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TECHNICAL AND ECONOMIC ASSESSMENT OF SOLAR HYBRID
REPOWERING

Final Report

September 1978

Work Performed Under Contract No. EG-77-C-03-1608

Public Service Company of New Mexico
Albuquerque, New Mexico

MASTER

U.S. Department of Energy

Solar Energy

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The technical and economic assessments described in this report are preliminary in nature and the scope of the study was limited to make early results available. This study is a point of departure for more comprehensive studies which will be sponsored by the Department of Energy. These additional studies will examine various combinations of economic parameters, utilities with a higher fraction of gas and oil generating capacity, the use of second generation solar central receiver technology which will allow repowering of reheat plants, and the market potential for repowering outside of the nine state area surveyed by Public Service of New Mexico.

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1.0 INTRODUCTION AND SUMMARY

Public Service Company of New Mexico (PNM) has performed a Technical and Economic Assessment of Solar Hybrid Repowering under funding by the Department of Energy (DOE), the Electric Power Research Institute (EPRI), Western Energy Supply and Transmission (WEST) Associates, and a number of southwestern utilities.* Solar hybrid repowering involves placement of solar hardware adjacent to and connected to existing gas- and oil-fueled electric generation units to displace some of or all the fossil fuel normally used during daylight hours. The subject study assesses the technical and economic viability of the solar hybrid repowering concept within the southwestern United States and the PNM system. This document is a final report on the study and its results.

The study was divided into the six primary tasks to allow a systematic investigation of the concept:

- Task 1100 – Market Survey and Cost/Benefit Analysis

The primary objective of this task was to determine the near-term market potential of solar hybrid repowering. This was accomplished by conducting a mail survey of Southwestern utilities to identify potential candidate units, by identifying typical candidate plant characteristics from the results of the survey, and by performing a computer simulation of the economic dispatch of a typical candidate plant on four selected utility systems. The data resulting from this modeling allowed for the determination of a cost/benefit ratio for solar hybrid repowering.

- Task 1200 – Study Unit Selection

The objective of this task was to select a specific PNM plant/unit as a candidate demonstration site for the concept. The selection of the unit was based on the typical plant as identified by the market survey, its suitability to future needs of the PNM system, and its ability to meet the goals of the DOE Solar Hybrid Repowering Program.

*Arizona Power Authority, Public Service Company of Oklahoma, San Diego Gas and Electric Company, and Tucumcari Power and Light.

- Task 1300 — Conceptual Design and Cost Estimates

The purpose of this task was to prepare a conceptual design and detailed cost estimate of a solar hybrid repowering demonstration at the selected study unit site. The solar system design was based on the McDonnell Douglas Astronautics Company central receiver system as defined in the DOE Phase I Preliminary Design Report. This system was selected predicated on PNM analysis, DOE guidance, and the Sandia Laboratory recommendations for the Barstow Pilot Plant. The technical feasibility of the concept was thoroughly addressed, and approaches were devised for the resolution of problems.

- Task 1400 — Unit Economic Analysis

This task involved performing a detailed economic analysis of the selected study unit based on operating conditions and cost estimates developed for the conceptual design.

- Task 1500 — Program Planning, Future Phases

The goal of this task was preparation of a work plan for future phases of a Solar Hybrid Repowering Demonstration Project. The work plan includes a work breakdown structure, a schedule, and a management plan.

- Task 1600 — Program Management

The final task called for the organization, direction, control and reporting of the project within a specified schedule and budget. Utility interfacing through Supporting and Advisory Programs was also accomplished under this heading.

Sections 1.1 through 1.5 of this Report include summaries of the major results of the market survey and cost/benefit analysis, selection of a study unit, development of a conceptual design, and results of the study unit economic analysis. A summary of the program plan for future phases of the Solar Hybrid Repowering Project is also presented.

1.1 MARKET SURVEY AND COST BENEFIT ANALYSIS

The evaluation of the commercial market potential for solar hybrid repowering of existing fossil-fueled electric power generating plants has been completed. This evaluation includes a market survey directed toward the potential repowering of oil- and gas-fired plants of less than 200 MWe located in the Southwest. Tables 1.1-1 through 1.1-4 summarize the results of this evaluation; Table 1.1-5 summarizes the results of the market evaluation for units greater than 200 MWe. These evaluations are discussed in detail in Section 2.0 of this Report.

A literature survey also was performed using Federal Power Commission Form 12 data. As shown in Table 1.1-1, this literature survey identified 755 gas- and oil-fueled electric power generating units with ratings less than 200 MWe, with more than half rated at 50 MWe or less. These units are located in the Southwest, are potential candidates for solar hybrid repowering, and represent more than 40,000 MWe of generating capacity. Since most of these units were built in the 1950s, they will either have to be repowered or replaced with new generating capacity within the next 25 years.

A questionnaire was distributed to 78 utilities to determine interest in the solar hybrid repowering concept, to identify candidate plants for repowering, and to determine the availability of land adjacent to the candidate plants. Environmental and safety issues were not addressed in the market survey. The 78 selected utilities represent most of the electric power generating capacity in the Southwestern United States, including Arizona, California, Colorado, Louisiana, Nevada, New Mexico, Oklahoma, Texas and Utah. Of the 78 utilities that were sent the questionnaire, 61 responded, with approximately 50 indicating an interest in solar repowering of their existing gas- and oil-fired units.

As indicated in Table 1.1-1, the survey identified 272 candidate units for solar hybrid repowering, representing a total rated capacity of approximately 19,700 MWe. Considering land availability for solar collector fields, these 272 units represent a solar repowering potential of ~11,200 MWe. Of the 272 candidate units, 206 have land available within 2500 feet and represent a solar repowering capacity of ~7200 MWe. Considering a) available land located

TABLE 1.1-1. MARKET EVALUATION SUMMARY*

<u>Category</u>	<u>Number of Units</u>	<u>Total MWe</u>
Potential Market Size (Rated MWe)		
● Literature Survey	755	40,954
● Utility Survey	272	19,749
Solar Repowering Potential (Effective MWe)		
● Based on Land Availability	272	11,171
- and ≤ 2500 -ft from Plant	206	7,248
- and $> 50\%$ Repowering	82	5,189
- and Utility Interest	82	5,189
*For Units Rated ≤ 200 MWe		

TABLE 1.1-2. MARKET EVALUATION SUMMARY FOR NON-REHEAT STEAM TURBINES*

<u>Category</u>	<u>Number of Units</u>	<u>Total MWe</u>
Potential Market Size (Rated MWe)		
● Utility Survey — Repowerable Units	152	7,455
Solar Repowering Potential (Effective MWe)		
● Based on Land Availability	152	3,953
- and ≤ 2500 -ft from Plant	116	2,742
- and $> 50\%$ Repowering	47	1,983
- and Utility Interest	47	1,983

*For Units Rated ≤ 200 MWe

TABLE 1.1-3. MARKET EVALUATION SUMMARY FOR REHEAT STEAM TURBINES*

<u>Category</u>	<u>Number of Units</u>	<u>Total MWe</u>
Potential Market Size (Rated MWe)		
• Utility Survey — Repowerable Units	92	11,186
Solar Repowering Potential (Effective MWe)		
• Based on Land Availability	92	6,775
- and ≤ 2500 -ft from Plant	65	4,138
- and $> 50\%$ Repowering	29	3,068
- and Utility Interest	29	3,068
*For Units Rated ≤ 200 MWe		

TABLE 1.1-4. MARKET EVALUATION SUMMARY FOR COMBUSTION TURBINES*

<u>Category</u>	<u>Number of Units</u>	<u>Total MWe</u>
Potential Market Size (Rated MWe)		
• Utility Survey — Repowerable Units	28	1,108
Solar Repowering Potential (Effective MWe)		
• Based on Land Availability	28	443
- and ≤ 2500 -ft from Plant	25	368
- and $> 50\%$ Repowering	6	138
- and Utility Interest	6	138
*For Units Rated < 200 MWe		

at less than 2500 feet from the candidate unit, b) a repowering potential of greater than 50 percent of the rated unit output, and c) utility interest, 82 units representing ~5200 MWe of effective repowering potential were identified. Therefore, a large potential market exists for the solar hybrid repowering concept if the approach can be proven to be economically attractive.

Tables 1.1-2, 1.1-3 and 1.1-4 summarize the market evaluation (similar to Table 1.1-1) according to non-reheat steam turbine, reheat steam turbine, and combustion turbine units, respectively. Of the 272 total candidate units, 152 units (56 percent) with a rated capacity of ~7400 MWe and an effective solar repowering potential of ~4000 MWe were identified as non-reheat steam turbines (see Table 1.1-2). Of the 152 non-reheat units, 116 have land available within 2500 feet of the plant, representing a repowering potential of ~2700 MWe. Based on both land available within 2500 feet and a repowering level of greater than 50 percent, 47 units at ~2000 MW of solar repowering capacity were identified.

For the reheat steam turbines summarized in Table 1.1-3, 92 candidate units were reported with an effective solar repowering potential of ~6800 MWe (based on land availability). When both the land distance and repowering percentage restrictions were applied, 29 reheat units at an effective solar power capacity of ~3100 MWe were identified.

Of the 272 repowerable units, 28 are combustion turbines that represent an effective solar repowering capacity of ~400 MWe, as shown in Table 1.1-4, which is approximately four percent of the total effective solar repowering potential. Based on available land located at less than 2500 feet and a repowering level of greater than 50 percent, six units at ~140 MWe of effective solar repowering potential were identified in this evaluation.

A verification of the land available for solar repowering of a few selected units has been performed. Of the 82 units having a total of ~5200 MWe of solar repowering potential (shown in Table 1.1-1) based on available land at ≤ 2500 feet and > 50 percent repowering, 23 units from 20 utilities, having an effective solar

repowering potential of ~1600 MWe, were selected for verification by contacting the specific utilities involved. The results of the verification show that ~1560 MWe of solar repowering potential (~98 percent of the ~1600 MWe initially identified) can be repowered based on the available land. Of these 23 units, however, two units have their available land at >2500 feet. Thus, the net solar repowering potential of the 21 units at >50 percent repowering and <2500 feet is ~1420 MWe.

The characteristics of a typical candidate unit for solar hybrid repowering were defined on the basis of the utility survey results. Based on the relatively high number of non-reheat steam turbine units to be repowered, and in order to be consistent with the first generation solar central receiver technology being developed by the Department of Energy, the non-reheat steam turbine was selected as the recommended type of unit to be repowered in the initial phase of the program. Therefore, the typical unit is a non-reheat steam turbine with inlet conditions of 850 to 1250 psig/900 to 950°F. The rated power of the typical unit, built between 1950 and 1960 and likely to be retired before the year 2000, is between 10 and 50 MWe. In general, the candidate units are in good condition and are being used for either intermediate or peaking load service.

A literature survey and a utility survey that include units rated above 200 MWe also have been performed. As shown in Table 1.1-5, the literature survey has identified an additional 129 oil- or gas-fired units >200 MWe at a total rated capacity of ~53,000 MWe. These totals should be compared with and added to the 755 units and ~41,000 MWe results shown in Table 1.1-1. From the utility survey, 61 units at a rated capacity of ~26,000 MWe were identified as possible candidates for solar hybrid repowering. All of the 61 units >200 MWe are reheat steam turbine units. Based on land availability, these 61 units represent an effective solar repowering potential of ~15,100 MWe (see Table 1.1-5). These totals are in addition to the 272 units and ~11,200 MWe repowering potential shown in Table 1.1-1. Considering available land at ≤2500 feet from the plant, 37 units at ~6300 MWe of solar repowering capacity were identified. A total of 17 units at ~5700 MWe of solar repowering potential have land available at ≤2500 feet and sufficient land for repowering at >50 percent. These totals should be compared with and added to the 82 units and ~5200 MWe of solar repowering potential shown in Table 1.1-1.

TABLE 1.1-5. MARKET EVALUATION SUMMARY FOR UNITS ABOVE 200 MWe

<u>Category</u>	<u>Number of Units</u>	<u>Total MWe</u>
Potential Market Size (Rated MWe)		
● Literature Survey	129	53,459
● Utility Survey	61	25,594
Solar Repowering Potential (Effective MWe)		
● Based on Land Availability	61	15,073
- and <u>≤</u> 2500-ft from Plant	37	6,294
- and >50% Repowering	17	5,728

A cost/benefit analysis has been performed for the solar hybrid repowering concept for four selected Southwestern utility systems: Arizona Public Service, Public Service Company of New Mexico, Nevada Power Company, and the Electric Power Research Institute Synthetic Utility System E, which is representative of utility systems in Texas, Oklahoma and Louisiana. A reference 50 MWe Solar Hybrid Repowering Plant was defined for performing the cost/benefit analysis based on the characteristics of the typical candidate unit discussed above. The results of this analysis indicate that the solar hybrid repowering concept has the potential to be economically attractive for utility applications when compared with conventional methods of electric power generation (a cost/benefit ratio of approximately 0.9 for a repowered unit operating as part of Synthetic Utility System E).

1.2 STUDY UNIT SELECTION

Task 1200 of the DOE/PNM Technical and Economic Assessment of Solar Hybrid Repowering requires selection of a study unit to represent a typical plant for the expected market. The study unit is to reflect data derived from a market survey and be well suited to future needs of the PNM system. This will ensure optimum use of the study unit for demonstration purposes while maintaining system integrity.

Four potential methods for solar hybrid repowering were evaluated:

- Steam Rankine cycle solar feedwater heating
- Steam Rankine cycle evaporation and superheating (boiler displacement)
- Brayton cycle (combustion turbines)
- Combined cycles (Brayton/Steam Rankine)

It was recommended that the optimum system, in terms of market penetration and cost benefit ratio, was solar evaporation and superheating of an existing Steam Rankine plant.

It was required that the size and type of a solar system for demonstration of evaporation and superheating coincide with current DOE technology in order to demonstrate application in the near term. It was determined that a 25 MWe power level utilizing an external central receiver was a satisfactory evolution from the Barstow Pilot Plant toward a 100 MWe commercial goal for solar plants. This power level was confirmed by Rockwell International,* developer of the external central receiver, and by the project review team.

Based on use of a steam Rankine boiler displacement at a capacity level of 25 MWe, candidate sites and units were evaluated by seven PNM groups to determine which was most suitable to become the study unit. Inputs were provided to

*Rockwell's design was selected for use at the Barstow Pilot Plant in July 1978.

Project Management on the suitability of repowering the candidate units in terms of the future needs of the PNM system, and the optimum usefulness of each unit to the utility and to DOE as a demonstration unit.

PNM Project Management also carefully evaluated the typical candidate unit criteria as established through the market survey and cost/benefit analysis (discussed in detail in Section 2.4). It was concluded that the Reeves Station was the ideal site for study of the solar hybrid repowering concept. Based upon Power Production recommendations and definition of the candidate repowering unit, the most desirable machine was determined to be Unit No. 2 with its 50 MWe net output. Considering the requirements for evaporation superheating displacement and a 25 MWe power level, it was concluded that a 25 MWe solar field would be adequate to demonstrate the concept while remaining within technological limits. This allows for a 50 percent repowering of the unit and allows for demonstration of solar, fossil and solar/fossil operation. Section 3.0 of this Report presents detailed information on the study unit selection.

1.3 CONCEPTUAL DESIGN AND COST ESTIMATE

Reeves Unit No. 2, selected under the preceding task, was established as the potential candidate plant for solar hybrid repowering. This plant was investigated under this conceptual design and cost estimate task to provide a reasonably definitive design and to identify the required modifications. The existing land situation, as well as the particular environmental aspects of Reeves Unit No. 2, were investigated. Upon complete definition, a cost estimate was prepared that is related to the present configuration of Reeves Unit No. 2.

All significant changes in the plant necessary to accommodate the solar facilities and control systems were determined and estimated. A heliostat field was defined using the MIRVAL* program developed by Sandia Livermore, and the power level available from a given configuration was established.

The design point selected for this conceptual design, 2:00 p.m. winter solstice, is intended to provide at least a total solar electrical output of 25 MWe gross. The solar collector field and the receiver sizes were designed to meet this requirement. System component sizes were based on the summer solstice condition at noon, which could produce approximately 39 MWe gross electrical output. The summer solstice design point was used to size all the system components and to establish steam and feedwater flow rates, pressures, and temperatures.

The design approach used during the conceptual design for solar repowering is as follows:

- Reeves Station Unit No. 2 was selected for repowering
- The solar system design was to be based on the 10 MWe solar central receiver preliminary design for Barstow, California
- A design goal of 50 percent solar repowering (25 MWe) was established
- A collector field layout generated by the DOE/Sandia Livermore Laboratories, California, from its MIRVAL computer program was used

*The MIRVAL computer code, along with two preprocessor codes, was used to size the field and locate the heliostats in order to obtain the desired station power output. The MIRVAL program is described in Section 4.6.1 of this Report.

- Definitions of possible plant operating modes were used as a design base
- Preliminary EPGS general arrangement drawings were to be prepared to define the integration of the new solar system equipment with existing plant equipment
- Computer modeling of the basic fossil/solar cycles was to be prepared to provide heat balance data for system performance and equipment sizing
- Piping interface locations were to be defined
- Changes to the existing plant were to be minimized
- Water treatment system design was to be based on once-through boiler requirements

The control system design provided for the solar portion of the repowered Reeves Unit No. 2 has been optimized to provide the simplest and most straightforward design to minimize the impact on existing plant equipment.

The design of the receiver for this solar repowering project is to be based upon the receiver used in the Barstow, California Pilot Plant. That receiver is a Rocketdyne once-through boiler, fabricated of Incoloy 800 tube materials. The Barstow design will be scaled-up to meet the capacity requirements of this Project.

The Reeves Station repowering collector design was based on the use of the MDAC collectors, drives, and controls as proposed for the Barstow Pilot Plant. That design was modified to comply with the Reeves site conditions. Major changes include:

- Revising the size and layout of the collector field and number of heliostat units to conform to the physical characteristics of the Reeves site. This revision was based on the design insolation at the Reeves site, the reflectivity of the heliostat mirrors, the absorptance of the receiver, and the general design plan of power required.
- Integration of the collector control system into the Master Control System being proposed for the repowered Reeves station.

A design utilizing 4289 heliostats in a field to the south of the existing station was conceived. The tower was set in the southern half of a rectangular field, and access roads, fencing, relocation of existing facilities, and potential for maintenance of the solar facilities were established.

Further program revisions and MIRVAL runs to allow for the inclusion of all roads and steam piping established the actual number of heliostates required; the resulting heliostat field contains 4086 heliostats. Further work will be performed during the detailed design to establish the exact field position of all heliostats. The variance, however, is considered minor relative to the data available for insolation, cloud cover and other environmental factors. Use of the maximum number of heliostats was considered as a conservative figure in this effort.

Environmental aspects such as rainfall, cloud cover, dust, and traffic hazards, were considered in the conceptual design.

Potential problems were identified and solutions were defined through trade studies and engineering analysis. The conceptual design was developed to a level sufficient to establish a construction and program cost estimate.

The Conceptual Design Study for Solar Repowering Reeves Station Unit No. 2 reveals no major barriers that would impede detailed design and construction. Given a normal anticipation of expected problems associated with a retrofit and/or upgrading project, the technical aspects of solar repowering of Reeves Station appear to be relatively straightforward.

Reasonable approaches have been identified as possible solutions for major design problems. Areas meeting extended future detailed design investigation also are identified.

1.4 UNIT ECONOMIC ANALYSIS

A cost/benefit analysis has been performed for the solar hybrid repowering concept (Reeves Unit No. 2) for the PNM system. The intent of the analysis is to realistically assess the economics of the "first" repowered plant using present cost data for a limited production level for the solar hardware. The results therefore are not indicative of the economic potential of solar repowering but rather only of the economics of the "first demonstration" plant. The economic potential of solar repowering was presented in Section 1.1 of this Report.

The economic analysis performed for Reeves Unit No. 2 was similar to the analysis discussed in Section 1.1 for four selected southwestern utilities (including PNM), except that the following changes were incorporated:

- The reference plant description has been revised consistent with the conceptual design presented in Section 1.3
- The insolation data base has been updated consistent with the 1978 version of the Aerospace tapes for Albuquerque, New Mexico
- The PNM system description has been revised to reflect the July 1978 plan for future power generation capability
- The economic scenario has been modified to approximate PNM system changes
- The cost of the repowered plant has been revised consistent with the conceptual design

A reference solar hybrid repowered plant concept has been established for the Reeves Unit No. 2 for the purpose of performing the unit economic analysis. The reference plant concept for Reeves Unit No. 2 is based on the solar hardware and technology being developed for the 10 MWe solar central receiver pilot plant to be built near Barstow, California. The solar subsystem has been sized to provide 25 MWe (50 percent repowering) at 2:00 p.m. winter solstice based on an insolation level of 950 watts/m².

For the economic analysis, detailed modeling of the operation of the repowered plant and the PNM system was performed for several discrete years, beginning in

1981. The penalty for the loss of the Reeves Unit No. 2 during repowering was estimated. The operating strategy was varied from year to year, requiring 25 MWe of fossil firing any time the solar system was being used in years 1982 through 1985, and requiring the same operating strategy 50 percent of the time in the years 1985 through 1986. Beyond 1986 the repowered plant was allowed to operate in the most economical mode. A detailed PNM expansion plan for conventional generation was used for the analysis.

The cost/benefit of a demonstration program, as viewed from immediate utility economic impacts, is substantially higher than might be expected for commercial implementation. The higher cost/benefits are due to higher costs for solar components (such as heliostats) and restricted plant operation in the early years (due to testing and the establishment of operating mode confidence/experience). A heavy addition of base-load conventional capacity (nuclear and coal) during the early years of operation also decreases the benefit.

These cost/benefit factors are consistent with other demonstration programs in that the real benefits are achieved through the experience and information gained, and the benefits result in the commercialization phase.

1.5 PROGRAM PLANNING, FUTURE PHASES

Public Service Company of New Mexico (PNM) developed the Program Plan outlined in Section 6.0 of this Report as a means of demonstrating the Solar Hybrid Repowering concept. The plan is structured to permit the program to be conducted in a manner similar to previous successful utility-oriented, pre-commercialization programs. The Program Plan provides appropriate visibility and control of all technical effort, schedules and costs. It utilizes the Work Breakdown Structure approach and anticipates control documents, such as design requirements and interface control drawings, to ensure a successful demonstration of the Solar Hybrid Repowering concept. It recognizes and accommodates the acquisition, analysis and reporting of data vital to the repowering program.

The principal goal of the PNM Program Plan is to establish the technical viability and economic attractiveness of the Solar Hybrid Repowering concept and widespread utility application. The specific objectives are:

- To prepare a detailed design for a solar repowered plant
- To construct a solar repowered plant
- To start-up and operate a solar repower plant successfully for two years
- To disseminate progress reports and program results to other utilities, industries and government agencies to enhance the early commercialization of solar repowering

The program to implement the Solar Hybrid Repowering concept is divided into six principal phases:

- Phase 1 - Technical/Economic Assessment
- Phase 2 - Design
- Phase 3 - Procurement
- Phase 4 - Construction
- Phase 5 - Checkout
- Phase 6 - Operation

Figure 1.5-1 presents the schedule for the proposed program.

The Phase 1 portion of the program is completed with the issuance of this final report; the following output will be available to initiate the Phase 2 Design:

- Market survey and cost/benefit analysis
- Specific site for the solar repowering program
- Conceptual design of the solar repowered unit
- Cost estimate for the solar repowering unit

Phases 2 through 5, Design through Checkout, are scheduled to take place over a 42-month period. An approximate two-year operating period (Phase 6) is also planned, but the option for DOE to continue the operations beyond two years should be reevaluated when successful operation of the unit has been achieved.

Figure 1.5-1. Schedule for the Proposed Program

2.0 MARKET SURVEY AND COST BENEFIT ANALYSIS

This section contains a description of the subject market survey, a discussion of utility interest, an evaluation of the solar repowering potential in the Southwest, a description of the typical candidate unit for repowering, and the results of the cost/benefit analyses that have been performed.

2.1 MARKET SURVEY DESCRIPTION

The technical approach used in developing a comprehensive survey of the potential market for solar hybrid repowering involved the following:

- Review of the results of previous PNM surveys
- A literature survey of the utilities in the Southwestern United States, based primarily on Federal Power Commission Form 12 data (2-1)*
- Mailing of a data questionnaire on the PNM Solar Hybrid Repowering Project to 78 utilities in a nine-state area of the Southwest

The results from the previous PNM surveys and the literature survey were used for: a) guidance in developing the utility questionnaire, and b) information purposes to supplement the responses to the questionnaire.

The PNM Solar Hybrid Repowering Project Utility Questionnaire submitted to the Southwestern utilities was transmitted by a cover letter that summarizes the PNM Solar Hybrid Repowering Project. It emphasizes that the study efforts "will identify, from a utility point of view, if a cost-effective approach exists to repower existing steam or combustion turbine units with solar energy systems to reduce or supplant natural gas and/or oil boiler firing." Additional references to the solar hybrid repowering of existing units (as opposed to building new solar hybrid power plants) were made in the cover letter and in the questionnaire, both of which are included in Appendix A to this Volume.

*References are provided in Section 7.0 of this Report.

Included in the utility questionnaire (Appendix A) were the following basic questions:

- 1) Has your utility considered the possibility of solar power generation as a future alternative?
- 2) Would your company be interested in participating in a solar hybrid plant program if financial incentives made it equivalent or superior to existing generation alternatives?
- 3) Do you have any plans or interest in repowering any units of 200 MWe or less?

The questionnaire also requested the following general utility information:

- Approximate generation mix (oil/natural gas, coal and nuclear)
- Time of system peak
- Availability requirements for peaking and intermediate units

For each of the units less than 200 MWe owned and operated by the utility, the following information was requested (see Appendix A):

- Rated size (MWe)
- Unit type (Steam/reheat, Steam/non-reheat, Combustion, Combined cycle)
- Turbine inlet temperature
- Turbine inlet pressure
- Year built
- Unit condition
- Current use (Base, Intermediate, Peak, Stand-by)
- Estimated retirement
- General plant location (Industrial, Urban, Suburban, or Rural)
- Land availability (Based on a requirement of approximately six acres of land per MWe for the solar collector field, there is sufficient vacant land near the plant to repower ___ percent of of the unit.)
- Distance from unit to available land

The market survey questionnaire was mailed to the appropriate investor-owned municipal, federal, state, district and cooperative systems/utilities in the nine-state area. The survey was limited initially to units of ≤ 200 MWe in rated size, consistent with the most recent prior PNM survey conducted in 1976 and discussed in Section 1.3 of the PNM proposal. The program plan in Section 3.4 of the proposal, relating to a market cost/benefit analysis, included a statement that one of the objectives was to validate the survey presented in Section 1.3. During the initial phase of the Solar Hybrid Repowering Project at PNM in November 1977, study requirements and guidelines were set forth that included a limitation on the unit size to be considered of ≤ 200 MWe.

One of the objectives of the PNM project was to make the utility survey consistent with the first generation solar central receiver technology being developed by the Department of Energy for a 10 MWe pilot plant (to be constructed at Barstow, California) and a 100 MWe commercial plant. An extension of this market survey to oil/gas-fired units above 200 MWe also has been performed, and the results are included in this Report. The 200 MWe rated size does not represent a restriction on the potential for solar hybrid repowering.

In evaluating the market survey results, as discussed in Section 2.3 of this Report, consideration was given to the desirability of having the available land at less than 2500 feet from the existing unit. If the land is adjacent to the plant, the thermal, pressure and efficiency losses resulting from the horizontal lengths of steam and feedwater piping between the base of the central receiver tower and the existing turbine generator will be minimized, as will the initial cost for this piping. The ≤ 2500 feet restriction does not represent an absolute limit. The actual limitation will be determined by the various costs and efficiencies, as well as by the cost for the solar plant as compared to the costs for conventional power generation on their system. The 2500 feet restriction is consistent with the conceptual design for a solar hybrid repowered plant (see Section 4.0).

Consideration also was given to the desirability of having sufficient land available to repower an existing unit to a level of greater than 50 percent. Again, the >50 percent repowering criteria does not represent an absolute restriction.

The percentage of repowering desired for a specific unit will depend on the site and utility system, and will be contingent upon the relative cost and benefit the solar plant when compared with conventional power generation.

Other factors that could influence the selected repowering level for a given unit include the following:

- Fossil boiler efficiency at reduced power
- Minimum practical operating point of the fossil boiler
- Maximum ramp rates for increasing and decreasing the fossil boiler output as the solar boiler output varies with intermittent cloud cover
- Required dispatch of the unit to the utility system
- Time of day and period of year for the utility's system peak, coupled with the normal weather conditions for the site during those periods
- Desirability of utilizing all the solar-generated steam from the hybrid repowered plant during those days when the solar insolation is at a maximum

An extensive discussion of the cost/benefit analyses for solar hybrid repowered plants performed for selected utilities in the Southwest is presented in Section 2.5 of this Report. One of the objectives of these analyses was to determine the effect, for one utility, of varying the percentage of repowering of a 50 MWe plant from a cost/benefit ratio standpoint. Lower cost benefit ratios were achieved for repowering percentages >50 percent.

This utility survey is limited in scope in several respects. The survey was limited initially to units of ≤ 200 MWe in size, but data from a literature survey of the oil- and gas-fired units >200 MWe in the Southwest have been developed. A total of 129 units, at a rated capacity of $\sim 53,000$ MWe, was tabulated. These totals should be compared with and added to the 755 units and $\sim 41,000$ MWe results shown in Table 1.1-1 (see Section 1.1). Oil- and gas-fired units >200 MWe, which are potentially solar hybrid repowerable, also have been surveyed from the utilities by PNM. A summary of this literature survey extension and the subsequent utility survey follows.

As discussed in Section 2.2 of this Report, 61 of the 78 utilities surveyed elected to respond to the PNM questionnaire, and these utilities reported data on 394 units. This represents ~52 percent of the 755 unit total from the literature survey shown in Table 1.1-1. Thus, if the balance of the 78 utilities were to respond to the survey, and if all the units had been reported by each of the utilities that responded, a significant increase in the number of repowerable units and effective solar repowering potential might be realized.

Section 2.3.1, Overview of the Solar Repowering Potential, describes the method used for determining the effective solar repowering potential from the utility supplied data of rated power and available land. Although some utilities responded with a specific repowering percentage based on land availability, most utilities reported their repowering levels in brackets of 0 percent, 1 to 25 percent, 26 to 50 percent, 51 to 75 percent and 76 to 100 percent. By using the upper bound of the bracketed repowering level for this latter group of utilities, the results for the repowering potential could be, on the average, ~12 percent lower than shown in Section 2.3.1.

This utility survey is also limited in scope in that only a nine-state area in the Southwestern United States was included. A complete survey to encompass the balance of the 50 states may significantly increase the number of repowerable units, as well as the solar hybrid repowering potential.

PNM anticipates that as solar technology becomes better known and developed, as costs are decreased, as the commercialization of solar hybrid repowering is demonstrated, and as the cost/benefit ratios are decreased to make repowering of existing units more economically attractive, additional units will be identified by the southwestern utilities as repowerable. The available land for the solar collector fields for the candidate units also could be increased if it could be shown that it was economically attractive to acquire this additional land.

2.2 UTILITY INTEREST

The market survey questionnaire was transmitted to 78 utilities in the Southwestern United States, and 61 responses (77 percent) were received. Considering the significant efforts required of these utilities to prepare the detailed information for their response to the questionnaire, including plant data on 394 units, the conclusion was drawn that most of the utilities in the Southwest are interested in solar power and, in particular, solar hybrid repowering.

As discussed in Section 2.1 of this Report, three basic questions were posed to the utilities. Table 2.2-1 contains the responses to these questions.

TABLE 2.2-1. RESULTS OF UTILITY SURVEY QUESTIONS

Question	Number of Utility Responses*	
	Yes	No
Has Your Utility Considered the Possibility of Solar Power Generation as a Future Alternative?	27	29
Would Your Company be Interested in Participating in a Solar Hybrid Plant Program if Financial Incentives Made it Equivalent or Superior to Existing Generation Alternatives?	51	3
Do You Have Any Plans or Interest in Repowering Any Units of 200 MWe or Less?	39	17

*Of 61 Utilities responding to the survey, only 56/54/56 elected to answer these questions.

For the first question, related to solar power generation as a future alternative, about half the utilities indicated that they have considered this possibility.

In answering the second question, 51 of 54 utilities (94 percent) stated that their respective companies would be interested in participating in a solar hybrid repowering program if financial incentives made it equivalent or superior to existing generation alternatives. This high percentage response was considered favorable and supportive of the Solar Hybrid Repowering Program.

Referring to the third question, 39 of 56 utilities (70 percent) indicated that they have plans or interest in repowering some of their units of 200 MWe or less. This response is indicative of their recognition of the anticipated dwindling supplies of natural gas and/or fuel oil, coupled with the expected rapid escalation in the costs of these fuels. In particular, solar hybrid repowering was mentioned by several of the utilities in their questionnaire comments and cover letters as an attractive and logical alternative.

The responses by the utilities to these three questions are favorable and indicate support of the Solar Hybrid Repowering concept. These responses also indicate an encouraging level of utility interest in the program.

Table 2.2-2 indicates by state the number of utility responses, the number of candidate units of ≤ 200 MWe reported, and the number of candidate units that are repowerable by solar technology, based on land availability. The majority of the utilities are located in the larger size and/or high population states of Texas, Louisiana, California, Colorado, New Mexico, Oklahoma and Arizona.

TABLE 2.2-2. UTILITY DATA QUESTIONNAIRE RESPONSE

<u>State</u>	<u>Number of Responses</u>	<u>Number of Candidate Units Reported</u>	<u>Number of Candidate Repowerable Units</u>
Arizona	5	30	22
California	7	121	61
Colorado	7	15	9
Louisiana	8	36	25
Nevada	2	9	9
New Mexico	6	22	22
Oklahoma	5	25	21
Texas	17	129	100
Utah	3	5	1
Others	1	2	2
TOTAL	61	394	272

A total of 394 candidate units of ≤ 200 MWe were reported by the 61 utilities. Of these 394 units, 272 oil/gas fired units were reported as potentially repowerable

to some degree by solar energy, based on land availability. As shown in the right column in Table 2.2-2, Texas, California, Louisiana, New Mexico, Arizona and Oklahoma (ranked in that order) contain the majority of the units that are solar repowerable. As discussed further in Section 2.3 of this Report, the effective solar hybrid repowering potential (in MWe) and the degree of repowering for each unit, based on land availability, is an important consideration in the selection of candidate units for solar repowering.

2.3 SOLAR REPOWERING POTENTIAL IN THE SOUTHWEST

The basis for the data in this Report on solar repowering potential is an extensive utility survey of nine states including Arizona, California, Colorado, Louisiana, Nevada, New Mexico, Oklahoma, Texas and Utah. In addition, a literature survey of the area was conducted using the following sources:

- Federal Power Commission Form 12 files⁽²⁻¹⁾
- DOE/RA-0001 "Inventory of Power Plants in the United States"⁽²⁻²⁾
- Federal Power Commission Regional Reliability Council Reports for the Southwest

The literature survey was utilized to supplement the results of the specific utility survey where necessary.

2.3.1 OVERVIEW OF SOLAR REPOWERING POTENTIAL

A total of 61 utilities in the Southwest responded to the utility survey conducted by the Public Service Company of New Mexico. In these responses, 394 units ≤200 MWe were identified. Considering land availability, 272 of these 394 units were reported as potentially solar repowerable. Thus, the PNM utility survey responses of repowerable units covered approximately 36 percent of all the units identified by the literature survey. These 272 units represent 48 percent of the total rated generating capacity contained in the literature survey.

The results of the literature survey and the PNM utility survey (Table 1.1-1, Section 1.1), coupled with the fact that approximately 78 percent of the utilities elected to respond to the survey (61 to 78 utilities), indicate a strong potential for, and definite interest in, solar hybrid repowering in the southwestern United States.

The 272 units reported in the utility survey represent 19,749 MWe of rated generating capacity. After the reported repowering levels (based on land availability) were applied to the rated sizes of the units, 11,171 MWe of effective solar repowering potential resulted (see Table 1.1-1). In some cases, the utilities responded with a specific repowering percentage, based on a land

availability criterion of ~6 acres per MWe. In most cases, the utilities reported their repowering levels in brackets of: 0 percent, 1 to 25 percent, 26 to 50 percent, 51 to 75 percent, and 76 to 100 percent. In the latter case, the upper bound of the bracketed repowering level was applied to the rated size to arrive at an effective solar repowering level in MWe. Based on this 11,171 MWe of effective solar repowering capacity, a large potential market exists for the solar hybrid repowering concept if the approach can be proven to be economically attractive.

By restricting the distance of the available land to ≤ 2500 feet from the existing unit, the number of units is reduced to 206, representing a solar repowering potential of 7248 MWe (see Table 1.1-1). If a further restriction of repowering percentage (>50 percent) is applied to these units, the total potential is reduced to 82 units at 5189 MWe of effective solar repowering. It should be noted that the latter numbers represent a realistic and practical potential in terms of solar repowering because they include: a) only those units the utilities chose to report as being candidates for solar repowering, and b) only those units that also meet the land distance (≤ 2500 -ft) and repowering percentage (>50 percent) restrictions.

Tables 1.1-2, 1.1-3 and 1.1-4 of Section 1.1 present a market evaluation summary (similar to Table 1.1-1) for non-reheat steam turbine, reheat steam turbine and combustion turbine units, respectively. Of the 272 total candidate units, 152 units (56 percent) with a rated capacity of 7455 MWe and an effective solar repowering potential of 3953 MWe were identified as non-reheat steam turbines (see Table 1.1-2). Available land is located within 2500 feet of 116 non-reheat units with a repowering potential of 2742 MWe. Based on land available within 2500 feet of a given unit, a repowering level of greater than 50 percent, and utility interest, 47 units at 1983 MWe of solar capacity were identified.

For the reheat steam turbines summarized in Table 1.1-3, 92 candidate units were reported with a rated capacity of 11,186 MWe and an effective solar repowering potential of 6775 MWe, based on land availability, and 65 units at an effective solar repowering capacity of 4138 MWe have land available within 2500 feet. When both the land distance and repowering percentage restrictions were applied, 29 reheat units at an effective solar power capacity of 3068 MWe were identified.

Of the 272 repowerable units, 28 are combustion turbines with 1108 MWe of total rated power, representing an effective solar repowering capacity of 443 MWe, as shown in Table 1.1-4. This is approximately four percent of the total effective solar repowering potential. Of these units, 25 have available land at ≤ 2500 feet and a repowering potential of 368 MWe. Based on available land located at ≤ 2500 feet and a repowering level of >50 percent, six units at 138 MWe of effective solar repowering potential were tabulated in this evaluation.

A verification of the land available for solar repowering of a few selected units has been performed. Of the 82 units at a total of 5189 MWe of solar repowering potential (Table 1.1-1), based on available land at ≤ 2500 feet and >50 percent repowering, 23 units with an effective solar repowering potential of 1601 MWe were selected from 20 utilities for verification. This was accomplished by contacting the specific utilities involved. The results of the verification show that 1561 MWe of solar repowering potential (~ 98 percent of the 1601 MWe initially identified) can be repowered based on the available land. Of these 23 units, however, two units have their available land at >2500 feet. Thus, the net solar repowering potential of the 21 units at >50 percent repowering and <2500 feet is 1421 MWe.

An evaluation of the size distribution of the units from the literature and utility surveys is given in Figure 2.3-1, where the lightly-shaded bars represent the number of units from the literature survey. The concentration of the units at the low plant rating levels, particularly in the 0 to 50 MWe categories, is obvious from the chart. The darker shaded bars in Figure 2.3-1 represent the number of repowerable units reported in the utility survey. A similar concentration of units in the 0 to 50 MWe categories (114 units total) exists. However, it is not as obvious from the figure because the size categories at the upper end of the plant rating scale cover a wider band (50 MWe) than the bands for those categories at the lower end of the scale (10 MWe, 20 MWe and 30 MWe). For equal size band categories, corresponding to the 114 units in the 0 to 50 MWe range, the following numbers of repowerable units were identified: for a plant rating range from 51 to 100 MWe, there are 70 units; for a range from 101 to 150 MWe, there are 61 units; and for a range from 151 to 200 MWe, there are 27 units.

Figure 2.3-1. Candidate Units for Solar Hybrid Repowering (Southwestern United States)

Table 2.3-1 lists the top 20 utilities ranked by effective solar repowering in MWe. These utilities have a total effective solar repowering potential of 9264 MWe, the equivalent of 83 percent of the total effective solar repowering potential defined in the survey. Note that the average percentage of repowering for each of these top 20 utilities has also been shown in Table 2.3-1. These results demonstrate that most of the utilities in the southwest have sufficient land available for solar hybrid repowering (on the average) at a level greater than 50 percent. Conversely, one Louisiana and the three California utilities in the top 20, because of the lack of available land, could not repower their units (on the average) at greater than 50 percent.

A literature review and a utility (telephone) survey that includes units rated above 200 MWe also have been performed. The literature survey (Table 1.1-5) identified an additional 129 oil- or gas-fired units >200MWe at a total rated capacity of 53,459 MWe. These totals should be compared with and added to the 775 units and 40,954 MWe results (shown in Table 1.1-1). From the utility survey, 61 units at a rated capacity of 25,594 MWe were identified as potentially solar hybrid repowerable. All 61 units >200 MWe are reheat steam turbine units. Based on land availability, these 61 units represent an effective solar repowering potential of 15,073 MWe (see Table 1.1-5). These totals are in addition to the 272 units and 11,171 MWe repowering potential (shown in Table 1.1-1). Considering available land at ≤ 2500 feet from the plant, 37 units at 6294 MWe of solar repowering capacity were identified. A total of 17 units at 5728 MWe of solar repowering potential have land available at ≤ 2500 feet and sufficient land for repowering at >50 percent. These totals should be compared with and added to the 82 units and 5189 MWe of solar repowering potential (shown in Table 1.1-1).

2.3.2 DETAILED SURVEY RESULTS ON SOLAR REPOWERING POTENTIAL

Table 2.3-2 summarizes by state the number of repowerable units, and the corresponding rated power reported in the survey. From the utility survey, it was determined that 272 repowerable units exist with a total rated capacity of 19,749 MWe. Especially noteworthy is Texas with 8482 MWe of total rated capacity and 100 repowerable units.

TABLE 2.3-1. RANKING OF UTILITIES BY TOTAL EFFECTIVE SOLAR REPOWERING (MWe)

<u>Ranking</u>	<u>State</u>	<u>Utility</u>	<u>Effective Solar MWe</u>	<u>Percentage of Repowering (Average)</u>
1	TX	Houston Lighting & Power	1232 MWe	83%
2	TX	West Texas Utilities	922	90
3	TX	San Antonio Public Service Board	660	87
4	AZ	Tucson Gas & Electric	580	100
5	CA	Pacific Gas & Electric	575	28
6	CA	Southern California Edison	509	32
7	TX	Gulf States Utilities	492	100
8	TX	Texas Electric Service	478	100
9	OK	Western Farmers Electric Cooperative	421	56
10	NE	Sierra Pacific Power	388	84
11	TX	Texas Power & Light	372	100
12	CA	San Diego Gas & Electric	364	34
13	TX	Garland Municipal Power & Light	342	100
14	OK	Public Service Company of Oklahoma	334	59
15	TX	El Paso Electric	304	59
16	NM	Public Service Company of New Mexico	297	93
17	NE	Nevada Power	278	100
18	AZ	Arizona Public Service	278	89
19	LA	Cajun Electric Power Cooperative	230	100
20	LA	Southwestern Electric Power	208	43
TOTAL			9264	

TABLE 2.3-2. UTILITY DATA QUESTIONNAIRE* RESPONSES BY STATE

<u>State</u>	<u>Number of Utilities</u>	<u>Number of Candidate Units</u>	<u>Total Rated Power (MWe)</u>
Arizona	5	22	1,217
California	7	61	5,300
Colorado	7	9	166
Louisiana	8	25	1,664
Nevada	2	9	739
New Mexico	6	22	423
Oklahoma	5	21	1,492
Texas	17	100	8,482
Utah	3	1	66
Others	1	2	200
TOTAL	61	272	19,749

*Questionnaire submitted to 78 utilities; 61 responded.

Table 2.3-3 shows the same breakdown by state, including the effective solar MWe and the repowering percentages for each state. The effective solar repowering potential (MWe) for each unit was derived by applying the reported repowering percentage, based on a land availability of approximately six acres per MWe, to the individual rating of the unit. When reported by the utility, specific repowering percentages were applied to the MWe ratings of the units. In most cases, however, the effective solar repowering potentials were determined by applying the upper bound of the appropriate notation to the following repowering levels: 0 percent, 1 to 25 percent, 26 to 50 percent, 51 to 75 percent and 76 to 100 percent. The effective solar repowering potential for each individual unit was totaled for each utility and each utility was likewise included in the overall state total. The percent repowering for each state is the total effective solar MWe divided by the total rated capacity of the repowerable units. The percent repowering is an indication of the general repowering potential of units ≤ 200 MWe in that state.

The data in Table 2.3-3 make it apparent that some states have a larger power generating capability of units ≤ 200 MWe, and therefore a high number of rated MWe

and effective solar MWe. California, for example, has 5300 MWe of rated capacity of repowerable units. California's effective solar repowering potential is 1602 MWe. Thus, the overall state repowering percentages indicate that the availability of land is a major factor in considering solar repowering. This can be seen from the fact that California's effective solar MWe potential is 30 percent of its reported MWe capacity.

TABLE 2.3-3. UTILITY MARKET SURVEY EVALUATION BY STATE

State	Number of Candidate Units	Rated MWe	Effective Solar MWe	Percent Repower	Percent of Effective Solar
Arizona	22	1,217	974	80.0	8.7
California	61	5,300	1,602	30.2	14.3
Colorado	9	166	35	21.1	0.3
Louisiana	25	1,664	757	45.5	6.8
Nevada	9	739	665	90.0	6.0
New Mexico	22	423	371	87.7	3.3
Oklahoma	21	1,492	885	59.3	7.9
Texas	100	8,482	5,616	70.2	50.3
Utah	1	66	66	100.0	0.6
Others	2	200	200	100.0	1.8
TOTAL	272	19,749	11,171	56.6 (avg)	100.0

These results become important when the repowering percentages are interpreted as a function of rated size of the candidate repowerable units, as presented in Table 2.3-4. Two high repowering percentage categories are indicated: 1 to 25 percent, and 76 to 100 percent. The 1 to 25 percent category is large because many of these units are located in or near densely populated areas where sufficient land is not generally available for significant percentages of solar repowering. There are 109 units that can be repowered in the 76 to 100 percent category. The units in this higher percentage of repowering category are clustered around the 11 to 50 MWe size (41 units) and the 71 to 100 MWe size (28 units).

Table 2.3-5 contains an evaluation of land availability and the distance from a given unit to this available land. It is significant that 206 repowerable units having an effective solar repowering total of 7248 MWe, have land within 2500 feet.

TABLE 2.3-4. REPOWERING PERCENTAGE EVALUATION OF CANDIDATE UNITS (TOTAL NUMBER OF UNITS)

Rated Size (MWe)	Repowering Percentage				Total
	1 to 25	26 to 50	51 to 75	76 to 100	
0 to 10	12	7	0	6	25
11 to 30	30	2	0	27	59
31 to 50	15	0	1	14	30
51 to 70	13	4	1	9	27
71 to 100	8	6	1	28	43
101 to 150	32	10	4	15	61
151 to 200	15	0	2	10	27
TOTAL	125	29	9	109	272

When the restriction of >50 percent repowering potential is applied to the evaluation of land availability and land distance (Table 2.3-5), as shown in Table 2.3-6, the total number of repowerable units at a distance of ≤ 2500 feet is reduced to 82, and the total effective solar repowering potential is reduced to 5189 MWe. With the exception of Texas, the ranking of states by total effective solar MWe changes dramatically. With the restrictions of >50 percent repowering and ≤ 2500 feet applied to the repowerable units, the ranking of states by effective solar MWe becomes:

Texas	2999 MWe
Nevada	503 MWe
Arizona	378 MWe
New Mexico	353 MWe
Oklahoma	286 MWe
Louisiana	274 MWe
Others	200 MWe
California	166 MWe
Colorado	30 MWe
Utah	----
TOTAL	5189 MWe

TABLE 2.3-5. UTILITY MARKET SURVEY RESULTS — EVALUATION OF LAND AVAILABILITY

State	Land Distance (feet)							
	<1000		1001 to 2500		2501 to 5000		>5000	
	No. of Units	Effective Solar MWe	No. of Units	Effective Solar MWe	No. of Units	Effective Solar MWe	No. of Units	Effective Solar MWe
Arizona	2	198	12	221	7	480	1	75
California	32	671	16	533	4	124	9	274
Colorado	7	5	2	30	--	--	--	--
Louisiana	12	427	7	172	6	158	--	--
Nevada	4	278	3	225	2	162	--	--
New Mexico	17	243	5	128	--	--	--	--
Oklahoma	2	212	8	211	5	298	6	164
Texas	41	1807	34	1687	18	1127	7	995
Utah	--	--	--	--	--	--	1	66
Others	--	--	2	200	--	--	--	--
TOTAL	117	3841	89	3407	42	2349	24	1574

TABLE 2.3-6. UTILITY MARKET SURVEY RESULTS -- EVALUATION OF LAND AVAILABILITY
FOR CANDIDATE UNITS HAVING >50 PERCENT REPOWERING POTENTIAL

State	Land Distance (feet)							
	<1000		1001 to 2500		2501 to 5000		>5000	
	No. of Units	Effective Solar MWe	No. of Units	Effective Solar MWe	No. of Units	Effective Solar MWe	No. of Units	Effective Solar MWe
Arizona	2	198	5	180	7	480	1	75
California	2	146	1	20	--	--	2	20
Colorado	--	--	2	30	--	--	--	--
Louisiana	3	274	--	--	1	133	--	--
Nevada	4	278	3	225	1	110	--	--
New Mexico	10	228	3	125	--	--	--	--
Oklahoma	2	212	1	74	5	298	3	77
Texas	23	1534	19	1415	9	970	5	883
Utah	--	--	--	--	--	--	1	66
Others	--	--	2	200	--	--	--	--
TOTAL	46	2920	36	2269	23	1991	12	1121

In the above ranking of states, the restrictions of greater than 50 percent repowering and ≤ 2500 feet show that Texas, Nevada, Arizona and New Mexico are the major contributors to the total practical repowering potential in the Southwest. This ranking reflects the fact that many of the repowerable units in these states are located in rural areas that generally have enough available land to repower to a relatively high percentage; frequently to 100 percent. The "others" listed above is actually one utility, located outside the nine-state survey, that requested to be involved in the Solar Hybrid Repowering Program.

The total of 5189 MWe represents the practical solar repowering potential because this total power level includes: a) only those units that the utilities chose to report as repowerable candidates, b) only those units that are within a distance of 2500 feet of the available land, and c) only those units that can be repowered to >50 percent.

