) Differential Escalation Rate (8 %) Factor	20.05
(5) Discounted Dollar Decrease/Increase [(3) x (4)]	$ 1,553,173
d. Type of Fuel:	
(1) Annual Energy Decrease (+)/Increase (-)	MBTU
(2) Cost per MBTU	$ /MBTU
(3) Annual Dollar Decrease/Increase [(1) x (2)]	$ /Yr.
(4) Differential Esclation Rate (%) Factor	
(5) Discounted Dollar Decrease/Increase [(3) x (4)]	$
e. Discounted Energy Benefits [3a(5)+3b(5)+3c(5)+3d(5)]	$ 6,534,279
4. Total Benefits (Sum 2j + 3e)	$ 4,713,690
5. Discounted Benefit/Cost Ratio (Line 4 ÷ Line 1d)	$ 1.48
6. Total Annual Energy Savings [3a(1)+3b(1)+3c(1)+3d(1)]	55,236 MBTU
7. E/C Ratio (Line 6 ÷ Line 1a/1000)	22.50
8. Annual Dollar Savings [2d+3a(3)+3b(3)+3c(3)+3d(3)]	$ 138,941
9. Pay-Back Period [(Line 1a - Salvage) ÷ Line 8]	17.6 Yrs.

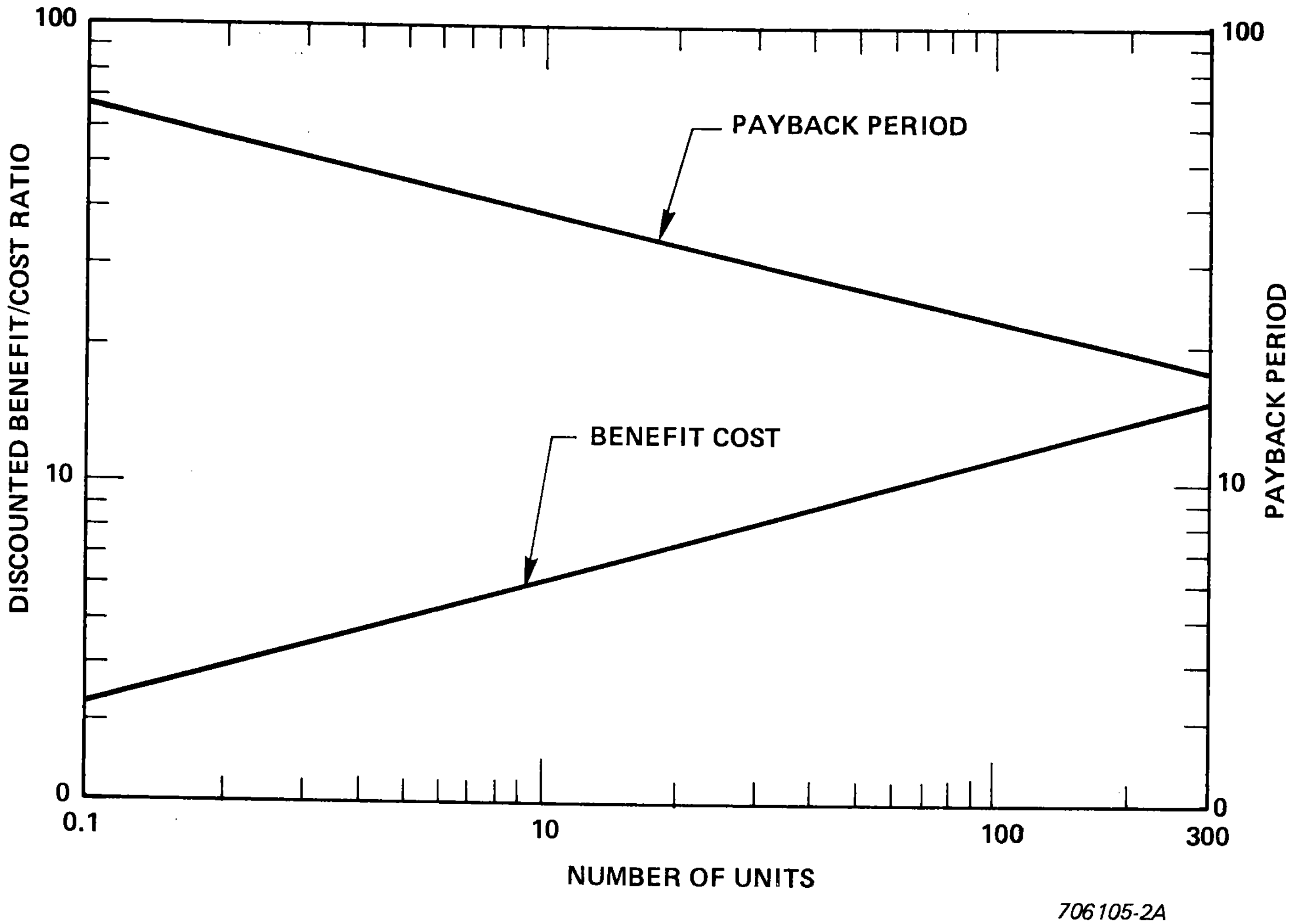

Figure 6.3-1. Discounted Benefit/Cost Ratio and Payback Period vs. Number of Units

The results of the economic analysis from a DOE economic view are presented in Table 6.3-3. The benefit/cost ratio was calculated to be approximately 0.33 with a payback period of approximately 26 years. (Note that the ECIP guideline method does not include one time engineering cost in computing the payback period.)

6.3.4 INCREASED FUEL DIFFERENTIAL ESCALATION RATES (SCENARIOS F AND G)

Scenarios F and G are identical to Scenario A except the differential escalation rates for natural gas and oil were increased to 10 percent for Scenario F and 12 percent for Scenario G. Tables 6.3-6 and 6.3-7 show the results of the economic analysis for Scenarios F and G, respectively. Figure 6.3-2 shows that with all else remaining the same the effects of these changes are seen in the beneift/cost ratio which increases from the approximate 0.36 for the ECIP differential escalation rates to approximately 0.44 for 10 percent and 0.58 for 12 percent. Using the ECIP methodology the payback period remains constant at 67.1 years. Figure 6.3-3 shows that the benefit/cost ratio equals 1.0 at 65 units for 8 percent differential escalation. This reduces to 25 units and 10 units for 10 percent and 12 percent, respectively. Finally, Figure 6.3-4 is a plot of the differential escalation rate vs the number of units for a benefit/cost ratio equal 1.0 and illustrates that modest increases in fuel escalation rates have a strong impact upon the benefit/cost ratio.

6.3.5 NATURAL GAS DE-REGULATED (SCENARIO H)

Due to the possibility of natural gas de-regulation, it was decided to look at a case where the natural gas costs were assumed to be equal to the current oil costs on a $/MBtu basis. These results are contained on Table 6.3-8. From this table it can be seen that a benefit/cost ratio of 0.9 is achieved with an approximate payback period of 17 years. A comparison to Scenario A shows this assumption of natural gas de-regulation to have a profound effect on the facility from an economic assessment point of view.

TABLE 6.3-6: ECIP ECONOMIC ANALYSIS SUMMARY
(SCENARIO F)

Location: Robin Air Force Base FY 1985

Project: Solar Cogeneration Facility

Economic Life: 25 Yrs. Date Prepared: 1981 Prepared by D. W. Miller

COSTS	
1. Non-recurring Initial Capital Costs:	
a. CWE	$9,323,926
b. Design	$2,523,893
c. Indirect	$2,815,060
d. Total	$14,662,879
BENEFITS	
2. (i) Recurring Benefit/Cost Differential Othern than Energy:	
a. Annual Labor Decrease (+)/Increase (-)	$ 2,387 /Yr.
b. Annual Material Decrease (+)/Increase (-)	$ - /Yr.
c. Other Annual Decrease (+)/Increase (-)	$ -206,970 /Yr.
d. Total Costs	$ -204,583
e. 10% Discount Factor	$ 9.524
f. Discounted Energy Benefit/Cost (d x e)	$-1,948,449
(ii) Non-recurring Benefit/Cost Differential Other than Energy:	
g. Annual Material Decrease (+)/Increase (-)	$ 560,790
h. 10% Discount Factor	0.228
i. Discounted Benefit/Cost (g x h)	$ 127,860
j. Total Benefit/Cost Differential Other than Energy (f + i)	$-1,820,589
3. Recurring Energy Benefit/Costs:	
a. Type of Fuel: Electricity	
(1) Annual Energy Decrease (+)/Increase (-)	7,149 MBTU
(2) Cost Per MBTU	$ 4.96 /MBTU
(3) Annual Dollar Decrease/Increase [(1) x (2)]	$ 35,459 /Yr.
(4) Differential Escalation Rate (7 %) Factor	18.049
(5) Discounted Dollar Decrease/Increase [(3) x (4)]	$ 640,000
b. Type of Fuel: Natural Gas	
(1) Annual Energy Decrease (+)/Increase (-)	42,874 MBTU
(2) Cost per MBTU	$ 5.05 /MBTU
(3) Annual Dollar Decrease/Increase [(1) x (2)]	$ 216,514 /Yr.
(4) Differential Escalation Rate (10 %) Factor	25.0
(5) Discounted Dollar Decrease/Increase [(3) x (4)]	$5,412,850
c. Type of Fuel: Oil	
(1) Annual Energy Decrease (+)/Increase (-)	5,213 MBTU
(2) Cost per MBTU	$ 14.86 /MBTU
(3) Annual Dollar Decrease/Increase [(1) x (2)]	$ 77,465 /Yr.
(4) Differential Escalation Rate (10 %) Factor	25.0
(5) Discounted Dollar Decrease/Increase [(3) x (4)]	$1,936,625
d. Type of Fuel:	
(1) Annual Energy Decrease (+)/Increase (-)	MBTU
(2) Cost per MBTU	$ /MBTU
(3) Annual Dollar Decrease/Increase [(1) x (2)]	$ /Yr.
(4) Differential Esclation Rate (%) Factor	
(5) Discounted Dollar Decrease/Increase [(3) x (4)]	$
e. Discounted Energy Benefits [3a(5)+3b(5)+3c(5)+3d(5)]	$ 7,989,475
4. Total Benefits (Sum 2j + 3e)	$ 6,168,886
5. Discounted Benefit/Cost Ratio (Line 4 ÷ Line 1d)	$ 0.44
6. Total Annual Energy Savings [3a(1)+3b(1)+3c(1)+3d(1)]	55,236 MBTU
7. E/C Ratio (Line 6 ÷ Line 1a/1000)	5.92
8. Annual Dollar Savings [2d+3a(3)+3b(3)+3c(3)+3d(3)]	$ 138,941
9. Pay-Back Period [(Line 1a - Salvage) ÷ Line 8]	67.1 Yrs.