Of the 11,171 MWe of total effective solar repowering potential, approximately 9980 MWe (~ 89 percent) represents units located at plants with multiple units. The concept of multiple units located at a given solar hybrid repowered plant lends itself to the possibilities of steam sharing* from other existing units to assist in providing a more economic and a more flexible solar repowered plant.

2.3.3 EXTENSION OF SURVEY TO UNITS ABOVE 200 MWe

As discussed in Section 2.3.1, a literature survey and a utility survey to include units rated above 200 MWe also have been performed (see Table 1.1-5 in Section 1.1). The number of units, the rated power, and the solar repowering potential based on land availability and the various constraints, from these

*Steam Sharing: Fossil generated steam is borrowed from an adjacent unit. The steam sharing option is attractive from the standpoint of minimizing the fossil fuel required to operate the repowered plant or increase or maintain the power generated by the multiple unit plant. Further details on the cost/benefit aspects of the steam sharing option are discussed in Section 2.5 of this Report.

surveys as presented in Section 2.3.1 will not be repeated here. It should be noted, however, that all 61 units >200 MWe identified by the utility survey are reheat steam turbine units.

Table 2.3-7 contains a breakdown by state of the utility market survey evaluation for the 61 units rated above 200 MWe. The number of units, rated power, and effective solar repowering potential are given for the four states that reported data for the utility survey. A total of 43 units at an effective solar power of 9220 MWe are located in Texas.

TABLE 2.3-7. UTILITY MARKET SURVEY EVALUATION BY STATE
FOR UNITS ABOVE 200 MWe

<u>State</u>	<u>Number of Candidate Units</u>	<u>Rated MWe</u>	<u>Effective Solar MWe</u>
California	2	666	666
Louisiana	10	4,482	2,665
Oklahoma	6	2,679	2,522
Texas	43	17,767	9,220
TOTAL	61	25,594	15,073

2.4 CANDIDATE REPOWERING UNIT DESCRIPTION

An overview of the typical candidate repowering unit description and an assessment of the utility survey results for the candidate unit description are presented in the following subsections.

2.4.1 CANDIDATE REPOWERING UNIT DESCRIPTION OVERVIEW

Table 2.4-1 shows the characteristics and general data of the typical candidate unit for solar hybrid repowering, as determined from the utility and literature surveys. The typical candidate unit is a non-reheat steam turbine with an overall power generating capacity between 10 and 50 MWe (see Figure 2.3-1 and Table 2.3-4). The steam turbine inlet conditions include a throttle pressure range of 850 to 1250 psig and a turbine inlet temperature range of 900° to 950°F at the nominal unit MWe rating.

TABLE 2.4-1. TYPICAL CANDIDATE UNIT FOR SOLAR HYBRID REPOWERING

<u>Unit Characteristics</u>	
Type	Non-Reheat Steam Turbine
Rating	10 to 50 MWe
Turbine Inlet	850 to 1250 psi/900° to 950°F
<u>General Unit Data</u>	
Year Built	1950 to 1960
Condition	Good
Current Use	Intermediate/Peak
Location	Rural
Estimated Retirement	Before 2000

The general unit data indicate that the typical candidate repowering unit is in good condition and was built (or went into initial service) between the years 1950 and 1960. The typical repowering unit is being used for intermediate or peak load service and has an estimated 20 to 25 years of useful service before its planned retirement. The typical candidate unit is located in a rural area.

2.4.2 SURVEY RESULTS FOR CANDIDATE REPOWERING UNIT DESCRIPTION

The selection of the appropriate characteristics and general data for the repowering candidate unit was based on a detailed assessment of the utility survey results and the parallel literature survey information. As shown previously, 272 repowerable units representing 19,749 MWe of total rated capacity were identified by the utility survey. Table 2.4-2 shows a breakdown of this potential by state and repowering unit type (steam turbine or combustion turbine). A total of 244 steam Rankine cycle units were identified by the survey, which represents 18,641 MWe of rated capacity. Table 2.4-2 also shows that 28 combustion turbine units representing 1108 MWe of rated capacity were identified by the survey.

TABLE 2.4-2. EVALUATION OF REPOWERING UNIT TYPE

State	Steam Turbine		Combustion Turbine	
	Number of Units	Rated MWe	Number of Units	Rated MWe
Arizona	15	1,042	7	175
California	45	4,572	16	728
Colorado	9	166	0	0
Louisiana	24	1,645	1	19
Nevada	9	739	0	0
New Mexico	21	405	1	18
Oklahoma	18	1,324	3	168
Texas	100	8,482	0	0
Utah	1	66	0	0
Others	2	200	0	0
TOTAL	244	18,641	28	1,108

When the restrictions of available land at a distance ≤ 2500 feet from the candidate unit and >50 percent repowering based on land availability (see Tables 1.1-1 and 2.3-6) are applied, the number of repowerable candidates (both steam and combustion turbines) was reduced to 82 units representing 5189 MWe of effective solar repowerable potential. Included in the 82 units are six combustion turbines with a total of 138 MWe of effective solar repowerable potential (see Table 1.1-4). It can be concluded that steam turbines are typical candidate units for solar hybrid repowering.

Table 2.4-3 categorizes, by state, the repowerable steam turbines (244 units total) as either reheat or non-reheat. Since the number of non-reheat units exceeds the number of reheat units by a factor of 1.65, a non-reheat steam turbine was selected for the typical candidate unit.

TABLE 2.4-3. EVALUATION OF REPOWERABLE STEAM TURBINE UNITS

<u>State</u>	<u>Non-Reheat Number of Units</u>	<u>Reheat Number of Units</u>	<u>State Totals</u>
Arizona	8	7	15
California	20	25	45
Colorado	9	0	9
Louisiana	15	9	24
Nevada	4	5	9
New Mexico	21	0	21
Oklahoma	13	5	18
Texas	61	39	100
Utah	1	0	1
Others	0	2	2
TOTAL	152	92	244

Table 2.4-4 categorizes the repowerable steam turbine units by plant rating (MWe) and by typical operating conditions. The table maintains the reheat/non-reheat unit type distinction shown in the previous table. Of the 152 non-reheat units, 95 units (62 percent) have inlet conditions of 850 to 1250 psig and 900° to 950°F. A total of 51 of the 92 reheat units (55 percent) have inlet conditions of 1800 psig and 1000°F with a 1000°F reheat cycle.

The selection of the non-reheat steam turbine as the typical candidate unit is in line with the first-generation water/steam receiver technology being developed by the Department of Energy. The selection also was based on the fact that a reheat cycle unit would require:

- A more complex solar receiver at the top of the tower
- Additional extensive lengths of steam piping between the receiver at the top of the tower and the existing turbine generator (possibly including significant horizontal runs)

TABLE 2.4-4. STEAM TURBINE UNITS -- OPERATING CONDITIONS (PRESSURE/TEMPERATURE)

	Non-Reheat Units					Reheat Units			TOTALS
Pressure:	350 psi	600 psi	850 psi	1250 psi	1450 psi	1450 psi	1800 psi	2000 psi	
						1000°F	1000°F	1000°F	
Temperature:	625°F	825°F	900°F	950°F	950°F	1000°F	1000°F	1000°F	
<u>Plant Rating (MWe)</u>									
0 to 10	12	12	1						25
11 to 25	3	10	13	1		1			28
26 to 50	4	1	23	9		3			40
51 to 75			14	15		5	5		39
76 to 100			3	5	2	15	3		28
101 to 125				11	13	11	10		45
126 to 150						1	8	3	12
151 to 200							25	2	27
TOTALS	19	23	54	41	15	36	51	5	
					152			92	244

- A more elaborate interface with the existing fossil boiler (intermediate as well as high pressure sections)
- A more complex control system

Reheat cycle steam turbine units are still considered to be excellent candidates for solar hybrid repowering, particularly when the advanced receiver concepts, such as those using liquid sodium or molten salt, are developed. These concepts are under study by the Department of Energy, and testing is expected to be completed by the end of 1980.

Table 2.4-5 shows the additional features that are typical of the candidate unit. It also shows that most of the non-reheat units (81) were built between 1951 and 1960, are generally in good condition (110 units), and have an estimated retirement date before the year 2000. The same conclusion can be drawn on the year built, unit condition, and estimated retirement for the reheat units with one exception: most of the reheat units are scheduled to be retired after the year 2000. Most of the non-reheat units are used for intermediate (45 units) and peak (46 units) load service, while most of the reheat units are used for intermediate and base load service. Data on general plant location indicate that the typical candidate unit is located in a rural area.

Most of the utilities (50 out of the 54 reporting such data) established the time of their system peak load demand as occurring between 8:00 a.m. and 6:00 p.m. in the summer. In the winter, 34 utilities (out of 53 reporting such data) established the time of their system peak load demand as also occurring between 8:00 a.m. and 6:00 p.m. This period corresponds to the period of best solar insolation.

TABLE 2.4-5. EVALUATION OF GENERAL UNIT DATA (NUMBER OF UNITS).

Category:	Steam Turbine -- Non-Reheat	Steam Turbine -- Reheat	Combustion Turbine	
<u>Year Built</u>				<u>Totals</u>
Before - 1941	7	0	0	7
1941 - 1950	37	0	0	37
1951 - 1960	81	51	0	132
1961 - 1970	17	26	15	58
1971 +	10	15	13	38
<u>General Unit Condition</u>				
New	9	12	3	24
Good	110	77	25	212
Fair	26	3	0	29
Poor	7	0	0	7
<u>Current Use</u>				
Base	28	33	0	61
Intermediate	45	55	2	102
Peak	46	4	26	76
Standby	31	0	0	31
<u>Estimated Retirement</u>				
1973 - 1980	3	0	0	3
1981 - 1990	64	5	0	69
1991 - 2000	44	34	12	90
2001 +	25	45	8	78
<u>General Plant Location</u>				
Industrial	32	14	4	50
Suburban	37	25	3	65
Urban	22	4	11	37
Rural	57	46	9	112

2.5 COST/BENEFIT ANALYSIS

The integration of solar hybrid repowering plants into electric utility systems raises a number of questions as to the value of the plants, problems they might introduce, and requirements that should be placed upon them. A cost/benefit analysis was performed for selected southwestern utilities to assess the prospective value and impact of solar hybrid repowered plants upon electric utility systems. The analysis was performed utilizing the methodology developed by Westinghouse as part of EPRI Contract RP 648-1 entitled "Requirements Definition and Impact Analysis of Solar Thermal Power Plants."

Four southwestern utilities were selected for analysis on the basis of the results of the market survey discussed in the previous sections. The utilities selected for analysis were:

- Public Service Company of New Mexico (PNM)
- Arizona Public Service Company (APS)
- Nevada Power Company (NPC)
- EPRI Synthetic Utility System E (Texas, Louisiana and Oklahoma)

A reference 50 MWe solar hybrid repowering plant was defined for performing the cost/benefit analysis based on the characteristics of the typical candidate unit defined in Section 2.4 of this Report. The results of the cost/benefit analysis indicate that the solar hybrid repowering concept has the potential to be economically attractive for utility applications when compared with conventional methods of electric power generation (a cost/benefit ratio of 0.94 for a repowered unit operating as part of Synthetic Utility System E).

2.5.1 METHODOLOGY

For the proper assessment of the prospective value and impact of solar hybrid repowered plants upon an electric utility system, detailed modeling of the operation of such a plant is required. This modeling must involve the interactive dispatch of the solar plant with other generation units on the utility system. Through this procedure proper sizing of the solar plant and its subsystems, such as solar collector area, can be ascertained. Solar plant operational strategies involving the use of the fossil boiler also can be evaluated.

The sophisticated methodology developed for analyzing the solar hybrid repowered plant consists of the coordinated use of several computer models and procedures for economic evaluation (Figure 2.5-1). The basis of the evaluation models is a set of Westinghouse Electric Corporation utility planning computer programs and a specially developed solar plant model. The utility models include a production costing model that simulates the operation of the balance of the utility system in bi-hourly increments. Capacity credit is calculated using a loss-of-load probability model capable of accepting a probability distribution for the availability of the solar plant. A detailed discussion of the economic analysis methods is given in Appendix B; a brief summary is presented below.

The methodology implemented for economic and reliability system impact assessment relies heavily upon system simulation. The Load Projection, Load Statistical Analysis, Reliability Analysis and Detailed Production Cost blocks (Figure 2.5-1) are separate existing Westinghouse models (computer programs) that are routinely used to analyze utility systems. These models have had minor modifications to allow them to interface with the Solar Thermal Plant Model. This latter model is a modified version of the one developed by Westinghouse as part of EPRI Contract RP 648-1. The projected hourly system load is input to the solar plant model, which simulates the operation of the solar plant and outputs for further analysis the remaining load to be served. The solar plant model uses incremental operating cost data for the balance of the utility system to guide its dispatch. This is particularly important for the optimum conservation of fossil fuel.

Figure 2.5-2 shows the basic solar hybrid repowering plant model used for the cost/benefit analysis, including the assumptions used to develop the model. Included in the model is a dispatch routine that recognizes balance of utility system incremental costs, turbine efficiency variations, and insolation projections. The dispatch rule that has been implemented is shown in Table 2.5-1.

The dispatch rule is a daily iterative procedure that relies upon a simple preliminary dispatch, which is iteratively improved. This rule utilizes an assumption of foreknowledge of the full day's insolation and load profile at the beginning of each day. It also uses information as to the incremental operating cost of the utility system at various load levels, along with the various solar plant efficiencies.

Figure 2.5-1. Model Usage Flow

The solar plant model developed as part of EPRI RP-648 will be used in the cost/benefit analysis.

Plants will be operated to maximize the benefit of the solar repowering.

GENERAL ASSUMPTIONS

Plant can operate from either solar, fossil, or a combination of solar and fossil.

Aerospace insolation tapes will be used for the analysis.

The repowering model will be based on steam turbine plants.

Wet cooling towers will be used for the heat rejection system.

The days insolation profile and load demand are known.

Figure 2.5-2. Solar Hybrid Repowering Model for Cost/Benefit Analysis

For realism in the modeling of the operation of the hybrid plant, those items shown in Table 2.5-1 include fossil fuel consumption to bring the boiler up to temperature, accounting for both fuel consumption and the time required. Operating scenarios where the boiler heat is maintained (stand-by) is an option in the program.

Logic requiring fossil boiler energy to buffer the turbine during insolation transients also has been incorporated. The skycover conditions are sampled hourly from the insolation tape to determine when insolation transient conditions apply.

To prevent excessive cycling of the turbine, the plant is fired to run through what otherwise would be a brief shutdown period. When wind speeds exceed the input design limits, the heliostats are assumed stowed and no solar energy is collected for that hour. Both boiler and turbine generator part-load efficiency curves are incorporated in the solar plant model.

TABLE 2.5-1. SOLAR HYBRID REPOWERING MODEL DISPATCH

-
- Oil Startup Logic
 - Oil Buffer for Insolation Transients
 - Closeup Potential Shutdown Windows
 - High Wind Speed Solar Shutdown
 - Boiler Efficiency Corrections
 - Oil Recovery of Low Insolation
 - Economic Oil Dispatch
 - Hot Stand-by Oil (Option)
 - Economic Shutdown at End of Day
 - Cost/Benefit of Daily Oil Use

RECOGNIZING

- Foreknowledge of Day's Insolation Profile
 - Foreknowledge of Day's Load Profile
 - Utility System Incremental Cost Curve
 - Fossil Boiler Limits and Efficiency
 - Turbine-Generator Limits and Efficiencies
 - Insolation High Transient Conditions
 - Operational Wind Limits
-

When the insolation is not sufficient to operate the turbine at its minimum level and a specified insolation threshold is exceeded, the boiler is fired to provide enough supplemental energy to salvage the insolation and operate the turbine generator.

The incremental cost of competing conventional plants is tested hourly to establish whether additional fossil firing is justified. A test is made to determine whether it is economically advantageous to start the boiler each day, or to leave the boiler cold and suffer operating consequences such as no electrical output during solar transients. The proper boiler shutdown hour is also established on an economic dispatch basis.

The economic methods developed use conventional Revenue Requirements analysis, recognizing both the time value of money and independent escalation of various cost elements. These methods are consistent with electric utility practice and

provide the needed flexibility. The Revenue Requirements methodology is also consistent with the EPRI economic evaluation guidelines stipulated in the August 1977 EPRI "Technical Assessment Guide." The principal economic measures of solar plants implemented in this methodology are shown in Table 2.5-2.

TABLE 2.5-2. SOLAR PLANT ECONOMIC MEASURES

-
- Solar Plant Value
 - Operating Cost Savings
 - Capital Investment Displacement
 - Solar Plant Busbar Energy Cost
 - Plant Capital Cost
 - Plant Operating Cost
 - Energy Produced
 - Utility System Cost Impact
 - Solar Plant Costs
 - Utility Differential Costs
 - Solar Plant Cost/Benefit Ratio
 - Solar Plant Lifetime Costs
 - Solar Plant Lifetime Value
-

Because of the uncertainty of the costs of certain portions of the solar plant, particularly under mass production conditions, the economic value of the solar plant was assessed independent of its costs. The value arises potentially from both operating cost savings and capital cost savings to the balance of the utility system. The operating cost savings are derived from reduction in fuel consumption and variable operating and maintenance costs. The capital cost savings arise from reduced conventional capacity requirements and a potential shift in the mix of conventional units.

The operating value of solar repowered plants results from a reduction in energy production by the balance of the electric utility system. The reduction in conventional plant operation saves fuel and variable operating and maintenance (O&M) costs on the most costly (operating cost) units that would have been operating at the time the solar repowered plant is producing power. Since the solar repowered

plant operates during different times of the day and throughout the year, the highest cost conventional unit being displaced changes. Thus the operating credit varies with the utility system chronological load shape and the mix of available generation, as well as with many other parameters. The major parameters affecting the operating value of a solar repowered plant are shown in Table 2.5-3.

TABLE 2.5-3. OPERATING VALUE FACTORS

Insolation Characteristics
Utility System Load Shape
Utility Mix of Generating Units
Fuel Cost and Escalation Projections
Conventional Unit Heat Rates
Variable O&M Cost and Projections
Plant Collector Area
Penetration of Solar Hybrid Repowered Plants
Present Worth Discount Rate

Capacity credit can be interpreted as the megawatts of conventional generating capacity not required to be installed due to the presence of the solar repowered plant or in terms of the dollars represented by this saved capacity. The capacity credit can be taken only for those years of operation of the repowered plant beyond the normal retirement date. From an analysis standpoint, megawatt savings may be considered first and then converted to dollars. In general, for a solar hybrid plant, 100 percent capacity credit can be considered for those years of operation beyond the normal retirement date due to the presence of the fossil boiler. This is not true for solar plants having thermal storage.

The busbar energy costs, which are consistent with ERDA/EPRI guidelines, are functions of solar plant cost and electric energy production.

The net economic impact of a solar plant upon a utility system is calculated by subtracting the solar plant value from its estimated costs.

The cost/benefit ratio is calculated by dividing the present worth of solar plant lifetime costs (revenue requirements) by the present worth of its lifetime value.

Since the inclusion of plant value (to a specific utility system) as well as plant cost is considered in determining the economic choice, the cost/benefit ratio was selected as the primary evaluation criterion.

Since the solar repowered plant operates during different times of the day and throughout the year, the highest cost conventional unit being displaced is not constant. For example, during reduced-load periods of the day, the solar repowered plant may displace energy normally provided by a base unit. On the other hand, the solar repowered plant will displace a peaking unit on the days in which the load is high. The operating credit varies with the utility system chronological load shape and the mix of available generation, as well as with many other parameters.

Conventional unit heat rates used to determine the incremental cost of the system at various load levels range from approximately 9000 Btu/kWhr for base loaded coal units to 14,000 Btu/kWhr for combustion turbines.

Capacity credit can be interpreted as the megawatts of conventional generating capacity not required to be installed due to the presence of the solar power plant or in terms of the dollars represented by this saved capacity. Megawatt savings may be considered first, and then converted to dollars. In general, for a solar hybrid plant, 100 percent megawatt capacity credit can be considered, due to the presence of the fossil boiler. The dollar capacity credit is a function of not only capacity displaced, but also of the types of generating units being displaced. This is determined by the use of optimal breakpoint analysis (defined as the most economic mix of peaking, intermediate and base load units required to satisfy a given utility system load) applied to the original and adjusted system loads. Although operating as an intermediate unit, hybrid solar plants can be observed to optimally displace a combination of peaking, intermediate and base load capacity.

Unlike the solar hybrid plant, a solar stand-alone plant cannot claim 100 percent capacity credit. Of major importance to the capacity credit is the ability of the solar plant to produce power during the utility system demand peak. The correlation of insolation with system demand on both a daily and seasonal basis is quite important. Some relaxation in the daily correlation can be accepted with major degradation in capacity credit provided adequate solar energy is collected on a daily basis and adequate thermal storage exists. Daily load peaks that occur after sunset cause decreases in capacity credit, even with sufficient energy storage, because of the turbine generator derating when operating from the first generation storage subsystems being developed for solar plants. The second generation storage subsystems being evaluated may not require a turbine generator derating.

In addition to the daily load correlation with insolation, seasonal correlation is also important. If the annual load peak for a system generally occurs in August, the quality of the insolation in August can play a dominant role in establishing the megawatt capacity credit. This is due to the peak demand month establishing the system install capacity requirements.

Penetration and geographic dispersion also impact the capacity credit. As more solar capacity is added to the system, the ease is diminished with which the next solar plant can further reduce the daily load peak. High time correlation of insolation among solar plants in a service area reduces the capacity credit, and the degree of geographic dispersion for several plants is also important.

2.5.2 REFERENCE PLANT DESCRIPTION

A reference solar hybrid repowered plant concept has been established for the purpose of performing the cost/benefit analysis. The reference concept consists of repowering existing gas- and oil-fueled electric power generating units to operate on solar energy when it is available. The concept will displace a large portion of or all the fossil fuel normally used during daylight hours. The ability of the plant to operate on fossil fuel is retained, however, to provide full backup capacity and maximum operational flexibility during the periods of

inclement weather, as well as the potential for conventional electric power generation at night. The basic concept utilizes the solar hardware and technology being developed for the 10 MWe solar central receiver pilot plant to be built near Barstow, California.

The reference solar hybrid repowered plant has been defined utilizing the characteristics of the typical candidate unit resulting from the market survey.

Table 2.5-4 summarizes the characteristics of the reference plant, a 50 MWe steam plant having a non-reheat steam turbine. The solar subsystem has been sized to provide 100 percent repowering based on an insolation level of 950 watts/m^2 and a net solar plant efficiency of 17 percent (the ratio of electric power output to solar insolation available to the heliostat field). The net solar plant efficiency of 17 percent is based on analyses performed for similar plants during studies under EPRI Contract RP 648-1. The optimum heliostat field size depends in general on the utility system. Therefore, a parametric analysis of field size was performed during the cost/benefit analyses.

The solar system design is characterized by an external receiver mounted on a tower located in a 360° array of two-axis sun-tracking heliostats. These heliostats comprise the collector subsystem. Feedwater from the electrical power generation subsystem is pumped through a riser to the receiver and converted to superheated steam in a single pass through the tubes of the receiver panels. The steam from the receiver is routed through a downcomer to ground level and transported from the tower base through horizontal steam lines to the turbine.

The collector field has been sized to provide for 100 percent repowering of the 50 MWe fossil plant; 8160 heliostats having a total mirror area of $310,000 \text{ m}^2$ are required to produce 50 MWe at an insolation level of 950 watts/m^2 . The 950 watts/m^2 insolation level assumed for sizing the collector fields is representative of 2:00 p.m. winter solstice conditions, which is the design point for the solar repowering project being used by PNM. Since the insolation level varies throughout the year (peak value to about 1100 watts/m^2), there will be periods when the thermal power producing capability of the heliostat field will exceed the turbine generator 50 MWe rating. During those periods, a portion of the heliostat field could be defocused in order not to exceed the turbine

TABLE 2.5-4. SOLAR HYBRID REPOWERED PLANT REFERENCE PARAMETER SUMMARY

Plant Type	Steam Turbine/Non-Reheat
Plant Rating	50 MWe
Plant Repowering Percentage*	100%
Plant Operating Scenario	Maximize solar benefit Fossil operation only on cloudy days Economic dispatch fossil energy
Collector Subsystem:	
- Field Configuration	360°
- Field Area	300 Acres
- Heliostat Area	310,000 m ²
- Number of Heliostats	8160
Receiver/Tower Subsystem:	
- Receiver Type	External (single pass to superheat)
- Receiver Size	15 m dia by 27 m long
- Tower Height	175 m
Electric Power Generation Subsystem:	
- Cycle	Steam Rankine
- Net Plant Efficiency	33%
- Turbine Inlet	950°F/1250 psi
- Heat Rejection	Wet Cooling Tower
Fossil Boiler:	
- Type	Oil
- Rated Load Efficiency	82%
- Start-up	Cold

*Based on an insolation level of 950 watts/m²

generator rating. Turbine generator units can nominally operate in excess of their nameplate ratings (15 percent or greater), and a solar repowering level at 100 percent of nameplate may allow for complete utilization of available insolation throughout the year. This effect will be system and unit dependent and is beyond the scope of this evaluation. A subsequent detailed analysis of one of PNM's units is planned to evaluate the effect of permitting unit operation in excess of the nameplate rating.

Since the 310,000 m² reference collector field may not represent the most cost effective size, one of the sensitivities being considered in the cost/benefit analysis is collector field size. Two collector field sizes — 163,000 m² and 233,000 m² — have been established in addition to the reference field for the cost/benefit analysis. These latter two collector fields represent, on the basis of the design insolation level of 950 watts/m², a repowering percentage of 50 percent and 75 percent, respectively.

The ability to operate on fossil fuel has been maintained in the repowered plant concept. The plant can operate and produce 50 MWe using steam generated from the solar subsystem, the fossil boiler, or a combination of both fossil or solar. It is assumed that the plant will operate either on fossil fuel alone, or on steam produced by a combination of solar and fossil fuel during cloudy days. A cloudy day for the purpose of the cost/benefit analysis is defined as a day during which sky cover exceeds 0.5 for two or more consecutive hours.

In general, any day in which sky cover exceeds 0.3 can be classified as cloudy. As part of EPRI Contract RP 648-1, a comparison between insolation transients (for various degradation levels and time periods) and sky cover for a range of 0.3 to 0.7 for Albuquerque, New Mexico indicated that a correlation between these variables was not possible from the existing data base. For example, a sky cover of 0.3 on the data records may correspond with more insolation transients of greater magnitude and longer duration than a sky cover 0.7 and vice-versa. A sky cover value of 0.5 was selected until improved weather records and data on sky cover versus insolation transients are available, or until planned pilot plant experiments for solar thermal electric plants produce data indicating a correlation between sky cover and plant operating capabilities on "solar only."

The operation scenario assumed for the fossil boiler is important in determining the economic benefit of solar hybrid repowering. In order for the fossil boiler to be capable of responding to insolation variations during periods of intermittent cloud cover, the boiler must be operating at a minimum of 25 percent of rated thermal output. The boiler response time to achieve 100 percent rated output from an operating level of 25 percent of rated output is approximately 10 to 15 minutes.* The cost of the fossil fuel required to maintain the boiler at 25 percent of rated output is high, and it subtracts directly from the economic benefit derived from operating the plant on solar energy. A strong incentive exists to minimize the amount of fossil fuel consumed in a solar hybrid repowered plant.

Three operating scenarios have been established and simulated for the fossil boiler for the purpose of performing the cost/benefit analysis. These scenarios use approximate boiler operating parameters and do not necessarily represent any specific boiler. These scenarios are:

- The fossil boiler operated only on cloudy days — The fossil boiler is assumed to be started from a cold condition for each cloudy day. A ten hour startup period is assumed for the boiler in order to reach 25 percent of rated load; the fossil fuel consumed during startup is approximately 750 MBtus. The fossil boiler is maintained in the hot standby condition (25 percent of rated load) throughout the cloudy day. The boiler firing is increased if it is economical to supplement the steam produced by the solar receiver (when compared to generating the equivalent power using units within the balance of the utility system) or if it is required in order to overcome severe insolation transients in order to maintain steam conditions at the turbine inlet. The boiler is shut down at the end of each cloudy day.
- The fossil boiler is operated every day — This scenario assumes the fossil boiler is operated on both clear and cloudy days and is shut down for routine or forced maintenance. During those periods of the day when the plant is operating from solar generated steam, the fossil boiler is maintained in the hot standby condition similar to the above scenario. At the end of the day, however, the boiler is "banked" and maintained in a warm standby condition overnight. The boiler is also "banked" during days when it is not economical to operate the plant from

*Boiler operating characteristics/constraints will be dependent on the specific design and may vary significantly from the typical values presented here.

either solar or fossil energy. The amount of energy required to maintain the boiler in a warm standby (banked) condition is approximately 7.5 MBtu for 12 hours. The boiler can achieve 25 percent of rated output from the warm standby condition in approximately 1 to 2 hours. In order to account for scheduled and forced plant outages throughout the year, three "cold" starts of the boiler have been included in the cost/benefit analysis for this option.

- Steam sharing — This scenario assumes that the repowered unit is part of a multiple unit station. The results of the market survey indicated that approximately 90 percent of the candidate units were part of a multiple unit station. A dedicated boiler, in this option, would not be proposed for the repowered unit; rather, the repowered unit would use steam produced from a boiler dedicated to an adjacent unit at the plant (even if the power produced by the adjacent unit had to be reduced to provide steam to the repowered unit and the balance of the utility system had to be utilized to offset the loss in power generation by the adjacent unit). The amount of fossil fuel required for starting the boiler and maintaining the boiler in a "banked" or hot standby condition as required for the options discussed above would not be required for the steam sharing option. Steam would be supplied to the repowered unit from an adjacent unit only when required to maintain the operation of the repowered plant during cloudy days. The cost of the fossil fuel to provide the steam must be accounted for in establishing the overall economic benefit of solar repowering. The steam sharing option, however, is attractive from the standpoint of minimizing the fossil fuel required to operate the repowered plant.

Table 2.5-5 defines the capital cost of the reference solar hybrid repowered plant. The estimates for the solar subsystem cost for the first and Nth commercial plants are based on Sandia's evaluation of the results of the Phase I Central Receiver Program Preliminary Designs. The estimated heliostat costs for these plants are approximately \$160/m² and \$100/m², respectively. The DOE heliostat cost goal estimate is based on achieving a heliostat cost of \$65/m². The cost estimates for the other plant components are based on the results of the conceptual design to date obtained in Task 1500 of the subject Assessment Study.

2.5.3 ECONOMIC ANALYSIS BASIS

The economics used in the preliminary analysis are an attempt to represent the costs and value as viewed directly by the utility. That is, it is somewhat of

TABLE 2.5-5. REFERENCE SOLAR HYBRID REPOWERING PLANT (50 MWe)
COST ASSUMPTIONS (1977 M-\$)

	<u>First Commercial</u>	<u>Nth Commercial</u>	<u>DOE Heliostat Goal</u>
Land	0.3	0.3	0.3
Structures and Facilities	0.5	0.5	0.5
Heliostats	48.5	31.0	20.2
Receiver/Tower	14.5	13.0	13.0
Turbine Plant Equipment	3.0	3.0	3.0
Electric Plant Equipment	2.2	2.0	2.0
Miscellaneous	1.0	1.0	1.0
TOTAL DIRECT	<u>70.0</u>	<u>50.8</u>	<u>40.0</u>
Contingency and Spares (15%)	10.5	7.6	6.0
Indirect Costs (10%)	<u>7.0</u>	<u>5.1</u>	<u>4.0</u>
TOTAL CAPITAL INVESTMENT	87.5	63.5	50.0
IDC (15%)	<u>13.1</u>	<u>9.5</u>	<u>7.5</u>
TOTAL CAPITALIZATION	100.6	73.0	57.5
Escalated to 1985 (@ 7%/yr)	172.8	125.4	98.8
Annual O&M 1985 (3%)	5.2	3.7	3.0

a microeconomic approach in that it does not consider any potential gains in national Balance of Payments conditions, environmental or employment gain benefits, or any other socioeconomic factors. These additional factors might be reflected by Federal incentive programs that are not considered in this Report.

The basic economic assumptions used in the subject analysis are shown in Table 2.5-6. For solar repowering, an 18 percent Fixed Charge Rate was used on the new investment. The operating and maintenance costs were assumed to be three percent of the capitalization the first year, with an escalation rate of eight percent annually. The operating and maintenance costs may eventually be considerably reduced from the values assumed for this analysis as more definitive designs are prepared and more substantial hardware experience obtained. A present worth discount rate of 11 percent was used for all analyses.

TABLE 2.5-6. REFERENCE ECONOMIC ASSUMPTIONS (1985 \$,
PRESENT WORTH DISCOUNT RATE 11 PERCENT)

	Combustion Turbine	Combined Cycle	Coal Plants	Nuclear Plants
Capital Cost (\$/kWe)	300	600	1400	1,500
Capital Escalation Rate (%/yr)	10%	10%	10%	10%
Carrying Charge Rate (%)	20%	18%	18%	18%
Fixed O&M (\$/kW-yr)	1.0	2.5	10.0	10.0
Variable O&M (mills/kW-hr)	8.0	1.85	3.16	0.76
O&M Escalation Rate (%/yr)	8%	8%	8%	8%
Fuel Cost (\$/MBtu)	5.5	5.5	2.0	1.25
Fuel Escalation Rate (%/yr)	12%	12%	10%	9/13%*
Heat Rate (Btu/kW-hr)	12,000	8400	9500	10,400
Scheduled Maintenance (weeks/hr)	2	2	5	6
Forced Outage Rate (%)	10%	10%	13%	11%

*Nine percent to the year 2000; 13% thereafter.

The economic methodology (Appendix B) used in the study is based upon Minimum Revenue requirement analysis frequently used by electric utilities. This methodology incorporates the present worth of the lifetime costs and value of the repowered plant. A 30-year life from repowering was assumed, with repowered operation beginning in 1985.

For capacity credit calculations, it was assumed the plant to be repowered had a life expectancy to 1995 if not repowered. Thus, capacity credit was calculated to begin in 1995 and last for 20 years at full nameplate rating.

The time increment used in the analysis involved hourly modeling of the operation of the repowered plant as well as the balance of the utility system.

Three utility systems were analyzed utilizing actual load and generating unit data: Public Service of New Mexico, Arizona Public Service Company and Nevada Power Company. A fourth synthetic utility system, developed by EPRI, characteristic of the Texas-Oklahoma region, also was used. PNM has a moderate amount of oil/gas-based generation; APS and NPC have more, and the EPRI synthetic utility system has a maximum. Number 2 fuel oil prices were used for plants burning gas at a cost of \$5.50/MBtu (1985).

2.5.4 UTILITY SYSTEM ASSUMPTIONS

Load data from PNM, APS and NPC were obtained and adjusted by Westinghouse in accordance with the utilities' expected peak loads in 1985. Hourly loads created by Westinghouse for the EPRI synthetic utility system were based on the information obtained in EPRI Report EM-285.

Figures 2.5-3 and 2.5-4 shows a relative mix of generating capacity by fuel type for PNM and APS. These figures do not reflect the total reserve assumed, but rather an approximation to the capacity that would likely be operating during a high load day. The peak load and the generating mix shown in the figure have been altered slightly for the study, but the general shape of the curve is representative.

Figure 2.5-3. PNM Generation Mix and Typical Daily Load Curves

Figure 2.5-4. APS Generation Mix and Typical Daily Load Curves

A tabulation of the 1985 generating mix assumed for the four utilities is shown in Table 2.5-7 with their expected annual peak load. As indicated for PNM, a good percentage of the capacity is base load, and during reduced-load periods, the solar powered plants must compete with coal. This is also true to a lesser degree with APS and NPC, both of which are more dependent on oil fueled plants. The EPRI Utility System E capacity consists primarily of oil- and gas-fueled plants. The value of the repowered plant will be higher on this system as more costly generation is displaced. Natural gas is not included in the mixture of fuels since it was assumed that combustion turbines or any other gas-burning plant will be using Number 2 oil or an equivalent surrogate fuel during the period of operation of the hybrid plant.

2.5.5 PNM SYSTEM ANALYSIS RESULTS

The performance and cost analysis for operating a 50 MWe solar hybrid repowered plant on the PNM system is presented in this section. The results are based on the use of the general economic assumptions given in Section 2.5.4 of this Report for utilities located in the Southwestern United States.

Variations in the size of the repowering collector area were examined to determine the effect of this parameter on the cost benefit ratio. In addition to the reference plant collector area, two smaller sizes were assumed. The results are shown in Table 2.5-8. The collector area that resulted in the best cost/benefit ratio was the intermediate collector area of 233,000 m². This area was used as the collector area for the remaining cases shown. A brief explanation of each line element shown in Table 2.5-8 follows:

Direct Plant Cost

The estimated cost of repowering for three bases is given in Table 2.5-5. The direct costs using the DOE heliostat goal assumptions are \$40M for a 50 MWe plant. This is in 1977 dollars prior to adders for contingency and spares. This represents 800 \$/kWe as shown in Table 2.5-8.

TABLE 2.5-7. ESTIMATED UTILITY GENERATING MIX

	1985							
	PNM		APS		NPC		EPRI-E	
	MWe	%	MWe	%	MWe	%	MWe	%
Combustion Turbine	20	1.0	652	12.8	470	25.5	500	4.9
Oil-Steam	282	13.5	836	16.4	248	13.4	5,600	54.4
Combined Cycle	--	--	225	4.4	--	--	--	--
Coal	1222	58.6	2443	48.0	1128	61.1	2,600	25.2
Nuclear	260	12.5	714	14.0	--	--	1,600	15.5
Hydro-Electric								
- Pumped Storage	300	14.4	225	4.4	-	--	--	--
- Conv. Hydro.	--	--	4	--	--	--	--	--
TOTAL	2084	100	5099	100	1846	100	10,300	100
Annual Peak Load	1545 MWe		4432 MWe		1612 MWe		8,078 MWe	

TABLE 2.5-8. COST/BENEFIT ANALYSIS RESULTS FOR ALTERNATE SOLAR PLANT COLLECTOR FIELD SIZE, PUBLIC SERVICE COMPANY OF NEW MEXICO, 50 MWe SOLAR HYBRID REPOWERED PLANT,* 1985 INSTALLATION

	Collector Area (m ²)		
	Reference 310,000	233,000	163,000
<u>Direct Plant Cost</u> (1977 M\$)	40.0	32.8	26.0
(\$/kWe)	(800)	(656)	(520)
<u>Plant Cost</u> (PWRR, 1985 M\$)**			
- Capital	154.6	126.8	100.4
- Operating	55.4	45.4	36.0
TOTAL	210.0	172.2	136.4
<u>Value</u> (PWRR, 1985 M\$)			
- Fuel Savings	134.6	119.7	88.8
- Fuel Cost	(35.4)	(33.5)	(32.8)
- Variable O&M	6.9	5.9	4.3
- Capacity Credit	22.3	22.3	22.3
TOTAL	128.4	114.4	82.6
Energy (GWH/yr)	140.2	121.1	87.1
<u>Cost</u> (mills/kWh, 1985)	201.3	195.4	223.4
<u>Direct Plant Breakeven</u>			
(\$/kWe, 1977)	489.2	435.9	314.7
<u>Cost/Benefit Ratio</u>	1.64	1.50	1.65

*Plant Cost — DOE Heliostat Goal

Fossil Boiler Startup Mode — Cold

Repowering Fraction corresponding to Collector Area of 310,000 m², 233,000 m² and 163,000 m² is approximately 100 percent, 75 percent and 50 percent, respectively, at the 2:00 p.m. winter solstice design point.

**PWRR — Present worth of revenue requirements.

Plant Costs

The Capital item listed under Plant Costs represents the lifetime (30-year) present worth of revenue requirements associated with the capital investment to repower the plant. Using the total capitalization, escalated to 1985 dollars as shown in Table 2.5-5, a fixed charge rate (18 percent in this case) is applied giving the annual revenue requirements to support the investment. This 30-year string of revenue requirements is present-worthed (at 11 percent per year) to 1985 to obtain the Present Worth of Revenue Requirements (PWRR) shown in Table 2.5-8.

The Operating item under Plant Costs is the present worth of the revenue requirements to support the plant operating and maintenance costs (except for fuel). It was assumed to be three percent of the repowering investment the first year (1985) and to escalate at an eight percent rate thereafter.

The Total is the sum of the capital and operating revenue requirements for the repowered plant, given in 1985 millions of dollars. This represents the total lifetime cost of owning and operating the repowered plant, exclusive of fuel costs.

Value

The following elements define the total value of the repowering to the electric utility system. These are shown in millions of dollars, over 30 years, present worthed to 1985.

The Fuel Savings item listed under Value is determined by detailed modeling of the operation of the utility system with and without the repowering. The fuels displaced are assumed to have the costs and escalation rates as shown in Table 2.5-6. Start-up, spinning reserve requirements and incremental heat rates are considered in the modeling to determine fuel consumptions.

Fuel Cost is the present worth of the lifetime fuel cost for the fuel consumed by the repowered plant. As such, it appears as a negative value. Fuel is consumed by the hybrid plant for boiler start-up, standby, insolation transient buffering, to operate through insolation shutdown windows and when economically competitive.

Variable O&M is the credit given for the presence of the solar plant and its displacement of energy on the balance of the utility system since it saves variable operating and maintenance costs, in addition to fuel, on the conventional units on the system. This was determined by the detailed operational modeling of the utility system with and without the repowering.

Capacity Credit is the revenue requirements associated with the displacement of installed generating capacity. It has been assumed that the normal retirement date of the plant would have been in 1995; thus, the capacity credit has been assumed to occur at that date and to extend for 20 years. Solar/fossil hybrid plants, because of their ability of production upon demand, have 100 percent megawatt capacity credit. For value calculations, the displacement was assumed to be combustion turbines as per Table 2.5-6. Both fixed charges and fixed O&M were included in calculating the credit.

The Total is the sum of the items listed under Value. It can be argued that the Fuel Cost might more appropriately belong under Plant Cost, but it is all a matter of accounting preference. It is, in fact, a negative fuel savings.

Energy (GWH/yr)

The total energy per year generated by the repowered plant is obtained from a detailed hybrid plant simulation model. This electric energy includes that derived from insolation and the use of oil.

Cost (mills/kWhr)

This is the levelized annual cost (revenue requirements) of generating energy with the repowered plant, over 30 years, divided by the annual energy. The cost includes capital, operating and fuel.

Direct Plant Breakeven (\$/kWe)

This number represents what one can afford to pay for the repowering in direct costs (see Table 2.5-5) and have its lifetime value exactly equal its costs. This is given in 1977 dollars for direct comparison with the first item in this table and Table 2.5-5. The analysis is based upon present worth of revenue requirement calculations and the economic assumptions given.

Cost/Benefit Ratio

This is the ratio of the total plant cost to the total value, shown in the table. It is a reflection of dollar cost per dollar return or benefit.

The three cost assumptions discussed in Section 2.5-3 and shown in Table 2.5-5 were adjusted to represent a collector area of 233,000 m² instead of 310,000 m². The effect of these adjusted plant costs on the cost/benefit ratio is shown in Table 2.5-9.

Since the plant value is independent of the plant cost, the value of the solar repowered plant remains the same. Therefore, as can be seen, the lowest cost assumption will produce the best cost/benefit ratio. From the results shown, the DOE Heliostat Goal cost assumption will be used as the plant cost in the remainder of the analysis.

Also of interest is the type of energy that the hybrid repowered plant displaces. Because the plant operates during all load conditions, it displaces energy normally supplied by base and intermediate units, as well as peaking units as shown in Table 2.5-10.

The value of solar repowered plant was also determined using an alternative economic scenario. This differs from the reference scenario only in the carrying charge rate (fixed charge rate). The carrying charge rate is changed from 18.0 to 14.6 percent for the hybrid repowered plant and from 20.0 to 16.0 percent for the conventional peaking units on the rest of the system. The differences in cost benefit are shown in Table 2.5-11.

Three different operating modes of the solar hybrid repowered plant were investigated. These are cold start, warm start and steam sharing as discussed in Section 2.5.3.

The cold start operating mode assumes that every time the plant is brought on line it is started from a cold boiler condition.

TABLE 2.5-9. COST/BENEFIT ANALYSIS RESULTS FOR ALTERNATE SOLAR PLANT COST MODELS, PUBLIC SERVICE COMPANY OF NEW MEXICO, 50 MWe SOLAR HYBRID REPOWERED PLANT,* 1985 INSTALLATION

	DOE Heliostat Goal	Nth Commercial Plant	First Commercial Plant
<u>Direct Plant Cost</u> (1977 M\$)	32.8	40.9	55.6
(\$/kWe)	(656)	(818)	(1112)
<u>Plant Cost</u> (PWRR, 1985 M\$)**			
- Capital	126.8	158.1	214.9
- Operating	45.4	56.6	76.9
TOTAL	172.2	214.7	291.8
<u>Value</u> (PWRR, 1985 M\$)			
- Fuel Savings	119.7	119.7	119.7
- Fuel Cost	(33.5)	(33.5)	(33.5)
- Variable O&M	5.9	5.9	5.9
- Capacity Credit	22.3	22.3	22.3
TOTAL	114.4	114.4	114.4
<u>Energy</u> (GWH/yr)	121.1	121.1	121.1
<u>Cost</u> (mills/kWh, 1985)	195.4	235.7	309.0
<u>Direct Plant Breakeven</u>			
(\$/kWe, 1977)	435.9	435.9	435.9
<u>Cost/Benefit Ratio</u>	1.50	1.88	2.55

*Collector Area — 233,000 m²
Fossil Boiler Startup Mode — Cold

**PWRR — Present worth of revenue requirements.

TABLE 2.5-10. PNM SYSTEM-FOSSIL OPERATING ENERGY DISPLACED
BY SOLAR HYBRID REPOWERED PLANT

	<u>% Energy Displacement</u>	<u>1985 M\$ Value</u>	<u>%-\$ Value</u>
Coal	66.6	1.8	43.9
Oil	33.4	2.3	56.1
TOTAL	100.0	4.1	100.0

Under the warm start operating mode, oil is burned to keep the boiler warm when the plant is not being used. As a result, less energy is needed to start the plant when it is brought on line. For the analysis it was assumed that the plant would require three cold starts over the year to allow for maintenance.

With the steam sharing operating mode it was assumed that an auxiliary steam supply is available for the hybrid plant to use for startup and standby conditions. Therefore, the cost to the hybrid plant of startup and maintaining the plant in stand-by condition is very small, if not zero. In the steam sharing results shown, these were assumed to be zero.

Based on these assumptions, Table 2.5-12 indicates that the best operating mode is steam sharing using cost/benefit as a criterion. The operating value of the steam sharing mode is not as high as the other two modes, but the fuel cost is approximately 50 percent less than the others, resulting in a greater net plant value. However, the steam sharing concept has not been evaluated in the same depth as the other operating modes since a conceptual design for this approach has not been prepared. The repowering cost estimate for the steam sharing operating modes is most likely somewhat optimistic. In addition, the fossil fuel cost may be shown, with further analysis, to be optimistic since the present analysis assumed that the neighboring unit from which the steam is obtained to permit operation of the solar repowered plant will always be available. The availability of steam from the neighboring unit will depend on the unit capacity, the unit operation mode, and the unit maintenance schedule. These factors will tend to increase the cost of fossil fuel which is required for operation of the solar repowered plant. The selection of the steam sharing operating mode for a solar repowered plant is therefore not presently recommended due to the uncertainties in the performance and cost assumptions.

TABLE 2.5-11. COST/BENEFIT ANALYSIS RESULTS FOR ALTERNATE ECONOMIC SCENARIOS, PUBLIC SERVICE COMPANY OF NEW MEXICO, 50 MWe SOLAR HYBRID REPOWERED PLANT,* 1985 INSTALLATION

	Reference Economic Scenario	Alternate Economic Scenario
<u>Direct Plant Cost</u> (1977 M\$)	32.8	32.8
(\$/kWe)	(656)	(656)
<u>Plant Cost</u> (PWRR, 1985 M\$)**		
- Capital	126.8	102.8
- Operating	45.4	45.4
TOTAL	172.2	148.2
<u>Value</u> (PWRR, 1985 M\$)		
- Fuel Savings	119.7	119.7
- Fuel Cost	(33.5)	(33.5)
- Variable O&M	5.9	5.9
- Capacity Credit	22.3	17.8
TOTAL	114.4	109.9
<u>Energy</u> (GWH/yr)	121.1	121.1
<u>Cost</u> (mills/kWh, 1985)	195.4	172.6
<u>Direct Plant Breakeven</u> (\$/kWe, 1977)	435.9	486.4
<u>Cost/Benefit Ratio</u>	1.50	1.35

*Collector Area — 233,000 m²
 Plant Cost DOE Heliostat Goal
 Fossil Boiler Startup Mode — Cold

**PWRR — Present worth of revenue requirements.

TABLE 2.5-12. COST/BENEFIT ANALYSIS RESULTS FOR ALTERNATE FOSSIL BOILER OPERATING MODES, PUBLIC SERVICE COMPANY OF NEW MEXICO, 50 MWe SOLAR HYBRID REPOWERED PLANT,* 1985 INSTALLATION

	<u>Fossil Boiler Startup Mode</u>		<u>Steam Sharing</u>
	<u>Cold</u>	<u>Warm</u>	
<u>Direct Plant Cost</u> (1977 M\$) (\$/kWe)	32.8 (656)	32.8 (656)	32.8 (656)
<u>Plant Cost</u> (PWRR, 1985 M\$)**			
- Capital	126.8	126.8	126.8
- Operating	45.4	45.4	45.4
TOTAL	172.2	172.2	172.2
<u>Value</u> (PWRR, 1985 M\$)*			
- Fuel Savings	119.7	123.9	114.1
- Fuel Cost	(33.5)	(34.9)	(16.2)
- Variable O&M	5.9	6.2	5.8
- Capacity Credit	22.3	22.3	22.3
TOTAL	114.4	117.5	126.0
Energy (GWH/yr)	121.1	127.0	117.7
<u>Cost</u> (mills/kWh, 1985)	195.4	187.6	184.1
<u>Direct Plant Breakeven</u> (\$/kWe, 1977)	435.9	447.7	480.1
<u>Cost/Benefit Ratio</u>	1.50	1.47	1.37

*Collector Area — 233,000 m²
Plant Cost — DOE Heliostat Goal

**PWRR — Present worth of revenue requirements.

When the plant is operating under the warm startup mode, the energy output of the hybrid plant is greater than that of the cold startup mode because the plant is run more often due to economic reasons. This is due to the difference in startup cost between the warm and cold startup modes. The fuel cost associated with the warm startup scenario is greater than that of the cold startup because of the fuel needed to keep the boiler warm. However, the increased energy output of the hybrid plant outweighs the additional fuel cost, giving an improved cost/benefit of the warm startup plant.

2.5.6 APS SYSTEM ANALYSIS RESULTS

The value of the solar repowered plant using both cold and warm startup operating modes was analyzed on the APS system. The results are shown in Table 2.5-13. These results indicate that the cost/benefit ratios of the two operating modes are very close with a slightly better cost/benefit using warm startup. The difference is not greater since the solar repowered plant does not rely to a great extent on the use of oil to start the boiler, as can be seen by the relatively small fuel cost. This is due to a relatively good weather year (few cloudy days) being used for Phoenix, which precludes the need to operate the plant on fossil energy.