TABLE 6.3-7 ECIP ECONOMIC ANALYSIS SUMMARY

(SCENARIO G)

Location: Robin Air Force Base FY 1985

Project: Solar Cogeneration Facility

Economic Life: 25 Yrs. Date Prepared: 1981 Prepared by D. W. Miller

COSTS	
1. Non-recurring Initial Capital Costs:	
a. CWE	$ 9,323,926
b. Design	$ 2,523,893
c. Indirect	$ 2,815,060
d. Total	$ 14,662,879
BENEFITS	
2. (i) Recurring Benefit/Cost Differential Othern than Energy:	
a. Annual Labor Decrease (+)/Increase (-)	$ 2,387/Yr.
b. Annual Material Decrease (+)/Increase (-)	$ - /Yr.
c. Other Annual Decrease (+)/Increase (-)	$ -206,970/Yr.
d. Total Costs	$ -204,583
e. 10% Discount Factor	$ 9.524
f. Discounted Energy Benefit/Cost (d x e)	$ 1,948,449
(ii) Non-recurring Benefit/Cost Differential Other than Energy:	
g. Annual Material Decrease (+)/Increase (-)	$ 560,790
h. 10% Discount Factor	0.228
i. Discounted Benefit/Cost (g x h)	$ 127,860
j. Total Benefit/Cost Differential Other than Energy (f + i)	$-1,820,589
3. Recurring Energy Benefit/Costs:	
a. Type of Fuel: Electricity	
(1) Annual Energy Decrease (+)/Increase (-)	7,149 MBTU
(2) Cost Per MBTU	$ 4.96 /MBTU
(3) Annual Dollar Decrease/Increase [(1) x (2)]	$ 35,459 /Yr.
(4) Differential Escalation Rate (7 %) Factor	18.049
(5) Discounted Dollar Decrease/Increase [(3) x (4)]	$ 640,000
b. Type of Fuel: Natural Gas	
(1) Annual Energy Decrease (+)/Increase (-)	42,874 MBTU
(2) Cost per MBTU	$ 5.05 /MBTU
(3) Annual Dollar Decrease/Increase [(1) x (2)]	$ 216,514/Yr.
(4) Differential Escalation Rate (12 %) Factor	31.1
(5) Discounted Dollar Decrease/Increase [(3) x (4)]	$ 6,733,585
c. Type of Fuel: Oil	
(1) Annual Energy Decrease (+)/Increase (-)	5,213 MBTU
(2) Cost per MBTU	$ 14.86/MBTU
(3) Annual Dollar Decrease/Increase [(1) x (2)]	$ 77,465/Yr.
(4) Differential Escalation Rate (12 %) Factor	31.1
(5) Discounted Dollar Decrease/Increase [(3) x (4)]	$ 2,409,162
d. Type of Fuel:	
(1) Annual Energy Decrease (+)/Increase (-)	MBTU
(2) Cost per MBTU	$ /MBTU
(3) Annual Dollar Decrease/Increase [(1) x (2)]	$ /Yr.
(4) Differential Esclation Rate (%) Factor	
(5) Discounted Dollar Decrease/Increase [(3) x (4)]	$
e. Discounted Energy Benefits [3a(5)+3b(5)+3c(5)+3d(5)]	$ 9,786,787
4. Total Benefits (Sum 2j + 3e)	$ 7,966,158
5. Discounted Benefit/Cost Ratio (Line 4 ÷ Line 1d)	$ 0.54
6. Total Annual Energy Savings [3a(1)+3b(1)+3c(1)+3d(1)]	55,236 MBTU
7. E/C Ratio (Line 6 ÷ Line 1a/1000)	5.92
8. Annual Dollar Savings [2d+3a(3)+3b(3)+3c(3)+3d(3)]	$ 138,941
9. Pay-Back Period [(Line 1a - Salvage) ÷ Line 8]	67.1 Yrs.

TABLE 6.3-8

ECIP ECONOMIC ANALYSIS SUMMARY
(SCENARIO H)

Location: Robin Air Force Base FY 1985
Project: Solar Cogeneration Facility

Economic Life: 25 Yrs. Date Prepared: 1981 Prepared by D. W. Miller

COSTS

1. Non-recurring Initial Capital Costs:

a.	CWE	$ 9,323,926
b.	Design	$ 2,523,893
c.	Indirect	$ 2,815,060
d.	Total	$ 14,662,879

BENEFITS

2. (i) Recurring Benefit/Cost Differential Othern than Energy:

a.	Annual Labor Decrease (+)/Increase (-)	$ 2,387/Yr.
b.	Annual Material Decrease (+)/Increase (-)	$ - /Yr.
c.	Other Annual Decrease (+)/Increase (-)	$ -206,970/Yr.
d.	Total Costs	$ -204,583
e.	10% Discount Factor	$ 9.524
f.	Discounted Energy Benefit/Cost (d x e)	$-1,948,449

(ii) Non-recurring Benefit/Cost Differential Other than Energy:

g.	Annual Material Decrease (+)/Increase (-)	$ 560,790
h.	10% Discount Factor	0.228
i.	Discounted Benefit/Cost (g x h)	$ 127,860
j.	Total Benefit/Cost Differential Other than Energy (f + i)	$-1,820,589

3. Recurring Energy Benefit/Costs:

a. Type of Fuel: Electricity

(1)	Annual Energy Decrease (+)/Increase (-)	7,149 MBTU
(2)	Cost Per MBTU	$ 4.96 /MBTU
(3)	Annual Dollar Decrease/Increase [(1) x (2)]	$ 35,459 /Yr.
(4)	Differential Escalation Rate (7 %) Factor	18.049
(5)	Discounted Dollar Decrease/Increase [(3) x (4)]	$ 640,000

b. Type of Fuel: Natural Gas

(1)	Annual Energy Decrease (+)/Increase (-)	42,874 MBTU
(2)	Cost per MBTU	$ 14.86/MBTU
(3)	Annual Dollar Decrease/Increase [(1) x (2)]	$ 637,108 /Yr.
(4)	Differential Escalation Rate (7 %) Factor	20.05
(5)	Discounted Dollar Decrease/Increase [(3) x (4)]	$12,774,015

c. Type of Fuel: Oil

(1)	Annual Energy Decrease (+)/Increase (-)	5,213 MBTU
(2)	Cost per MBTU	$ 14.86/MBTU
(3)	Annual Dollar Decrease/Increase [(1) x (2)]	$ 77,465 /Yr.
(4)	Differential Escalation Rate (%) Factor	20.05
(5)	Discounted Dollar Decrease/Increase [(3) x (4)]	$ 1,553,173

d. Type of Fuel:

(1)	Annual Energy Decrease (+)/Increase (-)	MBTU
(2)	Cost per MBTU	$ /MBTU
(3)	Annual Dollar Decrease/Increase [(1) x (2)]	$ /Yr.
(4)	Differential Esclation Rate (%) Factor	
(5)	Discounted Dollar Decrease/Increase [(3) x (4)]	$

e. Discounted Energy Benefits [3a(5)+3b(5)+3c(5)+3d(5)] $ 14,967,188

4.	Total Benefits (Sum 2j + 3e)	$ 13,146,599
5.	Discounted Benefit/Cost Ratio (Line 4 ÷ Line 1d)	$ 0.90
6.	Total Annual Energy Savings [3a(1)+3b(1)+3c(1)+3d(1)]	55,236 MBTU
7.	E/C Ratio (Line 6 ÷ Line 1a/1000)	5.92
8.	Annual Dollar Savings [2d+3a(3)+3b(3)+3c(3)+3d(3)]	$ 545,449
9.	Pay-Back Period [(Line 1a - Salvage) ÷ Line 8]	17.1 Yrs.

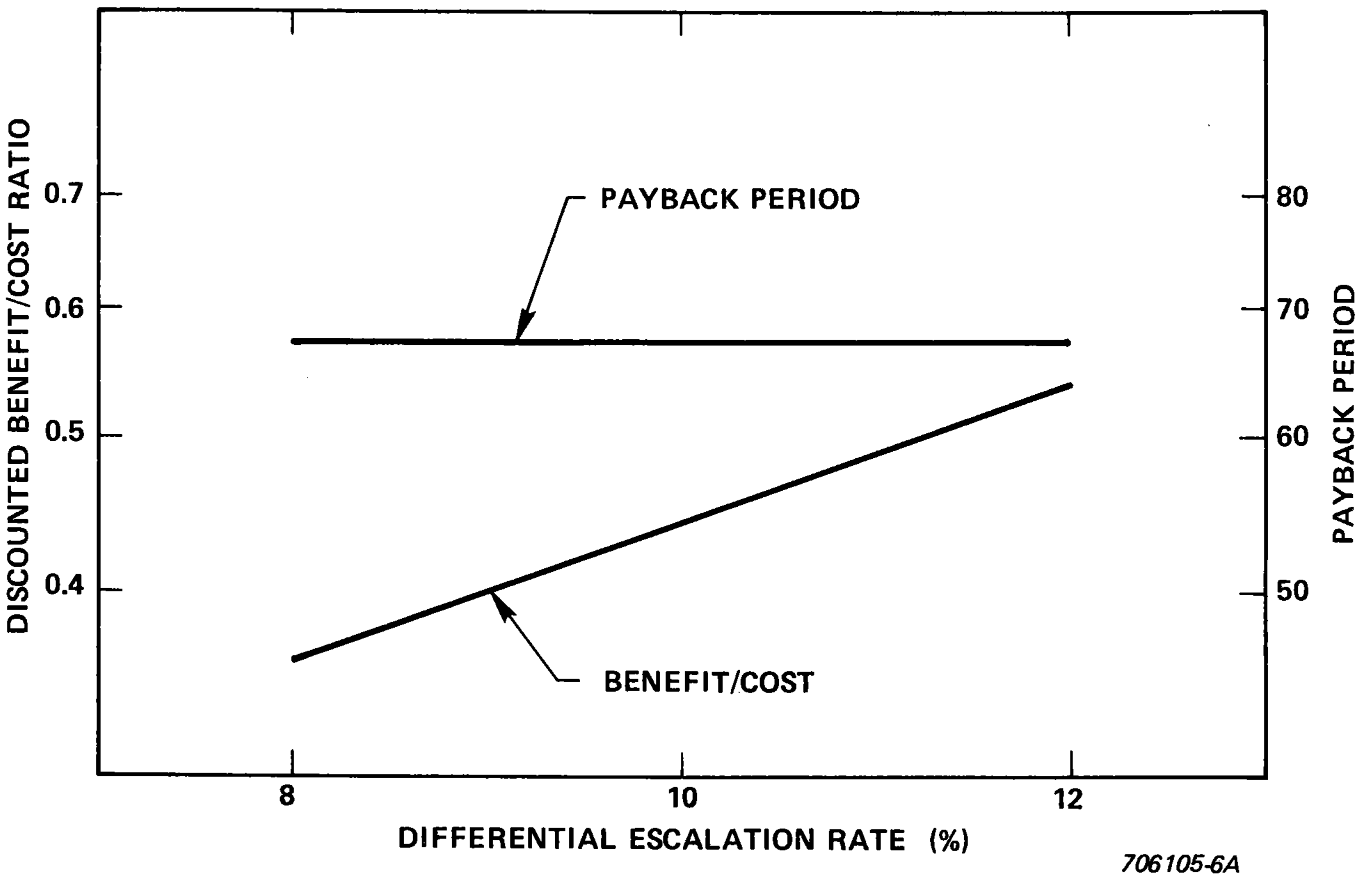

Figure 6.3-2. Discounted Benefit/Cost Ratio and Payback Period vs. Differential Escalation Rate

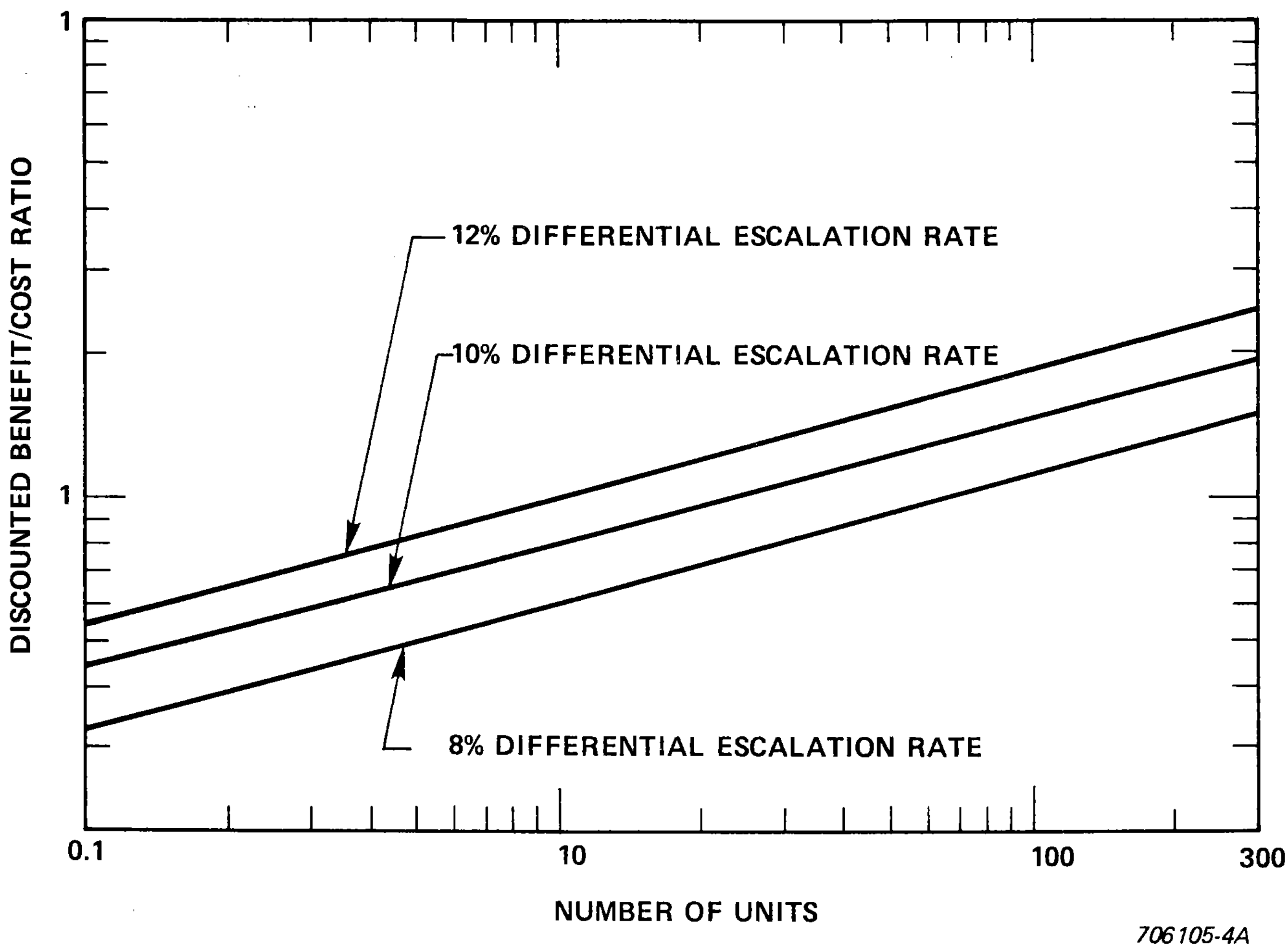

Figure 6.3-3. Discounted Benefit/Cost Ratio vs. Number of Units

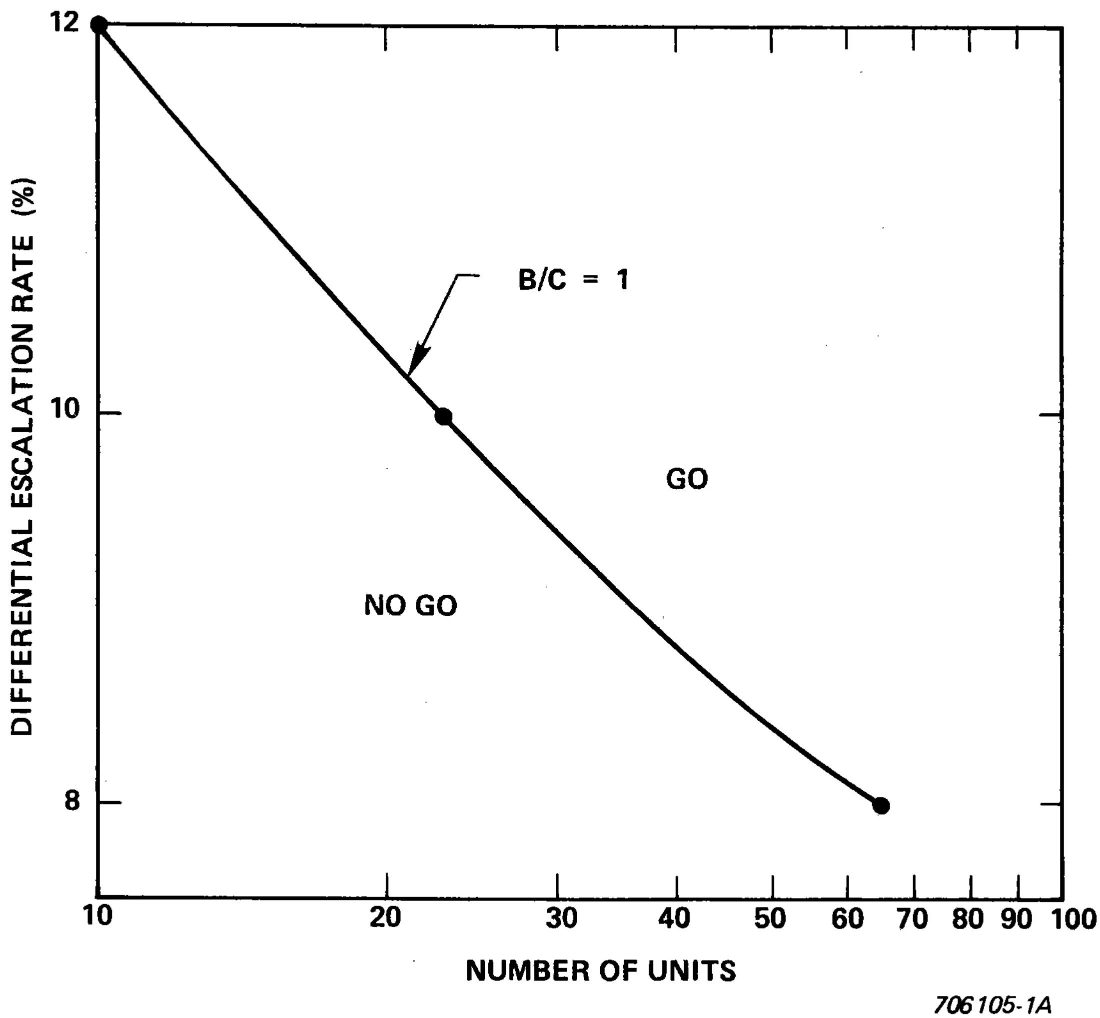

Figure 6.3-4. Differential Escalation Rates vs. Number of Units

6.3.6 SUMMARY

The economic assessment of the solar facility was based on the methodology and economic assumptions defined by the USAF Energy Conservation Investment Program (ECIP). This approach is basically a present worth analysis of non-recurring capital costs, recurring operating and maintenance costs, and recurring benefits due to reduced energy usage.

A marked improvement in the economic analysis occurred as a result of considering multiple installations with the benefit/cost ratio going from 0.32 to 1.0 after only 65 installations. Similarly the payback period decreased from 67 years to 25 years after 65 installations and to 17 years after 300 installations.

With a benefit/cost ratio of 8.2 the Air Force economic view showed that the Air Force would obtain a payback of the initial owners costs in about 4 years.

With the Air Force providing the owners' costs and the on-going O&M costs, the DOE economic view showed a benefit/cost ratio of 0.33 with a payback period of approximately 26 years (Payback period calculation ignores one-time engineering costs). If all DOE costs are included in payback calculation, the period becomes approximately 37 years.

Consideration of 10 and 12 percent differential escalation rates as compared to the ECIP 8 percent yielded improvements in the benefit/cost ratio from 0.36 to 0.44 and 0.58 for 10 and 12 percent, respectively.

A large change was observed when the natural gas costs were assumed to be equal to oil costs on a $/MBtu basis. The Benefit/Cost ratio raised to 0.9 as compared to 0.32 for Scenario A and the payback period decreased from 67.1 years in Scenario A to 17 years.

Summarily, we believe that considerable technological advances in solar energy systems could be obtained from the installation and operation of the solar cogeneration facility at Robins Air Force Base with, what is considered to be, a modest capital investment.

7.0 DEVELOPMENT PLAN

The Development Plan (Task 6) for the design and construction of a solar cogeneration facility at Robins Air Force Base is presented in this section. This development plan covers the steps required to proceed from the conceptual design of the facility up to and including the initiation of the user (USAF) operations phase. These steps consist of the advanced conceptual design, preliminary and detailed design, procurement, construction, checkout, startup, training, performance validation and monitoring of one year of USAF operations. Each phase in the development is described in this section with the objective of providing a solar cogeneration facility capable of operation by March 1, 1986.

Shown in Table 7.1-1 is a Work Breakdown Structure (WBS) for the preliminary and detailed design and construction phases of the solar facility. This WBS summarizes the major areas of activity occurring over a three and one-half year period beginning on October 1, 1982. The WBS approach to the development plan provides appropriate visibility and control of the technical effort, schedules and costs during the project.

Included in this section on the development plan are discussions of the objectives, technical and economic issues, preferences for project management, major milestones, schedule and activities to be performed during each of the following phases: Design Phase (Section 7.1), Construction Phase (7.2), Cogeneration Facility Checkout and Startup Phase (7.3), Cogeneration Facility Performance Validation Phase (7.4) and the User (USAF) Operations Phase (7.5). Included in Section 7.6 is the overall Schedule and Milestone Chart. The roles of the Site Owner (USAF), Government (DOE) and Industry, a discussion of Risk Sharing, and the Expenditures Schedule are presented in Section 7.7.