The total value of the hybrid plant is quite high because there is a relatively large percentage (~35 percent) of oil generation on the system which the solar repowered plant can displace. Note that the APS system model used for the analysis was developed in 1976 as part of EPRI Contract RP 648-1. In general, utility system models tend to change with time because of, for example, variations in anticipated load demand. The results presented herein may therefore not be completely representative of the APS system since most likely the current system description for the 1980s and beyond is different from that indicated in Table 2.5-7.

2.5.7 NPC SYSTEM ANALYSIS RESULTS

The Nevada Power Company system was analyzed using the insolation data obtained for Barstow, California. The results of the analysis are shown in Table 2.5-14 for the two fossil boiler operating scenarios assumed for NPC. These results

TABLE 2.5-13. COST/BENEFIT ANALYSIS RESULTS FOR ALTERNATE FOSSIL BOILER
OPERATING MODES, ARIZONA PUBLIC SERVICE, 50 MWe SOLAR
HYBRID REPOWERED PLANT,* 1985 INSTALLATION

	<u>Fossil Boiler Startup Mode</u>	
	<u>Cold</u>	<u>Warm</u>
<u>Direct Plant Cost</u> (1977 M\$)	32.8	32.8
(\$/kWe)	(656)	(656)
<u>Plant Cost</u> (PWRR, 1985 M\$)**		
- Capital	126.8	126.8
- Operating	45.4	45.4
TOTAL	172.2	172.2
<u>Value</u> (PWRR, 1985 M\$)		
- Fuel Savings	125.9	132.3
- Fuel Cost	(12.7)	(18.0)
- Variable O&M	6.8	7.2
- Capacity Credit	22.3	22.3
TOTAL	142.3	143.8
Energy (GWH/yr)	105.5	112.8
<u>Cost</u> (mills/kWh, 1985)	201.5	193.9
<u>Direct Plant Breakeven</u> (\$/kWe, 1977)	542.2	547.9
<u>Cost/Benefit Ratio</u>	1.21	1.20

*Collector Area — 233,000 m²
Plant Cost — DOE Heliostat Goal

**PWRR — Present worth of revenue requirements.

TABLE 2.5-14. COST/BENEFIT ANALYSIS RESULTS FOR ALTERNATE FOSSIL BOILER OPERATING MODES, NEVADA POWER COMPANY, 50 MWe SOLAR HYBRID REPOWERED PLANT,* 1985 INSTALLATION

	<u>Fossil Boiler Startup Mode</u>	
	<u>Cold</u>	<u>Warm</u>
<u>Direct Plant Cost</u> (1977 M\$)	32.8	32.8
(\$/kWe)	(656)	(656)
<u>Plant Cost</u> (PWRR, 1985 M\$)**		
- Capital	126.8	126.8
- Operating	45.4	45.4
TOTAL	172.2	172.2
<u>Value</u> (PWRR, 1985 M\$)		
- Fuel Savings	126.7	131.5
- Fuel Cost	(13.8)	(16.2)
- Variable O&M	9.4	9.7
- Capacity Credit	22.3	22.3
TOTAL	144.6	147.3
<u>Energy</u> (GWH/yr)	105.9	108.0
<u>Cost</u> (mills/kWh, 1985)	202.0	200.7
<u>Direct Plant Breakeven</u> (\$/kWe, 1977)	550.9	561.2
<u>Cost/Benefit Ratio</u>	1.19	1.17

*Collector Area — 233,000 m²
 Plant Cost — DOE Heliostat Goal

**PWRR — Present worth of revenue requirements.

are similar to those obtained for the APS system since, as indicated in Table 2.5-7 for each of the utility systems considered, the generation mix is similar. The cost/benefit ratio for a solar repowered plant operating on the NPC system is 1.17 to 1.19 for the two fossil boiler operating scenarios. Similar to the previous APS results, a "warm" fossil boiler startup mode yields the lower cost/benefit ratio.

2.5.8 EPRI SYNTHETIC UTILITY SYSTEM E ANALYSIS RESULTS

The EPRI Synthetic Utility System E was analyzed for both cold and warm boiler startup modes using Midland, Texas insolation data. In addition El Paso, Texas, which has better insolation, was analyzed for the cold startup mode. The results are shown in Tables 2.5-15 and 2.5-16, respectively.

Although the energy output of the solar repowered plant on this system differs only slightly from that of the other utility systems considered, the total value of the plant is greatly increased, producing a cost/benefit of less than one. This is due to the large percentage of oil-based generation (~50 percent on the system).

Similar to previous results, a warm startup operating mode has a better cost/benefit than that of the cold startup mode, but unlike previous results the fuel cost of the solar repowered plant using the warm startup mode is less than that using the cold startup mode. This again is due to the fact that the solar repowered plant is displacing high incremental cost conventional plants, such as oil plants. As a result, the solar repowered plant is less frequently shut down for economic reasons. Since the plant is almost always used, it would be more economic for it to start up using the warm rather than the cold mode for the fossil boiler.

Although it was not investigated, it can be expected that a warm startup using the El Paso insolation tape would produce a better cost/benefit ratio. Again, based upon the PNM analysis, a steam sharing operating mode, assuming zero startup and stand-by costs, would have the best cost/benefit ratio.

TABLE 2.5-15. COST/BENEFIT ANALYSIS RESULTS FOR ALTERNATE FOSSIL BOILER OPERATING MODES, EPRI SYNTHETIC UTILITY E (TEXAS, LOUISIANA, OKLAHOMA), INSOLATION — MIDLAND, TEXAS, 50 MWe SOLAR HYBRID REPOWERED PLANT,* 1985 INSTALLATION

	<u>Fossil Boiler Startup Mode</u>	
	<u>Cold</u>	<u>Warm</u>
<u>Direct Plant Cost</u> (1977 M\$)	32.8	32.8
(\$/kWe)	(656)	(656)
<u>Plant Cost</u> (PWRR, 1985 M\$)**		
- Capital	126.8	126.8
- Operating	45.4	45.4
TOTAL	172.2	172.2
<u>Value</u> (PWRR, 1985 M\$)		
- Fuel Savings	197.5	198.5
- Fuel Cost	(53.7)	(40.3)
- Variable O&M	3.6	3.6
- Capacity Credit	22.3	22.3
TOTAL	169.7	184.1
<u>Energy</u> (GWH/yr)	115.4	116.1
<u>Cost</u> (mills/kWh, 1985)	225.2	210.5
<u>Direct Plant Breakeven</u> (\$/kWe, 1977)	646.6	701.4
<u>Cost/Benefit Ratio</u>	1.02	0.94

*Collector Area — 233,000 m²
Plant Cost — DOE Heliostat Goal

**PWRR -- Present worth of revenue requirements.

TABLE 2.5-16. COST/BENEFIT ANALYSIS RESULTS FOR ALTERNATE PLANT SITE LOCATIONS, EPRI SYNTHETIC UTILITY E (TEXAS, LOUISIANA, OKLAHOMA), 50 MWe SOLAR HYBRID REPOWERED PLANT,* 1985 INSTALLATION

	Insolation Base	
	Midland, Texas	El Paso, Texas
<u>Direct Plant Cost</u> (1977 M\$)	32.8	32.8
(\$/kWe)	(656)	(656)
<u>Plant Cost</u> (PWRR, 1985 M\$)**		
- Capital	126.8	126.8
- Operating	45.4	45.4
TOTAL	172.2	172.2
<u>Value</u> (PWRR, 1985 M\$)		
- Fuel Savings	197.5	208.2
- Fuel Cost	(53.7)	(44.1)
- Variable O&M	3.6	3.2
- Capacity Credit	22.3	22.3
TOTAL	169.7	189.6
<u>Energy</u> (GWH/yr)	115.4	128.0
<u>Cost</u> (mills/kWh, 1985)	225.2	194.4
<u>Direct Plant Breakeven</u> (\$/kWe, 1977)	646.4	722.4
<u>Cost/Benefit Ratio</u>	1.02	0.91

*Collector Area — 233,000 m²
 Plant Cost — DOE Heliostat Goal
 Fossil Boiler Startup Mode — Cold

**PWRR -- Present worth of revenue requirements.

A penetration analysis for the EPRI Synthetic Utility System E was performed; Table 2.5-17 summarizes the results of the analysis. As indicated in Table 2.5-17, the cost/benefit ratio increases from 1.02 to 1.51 with increasing penetration levels up to 20 percent. The increase in the cost/benefit ratio is primarily due to the solar repowered plant competing with less costly fuels (coal) at the higher penetration levels during portions of the year.

TABLE 2.5-17. SOLAR HYBRID REPOWERED PLANT PENETRATION ANALYSIS,*
EPRI SYNTHETIC UTILITY E, INSOLATION — MIDLAND, TEXAS,
1985 INSTALLATION

	Penetration (%)			
	<1	10	15	20
Number of Plants	1	16	24	32
Direct Plant Cost (1977 \$/kWe)	656	656	656	656
Plant Cost (PWRR, 1985 M\$)**	172.2	172.2	172.2	172.2
Plant Value (PWRR, 1985 M\$)	169.7	146.1	133.6	113.9
Breakeven Cost (1977 \$/kWe)	646.6	556.6	509.0	433.9
Cost/Benefit Ratio	1.02	1.18	1.29	1.51

*Plant Rating — 50 MWe
Collector Areas — 233,000 m²
Plant Cost — DOE Heliostat Goal
Fossil Boiler Startup Mode — Cold

**PWRR — Present worth of revenue requirements

An analysis of two alternative plant ratings (25 MWe and 100 MWe) in addition to the Reference Plant rating (50 MWe) was performed for the EPRI Synthetic Utility System E. The results of the analysis are presented in Table 2.5-18. These results indicate that similar cost/benefit ratios are achieved for plants rated at 50 MWe and 100 MWe and that these plant ratings from a cost/benefit standpoint are preferred to a smaller plant (25 MWe). It should be noted that even though the cost/benefit ratio for the 100 MWe plant rating is somewhat lower than for a plant rated at 50 MWe, the uncertainties in the repowering cost estimates for the 100 MWe plant are great enough to potentially negate the indicated advantage. A conceptual design and cost estimate of a repowered plant rated at 100 MWe must be performed before a definitive conclusion can be reached in comparison with the Reference Plant rating of 50 MWe.

TABLE 2.5-18. PLANT RATING AND ANALYSIS, EPRI SYNTHETIC UTILITY E
(TEXAS, LOUISIANA, OKLAHOMA), INSOLATION —
MIDLAND, TEXAS, 1985 INSTALLATION

	Plant Rating*		
	25 MWe	50 MWe	100 MWe
<u>Collector Area</u> (m ²)	118,000	233,000	450,000
<u>Direct Plant Cost</u> (1977 M\$)	21.4	32.8	54.8
(1977 \$/kWe)	856	656	548
<u>Plant Cost</u> (PWRR, 1985 M\$)**	112.4	172.2	287.8
<u>Value</u> (PWRR, 1985 M\$)	84.3	169.7	314.4
<u>Energy</u> (GWH/yr)	57.3	115.4	220.7
<u>Cost</u> (mills/kWh, 1985)	287.5	225.2	205.4
<u>Direct Plant Breakeven</u> (\$kWe, 1977)	643.6	646.6	595.6
<u>Cost/Benefit Ratio</u>	1.33	1.02	0.92

*Plant Cost — DOE Heliostat Goal

Fossil Boiler Startup Mode — Cold

**PWRR — Present worth of revenue requirements.

For synthetic utility E, an experiment was performed on collector area variations for a 50 MWe repowered plant. The results are shown in Table 2.5-19. The larger collector area is shown to have the better cost/benefit ratio. The larger solar collector area advantage is due to lesser insolation compared with PSM and the greater potential for displacing oil.

A better cost/benefit potential for solar repowering exists for utility system E than for the other systems. However, each company must be modeled using its own detailed parameters to determine the best impact and repowering configuration, such as collector area.

TABLE 2.5-19. COLLECTOR AREA SIZING ANALYSIS,* EPRI SYNTHETIC UTILITY E,
INSOLATION — MIDLAND, TEXAS, 1985 INSTALLATION

	Collector Area (m ²)		
	163,000	233,000	310,000
Direct Plant Cost (1977 \$/kWe)	520	656	800
Plant Cost (PWRR, 1985 M\$)**	136.4	172.2	210.0
Plant Value (PWRR, 1985 M\$)	119.6	169.7	210.7
Direct Breakeven Cost (1977 \$/kWe)	456	647	803
Cost/Benefit Ratio	1.14	1.02	1.00

*Plant Rating — 50 MWe

Plant Cost — DOE Heliostat Goal

Fossil Boiler Startup Mode — Cold

**PWRR — Present worth of revenue requirements

3.0 STUDY UNIT SELECTION

Task 1200 of the DOE/PNM Technical and Economic Assessment Phase of the Solar Hybrid Repowering Project called for the selection of a study unit. This unit was to represent a typical plant for the expected market based on results of the market survey. It was to be the unit best suited to future needs of the PNM system and ensure optimum use as a demonstration unit while maintaining system integrity. During the current phase of the project, the study unit received extensive analytical treatment from both a technical and economic viewpoint.

A conceptual design was prepared to determine solar system requirements, interface requirements, and master control logic. System dispatch computer analyses were completed as well as economic studies to determine the required capital investment, the net energy cost of the repowered unit, and the energy displacement value of the solar system over the unit operating life as compared to fuel oil firing. This intensive study, in parallel with PNM in-house efforts, allowed a decision on the merit of constructing a demonstration facility at the study unit site. The following sections discuss the rationale and results of the Study Unit Selection Task.

3.1 REPOWERING METHOD ASSESSMENT

PNM has evaluated four potential repowering methods for solar hybrid repowering:

- Steam Rankine Cycle
 - Feedwater Heating
 - Evaporation and Superheating (Boiler Replacement)
- Brayton Cycle (Combustion Turbine)
- Combined Cycle (Brayton/Steam Rankine)

Following are descriptions of the typical candidate cycles considered and the method of application of solar repowering to existing oil- and gas-fired plants.

STEAM RANKINE CYCLE

Solar Feedwater Heating

In the solar feedwater heating system, steam generated in the solar thermal system is used for boiler feedwater heating in an existing steam turbine regenerative Rankine cycle, thereby reducing the fossil fuel requirement for a given electrical generation. A schematic of a typical solar feedwater heating cycle is shown in Figure 3.1-1.

As shown in this figure, the first and second extraction point heaters are supplied with steam generated in the solar thermal system, rather than by extracting steam from the turbine.

Steam is condensed in the existing feedwater heaters and returned to the feedwater cycle through the existing heater drain system. Feedwater is then pumped back to the solar thermal system where heat is added and the process repeated.

The solar collector/receiver system used for solar feedwater heating could be either the distributed collector type or the central receiver type, as economics dictate. The solar heat transport fluid temperature required for feedwater heating is in the 400° to 600°F range, depending on the method of application and cycle requirements.

Solar Evaporation/Superheating

Solar evaporation/superheating utilizes solar thermal energy for the combined evaporation and superheating duty, such as boiler replacement, for an existing steam Rankine cycle, and may represent all or a portion of the total energy requirement. Figure 3.1-2 shows the steam Rankine cycle diagram utilizing the solar central receiver concept. In this concept, reflected solar radiation is absorbed in the receiver which generates steam at a temperature and pressure matching that of the existing steam cycle and paralleling the existing fossil-fired boiler. The existing turbine extraction cycle remains unchanged. Feedwater is then pumped back to the receiver where the process is repeated.

In this study, only non-reheat steam turbine cycles will be considered due to the technical difficulties associated with solar reheating using the current first generation central receiver concepts and increased operational problems.

LEGEND

SOLAR STEAM	
SOLAR FEEDWATER	
EXIST. STEAM	
EXIST. FEEDWATER	
NEW EQUIPMENT

TYPICAL STEAM RANKINE CYCLE

Figure 3.1-1. Solar Feedwater Heating (Solar Hybrid Repowering Study)

LEGEND

SOLAR STEAM	
SOLAR FEEDWATER	
EXIST. STEAM	
EXIST. FEEDWATER	
NEW EQUIPMENT

TYPICAL STEAM RANKINE CYCLE

Figure 3.1-2. Solar Evaporation and Superheating (Boiler Replacement)

The system capability is such as to permit different operating modes: solar only, solar-fossil mix, or fossil only, without adversely affecting the turbine-generator performance. No thermal storage capacity is required in this concept.

The solar central receiver system appears best suited to generate the relatively high temperature (700° to 1000°F) steam required for the typical existing electric power generation system.

BRAYTON CYCLE

Brayton cycle plants in the United States utilize the open cycle combustion gas turbine, burning natural gas or light oil fuel. Figure 3.1-3 shows a typical basic open Brayton Cycle with solar repowering. Solar repowering of an existing Brayton Cycle would involve the addition of an air/solar working fluid heat exchanger, operating in parallel with the fossil-fired combustor. Since a very high solar fluid temperature is required (in the 1300° to 1700°F range), an advanced central receiver using sodium or helium for the solar working fluid operating in a closed cycle is required. As an alternate, the solar receiver may operate at 1000°F and fossil fuel may be used to boost the air temperature to the required gas turbine inlet temperature.

COMBINED CYCLE

The typical combined cycle plant utilizes both the open Brayton cycle and the steam Rankine cycle as shown in Figure 3.1-4. Many variations of combined cycle plants exist; however, the basic concept utilizes gas turbine exhaust heat in a recovery boiler that may or may not need supplemental fossil-fuel firing to generate steam that drives a steam turbine-generator.

Since the combined cycle includes both Brayton and steam Rankine cycles, the solar repowering methods described previously for these cycles would apply.

REPOWERING METHOD ASSESSMENT

Table 3.1-1 shows a rating of the various cycle configurations considered for solar hybrid repowering.

Figure 3.1-3. Brayton Cycle Repowering

Figure 3.1-4. Combined Cycle Repowering

TABLE 3.1-1. SOLAR HYBRID REPOWERING METHOD ASSESSMENT

CYCLE CONFIGURATION	COMPARISON BASED ON INDIVIDUAL CYCLES						COMPARISON BASED ON ESTIMATED UNITS AVAILABLE IN EACH CONFIGURATION	
	RECEIVER TEMPERATURE	TECHNICAL RISK	COMPLEXITY	DIFFICULTY OF OPERATION	FUEL DISPLACEMENT	COST	POTENTIAL CANDIDATE MARKET	OVERALL BENEFIT TO COST RATIO
RANKINE CYCLE REEDWATER HEATING	LOW	LOW	LOW	LOW	LOW	LOW	HIGH	VERY LOW
RANKINE CYCLE EVAPORATION AND SUPERHEATING	MEDIUM TO HIGH	LOW	MEDIUM	MEDIUM	HIGH	MEDIUM	HIGH	HIGH
BRAYTON CYCLE	HIGH	MEDIUM TO HIGH	MEDIUM TO HIGH	MEDIUM TO HIGH	MEDIUM TO HIGH	HIGH	LOW	LOW
COMBINED CYCLE	MEDIUM TO HIGH	MEDIUM TO HIGH	HIGH	MEDIUM TO HIGH	MEDIUM TO HIGH	MEDIUM TO HIGH	VERY LOW	VERY LOW

The various repowering methods considered are compared both relative to each other and on an estimated overall market applicability. Each repowered cycle configuration has been rated against six evaluation factors; namely, receiver temperature, technical risk, complexity, difficulty of operation, fuel displacement and cost. These evaluation factors are discussed in the following pages.

The receiver temperature required for the four repowering methods is an important consideration since receiver temperatures above 1000°F have not been demonstrated; experience is limited to the DOE water-steam central receiver program. Thus, solar repowering of the steam Rankine cycle, either solar feedwater heating or solar evaporation and superheating, can be considered within the current state-of-the-art. However, for effective solar repowering of a Brayton cycle, receiver temperatures in the range of 1300° to 1700°F are required. Special high temperature metallurgy and fatigue life of the receiver and piping system then become very important considerations which are not readily resolved with near-term technology.

From a technical risk standpoint, solar feedwater heating presents the least risk but also produces the least benefits of the four solar repowering methods. Solar evaporation and superheating (boiler replacement) utilizing the central receiver concept appears at this time to be of low technical risk using current water-steam central receiver technology. Brayton cycle repowering involves the high temperature design problems previously mentioned, a wide variation in existing Brayton cycle configurations (complexity), and potential installation and interface problems (for both Brayton and combined cycles); the technical risk here must be considered medium to high as compared to steam cycle repowering.

In addition to selecting repowering methods that reduce the technical risk, it is also desirable to minimize system complexity, both in design and operation. It is judged, therefore, that solar feedwater heating is the least complex method following in order of increased complexity by evaporation and superheating, open Brayton cycle and combined cycle.

The difficulty of operation of the repowered plant must be considered. Of primary importance is the ability of the repowering method to provide the operational flexibility required for solar operation while interfacing with an existing plant.

In general, solar feedwater heating should pose no major operating problems. Repowering an open Brayton cycle may lead to operational problems in maintaining gas turbine inlet temperature and in paralleling the fossil-fired combustor, particularly during load fluctuations. Gas turbines in use today are normally used for peak load service, quick start and short operating periods. Solar repowering would involve a change in plant usage and operating philosophy.

Combined cycle plants on the other hand are normally designed for mid- and base-load applications. However, due to the higher complexity of these plants compared to the straight gas turbine plant, it is expected that operational problems due to solar repowering of a combined cycle plant would increase.

The difficulty of operation associated with steam Rankine cycle repowering is ranked as medium relative to the other repowering methods considered. The principal operating problems are expected to be associated with solar steam temperature control and fossil boiler stability at low loads (high solar input) while operating in parallel with the solar central receiver.

Fossil fuel conservation is an important objective of solar hybrid repowering. The potential fuel displacement offered by solar feedwater heating in a steam Rankine plant is deemed low, estimated at less than 10 percent of the rated boiler fuel input.

Solar evaporation and superheat can displace up to 100 percent of the fossil fuel requirement at rated load during the peak daylight hours, thus its fuel displacement potential is high.

The Brayton or gas turbine cycle also can be repowered by solar energy up to 100 percent of its rated output. However, it is likely that some fossil fuel firing will be required to maintain rated gas turbine inlet temperature. Also, since gas turbine units are normally installed for peaking service, the potential fuel displacement by solar repowering is further minimized.

Combined cycle plant solar repowering can result in fuel displacement equal to or greater than straight gas turbine plants, depending on whether or not a supplemental fossil-fired heat recovery cycle is used.

Based on solar repowering plants of equal size, solar feedwater heating can be accomplished for the least capital cost of the four repowering methods considered. Solar evaporation and superheating is expected to cost less than Brayton cycle repowering, primarily due to advanced receiver design (high receiver temperature), solar working fluid air/heat exchangers and collector costs (due to lower cycle efficiencies). The cost of combined cycle plant repowering is expected to fall either between steam Rankine cycle and Brayton cycle repowering, or higher than Brayton cycle repowering, depending upon the method and extent of repowering, since combined cycle plant configurations are widely varied.

Table 3.1-1 shows the potential market and estimated overall benefit-to-cost ratio for the various solar repowering methods considered. As expected, solar feedwater heating has high market potential but relatively low benefits. Solar evaporation and superheating (boiler replacement) has high market potential and the highest benefit-to-cost ratio. Brayton cycle plants are judged to have low market potential and low benefits compared to steam Rankine cycle repowering; combined cycle plants are judged very low in both categories.

SUMMARY AND CONCLUSIONS

Solar hybrid repowering of existing oil-/gas-fired generating plants has been evaluated using four basic repowering methods: steam Rankine cycle solar feedwater heating; steam Rankine cycle evaporation and superheating (boiler replacement); Brayton cycles (combustion turbines); and combined cycles (Brayton/Steam Rankine).

Solar repowering of existing steam Rankine cycles, either feedwater heating or boiler replacement, is feasible and within current state-of-the-art technology. Of the two methods, evaporation and superheating result in the greatest overall market benefit.

Solar repowering of Brayton cycles without fossil fuel assistance fall under the advanced central receiver concept because of the high receiver temperatures required (1300° to 1700°F) and are considered to be outside of the near-term technology required in this study.

Solar repowering of combined cycles presents the same problems as defined for Brayton cycles, with the addition that supplementary fossil-fired heat recovery steam boilers may also be required. Combined cycle plant solar repowering represents the lowest market potential and lowest benefit-to-cost ratio of all repowering methods considered.

It was recommended that only solar evaporation and superheating (boiler replacement) of existing steam Rankine cycles be considered for further study in the market cost/benefit analysis of solar hybrid repowering.

3.2 CANDIDATE PNM UNITS

Solar system size for a demonstration of evaporation/superheating solar repowering (the MWe output of the solar steam Rankine unit) must coincide with the current DOE technology in order that applications may be utilized in the near term. The technical driver for size, therefore, becomes the solar boiler or receiver.

A DOE objective is to reach a commercial plant size of 100 MWe. However, the first unit for the Barstow 10 MWe Pilot Plant has a capacity that will allow for approximately 17 MWe production (the capacity is in excess of 10 MWe required for charging thermal storage while operating the plant in parallel). Since the solar hybrid demonstration is envisioned as an evolution in size toward the 100 MWe commercial goal, 17 MWe is considered a minimum, with a maximum power level in the 25 to 30 MWe range.

The current technical feasibility of this size was agreed to by Rockwell International in a meeting on January 24, 1978. It should be noted that the Rockwell design was recommended by DOE in October 1977 as the prime candidate for future development work, and selected by DOE in July 1978 as the concept to be utilized at the Barstow Pilot Plant. PNM has utilized the MDAC central receiver design (which incorporates the Rockwell receiver) as a baseline for this study. This was based on PNM project management reviews, the Sandia Laboratories recommendations for the Barstow Pilot Plant, and guidance received from DOE.

Based on the constraint of steam Rankine boiler displacement utilizing the central receiver concept at a capacity level of 17 to 30 MWe, PNM candidate sites and units were evaluated by the following eight PNM groups:

● System Planning (Lead)	● Gas- and Oil-Fired Plants
● Environmental Affairs	● Production Plant
● Right-of-Way	● Generation Planning
● Power Production	
● Revenue Requirements	

The specific PNM units reviewed are listed in Table 3.2-1.

TABLE 3.2-1. PNM CANDIDATE UNITS FOR SOLAR HYBRID REPOWERING

<u>Plant</u>	<u>Unit Rating, MWe</u>
Person No. 1 & 2	22
Person No. 3 & 4	35
Reeves No. 1 & 2	44
Reeves No. 3	66
Prager No. 7	7.5
Prager No. 8	6.0
Prager No. 9	11.5
Santa Fe No. 1 & 2	7.5
Valencia Combustion Turbine	21.5

A demonstration in this capacity range would require as much as 200 acres of adjacent land, thus eliminating the Prager and Santa Fe sites. The Valencia Combustion Turbine is a Brayton cycle machine and falls under the second generation hardware, which is not being considered for reasons noted above. Attention was focused on the Person and Reeves units, and the 14 selection criteria noted in Table 3.2-2 were addressed by team members in their areas of expertise.

Sections 3.3 through 3.6 of this Report present the detailed recommendations of the PNM functional units providing significant input on the study unit selection.

TABLE 3.2-2. SOLAR HYBRID REPOWERING PROJECT — PNM CANDIDATE
UNIT TECHNICAL SELECTION CRITERIA

1. Unit Type, Location and Rating
2. Adjacent Land Availability/Surrounding Structures
3. Date Constructed
4. Unit Condition/Remaining Useful Life
5. Insolation and Climatological Characteristics
6. Fuels Used/Fuel Options
7. Turbine Type/Operating Conditions
8. Plant Operation/Availability Requirement
9. Solar/Fossil Interfaces
10. Current Use/Planned Future Use
11. Environmental Impacts
12. Site Characteristics/Terrain
13. Institutional Impacts
14. Proximity to Airports

3.3 POWER PRODUCTION CONSIDERATIONS

Items considered during evaluation of the candidate generating units were:

- Remaining useful life
- Maintainability (based upon maintenance histories and projected maintenance requirements)
- Unit Condition (based upon maintenance histories)
- Operational Stability (based upon operational requirements during minimum load operation and operation during boiler upset conditions)
- Fuel Types

While none of the Reeves and Person units has maintenance or operational restrictions that would prohibit its participation in the Solar Hybrid Project, the Reeves Station Unit No. 2 was recommended as a first choice by the operation, maintenance and engineering groups within the PNM Gas and Oil (G&O) Plants. Following are their recommendations:

FIRST CHOICE: Reeves Station Unit No. 2

- Estimated Retirement Date: 1996
- Maintainability:
 - Boiler: Present condition is good, tube failure has been experienced in the boiler furnace roof arch section. This is thought to be due to a flow deficiency inherent in the unit design. The boiler has minimal brick refractory, thus, it will endure the expected temperature transients that will be experienced as a hybrid unit.
 - Boiler Auxiliaries: Present condition good
 - High-Pressure Turbine: The horizontal joint has had a history of leakage; the effect of cycling the unit will accelerate this problem.
 - Low-Pressure Turbine: Present condition is good. Last stage blading replaced February 1977.
 - Turbine/Generator: Present condition good

- Operational Stability: The location of the unit in the plant area is immediately adjacent to the control room, thus making operator attention more readily available during times of boiler ramping or upset.

The minimum load the unit may carry with all boiler controls in full automatic operation is 20 MW. (Six burners in service; for 25 MWe solar input, gross boiler load = 25 MW at maximum output.)

- Future Boiler Fuels: It is expected that this unit will operate on fuel oil as a primary boiler fuel after the year 1981.

SECOND CHOICE: Reeves Station Unit No. 3

- Estimated unit retirement date: 2000
- Maintainability:
 - Boiler: Present condition is good. This unit has not experienced failure of the roof arch section although design is similar to Reeves Unit No. 2.
 - Boiler Auxiliaries: Present condition good
 - Turbine/Generator: Present condition good
 - High Pressure Turbine: Some modification has been made on the high pressure turbine inlet valve cam assembly to more readily permit cycling of the unit. Thermocouples have been installed in the upper and lower halves of the high pressure casing to aid in temperature control during unit roll out.
 - Low Pressure Turbine: The low pressure turbine is in good condition, however, reblading of the last row of rotating blades in the low pressure section will be required during the next scheduled unit overhaul (1981).
 - Generator: The generator has experienced a history of tape separation; corrective maintenance has been done during the normal turbine overhauls. The causes of this problem have not been satisfactorily determined.
 - Operational Stability: The location of the unit in the plant area is immediately adjacent to the Control Room.

The present minimum load that may be carried by the unit's boiler in full automatic operation is 32 MW (six burners in service).

- Future Boiler Fuels: Again, it is expected that the primary boiler fuel for this unit will be fuel oil after 1981.

THIRD CHOICE: Person Station Units No. 1 or 2

- Estimated unit requirement dates: Person No. 1, 1988;
Person No. 2, 1992
- Maintainability: (both units)
 - Boiler: Present condition is fair. Both units have had a history of tube failure in the superheater area; these tubes were replaced in Unit No. 2 during the major unit inspection in February of this year. Person Unit No. 1 will have the furnace refractory replaced during the next inspection outage and it is expected that some superheater tube replacement will also be done.

Both units have experienced deterioration of the furnace refractory; this is felt to be due to the cyclic operation of these units.
 - Boiler Auxiliaries: Present condition good
 - Turbine/Generator: The present condition of the turbine/generators is felt to be good. Both units are scheduled for major overhauls during 1978 at which time a more detailed evaluation will be made.
 - Operational Stability: The location of the unit(s) control room with respect to the boiler(s) again provides for immediate operator attention. The Control Room is located near the boiler fronts.

The present minimum load that may be carried on either boiler is 7 MW (three burners in service).
- Future boiler fuels: Fuel oil is expected to be the primary boiler fuel after 1981.

The primary reason for selecting Reeves Station, Unit No. 2 or Unit No. 3, is the maintainability and operational stability of the units. It was felt that the boilers on the recommended Reeves units are more suitable for the cyclic duty that would be experienced as a hybrid unit because of the minimal use of refractory in their construction. This is opposed to the Person units whose boilers incorporate considerably more refractory and are not well suited for continuous cyclic duty and the temperature excursions expected of a hybrid unit, assuming some degree of combined firing (fossil fuel and solar). It was also felt that sudden loss of turbine load (solar steam flow) may also be more desirable on the Reeves units since this loss can be absorbed by the turbine/generator as well as the fossil boiler.

It should be noted that reliability and availability of the recommended Person units on fuel oil for start-up and continuous operation is also dependent upon cost of conversion studies. These are currently being performed as a part of a PNM in-house G&O Plant fuel oil conversion study due to the age and expected retirement dates of these units.

3.4 GENERATION PLANNING CONSIDERATIONS

Selection of a unit for solar repowering study purposes must be consistent with the overall PNM system expansion plans. Given a high probability that PNM may have a demonstration project to follow the feasibility study, it is prudent that the study plant be not only feasible for repowering, but also as compatible as possible with system needs after repowering. Therefore, the following areas must be recognized in addition to the environmental, location and plant characteristics areas.

If the repowered unit is not to require significant oil consumption, the solar system must be capable of conservatively providing minimum load energy which is 40 to 50 percent of unit capacity. The 40 to 50 percent is the minimum stable operating point that is influenced both by turbine and boiler designs. If this was only a boiler constraint, then it would imply that whenever supplemental firing is required for transients, etc., oil would be used to supply the 40 to 50 percent capacity. The boiler minimum can probably be limited through modified design and improved control schemes. Given any boiler minimum, oil usage would be minimized by designing the solar system so that supplemental firing would be limited based primarily on exceeding turbine minimum load and economic dispatch of oil-firing.

The solar design of the proposed repowering unit is basically the same as the stand-alone 10 MW plant with regard to collector field and steam supply. This plant without the storage system is designed for 17 MWe peak conditions. It is assumed that an average level would be less than 17 MW. It appears, therefore, that this solar steam system would be more than adequate to fit a Person unit and conservatively supply well over 50 percent of the unit's steam. However, it would appear that the present design would have to be extended even before full testing in order to use the solar concept with Reeves Unit No. 1 or 2 and meet minimum load segments. This assumes turbine and boiler minimum loading segments are about the same, 40 to 50 percent.

Similar to our other gas/oil units, Person and Reeves are scheduled for future retirement; in the mid to late 1980s and the mid 1990s, respectively. This is

due to plant age (useful life due to deterioration of major components) and economics. Basically, the oil unit capacity/energy will be displaced by pumped storage or other peaking generation. These basic system constraints should be recognized in selecting a unit.

3.5 ENVIRONMENTAL CONSIDERATIONS

PNM Environmental Affairs performed a candidate site selection of the two alternative sites. These sites, as noted in Section 3.2 of this Report, are:

- Site Alternative 1: Reeves Station
- Site Alternative 2: Person Station

Both sites are located in Bernalillo County within the Albuquerque metropolitan area. The locations of the two candidate sites are shown in Figures 3.5-1 through 3.5-3. The sites are located approximately 14 miles apart on a north-south orientation and are situated to the west of I-25 within the Rio Grande Valley.

A study area was defined and a site selection analysis performed based upon the assumptions that the site would:

- Require a minimum of 120 acres
- Be in a square or rectangular configuration
- Be contiguous or in close proximity to the station
- Require that the 120-acre site be level or be graded and filled
- Be covered by gravel or use a chemical means to suppress vegetation (site would not be paved)

Due to the close proximity of the candidate sites to one another within the Rio Grande Valley, many environmental parameters are similar. In order to comparatively screen the candidate sites, Environmental Affairs' site selection investigation was responsive to the following two site selection criteria as defined:

- Site Characteristics/Terrain
 - Slope and Dissection
 - Soils
 - Vegetation

SOLAR HYBRID REPOWERING CANDIDATE UNIT SELECTION **LOCATION OF CANDIDATE UNITS**

Figure 3.5-1. Locations of Candidate Units

SOLAR HYBRID REPOWERING CANDIDATE UNIT SELECTION

SITE ALTERNATIVE #1, REEVES STATION

Figure 3.5-2. Site Alternative #1, Reeves Station

SOLAR HYBRID REPOWERING CANDIDATE UNIT SELECTION

SITE ALTERNATIVE #2, PERSON STATION

BcA, Gm, etc. = soil types, see Appendix

Figure 3.5-3. Site Alternative #2, Person Station

- Environmental Impacts
 - Erosion and Drainage
 - Vegetation
 - Land Use Patterns
 - Transportation Corridors and Glint Potential
 - Visual Resources

The analysis was performed based upon field investigation at the site in January 1978, a review of literature, and in-house knowledge of the area.

Based on this analysis, Environmental Affairs ranks the alternative sites as follows:

1. Reeves Station
2. Person Station (west site)
3. Person Station (north site)

Reeves Station site is characterized by a 3.6 percent slope with soils of moderate erosion potential. Drainage impacts may be mitigated by channelization. Native vegetation and fauna would be displaced during construction activities. The Reeves site would not alter existing land use patterns and would not have as negative a visual impact as compared to the two sites at Person Station. Glint might prove to be a problem to traffic on I-25. The site would be accessible to the public and would have good visibility without creating an overwhelming visual impact upon the viewer.

Person Station (west side) would be the second ranked site. This site offers the advantage of being on level ground with low erosion potential. No native vegetation or fauna would be removed by development, but agricultural land would be taken out of production. The facility would not be a compatible land use. The visual intrusion of this site would be greater than at Reeves Station. Glint might prove a problem to I-25 traffic. The site would be accessible to the public and would have good visibility but, due to closer viewing distances, would have a more overwhelming visual impact on the viewer than the Reeves site.

The least favored site is Person Station (north site) with a 6.3 percent slope, greater dissection, and higher erosion potential. The proximity of this site to I-25 would create a glint problem and positive viewing of the site would be less than at either of the other two sites due to the sites' location immediately adjacent to transportation corridors minimizing viewing distances.

3.6 SAFETY CONSIDERATIONS

Certain hazards are associated with locating any central receiver solar thermal power system stemming from both of the major components; the central tower/boiler and the heliostat field.

Any structure of over 200 feet height is considered hazardous by the FAA and construction must be preceded by filing Form 004-R0001 notifying them of the proposed facility. This, of course, would be true of a central tower as its height could range from 345 feet to as much as 700 feet.

The heliostat system poses an even greater safety risk to personnel in a problem defined as "glint," or stray reflections from the mirror surfaces. Glint can be a severe problem to people operating a motor vehicle, piloting an aircraft, etc. The 10 MWe PON (Program Opportunity Notice) states "Location of the pilot plant within the control zone of, or adjacent to any state, municipal, or privately owned airport must be avoided." This expresses the fact that although no definitive information is available on glint, it is recognized as a problem by ERDA, which is severe enough to restrict facility siting.

Although ground-based personnel certainly should and will be considered with respect to safety for solar repowering of Person Station, the proximity of it to the Albuquerque Sunport presents rather severe problems. As shown in Figure 3.6-1, Person Station is slightly more than one mile from the major commercial east/west runway. In addition, it is approximately three-quarters of a mile from the secondary northeast/southwest diagonal runway. This runway handles a majority of the private and small aircraft which account for 150,000 out of 225,000 landings and takeoffs on the runway system each year (per FAA).

Jerry Jersenov of Sandia Laboratory, in charge of the central receiver safety analysis, stated that for our location on the flight path for the major small aircraft runway at the Sunport, there could be some difficulty in siting a 120- to 285-acre heliostat field with today's system safety design requirements. The inclusion of a 400-foot or taller tower adjacent to commercial airline glide paths is also a significant issue. These appear to be major problems and could

Figure 3.6-1. Albuquerque Sunport/Person Station Area

expressly exclude Person from a first-time solar hybrid repowering application. Once safety parameters are established, Person could become an excellent candidate.

Reeves Station has two smaller local airports, Alameda and Coronado, located to the northwest and northeast, respectively. The approach paths to these facilities could be directed to avoid a solar field flyover much more readily than the Albuquerque Sunport when considering proximity, aircraft type and volume usage. The Reeves plant, therefore, appears superior with respect to aircraft safety considerations.

3.7 STUDY UNIT

The selection of a study unit was noted in Section 3.0 of this Report as being predicated on two primary considerations:

- The unit was to represent a typical plant as defined in the market survey
- The unit was to be one which is best suited to meet future needs of the PNM system and ensure optimum use as a demonstration unit while assuring system integrity

Section 2.4 of this Report presented a discussion of the typical candidate repowering plant; these results are summarized for reference in Table 3.7-1. Many of these criteria can be met by either the Person or the Reeves units.

TABLE 3.7-1. TYPICAL CANDIDATE UNIT COMPARED TO REEVES UNIT NO. 2

	<u>Candidate Unit</u>	<u>Reeves No. 2</u>
Unit Characteristics		
- Type	Non-reheat Steam Turbine	Non-reheat Steam Turbine
- Rating	10 to 50 MWe	44 MWe Nameplate
- Turbine Inlet	850 to 1250 psi/900° to 950°F	1250 psi/950°F
General Unit Data		
- Year Built	1950 - 1960	1958
- Condition	Good	Good
- Current Use	Intermediate/Peak	Base/Intermediate
- Location	Rural	Rural
- Estimated Retirement	Before 2000	1997

An assessment of the information presented in Sections 3.2 through 3.6 of this Report was made, and consideration was given to the market survey results. It was concluded that the Reeves plant is the most ideal site for the development of a conceptual design and for a demonstration of the solar hybrid repowering concept. Primarily based on power production recommendations, Unit No. 2 is the most desirable machine. A 25 MWe net solar field was recommended to provide for an adequate demonstration of the concept while remaining within technology limits. Should the concept prove successful, the unit could be upgraded to 100 percent solar capacity at a later date.

As shown in Table 3.7-1, comparing the typical candidate unit criteria with that of Reeves No. 2, the selected study unit meets all criteria established for the typical candidate unit.

Section 4.1.1 of this Report contains a detailed description of the engineering features of Reeves Unit.No. 2.

3.8 SITE DESCRIPTION

Reeves Station, the proposed site for the demonstration solar hybrid repowering project, is located in Bernalillo County within the Albuquerque metropolitan area. The site area is characterized by rapid urban development. The following discussion summarizes the physical, biotic and socioeconomic features of the Reeves site.

3.8.1 INSOLATION

The Reeves Station of the Public Service Company of New Mexico system is an excellent choice for the location of a Solar Hybrid Repowering Plant for several reasons:

- The insolation level is relatively high for most of the year enhancing the potential for demonstrating economically competitive and useful commercialization of solar hybrid repowering.
- Most of the reliable direct normal insolation data available in the United States has been accumulated for Albuquerque New Mexico and will thus permit a high level of confidence to be achieved in the design of and the performance predictions for the plant.
- An instrument package for recording direct normal insolation data has been installed at the station as part of the WEST Solar Resource Evaluation Study, and measurements (every 15 minutes) of direct normal insolation has been recorded since June 1977; thus, providing a site specific data base for verification of the plant design (see Section 4.9).

Figure 3.8-1 shows the predicted geographic variations in direct normal insolation for the United States.* These data indicate that the yearly average day values for the direct normal insolation varies from approximately $5.5 \text{ kW-h/m}^2\text{-day}$ for the Texas/Oklahoma region of the country to $7.2 \text{ kW-h/m}^2\text{-day}$ for the Arizona/Nevada region. The value for Albuquerque, New Mexico is approximately $6.6 \text{ kW-h/m}^2\text{-day}$. Therefore, it can be expected that the data obtained from a demonstration program for solar repowering performed in New Mexico from an insolation level standpoint will be representative of what can be achieved through solar repowering of other units located in other regions of the Southwestern United States.

*On the Nature and Distribution of Solar Radiation (UC-59,62,53A) by WATT Engineering. Prepared for Department of Energy, March 1978.

Figure 3.8-1. Predicted U.S. Insolation Variations

Table 3.8-1 presents the monthly and annual average direct normal insolation values for Albuquerque, New Mexico for the years 1961 through 1964; the average annual values range from 6.59 to 7.08 kW-h/m²-day for these four years. These data were obtained from 10 minute digitized records available for Albuquerque, New Mexico from the National Environmental and Climatic Data Center. The variation in direct normal insolation on a day-by-day basis for June 1962 is given in Figure 3.8-2. The data presented in this figure indicate that solar energy could be used to displace a significant portion of the fossil fuel required to operate a power plant at Albuquerque during every day of June 1962. In addition, "clear day" insolation profiles were observed for approximately 50 percent of the time during June indicating the potential of the solar hybrid repowered plant to displace in excess of 90 percent of the fossil fuel normally used during these days. Likewise, as indicated for the year 1962 (see Section 2.5) solar energy has the potential to displace significant portions of the fossil fuel that would normally be consumed during more than 300 days of plant operation.

3.8.2 PRECIPITATION

Normal precipitation totals for the year average about eight inches at 5000 feet above mean sea level (MSL). Departures from the yearly normals can range about half to double the normal. Usually such departures are widespread. Droughts, which can last months or years, are more persistent than wet periods. Snow cover rarely lasts more than a few days below 7000 feet. Winter precipitation is mostly associated with polar pacific airmasses and occasionally arctic airmasses. The onset of the summer thundershower season is a result of a monsoon-type circulation that imports a greatly modified tropical maritime airmass. This occurs regularly between July and late September. Temperature and precipitation data are shown in Table 3.8-2.

3.8.3 WINDS

Winds and wind storms occur mainly in the spring with thunderstorms. Both types of winds can exceed 60 MPH but most average 25 to 35 MPH. Spring winds usually diminish after sunset and blow out of the quadrant from south to west. Table 3.8-3 shows mean wind speeds and prevailing directions by month.

TABLE 3.8-1. DIRECT NORMAL INSOLATION FOR ALBUQUERQUE, NEW MEXICO
MONTHLY AND ANNUAL VALUES, kW-h/m² DAY

Month	1961	1962	1963	1964	Average
January	6.26	4.87	6.06	5.61	5.70
February	6.05	6.21	6.32	5.75	6.08
March	5.76	5.99	6.16	5.66	5.89
April	8.09	7.15	6.92	6.99	7.29
May	7.52	8.85	7.51	7.50	7.85
June	8.54	9.82	8.80	9.35	9.13
July	8.21	6.98	7.03	7.49	7.43
August	6.84	8.78	6.23	7.25	7.28
September	7.43	5.67	6.88	6.05	6.51
October	7.69	7.28	6.09	7.69	7.19
November	4.75	6.47	5.23	5.97	5.61
December	5.37	6.88	6.17	3.75	5.54
AVERAGE	6.88	7.08	6.61	6.59	6.79

Figure 3.8-2. Direct Normal Solar Radiation Observed at Albuquerque, NM

TABLE 3.8-2. CENTRAL RIO GRANDE VALLEY REGION TEMPERATURE AND PRECIPITATION

Item	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Temperature (°F)												
- Average daily maximum	47	52	59	70	80	89	92	90	83	72	57	48
- Average daily minimum	24	27	32	41	51	60	65	63	57	45	32	25
- Daily mean	35	40	46	56	65	75	79	77	70	58	44	37
- Extreme maximum	68	72	81	89	98	102	104	104	100	98	74	72
- Extreme minimum	-7*	-5	8	19	28	43	54	52	37	25	10	3
Precipitation												
- Average (inches)	0.31	0.40	0.47	0.47	0.56	0.53	1.37	1.38	0.83	0.78	0.34	0.52
- Average days 0.10-in. or more (no.)	1	2	2	2	2	1	4	4	2	2	1	2
- Average snowfall	1.3	1.7	1.7	0.3	T	0	0	0	T	T	1.2	2.6

T = Trace, less than 0.5-inch

For period of record August 1939 through December 1970.

Recording Station: Albuquerque Airport, Bernalillo County, New Mexico.

*An extreme minimum of -17 was subsequently recorded on January 7, 1971.

TABLE 3.8-3. MEAN SPEED AND PREVAILING DIRECTION
AT ALBUQUERQUE SUNPORT

	Mean Speed	Prevailing	Fastest Wind Speed Recorded		
			Speed	Direction	Year
January	8.0	N	61	E	1949
February	8.8	N	68	NW	1944
March	10.1	SE	80	NW	1943
April	11.0	S	72	S	1946
May	10.5	S	72	W	1950
June	10.0	S	82	SE	1946
July	9.1	SE	68	E	1945
August	8.1	SE	61	SE	1951
September	8.6	SE	62	SE	1945
October	8.3	SE	66	N	1959
November	7.8	N	57	NW	1948
December	7.6	N	90	SE	1943
YEAR	9.0	SE	90	<u>SE</u>	Dec. 1943

*Wind direction divided into sixteen 22.5° sections.

Source: Weather Service, Albuquerque Airport

Dust and dust storms are unattractive features of the arid Southwest. The following discussion is taken from the New Mexico State Planning Office publication, "The Climate of New Mexico" (Tuan, et al.) concerning the nature of such storms and their occurrence in Albuquerque:

The basic conditions for blowing dust are the presence of wide areas of exposed dry topsoil and strong, turbulent wind. In New Mexico, dry soil with scanty vegetation cover is widespread in areas that average less than ten inches of rain a year (in the trough of the Rio Grande). The large tracts of sand hills, one series to the east of the Pecos River and another on the Staked Plains to the south of Clovis, are evidence of the effect of wind action on loose soils in the southeastern sector of New Mexico.

Dust Streams

Given the presence of loose soil, the severity of blowing dust depends on the strength and turbulence of the wind. In the dry months of late fall, winter and early spring, a common phenomenon (not dignified by the name "dust storm") is the swift motion of dust and sand in wandering sheets and narrow streams. The dust and sand bound and skip along the surface, and the mass of material appears to be concentrated in a shallow layer less than two feet in thickness. Such local dust movements are caused by sudden, horizontal sweeps of air moving at speeds of fourteen to eighteen miles per hour.

Dust Devils

In contrast to the ground-hugging dust streams are the vertical dust devils. The small vortices of rapidly moving air, made visible by the dust and loose organic matter they sweep up, are especially common in sparsely vegetated, flat and open parts of southern New Mexico during the summer half of the year.

Dust Storms

Widespread and thick drifts of dust affecting the entire state or a large portion of the state are associated with the passage of cyclones, and in particular, cyclones with sharp, cold fronts. Dust storms caused by general cyclonic winds tend to develop gradually, and the life of the typical cyclonic duster is limited to daylight hours.

Statistical information is lacking as to the seasonal distribution, intensity, and duration of dust storms for New Mexico as a whole. Von Eschen has compiled data for Albuquerque. The*

*Von Eschen's compiled data are summarized in Table 3.8-4.