7.1 DESIGN PHASE

The Design Phase in the development of a solar cogeneration facility at Robins AFB encompasses several activities that focus on the development of more

TABLE 7.1-1: WORK BREAKDOWN STRUCTURE FOR PRELIMINARY AND DETAILED DESIGN AND CONSTRUCTION OF ROBINS AFB SOLAR COGENERATION FACILITY

WBS NO.	DESCRIPTION	WBS NO.	DESCRIPTION	RESPONSIBILITY/SUPPORT		
				W	H&H	F-W
1100	Facility Engineering	1110	Facility Specifications	R	S	S
		1120	Integrated Facility Design and Analysis	R	S	S
		1130	Safety Analysis/Assessment	R	S	S
		1140	Environmental Impact Statement/Permit	R	S	S
		1150	Facility Operating and Maintenance Manuals	S	R	S
		1160	Training of Operating and Maintenance Crews	S	R	S
1200	Site Preparation and Improvements	1210	Site Plan	S	R	-
		1220	Site Preparation	S	R	-
		1230	Site Modifications	S	R	-
1300	Collector System	1310	Tailor Collector Subsystem Specification A10772 to Site-Specific Application	R	S	-
		1320	Heliostats and Auxiliary Equipment	R	S	-
		1330	Heliostat Control Subsystem	R	S	-
		1340	Heliostat Foundations	S	R	-
1400	Receiver System	1410	Receiver			
		1411	Preliminary and Detailed Engineering and Design	S	-	R
		1412	Receiver Components and Auxiliary Equipment	S	S	R
		1413	Receiver Control Subsystem	S	S	R
		1420	Tower			
		1421	Preliminary and Detailed Design	S	R	S
		1422	Foundation	S	R	-
		1423	Tower and Accessories	S	R	S

TABLE 7.1-1: WORK BREAKDOWN STRUCTURE FOR PRELIMINARY AND DETAILED DESIGN AND CONSTRUCTION OF ROBINS AFB SOLAR COGENERATION FACILITY (Continued)

WBS NO.	DESCRIPTION	WBS NO.	DESCRIPTION	RESPONSIBILITY/SUPPORT		
				W	H&H	F-W
1500	Master Control System (including Data Acquistion System)	1510	Preliminary and Detailed Design	R	S	-
		1520	Master Control System Computer and Auxiliary Equipment	R	S	-
		1530	Software	R	-	-
		1540	Control Interfaces and Equipment	R	S	S
		1550	Instrumentation and Data Acquisition	R	S	S
1600	Electrical Power Generating System	1610	Preliminary and Detailed Design	R	S	-
		1620	Steam Turbine, Gearbox and Generator	R	S	-
		1630	Switchgear, Transformer and Electrical Interface	S	R	-
1700	Balance of Facility - Steam and Feedwater System	1710	Preliminary and Detailed Design	S	R	S
		1720	Steam System Components and Piping	S	R	S
		1730	Feedwater System Components and Piping and Power Building	S	R	S
		1740	Facility Steam and Feedwater System Interface with Steam Plant No. 4	S	R	-
1800	Program Management	1810	Administration	R	S	S
		1820	Program Plan	R	S	S
		1830	Program Control	R	S	S
		1840	Quality Control	R	S	S
		1850	Reports and Reviews	R	S	S

detailed engineering information, procurement of long-lead hardware and revisions of design information based on DOE and vendor's data to support construction. These activities are discussed in the subsections which follow.

The basic objectives of the activities to be performed during the design phase are: a) to develop a preliminary and a detailed design of the solar facility and its components and systems, b) to identify the needs for and initiate the procurement of long-lead hardware and c) to perform appropriate safety analyses/assessments and environmental impact assessments, as required. In addition, parallel activities on upgrading the facility specifications and performing the overall integrated facility design and analysis efforts will be completed.

There are no technical or economic issues to be resolved during this design phase. The Westinghouse team plans to develop a detailed design which is best suited for this application at Robins AFB using a straightforward engineering design and analysis approach and which will achieve maximum economic value to the USAF and DOE at a minimal capital cost, while still deriving the full benefits of a solar cogeneration facility demonstration unit.

Project management during the design phase, as well as during the construction, checkout, startup and performance validation phases, will be performed by the Westinghouse Advanced Energy Systems Division. Thus, Westinghouse will be responsible for the design, development, construction and initial operation of the solar facility and they will be supported in this endeavor by the other Westinghouse team members: Heery and Heery, Inc., Foster Wheeler Solar Development Corporation, the U. S. Air Force Logistics Command and the Georgia Power Company.

The major milestones to be accomplished during the design phase and subsequent phases, as well as the schedule for these milestones, are summarized in Section 7.6, Schedule and Milestone Chart, below.

As currently envisioned, no developmental tests will be required of specific components or systems for this solar facility.

7.1.1 PRELIMINARY DESIGN

The conceptual design data and drawings resulting from the current study contract (or from the advanced conceptual design contract) will be utilized as a starting point for refining the facility design descriptions and requirements to the level of detail necessary for the preparation of bid packages for major hardware procurements and for construction subcontracting.

Activities to be performed during the preliminary design phase will include detailed planning and scheduling through construction; planning and coordinating work by the U. S. Air Force Logistics Command and Robins Air Force Base on providing land for the collector field, relocating the 14th tee of a golf course and displacing part of the length of the fairway, closing part of Seventh Street and displacing the temporary band building to provide space for the tower and receiver; planning for on-site insolation data monitoring during the operations phase; continuing to monitor the RAFB expansion plans/executions to insure that the size of the solar facility optimally matches the anticipated demand; initiating the safety analysis/assessment efforts and the preparation of an environmental impact statement/permit; continuing the detailed integrated facility design and analysis work and revising the facility specifications.

The preliminary and detailed design of the receiver and the preparation of bid packages for the procurement of receiver equipment/hardware will be emphasized since the receiver system has a major impact on the overall project schedule (Section 7.6, Schedule and Milestone Chart). Also, the selection of potential heliostat manufacturers may have an impact on the detailed design of the facility. The design of the heliostat foundations, the locations of the heliostats in the collector field and the electrical requirements/interfaces for the various systems are examples of important design areas that will require vendor data inputs.

Additional preliminary design activities to be pursued are the refinement of the site plan and the site preparation/modification plans and schedule, the tailoring of the Collector Subsystem Specification A10772 to the site-specific application and the development of preliminary design drawings and/or specifications for the tower, master control system, components of the electrical power generating system and the balance of the facility - steam and feedwater system.

7.1.2 DETAILED DESIGN

From the design information and the revisions to the facility specifications developed during the preliminary design efforts, the detailed design activities will focus primarily on the preparation of bidding documents to procure major equipment, systems and construction work for the facility. Most of this equipment and construction work will be procured/subcontracted during the construction phase. These procurements will be scheduled on a priority basis to minimize the impact on the design and expected performance of the facility, on the projected capital costs and associated cost flow considerations and on the overall project schedule. The procurement of most of the systems, components and construction subcontracts for the facility will be by competitive bidding. The major procurement activities include bidders list approval, preparation of specifications, cost and performance evaluation, selection of vendors and purchasing/contracting.

Concurrent with the initiation of these procurement activities, detailed design drawings and overall performance predictions will be developed and refined based on the specifications/information provided by the vendors of the various components and systems. Final drawings and specifications will be prepared for the entire solar facility and for the equipment/systems to be included within the facility. Also, detailed plans and schedules for the construction, site preparation and facility integration and checkout will be finalized.

7.2 CONSTRUCTION PHASE

The objectives of the work to be performed during the Construction Phase are: a) to complete the site preparation and site improvement (modification) activities for the installation of a solar cogeneration facility at Robins Air

Force Base, b) to complete the procurement, delivery, erection and/or installation of all of the components and systems for the facility, c) to integrate the solar facility with the existing Robins AFB steam plant and base electrical grid facilities at the steam, feedwater and electrical interfaces and d) to provide the required management, quality control and support efforts to ensure timely completion of the construction schedule within the specified budget.

There are no technical or economic issues to be resolved during the construction phase of this project.

The Westinghouse Advanced Energy Systems Division will retain overall responsibility for project management of the construction activities, with significant assistance from other team members, thereby ensuring successful completion of this phase on schedule and within budget. The major milestones and schedule for the construction phase activities are summarized in Section 7.6, Schedule and Milestone Chart.

Since the procurement, fabrication and installation of the receiver is the critical path/long-lead-time procurement activity of the construction phase, the procurement of several components/materials for the receiver must be initiated in July 1983 Figure 7.6-2. Therefore, this part of the construction phase activities will be started shortly after the completion of the preliminary design and in parallel with the detailed design of the overall facility. Most of the preliminary and detailed engineering and design work on the receiver, however, will have been completed prior to the July 1983 procurement activities for the receiver.

Actual construction work at the site is scheduled to begin approximately 22 months after the start of the preliminary design (Figure 7.6-2). Subsequent to preparing the bidding documents for the various systems and components of the facility and for the site preparation/construction subcontract activities (as discussed above in the detailed design phase) and subsequent to a DOE review of the detailed design and these bidding documents, on-site construction can be initiated. The on-site construction management activities will include overall subcontractor direction, coordination and evaluation; cost, schedule and quality control; processing of invoices in conjunction with contract administration; site safety and security programs; technical direction from cognizant engineering organizations and from manufacturers' representatives; and contact with governing or regulatory agencies.

The first construction activity to be started at the site will be the installation of the underground steam and feedwater system piping to Steam Plant No. 4 (Figure 7.6-2). This will be followed closely by the pouring of a foundation for the power building, the installation of the foundations for the tower and the site preparation activities. Later on in the construction phase, the heliostat foundations and the heliostats are installed; the tower and associated components are erected/installed; the receiver is installed on the tower; the power building is constructed and its essential services are installed; and the turbine generator, transformer and switchgear are installed. Next, the hardware components of the master control system are assembled and installed; the components required for the balance of the facility - steam and feedwater system are assembled and installed; the final interface connections to the RAFB EMCS, to the steam and feedwater headers in Steam Plant No. 4 and to the base grid are performed; and the installation of the substation protection devices is completed.

7.3 SOLAR COGENERATION FACILITY CHECKOUT AND STARTUP PHASE

The objectives of the Solar Cogeneration Facility Checkout and Startup Phase are: a) to check out and verify the functional operation of each individual system for the facility, b) to verify the functional operation of the complete solar cogeneration facility with all of the systems integrated and operational and c) to systematically confirm the proper installation and operation of the facility and all supporting systems during initial startup. This checkout and startup phase is scheduled to begin approximately 36 months after the initiation of the preliminary design (Figure 7.6-2).

A detailed plan for system checkout, facility checkout and facility startup will be developed during the design and construction phases. This plan will address component and system checkout, facility checkout, startup, initial operations and performance testing. A quality control/assurance effort will also be pursued in parallel with these checkout and startup operations.

There are no significant issues to be resolved during the facility checkout and startup phase. However, 3 months have been allowed in the schedule to permit minor modifications to the facility, if required.

The Westinghouse Advanced Energy Systems Division will be responsible for overall project management during this checkout and startup phase and they will be supported by other members of the solar cogeneration project team. The major milestones and schedule for the activities to be performed are briefly summarized in Section 7.6, Schedule and Milestone Chart.

7.3.1 COMPONENT, SYSTEM AND FACILITY CHECKOUT

Procedure documents will be developed during the design and construction phases for electrical checkout and testing, instrumentation checkout and testing, control verification and pressure testing. Procedure documents will also be prepared for the final checkout and testing of the collector system, receiver system, electrical power generating system, master control system and the balance of the facility.

The above procedures will be performed during this facility checkout phase. Startup and service engineers will be provided by the heliostat and master control system manufacturers. Personnel from the Westinghouse design team will perform instrumentation calibration and supervise the checkout and testing of the receiver, the turbine generator and other components of the electrical power generating system, all of the components for the balance of the facility, the substation protection devices, the electrical interface equipment and the steam and feedwater interfaces with Steam Plant No. 4. One of the more significant activities will be the checkout of the heliostat gear boxes, drive motors, power supplies and controls. Initial positioning, adjustment and focusing of each heliostat will be required prior to facility startup.

7.3.2 FACILITY STARTUP

Procedure documents will be developed during the design and construction phases for the testing and startup of the facility. Initial facility testing and startup will involve partial load steam generation by the receiver, with limited amounts of steam being supplied at approximately 0.96 MPa (140 psia) to the steam header in Steam Plant No. 4. These initial tests of the facility will verify the ability of the master control system to maintain the desired flux on the receiver and to maintain boiler drum level during variations in steam flow. Additional testing at progressively increasing loads will lead to full-load operation of the facility with steam flow to the turbine generator and finally testing of the switchgear to deliver electrical power to the RAFB 12.6 kV distribution system.

7.4 COGENERATION FACILITY PERFORMANCE VALIDATION PHASE

The objectives of the Facility Performance Validation Phase are: a) to evaluate the performance of the facility and confirm the overall performance predictions, b) to permit the owner (USAF) to gain experience in the operation of the facility and c) to allow the DOE and other interested organizations to obtain data and knowledge on its operation and performance.

No technical or economic issues need to be resolved during this phase. However, technical verification of the performance capabilities of the solar facility will be completed.

In-plant acceptance testing of some of the components and systems for the facility will have previously been conducted, e.g., sample in-plant testing of the heliostats and the heliostat control subsystem for the collector system, the receiver components and control subsystem for the receiver system, the steam turbine for the electrical power generating system and the computer for the master control system. During the facility performance validation phase, proper performance of each of these (and other) components and systems for the facility will be reconfirmed (verified). During and subsequent to the completion of the facility checkout and startup phase testing discussed above in Section 7.3, the solar cogeneration facility will be operated on line and deliver electrical power to the existing 12.6 kV distribution line at RAFB and produce and supply steam to the steam header in Steam Plant No. 4.

Since this facility will be a first-of-a-kind demonstration of solar cogeneration, there will be an extended period of operation in which several unique tests will be completed to validate proper facility operation and performance. A preliminary review of the required tests will be completed during the design phase. The testing operations which have been identified to date encompass verification of normal steady-state and transient operation and performance, as well as the verification of the capabilities of the facility to handle abnormal operations/conditions. A detailed test plan will be prepared during the design and construction phases to identify the scope and schedule for specific tests to be performed during this validation phase. This test plan will probably include the following types of tests:

- Demonstration tests to verify facility performance.
- Normal operational performance testing as a function of time of day, weather conditions and equipment status.
- Demonstration tests to validate and/or modify computer simulation models and software and operation, maintenance and testing manuals.
- Demonstration tests to confirm the adequacy of the data acquisition system to produce the data required for performance analyses and comparisons with predictions.
- Demonstration tests to confirm that adequate safety measures have been incorporated into the design of the facility to ensure the health and/or safety of the operating personnel, visitors to the facility, the existing facility and the solar cogeneration facility, including the demonstration of the adequacy of the instrumentation and control systems to handle normal and emergency transient conditions.
- Transient operational performance tests as a function of startup, shutdown, cloud passage and storm or other environmental conditions.
- Component and system operational performance tests, including weather and other environmental impacts, off-design operating

conditions, trends (such as degradation in performance) and special tests to fulfill the maintenance requirements/evaluations.

In addition, the performance of the solar cogeneration facility will be confirmed during its operation in parallel with the operation of Steam Plant No. 4 in supplying process steam to the steam header and in turn the steam distribution system at Robins AFB. Thus, the performance validation phase efforts will emcompass the adequate verification of performance of the facility after it has been integrated with the existing electrical and steam distribution systems at Robins AFB.

7.5 OWNER (USAF) OPERATIONS PHASE

The design, construction, checkout and performance validation phases will be expedited so that the facility can be released to the United States Air Force (Robins AFB) on March 1, 1986. At that time, the Owner (USAF) Operations Phase will be initiated. After an Introduction (Section 7.5.1), this section discusses the Objectives and Project Management (7.5.2) and the Operations Phase Activities (7.5.3).

7.5.1 INTRODUCTION

As discussed in Section 1.8, Site Owner's Assessment, the U. S. Air Force Logistics Command (headquartered at Wright-Patterson Air Force Base, Ohio) has reviewed the energy/power generation needs for various Air Force bases throughout the United States. This review identified a cogeneration application at Robins Air Force Base that will find widespread military and industrial use and that is uniquely suited to solar thermal power generation. The Logistics Command's enthusiastic support of this project, which has tremendous market potential in that the facility directly supports the long term U.S. Air Force strategic and economic objectives for alternate energy sources, assures intensive evaluation of the facility for applicability to other Air Force bases. The Air Force is fully committed to making the specific site available and they have contributed and will be contributing significant personnel and other support to assure the success of the project.

Since the overall objective of this project is to achieve widespread application and commercialization of solar cogeneration facilities at a number of Air Force bases, as well as at other industrial and military locations, the operation and maintenance of this facility will be performed by Robins AFB personnel during the Owner (USAF) Operations Phase. This operations phase will be defined in more detail during the design and construction phases of this project. However, the operational and maintenance aspects have been considered in sufficient detail to permit a discussion of the objectives of this phase and the activities to be performed.

7.5.2 OBJECTIVES AND PROJECT MANAGEMENT

The objectives of the Owner (USAF) Operations Phase are: a) to operate the solar cogeneration facility and to produce electrical and/or thermal (process steam) power (thereby displacing some of the electrical and process steam energies provided by the Georgia Power Company and Steam Plant No. 4) during as many hours throughout the year as possible for those days with sufficient solar insolation, b) to perform the required scheduled and unscheduled maintenance of the facility to ensure maximum utilization of the available solar energy, c) to collect and analyze appropriate data from the facility to ensure continued operation without significant degradation in performance, d) to compare the results obtained from actual operation with performance predictions for various operating modes, e) to evaluate, through specific testing of components and systems, the needs to revise/upgrade the operating and maintenance procedures and f) to issue an Initial Operations Summary Report covering the first year of facility operation.

As currently envisioned, there are no technical or economic issues to be resolved during this operations phase.

The management of the project during the operations phase will be performed by appropriate Robins Air Force Base personnel. The management activities to ensure completion of the aforementioned objectives may require some consulting/technical direction/support services from members of the Westinghouse team, the DOE - San Francisco Operations Office and/or the Sandia

National Laboratories, Livermore. Should these requirements for consulting and support services be made known, it is anticipated that the appropriate organizations will give these additional requirements positive consideration within specified budgetary and time schedule constraints.

7.5.3 OPERATIONS PHASE ACTIVITIES

Major milestones and the schedule for some of the activities to be performed during the Owner (USAF) Operations Phase are discussed briefly in Section 7.6, Schedule and Milestone Chart.

The preparation of preliminary operating and maintenance plans will be initiated during the design phase to establish additional requirements for the design of the solar facility and for the support activities. These operating and maintenance plans will be developed to fulfill the above objectives, as revised, for this operations phase. In addition, descriptions of the data to be obtained and the format in which these data are to be reported will be treated. These plans, then, will become the basis for defining the requirements for the instrumentation and data acquisition system to be developed during the preliminary and detailed design phase. Manuals for operation, maintenance and crew training will be finalized during the construction phase of the project after the detailed design activities have been completed and the appropriate operating and maintenance data are available from the vendors.

Personnel for the facility operating and maintenance crews will be selected by the Robins AFB Project Manager for the Operations Phase, utilizing a thorough screening and testing process. Participation and support may be required from the Westinghouse design team and/or from specific manufacturers of the solar equipment to provide adequate crew selection and training. A test engineering team, a necessary requirement during the operations phase, will also be selected from Robins AFB personnel. This team will include individuals with a background in the startup and testing of solar and conventional components and systems.

Operating, maintenance and testing crews will be trained and tested during the facility checkout, startup and performance validation phases in preparation for their responsibilities. They will be given thorough exposure to the construction, fabrication, erection and/or assembly activities to provide familiarity with the actual equipment and the as-built drawings. Equipment manuals will be supplied by the equipment vendors and the operating and maintenance manuals will be prepared with input from the crew members.

During the latter part of the construction phase, operating and maintenance crews will work with the construction, installation and erection crews as components and systems for the facility are completed and operated in their respective checkout modes. Thus, as each of the overall systems becomes operational and as the solar cogeneration facility is carried through the final checkout and startup procedures, the operating crew will be assuming greater responsibility and acquiring familiarity with their assignments during the operations phase.

Pertinent data will have been generated during the cogeneration facility checkout, startup and performance validation phases and these data will be recorded, analyzed and reported. The detailed operating plans/procedures will be finalized at this time and these will be executed during the operations phase. The plans will include tests and operations to a) periodically verify adequate operation and performance of the facility in terms of providing electrical and thermal (process steam) power to Robins AFB and b) generate data to promote technology transfer, public relations and other functions that enhance the commercialization efforts.

The test and operating plans and procedures will be made flexible so as to respond to a wide sprectrum of steady-state and transient conditions that will be typically imposed on the solar cogeneration facility, as a result of the uncontrollable variation in environmental conditions and solar insolation. The operating procedures must therefore account for all possible actions to maintain readiness of the solar facility and to operate the facility whenever the insolation is available.

The operating, testing and maintenance plans and procedures will be executed by Robins AFB personnel during the Owner (USAF) Operations Phase. Subsequent to the completion of a one year operating period of the facility, an Initial Operations Summary Report will be prepared which presents the interim results of the operations phase. This report will include technical data, comparisons of actual performance results with predictions, the definition and resolution of some of the design and operational problems encountered and a tabulation of recommendations to be incorporated in future designs of solar cogeneration facilities. The Westinghouse design team, the Air Force Logistics Command and the Georgia Power Company will provide assistance to Robins AFB in properly performing the Operations Phase activities delineated above, within appropriate budgetary and time schedule constraints.

7.6 SCHEDULE AND MILESTONE CHART

Approximately 41 months (October 1, 1982 through March 1, 1986) are required between the initiation of the preliminary design efforts in the Design Phase and the full power operation of the solar cogeneration facility. At that time, the facility is released to Robins Air Force Base and the Owner (USAF) Operations Phase is started.

Figure 7.6-1 summarizes the major milestones and schedule after the initiation of the preliminary design on October 1, 1982.

Figure 7.6-2 provides a general overall schedule of the activities to be performed during the Design, Construction, Facility Checkout and Startup, Facility Performance Validation and User (USAF) Operations Phases. A detailed schedule and milestone chart for all of the activities to be performed for all of the above phases is included in Appendix B, Drawings.