TABLE 3.8-4. DUST STORMS IN ALBUQUERQUE* (16-YEAR PERIOD 1945-1960)

Month	Total Number of Days with Blowing Dust	Storms Classified		
		Severe	Moderate	Light
January	14	4	3	7
February	26	7	11	8
March	44	15	12	17
April	75	18	21	36
May	55	2	8	45
June	56	5	6	45
July	38	1	2	35
August	10	0	1	9
September	8	0	2	6
October	15	0	5	10
November	13	1	2	10
December	10	3	3	4
TOTAL				
AVERAGE	364	56	76	232
YEAR	23	3	5	15

*After Von Eschen

information is based on 19 years (1954-1960) of hourly weather observations made at the Municipal Airport (Sunport) in Albuquerque. Dust storms are divided into three categories:

- Severe: Continuous blowing dust for three hours or more with the visibility restricted to one mile or less at some time during the storm;
- Moderate: Continuous blowing dust for two hours or more and visibility four miles or less during the storm (but not qualifying as severe);
- Light: All other dust storms during which the visibility was restricted to six miles or less (but not qualifying as moderate or severe).

Spring months have the most dust storms, with an average of about five days in April when some blowing dust will occur. Fall and early winter months have the least dust, with September recording some dust on an average of every other year. Although April averages more dust storms than any other month, March storms normally last somewhat longer. September has the least number of dust storms but those in July and August are usually of shorter duration.

It is not anticipated that any mitigation measures are required other than protective heliostat stowage during periods of high winds. Station personnel will notify the project coordinator of any unusual occurrences involving this issue in the future.

3.8.4 TOPOGRAPHY, VEGETATION AND HYDROLOGY

The site lies in the southern portion of the Basin and Range Physiographic Province in the Mexican Highland Section, which is characterized by isolated dissected black mountain ranges separated by aggraded desert plains. The Sandia Mountains' crestline lies approximately 10 miles east, reaching 10,678-feet above mean sea-level (MSL) at Sandia Crest. Westward from these mountains elevations decrease to 5000 feet MSL at the Rio Grande which lies approximately three miles west. The site has a surface that slopes gently westward from elevation of 5130 feet MSL on the east to 5070 feet MSL on the west near the AMAFCA drainage canal. The slope of the 120-acre rectangular plot is 3.6 percent.

VEGETATION

Native vegetation around the solar hybrid repowering site is low in profile principally because of low rainfall, 7 to 10 inches annually, and high elevation, 5000 to 6000 feet above MSL. The plant community at a typical site in this part of the county is mainly comprised of grasses mixed with some shrubs and herbaceous plants. Vegetation covers only approximately 15 percent of the soil surface. The most abundant grass is usually black grama (*Bouteloua eriopoda*), which may comprise approximately 35 percent of the total vegetation by weight. Less abundant species are sand dropseed (*Sporobolus cryptandrus*), mesa dropseed (*Sporobolus flexuosus*), galleta (*Hilaria jamesii*), three awn (*Aristida glauca*), blue grama (*Bouteloua gracilis*), alkali sacaton (*Sporobolus airoides*), bush muhly (*Muhlenbergia porteri*), Indian ricegrass (*Oryzopsis hymenoides*) and fluffgrass (*Tridens pulchella*). In places, there are broom snakeweed (*Gutierrezia sarothrae*), broom dalea (*Dalea, sp.*), pricklypear cactus (*Opuntia, sp.*), small soapweed (*Yucca glauca*), cholla cactus (*Opuntia, sp.*) and winterfat (*Eurotia lanata*). Annual plants which increase during years of above average precipitation are tansymustard (*Descurania, sp.*), Indian painbrush (*Castilleja leonardi*), woolly Indian-wheat (*Plantago purshii*), lambsquarters (*Chenopodium album*), Russian-thistle (*Salsola kali*) and bladderpod (*Lesquerella intermedia*). Woody plants such as Apache plume (*Fallugia paradoxa*) may occur in the drainage ways.

The vegetation of the site is characterized principally by black gamma, sand dropseed, three awn, bush muhly, Indian ricegrass, fluffgrass, broom snakeweed, pricklypear, cholla cactus, transymustard, Russina-thistle and bladderpod. When such a plant community is disturbed, annual plants increase. Vegetation of the site has already undergone some disturbance because of the existing power plant and is also affected by several small washes which dissect the proposed plot for the solar heliostat field.

Of the Federal threatened and endangered plant species and the plants protected by the State of New Mexico, none are known to occur on the site at this time. Of those listed only a few species could potentially occur at the site, such as grass cactus (*Pediocactus papyracanthus*) and only a more detailed study could verify their presence or absence.

HYDROLOGIC CONDITIONS

For Embudo gravelly fine sand loam, zero to five percent slopes, runoff is medium and the hazard of water erosion is moderate.

For Wink fine sandy loam, one to five percent slopes, runoff is medium. The hazard of water erosion is slight to moderate and the hazard of soil blowing is moderate.

Since the slope of this site is not great and the soil type has moderate absorption qualities, the erosion potential is moderate.

The site slopes gradually from east to west toward the drainage canal to the west of the site. Offsite drainage will be intercepted on the east side of the site and a culvert installed to conduct the flow across the site discharging into the drainage canal. The interceptor and the culvert will be sized to handle 1125 c.f.s. which is the runoff calculated for a 100-year storm. In addition, the drainage through the site will be channelized to control erosion. With the above features the site and the surrounding area will be adequately protected from flooding and erosion.

3.8.5 SEISMIC STABILITY

The seismic stability discussion below complements and amplifies the presentation given in Section 4.8.2.4.

ESTIMATE OF SEISMIC RISK IN THE AREA OF STUDY

The instrumentation data since 1962 indicates that the strongest shock in a 100-year period for the entire region (including the 100 km wide buffer zone) should not exceed Richter magnitude 4.9. On the other hand, the reports of felt shocks for the 94-year period prior to 1962 indicate six shocks had magnitudes greater than 5. On the basis of this data, the strongest shock in a 100-year period is likely to have a magnitude near 6. The discrepancy in these estimates of seismic risk can be explained in two ways. Activity during the past 16 years was lower than normal or the activity in the 94 years prior to 1962 was higher than normal. With the short time history of seismic activity available, one cannot determine which of these two interpretations is correct. Therefore, the safest procedure

at this time is to assume that a magnitude 6 shock is possible somewhere in the region (including the buffer zone) during the next 100 years.

VARIATIONS OF SEISMIC RISK WITHIN THE AREA OF STUDY

The vicinity of the Reeves site has been divided into three regions: Region 1 lies mostly in the Rio Grande Valley south of Bernalillo, Region 2 is mostly in the Rio Grande Valley north of Bernalillo, and Region 3 is located to the east of the Manzano and Sandia Mountains.

Seismicity in Region 3 appears very low inasmuch as very few epicenters or recent faults lie within or near its boundaries. The strongest shock in this region in a 100-year period is estimated to be so weak that it constitutes no danger whatsoever to well-built structures. On the other hand, Regions 1 and 2 do have a potential for moderate shocks. Of these two, Region 1 appears to have the highest seismic risk because it has had the largest number of shocks within or adjacent to its boundaries. In addition, faults that cut late Tertiary or Quaternary rocks in Region 1 appear to be geologically younger than those in Region 2.

The strongest earthquakes in a 100-year period in Regions 1 and 2 are estimated to be of magnitudes 6 and 5.5, respectively. Shocks of this magnitude are considered moderate and will not damage well-built structures unless they occur beneath or very near these structures. In the latter case, damage is generally minor to properly designed power distribution equipment; e.g., transmission lines and substations (Steinbrugge, et al. 1970; San Fernando, California Earthquake of February 9, 1971).

3.8.6 ACCESSIBILITY

The accessibility discussion below on air service, highways, and roads complements the presentation given in Section 4.8.2.10 of this Report.

RAILROAD

The existing Reeves Station has a railroad spur served by the Atchison, Topeka & Santa Fe line that serves Albuquerque. Amtrak service is also available in Albuquerque.

AIR SERVICE

The largest and most active airport in the state is Albuquerque International. In 1969, the FAA reported that it ranked 47th in the United States in terms of volume of passengers. Also, the airport ranked 22nd in operations of civilian and military aircraft. In the 1972 State Airport System Plan, the north-south runway was listed as 8993-feet in length with a 1000-foot overrun. This length is sufficient to land almost any commercial aircraft. This airport is within 10 miles of the Reeves Station.

HIGHWAYS AND ROADS

Extensive improvement and expansion of transportation networks are planned for northwest Albuquerque. Within the vicinity of Reeves Station, the Frontage Road will be improved, running in a north to south flow west of I-25, and a south to north flow east of I-25. An I-25 interchange will be constructed at Los Angeles Boulevard. A major improvement will be the construction of a North Valley River Crossing which will follow the alignment of either Montano Road, Los Angeles Boulevard (El Pueblo Road) or Richfield Avenue. At the present time, Montano Road is the favored alignment. If Montano is not feasible, Los Angeles Boulevard is the likely alternative. All of these improvements to the circulation system will increase the opportunities for large-scale development in the early to mid-1980s for this area through increased accessibility and visibility of the area.

AVAILABILITY OF CONSTRUCTION MATERIALS

Based on experience on construction projects in New Mexico, no difficulty is foreseen in obtaining general materials for construction purposes of consumable supplies from local distributors or suppliers. It is most likely that local suppliers will be able to furnish most of the construction equipment such as long-boom cranes, compressors, compaction equipment, and other special equipment and materials required for the project on a rental or purchase basis. Suppliers of most bulk consumables such as fuel, industrial gases, and concrete supplies will usually establish satellite depots for their products in or near the project site so that adequate supplies will be available at all times. Due to the proximity of the project site to Albuquerque, supply sources are deemed readily available with a minimum of hauling distances.

3.8.7 AREA (LAND AVAILABILITY)

A search has been conducted as to the availability of lands immediately adjacent to the Reeves Station and an effort to determine the approximate values of these lands has also been completed.

The required additional rectangular area of approximately 120 acres adjacent to the Reeves Station appears to be readily available.

Options to use the land for the Solar Hybrid Program are under consideration.

3.8.8 ZONING AND LAND USE

The solar hybrid facility will require 120 acres of additional land and would preclude use of this acreage for other purposes.

This site is located in an area of rapid urban development activity. The Metropolitan Areas and Urbans Centers Plan of the City's Comprehensive Plan classifies the area of the proposed Reeves site as established urban land. Established urban land is land suited for development as there exists financing and public services which will permit higher densities.

The Reeves site is bounded by two established industrial parks, Academy Industrial Park to the south and Loop Industrial Park north of Los Angeles Boulevard. The area between these two industrial parks is vacant land with the exception of the heavy industry activity of PNM's Reeves Station and American Gypsum, both located south of Los Angeles Boulevard. The other principal land use in the area is the Coronado Mobile Home Park (Los Angeles and I-25). To the west of Reeves Station, between the AMAFCA North Diversion Channel and North Edith Boulevard, the land is classified as developing urban which is land that has not been plotted extensively and is presently acceptable for low-level urban development. Albuquerque Gravel Products occupies most of this land. Small portions of land adjacent to Edith Boulevard are designated as semi-urban and rural, with low density residential development.

Most of the projected industrialization in this area will be related to Loop Industrial Park and a speculative and yet to be designed industrial community east and south of Reeves Station. Development of a solar hybrid repowering facility is considered compatible with future activities in this area.

3.8.9 SOILS INVESTIGATION

The soil types described in the vicinity of the Reeves Station, north of Albuquerque, are as follows:

- EmB — Embudo gravelly fine sandy loam
- WeB — Wink fine sandy loam

This description is quite general and was used in the past by the Public Roads Administration and Highway Research Board, and used for highways, airfields and dams. Further information is presented in Section 4.8.2.5 of this Report.

During the design of the proposed structures, an appropriate foundation investigation program will be performed, developing this portion of the design criteria for the project. For the purpose of this study, assumptions were made that will be confirmed prior to the design of the project.

It is assumed that the EmB type soils are transported or alluvial soils overlying the WeB type soils of undefined thickness. The drainage of the area is to the west toward the Rio Grande. The descending-in-elevation contours and drainage paths from east to west also suggest this condition. Accordingly, for the purpose of this study, the EmB, or gravelly fine sandy loam, is assumed to be the foundation materials for the proposed structures.

The term "loam," no longer used in geotechnical and foundation engineering, suggests a mixture of sand silt and clay and, for the purpose of this study, the following engineering properties are assumed:

SOLAR HYBRID REPOWERING STUDY — REEVES STATION

- Allowable bearing capacity of compacted material: 1 to 2 tons per S.F.

● Dry unit weight:	80 to 100-lb/pcf
● Optimum moisture:	22 to 30 percent
● Frost action:	Susceptible
● Compaction required:	100% Std. Proctor ASTM 698
● Compaction methods:	Tamping or Rubber Tire Roller
● Drainage characteristics:	Relatively impervious characteristics
● Shrinkage and expansion characteristics:	High Susceptibility
● Value as roadway:	Poor, granular base and sub-base coarse materials probably required

Current engineering practice dictates that for the design of any structures sensitive to settlement and loading conditions, appropriate foundation investigations and analysis must be performed as part of the design. The investigation program designed for each project is usually performed by firms knowledgeable in the engineering properties of the foundation materials and experience in construction in the immediate vicinity of the proposed project. The results of this foundation investigation will provide the designer with basic criteria for site preparation, foundation design, construction criteria and related engineering tasks.

For the purpose of this study, assumptions were made with the conclusion that a safe and reliable foundation system can be designed for the structures associated with the proposed project, based on the results of an appropriate foundation investigation program.

4.0 CONCEPTUAL DESIGN

Reeves Unit No. 2, selected under the preceding task, was established as the potential candidate plant for solar hybrid repowering. This plant was investigated under this conceptual design and cost estimate task to provide a reasonably definitive design and to identify the required modifications. The existing land situation, as well as the particular environmental aspects of Reeves Unit No. 2 were investigated. Upon complete definition, a cost estimate was prepared that is related to the present configuration of Reeves Unit No. 2.

4.1 EXISTING MECHANICAL AND ELECTRICAL PLANT FACILITIES

The selected plant to be used for the subject solar repowering conceptual design is the Public Service Company of New Mexico Reeves Station Unit No. 2 located in Albuquerque, New Mexico at an elevation of 5130-feet. This unit meets the criteria for a solar repowered plant developed during the "Market Survey and Cost Benefit Analysis," Task 1100.

These criteria are as follows:

- Plant Characteristics
 - Non-reheat steam turbine
 - 10 to 50 MWe output
 - 850 to 1250 psi/900° to 950°F turbine throttle condition
- Historic Plant Data
 - Year built: 1950 thru 1960
 - Good unit condition
 - Intermediate/peak current use
 - Rural location
 - Estimated retirement before the year 2000

Table 4.1-1 contains recent Reeves Unit No. 2 test data that verify that this unit meets the established repowering design criteria.

The turbine/generator was manufactured by Westinghouse and is in good condition. Modifications have already been performed on the turbine to increase its life based on Westinghouse recommendations. These modifications are:

- Last two rows of blading replaced in 1977 and stainless steel liners installed in L.P. turbine
- Partial rotor modification for stress relieving purposes in 1965
- Two segments of nozzle blocks replaced
- A completely modified rotor is scheduled for completion by the fall of 1979
- Borescope of the turbine rotor

Westinghouse has estimated that when these modifications are completed, load changes of 10 MW in 20 minutes should produce 8×10^5 cycles to crack formation. This assumes throttle pressure and temperature are constant, and that rotor temperature drops 55°F for each cycle. For a boiler temperature drop of 200°F during load change, and a rotor temperature drop of 200°F, the cycles to crack are estimated to be 3.5×10^4 .

These estimates of turbine cycling effects show that the as-modified Reeves Unit No. 2 turbine will be well suited for the cyclic operations due to solar repowering. The boiler is also well suited for cyclic operation as determined by information from Babcock and Wilcox, the manufacturer.

The boiler and fuel cycle is being studied for modernization from gas/oil operation to oil-only operation due to the anticipated future scarcity of natural gas. As discussed in Section 4.2.4.1 of this Report, modifications to the boiler and fuel oil supply, and control systems would be required for solar repowering of this unit.

The boiler make-up water treating system at the Reeves Station consists of a demineralizer, water softening equipment, and a boiler makeup evaporator system

TABLE 4.1-1. REEVES STATION UNIT NO. 2 PERFORMANCE DATA

Turbine Generator:

Manufacturer	Westinghouse
Turbine Rated Capacity, kW	44,000
Turbine Actual Capacity, kW	49,593
Turbine Type	Tandem-Compound Non-reheat
Throttle Steam Pressure, psia	1,250
Throttle Steam Temperature, °F	950
Speed, rpm	3,600
Exhaust Pressure, in HgA	1.5
Generator Rating, kVA/p.f.	47,058/0.85

Boiler:

Manufacturer	Babcock and Wilcox
Type	Natural Circulation, Pressurized, Drum-type
Steam Capacity, lb/hr	467,500
Steam Pressure, psia	1,380
Steam Temperature, °F	950
Combustion Fuel	Gas/Oil
Efficiency, %	88.24 (Gas)
Maximum Gas Consumption, cu-ft/hr	539,500
Maximum Oil Consumption, gal/hr	3,571

Heat Rate:

Unit-Gross (Gas), Btu/kW-hr	10,851
Unit-Net (Gas), Btu/kW-hr	11,431
Gross Unit Efficiency (including boiler), %	31.46
Net Unit Efficiency (including boiler and Auxiliary Power)	29.86

using turbine extraction steam as the heat source. As will be discussed further in the Water Treatment section of this Report, the present evaporator system is considered unsatisfactory to supply makeup water of the quality required for the solar receiver. Additional water treatment equipment is therefore recommended.

In general the mechanical equipment at the Reeves Station Unit No. 2 is in good condition and will meet the criteria as defined for solar repowering.

The Reeves Station Unit No. 2 electrical system consists of the turbine generator (described previously), the 55,000 kVA main transformer 2A, and a 3750 kVA unit auxiliary transformer 2A. The unit auxiliary transformer secondary feeds the 2.4 kV switchgear 2A. The 2.4 kV switchgear feeds the Unit 2 large motor drives and a 480V load center via the 1000 KVA auxiliary transformer 2A. The load center feeds three motor control centers and provides a tie to Units 1 and 3 load centers. Units 1, 2, and 3 switchgear are all tied into a common 5000/6250 KVA, OA/FA start-up transformer 2A. A 175 kW emergency diesel generator serves the essential auxiliaries, of all three units.

The Conceptual Design Study for Solar Repowering Reeves Station Unit No. 2 reveals no major barriers that would impede detailed design and ultimately construction. Given a normal anticipation of expected problems associated with a retrofit and/or upgrading project, the technical aspects of solar repowering of Reeves Station appear to be relatively straightforward.

Reasonable approaches have been identified as possible solutions for major design problems. Areas needing extended future detailed design investigation are also pointed out.

4.2 MECHANICAL DESIGN

This section describes the mechanical design of the subject solar energy system and the major interfaces required for the solar repowering of the Reeves Unit No. 2 Station. The conceptual design consists of the integration of a solar collector field and the solar receiver, which is a once-through-type boiler located on top of a 423-foot tower with an existing oil-fired plant of a name-plate rating of 44 MWe.

The solar system consists of approximately 4100 solar collectors (heliostats), each with a reflective area of 38 m^2 , located on an available land area just south of the main plant facility (see Figure 3.5-2). The conceptual mechanical design is based on a total of 4289 collectors, which was determined by the Sandia Laboratories, Livermore, using the MIRVAL computer program based on an insolation value of 950 W/m^2 . Further work on the collector field, which includes the addition of an access road and the resolution of a heliostat interference problem, has reduced the number of heliostats to 4086. The system design and performance changes will be accounted for during the detail design phase of the Project. An external central receiver is located on the top of a concrete tower in the center of this field. The design of the collectors and the solar receiver is based on the work and preliminary design of the 10 MWe pilot plant solar thermal receiver system being designed for Barstow, California. A basic design criterion of this conceptual design was to use the collectors as designed by McDonnell Douglas and the receiver as designed by Rocketdyne Corporation for the Barstow Pilot Plant. These solar system components will be described in greater detail in later sections of this Report.

The design point for this conceptual design was selected as 2:00 p.m. winter solstice (insolation - 950 W/m^2) and is intended to provide at least a total solar electrical output of 25 MWe gross. The solar collector field and the receiver sizes were designed to meet this requirement. System component sizes were based on the summer solstice condition at noon, which could produce approximately 39 MWe gross electrical output. The summer solstice design point was used to size all of the system components and to establish steam and feedwater flow rates, pressures and temperatures.

4.2.1 SOLAR SYSTEM DESIGN

This subsection describes the overall solar system in terms of the major components and how they interface with one another. The major components are the receiver, the collector subsystem, the feedwater heaters, the feed pumps, the condensate hotwell pumps, and the associated piping.

4.2.1.1 SYSTEM DESCRIPTION AND MAJOR INTERFACES

To integrate the solar system with the existing Reeves Unit No. 2 oil-fired plant, flow diagrams were obtained to identify potential interface locations and also to define existing mechanical and control systems. The existing flow diagrams, together with new repowering design flow diagrams, schematically show the solar system equipment that will be added to, and interfaced with, the existing Reeves station equipment. The modifications, new equipment, and interfaces are shown on Drawing L22929, Sheets P3-1 through P3-7 (see Appendix).

The following design approach was used during the conceptual design for solar repowering:

- Reeves Station Unit No. 2 was selected for repowering
- The solar system design was to be based on the 10 MWe solar central receiver preliminary design for Barstow, California
- A design goal of 50 percent solar repowering (25 MWe) at winter solstice was established
- A collector field layout as generated by the DOE/Sandia Livermore Laboratories, California, from their MIRVAL computer program was used
- Definitions of possible plant operating modes were used as a design base
- Preliminary EPGS general arrangement drawings were to be prepared to define the integration of the new solar system equipment with existing plant equipment
- Computer modeling of the basic fossil/solar cycles was to be prepared to provide heat balance data for system performance and equipment sizing
- Changes to the existing plant were to be minimized
- Water treatment system design was to be based on once-through boiler requirements

Table 4.2-1 includes the design criteria used in the mechanical design of the repowered systems and the component and equipment specifications. The collector field is designed to produce 25 MWe at 2:00 p.m. winter solstice using 950 W/m^2 solar insolation. During the summer months, considerably more power will be generated. Solar insolation was increased to 1045 W/m^2 based on preliminary insolation data in the Albuquerque area. In order not to defocus heliostats during months of higher thermal power and to be able to take advantage of all available solar power, the system was designed to the modified insolation of 1045 W/m^2 as shown in Table 4.2-1.

TABLE 4.2-1. EQUIPMENT DESIGN CRITERIA

Environmental:

Ambient Pressure	12.09 psia
Ambient Temperature	70°F Daytime Annual/12°F Minimum
Wind Speed	10 MPH Daytime Annual Average

Solar:

Solar Repowering	50%
Gross Generation	50 MWe
Number of Heliostats	4289
Insolation	1045 W/m^2

Design Receiver Incident Heat:

Annual Average	105.5 MWth
Summer Solstice Noon (Max)	125.4 MWth

Gross Turbine Cycle Efficiency:

At 50 MWe	36.57%
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Figures 4.2-1 and 4.2-2 show system losses for the 2:00 p.m. winter solstice and the noon summer solstice design conditions, respectively. These figures show the system power flow, including losses, from the incident thermal energy on the collector field through the net electric power generating by the solar portion of the plant. Figure 4.2-1 shows that the design goal of 25 MWe will be met or exceeded for the winter solstice design point.

Figure 4.2-1. System Power Flow (2 p.m. Winter Solstice)

Figure 4.2-2. System Power Flow (Noon, Summer Solstice)

To establish a basis for system design, the operating modes for the Reeves Stati Unit No. 2 with solar repowering were investigated and are shown in Figures 4.2-3 and 4.2-4. Figure 4.2-3 depicts the operating modes of the solar-only operating condition where the fossil boiler can be either in a cold or a hot standby condition. Consideration was given to night turbine generator shutdown with capability for a morning startup, solar insolation transients, and night operation on fossil fuels.

The hot stand-by condition is the situation during which the fossil boiler is maintained at the operating pressure and the corresponding saturated steam temperature. The outlet of the superheater is shut off, thus allowing no steam to be supplied to the turbine. During some solar insolation transients, electrical output could be maintained by anticipating the transient and bringing the fossil boiler on line from a hot standby condition, simultaneously shutting down the solar system. This operation could not be accomplished if the fossil boiler was in the cold condition, since it would take approximately six hours to bring the boiler up to temperature.

Figure 4.2-4 shows the solar hybrid repowering mode of operation where the solar system and the fossil system are each providing a percentage of the total plant output. This percentage will be controlled by the plant operators in order to maximize the contribution of the solar system output, with the fossil system providing any deficiency of power required to maintain the plant load.

Solar/Fossil Hybrid operation will provide day and night continuous operation with constant electric power output. Electric power fluctuations due to solar insolation transients may be eliminated by increasing the fossil boiler power level to make up for any reduction in solar power. The question of solar insolation transients will be discussed in further detail in Section 4.2.4.2 of this Report.

Figure 4.2-5 is a compilation of the various operating modes which may be expected, together with the effects on the system and controls and the system modifications which will be required. Figure 4.2-5 depicts potential operating

Figure 4.2-3. Operating Modes, Reeves Station Unit No. 2

Figure 4.2-4. Operating Modes--Reeves Station Unit No. 2

OPERATING MODE	UNMODIFIED SYSTEM EFFECTS:	EFFECTS ON EXISTING CONTROL SYSTEM	CONTROL SYSTEM MODIFICATIONS & ADDITIONS	COMMENTS
1. SOLAR ONLY, NOT INCLUDING INTERMITTENT CLOUDS. FOSSIL BOILER SHUTDOWN, BASE LOADED.	<ul style="list-style-type: none"> - VARIABLE TURBINE THROTTLE PRESSURE DUE TO FLOW CHANGES THROUGH RECIPIENT CAUSED BY SOLAR INSOLATION CHANGES. - VARIABLE POWER GENERATION DUE TO AVAILABLE TURBINE POWER. - VARYING FEEDWATER TEMPS. - DEAERATOR PRESSURES WOULD VARY IN PROPORTION TO EXTRACTION PRESSURE. - POSSIBLE LOW NPSH ON RECEIVER PUMP DUE TO CHANGES IN DEAERATOR PRESSURE. 	<ul style="list-style-type: none"> - PRESSURE TRANSMITTER TO COMBUSTION CONTROL SYSTEM INOPERABLE. - POSSIBLE TURBINE GOVERNOR CONTROL PROBLEMS. 	<ul style="list-style-type: none"> - CONTROL OF TURBINE THROTTLE PRESSURE BY MODIFICATIONS TO THE THROTTLE VALVES AND TURBINE/GEN. GOVERNOR. - AUTO. ISOLATION OF THE FOSSIL BOILER SECTION FROM BFP'S ON. 	<ul style="list-style-type: none"> - THROTTLE PRESSURE MUST BE CONTROLLED OR ELSE TURBINE EXTRACTION FLOWS WILL VARY IN PROPORTION TO THROTTLE PRESSURE RESULTING IN VARYING FEEDWATER TEMPERATURES AND A TOTALLY UNCONTROLLED SYSTEM.
2. SOLAR/FOSSIL FUEL HYBRID OPERATION ALL TYPES OF CLOUDS, BASE LOADED OR VARIABLE DISPATCH.	<ul style="list-style-type: none"> - TURBINE THROTTLE PRESSURE CONTROLLED BY FOSSIL BOILER COMBUSTION CONTROL SYSTEM (EXISTING). - IF FOSSIL BOILER CANNOT KEEP UP WITH SOLAR TRANSIENTS, THROTTLE PRESSURE WILL VARY WITH SOLAR INSOLATION. - DURING PERIODS OF HIGH INSOLATION (SUMMER) COLLECTOR FIELD CAN DELIVER 25 MW (50% REPOWERING). FOSSIL BOILER IS 50% LOAD AND WILL NOT BE IN AUTO MODE, BUT WILL BE HAND OPERATED, THIS IS UNSATISFACTORY. - VARYING FEEDWATER TEMPS. - VARYING DEAERATOR PRESSURES. - POSSIBLE LOW NPSH ON RECEIVER PUMP. - VARIABLE POWER GENERATION. 	<ul style="list-style-type: none"> - FOSSIL BOILER COMBUSTION CONTROL SYSTEM MAY NOT MAINTAIN CONSTANT THROTTLE PRESSURE, DEPENDING ON SOLAR TRANSIENT. - POSSIBLE GOVERNOR CONTROL PROBLEM. - EFFECTS ON FOSSIL BOILER DRUM LEVEL CONTROL SYSTEM DUE TO VARYING THROTTLE PRESSURE AND DEAERATOR PRESSURE. - EFFECT ON COMBUSTION CONTROL SYSTEM DUE TO VARYING FEEDWATER TEMPERATURE. - MINIMUM AUTO. BOILER CONTROL POINT IS 50% LOAD. HAND OPERATION < 50% LOAD. 	<ul style="list-style-type: none"> - CONTROL TURBINE THROTTLE PRESSURE BY MODS. TO THROTTLE VALVES AND GOVERNOR. - MODIFY COMBUSTION CONTROL SYSTEM FOR AUTO. OPERATION OF BOILER DOWN TO 20%. 	<ul style="list-style-type: none"> - AUTO. OPERATION OF BOILER COMBUSTION CONTROL DOWN TO 20% IS NECESSARY FOR SAFE UNIT OPERATION.

Figure 4.2-5. Control System Functional Analysis (Sheet 1 of 3)

OPERATING MODE	UNMODIFIED SYSTEM EFFECTS	EFFECTS ON EXISTING CONTROL SYSTEM	CONTROL SYSTEM MODIFICATIONS & ADDITIONS	COMMENTS
3. SOLAR ONLY (COLD OR HOT RECEIVER) TURBINE START (COLD OR HOT TURBINE) INTERMITTENT CLOUDS EXCLUDED.	<ul style="list-style-type: none"> UNCONTROLLED SOLAR STEAM GENERATION. OVER TEMPERATURE OF TURBINE COMPONENTS DURING START UP. POSSIBLE CONTAMINATION OF SOLAR BOILER DUE TO FEEDWATER IMPURITIES AFTER EXTENDED SHUTDOWN. POSSIBLE INTERACTION WITH FOSSIL BOILER BFP SECTION. 	<ul style="list-style-type: none"> PRESSURE TRANSMITTER TO FOSSIL COMBUSTION CONTROL SYSTEM INOPERABLE. POSSIBLE EFFECTS ON DRUM LEVEL CONTROL SYSTEM. 	<ul style="list-style-type: none"> SOLAR STEAM TEMP. ATTENUATOR MUST BE DESIGNED TO CONTROL STEAM TEMP. FROM 1000°F TO 950°F NORMAL OPERATION DOWN TO ABOUT 700°F FOR COLD TURBINE START LIMITATIONS. SELECTIVE DEFOCUSING OF HELIOSTATS TO LIMIT SOLAR RECEIVER STEAM OUTPUT. POSSIBLE REQUIREMENT FOR AUTOMATIC TURBINE START UP. AUTOMATIC ISOLATION OF THE FOSSIL BOILER SECTION FROM BFP'S. 	<ul style="list-style-type: none"> AFTER EXTENDED SHUTDOWN OF SOLAR BOILER, SOLAR ONLY START UP NOT RECOMMENDED, REQUIRES FLUSH PROCEDURES. RECEIVER STEAM PIPING WILL TAKE EXTENSIVE TIME FOR WARM-UP AND SHOULD BE DONE BY FOSSIL BOILER STEAM OR SHOULD BE KEPT WARM DURING EXTENDED RECEIVER DOWN TIME BY FOSSIL STEAM.
4. FOSSIL BOILER (COLD OR HOT) ONLY TURBINE START (COLD OR HOT TURBINE).	<ul style="list-style-type: none"> NORMAL START UP. 	<ul style="list-style-type: none"> NONE. 	<ul style="list-style-type: none"> SOLAR PORTION OF SYSTEM MUST BE ISOLATED FROM TURBINE/ FOSSIL BOILER SYSTEM. 	<ul style="list-style-type: none"> NORMAL TURBINE START.
5. SIMULTANEOUS SOLAR/FOSSIL BOILER TURBINE START (HOT OR COLD).	<ul style="list-style-type: none"> UNCONTROLLED SOLAR STEAM GENERATION. POSSIBLE OVER TEMPERATURE OF TURBINE COMPONENTS DURING START UP. 	<ul style="list-style-type: none"> PRESSURE TRANSMITTER TO FOSSIL COMBUSTION CONTROL SYSTEM WILL CONTROL TO TURBINE INLET PRESSURE. NO AUTOMATIC OPERATION OF FOSSIL BOILER < 50% LOAD. 	<ul style="list-style-type: none"> SOLAR STEAM TEMP. ATTENUATOR MUST BE DESIGNED TO CONTROL STEAM TEMP. FROM 1000°F TO 950°F. NORMAL OPERATION DOWN TO 700°F. FOR COLD TURBINE START LIMITATIONS. SELECTIVE DEFOCUSING OF HELIOSTATS TO LIMIT SOLAR RECEIVER STEAM OUTPUT. POSSIBLE REQUIREMENT FOR AUTOMATIC TURBINE START UP. BOILER ON AUTOMATIC AT < 50% LOAD. 	

Figure 4.2-5. Control System Functional Analysis (Sheet 2 of 3)

OPERATING MODE	UNMODIFIED SYSTEM EFFECTS	EFFECTS ON EXISTING CONTROL SYSTEM	CONTROL SYSTEM MODIFICATIONS & ADDITIONS	COMMENTS
6. NORMAL/EMERGENCY TURBINE SHUTDOWN, SOLAR ONLY OPERATION.	<ul style="list-style-type: none"> - UNCONTROLLED SOLAR STEAM TEMP. DURING SHUTDOWN. - POSSIBLE EFFECTS ON FOSSIL BOILER PORTION. 	<ul style="list-style-type: none"> - PRESSURE TRANSMITTER TO FOSSIL COMBUSTION CONTROL SYSTEM INOPERABLE. - FOSSIL DRUM LEVEL CONTROL EFFECTS. 	<ul style="list-style-type: none"> - SOLAR STEAM ATTEMPERATOR MUST BE DESIGNED TO CONTROL STEAM TEMP. FROM 1000°F TO 950°F NORMAL OPERATION DOWN TO 700°F FOR TURBINE SHUTDOWN LIMITATIONS. - SELECTIVE DEFOCUSING OF HELIOSTATS TO LIMIT SOLAR RECEIVER STEAM OUTPUT. - AUTO ISOLATION OF FOSSIL BOILER PORTION. 	
7. NORMAL/EMERGENCY TURBINE SHUTDOWN SOLAR/FOSSIL BOILER HYBRID OPERATION.	<ul style="list-style-type: none"> - UNCONTROLLED SOLAR STEAM TEMP. DURING SHUTDOWN 	<ul style="list-style-type: none"> - COMBUSTION CONTROL SYSTEM CONTROL OF THROTTLE PRESSURE. - NO AUTOMATIC OPERATION OF FOSSIL BOILER < 50% LOAD. 	<ul style="list-style-type: none"> - SOLAR STEAM ATTEMPERATOR DESIGNED TO CONTROL TEMP. FOR TURBINE SHUTDOWN LIMITATION. - SELECTIVE DEFOCUSING OF HELIOSTATS. - FOSSIL BOILER DESIGNED FOR AUTOMATIC OPERATION < 50% LOAD. 	
8. TURBINE OPERATION, FOSSIL BOILER OPERATION, SOLAR BOILER START UP.	<ul style="list-style-type: none"> - POSSIBLE ADVERSE INTERACTION OF SOLAR BOILER START UP STEAM WITH OPERABLE FOSSIL BOILER SYSTEM. 	<ul style="list-style-type: none"> - NO AUTOMATIC OPERATION OF FOSSIL BOILER < 50% LOAD. 	<ul style="list-style-type: none"> - FOSSIL BOILER DESIGNED FOR AUTOMATIC < 50% LOAD. - AUTOMATIC ISOLATION CAPABILITY OF SOLAR PORTION. 	
9. TURBINE OPERATION, SOLAR BOILER ONLY OPERATION, FOSSIL BOILER START UP.	<ul style="list-style-type: none"> - SOLAR PORTION EFFECTS ON IN-OPERATIVE FOSSIL BOILER SYSTEM. 	<ul style="list-style-type: none"> - EFFECTS ON DRUM LEVEL CONTROL SYSTEM. 	<ul style="list-style-type: none"> - AUTOMATIC ISOLATION OF FOSSIL BOILER PORTION. - FOSSIL BOILER COMBUSTION CONTROL DESIGNED FOR AUTOMATIC OPERATION < 50% LOAD. - MODIFY TURBINE CONTROL FOR CONSTANT THROTTLE PRESSURE OPERATION. 	

Figure 4.2-5. Control System Functional Analysis (Sheet 3 of 3)

problem areas to be expended from during the interfacing of the existing system and the solar repowered additions and also gives possible solutions.

Figure 4.2-6 shows a simplified schematic of the solar repowering system with the solar system operating in parallel with the fossil boiler feedwater system. Additional details of this schematic are shown on P and I Diagrams P3-1 and P3-6. The condensate system is not shown in Figure 4.2-6 since it is a common system. The condensate system is shown in detail on P and I Diagram P3-1. The solar receiver feed pumps take feedwater in parallel from the deaerator with the boiler feed pump for the fossil boiler system. This feedwater is raised in pressure to 2417 psia and passes through the new No. 7 and No. 6 high pressure feedwater heaters. These two feedwater heaters operate in parallel with the No. 1 and No. 2 heaters in the existing fossil boiler system and receive extraction steam from the No. 1 and No. 2 high pressure extraction points on the turbine. The new feedwater heaters are more fully described in the Feedwater Specification Section of this Report.

Drains from the No. 6 heater are cascaded to the No. 7 heater and then to the deaerator. Emergency drains for these two heaters will be piped to the protection requirements as defined by the ASME. At the system design point, feedwater from the No. 6 heater is at a temperature of 437°F. These feedwater heaters are to be located on the operating floor in the Main Turbine Building in the general area of the evaporators which will be removed due to the addition of a new demineralization system.

Receiver feedwater piping is to be routed in an overhead rack approximately 3200 feet long. The feedwater flows through the receiver preheater panels, through the temperature control valves and enters the boiler superheat panels. It is our understanding that the steam temperature from the solar receiver can vary as much as plus or minus 50°F; therefore, a trim on temperature will be made in a steam attemperator to be located in the Turbine Building. The receiver steam piping interfaces with the fossil boiler steam piping in the Turbine Building and is shown on Drawing L-22929, Sheet No. P4-4.

Figure 4.2-6. . Reeves Station Unit No. 2 Schematic

The receiver feed pumps will be two 100 percent capacity pumps and are described more fully in the Feed Pump Specification Section. The receiver feed pumps were designed to be operated in parallel with the existing boiler feed pumps in order to minimize control and installation problems. The control systems for the solar receiver and combustion control system of the fossil boiler must operate in parallel with the solar control system. The total head developed across the pump is based on the pressure losses of the feedwater piping, heaters No. 6 and No. 7, receiver pressure losses, receiver elevation, steam piping losses and throttle steam pressure requirements. Two 100 percent capacity pumps are recommended on the basis of system reliability.

The receiver feed pumps are to be located in the new Solar System Equipment Building which is to be located on the west side of the plant at the junction of Units 1 and 2. This building will be constructed adjacent to and connected with the main Turbine Building.

The receiver is described in detail in the Receiver Specification of this Report. Briefly, the receiver consists of preheat panels and superheat panels. The number of panels will be determined during detailed engineering design. A temperature control valve is located between each of the preheat and superheat panels to control the receiver outlet steam temperature to 1000°F. During hybrid operation, solar insolation transients could result in a reduction in solar electrical generation. The fossil boiler may be brought up in load to minimize power fluctuation. A solar insolation transient during solar only operation will result in a drop in solar electrical power generation.

The flash tank system, to be located just below the receiver panels, will be used during start-up and shut-down operations of the receiver. Also, steam will be routed to the flash tank during periods of solar transients when the receiver output drops below 15 percent of maximum receiver load.

Start-up and shut-down operations are described in Section 4.2.4.3 of this Report. During conditions of low receiver steam pressure, temperature and flow, the discharge of the receiver will be routed to the flash tank through a pressure control valve (PCV-1-6). Depending on the steam conditions (water, saturated steam or

superheated steam), the flow to the flash tank will be expanded to a predetermined pressure as determined by another pressure control valve (PCV-2-6). The vapor and drains from the flash tank are routed to the condenser through piping to be located on the overhead pipe rack.

Figure 4.2-7 shows the estimated overall dimensions of the receiver that were based on a scaling of the 10 and 100 MWe pilot and commercial plants for Barstow. This figure also shows a tabulation of the estimated weights for the receiver.

Steam attemperature is used to modify the receiver outlet steam temperature to maintain the required turbine throttle temperature of 950°F. This involves spraying water from the receiver feedwater pump discharge into the receiver steam. The air operated valve at the attemperator will be specified so as to comply with turbine water damage prevention standards. If an upset condition occurs, the turbine water damage prevention system will signal the air operated valve to close, thus providing a positive shut off of attemperator water flow.

Additional water induction protection is provided by the moisture separator located at the discharge of the steam attemperator. Also five (5) drain pots, or drip legs, each with a level control valve, will be installed in the receiver steam piping at each low point of the thermal expansion loops as described in the Piping Design Section. Drains from the drain pots and from the moisture attemperator will be combined and routed to the condenser hotwell.

The major mechanical interfaces of the solar system to the existing fossil boiler system at Reeves repowered unit are as follows:

- The feedwater interface will be at the receiver feed pumps inlet and will be from the deaerator exit piping and in parallel with the boiler feed pump. This interface location is shown by note on Drawing L-22929, Sheet P4-6.
- Extraction steam interfacing will be as described previously from the No. 1 heater piping to the No. 6 heater and from the No. 2 extraction piping to the No. 7 heater. These interface locations are shown on Drawing L-22929, Sheet P4-6.
- Receiver steam piping will interface with the existing fossil boiler main steam line supplying the turbine. The routing is shown on Drawing L-22929, Sheet P4-4.

* MDAC PRELIM. DESIGN REPORT, VOL. 4, DOE SAN/1108 - 8/4, NOV. 1977

Figure 4.2-7. Receiver Weight Comparison

- Interfacing of the flash tank vent and drain lines is shown on Flow Sheets P3-1 and P3-6 and Drawings L-22929, Sheets P4-4 and P4-6.
- Condensate system interfaces with the condensate polisher are shown on Drawing L-22020, Sheet P4-2.

Control system interfaces between the solar system and the existing fossil boiler combustion control system are described in the Controls Section of this Report.

The system design described herein for the solar portion of the repowered Reeves Unit No. 2 has been optimized to provide the simplest most straightforward design to minimize the impact on existing plant equipment. The design is based on data from the central receiver 10 MWe pilot plant program for Barstow.

The remaining portions of this section describe in greater detail the major solar system components and the piping design and analysis arrived at for the steam and feedwater piping to and from the solar receiver.

4.2.1.2 RECEIVER DESCRIPTION

The design of the receiver for this solar repowering project is to be based upon the receiver used in the Barstow, California Pilot Plant. That receiver is a Rocketdyne once-through boiler, fabricated of Incoloy 800 tube materials. The Barstow design will be scaled-up to meet the capacity requirements of this Project.

Receiver design characteristics are contained in Table 4.2-2, and operating conditions are summarized in Table 4.2-3. Specific design issues to be included in this section are as follows:

Thermal Losses

Thermal losses from the Pilot Plant were used. Reflected insolation was calculated from solar absorptance measurements obtained during the Solar Research Experiment (SRE). Infrared radiation losses were calculated based on emissivity measurements obtained during the SRE. Convective losses were calculated by a fairly complex procedure, the details of which are discussed in Section 2.4.4.1. Thermal losses are summarized in Table 4.2-4.

TABLE 4.2-2. RECEIVER DESIGN CHARACTERISTICS

1	Total Weight of Receiver (estimated), kips	1450
2 (a)	Height (feet)	69
2 (b)	Diameter (feet)	39
3 (a)	Tube Boiler Material	Incoloy 800
4	ASME Code for Design	ASME Boiler and Pressure Vessel Code Section I
5 (a)	Absorptivity	0.95
5 (b)	Emissivity	0.89
6	Absorber Rated ΔP (includes TCV) (psi)	685

Sensitivity to Clouds and Other Heat Flux Disturbances

Each modular receiver panel, consisting of a preheat and superheat panel with interconnecting water flow/temperature control valve, is capable of approximately 6.7:1 flow turndown ratio. This design compensates for the power fluctuations caused by some types of clouds moving across part of the heliostat field without affecting the other panels. The approach in operations in the presence of passing clouds is discussed more fully in Section 4.2.4.2, but briefly is as follows: It is anticipated that dense, fast-moving cloud formations will be forecast and the fossil boiler load would be increased to smooth the system transients. For intermittent small clouds, the receiver will produce somewhat less than rated steam flow and power output would be curtailed accordingly. If the heat loads get sufficiently low due to the cloud cover such that receiver flow is less than 15 percent of maximum, then the receiver output would be routed to the receiver flash, tank, and the solar portion of the system would be shut down.

A review of predicted heat flux distribution for the receiver has been performed by MDAC and Rocketdyne. As a result of this review, the following conclusions were reached:

- Receiver cooling margin will be enhanced due to the increased available water/steam flow per unit of heated circumference for the repowered system over the Pilot Plant.
- A potential problem of thermal gradients around the circumference of the receiver may be experienced. The predicted data shows a maximum gradient of 48 percent between two panels where the Pilot

TABLE 4.2-3. RECEIVER OPERATING CHARACTERISTICS

1 (a)	Design Flow (lb/hr)	328,900
1 (b)	Minimum Flow (lb/hr)	49,300
Fluid States:		
2 (a)	Maximum Inlet Pressure (psig)	2,975
2 (b)	Design Inlet Pressure (psig)	2,138
2 (c)	Design Outlet Pressure (psig)	1,453
2 (d)	Maximum Inlet Temperature (°F)	450
2 (e)	Design Inlet Temperature (°F)	437
2 (f)	Maximum Outlet Temperature (°F)	1,050
2 (g)	Design Outlet Temperature (°F)	1,000
2 (h)	Minimum Outlet Temperature (°F)	950
3 (a)	Maximum Absorbed Heat Flux (MWt/m ²)	0.32
3 (b)	Average Absorbed Heat Flux (MWt/m ²)	0.14
4	Design Incident Power (MWt)	125.4
5	Absorber Efficiency (percent)	
5 (a)	At Maximum Insolation (noon summer solstice)	85.4
5 (b)	At Design Insolation (2:00 p.m. winter solstice)	84.3

TABLE 4.2-4. RECEIVER HEAT LOSSES

	<u>Noon Summer Solstice</u>	<u>2:00 p.m. Winter Solstice</u>
IR Radiation (MWth) }		
Convection (MWth) }	12.03	10.92
Reflected Insolation (MWth)	6.27	5.09
TOTAL (MWe)	18.30	16.01
Incident Energy	125.40	101.76
Percent Loss	14.6	15.7

Plant and commercial central receiver designs are limited to 20 to 25 percent. This issue will receive attention during the STTF panel test program.

Hydraulic Stability

It has been shown recently that intertube hydraulic instability could possibly exist, and a static instability problem could develop at flows below 20 percent of the rated steam conditions. Orifices installed at the boiler superheat tube inlets have been shown analytically, to be a fix to this problem by adding a dampening pressure drop to the system. Tests are scheduled for October 1978 at Sandia, Albuquerque, to determine if this problem exists and to verify its solution.

Receiver Thermal Fatigue Life

Recent analyses by Rocketdyne and two other independent contractors have shown that a receiver design based on the Barstow Pilot Plant design will have adequate thermal fatigue life for the Reeves Station Hybrid Repowering conceptual design.

Receiver Reflectivity

Reflectivity for the receiver surface is as follows:

<u>Wave Length (Microns)</u>	<u>Reflectivity (Percent)</u>
0.25	5
0.4	4.5
0.8	4
1.0	4
1.0	4
1.5	6
2.0	7
2.5	10

4.2.1.3 COLLECTOR SUBSYSTEM DESCRIPTION

The Reeves Station repowering collector design was based on the use of the MDAC collectors, drives and controls as proposed for the Barstow Pilot Plant. That design was modified to comply with the Reeves site conditions. Major changes included:

- Revising the size and layout of the collector field and number of heliostat units to conform to the physical characteristics of

the Reeves site. This revision was based on the design insolation at the Reeves site, the reflectivity of the heliostat mirrors, the absorptance of the receiver, and the general design plan of power required. The collector field design is described in Section 4.5.3.1.

- Integrating the collector control system into the Master Control System being proposed for the repowered Reeves Station
- Establishing the most effective foundation for each heliostat

The design operating environment is as follows:

- Design wind speeds (with gusts) are:

Operational Mode

- Sustained winds of 13.5 m/s (30 mph)
- Gusts with rms velocity of 18 m/s (40.3 mph)

Nonoperational Mode

- Sustained winds of 32 m/s (71.6 mph)
- Gusts with rms velocity of 44.7 m/s (100 mph)
- Temperature: -22°F (minimum) to 110°F (maximum)
- Track the sun at low insolation levels (0.3 kW/M^2)
- 30 year life
- Earthquake: (see Section 4.5)
- Precipitation:
 - Snow, average annual: 10 inches
 - Rain, average annual: 8 inches
 - Max. 24 hour rate: 1.92 inches

The safety requirements are:

- Meet OSHA, NFPA, ANSI, and Public Service Company of New Mexico requirements.
- Control reflected beam.
 - No unsafe reflected beam outside exclusion area.

- No unsafe reflected beam on structures or plant personnel
- Provide for automatic safe stowage in the event of failure

The operating requirements are functions of: (1) interfaces between the collector and the balance of the central receiver system; and (2) the operating modes.

The collector interfaces with the receiver through the reflected beams from the heliostats. The heliostats track the sun and direct the reflected beams so that the light falls on the receiver with a prescribed flux distribution. Spillage of light missing the receiver is minimized, consistent with overall system economics. The collector receives power from the distribution system to operate the electric motors and control system.

PRELIMINARY DESIGN COLLECTOR CONFIGURATION

The inverting heliostat configuration is 6.5 meters on a side with an actual reflective area of 38.03 m^2 . The structural support is a main torque tube with four cross beams. The drive unit incorporates separate azimuth and elevation drive rotary units. The cylindrical pedestal supports the drive unit through a bolted interface and is in turn attached to a reinforced concrete foundation. The control system comprises heliostat, field controllers and collector control computer using an open loop system.

The inverting orthogonal design has the adaptability of being stored face down, vertical, or face up. The choice depends upon safety, dust accumulation and cleaning, and heliostat wind loads. The face down position has the following advantages:

- Heliostat cannot reflect sunlight in a dangerous manner.
- Under light rain conditions, less dust adheres to mirror.
- Best under high winds with blowing sand or dust, unattended fields, and for extended periods of time.

Vertical stowage position has the following characteristics:

- Self-cleaning due to rain, heavy dew, and frost.

- Higher wind loads and potential danger of damage due to blowing sand.