As shown in Figure 7.6-1, 18 months are required to complete the preliminary and detailed designs of the components and systems for the facility and for a DOE review of these designs and the associated bidding documents. Also, since the procurement, fabrication, construction and erection of the receiver is the

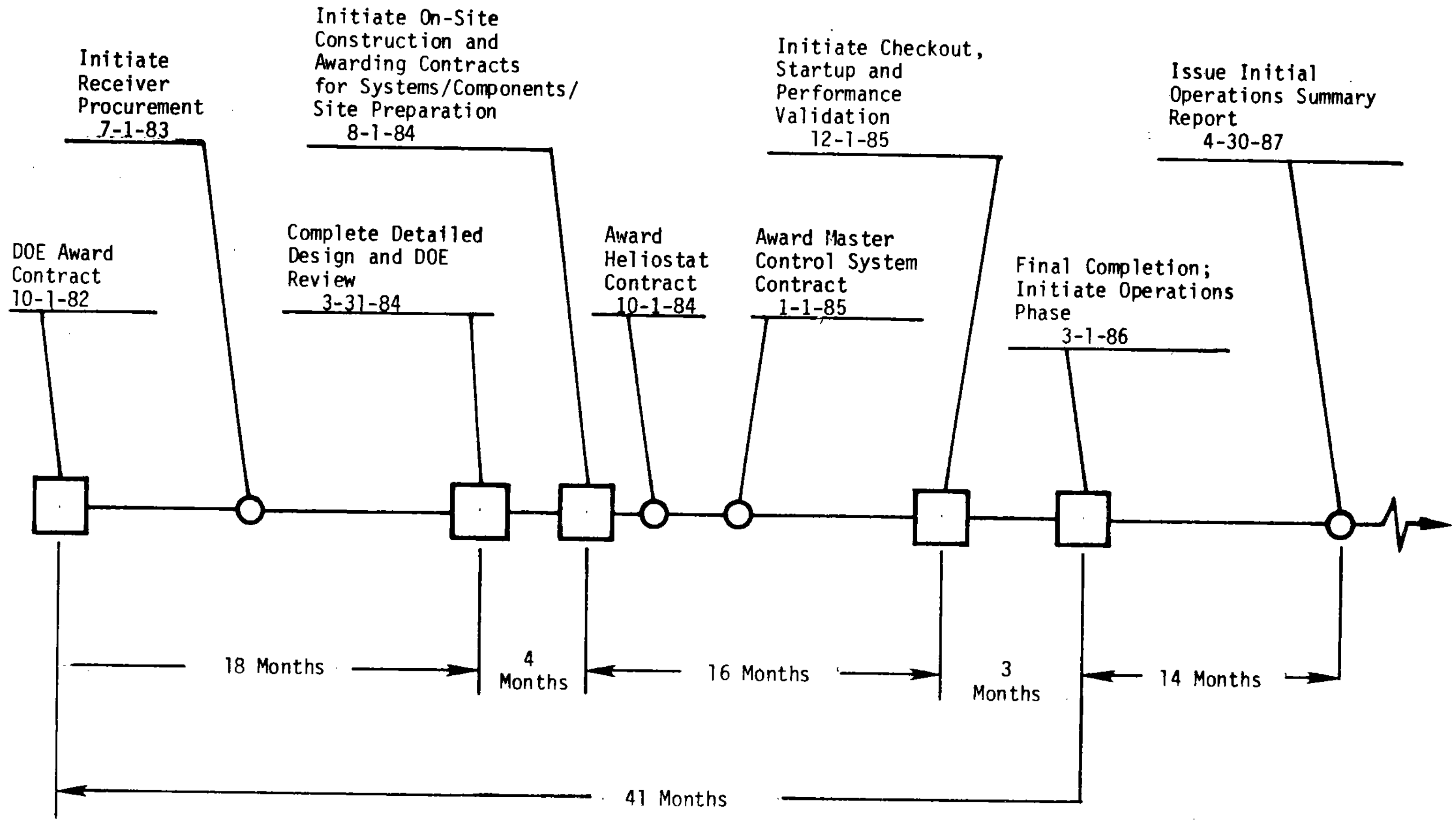

Figure 7.6-1. Major Milestones and Schedule for Design, Construction, Startup, and Initial Operation of Robins AFB Solar Cogeneration Facility

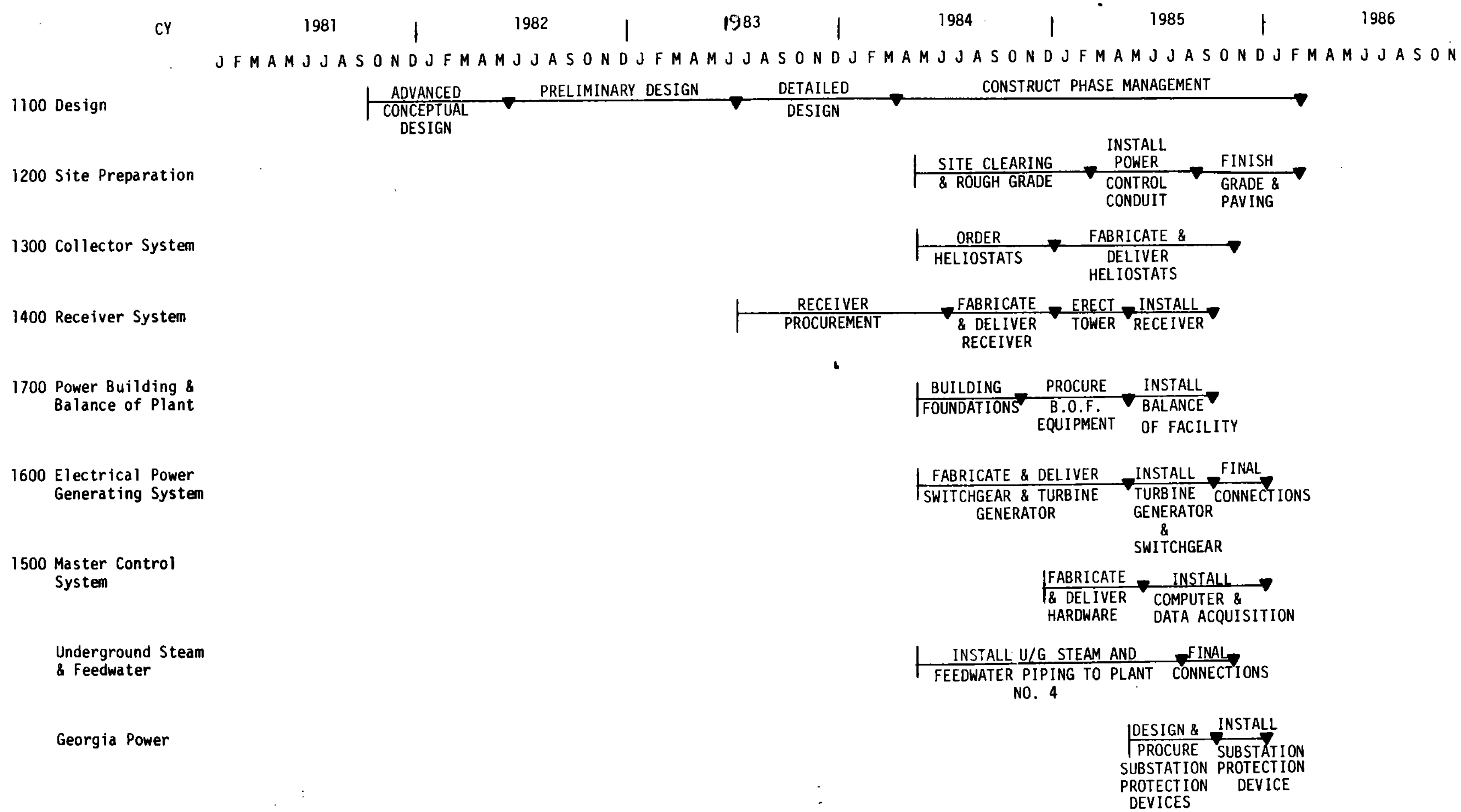

Figure 7.6-2. Overall Schedule, Activities and Milestones for Design, Construction, Startup and Initial Operation of Robins AFB Solar Cogeneration Facility

critical path/long-lead-time controlling item in the Construction Phase, the procurement of some of the components and materials for the receiver must be initiated on July 1, 1983. Therefore, this aspect of the construction phase activities is pursued in parallel with the balance of the detailed design efforts during the design phase.

On-site construction activities are started on August 1, 1984, approximately 22 months after the initiation of the Design Phase. Subcontracts for the manufacture of various systems and components and construction subcontracts for site preparation and the installation of the underground steam and feedwater piping to Steam Plant No. 4 are awarded on or about August 1, 1984. The contract for the procurement of the heliostats for the Collector System is scheduled to be awarded on October 1, 1984. The purchase order for the Master Control System, including the data acquisition system, is scheduled to be signed on January 1, 1985. These latter two procurements have been placed as late as feasibly possible in the overall schedule, consistent with the initiation of the Operations Phase on March 1, 1986, to take best advantage of the most recent technological advances/cost improvements in the development of the heliostats for the Collector System and the computer and software for the Master Control System.

As each of the components, subsystems and systems are erected, assembled and/or installed into the facility, the individual checkout and quality assurance/quality control tasks are performed to ensure timely completion of the Construction Phase activities. On December 1, 1985 (approximately 38 months after the award of a DOE contract), the Facility Checkout and Startup Phase and the Facility Performance Validation Phase activities are initiated. Concurrent with the construction, checkout, startup and performance validation phases, training of the operating and maintenance personnel will be completed. The solar facility will produce some electrical and thermal (process steam) power during the startup and performance validation phases.

On March 1, 1986, the construction, checkout, startup and performance validation phases are completed; the solar cogeneration facility is released to

Robins AFB; and the Owner (USAF) Operations Phase is initiated. At that time, the facility is fully operational and the operating, maintenance and testing crews from Robins AFB will perform their respective responsibilities and tasks. On March 1, 1987, the first year of operation will be completed. An Initial Operations Summary Report presenting results on this first year of operation is scheduled to be published on April 30, 1987.

The lead times required for the fabrication, erection, installation and checkout of the heliostats for the Collector System and the receiver hardware for the Receiver System will be given close attention during the design phase to insure that there is no major impact on the overall project schedule. Preliminary estimates of the schedule requirements for these activities were provided by potential vendors for the heliostats and by the Foster Wheeler Solar Development Corporation for the receiver and these are reflected in Figures 7.6-1 and -2. Any major variation in these two procurements schedules may have a significant impact on the completion date for this project. However, since the checkout and startup of the facility can be initiated with a partial heliostat field in place, the collector system installation schedule is less critical than the installation schedule for the receiver.

7.7 ROLES OF SITE OWNER (USAF), GOVERNMENT (DOE) AND INDUSTRY; RISK SHARING; AND THE EXPENDITURES SCHEDULE

Included in this subsection are an Introduction and a discussion of Project Management (Subsection 7.7.1) and discussions of the Role of the Site Owner (USAF) (7.7.2), the Role of the Government (DOE) (7.7.3), the Role of Industry (7.7.4) and Risk Sharing (7.7.5). The Expenditures Schedule is presented in Subsection 7.7.6.