Face-up stowage position has the following characteristics:

- Minimizes the transitional time from the operational position to the stowed position, and therefore the duration of exposure to wind loads during periods of rapidly rising winds.
- Minimizes the wind load duration to go from operational position to be used face-up in a rapidly rising wind.

It is recommended that vertical stowage be used (unless safety is critical) to minimize dust buildup.

The details of the heliostat components are discussed in the following subsections.

REFLECTOR

Each reflector panel is a flat structural sandwich. The front face is a 3.17 mm (1/8-inch) second surface mirror, and the back face is a 0.56 mm (0.022-inch) galvanized steel sheet. The faces are adhesively bonded to a 5.08 cm (2-inch) core, made from rigid extruded polystyrene foam (STYROFOAM) of 2 lbs per cubic foot density. Each of the six panels measures 2.16 m by 2.9 m (85 inches by 114 inches). The panel edge is protected from damage by a small extension of the core and is sealed by a polyurethane weatherseal compound. At the four attachment points, the loads are transferred to the cross beams by shallow, formed, circular steel cups. Collector mirror characteristics are shown in Table 4.2-5.

STRUCTURAL SUPPORT

The support structure consists of a main torque tube attached to the drive system and four channel cross beams. Each pair of cross beams supports a group of three reflector panels. The slot between these panel groups provides clearance for the central pedestal when the assembly is rotated to the face-down stowage position. Two drive attachment fittings are machined on the surfaces which mate with the drive and welded to the torque tube. Four ring flanges are also welded to the tube for attachment of cross beams.

TABLE 4.2-5. MIRROR REQUIREMENTS

Requirement	Required Value	Expected Value
Reflectivity	0.88	0.91
Specularity (% in 4 mr Cone)	0.99	0.99
Hail Capability:		
Any Orientation	19 mm (3/4-in.)	19 mm (3/4-in.)
Stowed	25 mm (1-in.)	25 mm (1-in.)
Flatness (Standard Deviation)	1.0 mr	1.0 mr
Durability	Units must survive Albuquerque, NM environment for 30 years without significant permanent degradation (1% reflectivity) and maintain structural integrity.	

DRIVE UNITS

Each heliostat incorporates a drive unit that produces appropriate reflector motions for solar tracking, emergency slewing, routine reflector positioning, and stowage. The drive unit consists of azimuth and elevator drive mechanisms. These drive mechanisms are composed of motors, drive trains, position feedback transducers, reflector support bearings, and structural housings. The azimuth and elevation drive trains are schematically identical, and each is essentially a motor with two stages of reduction, capable of producing the high-torque.

PEDESTAL/FOUNDATION

The pedestal is a thin-walled steel column, 50.8 cm (20 inches) in diameter and 2.74 m (108 inches) long, welded at the lower end to a tapered cone. The upper end has a 1.9 cm (0.75-inch) thick steel plate for attachment of the drive unit. Attachment of the concrete foundation is done by sliding the pedestal unit tapered cone down over a similar cone on the foundation. Foundation design is discussed in Section 4.5.2.

The collector operating modes which the various control systems must address are shown in Table 4.2-6.

TABLE 4.2-6. COLLECTOR OPERATING MODES

Mode	Field Controller/ Heliostat Controller	Collector Control Computer
Normal Track	Tracks to gimbal axis positions supplied by collector control computer	Provides gimbal axis positions based on solar ephemeris or tracking points for beam safety
Command Position	Tracks to gimbal axis positions supplied by collector control computer	Provides gimbal axis positions based on mode; e.g., stowage cleaning, maintenance, etc.
Local Control at Field Controller	Mobile test set controls heliostats through field controller	Locked out
Local Control at Heliostat Controller	Mobile test set controls heliostat through heliostat controller	Locked out

WEIGHTS

The weights of the collector system, less electronic components, are as follows:

	1b	1b
• Reflector panels	556	1,227
• Structural support	503	1,108
• Drive unit	304	670
• Pedestal	231	509
TOTAL (no foundation)	1,594	3,514
• Foundation	4,423	9,750
TOTAL (with foundation)	6,017	13,264

Collector Power Requirements

Collector field power requirements are shown in Table 4.2-7. The trenching and calibrating costs are minimized by:

- Primary and secondary feeders direct to the heliostat triac switching

- Data buses run from the central computer to groups of field controllers. Local data buses run among the field controllers in a group and to the associated heliostat controllers. Decentralization of the controller reduces the wiring costs substantially.

TABLE 4.2-7. COLLECTOR FIELD POWER REQUIREMENTS

Operating Condition	Power Required/ Heliostat	Power Required/ Field	Comments
Tracking	14 W	60 KW	
Emergency Slew	300 W	315 KW	Approximately 1050 heliostats will be slewed (in one axis) at a time, outer heliostats first.

4.2.1.4 RECEIVER FEEDWATER HEATERS

Two receiver feedwater heaters will be required to heat the feedwater from the receiver feed pumps to a design temperature of 437°F before it enters the receiver. The heaters will be arranged in series with each capable of accepting the entire output from the receiver feed pump. These heaters are of the shell and tube type with the high pressure feedwater being contained in the tubes. The units are heated with high pressure extraction steam from the turbine. No redundancy is thought necessary at this time, as this type of heat exchanger normally requires little repair or maintenance work. Bypasses around the heaters are included in the event that a heater is taken out of service for maintenance. For the heater condition out, receiver steam flow will be slightly reduced; also, the extraction flow from the turbine will be reduced. During the detailed design phase, the turbine manufacturer should be contacted for the effects on the turbine of a one or two high pressure heater out condition.

The heaters will be designed to conform to the ASME Boiler and Pressure Vessel Code, Section VIII, Division 1, and the Heat Exchanger Institute (HEI) Standards for Closed Feedwater Heaters.

The units will comply with the design conditions of service as specified in the Closed Feedwater Heater Design Summary Sheets, No. JD20.2-1, pages 1 and 2.

4.2.1.5 RECEIVER FEED PUMPS

Receiver feed pumps will be required to pump condensate from the existing deaerator through the new feedwater heaters to the Solar Receiver. Two pumps, each with capacity to supply 100 percent of the receiver demand, will be required. This redundancy ensures adequate flow through the receiver should one pump be shut down for maintenance or repairs. The pumps are equipped with variable speed drive to enable the Receiver Feed Pump Controller to regulate flow to the Solar Receiver, as required, during system start-up, shut-down, steady state operation and emergencies.

The pumps will also be equipped with warm-up orifices, minimum flow recirculation orifices, and recirculating flow control valves, as shown on Drawing L-22929, Sheet P3-6, and discharging to the deaerator. Pump minimum flow requirements should be established during detail design and during pump selection.

These pumps shall comply with the design conditions of service as specified in Table 4.2-8, Receiver Feed Pump Data Sheet.

4.2.1.6 CONDENSATE HOTWELL PUMPS

New condensate hotwell pumps will be required to pump the condensate from the Unit No. 2 Condenser Hotwell through the condensate polisher. These new pumps that will replace existing Hotwell Pumps 2A and 2B are required because the new condensate polisher will create an additional 70 psi pressure drop in the system, and the present pumps cannot maintain flow with this additional system pressure drop. Each pump will have the capacity to supply approximately 60 percent of the condensate design load when operating individually. The pumps are to be of the vertical turbine type, complete with 480 volt electric motor and accessories.

DIVISION USAGE						Stearns-Roger <small>INCORPORATED</small> ENGINEERING STANDARD		STANDARD NUMBER	
MM	P	PP	SH	FI	SP			JD 20.2-1	
APPROVALS						CLOSED FEEDWATER HEATER DESIGN CRITERIA SUMMARY SHEET		PAGE <u>1</u> OF <u>2</u>	
Des. Sect. <i>J. J. Munn</i>									
Sect. Supv. <i>H. J. Munn</i>									
Div. <i>W. J. Munn</i>									
1 Job No. C-20266 Customer: PNM									
2 Station: Reeves Unit No. 2 Heater No. 7 No. of Shells Req'd Per Unit									
3 Data Based on Heat Balance No. 5/11/78 S-R Reference Dwg.									
DESIGN REQUIREMENTS									
5 Heater Arrangement: ☒ Horizontal ☐ Vertical-Channel Up									
6 ☐ Vertical-Channel Down ☐ Horizontal-Condenser-Back									
7 Zone Requirements: ☒ Desup. ☒ Condensing ☒ Sub-Cooling ☒ Internal ☐ External									
8 Channel: ☒ Hemispherical ☐ Elliptical ☐ Bolted/Flanged ☐ Full Access									
9 Manway Cover Types: (Used with Hemispherical or Elliptical)									
10 ☐ Bolted/Flanged ☒ Pressure Seal ☐ Threaded Plug ☐ Breach Lock ☐ Davit Req'd									
11 Method of Removal: ☐ Bundle ☒ Shell - Rollers: ☐ Channel ☐ Shell									
12 Overall Length + Withdrawal: Ft. in - Centerline of Heater Above Floor: Ft.									
13 Tube Material: Monel (30/70, Cu/Ni) ASME SB-165									
14 Clad Tube Sheets: ☒ Yes ☐ No - Tube Attachment: ☒ Welded ☐ Expanded									
15 Insulation Clips: ☒ Yes ☐ No - Assembled: ☒ Yes ☐ No									
TUBESIDE OPERATING CONDITIONS									
17 Feedwater Flow Lb/Hr 326,657									
18 Feedwater Inlet Temperature °F 310									
19 Feedwater Inlet Enthalpy BTU/Lb 284									
20 Feedwater Outlet Temperature °F 368									
21 Feedwater Outlet Enthalpy Btu/Lb 342									
22 Operating Pressure PSIG 2,380									
23 Temperature Terminal Difference °F 3									
24 Maximum Possible Feedwater Flow Condition Lbs/HR									
TUBESIDE DESIGN CONDITIONS									
26 Design Pressure/Test Pressure PSIG 2975/4460									
27 Design Temperature °F 330									
28 Max. Velocity @ 60°F / @ Average Temperature Ft/Sec 8/8.9									
29 Allowable Tube Pressure Drop PSI 20									
SHELL SIDE OPERATING CONDITIONS									
32 Steam Flow Lb/Hr. 17,775									
33 Steam Inlet Temperature °F 518									
34 Steam Inlet Enthalpy Btu/Lb 1,281									
35 Shell Pressure PSIA 176									
36 Shell Saturated Temperature °F 571									
37 Drain Inlet Flow Lb/Hr 24,265									
38 Drain Inlet Temperature °F 577									
39 Drain Inlet Enthalpy Btu/Lb 350									
40 Drain Outlet Flow Lb/Hr 42,055									
41 Drain Outlet Temperature °F 320									
42 Drain Outlet Enthalpy Btu/Lb 291									
SHELL SIDE DESIGN CONDITIONS									
45 Shell Design Pressure / Test Pressure PSIG/VAC/PSIG 180 / 0 / ASME Co.									
46 Shell Design Temperature / Skirt Design °F 380 / 520									
47 Drains-Cooler Approach °F 10									
48									
49 TOTAL HEAT EXCHANGED Btu/Hr 18,990,000									
50 Remarks:									

Closed Feedwater Heat Design Summary Sheets (1 of 2)

DIVISION USAGE						Stearns-Roger <small>INCORPORATED</small> ENGINEERING STANDARD		STANDARD NUMBER	
MM	P	PP	SH	FI	SP			JD 20.2-1	
APPROVALS						CLOSED FEEDWATER HEATER DESIGN CRITERIA SUMMARY SHEET		PAGE <u>2</u> OF <u>2</u>	
Des. Sect. <u>J. J. Munn</u> Sect. Supv. <u>H. J. Munn</u> Div. <u>W. J. Munn</u>								ISSUED 12/12/73	
								REVISED	

1	Job No. C-20266 Customer: PNM		
2	Station: Reeves Unit No. 2 Heater No. 6		No. of Shells Req'd Per Unit <u>1</u>
3	Data Based on Heat Balance No. 5/11/78 S-R Reference Dwg.		
4	DESIGN REQUIREMENTS		
5	Heater Arrangement: ☒ Horizontal ☐ Vertical-Channel Up		
6	☐ Vertical-Channel Down ☐ Horizontal-Condenser-Neck		
7	Zone Requirements: ☒ Desup. ☒ Condensing ☒ Sub-Cooling ☒ Internal ☐ External		
8	Channel: ☒ Hemispherical ☐ Elliptical ☐ Bolted/Flanged ☐ Full Access		
9	Manway Cover Types: (Used with Hemispherical or Elliptical)		
10	☐ Bolted/Flanged ☒ Pressure Seal ☐ Threaded Plug ☐ Breach Lock ☐ Davit Req'd.		
11	Method of Removal: ☐ Bundle ☒ Shell - Rollers: ☐ Channel ☐ Shell		
12	Overall Length + Withdrawal: Ft. in - Centerline of Heater Above Floor: Ft. in		
13	Tube Material: Monel (30/70, Cu/Ni) ASME SB-165		
14	Clad Tube Sheets: ☒ Yes ☐ No - Tube Attachment: ☒ Welded ☐ Expanded		
15	Insulation Clips: ☒ Yes ☐ No - Assembled: ☒ Yes ☐ No		
16	TUBESIDE OPERATING CONDITIONS		
17	Feedwater Flow	Lb/Hr	326,667
18	Feedwater Inlet Temperature	°F	367
19	Feedwater Inlet Enthalpy	BTU/Lb	343
20	Feedwater Outlet Temperature	°F	437
21	Feedwater Outlet Enthalpy	Btu/Lb	417
22	Operating Pressure	PSIG	2,360
23	Temperature Terminal Difference	°F	0
24	Maximum Possible Feedwater Flow Condition	Lbs/HR	--
25	TUBESIDE DESIGN CONDITIONS		
26	Design Pressure/Test Pressure	PSIG	2975 / 4460
27	Design Temperature	°F	450
28	Max. Velocity @ 60°F / @ Average Temperature	Ft/Sec	8 / 9.3
29	Allowable Tube Pressure Drop	PSI	20
30			
31	SHELL SIDE OPERATING CONDITIONS		
32	Steam Flow	Lb/Hr.	24,263
33	Steam Inlet Temperature	°F	670
34	Steam Inlet Enthalpy	Btu/Lb	1,348
35	Shell Pressure	PSIA	371
36	Shell Saturated Temperature	°F	457
37	Drain Inlet Flow	Lb/Hr	0
38	Drain Inlet Temperature	°F	---
39	Drain Inlet Enthalpy	Btu/Lb	---
40	Drain Outlet Flow	Lb/Hr	24,263
41	Drain Outlet Temperature	°F	377
42	Drain Outlet Enthalpy	Btu/Lb	350
43			
44	SHELL SIDE DESIGN CONDITIONS		
45	Shell Design Pressure / Test Pressure	PSIG/VAC/PSIG	390 / 0 / ASME Code
46	Shell Design Temperature / Skirt Design	°F	440 / 680
47	Drains-Cooler Approach	°F	10
48			
49	TOTAL HEAT EXCHANGED	Btu/Hr	24,200,000
50	Remarks:		

Closed Feedwater Heater Design Summary Sheets (2 of 2)

TABLE 4.2-8. RECEIVER FEED PUMPS

Two — 100% pumps with variable speed drive and motor
Capacity — 740 gpm each
Total development head — 5800-feet
Temperature — 300°F
NPSH available — 52-feet
Discharge pressure — 2304 psig
Suction pressure — 22.5 psig
Hydraulic h.p. — 1181
Six to 12 stages*
Speed — 3600 rpm*
Efficiency — 55 to 75%*
BHP — 1574 to 2146*
NPSH required — 16 to 42 feet*
Motor HP — 2000 hp
Voltage — 2400 volts

*Manufacturer dependent

Hotwell Pump Design Conditions:

- 353 gpm/Pump Capacity*
- 422-ft tdh*
- 1760 rpm
- Approximately 10 stages
- Column Diameter Length (approximately) 9-1/2-inches/9-1/2-feet

4.2.1.7 PIPING DESIGN AND ANALYSIS

This section describes the feedwater and steam piping design from the receiver to the main Turbine Building where the steam line interfaces with the existing fossil boiler steam line and the feedwater line interfaces at the receiver feed pump discharge.

*With both pumps operating

An economic analysis was made to determine the sizes of the steam and feedwater piping based on material and thermal insulation costs and the costs of pressure heat losses based on plant economic factors as estimated by PNM.

Based on this economic sizing analysis, a stress analysis was performed on the steam line for a number of pipe routings to determine the most acceptable routing based on thermal, pressure and weight loadings. These stress analyses were made for the downcomer in the receiver tower, the steam piping routed in the overhead pipe rack located in the collector field, and the piping in the main Turbine Building where it interfaces with the existing fossil-boiler steam piping.

The remainder of this section discusses in detail the following studies and final piping design:

- Feedwater and Steam Piping Economic Analysis
- Steam Piping Stress Analysis
- Final Piping Design

FEEDWATER AND STEAM PIPING ECONOMIC ANALYSIS

Due to the lengths of piping required for the solar central receiver concept, steam and feedwater piping costs are significant. An economic analysis based on preliminary design data was performed in order to:

- Establish the optimum pipe sizes (inside diameters) for the two lines
- Establish the economic thickness for the piping insulation
- Refine the cost estimates for the lines

Based on engineering judgment of the range of pipe sizes feasible for the steam and feedwater flows anticipated, three sizes of pipe were considered for each service, specifically 8-inch, 10-inch and 12-inch inside diameter steam piping, and 6-inch, 8-inch and 10-inch schedule piping for the feedwater service. A range of thermal insulation thicknesses, 4 to 8 inches, was considered for each size of pipe. Cost estimates for material and installation labor were obtained for all sizes of pipe. Cost estimates for material and installation labor were

obtained for all sizes of pipe and insulation under consideration and escalated at 10 percent annually to December 31, 1981. The 1981 present worth cost of a 1 psi change in receiver feed pump head was developed, as was the 1981 present worth cost of a Btu of heat lost through the insulation. Total costs of the steam and feedwater piping installations were developed by summing the material and installation costs, costs of heat loss and costs of pressure drop for each combination of pipe size and insulation thickness. As a result of these calculations, the following configurations are recommended:

- Steam Pipe — 10-inch inside diameter, 1.425-inch wall thickness, P22 (ASTM A335) alloy steel pipe (2-1/4 percent chrome, 1 percent molybdenum) with 8 inches of calcium silicate insulation with sheet aluminum jacketing
- Feedwater Pipe — 8-inch XXS ASTM A106 Grade B carbon steel pipe with 6 inches of calcium silicate insulation with sheet aluminum jacketing

Estimated installed costs of the steam and feedwater piping in current dollars are \$1.102 million and \$0.332 million, respectively, for a total of \$1.434 million. When escalated to December 31, 1981, the installed cost estimates are \$1.576 million for the steam pipe and \$0.474 million for the feedwater pipe; the estimated total installed cost for both lines is \$2.050 million.

A tentative receiver steam and feedwater routing was established for the preliminary collector field layout. Based on the routing, the steam line will be about 3850 feet in length; the feedwater line, because of shorter expansion loops will be about 200 feet shorter, at 3650-feet. Receiver steam output temperature set-point was assumed to be 1000°F, while the turbine inlet temperature is 950°F. Since it is anticipated that temperature swings of as much as plus or minus 50°F could occur in the receiver outlet temperature due to solar insolation transients, the receiver steam line was designed for a maximum operating temperature of 1000°F, plus 50°F, or 1050°F. The conceptual design includes an attemperator at the outlet end of the steamline to reduce the steam temperature to 950°F during normal operation and to lower temperatures during start-up. Feedwater line design temperature was set at 439°F based on a preliminary heat balance.

Design pressures are determined by the required throttle pressure (1265 psia) and by pressure drops in the steam and feedwater lines; these are

determined by design flow rates. The following are design pressures that were used and corresponding minimum calculated wall thicknesses for the steam piping:

<u>Size</u>	<u>Design Pressure</u>	<u>Wall Thickness</u>
8-in.	1600	1.260
10-in.	1460	1.385
12-in.	1410	1.625

These design pressures were based on preliminary estimates of pipe length and design flow rates; piping cost estimates were obtained from a pipe manufacturer based on the calculated wall thicknesses given above. Design pressures based on the collector field configuration current at the time of this writing (4289 helio-states) would be as follows:

<u>Size</u>	<u>Design Pressure</u>	<u>Wall Thickness</u>
8-in.	1910	1.479
10-in.	1510	1.425
12-in.	1400	1.573

Using these design pressures, a considerably thicker wall would be required for the 8-inch pipe and a slightly thicker wall in the 10-inch size. Cost estimates were not obtained for these pipe sizes, but it is unlikely that small material cost changes would affect the conceptual design recommendation for 10-inch steam piping. Main steam pipe size and wall thickness should be re-examined during the preliminary or detail design phase when the maximum receiver steam outlet temperature is established and the collector field design and consequently the maximum steam flow, is fixed. Design temperature for the main streamline should also be re-examined; if the design temperature could be reduced by 50°F or more, then it is possible that lighter walled schedule piping could be used with resultant savings in cost and delivery time.

Design pressure for the feedwater line will be determined by the full speed shut-off head of the receiver feed pump. The pipe specification that was chosen is suitable for pressures of up to 2995 psig for temperatures of 500°F or less.

(The pipe schedules were XXS for the 6-inch and 8-inch pipe and 160 for the 10-inch pipe.) Since the calculated receiver pump discharge pressure at maximum flow is about 2380 psi with the recommended feed and steamlines, the selected schedule pipe should have adequate strength.

Insulation material and installation costs were obtained from contractors' quotes and escalated to December 31, 1978, at 10 percent annually; installation price quotes obtained from the contractors varied widely, so medium values were used. The calcium silicate insulation priced was of at least two layers in thickness.

The costs associated with the heat loss through the piping insulation was based on an estimate of the 1981 present worth of fuel (levelized cost) provided by PNM. This factor of 99.9 mils per KW-hour was divided by the gross turbine cycle heat rate of 9333 BTU/KW-HR to obtain a heat loss cost of .0107 Mils/BTU. The total cost of heat lost over the life of the plant was obtained by multiplying the heat lost through the insulation in BTU/Hr. by a 30 year plant life operating at a capacity factor of 23% and by the cost of .0107 Mils/BTU.

The heat loss for each combination of steam and feedwater line size and insulation thickness was determined using the Stearns-Roger program PIPELOSS. A temperature of 70°F and a wind speed of 10 miles per hour were assumed to represent average annual environmental conditions during the hours of solar operation and were the inputs used in the program. The heat losses were based on an initial feedwater temperature of 439°F (derived from the heat balance) and an initial steam temperature of 1000°F. The flow rate used in the heat loss calculations was 271,800 pounds per hour, which corresponds to 32.2 MW gross electrical generation. The gross electrical output was derived from the annual average radiation (100.5 MWth) Sandia Livermore calculated as incident on the receiver based on an annual average insolation of 950 W/m^2 and a 4289 heliostat receiver field. For the purposes of heat loss and friction drop calculations, the average annual insolation was assumed to be 105 percent of 950 W/m^2 or approximately 1 kW/m^2 . The following efficiencies were also assumed for the computation:

- Receiver absorptance = 0.95
- Radiation and convection — 0.883

- Pipint heat loss efficiency — 0.996
- Gross turbine cycle efficiency — 0.3657

The cost of heat lost over the life of the plant for each combination of pipe size and insulation thickness was calculated as the product of the heat loss per hour and the cost factor developed from the levelized fuel cost.

The friction heat loss for each size of pipe was calculated based on the average annual flow of 271,800 pounds per hour. The cost of pumping across an extra psi of friction head loss was determined by first calculating the required horsepower (0.47). This calculation was based on an annual average flow of 278,500 pounds per hour including attemperator flow, and a pump efficiency of 75 percent. Based on the assumption that electrical motors require approximately 1 kilowatt per horsepower output, the cost per psi was developed as the product of 0.47, the number of hours of solar operation during the life of the plant (60,500), the levelized cost per kilowatt hour for fuel oil (99.9 mils), and one minus the gross turbine cycle efficiency (0.6343). This last factor was applied since frictional head loss adds heat to the feedwater, a portion of which is converted to electrical output. The resulting cost is \$1802 per psi over the life of the plant.

The following curves, Figures 4.2-8 and 4.2-9, show the 1981 present worth costs of materials and installation, heat loss, pressure drop and totals for each combination of pipe size and insulation thickness.

STEAM PIPING STRESS ANALYSIS

General Philosophy

It was decided to divide the steam line into two systems for analysis purposes by introducing an anchor at the north end of the collector field. This would prevent forces and moments from this large amount of pipe being transmitted onto load-sensitive equipment such as the turbine.

The system from the central receiver area to the north end of the collector field was analyzed, utilizing the vertical run up the tower as flexibility for the

RECEIVER FEEDWATER LINE COSTS

Figure 4.2-8. Receiver Feedwater Piping Costs

Figure 4.2-9. Receiver Steam Piping Costs

horizontal run along the rack. This resulted in 370-feet 0-inches of pipe and loops in the tower to accommodate 1000-feet 0-inches on the rack, but the movement of the pipe at the base of the tower was 98-inches, which would provide problems for dead weight and seismic supports. Therefore, using the flexibility of the piping in the tower was deemed to be unacceptable due to the large piping movements at the base of the tower.

Loops were introduced in conjunction with anchors on the pipe rack, to contain and control the movement of the pipe. This resulted in two acceptable alternatives:

- Loops consisting of 70-feet 0 inches of pipe every 200-feet 0-inches, but contained within the area of the road
- Loops consisting of 120-feet 0-inches of pipe every 500-feet 0-inches, but penetrating the heliostat field by 25-feet 0-inches.

The system from the north end of the collector field to the boiler and turbine was analyzed using loops, anchors and guides to reduce the pipe stress to an acceptable level. Due to the low allowable reactions on the turbine, an anchor had to be located approximately in line with the turbine and 100 percent cold spring employed in the new section of pipe from this anchor to the connection of the existing system.

Detailed Philosophy

The system from the central receiver area to the north end of the collector field, consists of approximately 2200-feet of straight pipe.

A series of piping stress analysis computer runs were made on a number of configurations to determine the most acceptable design that would accommodate the thermal expansion loads. These runs and their results are shown below for the piping contained in the overhead pipe rack.

T-MS-01-A1-0

This run incorporated 95-feet 0-inches of pipe vertically in the tower to provide flexibility for 570-feet 0-inches horizontal along the rack.

- Maximum Pipe Stress = 55,000 psi
- Allowable Stress = 18,630 psi
- Resultant moment (Tower anchor) = 564,000 ft-lb

This routing is obviously not acceptable and more vertical leg would be required for flexibility.

T-MS-01-A1-1

This run incorporated 240-feet 0-inches of loops vertically in the tower, plus 1000-feet 0-inches horizontal along the rack.

- Maximum Pipe Stress = 35,000 psi
- Allowable Stress = 18,630 psi
- Resultant Moment (Tower Anchor) = 365,000 ft-lb

This routing was not acceptable and still more vertical leg would be required for flexibility.

T-MS-01-A1-2

This run incorporated 370-feet 0-inches of loops vertically in the tower, plus 1000-feet 0-inches horizontal along the rack.

- Maximum Pipe Stress = 17,900 psi
- Allowable Stress = 18,630 psi
- Resultant moment (Tower Anchor) = 183,000 ft-lb

Assuming the tower can support the moment, this routing is acceptable. Size of the tower, dead weight and seismic support in the tower have not been considered at this conceptual stage. Large horizontal moments of 98-inches.

T-MS-01-B1-0

This analysis represents a different concept in which anchors are located along the pipe rack and expansion is taken out by loops in line with the rack. This

routing represents 1000-feet 0-inches between anchors with a 70-foot 0-inch expansion loop located half way between anchors.

- Maximum Pipe Stress = 90,329 psi
- Allowable Stress = 18,630 psi
- Axial Force at Anchors = 49,000 lb

This routing is unacceptable.

T-MS-01-C1-0

This routing incorporates 500-feet 0-inches between anchors with a 70-foot 0-inch expansion loop.

- Maximum Pipe Stress = 45,270 psi
- Allowable Stress = 18,630 psi
- Axial Force at Anchors = 25,540 lb

This routing is unacceptable.

T-MS-01-D1-0

This routing incorporates 250-feet 0-inches between anchors with a 70-foot 0-inch expansion loop.

- Maximum Pipe Stress = 22,660 psi
- Allowable Stress = 18,630 psi
- Axial Force at Anchors = 12,300 lb

This routing is unacceptable.

T-MS-01-E1-0

This routing incorporates 200-feet 0-inches between anchors with a 70-foot 0-inch expansion loop.

- Maximum Pipe Stress = 18,140 psi
- Allowable Stress = 18,630 psi

- Axial Force at Anchors = 9840 lb
- Resultant moment at Anchor = 14,170 ft-lb

This routing is acceptable.

T-MS-01-F1-0

This routing is similar to T-MS-01-C1-0 in that there are 500-feet 0-inches between anchors, but the expansion loop is 120-feet 0-inches long.

- Maximum Pipe Stress = 18,600 psi
- Allowable Stress = 18,630 psi
- Axial Force on Anchors = 5300 lb

This routing was satisfactory and is recommended for this conceptual design and is shown on Figure 4.2-10.

Similarly, pipe stresses and loads on the turbine were analyzed for the piping from the anchor point at the north end of the collector field to the fossil boiler and turbine. This analysis included the existing steam piping from the fossil boiler which is 100 percent cold sprung. The results of these runs are shown below.

T-MS02-A1-0

This run was made with no restraints and 100 percent cold spring in existing line only.

- Maximum Pipe Stress = 41,581 psi
- Allowable Stress = 18,630 psi

The forces and moments on the turbine are too high. This routing was not acceptable, more flexibility is required.

Figure 4.2-10. Stress Analysis — Main Steam Line

T-MS-02-A1-1

This run has a 15-foot 0-inch loop added.

- Maximum Pipe Stress = 39,208 psi
- Allowable Stress = 18,630 psi

The forces and moments on the turbine are too high. This run was not acceptable, more flexibility is required.

T-MS-02-A1-2

This run incorporates two loops with anchors and guides.

- Maximum Pipe Stress = 65,102 psi
- Allowable Stress = 18,630 psi

The forces and moments on the turbine are too high. This run was not acceptable, but high stresses were limited to the loop area.

T-MS-02-A1-3

In this run, one anchor was removed to allow more flexibility in the loop.

- Maximum Pipe Stress = 46,786 psi
- Allowable Stress = 18,630 psi

The forces and moments on the turbine are too high. This run is not acceptable, more flexibility in the loop is required.

T-MS-02-A1-4

Another anchor was removed to add flexibility in the loop.

- Maximum Pipe Stress = 23,656 psi
- Allowable Stress = 18,630 psi

The stresses in this run are acceptable by utilizing the additive thermal, pressure weight and stresses. This configuration is recommended and is shown on Figure 4.2-11.

12" MAIN STEAM LINE
 12 3/4 O.D. 10" I.D.
 1000°F
 1250 PSIG
 CHR MO. P. 22

Figure 4.2-11. Recommended Configuration

T-MS-02-A1-5

This run was made with the new section at 70°F and the existing section at 1000°F to determine the range of reaction on the turbine and boiler.

- Maximum Pipe Stress = 7153 psi
- Allowable Stress = 18,630 psi

The turbine forces and moments are too high. This run is not acceptable.

T-MS-02-A1-6

This was a run at 1000°F using 100 percent cold spring in the new section of the system to the first anchor which is located about the same distance from the wye as is the turbine. This run supplies only the forces and moments used to determine the reaction range. The reactions on the first anchors on the rack are very high but could be reduced by removing some restraints or adding more pipe.

T-MS-02-A1-7

This was the same as A1-6, except it was run at 70°F to determine the forces and moments used to determine the reaction range. The reactions on one of the turbine loads was over the allowable limits, but this is the maximum condition as it includes 100 percent cold spring up to the first anchor on the rack. No allowable reactions are available for the boiler but the actual reactions appeared to be quite low.

T-MS-02-A1-8

The system was run at 1000°F and no cold spring to determine the actual stresses.

- Maximum Pipe Stress = 9781 psi
- Allowable Stress = 18,630 psi

The system is acceptable as analyzed.

FINAL PIPING DESIGN

Figures 4.2-10 and 4.2-11 show the routing of the steam piping as contained in the pipe rack and to the interface with the existing steam piping at the turbine. The feedwater piping was not analyzed during this conceptual design, since thermal stresses and pipe routing is not as severe a problem as for the steam piping. The analysis of the feedwater piping should be made during the detailed design engineering phase of the project.

A typical pipe routing of the steam and feedwater piping contained in the receiver tower is shown on Drawing L-22929, Sheet P4-12. A detailed stress analysis of the riser and downcomer in the receiver tower was not performed, and the routing shown on the Drawing is based on the results of the piping design for the commercial plant at Barstow, central receiver design study.

Figure 4.2-12 is a summary of the major design parameters as selected for the receiver steam and feedwater piping.

4.2.2 MODIFICATIONS TO EXISTING EQUIPMENT

This subsection describes modifications to existing equipment in several areas: heat balances, code review, piping interface design, equipment and motor list, auxiliary power requirements, turbine generator, and general arrangement of equipment.

4.2.2.1 HEAT BALANCES

This section presents the results of the heat balances developed by Stearns-Roger for the solar hybrid repowering of Reeves Unit No. 2. The heat balances were developed in order to:

- Evaluate alternative cycles as they affect cycle heat rates
- Predict the performance and operating characteristics of the recommended conceptual design configuration
- Determine duties, pressures, temperatures, flow rates, and so forth, for cycle equipment and piping in order to facilitate the sizing and specification of those items

DESIGN PARAMETER	STEAM	FEED WATER
• PIPE LENGTH, FT.	3850	3650
• TEMPERATURE, °F	1050	450
• PRESSURE, PSI	1510	2380
• FLOW, LB/HR	271800	271800
• FRICTION LOSS, PSI	128	21
• PIPE DIAMETER, IN.	10 I.D.	8
• WALL THICKNESS, IN.	1.425	XXS 0.875
• PIPE MATERIAL	P22 (ASTM A335) 2¼% CHR./1% MOLY.	ASTM A106 GR.B. CARBON STEEL
• INSULATION THICKNESS, IN.	8	6
• INSULATION MATERIAL	CA. SILICATE AL. JACKET	CA. SILICATE AL. JACKET

Figure 4.2-12. Steam/Feedwater Piping Design Summary

CALCULATION PROCEDURES

The Stearns-Roger computer program D-138 was used to calculate the expected performance and operating characteristics of the proposed cycle. This program uses a multivariable partial differential convergence technique in which the turbine stage pressures are varied to converge on the turbine stage flow. Turbine expansion line curves were developed from the turbine Vendor's design heat balances and input to the program. Auxiliary cycle equipment performance parameters were obtained from design heat balances or Vendor design information. The following design data were used to prepare the input for the heat balance calculations:

- Figure 4.2-13, "Generator Losses Curve," Westinghouse Electric Corp., Curve No. ST-227-b, dated 05/22/58.
- Figure 4.2-14, "Exhaust and Mechanical Losses Curve," Westinghouse Electric Corp., Curve No. ST-233, dated 12/13/48.
- Figures 4.2-15 through 4.2-19, "Tabulation of Heat Balance Computations," Stearns-Roger Manufacturing Co., dated 03/07/57.

Figures 4.2-20 through 4.2-25 are sketches of six of the calculated heat balances. All six heat balances were based on 50 MW gross electrical generation, the low pressure Heater No. 5 drain routed to the condenser, and two additional high pressure heaters provided for solar receiver feedwater heating. Figure 4.2-20 represents the design maximum solar insolation condition (noon summer solstice with 1045 W/m^2 direct normal solar insolation) with 78 percent of the steam generated by the solar portion and 22 percent by the fossil boiler. Figure 4.2-22 represents design annual average insolation conditions (approximately 1000 W/m^2 direct normal solar insolation) with 64.5 percent of the steam generated by the solar portion and 35.5 percent by the fossil boiler. Figure 4.2-21 and Figures 4.2-23 through 4.2-25 represent arbitrary design points of 75 percent solar — 25 percent fossil, 50 percent solar — 50 percent fossil, 25 percent solar — 75 percent fossil, and 100 percent fossil, respectively. Figure 4.2-26 summarizes important parameters at several of those design points plus an additional design point: 2:00 p.m. Winter solstice, 1045 W/m^2 direct normal solar insolation, and no fossil boiler firing.

It was noted that the 100 percent boiler load heat balance predicted a gross turbine heat rate of 9017.3 Btu/kW-hr. Test results taken on Reeves Unit No. 2

GENERATOR LOSSES

Figure 4.2-13. Generator Losses

during the years 1975 through 1977 show a gross turbine heat rate of 9333 Btu/kW-hr, more than three percent poorer. It is believed that the Vendor design information is more reliable and complete for this case than most field test data, especially data obtained using station instrumentation. An exception to this rule would be where an ASME PTC-6 test has been conducted using test grade, calibrated instrumentation with full documentation of all test and cycle insulation procedures. The difference between the heat rates predicted by the heat balance and the test value can be explained by degraded turbine or auxiliary performance and/or plant instrumentation error.

Since the predicted electrical power output contribution for each solar insolation condition was based on the test value of the gross turbine heat rate, it is likely that the solar contributions will be slightly higher than those shown for the noon summer solstice, 2:00 p.m. Winter solstice, and annual average cases.

EFFECT ON HEAT RATE OF ROUTING OF DRAINS

It is recommended that the Low Pressure Heater No. 5 drains be cascaded to the condenser so that the water can be passed through the condensate polisher. At present, the No. 5 Heater drains are pumped into the condensate pipe just upstream of the No. 4 Heater to utilize the heat content. It was desired to determine how much the heat rate would be degraded by cascading the drains to the condenser. A base case with 100 percent fossil boiler steam and the No. 5 Heater drains pumped ahead was therefore run; the resulting gross turbine heat rate was 8997.8 Btu/kW-hr. Compared to the equivalent heat rate with the drains cascaded, 9017.3 Btu/kW-hr, the difference is 19.50 Btu/kW-hr, or about 0.2 percent.

EFFECT OF DELETING THE NO. 6 AND NO. 7 HIGH PRESSURE HEATERS

It is recommended that two new high-pressure heaters be installed to heat the receiver feedwater. An investigation of the effect on the heat rate of not employing new high pressure feedwater heaters was made. Following is a summary of that study.

It was assumed that a 50 MW gross generator output was to be maintained. With 4289 heliostats (38 square meters/heliostat) employed, it was calculated that the annual average power generation contribution from the solar portion would be about 32 MWe.

Two heat balances were made: the first included the two proposed feedwater heaters; the second did not include high pressure heaters for the receiver feedwater. Steam output from the fossil boiler was held constant for both cases implying the same fuel oil flow and fuel cost for either case.

The steam flow to the turbine, and therefore the requirement from the solar receiver, since fossil boiler flow was held constant, was reduced when the receiver high pressure heaters were deleted. This was due to a higher loading in the low pressure stages of the turbine because of less extraction steam flow for feedwater heating. However, the duty on the solar receiver portion was increased ($2.987 \text{ by } 10^8 \text{ Btu/hr}$ versus $2.913 \text{ by } 10^8$) due to an increased temperature difference between feedwater and receiver steam if high pressure heaters are not used. This is a difference in receiver duty of 2.54 percent.

An additional 109 heliostats (2.54 percent of 4289) would be required to maintain 50 MWe output without increasing the boiler firing. Using a collector cost of \$250 per square meter, the additional collector cost would be about \$1.036 million. The cost estimate for H.P. Heaters No. 6 and 7 is \$125,000 with an additional \$30,000 required for installation; the estimated installed cost is \$155,000 or \$0.155 million. The employment of H.P. Heaters is therefore shown to be cost effective.

HEAT BALANCE COMPUTATIONS
FOR
PUBLIC SERVICE COMPANY OF NEW MEXICO
REEVES STATION
UNIT #2
ALBUQUERQUE, NEW MEXICO

ORDER NO. B-12500

BY
THE STEARNS-ROGER MANUFACTURING CO.
DENVER, COLORADO

DISTRIBUTION:

<u>LHG</u>	<u>LD (2)</u>	<u> </u>
<u>SMP</u>	<u> </u>	<u> </u>
<u>RER (4)</u>	<u> </u>	<u> </u>
<u>JSG</u>	<u> </u>	<u> </u>
<u>CJE</u>	<u> </u>	<u> </u>
<u>WMH</u>	<u> </u>	<u> </u>

REVISION

DATE

0

3/7/57

1

3/28/57

2

8/15/58

3

4

5

ASME-AIEE STANDARDIZED
40,000 KW
TURBINE-GENERATOR UNIT
1250 PSIG - 950° FTT - 1.5 IN. EG. AES.

Figure 4.2-14. Exhaust and Mechanical Losses

TABULATION OF HEAT BALANCE COMPUTATIONS
FROM
PUBLIC SERVICE COMPANY OF NEW MEXICO
ALBUQUERQUE, NEW MEXICO
REEVES STATION, UNIT NO. 2

Job No.B-12500
Complied by JSG
Date 3/7/57
Page 1 of 5

GENERAL INFORMATION

Turbine Generator

44,000 KW ASME-AIEE Preferred Standard Turbine Generator Unit
1250 PSIG, 9500 FTT Steam Conditions at Turbine Throttle
1 - 1/2" HG Abs. Exhaust Pressure
5 Heater Cycle
47,058 KVA Generator, 0.85 PF at 1/2" PSIG H₂ Pressure
13,800 volts, 3 phase, 60 cycle

Steam Generator

Pressurized Type, 425,000 LB/HR Maximum Continuous Rating
1280 PSIG, 955° FTT at Superheater Outlet
8,344 sq. ft. Total Effective Heating Surface
250,000 LB/HR Attenuation Point
Regenerative Type Air Heater

Fuel

Base - Natural Gas with 1,000 BTU/CU. FT. Heat Value at 14 PSIG - 60° F.
Standby - Fuel Oil, 27 + Gravity, 19,100 BTU/# Heat Value

Condenser

Surface Type, 35,000 sq. ft., Non-divided Water Box, Two Pass

Figure 4.2-15. Tabulation of Heat Balance Computations

THE STEARNS-ROGER MANUFACTURING CO
DENVER, COLORADO

HEAT BALANCE TABULATION
FOR
PUBLIC SERVICE COMPANY OF NEW MEXICO
REEVES STATION UNIT #2
ALBUQUERQUE, NEW MEXICO

Page 2 of 5
Date 3/7/57
Rev. 1 3/28/57
Job B-12500
By
Rev. 2 8/15/58

44,000 KW PREF-STD TURBINE GENERATOR UNIT
1250 PSIG 950° F.T.T. 1 - 1/2" HG. ABS.

DIAGRAM A - EVAPORATOR IN SERVICE

GENERATOR OUTPUT	KW	10,181	21,985	33,071	44,820	47,938	49,934
STATION AUX. POWER	KW	1,828	1,938	2,066	2,240	2,294	2,323
NET SALEABLE POWER	KW	8,353	20,047	31,005	42,580	45,644	47,611
TURBINE DATA:							
THROTTLE FLOW	#/HR	90,000	180,000	270,000	375,000	405,000	425,000
THROTTLE PRESSURE	PSIG	1,250	1,250	1,250	1,250	1,250	1,250
THROTTLE TEMPERATURE	°F	950	950	950	950	950	950
THROTTLE ENTHALPY	B/#	1,468	1,468	1,468	1,468	1,468	1,468
FIRST EXTRACTION STEAM:							
FLOW	#/HR	3,928	9,832	17,163	27,907	31,407	33,599
PRESSURE	PSIA	71.4	143.8	222.0	326.5	358.7	379.7
TEMPERATURE	°F	522	542	591	648	660	668
ENTHALPY	BTU/#	1,292.9	1,297.2	1,315.8	1,339.3	1,343.8	1,347.3
SECOND EXTRACTION STEAM:							
FLOW	#/HR	7,297	13,254	21,304	31,623	34,688	36,764
PRESSURE	PSIA	37.1	72.3	107.9	150.8	163.8	172.8
TEMPERATURE	°F	409	418	453	490	501	510
ENTHALPY	BTU/#	1,241.4	1,240.4	1,254.4	1,268.5	1,273.3	1,277.1
THIRD EXTRACTION STEAM:							
FLOW	#/HR	0	4,195	7,118	10,564	11,637	12,325
PRESSURE	PSIA	—	29.5	43.9	60.5	65.5	68.9
TEMPERATURE	°F	—	269	300	330	340	345
ENTHALPY	BTU/#	—	1,173.9	1,185.4	1,197.8	1,201.5	1,204.5
FOURTH EXTRACTION STEAM:							
FLOW	#/HR	3,552	8,247	13,008	18,734	20,500	21,654
PRESSURE	PSIA	6.6	12.2	18.0	24.8	26.8	28.3
TEMPERATURE	°F	174	202	222	240	244	247
ENTHALPY	BTU/#	1,127.9	1,119.4	1,128.4	1,139.8	1,143.1	1,145.3

Figure 4.2-16. Heat Balance Tabulation

DIAGRAM A - EVAPORATOR IN SERVICE (CONT'D.)

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Rev. 13/28/57

FIFTH EXTRACTION STEAM:								
FLOW	#/HR	1,584	6,573	13,173	21,794	24,259	26,081	
PRESSURE	PSIA	2.1	3.6	5.3	7.3	7.8	8.2	
TEMPERATURE	°F	128	149	165	179	182	184	
ENTHALPY	BTU/#	1,065.5	1,054.9	1,061.2	1,072.8	1,076.2	1,078.8	
TURBINE EXHAUST:								
TURBINE EXHAUST FLOW	#/HR	73,639	137,899	198,234	264,378	282,509	294,577	
TURBINE EXHAUST PRESSURE	HgA.	1.5	1.5	1.5	1.5	1.5	1.5	
TURBINE EXHAUST ENTHALPY	BTU/#	1,023.1	989.2	979.0	980.4	982.4	984.3	
TURBINE EXHAUST TEMPERATURE	°F	91.7	91.7	91.7	91.7	91.7	91.7	
TURBINE & CCND. AUXILIARY:								
SJAP STEAM FLOW	#/HR	600	600	600	600	600	600	
CONDENSER TEMP. IN	°F	91.7	91.7	91.7	91.7	91.7	91.7	
CONDENSER TEMP. OUT	°F	99.8	96.0	94.7	94.0	93.9	93.8	
NO. 5 L.P. HEATER:								
SHELL PRESSURE	PSIA	2.0	3.4	5.0	6.9	7.4	7.8	
SHELL TEMPERATURE	°F	126.1	146.4	162.2	176.2	179.3	181.7	
HEATER DRAIN TEMP.	°F	126.1	146.4	162.2	176.2	179.3	181.7	
HEATER DRAIN FLOW	#/HR	5,136	14,820	26,181	40,528	44,759	47,735	
CONDENSATE FLOW	#/HR	74,239	138,499	198,834	264,978	283,109	295,177	
CONDENSATE TEMP. IN	°F	99.8	96.0	94.7	94.0	93.9	93.8	
CONDENSATE TEMP. OUT	°F	121.1	141.4	157.2	171.2	174.3	176.7	
NO. 4 L.P. HEATER:								
SHELL PRESSURE	PSIA	6.3	11.6	17.1	23.6	25.5	26.9	
SHELL TEMPERATURE	°F	172.2	200.3	219.7	236.9	241.2	244.1	
HEATER DRAIN TEMP.	°F	136.4	156.9	172.8	186.9	190.0	192.4	
HEATER DRAIN FLOW	#/HR	3,552	8,247	13,008	18,734	20,500	21,654	
CONDENSATE FLOW	#/HR	79,375	153,319	225,015	305,506	327,868	342,912	
CONDENSATE TEMP. IN	°F	121.4	141.9	157.8	171.9	175.0	177.4	
CONDENSATE TEMP. OUT	°F	167.2	195.3	214.7	231.9	236.2	239.1	
DEAERATOR:								
SHELL PRESSURE	PSIA	* 15.2	28.0	41.7	57.5	62.2	65.5	
SHELL TEMPERATURE	°F	213.7	246.4	269.8	289.9	295.1	298.5	
CONDENSATE FLOW IN	#/HR	79,375	153,319	225,015	305,506	327,868	342,912	
CONDENSATE TEMP. IN	°F	167.2	195.3	214.7	231.9	236.2	239.1	
H. P. HEATER DRAIN FLOW IN	#/HR	7,551	18,861	31,985	50,359	56,155	59,915	
H. P. HEATER DRAIN TEMP. IN	°F	225.7	258.4	281.8	301.9	307.1	310.5	
EVAPORATOR VAPOR FLOW IN	#/HR	1,800	3,600	5,400	7,500	8,100	8,500	
EVAPORATOR DRAIN FLOW IN	#/HR	2,000	4,225	6,482	9,171	9,940	10,448	

* 1,674 #/HR driving steam from 2nd extraction.

Figure 4.2-17. Diagram A (Continued)

DIAGRAM A - EVAPORATOR IN SERVICE (CONT'D.)

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DEAERATOR (Cont'd.)								
EVAPORATOR DRAIN TEMP. IN	°F	261.0	303.0	331.1	356.4	362.9	367.2	
FEEDWATER FLOW OUT	#/HR	92,400	184,200	276,000	383,100	413,700	434,100	
FEEDWATER TEMP. OUT	°F	213.7	246.4	269.8	289.9	295.1	298.5	
EVAPORATOR:								
STEAM FLOW	#/HR	2,000	4,225	6,482	9,171	9,940	10,448	
SHELL PRESSURE	PSIA	16.0	29.4	43.8	60.4	65.3	68.8	
SHELL TEMPERATURE	°F	216.3	249.1	272.8	293.1	298.3	301.7	
VAPOR FLOW OUT	#/HR	1,800	3,600	5,400	7,500	8,100	8,500	
MAKEUP FLOW IN	#/HR	1,800	3,600	5,400	7,500	8,100	8,500	
MAKEUP TEMP. IN	°F	60	60	60	60	60	60	
DRAIN FLOW OUT	#/HR	2,000	4,225	6,482	9,171	9,940	10,448	
DRAIN TEMP. OUT	°F	261.0	303.0	331.1	356.4	362.9	367.2	
NO. 2 H.P. HEATER:								
STEAM FLOW	#/HR	3,623	9,029	14,822	22,452	24,748	26,316	
SHELL PRESSURE	PSIA	36.0	70.1	104.7	146.3	158.9	167.6	
SHELL TEMPERATURE	°F	261.0	303.0	331.1	356.4	362.9	367.2	
HEATER DRAIN TEMP.	°F	225.7	258.4	281.8	301.9	307.1	310.5	
HEATER DRAIN FLOW	#/HR	7,551	18,861	31,985	50,359	56,155	59,915	
FEEDWATER FLOW	#/HR	92,400	184,200	276,000	383,100	413,700	434,100	
FEEDWATER TEMP. IN	°F	215.7	248.4	271.8	291.9	297.1	300.5	
FEEDWATER TEMP. OUT	°F	258.0	300.0	328.1	353.4	359.9	364.2	
NO. 1 H.P. HEATER:								
SHELL PRESSURE	PSIA	69.3	139.5	215.3	316.7	347.9	368.3	
SHELL TEMPERATURE	°F	302.2	352.7	388.0	422.2	431.1	436.5	
HEATER DRAIN TEMP.	°F	268.0	310.0	338.1	363.4	369.9	374.2	
HEATER DRAIN FLOW	#/HR	3,928	9,832	17,163	27,907	31,407	33,599	
FEEDWATER FLOW	#/HR	92,400	184,200	276,000	383,100	413,700	434,100	
FEEDWATER TEMP. IN	°F	258.0	300.0	328.1	353.4	359.9	364.2	
FEEDWATER TEMP. OUT	°F	302.2	352.7	388.0	422.2	431.1	436.5	
BOILER:								
MAIN STEAM FLOW	#/HR	90,600	180,600	270,600	375,600	405,600	425,600	
MAIN STEAM PRESS.	PSIA	1,265	1,265	1,265	1,265	1,265	1,265	
MAIN STEAM TEMP.	°F	950	950	950	950	950	950	
MAIN STEAM ENTHALPY	BTU/#	1,468.0	1,468.0	1,468.0	1,468.0	1,468.0	1,468.0	
BLOWDOWN FLOW	#/HR	1,800	3,600	5,400	7,500	8,100	8,500	
BLOWDOWN ENTHALPY	BTU/#	580.6	580.6	580.6	580.6	580.6	580.6	

Figure 4.2-18. Diagram A (Continued)

DIAGRAM A - EVAPCRATOR IN SERVICE (CONT'D.)