7.7.1 INTRODUCTION AND PROJECT MANAGEMENT

In the interest of expediting the commercial viability of Solar Central Receiver Power Systems, and, in particular, solar cogeneration concepts, it is imperative that a demonstration program be undertaken that will meet all of the desired programmatic objectives in a successful manner. To enhance the probability of success of the project on schedule and within budget, the Westinghouse design team and the Air Force Logistics Command have determined that appropriate levels of technical and financial risk and/or responsibility must be accepted by the site owner (the U.S. Air Force Logistics Command and Robins Air Force Base), the government (DOE) and industry. Also, the roles and responsibilities of each of these participants during the design, development, construction and operation of the solar facility must be clearly defined and agreed upon.

Project management during the Design, Construction, Checkout, Startup and Performance Validation Phases will be performed by the Westinghouse Advanced Energy Systems Division. This overall project leadership/management role means that Westinghouse will be responsible for the design, development, construction and initial operation of the facility. They will be supported in this endeavor by the other Westinghouse team members: Heery and Heery, Inc., Foster Wheeler Solar Development Corporation, the U. S. Air Force Logistics Command, Robins Air Force Base and the Georgia Power Company.

During each of the above phases, the government, namely the DOE, will be providing overall technical and management direction and assistance in an advisory capacity. These efforts will include periodic detailed reviews and approvals of the design of the facility and the execution of the construction phase activities, as normally required for a governmental (DOE) funded project. A positive aspect of DOE's involvement in the management, design, development, construction and checkout of the solar facility is its (and its technical managers') vast knowledge, talent and experience. Westinghouse recognizes these characteristic abilities of DOE and its technical management and plans to utilize them substantially.

During the Owner (USAF) Operations Phase, the management of the project will be performed by appropriate Robins Air Force Base personnel. The management activities to ensure completion of the objectives of the operations phase, as discussed in Section 7.5, may require some consulting/technical direction/

support services from members of the Westinghouse design team, the DOE - San Francisco Operations Office and/or the Sandia National Laboratories, Livermore.

More details on the specific responsibilities and roles of the site owner, government and industry are discussed in the subsections which follow.

7.7.2 ROLE OF SITE OWNER (USAF)

The site owner (the U.S. Air Force Logistics Command and Robins Air Force Base) will be responsible for several activities and associated costs during the design, construction and operation of the facility. First, they will be responsible for concurring in the final design and configuration of all of the equipment for the facility and its interfaces with the existing steam plant and the base electrical distribution system. The Air Force will also have final approval authority in the design process on any facility feature which encroaches upon the existing community or upon Base operations.

The Air Force will also perform all of the site preparation work which is not an integral part of the facility during the construction phase of the project. These site preparation activities will include providing the land for the heliostat collector field, relocating the 14th tee of a golf course, performing traffic studies and closing off a portion of Seventh Street, removing the Band Building (Building No. 760) to provide sufficient land area for the tower and the power building, and repairing the water treatment system for the feedwater in Steam Plant No. 4.

During the Operations Phase, which is scheduled to begin on March 1, 1986, the Robins AFB Solar Cogeneration Facility will be operated and maintained by the U.S. Air Force (Robins AFB). Thus, the Air Force will be responsible for providing the required management, personnel and associated costs for the operation and maintenance of the facility. This will include the costs of spare parts beyond those which are delivered with the facility, provided such parts are required by normal use and wear. Design or workmanship deficiencies will require negotiation between DOE, its suppliers and the Air Force for resolution. The Air Force will collect and disseminate operating information and performance data accumulated by the data acquisition system during the first one year of operation. Finally, the Air Force will issue (with the assistance of the Westinghouse design team, DOE and Sandia, if required) an Initial Operations Summary Report which covers the interim results from this first year of operation. Operating and performance data after the first year of operation will be collected and disseminated, if required, subject to a future agreement and cost sharing arrangement.

7.7.3 ROLE OF GOVERNMENT (DOE)

The role and responsibilities of the government (DOE and its technical agent, the Sandia National Laboratories, Livermore, if appropriate) during the Design, Construction, Checkout, Startup and Performance Validation Phases are primarily: a) to provide the technical guidance and direction of the activities performed during these phases, b) to conduct and participate in project reviews/approvals during the design and construction efforts and c) to provide 100 percent of the design and capital costs for the construction of the facility so that it can be turned over to the Air Force on March 1, 1986. This share of the costs will include the complement of spare parts which are identified as needed at the time of facility startup.

No owner (USAF) costs will be chargeable to DOE. For example, when the Air Force operating, maintenance and testing crews are being trained at RAFB during the construction, startup, checkout and performance validation phases, the Air Force will provide these personnel and support services at no cost to DOE. On the other hand, the costs of providing various training instructors on the operation and maintenance of the facility will be included in the design and capital costs for the facility.

7.7.4 ROLE OF INDUSTRY

The role of industry in the development and construction of a solar cogeneration facility at Robins AFB is that of a supplier of design, analytical, procurement, construction and management services and/or hardware.

These will be provided to ensure successful completion of the project and release of the facility to the Air Force on March 1, 1986. The Westinghouse industrial team is comprised of the Westinghouse Advanced Energy Systems Division (W-AESD), Heery and Heery, Inc., Foster Wheeler Solar Development Corporation and the Georgia Power Company. These team members will assume various roles and responsibilities, both individually and collectively, in the development of the facility. Further details on the breakdown of responsibilities and support services for each of the Westinghouse team members have been included in the Work Breakdown Structure shown previously in Table 7.1-1.

WESTINGHOUSE ADVANCED ENERGY SYSTEMS DIVISION

As shown in the Work Breakdown Structure of Table 7.1-1, W-AESD will be assuming the lead responsibilities for the Facility Engineering; the designs and/or preparation of bid packages for the Collector System, Master Control System (including the Data Acquisition System), and the steam turbine, gearbox and generator of the Electrical Power Generating System; and overall Program Management during the design and construction phases. W-AESD will also perform the overall design, analysis and integration efforts to ensure compatibility of all of the systems within the facility. In addition, W-AESD will provide assistance to Heery and Heery, Inc. and Foster Wheeler Solar Development Corporation in the performance of some of their design and construction responsibilities (Table 7.1-1).

HEERY AND HEERY, INC.

Heery and Heery, Inc., will be responsible for operating as an overall architect/engineer (A/E) in the design and construction of this facility. As depicted in Table 7.1-1, Work Breakdown Structure, Heery and Heery will retain primary responsibility for the preparation of the facility Operating and Maintenance Manuals and for the training of the operating and maintenance crews; the performance of the Site Preparation for the facility; the design, analyses, preparation of a bid package and construction of the tower; the designs, preparation of bid packages and the assembly of the switchgear, transformer and electrical interface equipment of the Electrical Power

Generating System; and the design, analyses, procurement, construction and/or assembly of all the components and subsystems for the Balance of Facility.

Heery and Heery, Inc. will participate significantly in the project management activities, particularly those associated with on-site construction. They will schedule and coordinate the on-site construction, assembly and/or subcontractor activities for: installing the heliostat foundations, heliostats, auxiliary equipment and control subsystem for the Collector System; installing the receiver on the tower; installing the computer and auxiliary equipment for the Master Control System; installing the turbine generator of the Electrical Power Generating System into the Power Building; installing the underground steam and feedwater system piping from the Power Building to Steam Plant No. 4 and integrating the solar facility with the existing Steam Plant No. 4 and the Base grid at the steam, feedwater and electrical interfaces. Finally, Heery and Heery, Inc. will provide some support services to the other Westinghouse team members in their respective areas of responsibility (Table 7.1-1).

FOSTER WHEELER SOLAR DEVELOPMENT CORPORATION

Foster Wheeler Solar Development Corporation (as presented in the Work Breakdown Structure, Table 7.1-1) will have primary responsibility for the design, analyses, procurement, fabrication and assembly of all of the components, auxiliary equipment and control subsystem for the receiver of the Receiver System. They will perform the on-site installation of all of the receiver components and equipment. Foster Wheeler will also assist all of the other solar cogeneration facility team members in several of their areas of responsibility (Table 7.1-1).

GEORGIA POWER COMPANY

The Georgia Power Company will participate in the design, construction and checkout activities on a no cost basis, with the exception of the allowance for the one time connection fee. They will contribute (primarily in an advisory capacity) to the development of the power transfer arrangements/agreements and to the design of the electrical interface between the solar facility and the Base electrical distribution system. Georgia Power will design, procure and install the substation protection devices. The Georgia Power Company will also have approval authority on the design of the switchgear and the development of specifications for the electrical output power from the solar facility.

7.7.5 RISK SHARING

With regard to risk sharing, the Air Force risks during the design and construction of the facility are limited primarily to the investments and costs of a) providing the required engineering and management services associated with the design, construction and checkout of the facility, including interfaces, b) making the land area available for the collector field and the receiver/tower, c) performing the site preparation activities which are not an integral part of the solar facility (e.g., relocating the fourteenth tee of the golf course, performing traffic studies for and the actual work of closing off a portion of Seventh street and completing an archaelogical search for artifacts), d) participating in the performance of environmental studies and safety assessments as required for permits, e) performing public relations activities, f) coordinating the installation of piping connections to Steam Plant No. 4 and any utility relocations, g) modifying the RAFB Energy Management and Control System (EMCS) to monitor multiple points in the Solar Cogeneration Facility, h) the present value of (and removing) Building No. 760 (Band Building), i) miscellaneous, e.g., gate access control communications, relocation of outdoor services displaced by the land area devoted to tower and power building, etc., and j) repairing the feedwater deaerator and chemical treatment systems for the boilers in Steam Plant No. 4 to meet the feedwater system requirements of the solar facility.

The Air Force risks during the checkout, startup, performance validation and operations phases include the investments and costs of a) selecting and providing operating, maintenance and testing crews to be used at the solar facility, b) performing the actual operation and maintenance of (and associated management/logistics support for) the facility for a 25 year period (FY 1986 through FY 2011) during the Operations Phase, c) providing the support manpower and the short-lead-time hardware (spare parts) replacement costs for those spare parts not delivered with the facility and required for normal use and wear, d) collecting and disseminating operating and performance data during the first year of operation and e) issuing an Intial Operations Summary Report which presents the interim results from the first year of operating the facility.

The DOE risks in the design, construction and operation of a solar cogeneration facility at Robins AFB are a) all of the one-time engineering, design, analysis and management costs for the development of the facility and b) all of the facility capital and construction costs, including the procurement, assembly, erection, on-site construction, checkout, startup, and/or performance validation of the facility, as well as other indirect field costs and office costs. These capital, construction, indirect and design costs will be expended between October 1, 1982 and March 1, 1986, at which time the facility is released to the Air Force.

No additional cost to, or risk sharing by, DOE is required after the facility is turned over to Robins AFB. This is predicated on the assumption that no Westinghouse design team efforts/support services are required after the start of the Operations Phase on March 1, 1986. If there are any DOE requirements in that arena, then the additional investment and costs of these efforts will need to be included in the overall cost estimates for the facility to be borne by DOE.

7.7.6 EXPENDITURES SCHEDULE

An estimated $7.34 million (1981 $) will be required for the direct Capital Costs during the construction phase of this project between July 1, 1983 and March 1, 1986 excluding one-time engineering costs. A preliminary estimate of the annual capital requirements was developed utilizing the cost information described in Section 4.7, Capital Cost Summary for Project, and the Schedule and Milestone Chart discussed in Section 7.6. The results of this cash flow analysis are shown in the Expenditures Schedule of Table 7.7-1 by fiscal years (October 1 through September 30).