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BOILER (Cont'd.)							
FEEDWATER FLOW	#/HR	92,400	184,200	276,000	383,100	413,700	434,100
FEEDWATER TEMP.	°F	302.2	352.7	388.0	422.2	431.1	436.5
FEEDWATER ENTHALPY	BTU/#	274.3	326.4	363.5	400.2	409.9	415.8
BOILER EFFICIENCY	%	83.13	84.43	84.81	84.54	84.43	84.37
TOTAL HEAT FIRED	MKB/HR	130,759	245,278	353,791	476,010	509,947	532,437
GAS FIRED	MCF/HR	130.75	245.27	353.79	476.01	509.94	532.43
HT. OUTPUT OF BLR	MKB/HR	108.700	353.79	476.01	509.94	532.43	
PLANT PERFORMANCE							
THROTTLE FLOW/KW	GROSS	8.85	8.20	8.16	8.36	8.46	8.52
CONDENSER FLOW/KW	GROSS	7.24	6.27	6.00	5.91	5.90	5.91
CYCLE HEAT RATE (GROSS)	BTU/KWH	10,574	9,324	8,978	8,881	8,883	8,897
PLANT HEAT RATE (NET)	BTU/KWH	15,654	12,235	11,411	11,179	11,172	11,183
	Oh	22,059	38,190	53,741	73,591	79,399	83,220

Figure 4.2-19. Diagram A (Continued)

Figure 4.2-20. Heat Balance Diagram

Figure 4.2-21. Heat Balance Diagram

Figure 4.2-22. Heat Balance Diagram

Figure 4.2-23. Heat Balance Diagram

Figure 4.2-24. Heat Balance Diagram

Figure 4.2-25. Heat Balance Diagram

PARAMETER	100% SOLAR ONLY	22% FOSSIL 78% SOLAR	25% FOSSIL 75% SOLAR	35.5% FOSSIL 64.5% SOLAR	50% FOSSIL 50% SOLAR	100% FOSSIL
DESIGN POINT	WINTER SOLSTICE 2:00 PM	SUMMER SOLSTICE	————	ANNUAL AVERAGE	————	————
GROSS MWe	31.1	50	50	50	50	50
GROSS TURBINE HEAT RATE BTU/KW-HR	9067	9001	9001	8994	9020	9017
THROTTLE CONDITIONS						
FLOW, LB/HR	253710	427212	427183	426431	427022	428561
PRESSURE, PSIA	1265	1265	1265	1265	1265	1265
TEMPERATURE, °F	950	950	950	950	950	950
FOSSIL BOILER CONDITIONS						
FLOW, LB/HR	0	93519	106346	150996	213211	428561
PRESSURE, PSIA	1265	1265	1265	1265	1265	1265
TEMPERATURE, °F		840	862	940	950	950
RECEIVER ATTEMPERATOR INLET						
FLOW LB/HR	250083	332138	314030	270639	210312	0
TEMPERATURE, °F	985	987		986	9847	0

Figure 4.2-26. T/G System Performance

4.2.2.2 CODE REVIEW

The mechanical conceptual design for the solar repowering of Reeves Unit No. 2 was reviewed on the basis of the applicable design codes and standards. The codes that apply are:

- ASME Boiler and Pressure Vessel Code, Section I, Part PG-58
- ANSI B31.1, Power Piping Section 122 (Design Requirements Pertaining to Specific Piping Systems), Boiler External Piping

The code sections that apply to the solar repowering of Reeves Unit No. 2 deal with two boiler applications, where the main steam lines are cross connected. Cross connecting two boilers such as is required for this solar repowering application requires that double isolation valves be installed at the interface points within the area of code jurisdiction.

Drawing L-22929 Sheets P3-1 and P3-6 show the ASME Code/ANSI B31.1 interfaces.

On Sheet P3-1 a potential code problem exists with the interfacing of the receiver steam line with the existing steam line from the oil-fired boiler. The second isolation valve on the oil-fired boiler, MOV-1-1, can be located in two different places as indicated below; the advantages and disadvantages of these locations are discussed.

- (a) MOV-1-1 could be located immediately upstream of the interface with the receiver steam piping, in the existing steam pipe from the oil-fired boiler.

The principal advantage of this location is that during periods of solar system only operation, the steam piping between MOV-1-1 and the oil-fired boiler would be free of steam and could be drained dry.

The problem with this location is that the main steam line from the oil-fired boiler to the outlet of MOV-1-1 would then fall under the jurisdiction of the ASME Code and would require inspection and code stamping. Since this steam piping is approximately 20 years old, the code would require that a complete check of the metallurgical and fabrication records be made of this piping with the possibility present that this steam piping may have to be replaced if the piping material has been derated by the ASME.

There is a possibility that oxygen could also be introduced into this piping resulting in corrosion products if the blowdown valve located between the two isolation valves is left open. This valve would be open if maintenance work is performed on the oil-fired boiler during turbine operation on solar receiver steam.

- (b) MOV-1-1 could be located at the oil-fired boiler superheater outlet adjacent to the existing boiler block valve.

This location of MOV-1-1 would move the ASME Section I code jurisdiction back to the oil-fired boiler superheater outlet and would remove the existing steam line from ASME code requirement. If this location for MOV-1-1 is used, for conditions of solar only operation, the length of steam line to the oil-fired boiler would contain dead steam with some probable condensation in the line. This should not cause a corrosion problem since the feed-water has been treated to remove oxygen. During overnight shut down of the plant with no fossil fuel boiler firing, air would most likely enter into this section of pipe and present a potential corrosion problem. It is recommended, therefore, that during the initiation of startup of the solar receiver steam generator in the morning, this section of steam line should be blown out through the vent line shown on flow diagram Sheet P3-1. This should remove any corrosion products and air that may be in the line.

The recommended location for MOV-1-1 is item (b) above, which is locating the valve at the superheater outlet of the oil-fired boiler. Sheet P3-1 shows this location and the limits of ASME Section I code jurisdiction.

A drain pot that includes a level control valve and level switches connected to the turbine water induction protection system will be installed in the low point of the existing steam line from the fossil boiler superheater outlet to the interface with the receiver steam line. The purpose of this drain pot is to collect condensate formed in this section of piping during solar-only operation. This condensate will be drained to the condenser. This drain pot is shown on flow diagram Sheet P3-1.

Sheet P3-6 shows the code limits at the outlet of the receiver with a free blow to atmosphere located between the two isolation valves. This free blow line could also be used to warm up the receiver steam line using oil-fired boiler steam.

It is also recommended that the location of valve MOV-1-1 be studied further during the detailed design phase, and the feasibility of ASME coding the existing steam piping should be investigated.

4.2.2.3 PIPING INTERFACE DESIGN

The new piping for the solar portion of the project will be interconnected with the existing Unit No. 2 piping as both the boilers (Fossil and Solar) will deliver steam to the existing turbine/generator. These interconnection points are shown on the P4 Series Drawings where the existing plant piping and facilities have been shown in light tones and the new items shown in bolder tones.

The same technique of fading the original drawing data and darkening the new information has been used on the P and I Diagrams on the P3 Series Drawings. Thus, any interface between existing and new piping can be located on either a piping detail drawing or a P and I Diagram.

4.2.2.4 EQUIPMENT AND MOTOR LIST

This section describes in tabular form the additional equipment required for repowering the Reeves Unit 2 Station. Table 4.2-9 shows the equipment list developed for this conceptual design and includes mechanical equipment, water treating equipment and solar system equipment. Table 4.2-10 is the motor list that tabulates horsepower and voltage requirements for the required equipment. These lists are not total plant equipment or motor lists, but are lists of additional required equipment for the Reeves Unit.

4.2.2.5 AUXILIARY POWER REQUIREMENTS

This section defines the auxiliary power requirements for the solar repowered Reeves Unit No. 2. Table 4.2-11 shows the additional equipment power required for the solar repowering along with an estimated equipment load factor to account for the noncontinuous use of some of the equipment. The table also shows the auxiliary power requirement as it now exists for the Reeves Unit No. 2 so that a total auxiliary power requirement for the repowered plant can be defined. The existing Reeves Unit No. 2 auxiliary power of 5.5 percent of gross is based on an interpretation of existing plant test data.

TABLE 4.2-9. EQUIPMENT LIST (1 of 2)

<u>EQUIPMENT</u>	<u>QUANTITY</u>	<u>DESCRIPTION</u>
I MECHANICAL EQUIPMENT		
(1) Receiver Feed Pumps	2	100% Capacity, 740 GPM, TDH = 5800FT. Var. Sp., 2000HP Motor.
(2) Variable Speed Couplings	2	American Std., Type vs, Class-6, Size 171A
(3) No. 6 Receiver Feed Water Heater	1	Shell & Tube Type, Monel, Desup., Condensing, Sub cooling sections
(4) No. 7 Receiver Feed water heater	1	Shell & Tube Type, Monel, Desup, Condensing, Sub Cooling Sections
(5) Receiver Steam Attenuator	1	Yarway, 33000 Lb/Hr., 1000°F down to 400°F Min.
(6) Receiver Steam Moisture separator	1	
(7) Receiver steam piping drain pots & level controls	3	
(8) Condensate Hotwell Pumps	2	60% capacity, 353 GPM, TDH = 422 Ft. 1760 RPM, 60HP Motor.
(9) High Quality Sump Pumps	2	100% Capacity, duplex, 20 GPM, V50 Ft. TDH = 50 Ft.
(10) Low Quality Sump Pumps	2	100% capacity, duplex, 20 GPM, TDH = 50 Ft.
(11) Acid Sump Pump	1	100% Capacity, Submersible
(12) Caustic Sump Pump	1	100% Capacity, Submersible
(13) Emergency Diesel Generator	1	1600 KVA, 80% P.F., 240 V.

TABLE 4.2-9. EQUIPMENT LIST (2 of 2)

<u>EQUIPMENT</u>	<u>QUANTITY</u>	<u>DESCRIPTION</u>
II WATER TREATMENT EQUIP.		
(1) Demineralizer	1	TWO TRAIN, 3-BED, 376 PM/ Train complete with controls & Control Panel
(2) Condensate Polisher	2	100% capacity Each, 706 GPM, including regeneration tanks & controls
(3) Acid Tank	1	5000 Gal., 66° Be' Sulfuric Acid
(4) Caustic Tank	1	5000 Gal, sodium hydroxide
(5) Acid Feed Pumps	2	100% Cap., positive displ.
(6) Caustic Feed Pumps	2	100% Cap., positive displ.
(7) Ammonia Feed System	1	1-pump, mixing tank, measuring tank
(8) Sample panel	1	Complete with valves, controls, sample coolers, etc.
(9) Cation feed pumps		2-100% capacity, each pump 40 GPM, TDH = 175 Ft., 3 HP
III SOLAR SYSTEM EQUIPMENT		
(1) Collectors	4289	38 m ² Each, McDonnell Douglas
(2) Receiver Assembly	1	Includes receiver, flash tank and controls. Rocketdyne once through boiler, external receiver

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CORPORATION

MOTOR LIST

ORDER NO. C-20266

CUSTOMER PUBLIC SERVICE CO. OF NEW MEXICO

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ISSUE:

DATE:

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TABLE 4.2-10. MOTOR LIST (1 of 2)

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REV. NO	A-ACTUAL E-ESTIMATED	NAME PLATE DESCRIPTION	H.P.	RPM (SYN)	VOLTAGE PHASE & FREQUENCY	ENCLOSURE	INSULATION	TEMP. RISE ABOVE 40°C	FULL LOAD AMPERES	LOCKED ROTOR AMPERES	SPACE HTR WATTS	REMARKS	P.O. NO. OR CONTRACT NO.
		Condensate Hotwell	60	1800	460/3/60							Replacements for	
		Pump - 2A										Existing Pumps	
		Condensate Hotwell	60	1800	460/3/60							Replacements for	
		Pump - 2B										Existing Pumps	
		Receiver Feed Pump 2A	2000	3600	4160/3/60								
		Receiver Feed Pump 2B	2000	3600	4160/3/60								
		Pump 2A Cation Feed Water	3	1800	460/3/60								
		Pump 2B Cation Feed Water	3	1800	460/3/60								
		Pump 2A Demineralizer Acid Feed	1/2		460/3/60	TENV	B						
		Pump 2B Demineralizer Acid Feed	1/2		460/3/60	TENV	B						
		Feed Pump 2A Demineralizer Caustic	1/2		460/3/60	TENV	B						
		Feed Pump 2B Demineralizer Caustic	1/2		460/3/60	TENV	B						
		Acid Feed Pump 2A Condensate Polisher	1/2		460/3/60	TENV	B						
		Acid Feed Pump 2B Condensate Polisher	1/2		460/3/60	TENV	B						
		Caustic Feed Pump 2A Condensate Polisher	1/2		460/3/60	TENV	B						
		Caustic Feed Pump 2B Condensate Polisher	1/2		460/3/60	TENV	B						

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TABLE 4.2-11. AUXILIARY POWER REQUIREMENTS (1 of 2)

REEVES UNIT 2 SOLAR REPOWERINGAdditional Solar Systems Equipment

<u>EQUIPMENT</u>	Gross Power, Watts	Estimated Load Factor	Net Aux. Power, Watts
1. Receiver feed pump, one full capacity pump (1512 hp)	1,128,000	1.0	1,128,00
2. Heliostats 4200 heliostats steady state usage 14 W/helio	58,800	1.0	58,800
3. Demineralizer cation feed pump one full capacity pump (3 hp)	2,237	0.25	559
4. Demineralizer acid feed pump (1/2 hp)	373	0.25	93
5. Demineralizer caustic feed pump (1/2 hp)	373	0.25	93
6. Condensate polisher acid feed pump (1/2 hp)	373	0.25	93
7. Condensate Polisher caustic feed pump (1/2 hp)	373	0.25	93
8. Ammonia feed pump (1/2 hp)	373	1.0	373
9. Low quality sump pump (1/2 hp)	373	0.25	93
10. High quality sump pump (1/2 hp)	373	0.25	93
Total Solar Systems Equipment Aux. Power =			<u>1,188,290</u>

TABLE 4.2-11. AUXILIARY POWER REQUIREMENTS (2 of 2)

Gross Electrical Output	50 MW
Existing Plant Aux. Power (50 MW x 5.5%)*	(2.75 MW)
Additional Power Requirement for Solar Equipment	<u>(1.19 MW)</u>
Net Plant Output	46.06 MW
Aux. Power as a % of Gross Output	7.9%

*Test data average

4.2.2.6 TURBINE GENERATOR

Reeves Unit No. 2 is a Westinghouse 44 MW capacity, two-casing, tandem, 3600 rpm, double flow, AIEE-ASME preferred standard turbine designed for operating steam conditions of 1250 psig, 950°F and 1.5 in-Hg-abs exhaust pressure. The turbine is guaranteed for 44 MWe with rated steam inlet conditions with 3.5 in-Hg-abs exhaust pressure, five stages of feedwater heating and three percent makeup.

The Reeves Unit No. 2 has two combination stop and throttle valves, one mounted on each side of the steam chest that includes the following:

- Provision for testing each throttle valve while unit is in operation.
- Solenoid trip device for remotely tripping throttle valves and closing control valves
- Two signal switches on each throttle valve for remote indication of throttle valve position
- Signal switch on each throttle valve, which connected in series, will trip the main circuit breaker when both throttle valves are closed
- Removable steam strainer for each throttle valve body

A separate over-speed governor will trip the throttle valve in the event of 10 percent over-speed and a provision is included to test the over-speed trip while it is operating without over-speeding or tripping the turbine. The steam chest is integral with cylinder cover containing multiple governor control valves.

A hydraulically operated governing system controls the position of the governor control valves. The system has adequate response to prevent over-speed trip in the event of a sudden loss of load. The speed regulation is two percent for a gradual change in load equal to half the unit rating. The system is provided with a hand-operated steam flow limit device. The speed changer is suitable for hand and motor operation; speed changer range is plus or minus five percent of rated speed.

The complete oil system contains an oil reservoir, main oil pump mounted on turbine shaft, twin oil coolers, auxiliary oil pumps mounted on oil reservoir, and vapor extractor mounted on oil reservoir.

The thrust bearing is a pivoted shoe-type. Two thermometers are mounted on the exhaust hood. The turning gear is motor operated.

Tripping devices are provided for low vacuum and excessive thrust loading. Exhaust relief diaphragms are provided in exhaust hoods.

The Reeves Unit No. 2 performance specification is summarized as follows:

The heat consumption, when operating under design conditions, will not exceed the quantities specified below. These quantities include steam used and consumed by the turbine, and losses in the generator, including energy required in the field for excitation, and the losses of the exciters.

<u>kW</u>	<u>P-f</u>	<u>Heat Rate (Btu/kWh)</u>
44,000	0.935	8,955
40,000	0.85	8,964
30,000	0.85	9,095
20,000	0.85	9,485
10,000	0.85	10,618

The unit has been operated as a base-loaded unit except at night and during the noon hour.

The following repairs were made during an outage of April 1971:

- Lower pressure blades were modified to include stellite strips
- Cracks on the high pressure outer casing and main steam connections at horizontal joint were welded
- Magnaflux test performed on the bottom half of low pressure blade ring — found no defects
- Cracks in nozzle chamber were removed by grinding

- One small surface crack from shroud of Row #28 was removed
- The high pressure rotor expansion groove near control stage was machined

PNM plans to modify this unit for cyclic operation in preparation for planned intermediate dispatching in 1980. All major turbine components will be investigated and upgraded where appropriate as recommended by the manufacturer for optimum thermal cycling durability. PNM plant engineering and operational personnel are continuing to assess required modifications and will complete these actions by the end of calendar year 1979.

4.2.2.7 GENERAL ARRANGEMENT — EPGS

The additional equipment required for the solar repowering excluding the receiver and heliostats is to be located indoors. The west side of the existing building offered the best location for a new building addition at the interface of the existing Units No. 1 and 2. This location also offers the most convenient access to the existing piping interface points, thereby minimizing the length of new pipe runs. The arrangement for this is shown on Drawing L-22929 Sheets G1-1, G1-2 and G1-3.

Consideration was given to locating the new equipment in the existing building. This has two major disadvantages:

- Unit No. 2 would have to be completely shut down during the entire construction period if the work were to be done in and around the operating equipment, thereby placing additional load on the PNM system. Construction work can continue while Unit No. 2 is operating by constructing a separate building. When the new construction is ready, the existing equipment would be shut down on a schedule that would minimize operating downtime.
- Because of space limitations in the existing building, a much less functional equipment layout would result, thereby increasing operation and maintenance costs over the life of the equipment.

Within the new building addition, there are three levels. In general, equipment has been located on the same level as the original equipment was located in the existing building. This to further take advantage of the original plant equipment layout.

GROUND FLOOR

All water treating equipment is located on the ground floor — the full flow Condensate Polishers are located close to the Hotwell Pumps, so that pipint runs are minimized.

The Acid and Caustic Storage area is on the outside wall, furthest from the existing building, to minimize potential problems in case of leaks and to facilitate loading of the tanks. Each tank is located in a separate 6-foot high lined concrete enclosure that contains the liquid in case of a tank rupture. The enclosures have individual sumps with pump-out connections for emergency use of portable submersible chemical pumps. Acid fill connections penetrate the west wall so that tanker fill hoses remain outside of the building. It is planned that tank loading will use air pressure on the supply tanks to transport the acid and caustic. A freeze-proof combination eyewash and safety shower is located outside within 25 feet of the fill connections (OSHA requirements).

All acid and caustic pumps are enclosed by an 8-inch high curb to contain leakage. Equipment drains go to either the high or low quality sumps. High quality water from the Condensate Polisher, the demineralizers and the cooling water drains from the Receiver Feed Pumps will be piped to the high quality sump and from there to a suitable holding basin for possible reuse. All other drainage passes into the lined trench and flows by gravity to the low quality sump for disposal in an evaporation pond located west of the plant. Space is available in the northeast corner of the building addition for a future Condensate Polisher for Unit No. 1 should the need arise.

Solar Receiver Feed Pumps No. 2A and 2B are located close to the existing building wall where the length of the suction lines from the connection points near the Unit No. 2 Boiler Feed Pumps will be minimized. 2400-volt power to these pumps will come from the new switchgear located on the operating floor. Space is allocated for a third receiver feed pump for future repowering of Unit No. 1.

A new ammonia feed pump and storage tank will be located in the existing chemical feed treating area in order to keep all of the chemical treating equipment together.

Existing Hotwell Pumps No. 2A and 2B will be replaced with higher pressure units requiring deeper sumps although the locations will be the same. The existing piping will be modified as needed to connect to the new pumps.

480-volt ac Motor Control Center MCC-2A and its associated load center will house the controls and starters for the small pumps and all other new equipment in the general building area, except the Receiver Feed Pumps which will be fed from the new switchgear.

MEZZANINE FLOOR

Much of the mezzanine area will contain cable trays for power and computer applications. Main power cable will connect to and from the switchgear located on the Operating Floor. Computer interconnecting cable and input data leads will be run on this level below the Computer and Logic Rooms.

A battery room and Uninterruptible Power Supply (UPS) will also be located on this level in order to keep them close to the Computer and Logic Rooms.

An additional Emergency Diesel Generator will be located in the north east corner of the existing building immediately adjacent to the existing diesel generator unit. Space is available in this area that will be walled off from the remainder of the existing building.

OPERATING FLOOR

The operating floor level of the solar equipment building addition contains the computers and their associated software. In the Computer Room are the Master Control System computer, the Collector computer, the Analog/Digital multiplexing equipment, the consoles for programming and engineering, and the printing and recording equipment. The Logic Room contains the various control system hardware. This equipment is interconnected to the new Solar Systems Master Control Console and data display panels located in the existing Station Control Room. Because of the limited space available in the Control Room only operating control equipment can be placed there.

The new Switchgear was located on the operating floor above the mezzanine level to allow ample room for cable trays and cable spreading underneath. The Switchgear layout is sized to allow feeds for the two new Receiver Feed Pumps, the power supply to the collector field, the feeder for MCC-2A and its load center and a future supply to Unit No. 1 should it be repowered.

The computer and logic rooms will be protected from fire by Halon 1301 flooding systems whose manifolds and cylinders will be located on the operating floor just outside each room. These two rooms will be the only new areas that are air conditioned.

Space is available due to the removal of the evaporator and associated piping in the existing Unit No. 2 area for new Feedwater Heaters No. 6 and No. 7. This location is immediately adjacent to the turbine that is the source of the extraction steam used for heating the feedwater.

ROOF

All air handling equipment for the new building addition will be roof mounted. This is an ideal location because all levels require heat and ventilation.

Supply and return ductwork will extend from the heating and ventilating units on the roof, through the operating floor and mezzanine levels to the ground floor.

Exhaust fans will be roof-mounted with exhaust air being picked up at all three levels.

The roof mounted air conditioning unit located directly over the computer and logic rooms will supply cooled air to those rooms and will take its return air from the same area.

4.2.3 FACILITIES REVIEW

4.2.3.1 WATER TREATMENT

Solar repowering of a fossil-fueled power plant presents some special water treatment problems because the solar powered portion of the system will cycle

daily (much as in a peaking unit) and the solar boiler in this case will be a once-through design and have small-diameter boiler tubes. A unit subject to daily startups and shutdowns is more susceptible to corrosion and deposition than one that is continuously operated.

MAKEUP WATER

The makeup water for the plant is currently taken from existing wells. One water analysis has been provided for each of the two wells. The following design analysis (which is 10 percent higher in each constituent than the worst well water analysis obtained) is considered applicable:

Makeup Water Analysis

<u>Constituent</u>	<u>mg/l as CaCO₃</u>
Calcium	155
Magnesium	34
Sodium	57
TOTAL Cations	246
Bicarbonate	160
Sulfate	69
Chloride	17
TOTAL Anions	246
Silica	<u>26.6</u> (for ion exchange)
TOTAL Exchangeable Anions	272.6
Iron	0.10 (as Fe)
Manganese	0.10 (as Mn)
Turbidity	1.7 JTU
pH	8.1
Suspended Solids	less than 5
TOC (TOTAL Organic Carbon)	7

PRETREATMENT

Pretreatment might be required upstream of the boiler makeup water treating at certain times in order to reduce the load on the equipment. Pretreatment of

the well water could be required if the suspended solids, organic matter, or colloidal material contents were high in the wells. Pretreatment of well water could also be required if there are relatively large amounts of iron or manganese in the well water. However, the quantities of suspended solids, total organic carbon, iron and manganese given in the makeup well analysis do not appear to be high enough to require such pretreatment.

The Makeup Water Analysis indicates that the hardness and alkalinity of the well water is high enough that the use of lime softening as a pretreatment method to reduce the hardness and alkalinity and thereby lower the cost of demineralization was considered. The flow rate of demineralized water will be relatively low and the demineralizer equipment will be relatively small, therefore the use of lime softeners does not appear to be economically justified.

BOILER MAKEUP TREATMENT

The boiler feedwater and the boiler makeup must be of the very highest quality since any dissolved or suspended material entering the boiler will either deposit there or carry through to the turbine. No material can be allowed in the feedwater other than chemicals specifically designed for once-through boilers. Demineralization is required in this case for the production of high quality boiler makeup water.

Based on the given water analysis and the boiler makeup quality requirements of this system, a demineralizer consisting of two demineralizer trains is recommended. Each train will consist of a cation exchange vessel, with conventional cation resin; an anion exchange vessel, with Rohm and Haas IRA-458 anion resin; and a mixed-bed exchange vessel, containing a conventional cation resin with a strongly basic Type 1 anion resin.

CONDENSATE POLISHING AND CYCLE CLEANLINESS

Condensate Polishing

As indicated above, solids present in the feedwater to a once-through steam generator will be deposited on the boiler surfaces or in the turbine. The presence of small quantities of such material in the feedwater is inevitable

due to corrosion in the condensate feedwater cycle. Even though corrosion is reduced to a very low level by deaeration and pH control, it cannot be completely eliminated. A unit subject to daily startups and shutdowns is even more susceptible to corrosion than a continuously operated unit. Accordingly, full-flow condensate polishing is essential in order to maintain feedwater total solids at the required 20 to 50 ppb level. A condensate polisher is an ion exchange unit of sufficient capacity to treat the entire plant condensate stream.

Two basic types of condensate polishers are available, deep-bed and powdered resin: the deep-bed unit uses bead-form, strongly acidic cation exchange resins and strongly basic anion exchange resins in a mixed-bed configuration to remove impurities from the water by ion exchange and filtration. The resins are regenerated, as required, with acid and sodium hydroxide. The powdered-resin unit employs a thin layer of powdered resin deposited on a nylon or stainless-steel septum; it also removes impurities by ion exchange and filtration. When the pressure drop across this unit exceeds a predetermined value, the unit is taken out of service, the resin is removed by back flushing, and fresh resin is applied; there is no regeneration.

Both types of condensate polishers remove ionized dissolved solids such as might be present from a condenser leak. However, the reserve ion exchange capacity of a powdered-resin polisher is very small. Therefore, in the event of a slight condenser leak with its high suspended solids loading, operation could not be continued for any significant period of time with a powdered-resin unit.

Because of the reasonable possibility of slight condenser leaks a deep-bed polisher is recommended for this facility.

Cycle Cleanup

As a result of the types of boiler systems being considered, there are a number of special startup requirements that are required.

When boiler units are subjected to frequent (daily) startups and shutdowns more corrosion and solid particles (suspended solids) are generated. To reduce that load of solids, it may be necessary to flush the receiver and feedwater piping daily.

It cannot be determined at this time how often such action would be required, but provisions must be made, in any case, to flush water through the solar boiler tubes and piping to the condenser so that system impurities and solids can be removed in the condensate polisher.

When both the fossil-fueled boiler and the solar boiler are out of service, the fossil-fueled boiler should be started up first — so that the preboiler system may be cleaned before the solar boiler started. If the solar boiler must be started up without the fossil-fueled boiler, then provisions must be made to recycle the preboiler system to the condenser (at least that portion ahead of the solar boiler) so that the condensate polisher may be used to remove suspended solids and other impurities from the preboiler system.

It will be necessary to direct the low-pressure heater drains to the hotwell, at least at times when the system is being started up. These drains are a major source of unwanted particles and by directing the drains to the hotwell, the condensate polisher will be able to remove the contamination before it can get into the solar boiler.

FEEDWATER TREATMENT

"Volatile" treatment has been well established as the appropriate method of treating feedwater for once-through steam generators. With this approach, no solid chemicals (such as phosphate or caustic soda) are added to either the boiler or the preboiler cycle. Hydrazine is added to the feedwater to remove any last traces of dissolved oxygen. Any excess hydrazine will decompose at elevated temperature and pressure to produce nitrogen and ammonia. Thus, in addition to being volatile itself, hydrazine reaction products are also volatile. The ammonia thus formed reduces the requirement for another pH-control chemical. For systems using a once-through steam generator, ammonia is generally added to the feedwater to elevate the pH sufficiently to reduce corrosion to a practical minimum. Neutralizing amines are used in some systems (primarily those with drum-type boilers) in place of ammonia for pH adjustment. Their chief advantage is that, unlike ammonia, amines do not contribute to the corrosion of copper-bearing alloys. Ammonia is considerably less expensive than neutralizing amines,

and since a condensate polisher will remove some of the pH adjusting chemical, the material cost could become a significant operating consideration.

In general, a deep-bed condensate polisher may be operated in either the hydrogen-hydroxide cycle or the ammonia-hydroxide cycle. Immediately after a polisher is regenerated, the cation resin is in the hydrogen cycle and the anion resin is in the hydroxide cycle. The cation resin will become exhausted rather quickly by the ammonia (or amine) in the feedwater. The ammonia (or amine) must be replaced downstream of the polisher.

In systems that use ammonia for pH control, after the cation is exhausted, the polishers are said to be operating in the ammonia-hydroxide cycle. In conventional once-through systems, the polishers may operate for very long times in the ammonia-hydroxide cycle if the impurities load is low or there is no condenser leak. However, special regeneration equipment is required to operate in the ammonia-hydroxide cycle in order to reduce the sodium leakage that normally occurs after the cation resin is converted to the ammonia form.

In the case of a solar boiler, the impurities load can be expected to be high as a result of the daily startups and shut downs. It is therefore expected that the condensate polishing resin will require regeneration frequently, due to the high impurities loading, and no provision will be made for operating in the ammonia-hydroxide cycle.

CONDENSER TUBE MATERIAL

In general, it is our recommendation that copper alloys and ferrous alloy tube material not be mixed in the feedwater system. We recognize that this has been and probably is still being done in once-through boiler systems. However, the trend is toward all ferrous or all copper alloy systems. In this installation, it is recommended that the existing admiralty tubes in the air removal section of the condenser be replaced with 90/10 Cu/Ni tubes.

If copper alloys are used, the pH should be maintained in the range of 8.8 to 9.2. If ferrous alloys are used, the pH should be in the range of 9.5 to 9.7.

If both alloys are used in the feedwater system, either the copper will be corroded by ammonia or the iron will be corroded by low pH.

Copper alloys can be tolerated as a material for the condenser tubes in once-through systems with full-time condensate polishing because the corrosion products from the condenser would be reduced to a low-level by the condensate polisher.

HIGH-PRESSURE HEATER DRAINS AND DEAERATOR BLOWDOWN

In addition to directing the low pressure heater drains to the hotwell, piping should be included to cascade the high pressure heater drains back to the low pressure heater drains during the start-up of the feedwater system. Provisions should also be made to blow down the deaerator back to the hotwell. The high-pressure heater drains should be cascaded back to the low-pressure drains until the unit load reaches approximately 25 percent. The deaerator storage tank would act as a trap for suspended contamination which could be released during subsequent flow changes. Blow-down of the deaerator storage tank should be initiated if there are signs that the water there is contaminated.

BOILER WATER MONITORING

A considerable amount of instrumentation for monitoring the boiler water in modern high-pressure or once-through boiler systems is required. Boiler feedwater and steam must be monitored during all phases of start-up and operation to ensure that system cleanliness and other parameters are maintained. Figure 4.2-27 is a schematic drawing of a typical water sampling and monitoring system.

DEMINERALIZER

- (1) Two makeup water demineralizers, three bed trains, automatic controls:
 - Rating 37 gpm per train
 - Effluent quality:
 - Total dissolved solids — 50 ppb max
 - Silica — 10 ppb max

NOTES

1. SAMPLE COOLING PRESSURE REDUCTION, VALVING AND BLOWDOWN DETAILS NOT SHOWN
2. SAMPLE RECLAIM AND ANALYZER WASTE SYSTEMS NOT SHOWN
3. SHARED ANALYZER DETAILS NOT SHOWN

CE CONDUCTIVITY ELEMENT
 CI CONDUCTIVITY INDICATOR
 AT ANALYZER TRANSMITTER
 IN ANALYZER INDICATOR
 pHE pH ELEMENT
 pH1 pH INDICATOR
 □ CATION EXCHANGER

Figure 4.2-27. Water Sampling and Monitoring System

- (2) One demineralizer acid tank, 5000 gal
- (3) Two demineralizer acid pumps (1 spare), 1/2 hp, 460V ac motor
- (4) One demineralizer caustic soda tank, 5000 gal
- (5) Two demineralizer caustic soda pumps, 1/2 hp, 460V ac motor
- (6) One control panel

CONDENSATE POLISHING

Two full-capacity, mixed-bed polishers, 706 gpm per vessel

- Effluent quality, 30 to 40 ppb total dissolved solids, 90 percent suspended solids removed
- Including regeneration tanks and controls

AMMONIA FEED

- One ammonia solution feed tank, 55 gal, including a concentrated ammonia solution measuring tank
- Two ammonia solution feed pumps, 1/2 hp, 460V ac motor

SAMPLE PANEL

Sample panel including instruments, coolers, etc., per Figure 4.2-27.

CATION FEEDWATER PUMPS

Two 100 percent capacity horizontal centrifugal pumps to supply raw water to the demineralizer.

- Design Data:
 - 40 gpm
 - 3 hp
 - 175-ft TDH
 - 1760 rpm

4.2.3.2 BEARING COOLING WATER

The addition of the solar system equipment for the solar repowering of the Reeves Unit No. 2 will add to the heat rejection duty of the existing cooling water system.

Specifically, the additional equipment to be added to the water system (Ref. Drawing No. L-22929, Sheet No. P3-2) are:

- a. Receiver feedwater pumps:
 - Hydraulic coupling oil cooler
 - Lube oil cooler
 - Stuffing box cooler
- b. Sample Coolers:
 - Receiver feedwater
 - Receiver steam
- c. Demineralizer feed

The receiver feedwater pumps and hydraulic drive coolers are estimated to require 200 gpm of cooling water when operated at maximum capacity based on the summer solstice design point. The maximum cooling water usage will occur during solar/fossil hybrid operation at a gross output of 50 MW. However, the fossil-boiler feed pumps will be operating at below capacity since the solar portion will be supplying the major portion of the plant output. The net increase on the water system due to the receiver pumps is therefore estimated to be 89 gpm over the present operating conditions.

The sample coolers are estimated to require an additional 4 gpm bringing the total additional cooling water requirements to 93 gpm.

Operating data for Reeves Unit No. 2 indicate that for 38 MW output the cooling tower makeup requirement is 703 gpm, or scaled-up to 50 MW output approximately 925 gpm

The additional 93 gpm cooling load will therefore be subtracted from the cooling tower makeup which is supplied directly from the raw water storage tanks. This additional cooling water is assumed to act as cooling tower makeup, because after being discharged from the coolers it is drained to the bearing cooling water sump and then pumped into the circulating water system and ultimately into the cooling tower basin.

Flow in the 8-inch 602-raw water supply header will increase from a maximum of 771 gpm to 864 gpm. This flow increase will increase the velocity from 5-feet per second to 5.6-feet per second and the pressure loss from 1.0-feet per 100 feet to 1.14-feet per 100 feet. This increase in velocity and pressure loss does not appear at this time to warrant an increase in pipe size; however, this area will be studied in more detail during the design phase.

The new demineralizer feedwater is also taken from the raw water system at the rate of 37 gpm. This should have little impact on the water balance since Reeves No. 2 boiler makeup water has been taken from the water supply system and through the plant's existing water treatment system.

The Unit No. 1 bearing cooling water system drains to a common sump with the Unit No. 2 system. Apparently, the sump pump located in this sump is presently marginal in its capacity with both units operating. It is recommended that during detailed design, this pump be investigated and a determination should be made as to the desirability of installing separate sumps and pumps for each unit.

4.2.3.3 FIRE PROTECTION

In the new Solar Equipment building addition some fire protection will be required. In general, equipment and personnel will be protected because the basic structure is of nonflammable construction.

In the computer and logic rooms, Halon 1301 total flooding systems are recommended. Separate systems for each room are advised with the cylinders and manifolds to be located outside of the rooms in the switchgear area.

The switchgear area of the operating floor will have four photoelectric fire detectors. As many as 10 additional detectors would be placed over the cable trays in the mezzanine area. All detectors and the Halon systems will be connected to a new multi-zone control/alarm panel to be located near the existing fire alarm/control panel.

Hose stations and combination safety showers will be required on the first floor. A hose station with 100 feet of 1-1/2-inch hose will be located at a central location. Combination eyewash/safety shower stations will be located adjacent to the Condensate Polisher, the Acid and Caustic Storage area, and the Demineralizer area. The acid and caustic fill connections will be located outside the building.

Fifteen pound carbon dioxide fire extinguishers will be located at various points throughout the building additions.

Fire hydrants will be provided in the area of the receiver tower and the warehouse.

4.2.3.4 HEATING, VENTILATION AND AIR CONDITIONING

During the warmest weather, the new building addition will require some air conditioning in the computer and logic rooms. The entire addition will need heating or ventilation all year. The equipment sizing is based upon the building addition being of an architectural design similar to that of the existing station building. All HVAC units will be roof-mounted, with the supply and return ductwork extending downward through the building. Steam for the heating coils will be supplied from a header near the existing No. 2 condenser.

Major equipment items include:

1. Rooftop air conditioning unit complete with power return, 20 tons of cooling, 200 MBh steam heating coil and controls as needed
2. Rooftop heating and ventilation units complete with power return, 25,000 cfm capacity, 370 MBh steam heating coil and controls as needed
3. Rooftop exhaust fans, dome type, 1000 cfm capacity

4.2.4 SYSTEMS OPERATION

For the repowered unit, steam may be produced from either the solar or fossil boiler or from a combination of both. The unit will be in a condition of both boilers shut down and no electrical load being produced, or in a steady-state operating mode with the turbine generator on-line producing electricity with steam supplied by one or both boilers. The unit transitional states are the transition from a unit shutdown mode to an on-line mode (Plant Startup) or the reverse (Plant Shutdown). In addition, the unit can be in transition from one boiler operating to both boilers operating (Plant Operating with Startup of a second boiler, solar or fossil) or vice-versa (Plant Operating with Shutdown of one boiler). If the mode of all units being shut down is disregarded, then five possible unit operating modes exist: Plant Normal Operation, Plant Startup, Plant Shutdown, Plant Operating with Startup of a second boiler, Plant Operating with the Shutdown of one of the boilers.

Within these plant modes each can be in various states. The operating solar boiler can be defined in terms of the day's solar insolation condition. Basically, three types of insolation exist: full, a cloudless sunny day; low, an overcast or hazy day with constant cloud cover; and intermittent, a cloudy day with broken transient clouds causing relatively rapid transition in solar insolation. The starting conditions of the solar boiler are either cold, where the boiler has been shut down within the past two days and no extra water treatment must be done; or ambient, where the unit has been shut down for more than two or three days and the feedwater requires extra treatment, which requires the fossil boiler to be running.

The fossil boiler and steam turbine both have two operating states during startup: hot condition or cold condition based upon metal temperature. A startup varies in time and method for both depending upon these conditions.

Two other conditions affecting plant operation must be considered. First, the plant can be operated to maintain some fixed value of load based on an operator set load demand, or it can be responding to demand as received from some remote dispatching system (Variable Dispatch). The plant can also be shutting down equipment in a normal fashion or in an emergency mode of operation.

TABLE 4.2-12. COMBINATION OF UNIT CONDITIONS FOR OPERATION
OF THE SOLAR HYBRID REPOWERING PLANT (1 of 3)

STATE	ID	SOLAR BOILER						SUN			FOSSIL BOILER						TURBINE		LOAD		SHUTDOWN		NOT ALLOWED OPERATING MODE
		OFF	RUNNING	START	SHUT DOWN	COLDER	COLD	FULL	LOW	INTER CLOUD	RUNNING	START	SHUT DOWN	OFF	COLD	HOT	COLD	HOT	VARIABLE (INSPATCH)	BASE	EMER GENCY	NORMAL	
NORMAL OPERATION (TURBINE RUNNING NOTHING STARTING UP OR SHUTTING DOWN)	11		X			-	-	X						X	-	-	-	-		X	-	-	
	12		X			-	-		X					X	-	-	-	-		X	-	-	
	13		X			-	-			X				X	-	-	-	-		X	-	-	X
	14		X			-	-	X						X	-	-	-	-	X		-	-	X
	15		X			-	-		X					X	-	-	-	-	X		-	-	X
	16		X			-	-			X				X	-	-	-	-	X		-	-	X
	17	X				-	-	-	-	-	X				-	-	-	-		X	-	-	
	18	X				-	-	-	-	-	X				-	-	-	-	X		-	-	
	19		X			-	-	X			X				-	-	-	-		X	-	-	
	110		X			-	-		X		X				-	-	-	-		X	-	-	
	111		X			-	-			X	X				-	-	-	-		X	-	-	
	112		X			-	-	X			X				-	-	-	-	X		-	-	
	113		X			-	-		X		X				-	-	-	-	X		-	-	
	114		X			-	-			X	X				-	-	-	-	X		-	-	
PLANT STARTUP (STARTING THE TURBINE)	111			X			X	X						X	-	-	X		-	-	-	-	
	112			X			X		X					X	-	-	X		-	-	-	-	
	113			X			X			X				X	-	-	X		-	-	-	-	X
	114			X			X	X						X	-	-		X	-	-	-	-	
	115			X			X		X					X	-	-		X	-	-	-	-	
	116			X			X			X				X	-	-		X	-	-	-	-	X
	117			X		X		X						X	-	-	X		-	-	-	-	X
	118			X		X			X					X	-	-	X		-	-	-	-	X
	119			X		X		X		X				X	-	-		X	-	-	-	-	X
	1110			X		X								X	-	-		X	-	-	-	-	X
	1111			X		X			X					X	-	-		X	-	-	-	-	X
	1112			X		X				X				X	-	-		X	-	-	-	-	X
	1113	X				-	-	-	-	-		X			X		X		-	-	-	-	
	1114	X				-	-	-	-	-		X			X		X		-	-	-	-	
	1115	X				-	-	-	-	-		X				X	X		-	-	-	-	
	1116	X				-	-	-	-	-		X				X	X		-	-	-	-	
	1117			X			X	X				X			X		X		-	-	-	-	
	1118			X			X		X			X			X		X		-	-	-	-	
	1119			X			X			X					X		X		-	-	-	-	
	1120			X			X	X				X			X			X	-	-	-	-	
	1121			X			X		X			X			X		X		-	-	-	-	

TABLE 4.2-12. COMBINATION OF UNIT CONDITIONS FOR OPERATION
OF THE SOLAR HYBRID REPOWERING PLANT (2 of 3)

STATE	TIME	SOLAR BOILER						SUN			FOSSIL BOILER						TURBINE		LOAD		SHUTDOWN		NOT ALLOWED OPERATING MODE
		OFF	RUNNING	START	SHUT-DOWN	COLDER	COLD	FULL	LOW	INTER CLOUD	RUNNING	START	SHUT-DOWN	OFF	COLD	HOT	COLD	HOT	VARIABLE (DISPATCH)	BASE	EMERGENCY	NORMAL	
PLANT START UP - (CONT.) (STARTING THE TURBINE)	11:22			X			X			X		X			X		X		-	-	-	-	
	11:23			X			X	X				X			X	X	X		-	-	-	-	
	11:24			X			X		X			X				X	X		-	-	-	-	
	11:25			X			X			X		X				X	X		-	-	-	-	
	11:26			X			X	X				X				X		X	-	-	-	-	
	11:27			X			X		X			X				X		X	-	-	-	-	
	11:28			X			X			X		X				X		X	-	-	-	-	
	11:29			X		X		X				X			X		X		-	-	-	-	
	11:30			X		X			X			X			X		X		-	-	-	-	
	11:31			X		X				X		X			X		X		-	-	-	-	
	11:32			X		X		X				X			X			X	-	-	-	-	
	11:33			X		X			X			X			X			X	-	-	-	-	
	11:34			X		X				X		X			X			X	-	-	-	-	
	11:35			X		X		X				X				X	X		-	-	-	-	
	11:36			X		X			X			X				X	X		-	-	-	-	
	11:37			X		X				X		X				X	X		-	-	-	-	
	11:38			X		X		X				X				X		X	-	-	-	-	
	11:39			X		X			X			X				X		X	-	-	-	-	
	11:40			X		X				X		X				X		X	-	-	-	-	
PLANT SHUTDOWN (TURBINE SHUTTING DOWN)	11:41				X	-	-	X						X	-	-	-	-	-	-		X	
	11:42				X	-	-		X					X	-	-	-	-	-	-		X	
	11:43				X	-	-			X				X	-	-	-	-	-	-		X	X
	11:44				X	-	-	X						X	-	-	-	-	-	-		X	
	11:45				X	-	-		X					X	-	-	-	-	-	-		X	
	11:46				X	-	-			X				X	-	-	-	-	-	-		X	
	11:47					-	-	-	-	-					-	-	-	-	-	-		X	
	11:48	X				-	-	-	-	-			X		-	-	-	-	-	-		X	
	11:49	X				-	-	-	-	-					-	-	-	-	-	-		X	
	11:50			X		-	-	X					X		-	-	-	-	-	-		X	
	11:51			X		-	-			X			X		-	-	-	-	-	-		X	
	11:52			X		-	-	X					X		-	-	-	-	-	-		X	
	11:53			X		-	-		X				X		-	-	-	-	-	-		X	
	11:54			X		-	-			X			X		-	-	-	-	-	-		X	

TABLE 4.2-12. COMBINATION OF UNIT CONDITIONS FOR OPERATION
OF THE SOLAR HYBRID REPOWERING PLANT (3 of 3)

STATE	ID	SOLAR BOILER						SUN			FOSSIL BOILER						TURBINE		LOAD		SHUTDOWN		NOT ALLOWED OPERATING MODE
		OFF	RUNNING	START	SHUT- DOWN	COLDER	COLD	FULL	LOW	INTER CLOUD	RUNNING	START	SHUT DOWN	OFF	COLD	HOT	COLD	HOT	VARIABLE (UNSPATCH)	BASE	EMER- GENCY	UNHML	
PLANT RUNNING WITH START UP (STARTING SECOND BOILER)	IV-1			X			X	X			X				-	-		X		X	-	-	
	IV-2			X			X		X		X				-	-		X		X	-	-	
	IV-3			X			X			X	X				-	-		X			-	-	
	IV-4			X			X	X			X				-	-		X	X		-	-	
	IV-5			X			X		X		X				-	-		X	X		-	-	
	IV-6			X			X			X	X				-	-		X	X		-	-	
	IV-7			X		X		X			X				-	-		X		X			
	IV-8			X		X			X		X				-	-		X		X			
	IV-9			X		X				X	X				-	-		X		X			
	IV-10			X		X		X			X				-	-		X	X				
	IV-11			X		X			X		X				-	-		X	X				
	IV-12			X		X				X	X				-	-		X	X				
	IV-13		X			-	-	X				X			X			X		X			
	IV-14		X			-	-		X			X			X			X		X			
	IV-15		X			-	-			X		X			X			X		X			X
	IV-16		X			-	-	X				X			X			X	X				X
	IV-17		X			-	-		X			X			X			X	X				X
	IV-18		X			-	-			X		X			X			X	X				X
	IV-19		X			-	-	X				X				X		X		X			
	IV-20		X			-	-		X			X				X		X		X			
	IV-21		X			-	-			X		X				X		X		X			
	IV-22		X			-	-	X				X				X		X	X				
	IV-23		X			-	-		X			X				X		X	X				
	IV-24		X			-	-			X		X				X		X	X				
PLANT RUNNING WITH ONE BOILER SHUTDOWN	V-1				X	-	-	X			X				-	-	-	-		X			
	V-2				X	-	-		X		X				-	-	-	-		X			
	V-3				X	-	-			X	X				-	-	-	-		X			
	V-4				X	-	-	X			X				-	-	-	-	X				
	V-5				X	-	-		X		X				-	-	-	-	X				
	V-6				X	-	-			X	X				-	-	-	-	X				
	V-7		X			-	-	X					X		-	-	-	-		X			
	V-8		X			-	-		X				X		-	-	-	-		X			
	V-9		X			-	-			X			X		-	-	-	-		X			X
	V-10		X			-	-	X					X		-	-	-	-	X				X
	V-11		X			-	-		X				X		-	-	-	-	X				X
	V-12		X			-	-			X			X		-	-	-	-	X				X

Table 4.2-12 summarizes the probable combinations of unit conditions. Certain operating states are not felt to be valid operating states (particularly for the solar subsystems) and the plant will not be allowed to run in those modes.