An estimated $4.7 million (1981 $) will be expended for the Owner (USAF) Installation and the Operating and Maintenance (O&M) Costs during the construction and operations phases between the period of January 1, 1983 and March 1, 2011. Approximately 90 percent of this cost occurs during the 25 year operational period (starting on March 1, 1986). The owner cash flow requirements are also shown in the Expenditures Schedule of Table 7.7-1 by fiscal years.

TABLE 7.7-1
EXPENDITURES SCHEDULE
(Millions of Dollars) (1981 $)

		Fiscal Year (October 1 through September 30)				
	Total	1983	1984	1985	1986	1987 to 2011
Capital Costs (DOE)	7.34	0.02	0.59	5.65	1.08	0
Owner Costs (USAF) - Installation	0.5	0.1	0.3	0.1	0	0
Owner Costs (USAF) - 0 & M	4.2	0	0	0	0.1	4.1

In arriving at this expenditure schedule, the various activities' costs were allocated based on the Schedule and Milestone Chart (Section 7.6), assuming payments are made uniformly with time for each activity.

The results indicate that the peak annual capital requirement occurs in fiscal year 1985, for approximately $5.65 million. Also, only about $0.61 million of the $7.34 million total capital costs are required during the first two fiscal years of this four year period.

8.0 UTILITY/SITE PURCHASED POWER AGREEMENT

Electrical power generated by the solar cogeneration facility will be supplied to the Robins AFB electric power distribution system which is supplied with power at all times by the Georgia Power Company. When no electricity is generated by the solar cogeneration facility, the facility itself shall draw power from the Georgia Power Company. This exchange of power between the solar cogeneration facility and the Georgia Power Company shall be handled under the terms and conditions of a "Purchased Power Agreement" between RAFB and the Georgia Power Company. As described in this section, the initial effort to develop a "model" agreement between a utility and a cogeneration facility owner has established full confidence by Georgia Power Company and the RAFB that a mutually acceptable "Purchased Power" agreement can be developed and implemented in subsequent phases of the project.

A copy of a typical "Purchased Power Agreement" has been obtained from the Georgia Power Company and is portrayed below for information. This agreement sets forth contractual terms between a power utility (the "Utility") and an individual or company (the "Seller") to govern the selling of the Seller's surplus power to the Utility.

The agreement calls for the parallel operation of the two systems and requires that the Seller provide and maintain the protective equipment within the private system and also bear the cost of the protective equipment required to be added to the Utility's system.

Two utility owned and maintained meters will be required at the interchange point. The Utility will invoice the Seller for power delivered to the Seller and the Seller will invoice the Utility for power delivered to the Utility.

Power delivered to the Seller will be invoiced at the Utility's normal rate for the type of customer.

Power delivered to the Utility will be invoiced at a cost equal to the sum of the Utility's cost of power generation during the time period involved, plus the Seller's cost of power generation for the time period involved divided by two, but not to exceed the Utility's cost of power generation.

For this cogeneration facility, the Utility's cost of power generation is greatest during intervals of maximum demand. These maximum demand periods occur very close to the periods of maximum insolation. Therefore, the price of power "sold" to the utility would be highest at or near the time of maximum output of the solar cogeneration facility. In actual practice the solar cogeneration power output will never exceed the RAFB power demand. Therefore, no surplus power will actually be purchased by Georgia Power. The solar cogeneration power output will, however, reduce the RAFB daytime demand and kWh consumption, allowing Georgia Power Company to "sell" this demand and consumption to another customer (at higher costs than to RAFB).

During a subsequent engineering phase, an actual agreement will be developed between the Georgia Power Company and RAFB similar to the example. After the system is operational, metered data will be available to allow extrapolation of the results of the use of this "model" agreement to other applications.

PURCHASED POWER AGREEMENT

FOR COGENERATORS AND SMALL POWER PRODUCERS

THIS AGREEMENT is entered into as of the ____ day of ___________, _____, between Georgia Power Company (the "Company") a Georgia public utility corporation and _____________________ (the "Seller").

WITNESSETH:

WHEREAS Company and Seller have executed a Contract for Electric Power Service, dated as of _________, _____; and

WHEREAS Seller ownd and operates electric power generating facilities at __________, __________ County, Georgia, which may from time to time produce electric power surplus to its needs; and

WHEREAS Company is a public utility providing electric power service to customers located at various places in the state of Georgia; and

WHEREAS Seller is willing to deliver and sell and Company is willing to receive and purchase Seller's surplus; and WHEREAS Company and Seller desire to connect their respective electric systems and operate such systems in parallel to effect such deliveries and receipts.

NOW, THEREFORE, in consideration of the mutual covenants and agreements container herein, the parties agree as follows:

Section 1 - Interconnection

1.1 The electrical systems of Company and Seller shall be interconnected at a point or points mutually agreeable to the parties. Seller shall provide, own, and install or cause to be installed termination equipment such as power circuit breakers, switches, and associated relays, controls, and other necessary devices which are in compliance with Company standards and any applicable electrical codes to protect the systems of Company and Seller.

1.2 It it is necessary for Company, in Company's opinion, to install special facilities including metering equipment, or to reinforce its system to effect this interconnection, or protect Company's system, Seller shall reimburse Company for all costs involved. These costs have been determined to be $____, which shall be paid by Seller to Company on or before __________, _____.

Section 2 - Operation and Maintenance

2.1 Company and Seller shall operate their respective electric systems in parallel.

2.2 Only seller shall operate and maintain its equipment, except that Company shall retain operating control of Seller's low side power transformer circuit breaker and may exercise such control to the extent deemed necessary by the Company to protect its system.

2.3 Seller at its expense shall maintain its switching, controlling, and synchronizing equipment in good condition and shall arrange the operation of its equipment such that in the event the supply of electric service from Company to Seller is interrupted, Seller's generators shall separate from the system of the Company and remain so separated until Company restores three phase service; thereafter Seller shall at its convenience resynchronize its generators with the Company's system.

2.4 Company reserves the right to inspect on demand all of Seller's protective equipment including relays and circuit breakers associated with the interconnection, and maintenance records for such equipment.

2.5 Company reserves the right to open the interconnection with prior notice to Seller, if practicable, for any of the following causes:

(a) System emergency;

(b) Company's inspection of Seller's equipment reveals in Company's opinion a hazardous condition, a lack of scheduled maintenance, or a lack of maintenance records;

(c) Seller's generating equipment interferes with other customers of the Company or with the operation of Company's system.

2.6 Whenever Seller is furnishing power to Company hereunder, the respective liabilities of the parties shall be as follows:

(a) Neither party hereto shall be responsible for injury or damage to machinery, apparatus, applicances, or other property of the other party which is caused by lightning or by defects or failures in such machinery, equipment malfunction, apparatus or applicances of the party suffering the injury or damage.

(b) Seller shall not be responsible in any for transmission or control of electrical energy on the Company's side of the point of division between the Company's and Seller's systems and the Company shall not be liable for injury or damage to persons or property resulting in any manner from the generation, delivery, receipt, use or application of electrical energy covered by this agreement, which occurs on the Seller's side of the aforesaid connection point; and Seller agrees to indemnify the Company and save it harmless from such liability; provided however, Company shall be responsible for the results of its proven negligence.

Section 3 - Metering and Accounting

3.1 (a) The electrical energy which may be furnished by Seller hereunder shall be measured by a Watthour meter or meters and associated equipment specified by the Company to be owned and installed by the Company in accordance with Section 1.2 in a suitable place or building upon the Seller's premises. The Seller shall at his expense provide a suitable place or building in accordance with plans approved by the Company for the proper housing of metering equipment installed by the Company. Seller shall permit reasonable access to Company's metering equipment.

(b) All meters installed by the Company shall remain the property of the Company, and the Seller shall use reasonable diligence to protect the property of the Company on its premises.

(c) In the event the meters installed by the Company fail to register properly during any period, the amount will be estimated from readings for a l'kewise billing period or periods.

3.2 (a) Company shall bill Seller for electrical service supplied and Seller shall make payment for electrical service received as set forth in the Contract for Electric Power Service dated _______, _____ between the parties and any subsequent contract for Electric Power Service at this location.

(b) On a monthly basis Seller shall submit an invoice to Company and Company shall pay Seller for each kWh of energy Seller furnished to Company during the appropriate billion period as follows:

(1) Company shall notify Seller in writing by the ___ of the following month or as soon thereafter as practicable the amounts of energy delivered by Seller to Company hereunder accounted for by Peak and Valley periods, and Company's cost in each of the Peak and Valley periods.

(2) Company's cost in each of the Peak and Valley periods shall be the average incremental production cost calculated for Peak and Valley periods by the Southern Electric System associated with serving its system requirements including pumped storage requirements if any.

(3) Seller's cost shall be as identified by Seller calculated in accordance with standard utility practice using the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission. If Seller cannot identify its cost, such cost will be deemed to be 3.0 mills per kWh.

(4) The price Company shall pay Seller in each of the Peak and Valley periods shall be the sum of Company's and Seller's costs in that period multiplied by one half, except in no case shall the price exceed Company's cost as determined in 3.2(b) (2) above.

(5) As used in this seciton, Peak periods are the hours between 8:00 a.m. and 10:00 p.m., Eastern Standard Time, or Eastern Daylight Time, as appropriate, on weekdays which are not the days on which any of the following holidays are observed: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiv-ng and Christmas. All other periods are valley periods.

(c) Company shall make payment within ten days after the receipt of Seller's invoice.

Section 4 - Miscellaneous

4.1 This Agreement shall become effective as of the date first appearing above, and shall remain in full force and effect for a period of __ years and shall be considered renewed for a term of one year and from year to year thereafter, unless terminated earlier by either party on sixty days notice to the other.

4.2 Seller shall not transfer or assign its rights and obligations under this Agreement with Company's prior written consent, which shall not be unreasonably withheld. The terms of this Agreement shall be binding upon the parties, their successors and assigns.

4.3 Notwithstanding anything contained herein to the contrary, this Agreement shall not be interpreted to obligate Seller to deliver any energy to Company; but, Seller agrees that during the term hereof it will not deliver energy to any other entity.

4.4 The terms, rates and conditions set forth in the Agreement are subject to change at any time by the Georgia Public Service Commission in the manner prescribed by law. In the event of such change the new terms and conditions prescribed by the Commission will apply from the date made effective for the unexpired term of this Agreement.

4.5 Any notices, billing information and invoices required by this Agreement shall be deemed properly given if mailed, postage paid, to ____________________ ______________________________________ in the case of Seller, and to Georgia Power Company, 270 Peachtree Street, Atlanta, Georgia 30302, Attention: Manager, Bulk Power Services, in the case of the Company, or to such other addresses as may be designated in writing to the other party.

IN WITNESS WHEREOF, the parties have caused this Agreement to be executed by their duly authorized agents, as of the date first appearing above.

GEORGIA POWER COMPANY ("COMPANY")

BY: ____________________________

Its: ____________________________

(Officer - Title)

____________________("Seller")

By: ____________________________

Its: ____________________________

(Officer - Title)