- During Plant Normal Operations with only the solar boiler producing steam, the unit will not respond to electrical grid dispatching requests, but will produce whatever electrical energy is available based upon available solar thermal power. Therefore, Modes I-4, I-5 and I-6 are invalid. Also the plant cannot be reliably controlled during solar insolation transients if the solar boiler alone is producing steam. Therefore, Mode I-3, Solar Boiler Only on an Intermittent Cloudy day is an invalid normal operating mode.
- During Plant Startup, since operation with solar boiler only on an intermittent cloud day is not permitted, then neither will a plant startup with solar boiler only on an intermittent cloudy day be permitted. Thus, Modes II-3 and II-6 are invalid. Also, since the solar boiler is in the "Colder" mode (having been shut down for more than two or three days) extra water treatment requiring the fossil boiler to be in operation must be present, then Modes II-7 through II-12 are not valid since the fossil boiler is not running. Also, Modes II-29 through II-40 that involve the starting of both boilers simultaneously does not seem to be practical.
- During Plant Shutdown the only invalid mode is III-3; a normal shut down with only the solar boiler operating on an intermittent cloudy day. If the weather changes while operating the solar boiler, the shutdown (if chosen) would be an emergency shutdown or Mode III-6.

In the Plant Running with Startup of Second Boiler operating state, all modes are valid except IV-15 through IV-18. Mode IV-15 represents the starting of the cold fossil boiler while the solar boiler is running on an intermittent cloudy day. If the solar boiler is on-line and weather conditions change to an intermittently cloudy day then the solar boiler must either be shut down, taking the plant off line, or the fossil boiler must be started. However, with a cold fossil boiler the startup time of six to nine hours necessitates that the solar boiler be shut down. Modes IV-16 through IV-18 would be invalid modes since the plant will not run in a variable dispatch mode with only the solar boiler operating.

Finally, the Plant Running with Shutdown Mode, Modes V-9 through V-12, will not be permitted since after shutting down the fossil boiler, the plant will be in an invalid operation state. For Mode V-9 the solar boiler would be on-line only under intermittent cloudy conditions. In Modes V-10, V-11 and V-12, the solar boiler only would be running with variable load dispatch. Both of these conditions represent invalid operating modes.

4.2.4.1 INTEGRATION OF SOLAR SYSTEMS WITH BALANCE OF PLANT

This section defines a number of potential problem areas that were considered in the design and operation of integrating the solar systems with the existing Reeves Unit No. 2 plant. In accordance with the basic design philosophy of minimum change to the existing plant system, certain constraints become evident such as:

- Fossil boiler capabilities
- Existing condenser heat duty
- Condensate pump capability
- Existing water treatment equipment
- Receiver steam line cooldown and warmup
- Feedwater heater drains considerations

During the conceptual design, the above six items were examined to determine if any of these items would put serious constraints or cause questions concerning the feasibility of solar repowering of Reeves Unit No. 2.

As a result of preliminary design efforts, it appears that none of the constraint items will render the repowering concept infeasible. During the detailed design phase of this program further studies may be required of these items, and also additional investigation of potential integration problems that may become apparent.

The remaining portion of this section will be devoted to discussion of the studies that were conducted on the above six items.

FOSSIL BOILER CAPABILITIES

Several aspects of the fossil boiler capability for the Reeves Unit No. 2 station were studied during the Solar Repowering Conceptual Design. These studies were necessary to integrate the existing fuel oil-fired fossil boiler with the solar system equipment. One item that was looked at during this phase of the design (discussed further in Section 4.2.4.2) is the rate of load increase and decrease, otherwise known as ramp rate of the fossil boiler. The ramp rates are important during solar insolation transients such as intermittent cloud cover. Recent information received from Babcock & Wilcox (B&W), the supplier of the fossil boiler, indicate that a maximum ramp rate of approximately 30 percent of maximum capability per minute can be used.

B&W indicate that this ramp rate should be studied in more detail as it may affect other components of the boiler. Therefore, for this conceptual design a conservative ramp rate of 20 percent per minute has been used for all transient studies.

The problem of fossil boiler steam temperature drop below approximately 50 percent load was investigated since it would affect the control of the boiler steam temperature in relation to the solar steam temperature. During high insolation periods, such as summer solstice, the solar portion of the system can produce up to 78 percent of the total gross electrical output of 50 MWe. During solar/fossil operation and for a 50 MWe gross output this would mean that the fossil boiler would be operating at about 22 percent of its maximum capability. Based on steam temperature versus steam flow data contained in the data books for the Reeves unit and modified somewhat by operating experience at the Reeves Station, Figure 4.2-28 shows how secondary superheater outlet steam temperature varies with steam flow.

Figure 4.2-29 shows a plot of mixed throttle steam temperature versus percent fossil boiler operation. If no receiver steam attenuation is made, the curve shows the three data points at the mixed steam conditions of 22 percent fossil, 25 percent and 35.5 percent fossil boiler operation. The figure also shows that the mixed steam temperatures exceed the throttle steam requirement of 950°F. This indicates that during periods of high solar insolation and low fossil boiler

Figure 4.2-28. Fossil Boiler Steam Temperature Droop

load operation, throttle steam temperature can be controlled to 950°F by reducing the attemperation of the receiver steam. This procedure would greatly simplify the overall control system of the fossil/solar combination.

Another significant fossil boiler limitation is that automatic operation of the boiler at loads less than 50 percent is not possible. This is an unacceptable condition since, during periods of high solar insolation, the fossil boiler will regularly be operated at less than 50 percent load if the total gross output from the Reeves Unit is desired to be at 50 MWe. As mentioned in Section 4.2.1.1, one of the modifications to the fossil boiler should be to permit operation of the boiler in an automatic mode at loads less than 50 percent and preferably down to about 20 percent load. This requirement not only necessitates a modification to the existing control systems, but also will require modification to the fuel oil supply system and a determination of whether or not the existing fuel oil nozzles are capable of a turn-down ratio suitable to operate all six nozzles at a total load of 20 percent of maximum. Flow Sheet P3-3 shows a modification to the fuel oil supply system to handle the reduced fuel oil load. This modification consists of another flow control valve in the fuel oil system of a smaller size than the existing valve and in parallel to it so that fuel oil supply can be regulated down to the required low flow values. During periods of maximum boiler load, the fuel oil will flow through the existing valve; during periods of low load operation the larger existing valve will be closed and control will be maintained using the smaller parallel fuel oil valve.

For operation at 22 percent of maximum fossil boiler load, a turndown ratio of 4-1/2 to 1 would be required on the fuel oil atomizing nozzles. It is well known that for operation on No. 6 fuel oil using air or steam atomizing nozzles, turn down ratios of 5 or 6 to 1 can be obtained and ratios of 8 to 10 to 1 can be obtained if higher fuel and air pressure drops across the nozzle can be tolerated.

The boiler manufacturer should be contacted during the detailed design phase to determine if a turndown ratio of approximately 5 to 1 can be obtained using the existing nozzles. If it cannot, then new higher turn down ratio nozzles could be installed to permit automatic operation at loads down to 22 percent of maximum. The fuel oil control system will also have to be modified for this requirement and this modification is discussed further in the control section of this report.

Figure 4.2-29. Fossil Boiler Steam Temperature Droop

CONDENSER HEAT DUTY

A brief study was made of the existing Reeves Unit No. 2 condenser to determine if the condenser has sufficient capacity to handle the additional drain requirements of the solar systems. The result of the study indicated that for steady state operation the existing condenser will handle the total drain flow and condensate for a 50 MWe gross output. For the worst heat duty of approximately 316,000,000 Btu per hour (which corresponds to a 35-1/2 percent fossil, 64-1/2 percent solar hybrid operating point and for a two-inch mercury absolute condenser pressure) a margin of about 2.4 percent exists over and above the design point of the condenser. The design point for the condenser was determined from the Reeves Unit No. 2 data books; with 1.97-inch of mercury absolute condenser pressure, 312,000-pounds per hour steam can be condensed for a heat duty of 323,232,000 Btu per hour. This heat duty is based on a circulating inlet water temperature of 77°F.

A potential problem may be experienced in condenser duty during start-up conditions of the solar systems. Specifically, if the Reeves Unit No. 2 is operating on the fossil boiler with plant output set to 50 MWe, and it is desired to start the solar system, the start-up procedure for the receiver indicates that during initial periods of start-up the steam generated by the solar receiver will be passed through the flash tank and directly to the condenser.

The flash tank steam will put a considerable load on the heat transfer capability of the condenser and will cause the back pressure on the turbine to increase. For this reason it is recommended that during start-up of the solar system with simultaneous operation of the fossil boiler the unit load should be reduced during the start-up period to a point where condenser pressure can be maintained.

This may mean a reduction in load by as much as 50 percent or more in electrical output. It is also recommended that the condenser pressure be monitored and a signal sent to the flash tank to vent steam to atmosphere and close PCV-2-6 if condenser pressure rises to unacceptable levels. This control system is shown on flow diagram Sheet P3-6. During the detailed design phase of the program a more detailed study of condenser capability during solar systems start-up and simultaneous fossil boiler operation should be conducted.

CONDENSATE PUMP CAPABILITY

A study was made to determine the capability of the existing Reeves Unit No. 2 Condensate Hotwell Pumps when a condensate polisher is added between the pumps and the first low pressure heater. A total flow of 706 gpm and an additional pressure drop of 50 psi due to the condensate polisher being added to the system will cause the existing Reeves Hotwell Pumps to not meet the design conditions. The present Reeves Unit No. 2 Condensate Hotwell Pump design point is based on a 44 MWe rated condition and is 600 gpm with a total developed head of 305 feet.

It is recommended that two new condensate hotwell pumps be installed, replacing the existing pumps. Several problems may be encountered during the installation of these pumps. The pumps are 20 years old with a large diameter (approximately two feet) and a hosrt pump pit depth of only 4-1/2 feet. This indicates that the existing pump pit depth should be increased approximately 4-1/2 feet. The diameter could be considerably smaller. It may be possible to install booster pumps at the condensate polisher to supply the additional 50 psi pressure; however, for this conceptual design it is recommended that the older existing Reeves Unit No. 2 pumps be replaced with more modern pumps. During the detailed design of the project, this will be reviewed in greater detail.

FEEDWATER HEATER DRAINS CONSIDERATIONS

Due to the addition of two new feedwater heaters in the solar system to heat receiver feedwater, additional drains piping will be routed to the condenser. Since the original design of the Reeves Station Unit No. 2, the ASME has developed detailed recommendations for water induction protection of the turbine in design of feedwater heater and drain systems. For the conceptual design of the repowering solar portion of the plant these ASME water induction recommendations were followed and Flow Sheets P3-6 and P3-1 reflect the required changes. The conceptual designs therefore show cascading drains to the next lowest pressure heater plus alternate drains to the condenser. Another feedwater heater drain problem that was considered during this conceptual design is the draining of the No. 7 heater to the deaerator.

The location of the No. 7 heater is on the operating floor and in the same location as the evaporator that will be removed. This floor is at an elevation of 5108 feet. The corresponding heater for the fossil boiler is the No. 2 heater which has the same pressure for draining as the No. 7 heater. There is a difference in elevation of 17-feet 6-inches between the No. 7 and No. 2 heaters. The No. 2 heater is higher in elevation, therefore drainage should be a simpler problem to the deaerator. The available pressure drop for the No. 7 heater was examined at loads from 100 percent load (50 MWe) down to approximately 44 percent load (22 MWe). Drains consideration was given to the No. 7 heater shell pressure, the elevation head required and the deaerator pressure at these low levels.

Calculations indicate that at the 100 percent load point, there should be 96 psi available from the No. 7 heater to drain to the deaerator. This 96 psi would be available for frictional pressure losses in the drain line and also for the drain level control valve pressure drop. For the 22 MWe 44 percent load point 29 psi would be available for draining to the deaerator. It was concluded that for the conceptual design, a high pressure heater drain pump for the No. 7 heater would not be required since there appears to be sufficient pressure available down to a plant load of 44 percent. Below this point a drain pump may be required or the alternate drain to the condenser could be used for the low load levels. Future study is recommended based on more complete operation requirements to determine if an additional drain pump would be required.

EXISTING WATER TREATMENT EQUIPMENT

Based on a study of the water treating requirements for the once-through central receiver boiler, it was determined that the present Reeves Unit No. 2 evaporator equipment could not be used to supply adequate feedwater to the receiver boiler. It is recommended that the evaporator plus all the associated piping be removed during the solar repowering. The No. 6 and No. 7 receiver feedwater heaters are to be located in the area of the removed evaporator.

It is also recommended that the condensate system for Unit No. 2 be separated from Units No. 1 and 3. These changes are shown on the revised piping drawings and flow sheets. The reason for separating these systems is to maintain water quality and prevent possible contamination of the Unit No. 2 system from Units No. 1 and 3 condensate.

RECEIVER STEAM LINE COOLDOWN/WARMUP ANALYSIS

It was considered during the conceptual design phase of the Reeves Station repowering that due to the extreme length, approximately 3800 feet, of the steam line a considerable warmup problem prior to admitting steam to the turbine would occur. A cooldown and warmup analysis was made to determine the extent of the warmup problem. Two conditions were analyzed:

- The cooldown and warmup of the steam line during an overnight shut down of approximately 13 hours
- The warmup of the steam line after an extended period of shutdown where it was assumed that the steam line and thermal insulation systems would be at a steady state temperature of 40°F

The first analysis was more complex because of the change in phase of the warmup steam from superheated steam through saturated steam to saturated water. The low initial temperature of the steam piping compared to the desired final temperature made an iterative computer heat transfer solution approach more desirable than a cruder hand calculation. This section will describe each of the analyses that were performed and the results and conclusions of these analyses.

OVERNIGHT SHUTDOWN

The purpose of this analysis was to determine the cooldown temperature of the steam piping during a 13-hour overnight shut down of the solar systems and the length of time it would take to rewarm the piping to a suitable temperature prior to admitting steam to the turbine. The length of time assumed for the overnight shutdown was 13 hours. Table 4.2-13 describes the piping system parameters including the alloy steel pipe, thermal insulation and convection coefficients from the pipe to the air, and from the steam into the pipe which were assumed and calculated for both heat transfer problems. This table includes all of the necessary dimensional and thermal properties of the piping and thermal insulation. A steady-state time sharing computer program (PIPEHT) was run to determine the steady state temperatures through the piping and thermal insulation at the time of shut down. These steady-state temperatures are as follows:

- Fluid bulk temperature — 998°F
- Temperature on inside of pipe wall — 997.6°F

- Outside insulation temperature — 85.4°F with an outside ambient air temperature of 70°F

TABLE 4.2-13. PIPING SYSTEM PARAMETERS

<u>Pipe</u>	
Length (feet)	3,200.
Inside Diameter (inches)	10.
Outside Diameter (inches)	12.85
Density (lb/ft ³)	489
Specific Heat (Btu/lb-°F)	0.11
Conductivity (Btu/hr-ft-°F)	20.
Total Weight (pounds)	547,707.
<u>Insulation</u>	
Inside Diameter (inches)	12.85
Outside Diameter (inches)	28.85
Density (lb/ft ³)	13.0
Specific Heat (Btu/lb-°F)	0.225
Conductivity (Btu/hr-ft-°F)	0.043
Total Weight (pounds)	174,254.
<u>Convection from Pipe to Air</u>	
Wind Speed (mph)	10.
Ambient Temperature (°F)	12.
Convection Coefficient (Btu/hr-ft ² -°F)	2.1
<u>Convection Coefficients from Steam to Pipe</u>	
Superheated Steam to Pipe Wall (Btu/hr-ft ² -°F)	68.1
Condensing Steam (Btu/hr-ft ² -°F)	1,287.

This program calculates both the convection losses to the air and also radiation losses that are approximately 10 percent of the total heat loss. During night-time cooldown it was assumed that the ambient air temperature would drop to 12°F which is the minimum design point assumed for the study. The wind speed across the pipe was assumed to be 10 miles per hour.

Based on the steady state shutdown temperatures of the piping and thermal insulation, the heat contained in the pipe, insulation and in the remaining steam, was computed based on the physical properties of the system. A second run of PIPEHT was made with an outside air temperature of 12°F and with the pipe assumed to be radiating to space through a clear sky at night and an assumed receiving temperature of minus 20°F. The computer run was arranged so that an overall heat

transfer loss could be obtained based on the initial conditions. A stepwise calculation was performed using the heat loss in the piping as determined from the computer runs.

These calculations show that for a 13-hour shutdown it is estimated that the pipe wall temperature will decrease from 998°F initial temperature to 864°F final temperature.

The next portion of the analysis was an attempt to determine how long it will take to warm the pipe to approximately 970°F, which was considered adequate to start the turbine without incurring thermal problems.

A warmup steam flow of approximately 15 percent of the total receiver steam flow, which is 41,000 pounds per hour, was assumed. An average steam temperature (based on running the time sharing program called PIPELOSS) was calculated at 932°F for a 1000°F inlet steam temperature and a heat transfer coefficient from the steam to the pipe wall of 68.1 Btu/hr-ft²-°F was determined. Heat input of 18,977,000 Btu's per hour to the pipe and insulation was estimated to be required during the warmup time. Total heat loss of the system during the 13-hour shutdown was calculated to be 12,730,200 Btu. Dividing the heat loss during the overnight shutdown by the net heat gain per hour into the system during warmup time, an estimated warmup time of approximately 40 minutes was calculated.

Two conclusions can be drawn from this analysis:

- For a 13-hour shutdown of the receiver steam line, it is anticipated that a warmup time of approximately 40 to 60 minutes would be necessary to bring the piping temperatures close to the steady state temperature.
- Since the piping system only cools to 864°F overnight, it may be possible to start the turbine without a prior steam line warmup. Since the turbine also will have cooled down somewhat and will require slightly more than one hour to bring the turbine up to full rated capacity, both the turbine and the steam piping could be brought up to temperature simultaneously without adverse effects to the system.

EXTENDED SHUTDOWN

A heat transfer analysis was made to determine the warmup times of the receiver steam piping during an extended shutdown of possibly several days. This analysis assumed that the piping and insulation system would be at an overall ambient temperature of 40°F with the outside ambient air temperature at 12°F and a wind velocity of 10 miles per hour. The piping system parameters and the convection coefficients in Table 4.2-13 were used for the transient warmup analysis.

A computerized transient analysis was used due to the complexity of the problem. Initially it was expected that as warmup steam was introduced into the cold pipe, at some point along the pipe length two-phase flow would occur where the superheated steam is reduced in temperature and would start to condense on the pipe wall. As the warmup progresses, the heat transfer will be from superheated steam with no change in phase. A low initial temperature of the piping system warmed to a rather high temperature will change heat losses to the air at various points in time during the warmup period. For this problem, radiation was not considered as this would extend the computer run time considerably.

Heat transfer coefficients from the pipe to the air based on an air velocity of 10 miles per hour was calculated to be 2.1 Btu/hr-ft²-°F. The equation used to calculate this coefficient is of the Nusselt type and is as follows:

$$h_f = 0.26 \frac{K}{D} [N_{Re}]^{0.6} [N_{PR}]^{0.3}$$

where:

K = Thermal conductivity of the air

D = Insulation outside diameter

N_{Re} = Reynolds number over pipe

N_{PR} = Prandtl number

The heat transfer coefficient for superheated steam to the pipe at the flow condition of 41,000 pounds per hour was calculated to be 68.1 Btu/hr-ft²-°F using a conventional turbulent flow heat transfer coefficient correlation. The heat

transfer coefficient for condensing heat transfer is based on a correlation contained in McAdams "Heat Transmission" and includes the effects of vapor velocity. This correlation is:

$$\frac{h_f}{c_p G_m} (N_{PR})^{0.5} = 0.065 \sqrt{\frac{\rho_L}{\rho_v} \frac{f}{2}}$$

Condensate

where:

- c_p = Specific heat of condensate
- G_m = Median mass velocity, lb/hr-ft²
- N_{PR} = Prandtl number of condensate
- ρ_L = Density of condensate
- ρ_v = Density of vapor
- f = Friction factor

The condensing heat transfer coefficient was calculated to be 1287 Btu/hr-ft²-°F.

The program used to calculate the transient heat transfer is called ANSYS. This program was developed for the CDC computer and is used by Stearns-Roger to analyze complex heat transfer and thermal stress problems. The program calculates a solution as a function of time. A system of connecting thermal nodes based on the physical geometry of the system was developed.

Figure 4.2-30 shows the receiver piping heat transfer analysis node point diagram that was used in the calculation procedure. A total of 198 nodes were generated for 3200 feet of pipe, which is the approximate pipe length exposed to ambient conditions. Based on a given steam flow and initial steam temperature introduced to the pipe, the program iterates a finite element, simultaneous equation solution as a function of time for the various nodes using conduction and convection heat transfer. The results of this program are shown on Figure 4.2-31. This figure is a plot of innerwall steam pipe temperature versus hours, for pipe locations of 500; 1000; 2000; 3200 feet from the piping inlet at the receiver.

CONVECTION ELEMENTS - C
 CONDUCTION ELEMENTS - K
 FLOW ELEMENTS - F

Figure 4.2-30. Receiver Piping Warmup Analysis Node Points

Figure 4.2-31. Receiver Steam Line Warmup Time

The warmup steam flow rate assumed was 41,000 pounds per hour at 900°F. This figure also shows that the piping system warmup will take four to five hours depending on operating experience as to what is an acceptable steam inlet condition for turbine roll. From this analysis, it appears that using the receiver steam to warm up the receiver steam line is an unacceptable procedure due to the length of time involved. The better solution may be to borrow steam from Units No. 1 or 3, or even Unit No. 2, to keep the steam piping warm when long periods of receiver shutdown are anticipated. This borrowed steam would be used to pressurize the receiver steam line and hold it at a saturation temperature associated with the pressure. The economics of this procedure, however, would have to be justified since fuel oil would be burned during an extended receiver shutdown. Economically, it may be more justifiable to use the receiver steam over a five hour period to warm the line. These conclusions are reflected in the systems operation and startup procedures contained in Section 4.2.4.3.

4.2.4.2 SOLAR RECEIVER/FOSSIL FUEL BOILER TRANSIENT INTERACTION

This section describes the solar transient analysis that was performed to model the consequences of cloud shadow passage over the collector field. The underlying assumptions used in the development of the model are described, a simplified block diagram of the computer simulation is presented, and the conclusions of the analysis are discussed.

UNDERLYING ASSUMPTIONS OF COMPUTER SIMULATION MODEL

Design Cloud Shadow Velocity

Since the transient response of the solar/fossil hybrid is highly dependent on the rate of change of the solar insolation, an effort was made to determine a representative cloud shadow velocity. Form WBAN 33, Summary of Constant Pressure Data, giving wind speed data at various pressure levels, was obtained from the Environmental Data Service, National Climatic Center, National Oceanic and Atmospheric Administration. Data were obtained for the entire year of 1977, and consist of sounding records of twice daily (5:00 a.m. and 5:00 p.m. MST) balloon launchings from the Albuquerque, New Mexico Weather Bureau Station.

Hourly surface weather observations at Albuquerque for the year 1977 were obtained from the same source. These include cloud type, percent of sky coverage and estimated cloud layer height above the field, along with other weather information. The data were correlated to determine cloud speeds for each cloud layer twice daily for a six month period, April through September 1977. The period examined was limited to the spring and summer months for two reasons: 1) to limit the amount of data to correlate, and 2) since the balloon soundings were launched at 5:00 a.m. and 5:00 p.m. MST, wind speeds are available only for times either well before or after solar operation during fall and winter months. These wind speeds may not be characteristic of daytime operation.

A weighted average (weighted by the fraction of sky coverage for each layer) cloud speed for the six month period was then calculated. In the calculation of the average, days when the percentage of possible sunshine was less than 50 percent, were not included. In addition, cirrus cloud layers, which are high altitude clouds composed of ice crystals and are usually translucent, were not included in the summation. Since cirrus clouds are often formed in standing waves when strong, high altitude winds are present in mountainous regions such as the Albuquerque area, the wind speed does not necessarily correspond with cloud speeds. Also, since these clouds are usually wispy edged and semitransparent, they should not cause as severe insolation transients as dense, low altitude clouds pushed by lower wind speeds.

With the above limitations imposed, the calculated average cloud speed was 17 mph. Monthly resultant wind directions for each pressure level are given in the Summary of Constant Pressure Data and were generally in the southwest quadrant for the period under consideration. To facilitate computer modeling, the design cloud shadow velocity was 17 mph from the south.

Cloud Characteristics

The design clouds were assumed to be sharp-edged and opaque and to have shadows that were circular in form. While real clouds obviously do not conform to these criteria, these assumptions were made in order to facilitate computer modeling and are conservative in that they lead to more severe insolation transients for

a given wind speed than would occur with real clouds. Three different cloud shadow sizes were modeled; one one-mile in diameter causing a 100 percent loss of solar insolation incident on the collector field, one 1925-feet in diameter causing a 50 percent loss, and one 780-feet in diameter causing a 10 percent loss.

Linear Relationship Between Collector Field Unshaded Area and Receiver Incident Heat

This assumption was also made to facilitate computer modeling. For this situation to actually exist, not only would the heliostats have to be uniformly distributed over the collector field, but each heliostat would have to have equal blocking and shadowing loss, cosine, transmission loss, and so forth. This is obviously not the case, but the assumption of linearity between collector field unshaded area and receiver incident heat had to be made to allow for computer modeling within budgetary limits. It is not anticipated that the noted assumptions compromise the analytical results.

Linear Relationship Between Receiver Incident Heat and Steam Flow

The assumption was made that steam flow would be directly proportional to incident heat flux for values of heat flux about 15 percent of design maximum. Below 15 percent heat flux the design steam temperature cannot be maintained due to 1) radiation and convection heat losses that dissipate an increasingly large proportion of the incident energy at lower power levels, 2) a lower effective concentration ratio, and 3) limits of range of the receiver temperature control valves. Receiver steam will have to be diverted to the flash tank if the steam temperature cannot be maintained at 1000°F. The heliostats will then have to be defocused. When insolation on the field is re-established, the heliostats will gradually be refocused until 1000°F steam flow is attained. It is estimated that this process will require 15 to 20 minutes to complete.

For the computer simulation a linear relationship between incident heat and steam flow down to 15 percent flow was modeled, with a step decrease to zero steam flow at lower insolation levels. While the assumption of linearity is not strictly accurate, particularly at the lower flow rates, it is a good working approximation.

Linear Relationship Between Throttle Steam Flow and Generator Output

This assumption was made to simplify the computer simulation model. While not perfectly accurate, again it is a close approximation.

Generator Ramp Rate

A maximum generator ramp rate of five percent per minute for power increases under normal conditions was modeled. The reason for limiting the rate of change of output is to lengthen turbine rotor life by minimizing thermal stress cracking. Output rates of change during periods of rapidly diminishing solar insolation may exceed five percent per minute negative. A reduction in solar receiver steam output requires an increase in fossil boiler steam output if the generator output is to be held constant. Since the fossil boiler has a ramp rate itself (see below), it is possible for the receiver steam output to be decreasing at a much faster rate than the fossil boiler can increase. Thus generator ramp rates will unavoidably exceed five percent per minute negative occasionally. During periods of rapidly rising solar insolation, the generator output rate of change may exceed five percent per minute positive.

The recommended retrofit of a DEH turbine control system may permit turbine ramp rates that exceed five percent per minute. An improvement in transient response characteristics over what the computer simulation mode indicates should be realized if the DEH control system is implemented. Such modifications are discussed in detail in Section 4.3.

Boiler Ramp Rate

A maximum boiler ramp rate of 20 percent per minute for either load increases or decreases was modeled. Minor modifications to the drum level control system will have to be implemented to allow a 20 percent ramp rate. It is possible that the boiler manufacturer could endorse higher than 20 percent maximum ramp rates after a detailed study of the unit. Pending combustion and feedwater systems analysis, the manufacturer, Babcock & Wilcox Company, indicated that the boiler appears to be capable of operating from 15 to 55 MWe output in five minutes, which corresponds to a boiler ramp rate of 26 percent per minute. In the event of a conflict between the maximum boiler ramp rate and the maximum generator

ramp rate during periods of rapidly increasing solar insolation, the computer model gave precedence to the boiler ramp rate. That is, the boiler output rate of decrease was limited to 20 percent per minute and the generator rate of increase was allowed to exceed five percent per minute.

Boiler Steam Temperature

A constant outlet steam temperature of 950°F was modeled, although there may be a slight temperature droop (20° to 30°F) under worst case (lowest boiler load) conditions.

Total Power Output

The computer simulation model was based on a total gross power generation of 50 MWe under steady state conditions. It was assumed that the solar portion would be operated at the maximum possible output for the insolation conditions and the balance of the gross electrical generation would be produced using fossil boiler steam. Two different solar insolation conditions were modeled: One represented the design maximum solar insolation condition at noon on summer solstice with a direct normal solar insolation of 1045 W/m², resulting in a solar receiver steam generation of 335,277 pounds per hour, 78 percent of the 430,000 pounds per hour of steam generation required for 50 MW gross electrical generation. The other insolation condition modeled was one corresponding to equal contributions of solar receiver and fossil boiler steam: 215,000 pounds per hour each for a total of 430,000 pounds per hour.

No Thermal Storage System

Since a thermal storage system would be incompatible with the existing turbine, thermal storage is not envisioned. For this reason, a thermal storage system was not modeled.

COMPUTER SIMULATION MODEL

The solar/fossil hybrid transient analysis was performed using ANASIM, a BASIC language program that simulates an analog computer on a high-speed digital machine. The program solves set of simultaneous differential and algebraic

differential equations using numerical techniques. Forty-eight separate blocks including summers, integrators, clippers "and" gates, and so forth, are available. The patch board interconnections employed in the operation of a standard analog computer are simulated by specifying the interconnections between those blocks. About 40 blocks were required for the simulation of the solar insolation transient.

The time rate of change of solar insolation shown in Figure 4.2-32 was input, and then integrated with appropriate initial conditions and multiplied by a scaling factor to represent the receiver steam flow. A relay block was used to set receiver steam output flow to zero if receiver output dropped below 15 percent of maximum. Receiver steam flow and boiler steam were summed to obtain total steam flow, which was multiplied by a scaling factor to obtain the gross electrical output. Total steam flow was also compared to the set point (430,000 pounds per hour) by a summer. The resulting error was multiplied by a gain constant (3).

A network of blocks limited the error signal to an absolute value of 0.2 of the boiler steam flow. The resulting boiler ramp rate was summed with the receiver ramp rate to determine a tentative total steam ramp rate. That rate was compared with a rate equal to five percent of the total steam flow in a minimum value block to select the lesser of the two rates. The receiver ramp rate was subtracted from the total steam ramp rate in a summer to determine the boiler ramp rate. The boiler ramp rate was limited to a minimum of minus 20 percent per minute of boiler output by a maximum value block. The boiler ramp rate was integrated (with appropriate initial conditions) to determine the boiler steam flow. Block outputs plotted (see Figures 4.2-33 through 4.2-38) were incident radiation, M_{with} , receiver steam flow in pounds per hour, boiler steam flow in pounds per hour, total steam flow in pounds per hour, and gross generation, M_{We} .

CONCLUSIONS

Under conditions of maximum solar insolation (noon summer solstice, 1045 W/m^2 direct normal insolation), the model indicates a 34.2 megawatt power droop resulting from the design 100 percent solar insolation transient. Furthermore,

Figure 4.2-32. Simplified Block Diagram

Figure 4.2-33. 100 Percent Transient Summer Solstice

4-125

Figure 4.2-34. 50 Percent Transient Summer Solstice

Figure 4.2-35. 10 Percent Transient Summer Solstice

Figure 4.2-36. 100 Percent Transient 25 MWe Solar — 25 MWe Fossil

Figure 4.2-37. 50 Percent Transient 25 MWe Solar - 25 MWe Fossil

Figure 4.2-38. 10% Transient 25 MWe Solar - 25 MWe Fossil

the model indicates it will take about six minutes for the fossil boiler to bring the turbine generator back up to the initial output of 50 megawatts. The performance is based upon boiler steam and generator ramp rates of 20 percent per minute. If the generator ramp rate is limited to five percent, about 25 minutes will be required to recover the full 50 megawatt output.

The model indicates quite good system response to the 50 percent and 10 percent insolation transient, although in the cases of the 10 percent transients, there are minor power overshoots (1.2 megawatts at noon summer solstice insolation conditions). The maximum power droop for the 50 percent transient during maximum insolation conditions is about 16.7 megawatts. In general, the initial output was re-established within five minutes of the beginning of the transient.

While the overshoots and the magnitudes of the maximum droop are certainly significant, they do not pose problems that would jeopardize the successful operation of the solar/fossil hybrid power plant. Magnitudes of the droop and overshoot can be reduced or their effects made more tolerable by implementation of one or more of the following procedures:

Undershoot

Reliance is on the spinning reserve in the grid. It is expected that PNM will have about 100 megawatts of capacity available by the time the Reeves Unit No. 2 solar/fossil hybrid plant is operational. A 34.2 megawatt droop would not have serious detrimental effects.

It is expected that higher boiler ramp rates will be allowed. This will improve the system's transient response and reduce the magnitude of the power droop.

With some solar/fossil hybrid plants it may be necessary to use remote sensors to anticipate cloud shadow passage in order to increase boiler firing with an acceptable ramp rate and simultaneously defocus heliostats prior to the incidence of the cloud shadow on the collector field. In this manner, the power droop could be reduced or even eliminated. This concept is discussed in Section 4.9 of this Report.

Overshoot

A motor operated steam dump valve will be provided for Reeves Unit No. 2 in order to prevent steam overpressure and/or generator overload.

Higher allowable boiler and turbine ramp rates will improve the transient response of the system and reduce the power overshoot.

The unit could be operated at slightly reduced load during periods of cloud cover in order to prevent operation of the steam dump valve.

With some hybrid units, it may be beneficial to anticipate cloud shadow passage and defocus heliostats (simultaneously increasing the boiler firing rate) prior to actual shadowing of the field. When the cloud shadow has passed, the boiler firing rate would be reduced simultaneous with a refocusing of heliostats. In this manner the power overshoot could be reduced or eliminated.

4.2.4.3 STARTUP/SHUTDOWN PROCEDURES

This section describes typical startup and shutdown procedures that would be required for the several modes of operation of the solar/fossil boiler portions of the repowered Reeves Unit No. 2.

The valve numbers mentioned in the procedures are those used on flow diagrams P3-1 and P3-6.

It is expected that information developed during the detail design phase of the project will add greatly to the details of these procedures.

(a) Operating Mode: Solar only start, overnight shutdown

References

- (1) Reeves Unit No. 2, Plant Data Book, Volume 4, "Turbine Generator
- (2) Central Receiver Solar Thermal Power System, Pilot Plant Preliminary Design Report, Volume 4, Receiver Subsystem, SAN/1108-8/4

Procedure

- (1) Start circulating water pumps and circulate water through the condenser
- (2) Open all turbine drains
- (3) Close motor operated valves (MOV)

MOV-1-1 Fossil boiler steam block valve
MOV-2-1 Receiver steam to auxiliary steam system
MOV-2-6 Receiver feed pump 2B shutoff valve
MOV-3-6 H.P. Heater No. 7 bypass valve
MOV-6-6 H.P. Heater No. 6 bypass valve
MOV-10-6 Receiver steam downcomer block valve
MOV-11-6 Receiver steam block valve
MOV-12-6 Receiver warmup line block valve

- (4) Open motor operated valves

MOV-1-6 Receiver feed pump 2A shutoff valve
MOV-4-6 H.P. Heater No. 7 block valve
MOV-5-6 H.P. Heater No. 7 block valve
MOV-7-6 H.P. Heater No. 6 block valve
MOV-8-6 H.P. Heater No. 6 block valve
MOV-9-6 Receiver feedwater inlet block valve

- (5) Start receiver feed pump 2A to minimum flow of pump; 15 percent of design flow must flow through the receiver. If it is elected to run on pump 2B, then open MOV-2-6 and close MOV-1-6.

Circulate feedwater through receiver to receiver flash tank through PCV-1-6 and back to condenser through LCV-1-6. Set PCV-1-6 back pressure control valve to 425 psia.

- (6) Start condensate hotwell pumps and circulate cold condensate through L.P. heaters, deaerator and to receiver feed pump. Block valves at inlets to boiler feed pumps are closed to isolate fossil boiler feedwater system
- (7) Gradually focus heliostats and increase heat flux to receiver. As feedwater turns to steam from the boiler/superheat panels limit steam temperature to about 500°F during the first 20 minutes of sunlight. This will provide approximately 50 degrees of superheat at 425 psia out of the receiver to the flash tank.
- (8) When steam temperature of all the boiler/superheat panels has reached 500°F the receiver controller commands the steam temperature setpoint to change to 660°F. Focus additional heliostats to provide this heat.

PCV-3-6 Pressure control valve from flash tank to No. 6 H.P.
Heater set to 55 psia

PCV-4-6 Pressure control valve from flash tank to No. 7 H.P.
Heater set to 30 psia

PCV-2-6 Back pressure control valve from flash tank to condenser
set to 250 psia (flash tank pressure) plus line losses as
determined from operating experience

- (9) When 660°F steam has been reached at the exit of all the boiler/super-heat panels, set the back pressure valve PCV-1-6 to the nominal operating pressure of approximately 1458 psia.
- (10) Set steam temperature to 800°F at a pressure of 1458 psia and gradually start opening MOV-10-6 to pressurize the receiver steam line. Focus additional heliostats to meet this requirement.
- (11) During overnight shutdown of the receiver, it should not be necessary to warm up the receiver steam line prior to admitting steam to turbine. It has been estimated that the receiver steam line will be at 864°F after a 13-hour shutdown, 12°F ambient temperature and a 10 mph wind velocity. Initial testing will be required to verify steam line temperature after shut down and, if it is necessary to warm up the line MOV-12-6 to the condenser can be opened until receiver steam flow warms line to acceptable temperature. Close MOV-12-6 after steam line is warmed.
- (12) Open MOV-2-1, receiver steam to auxiliary steam system, after 800°F, 1458 psia steam is established. This will allow receiver steam to enter the Unit No. 2 auxiliary steam system for turbine seal steam condenser air removal and deaerator pegging.
- (13) Turn on turbine seal steam to the No. 1 gland and regulate to maintain 20 psig.
- (14) Turn on seal water to L.P. turbine glands only. Seal water to H.P. turbine seal glands is turned on when approximately 70 percent of normal operating speed has been reached.
- (15) Start air removal equipment and establish a 10- to 20-inch of mercury vacuum in the condenser.
- (16) Start steam driven auxiliary oil pump and shut down five H.P. motor driven oil pump.
- (17) Check that all turbine drains are open and steam lines are free from water.
- (18) When a vacuum of 10-inches Hg has been obtained, open throttle valves just enough to get turbine speed above turning gear speed.
- (19) Keep turbine rolling at low speed (approximately 100 to 400 rpm) with the vacuum 20-inches or better for about 20 minutes to allow turbine parts to become partly heated.

- (20) Close drains from pressure zones when it is assured that all water has been removed.
- (21) Check governing valves for operation.
- (22) Bring unit up to speed slowly. During this time allow the vacuum to increase gradually so as to obtain full vacuum when turbine reaches full speed.
- (23) At 70 percent normal speed, turn on seal water to high pressure glands.
- (24) Turn on water to oil and generator gas coolers.
- (25) Change set point on receiver outlet steam to 1000°F and set 950°F for outlet of receiver steam attemperator. Gradually focus additional heliostats to bring receiver steam temperature up to design.
- (26) Synchronize and add three to five percent load. Hold at this load until throttle temperature is stable at 950°F or approximately 18 minutes for 13-hour shutdown, whichever is longer. Limit exhaust casing temperature to 175°F. At this point approximately half of receiver steam flow will be flowing through the turbine, the other half will be passing through the receiver flash tank.
- (27) Bring turbine up to full capability (52 minutes for 13-hour shutdown). At this point no steam will be going through the flash tank and PCV-1-6 is signaled to close as turbine throttle valves control throttle pressure to 1250 psia.

Start-Up Time After Overnight Shut Down

<u>Start Function</u>	<u>Time (minutes)</u>
(1) Events 1 to 6	(Prior to Dawn)
(2) Event 7	20
(3) Events 8 to 11	45
(4) Events 12 to 18	25
(5) Event 19	20
(6) Events 20 to 24	20
(7) Event 25	15
(8) Event 26	18
(9) Event 27	52
TOTAL	
215	

(b) Operating Mode: Normal shutdown, solar only

Procedure

- (1) The steam temperature set point of 1000°F is maintained and the flow to each of the receiver panels decreases as the heliostats are sequentially slewed away from the receiver and the energy level decreases.
- (2) As turbine throttle flow decreases, load on turbine will decrease.
- (3) Below approximately 15 percent of design maximum receiver flow steam, temperature will become unstable. Throttle valves to turbine will be signaled to close.
- (4) Open all turbine drains.
- (5) Put turbine on turning gear.
- (6) Automatically close MOV-11-6 and 10-6; whenever receiver outlet temperature becomes less than 950°F, PCV-1-6 will start to open through the flash tank
- (7) Reduce receiver pressure to 425 psia.
- (8) As insolation energy continues to drop, all receiver boiler panel temperature control valves will reach minimum flow position and receiver will fill with sub-cooled water.
- (9) Shut down receiver feed pumps, condensate hotwell pumps and circulating water pumps.

(c) Operating Mode: Solar system start after overnight shut down; turbine operation on fossil boiler

References

- (1) Reeves Unit No. 2, Plant Data Book, Volume 4, "Turbine Generator
- (2) Central Receiver Solar Thermal Power System, Pilot Plant Preliminary Design Report, Volume 4, Receiver Subsystem, SAN/1108-8/4.
- (3) Systems Startup/Shutdown Procedures; solar only start.

Procedure

(1) Close Motor Operated Valves

MOV-2-1 Receiver steam to auxiliary steam system
MOV-2-6 Receiver feed pump 2B shutoff valve
MOV-3-6 H.P. Heater No. 7 bypass valve
MOV-6-6 H.P. Heater No. 6 bypass valve
MOV-10-6 Receiver steam downcomer block valve
MOV-11-6 Receiver steam block valve
MOV-12-6 Receiver warmup line block valve

(2) Open motor operated valves

MOV-1-6 Receiver feed pump 2A shutoff valve
MOV-4-6 H.P. Heater No. 7 block valve
MOV-5-6 H.P. Heater No. 7 block valve
MOV-7-6 H.P. Heater No. 6 block valve
MOV-8-6 H.P. Heater No. 6 block valve
MOV-9-6 Receiver feedwater inlet block valve

- (3) Start receiver feed pump 2A to minimum flow of pump; 15 percent to 20 percent of design flow must flow through the receiver. If it is elected to run on pump 2B, then MOV-2-6 is open and MOV-1-6 is closed.

Circulate feedwater through receiver to receiver flash tank through PCV-1-6 and back to condenser through LCV-1-6. Set PCV-1-6 back pressure control valve to 550 psia.

- (4) Reduce load on turbine if turbine is at 100 percent load to about 80 percent load to accommodate minimum flow through the receiver.
- (5) Gradually focus heliostats and increase heat flux to receiver. As feedwater turns to steam from the boiler/superheat panels limit steam temperature to about 500°F during the first 20 minutes of sunlight. This will provide approximately 22°F of superheat at 550 psia out of the receiver to the flash tank.
- (6) When steam temperature of all the boiler/superheat panels has reached 500°F the receiver controller commands the steam temperature set point to change to 660°F. Focus additional heliostats to provide this heat.

PCV-3-6 Pressure control valve from flash tank No. 6 H.P. Heater set to match the number one high pressure turbine extraction steam point. This could be a maximum of 80 percent turbine load or about 320 psia.

PCV-4-6 Pressure control valve from flash tank to No. 7 H.P. Heater set to match maximum turbine extraction steam pressure about 160 psia at 80 percent turbine load.

PCV-2-6 Back pressure control valve from flash tank to condenser set to approximately 350 psia.

- (7) When 660°F steam has been reached at the exit of all the boiler/super-heat panels, set the back pressure valve PCV-1-6 to the nominal operating pressure of approximately 1458 psia at 15 percent to 20 percent receiver steam flows.
- (8) Set steam temperature to 800°F, at a pressure of 1458 psia and gradually start opening MOV-10-6 to pressurize the receiver steam line.
- (9) Set steam temperature to 1000°F at outlet of receiver and operate until steam temperature is stable. Focus additional heliostats to provide heat.
- (10) Open MOV-12-6 to warm steam line up from 864°F to about 950°F if required based on initial operating experience. Close MOV-12-6 after receiver steam line is sufficiently warmed.
- (11) Set receiver attemperator control to 950°F.
- (12) Gradually open MOV-11-6 to allow receiver steam to mix with fossil boiler steam, PCV-1-6 will gradually close, shutting off flow to the flash tank.
- (13) At this point the receiver will be supplying 15 percent to 20 percent of the total steam flow and the fossil boiler will be supplying a maximum of 85 percent to 80 percent flow.
- (14) Gradually focus more heliostats on the receiver to increase receiver steam flow to its maximum, dependent on the current solar insolation. The fossil boiler combustion control system will decrease oil flow to the burners to maintain throttle pressure at 1250 psia. At maximum design receiver flow, receiver steam pressure will be approximately 1458 psig.
- (15) Set desired turbine load based on maximum receiver steam flow and parallel fossil boiler operation.

Start-Up Time After Overnight Shut Down

<u>Start Function</u>	<u>Time (minutes)</u>
(1) Events 1 to 4	(Just prior to dawn)
(2) Event 5	20
(3) Events 6 to 8	45
(4) Event 9	15
(5) Event 10	60
(6) Events 11 to 13	10
(7) Events 14 and 15	15
TOTAL	
165	

(d) Operating Mode: Solar only shutdown, fossil fuel operation continuing

Procedure

- (1) The receiver steam temperature set point of 1000°F is maintained and the flow to each of the receiver panels decreases as the heliostats are sequentially slewed away from the receiver and the energy level decreases.
- (2) As receiver flow decreases, the turbine throttle valves will close reducing load or, depending on load requirement, the fossil boiler will increase steam flow.
- (3) At 15 percent receiver steam flow MOV-11-6 and 10-6 will close and PCV-1-6 will open directing receiver steam through the flash tank.
- (4) Reduce receiver pressure to 425 psia.
- (5) As insolation energy continues to drop, all receiver boiler panel control valves will reach minimum flow position and receiver will fill with subcooled water.
- (6) Shutdown receiver feed pump 2A and close MOV-1-6.

(e) Operating Mode: Solar systems start after long shut down. Fossil boiler shutdown.

References

- (1) Reeves Unit No. 2, Plant Data Book, Volume 4, "Turbine Generator."
- (2) Central Receiver Solar Thermal Power System, Pilot Plant Preliminary Design Report, Volume 4, Receiver Subsystem, SAN/1108-8/4.
- (3) Systems Startup/Shutdown Procedures; solar only start.
- (4) Receiver cooldown/warmup, Section 4.2.4.1(f) of this Report.

Procedure

- (1) -through-
- (6) Events 1 to 6 identical to Reference (3).
- (7) Circulate condensate through system and through condensate polishing equipment, located between the hotwell pumps and the No. 5 L.P. Heater, until water quality is acceptable for receiver operation.
- (8) -through-
- (11) Events 8 to 11 identical to Reference (3) Events 7 to 10.

(12) Slowly open MOV-12-6 to the condenser for warm up of this steam line to approximately 800°F. This should take approximately five hours when ambient temperature is 12°F and wind speed is 10 mph, based on the analysis of Reference (4). A better solution to this warmup problem would be to keep the steam line warm during extensive shut-down using auxiliary steam from the Units No. 1, 2 or 3. This solution may adversely affect the economic analyses since oil would be expended during any shut down except for an overnight shut down.

(13) Close MOV-12-6 after steam line is warmed.

(14) -through-

(29) Events 14 to 29 identical to Reference (3) Events 12 to 27.

Startup Time After Long Shut Down of Solar System

<u>Start Function</u>	<u>Time (minutes)</u>
(1) Events 1 to 6	(Prior to Dawn)
(2) Event 7	(Prior to dawn)
(3) Events 8 to 11	20+
(4) Event 12	300
(5) Events 14 to 29	90+
<hr/>	
TOTAL	410

4.2.4.4 SOLAR SUBSYSTEM MAINTENANCE

This section describes the general maintenance plan required for the solar systems equipment.

RECEIVER

It is anticipated that a detailed receiver maintenance plan will be developed by the receiver manufacturer during the construction of the receiver.

This plan will basically consist of:

- Maintenance of the high absorbitivity of the receiver face by a scheduled repainting of the panels.
- Replacement of individual panels as required for necessary repair.
- Mechanical and electronic repair of control systems. This would include replacement of electronic circuit boards and servicing of control valve actuators. Also replacement of filters at inlet of absorber panels.

- Structural maintenance consisting of repainting for rust prevention.

HELIOSTATS

The maintenance program for the heliostats will consist of the following items:

- Mirror Washing — The washing procedure will be based on the criteria as developed by the Sandia Laboratories in Albuquerque during the heliostat testing program.
- Drive Units — Periodic lubrication and inspection for wear and corrosion.

MASTER CONTROL SYSTEM

Maintainability for the controls and instrumentation is achieved by designing a high degree of standardization and modularity throughout the control systems. Identical hardware components and types of hardware are used wherever practical such as cables, connectors, controllers, instruments, etc., including instrument and control signal types. This design allows for easy maintenance. Electronic modules can be easily replaced and elements subject to wear such as pneumatic controllers, actuators and printers can be conveniently serviced or replaced.

4.2.4.5 PRESENT PLANT MAINTENANCE

The Reeves Unit No. 2 is approximately 20 years old and has been under a planned maintenance program during this time. The current maintenance program has been satisfactory as evidenced by the good overall condition of the plant.

It is expected that this maintenance program will be continued during the solar repowering operation of this unit together with the additional requirements as defined in Section 4.2.4.4.

The resulting overall plant maintenance program will integrate the solar portion of the plant with the existing equipment maintenance plant to provide a maintenance schedule compatible with component and system requirements and to minimize plant downtime.

4.3 CONTROLS AND INSTRUMENTATION DESIGN

A control system design for solar hybrid repowering applications differ from a design for conventional plant control systems in two ways. First, it is not an entirely new system, and second it is not simply a retrofit of an old system. A repowering control system design calls for an integration of an existing system with a new technology.

Controls and instrumentation design is present in two parts: Section 4.3.1 builds the control system architecture and discusses its components. Section 4.3.2 applies this system to plants that are candidates for repowering, and particularly to the Reeves Station Unit No. 2.

REPOWERING CONTROL SYSTEM DESIGN REQUIREMENTS

Figure 4.3-1 is a simplified process and instrumentation diagram (P & ID) for control system purposes. This diagram may be referred to throughout the controls and instrumentation design report. It shows the principle control systems, instrumentation, controlled process variables, and control devices.

Solar hybrid repowering control system design requirements provide for the safe and economic production of electricity under all plant operating modes:

- Fossil Boiler Only
- Solar Only
- Combined Solar and Fossil

The plant should first be able to operate on fossil fuel as it now does as though no changes had been made. The system must be able to meet the generation needs of the utility. Second, it should be able to produce electricity on solar power alone. Third, and most important, it should operate and produce electricity in a combined solar and fossil or hybrid operating mode; thereby providing for the continuous and stable production of electricity, night or day, fully utilizing solar energy when it is available.

Inherent in all solar hybrid repowering control system designs will be the requirement to control the plant in all of the above described operating modes under all conditions of startup, shutdown, transient, steady state and emergency operation.

Figure 4.3-1. Simplified P&I Diagram for Control Systems

CONTROL SYSTEM DESIGN PHILOSOPHY

During control system conceptual design several philosophies or design criteria were used:

- Generate Electricity
The control system must provide for the safe and economic production of electricity.
- Automatic with Operator Override
Basic plant operation should be automatic with operator override capability.
- Maintain Existing Plant Control Philosophy
Certain control philosophies exist in virtually all power plants. Red indicating lights indicate equipment or process in operation, green indicating lights indicate equipment or process not in operation, etc. These control philosophies are power industry standards and should be maintained in accordance with those in effect at the station to be repowered.
- Minimize New Control Technology
An effort should be made to utilize existing control technology and conventional power plant control systems. New control technologies should be added only if necessary to provide control of new solar technologies.
- Minimize Existing Plant Modifications
The existing control systems is a candidate plant for solar repowering work. They provide for the generation needs of the utility; their integrity should not be compromised.
- Simplicity
A control system design must be free from over-complication. It must provide for plant operation by plant operating personnel without requiring excessive training beyond that normally required. Only the degree of sophistication absolutely necessary for plant operation should be provided in a control system. The opportunity for solar electric power generation success should not be compromised by overly complicated control systems that do not work well, or do not work.

4.3.1 SOLAR CONTROL DESIGN

This subsection describes the solar control system in terms of the basic design approach and the principal subsystems within the overall control system.

4.3.1.1 CONTROL SYSTEM DESIGN APPROACH

The solar hybrid repowering control system design approach incorporates the following features:

- Single operator control from a single control room
- Integrated Supervisory Control of all subsystems (Master Control)
- Coordinated control of all subsystems (distributed analog control)
- Independent subsystem control allows plant operation without master control
- Prime operating mode is automatic with operator override
- Minimize the cascade effects of single point failure

The general design approach is the utilization of a microprocessor based analog control system in conjunction with a standard, proven, off-the-shelf power plant computer. In recognizing the problems experienced by the utility industry with the reliability of the man-machine interface structure of computerized systems, it is considered that an analog control system architecture with a microprocessor base provides the best integration of the plant computer, solar subsystems and existing plant subsystems. Solar repowering control system architecture is shown in Figure 4.5-2. It is considered that this basic approach to an overall control system design will be amenable to all the fossil plant candidates for solar repowering. A more complete picture of control and monitoring systems interfacing is portrayed in Figure 4.3-3. The task of a detailed plant design will be to completely identify and specify in detail all of the system interconnections.

Control systems hierarchy will be as follows:

- Fully Automatic Master Control (MCS)
- Semi-Automatic Coordinated Control
- Independent Subsystem Automatic Control
- Manual Control
- Safety Interlock and Emergency Trip

Master Control is provided through the digital plant computer. Should the computer fail, semiautomatic control is provided in the microprocessor based analog control. In this mode, coordinated control between the independent subsystems is done by the distributed analog system. Independent subsystem controls enable each subsystem to operate in an automatic mode. However, coordination of the subsystems could be accomplished manually by the plant operator. Additionally each system is provided with manual controls from the control room and, in some cases, locally. Operator manual override capability will be provided at each level of control. Emergency trip and interlock systems will be implemented automatically in all cases where it is necessary to insure plant operating safety and to prevent equipment damage. This system basically conforms to power industry standards.

4.3.1.2 PRINCIPAL CONTROL SYSTEMS

Conceptual design of the principal control systems is divided into two parts. Section 4.3.1.2 discusses the Master Control Computer, Distributed Analog Control System, Collector Control System and Receiver Control System. These are the new control systems that must be added to a power plant for solar hybrid repowering. Section 4.3.2 discusses existing principal control systems including Boiler and Combustion controls and Turbine-Generator controls.

MASTER CONTROL COMPUTER

Hardware configuration for the master control computer is shown in Figure 4.3-4. This basic hardware configuration is a typical power plant computer and is identical to plant computers currently in widespread use across the nation. Power plant computers are commercially available from any one of several manufacturers and feature software and hardware designs that are both proven and accepted by the utility industry.

Functions performed by the master control computer are:

- Supervisory Plant Control
- Integrate Control of all Subsystems
- Process Data Acquisition
- Display/Monitor/Alarm

Figure 4.3-2. Solar Hybrid Repowering Control System

Figure 4.3-3. Control and Monitoring Systems Interface

Figure 4.3-4. Solar Power Plant Computer System

Software

Although data acquisition software for power plant applications is commercially available, the master control system and heliostat control system software will be entirely developmental. It should be noted that developmental software, especially that requiring untried control algorithms is iterative in nature, difficult to produce, and can be the critical path on a project.

Hardware

The basic equipment supplied for a Solar Power Plant Computer System consists of the following:

- A central processor
- An engineer's console, which includes an engineer's printer and a CRT
- An operator's console, which includes a set of function push-buttons and a set of display pushbuttons called a matrix (A CRT is included with the operator's console)
- Three CRT's on the BTG panel: one for alarms, one for utility messages, and one for graphic displays
- Strip chart or analog trend recorders that are driven by the plant computer
- Printers: one for alarms and one for general or utility messages, plus a line printer for large amounts of output as when programming work is being done
- A bulk memory system, which could be either disc or drum memory, or a combination of both
- A programmer's console, which includes a printer and a magnetic tape system for off-line memory
- Hardware for reading analog inputs such as flows, temperature, pressure levels and electrical inputs. These are processed through the analog to digital converter for use by the computer system. The necessary digital inputs, such as contact closures, and pulses.

Functions

The function of the engineer's console is to provide the plant engineer with the capability of communicating with the computer system in a location remote to the main control room so that there is no interference of the engineering personnel with the operation of the plant.

The functions available to the engineer on his console are:

- The ability to add or change analog and digital inputs
- Calibration of inputs
- Ability to build special logs
- The facility to initiate the running of special calculation sets
- Interface with the computer algorithms such as:
 - Steam tables
 - Arithmetic functions
- All other functions normally available to the operator

The operator console functions are as follows:

- Printing and display of all computer inputs and outputs in various modes
- Trend pen displays of all analog inputs
- Printing or displays of summaries such as all analog inputs and all digital inputs
- Group displays or prints of inputs to the system grouped by equipment or function
- Calling of graphic displays that represent various equipment groups or plant systems
- Any control functions that may be associated with the computer system

The function of the programmer's console is to provide for maintenance of the program in the system plus providing facility for adding programs to the computer system and the ability for maintaining and updating all the data files in the system.

Another function available on a computer system is a historical data, storage and retrieval system. This is a system that gathers data continually throughout the system operation and stores it for later retrieval by engineering personnel. This system is useful in determining changes of operating parameters over a long period of time or for recall of information during previous periods of abnormal operation.

CRT Displays

The three CRT's in the control room that display information to the operator are as follows:

- The alarm CRT — displays alarms to the operator as they occur, with flashing values so that the operator knows which alarms have not been acknowledged
- The utility CRT — displays messages to the operator, plus group displays and trending of inputs
- The graphic CRT — displays graphics that represent pieces of equipment or systems or bar charts or graphic of various system parameters

Automatic Functions

Automatic functions that normally occur without any operator requests or intervention are as follows:

- Scanning of all inputs
- Alarming of any inputs that go beyond prescribed bounds
- Automatic calculations; averages of several inputs or temperature differences
- Sequence of events summaries involving printing of a series of events in the order in which they occur with up to one milli-second resolution so that technical staff can determine:
 - That events happen in the proper order
 - Which events caused an outage
- Hourly, daily and monthly periodic logs that are used both by the operating personnel and the engineering personnel

- A post trip review that provides information concerning the status of inputs for a period before and after a trip
- Automatic monitoring of pieces of equipment, which provides information as to amounts of time the equipment has run, number of starts, any alarms about that equipment, possible permissives before start of equipment

Alarm Philosophy

The basic alarm philosophy of a computer system is:

- To provide instant information to an operator in a format that is easily understandable by him
- To provide hard copy of all alarms for later diagnosis
- To provide for further discrimination of information on alarms for those alarms normally on an annunciator system

DISTRIBUTED ANALOG CONTROL SYSTEM

The requirement for the addition of a distributed analog control system results from the need to provide control for new control loops as well as the need to provide an interface between existing plant control systems and new solar sub-system control. Functions performed by the analog system include:

- Semiautomatic coordinated control
- Control solar/fossil process interfaces
- Interface new solar and existing fossil control systems with the master control computer

System cabinets for the distributed analog control system will be located in the logic room addition as shown on Stearns-Roger Drawing No. L-22929, Sheet No. G1-3. A control console and CRT interface will be located on the BTG addition section.

● Distributed Analog Control Definition

Analog control systems have always existed in power plants and presently exist in the form of both pneumatic system and hardwired electronic systems. The term "distributed" denotes that all elements of the system are not physically located together. Basic components of the analog control system include:

- Process Transmitter (PT, TE, LT, etc.)
- PID Controller (Proportional, Integral, Deviative)
- Hand/Auto Station (Operator Interface)
- Actuator (Control valve, dampers, drives, etc.)

These elements are schematically shown in Figure 4.3-5. The process transmitter is typically locally mounted at the process measurement point. The actuator is also mounted locally on the control device, typically a control valve, damper, etc.

For simple control loops such as feedwater heater level controls, set point adjustments and controllers are also mounted locally. Typical valve controllers include gain and reset adjustments (proportional and integral).

Set point controls and PID controllers for major control loops (such as boiler drum level) are generally centrally located in a relay room (pneumatic) or logic room (electronic). Operator interface controls (Hand/Auto stations) are located on the operator control panel (BTG board - Boiler Turbine Generator Control Panel). Set point changes are in some cases made at the BTG board and in other cases are changeable only in the system cabinets or relay racks.

Control algorithms or control transfer functions in conventional power plant analog systems are provided in the PID controller. Gain control (proportional) and reset rate control (integral) are normally adjusted during plant start up. Derivative action and other complicated control transfer functions are seldom used, or required in power plants. Controller reset rates and gains are adjusted at some time during plant start up. Once the control system is tuned, calibrated and performs its functions, the settings are not likely to be changed.

State-of-the-art process plants are utilizing microprocessor based electronic analog control systems. Such systems are currently available from several manufacturers and new suppliers are appearing on the market with increasing frequency.

The use of a microprocessor based analog control system in a solar hybrid repowered power plant offers many advantages. The first important advantage is control loop design flexibility. Because a solar hybrid repowering plant of this design is a first-of-a-kind, requirements for control system design changes will inevitably be identified during start up and subsequent operation. The microprocessor base will allow most of these changes to be made through software rather than requiring hardware modifications. Secondly, the microprocessor base allows direct interface with the plant computer over a computer data bus. This is described in more detail in Section 4.3.1.2.

TYPICAL CONTROL LOOP (Single Element)

Figure 4.3-5. Distributed Analog Control Loop Elements

Thirdly, the microprocessor based analog system can be purchased in a conventional power plant configuration. This will allow conventional operator interface with the control system and will provide conventional hardware interfaces with existing plant systems as described in more detail in Section 5.3.1.2.

- Master Control Interface

Conventional analog system control in the automatic mode provides for plant control through preset control transforms and algorithms. As mentioned earlier, these usually consist of proportional and integral control action. These settings are typically fixed and not changeable from the control room.

The combination of the microprocessor based analog system with the master control computer provides the potential for much better overall plant control because the computer has the ability to automatically change set points, control transfer functions and gain coefficients in the analog system based on an on-line knowledge of plant operating conditions. This is the essence of so called "Master Control" or supervisory control.

- Interface With Collector Subsystem

The analog control system will develop a solar energy demand signal that will tell the collector control computer what the requirement is for solar insolation on the receiver. This solar energy demand signal will be based upon receiver steam outlet temperature and the requirement for electrical generation. During combined solar and fossil boiler operation, the analog control system will coordinate the solar energy demand with the boiler firing rate. This coordination in control will help to minimize or eliminate many plant operation transients.

- Interface With Receiver Subsystem

Receiver control consists of valves that will be both electrically and pneumatically operated. Therefore, the analog control system and the receiver control system will both be electronic analog systems. It would be highly desirable for both systems to be purchased from the same manufacturer so that hardware interfaces could virtually be eliminated. If the receiver subsystem is provided with a microprocessor based analog system, then software interfaces would also be eliminated.

The analog control system will coordinate and interface the receiver subsystem with the turbine-generator. During hybrid operation the analog control will coordinate both the turbine-generator and the fossil boiler with the receiver. Since only steam temperature can be controlled by the receiver, the normal plant operating mode will be turbine throttle pressure control (see Section 4.3.1.2(7) during solar-only operation. During combined solar/fossil operation the fossil boiler will be used to stabilize plant generation output during solar transients.

- Existing Combustion Control Interface

Existing combustion controls at Reeves Station Unit No. 2 are pneumatic. They are "Mini-Line Series" controls manufactured by the Bailey Meter Company (now Bailey Controls Company). The combustion control system is typical for most systems installed in power plants of this size and vintage. It consists of a "unit master station" that controls fuel and air flows based on steam pressure (boiler follow system), a three-element drum level control, a steam temperature control, a deaerator level and pressure control, a hotwell level control and a cooling tower blowdown flow control.

The existing pneumatic controls at the Reeves Station Unit No. 2 offer several advantages and disadvantages that have to be considered. For the conceptual design, a course of action was chosen from a list of alternatives that ranged from leaving the present system intact with no interfaces to completely replacing the entire system.

Chief among the advantages of the present controls is that they work. The plant operates and produces electricity. Pneumatic and electric interfaces are easy with commercially available, economic, and reliable hardware.

A major disadvantage of the existing system is that the Bailey Meter Company Mini-Line Controls are no longer manufactured and that some repair parts are no longer available. (This is not to say that pneumatic controls are no longer manufactured.) The existing relay racks are crowded and do not lend themselves to system modifications or additions. It is foreseen that the entire system could require replacement before the 30-year design life of the solar/fossil hybrid plant is expended.

It first appeared desirable to replace the existing system with a modern electronic system when solar hybrid repowering is added to the plant. However, a primary objective of the solar hybrid repowering design is to minimize all changes to the existing plant. Also from the utility point of view, it is a reasonable and justifiable objective to be able to operate the existing plant in its present condition as though there were no changes to the plant. The existing controls meet these objectives, as well as providing for subsystem autonomy.

The conceptual design is configured on the basis of utilizing the existing pneumatic combustion controls and interfacing only as required. Conceptual design has revealed three interfaces. First, the boiler demand signal, which presently comes from a steam throttle pressure transmitter, must come from the distributed analog control system during hybrid operation. Second, steam temperature control during hybrid operation becomes more

complicated and the existing set point must be provided by the distributed analog system steam temperature control. [This is explained further in Section 4.3.1.2(7).] Third, receiver feed-water flow and condensate flow changes must be measured and added back into the DA level control signal.

A typical electronic-pneumatic interface is seen in Figure 4.3-6. The transfer element in a very simple interface could be a three-way solenoid valve. When energized the combustion controls would receive a signal from distributed analog control via the electric to pneumatic converter. When de-energized, or upon power failure to the control system, the boiler receives its signal directly from the pressure transmitter. To provide bumpless transfer it will be necessary to "tee-in" to the pressure transmitter signal with a pneumatic to electric converter. The distributed analog control will then balance the control signals prior to transfer.

- Turbine Control Interface

The existing turbine control systems will be replaced with a digital electrohydraulic control system (a Westinghouse DEH System is discussed under Section 4.3.2.5). During solar-only plant operation, the turbine throttle will be used to control steam pressure. The distributed analog control system measures steam pressure and transmits a signal to the turbine controls. During hybrid operation the distributed analog control attempts to maintain throttle pressure by ramping the fossil boiler, but uses the turbine controls to maintain outside limits for steam pressure. This is discussed in detail in Section 4.3.1.2(7). Fossil-only operation may be done with the boiler maintaining throttle pressure (boiler following) with the existing pneumatic controls, or the distributed analog control system can provide coordinated control. Under coordinated control the analog system would ramp the turbine controls and boiler simultaneously in response to load change demands that may be from the operator or from a dispatch signal.

- Solar Fossil Process Interfaces

The addition of solar collector and receiver subsystems to an existing fossil power plant results in several process interfaces that must be controlled. These interfaces require a new control system because they are not included in any of the independent subsystem control systems. The distributed analog control system will provide for the control of these new control loops.

The major process interface control loops are throttle steam temperature control, throttle steam pressure control, and receiver feed pump control. Detailed plant design may reveal other new control loops in addition to these. Conceptual design for these interfaces indicate that they should be controlled as described below; however, it must be realized that an actual design could be considerably different.

ANALOG CONTROL SYSTEM

Figure 4.3-6. Electronic-Pneumatic Interface

- Steam Temperature Control

Steam temperature control is shown schematically in Figure 4.3-7. This system is designed to maintain the steam temperature at the inlet to the turbine at 950°F. Since both the solar receiver and the boiler supply steam to the turbine at various flows and temperatures the main controlled variable for this system is turbine inlet temperature. Turbine inlet temperature is compared to its set point (950°F) and the error signal is acted upon by controller action to establish a set point for the boiler and solar attemperator outlet temperatures.

For the boiler superheater outlet temperature control, this set point is compared to superheater outlet temperature and any error is corrected through controller action to produce a boiler attemperator spray valve control signal.

The solar attemperator outlet temperature control utilizes a feed forward receiver outlet steam temperature signal in addition to the turbine inlet temperature set point signal to produce a solar attemperator spray valve control signal. Solar attemperator outlet temperature is compared to the turbine inlet temperature set point signal. This produces a solar attemperator temperature error signal that is acted on by controller action and added to the receiver outlet temperature feed forward signal. The feed forward signal is delayed in time by an amount proportional to steam flow to correct for the distance between the receiver and the solar attemperator. Hand/automatic stations provide for direct operator interface on both the solar attemperator spray valve and the boiler attemperator spray valve.

With the system as described above, it is possible to have the boiler superheater outlet temperature greater than 950°F and the solar receiver attemperator outlet temperature less than 950°F, the combination of the two temperatures when mixed equaling 950°F at the turbine. It is therefore necessary, in order to prevent any boiler damage from an over-firing condition, to limit the boiler superheater outlet temperature to about 975°F through the use of a high temperature limit in the boiler attemperator spray valve control loop. This condition does not apply to the solar attemperator because receiver steam temperature is controlled and limited by an independent control loop; i.e., the receiver subsystem control.

- Throttle Pressure Control

Throttle pressure control is shown schematically in Figure 4.3-8. Throttle pressure control is designed for the simultaneous operation of the solar receiver and boiler. Changes in throttle pressure will be corrected for by the boiler controls when the boiler is in operation. The system is designed to accept all of the

Figure 4.3-7. Steam Temperature Control

Figure 4.3-8. Throttle Pressure Control

steam flow made available from the solar receiver. Turbine first stage pressure (steam flow) creates the initial feed forward demand. This feed forward demand is then characterized by the ratio of the boiler steam flow and receiver steam flow. If the boiler is contributing more to the total steam flow than the receiver, the system will provide for the correct amount of feed forward demand signal to the boiler controls thus minimizing any over and under firing from an unequal ratio of boiler versus receiver steam flow.

Throttle pressure is then compared to set point (1250 psig) and corrected through proportional and integral control action to vary the amount of firing rate required to maintain steam pressure at set point. Should the boiler be unable to maintain throttle pressure, a backup system utilizing a 100 psig deadband will control the turbine control valves if the throttle pressure drops to 1200 pounds or exceeds 1300 pounds. The boiler controls will continue to operate to bring the throttle pressure back to set point. During solar-only operation the turbine control alone will maintain throttle pressure. A transfer will shift the control signal to the turbine from the throttle pressure limit signal directly to the throttle pressure control signal.

- Receiver Feed Pump Control

Receiver feed pump control is shown schematically in Figure 4.3-9. Receiver feedwater is supplied by two pumps, each capable of supplying 100 percent of the required feedwater flow. The controlled variable is receiver feedwater inlet pressure at the base of the receiver.

Receiver outlet temperature is controlled through temperature control valves on the receiver panels. The totalization of these temperature control valve positions generates a signal that represents receiver flow demand. Receiver flow demand is characterized with a function generator $f(x)$ to match the pump and hydraulic coupling curve, and becomes the feed forward signal for the pump speed control.

Receiver inlet pressure is compared to the receiver inlet pressure set point and an error signal is created. Controller action is applied to the error signal and it is then added to the feed forward demand signal to correct the pump speed signal for any changes in receiver pressure.

Gain changes in the control system correct control signals for system response changes during one or two pump operations. Additionally, when both pumps are on automatic at the same time, the operator has the ability to bias one pump with respect to the other without creating any receiver inlet pressure changes.

Figure 4.3-9. Receiver Feed Pump Control

COLLECTOR CONTROL SYSTEM

The collector and heliostat control system architecture is shown in Figure 4.3-10. The final design of the control hardware will depend on the system manufacturer's design, but will basically consist of a digital computer for collector subsystem control, microprocessor field controllers, and heliostat controllers.

The collector control computer must be an independent digital computer separate from the master control computer. It must be provided with its own central processing unit, power supplies, and peripheral devices. This will ensure independent subsystem autonomy as well as provide increased reliability for plant operation.

The purpose of the collector control system is to provide for positioning of the heliostats. During normal operation the computer synthetically tracks the sun using a control algorithm based on accurate astronomical data. The computer makes corrections for atmospheric conditions that affect solar insolation index of refraction through the atmosphere. The computer then calculates positioning requirements for the heliostats and sends this information to the field controllers over a computer data highway. The field controllers will direct the position of the individual heliostats. Heliostat control will be "open loop"; that is, heliostat reflected insolation beam direction is not detected and sent back to the collector computer.

A solar energy demand signal can be generated either by the master control computer or by the distributed analog control system [see Section 4.3.1.2.(3)]. This control signal will provide feed-forward demand to the collector control computer indicating what the unit requirements are for solar insolation on the receiver. The collector control computer will selectively focus and defocus the required number of heliostats in response to solar energy demand while giving overall consideration for receiver metal temperature conditions.

Additional design requirements for the collector control system include emergency heliostat defocusing, automatic stowing, and manual control. Operator control of the collector subsystem will be from a computer control console located in

Figure 4.3-10. Collector Subsystem Control Architecture

the control room. From this control console, the operator will have the capability of independent subsystem automatic control or manual control of the entire collector field.

Collector control system hardware including the digital computer, field controllers, heliostat controllers, control console, preassembled interconnecting cables, etc., will be purchased from a manufacturer experienced in the assembly of large computer based control systems and control apparatus. Additionally, all system software and computer programming will be purchased from the hardware supplier. The collector system supplier will be responsible for all control system interfaces with the heliostat hardware and will be responsible for the correct and proper operation of the collector subsystem.

RECEIVER CONTROL SYSTEM

The receiver instrumentation and control architecture is shown in Figure 4.3-11. Receiver instrumentation and controls will be purchased with the receiver and will consist of an independent electronic analog control system, control valves and instruments, and receiver monitoring instruments.

The purpose of the receiver control system during normal operation is to maintain receiver steam outlet temperature within a specified tolerance band. Receiver steam outlet temperature is controlled by varying receiver feedwater flow rate in the individual panels in accordance with measured steam outlet temperature and incident energy on the panel. Flow control valves, temperature sensors, controllers, etc., should be of a design tested and proven by the receiver manufacturer. Receiver subsystem control schematic diagram is shown in Figure 4.3-12.

During startup, shutdown, mode transition and emergencies, the receiver control system must respond to and interface with commands from the plant operator and from the analog control or master computer controls.

The receiver system control console located on the BTG panel addition in the control room will provide the operator with both independent automatic and

Figure 4.3-11. Receiver Subsystem Instrumentation and Control Architecture

Figure 4.3-12. Receiver Subsystem Control Schematic

manual control of the receiver subsystem. Conventional Hand/Auto stations located on the console will provide conventional power plant operator interface with the receiver system.

4.3.2 PLANT MODIFICATIONS FOR CONTROL

An important objective for a solar hybrid repowering control system is to keep modifications to the existing control equipment at an absolute minimum. This objective can be accomplished only to a certain degree. Computer control and monitoring equipment impose a distinct change in operating and maintenance requirements for power plants such as the Reeves Station. Such plants typically have pneumatic combustion controls. Electronic instrumentation usually exists in such plants on a limited basis. Systems such as the collector field and heliostats are not practically controlled without computers and microprocessors. Master control for first-of-a-kind plants require flexibility for design changes that can only be provided with computer control. The addition of electronic controls and instrumentation is virtually unavoidable. A solar repowered power plant makes it a modern and state-of-the-art power plant. Such a plant demands modern and state-of-the-art controls and instrumentation.

4.3.2.1 CONTROL ROOM MODIFICATIONS

An objective of the control system design is to provide both solar and fossil plant operation by a single operator from a central control room. For most solar hybrid repowering applications this would require the addition of a new control room. Existing plant control panels would have to be relocated to the new control room or another alternative would be completely new control panels. This alternative could greatly enhance the integration of solar fossil plant operation as well as upgrade some of the existing equipment.

The existing control room design at the Reeves Station, shown in Figure 4.3-13, provided space for a fourth unit, so a new control room is not required. A control console and vertical panel will be added to the existing control room in the same general configuration as the existing panels. These are shown on Stearns-Roger Drawing No. L-22929, Sheet GI-3. All new solar controls will be located on these panel additions.

Figure 4.3-13. Reeves Station Control Room

Two significant problems are solved by using the existing control room. First, the pneumatic combustion control console with all of its tubing requirements will remain intact in its present location directly above the relay room. Second, the station will still have the potential for operation by a single operator in the control room for all three units as it now does.

Conceptually, the control console and vertical addition panels may appear as shown in Figure 4.3-14. Subsystem control consoles will be located on the horizontal or slanted section of the panel for easy operator access. The vertical section of the control console may house operator control system interface CRT's as well as additional controls and indicators.

Alarm, utility and graphic CRTs will be located on the larger vertical panel addition. CRTs will be provided with shields and non-glare screens to aid visibility in the highly lighted Reeves Station Control Room. There will be a small annunciator addition as well as instrument indicators and recorders on the vertical panel. The purpose of the vertical panel is display and indication. No controls should be mounted there.

Sizing of equipment located on the panel additions is not feasible in a conceptual design since these types of equipment vary significantly between different manufacturers. Therefore, actual panel arrangements may have to be altogether different than shown in the accompanying figure. Panel size is expected to be adequate, however. The existing control room will house a console addition up to 14 feet long and a vertical panel addition up to 12 feet long.

HVAC in the existing control room has been determined to be adequate for personnel comfort and therefore is expected to be adequate for the addition of several computer control consoles. Should this expectation prove incorrect or should additional heat loads overload the present system, additional HVAC equipment would be required to maintain control room temperature at an acceptable level.

Figure 4.3-14. Control Panel Additions

4.3.2.2 COMPUTER ROOM ADDITION

Computer systems and computer electronic hardware call for a space that is environmentally different from the usual power plant environment. Computers demand a space that is quiet, clean, dry and held within close temperature and humidity tolerance bands. Computer spaces must be free from large machinery and any electromagnetic interference such as might be produced by motors or switchgear.

Typically, therefore, power plants that are repowered with solar collectors and heliostat fields will require the addition of a computer room to house the computer systems. The Reeves Station Unit No. 2 computer room will be added on the operating floor in the solar equipment building addition (see General Arrangement Drawing No. L-22929, Sheet G1-3).

The computer room will house the MCS computer and the collector computer. Computer mainframes, analog to digital conversion units, multiplexing equipment and magnetic tape units will be housed in the computer room. Computer termination cabinets for field wiring will be housed in the adjacent log equipment room and interconnected to the computer system with preassembled plug-in connector cables.

The computer room will also contain programmer's consoles and printers for the two computers as well as the plant computer engineer's console, printer and recorders. The computer room will provide a work space for the plant engineer and the computer programmer that is segregated from all other plant activities.

Special heating, ventilating and air conditioning systems required to maintain temperatures and humidity as required by the computers will be mounted on the roof above the computer room.

4.3.2.3 LOGIC EQUIPMENT ROOM ADDITION

The addition of new and sophisticated electronic control systems and instrumentation lead to the requirement to provide a space for these systems. Although the space environmental conditions are not as demanding as those in the computer room, they must be suitable for electronic equipment.

Conceptually, the logic equipment room might appear as seen in Figure 4.3-15. Typical electronic control system cabinets are 24-inches wide, 24-inches deep and 90-inches high. They may be arranged in bays as long as the space will allow. Systems cabinets are provided with both front and rear access doors.

For the Reeves Station Unit No. 2 Solar Repowering, the logic room addition is located on the operating floor in the solar equipment building addition as shown on Stearns-Roger Drawing No. L-22929, Sheet GI-3.

A requirement for approximately 80 feet of system cabinets, four bays 20-feet long, has been identified. It must be realized, however, that an actual final design could be considerably different. Estimates for total cabinet sizes has been based on similar systems in other power plants.

4.3.2.4 BOILER AND COMBUSTION CONTROL MODIFICATIONS

Two potential problems were studied during conceptual design for repowering the Reeves Station Unit No. 2 existing fossil boiler. Neither of these present insurmountable technical difficulty. The first problem was the requirement for operating boiler burners at very low loads. The other problem, identified by plant operating personnel, was the inability of the combustion control system to operate automatically below 10 percent load.

During combined solar and fossil operation, the fossil boiler must operate at relatively low loads. Since the boiler is equipped with a total of six burners, low load operation is normally accomplished by shutting down all but two burners. Burner light-off and shut down is a manual operation performed locally at the burner. During severe solar transient operation, the boiler must be able to ramp from as low as 25 percent to 100 percent load in a short time. Additional burners cannot be put on line in a short time.

Two courses of action were considered. First, the burners could be replaced with new, automatic burners as part of furnace safety and fuel supervision (FSFS). This would provide for automatic control of the burners from the control room. A second choice is to operate at low loads with all six burners in operation.

32 x 30

Figure 4.3-15. Logic Room

This is feasible if adequate turndown capability exists on the burners and if adequate fuel atomization will occur with the burners turned down for low load operation. Discussions with the boiler manufacturer indicate that adequate turn down (10:1 with 5:1 required) does exist and that proper fuel atomization will occur. Therefore, at Reeves Station Unit No. 2 the conceptual design utilizes the existing burners.

The inability of the existing combustion controls to operate in an automatic mode below 50 percent load has been identified by plant operating personnel as a problem with the fuel oil control valve. At low loads, the control valve operates close to the seat and cannot maintain stable oil flow. In this case, the plant operator places the controller in manual and manually sets fuel oil flow.

The correction for this problem is to provide a smaller control valve for low load operation. This is shown on Drawing No. L-22929, Sheet P3-3. The smaller control valve will provide stable fuel oil control at low loads and the existing valve will operate at high loads. In a parallel control valve arrangement such as this, both valves operate off the same 3 to 27 psig control signal. The valve positioner on the smaller control valve is set to provide 100 percent valve stroke over a 3 to 16 psig signal while the other valve positioner strokes the larger control valve over an 14 to 27 psig control signal. Such parallel control valve arrangements have proven successful in many power plant applications.

At the conceptual design level, no other problems were encountered. For an actual design, however, boiler testing is warranted to ensure that other problems do not exist and to ensure that the known problems are corrected.

4.3.2.5 TURBINE CONTROL SYSTEM MODIFICATIONS

The following control system modifications are planned:

- Replace the existing 150-lb mechanism Hydraulic Control System with a Digital Electro-Hydraulic (DEH) Control System
- Replace the existing Turbine Supervisory instruments (TS) with a Bently Nevada design

- Add all turbine generator sensors required by the DEH for Automatic Turbine Control (ATC)
- Provide necessary sensors for the Steam & Metal Temperature Recorder

The above recommendations are based on the following:

- The DEH System provides valve management that will permit greater capability for handling load cycling with minimum rotor stress.
- The DEH System provides Automatic Turbine Control that will permit startup and load changing while automatically controlling rotor stresses as well as considering all significant T-G conditions. This provides the capability of handling unexpected main steam conditions that can occur in any plant using new technology.
- The DEH is a proven state-of-the-art system that is both esthetically and functionally most compatible with the Digital Plant Control System. A data Link can be provided for DEH/Plant Control communication.
- The DEH System provides maximum flexibility for modifying control functions as operation philosophy evolves during the design and early operation stages.
- The DEH System with Remote and Operator Adjustable Throttle Pressure Control option provides maximum turbine protection against water carry-over. Throttle pressure variation will be a normal operating condition.
- The DEH provides faster response than the existing mechanical control system as well as response to system frequency fluctuations.
- The DEH includes an over-speed protection control (PC) function in addition to the centrifugal trip weight presently provided.
- New Supervisory Instruments are provided as well as other primary measurement devices to insure that the DEH as well as the operator has reliable data to base operating decisions on.

A comparison between the DEH control system (recommended for the repowered plant) and an AEH system was performed. The advantages of a DEH over an AEH are:

- More flexible interfaces with other plant controls —
Many modern power plants have central computers for information gathering, control and alarming. With the use of a data link, all locations in DEH core are available to central computer for reading or setting values. With an AEH only limited information is available due to physical wiring limitations.

- Easier changes to settings, interlocks, operating procedures —
In that most changes can be accomplished in software rather than hardware, changes can be made by feeding in new instructions by punched tape, operator entry for certain items or at the controller maintenance panel. Similar changes to an AEH would generally require physically modifying printed circuit cards or wiring.
- Less impact on turbine availability for most control changes that may be necessary

Again because the controller is a digital computer-based system there are advantages to the customer. If changes in programs are required for the operation of the unit, these changes can be engineered with new tapes produced while the customer's unit is still on the line producing power. Since these programs can be checked at Westinghouse, there is a high level of assurance that the new operation will work the first time. The new programs could then be read into the DEH while the unit is in the manual mode still producing power. Since the loading of new tapes takes no more than two hours, minimal operator inconvenience would occur and no load reduction need occur. This advantage is not speculation. We have actually used this procedure on several of the more than 40 DEH units in operation.

For the most part, changes to AEH units would require the unit to be shut down.

- Safe Operation

With the availability of the ATC (Automatic Turbine Control) with the DEH, safe, consistent operation of the unit can be assured. The ATC continually monitors rotor stress and many other variables and thus allows for safe operation of the unit. This feature is especially valuable on a unit subjected to cycling duty.

4.3.2.6 PLANT INSTRUMENTATION ADDITIONS AND MODIFICATIONS

Additional instrumentation must be added to the existing plant to provide the plant computer with enough process information to perform plant monitoring and master control. Generation of a computer I/O (Input/Output) list is the task of a detailed design.

For purposes of conceptual design, the P and I Diagrams (Stearns-Roger Drawing No. L-22929, Sheets P3-1 through P3-6) have been drawn with necessary computer instrumentation. A great deal more instrumentation is utilized by the plant computer to monitor everything from boiler tube temperature to circulating

water pump on/off status. A tremendous amount of plant monitoring capability exists in the plant computer and perhaps only approximately 20 percent is shown on P and I diagrams.

For the solar repowered demonstration plant it is anticipated that the total I/O List will contain approximately 1000 analog inputs and 1000 digital inputs. For further discussion see Section 4.3.1.2, Master Control Computer.

4.3.3 CONCLUSIONS AND SUMMARY

4.3.3.1 DEMONSTRATION PLANT CONTROLS VERSUS COMMERCIAL PLANT CONTROLS

In considering the possibility of repowering many units, it is worth noting that the nth commercial plant may have some significant control system simplification.

The first solar repowered plant, or demonstration plant, will probably require a significant amount of monitoring, performance testing and data collection that should not be required on a commercial plant. This will require that the plant computer have a plant performance and backup central processing unit (see Figure 4.3-16). The commercial plant should not require this (see Figure 4.3-17).

In the same line of thinking, automatic turbine startup would probably not be necessary on all solar repowered units. Solar transient operation may prove controllable by the automatic control systems and the plant operator.

Conceptual design cannot determine with certainty what changes will be acceptable. These will only be determined after a detail design, construction and operation of a solar repowered power plant.

4.3.3.2 REPOWERING CONTROL SYSTEM — CONCLUSIONS AND SUMMARY

A control system has been presented and discussed that meets the basic needs for solar hybrid repowering applications. The implementation of this system on existing power plants was discussed with particular emphasis on Reeves Station Unit No. 2. From a controls and instrumentation point of view, solar hybrid repowering of existing power plants is feasible, reasonable and presents no unusual difficulty for a project of this magnitude.

Figure 4.3-16. Demonstration Master Control System

Figure 4.3-17. Commercial Master Control System

4.4 ELECTRICAL DESIGN

Figure 4.4-1 is a functional diagram showing the overall plant electrical power and distribution system. This diagram depicts the primary solar elements of the power system and also the tie-in to the existing plant primary components.

The following is a brief description of the solar repowering of the existing plant facilities.

MAIN ELECTRICAL SYSTEM

The main electrical system for Unit No. 2 and the Switchyard will be effectively unchanged with the solar addition, except for providing the extra auxiliary power as described in the next section.

AUXILIARY SYSTEM

A voltage of 2400 volts will be retained for the main auxiliary solar bus that will feed the 2000 horsepower receiver pump motors and distribution system for the heliostat field. This therefore enables startup power to be obtained from the existing startup transformer. Normal auxiliary power will be obtained from an additional unit auxiliary transformer. These two sources of power will feed separate auxiliary buses having a tie breaker between them. This bus arrangement facilitates the application of the reserve receiver feed pump to either Unit No. 1 or Unit No. 2, with the future addition of solar to Unit No. 1. This arrangement also provides redundancy to the heliostat distribution system to enable full plant operation in the event of a fault on the main solar auxiliary bus.

Since the existing plant emergency diesel generator is not automatic starting, and since it does not have sufficient capacity for the additional emergency load, it is necessary to add an additional 480 volt system capable of receiving emergency power from the new diesel generator. This will be arranged by feeding a new 1000 KVA load center from the 2400 volt solar bus. The new load center would be tied to the existing load center to form a double end load center.

Figure 4.4-1. Functional Diagram — Overall Plant Power and Distribution

On both the 2400 volt and 480 volt systems, automatic bus transfer would be provided to enable a controlled shutdown to be accomplished following a unit trip.

A diesel generator is provided to enable controlled unit shutdown to take place following system blackout.

4.4.1 SOLAR PORTION OF DESIGN

4.4.1.1 POWER TO HELIOSTATS

As shown on Drawing L-22929, Sheet E2-1 and Figure 4.4-2, approximately 145 KVA power at 2400 volts will be furnished to the heliostat field during normal daylight plant operation. This will be accomplished using a loop 5 kV, 3/C cable routed from the new 2.4 kV solar switchgear.

A cost study was made to determine whether the cable should be routed via cable tray or conduit. Means of supporting either raceway, ambient temperatures versus cable size and cable ampacities were taken into consideration.

It was determined that the least costly method would be to route the cable in conduit supported from the pipe rack that terminates at the receiver. The conduit will also function as an equipment grounding conductor.

4.4.1.2 HELIOSTAT SWITCHING UNITS

20 three-pole switching units will be installed. The switching units will be fed from the 2.4 kV loop and will permit partial isolation of the heliostat field in the event of a fault in the cable. A number of switching units will be located adjacent to the pipe rack, actual locations to be dictated by the heliostat requirements. The remainder of the units will be located in the vicinity of the receiver tower for convenient access. Each of the 20 switching units will feed a 225 KVA transformer.

4.4.1.3 HELIOSTAT TRANSFORMERS

20 225 KVA, 2400-240 volt, three-phase, pad-mounted transformers, each located central to a group of approximately 216 heliostats, will be provided. The

Figure 4.4-2. Heliostat Field Power Diagram

transformer(s) primary circuit will be 5 kV, 3/C cable routed in buried conduit. The transformer(s) secondary will consist of a 600 volt, 600 ampere, three-phase bus each routed to a distribution panel.

4.4.1.4 HELIOSTAT DISTRIBUTION PANELS

20 240 volt, three-phase distribution panels will be furnished, each one being located adjacent to a transformer. Each distribution panel will provide nine, three-pole branch circuits to feed approximately 24 heliostats per circuit. The branch circuits will be direct buried type CLX, 600 volts, 3/C No. 6 AWG. Type CLX was chosen on the basis of reliability; i.e., physical protection, including rodent protection. Economics dictate that the cable will be plowed in, using predetermined lengths. Terminations at each heliostat will use ring-type crimp connections onto terminal blocks.

The heliostat control cables will be a twisted pair, PVC insulated, aluminum armor with a thermoplastic jacket. This will provide physical protection, since the cable between heliostats will be direct buried using the plowing-in method. Spade and tongue terminations are being considered at each heliostat to allow for field breakable connections required for individual testing. An assembly line approach in the field utilizing available equipment would provide a cost savings in crimping these terminations to the cable. The control cables from each heliostat field controller to the collector control computer would be direct buried back to the receiver tower, and at that point would be routed in cable tray(s) supported from the available pipe rack.

4.4.2 MODIFICATIONS TO EXISTING EQUIPMENT

4.4.2.1 480 VOLT LOAD CENTER

As shown on Drawing L-22929, Sheet E2-1, the existing breaker No. IC will be reconnected to provide a tie to the new solar load center bus.

4.4.2.2 TIE TO START UP TRANSFORMER 2A

The 2.4 kV solar switchgear will be tied into the existing startup transformer 2A secondary bus, using 5-kV cable. The tie location has not been determined pending further information on existing configuration or visual inspection.

4.4.2.3 SOLAR AUXILIARY TRANSFORMER PRIMARY

It will be necessary to tap into the existing generator No. 2 Main Transformer 2A isolated phase bus for the solar auxiliary transformer primary feed. This will be accomplished by replacing the existing three-pole, interrupted switch with a double unit interrupter switch, including necessary internal busing, to serve both the existing unit auxiliary transformer 2A and the solar auxiliary transformer. Visual inspection, for available physical space, will determine whether this concept is feasible.

4.4.3 ADDITIONS OF ELECTRICAL EQUIPMENT

4.4.3.1 2.4 KV METAL CLAD SWITCHGEAR

It has been determined that the existing 2.4 KV switchgear was not suitable for solar extension due to the 1200 ampere bus rating and physical space limitations. A new line up of 2.4 KV switchgear will be installed (refer to Drawing L-22929, Sheet E2-1) for the Unit No. 2 solar repowering, with floor space being provided for the future Unit No. 1 solar repowering switchgear.

4.4.3.2 SOLAR AUXILIARY TRANSFORMER S2

Auxiliary power will be supplied by a solar auxiliary transformer. The transformer will be rated 3750 KVA, 13.2-2.4 kV, 0A. The primary will be Delta and the secondary will be resistance grounded wye. The primary will be fed from generator No. 2 main bus via an interrupter switch (see Section 4.4.2.3). The transformer secondary will feed the 2.4 kV bus (see Section 4.4.3.1) with a bus tie between sections. The secondary connection will be cable or bus duct.

The rating of this transformer is based not on the solar plant continuous load demand, but upon the starting requirement of the 2000 horsepower receiver pump motors. The transformer KVA rating and impedance is chosen to maintain more than 80 percent system voltage when starting this motor.

4.4.3.3 480 VOLT SOLAR LOAD CENTER 2B

The load center transformer will be rated 1000 KVA, 2400-480 volts. The primary will be Delta and the secondary will be grounded wye. The secondary of the

transformer will feed the 480 volt load center bus through a 1600 amp main breaker. An additional 1600 amp breaker will be used as a bus tie breaker to the existing plant 480 volt bus. The existing bus, together with the new solar load center bus, will form a double ended load center. Due to the relatively long cable connection to the existing load center bus, two tie breakers will be used, one at each end of the cable, to improve the plant integrity.

4.4.3.4 480 VOLT MOTOR CONTROL CENTER

The solar motor control center will be adjacent to and fed as an extension of the new 480 volt load center bus 2B. The motor control center will utilize molded breaker combination starters for motor drives, up to 100 horsepower, and molded case breakers for lighting transformers and miscellaneous services.

4.4.3.5 EMERGENCY DIESEL GENERATOR

An emergency power diesel engine generator will provide power for safe solar shut down and emergency service. The generator will be rated 1600 KVA, 80 percent power factor, 2400 volts, with regulator and rotating exciter. The generator will be connected to a 2400 volt switchgear bus section. The diesel will be automatic starting in the event of loss of primary power from the turbine-generator or the grid distribution system. Emergency power will be provided for the heliostat field and all other new and existing essential loads of Unit No. 2.

It is estimated that the heliostat field will require a total of approximately 2100 kW when operating all drive motors simultaneously, such as could occur during an emergency slew condition. However, the engine generator is sized to provide power to one-quarter the field, and then only to 1.5 motors per heliostat, based on elevation drive motors and partial azimuth drive motors. This reduces the emergency power demand to approximately 315 kW. This is based on information provided by McDonnell Douglas.

The 1600 KVA rating of the generator is based on two considerations:

- The heliostat loading of 315 kW has a power factor of 0.4 that represents a KVAR loading of 722 KVAR. When expressing this in terms of a 0.8 pf machine, a 1203 KVA generator rating is required to obtain the 722 KVAR.

Power factor correction has not been considered since the next condition requires an even larger emergency generator.

Since the heliostat motors are sequentially started, a starting duty of this 315 kW steady state load does not have to be considered.

- Other essential loads require 170 kW of power, this being mainly motor load. Assuming the locked rotor currents are six times the full load current, these additional loads will require 1020 KVA. This would be a momentary starting condition, and therefore the data contained in Beeman's "Industrial Power Systems Handbook," Figure 4.39, has been used to establish generator rating. This indicates that for a 600 to 1800 rpm generator with generator terminal voltage maintained above 85 percent of nominal, the motor starting KVA should not exceed 65 percent of machine rating when the generator has a high speed voltage regulator. Hence, Machine Rating = $1020/0.65 = 1569$ KVA.

4.4.3.6 FURTHER CONSIDERATIONS ON EMERGENCY POWER

The inclusion of the above generator is required for system blackout conditions on the assumption that the solar boiler (receiver) is not capable of taking a 100 percent load rejection down to auxiliary power of approximately 6.5 percent. If the boiler is capable of sustaining this load rejection, power system instability problems could be relayed. Detection of these conditions could trip the generator main breakers, leaving the plant self-sustaining and the need for emergency generators would be eliminated. This would also facilitate fast reinstatement of the main power system.

Assuming diesel generators are installed, with the solar addition to both Units No. 1 and No. 2, there would be sufficient capacity to black start the plant following the completion of a complete solar shut down. If this capability is required, some additional switching facilities would be required to enable both emergency generators to be connected to a single unit.

4.4.3.7 MISCELLANEOUS LIGHTING TRANSFORMERS AND PANELS

Lighting will be provided for all outdoor and indoor locations. The lighting transformers primary feed will be 480 volts ac from the motor control center. The transformer's secondaries (voltages as required) will feed lighting panels

at readily accessible locations. Lighting panel branch circuits will be designed to be switched at the panel utilizing the breakers, except for circuits with automatic controls or lighting circuits for areas with minimal personnel traffic. The latter will be controlled by switches in the area.

Aircraft obstruction warning lighting will be provided for the receiver tower.

4.4.3.8 MISCELLANEOUS FEED FOR AUXILIARIES

The 480 volt motor control center will provide power for solar auxiliaries (see Section 4.4.3.3), chemical pumps, sump pumps, HVAC, lighting transformers, etc. The 480 volt bus will be split into nonessential and essential services utilizing a tie breaker. The essential portion of the bus will be provided with a feed from the existing plant emergency diesel generator. This will provide an alternate power source in the event of loss of primary source.

4.4.3.9 CABLE TRAY SYSTEM

A cable tray system will be provided utilizing ladder-type tray for power circuits and solid bottom-type tray with solid covers for control and instrumentation circuits.

A cable spreading room will be provided below the switchgear and the computer and relay rack room to provide easy and isolated circuit access into the cable tray system.

4.4.3.10 CONTROL

The instrumentation and control wiring will start at the various master control cabinets, located in the solar plant control building, and be distributed to the various locations of the subsystem interfaces. Control and instrumentation field wiring for all subsystems except the collector fields is routed in cable tray. Collector subsystem wiring will be direct buried, twisted pair, PVC insulated with aluminum armor for physical protection and a thermoplastic jacket.

4.4.3.11 UNINTERRUPTIBLE POWER SYSTEM

The uninterruptible power system (UPS) will be implemented to provide protection to the solar master control subsystem. This system, illustrated in Figure 4.4-3, will provide power to the computers and control system hardware.

Under normal operating conditions, the battery charger will operate as a rectifier to provide dc to the inverter from the normal ac incoming line. The battery bank will be connected in parallel to the dc being supplied from the charger so that if any failure or voltage drop occurs in the ac line, the batteries will provide dc to the inverter. Thus, no break will occur in power to the load. An automatic bypass switch will be supplied to provide automatic bypass of the inverter of an alternate ac source in the event of UPS malfunction or overload.

4.4.3.12 LIGHTING

Outdoor lighting will be provided along access road, parking areas, operating areas, operating area perimeter and the collector field. Mercury vapor fixtures will be used with photocell control. The design will be based on an approximate average horizontal foot candle level of 1.5. Outdoor lighting will also be provided for all building entrances, loading docks and equipment locations outside the buildings.

Indoor lighting will be provided in all building rooms, offices and stairwells. The design will be based on foot candle levels for the various area functions as recommended by the Illuminating Engineering Society (IES).

Emergency lighting will be provided as required for the safety of personnel and equipment.

4.4.3.13 GROUNDING

A dependable grounding system will be designed and furnished to provide required protection to personnel and equipment as follows:

- Provide a low impedance path to ground for personnel and equipment protection and effective circuit relaying
- Withstand and dissipate repeated fault and surge currents

Figure 4.4-3. Uninterruptible Power System

- Proper grounding of metallic equipment enclosures and supporting structures that are part of the electrical system and may be contacted by personnel.
- Provide grounds for electric process control, instrumentation and communications circuits

4.4.3.14 LIGHTNING PROTECTION

The factors that will be considered during the design of the lightning protection system are as follows:

- The number of thunderstorm days or the number of lightning flashes per Km² per annum for the site area from available data
- The cone of protection area provided by protecting the RS tower
- No direct strike protection planned for heliostats in the collector field since the risk taken involves the possible repair or replacement of a struck heliostat
- Protection against direct lightning strokes
- Protection against lightning induced voltages

The design of an effective lightning protection system will:

- Provide a means by which a lightning discharge may enter or leave the earth without passing through a nonconducting part of the receiver tower or building
- Provide a grounding electrode and grounding electrode conductor for each heliostat in the collector field

4.4.4 LEAD TIME REQUIREMENTS

Lead times, estimated in weeks, are as follows:

- Auxiliary Transformer 15 to 20
- Switchgear 18 to 45
- Load Centers 25 to 30
- Motor Control Centers 10 to 24

4.4.5 CODE AND LEGAL REQUIREMENTS

The equipment, materials, design and construction of the plant will comply with all Federal, State, Local and user standards, regulations, codes, laws and ordinances that are applicable for the site and using utility. These will include, but not be limited to, the following:

- Regulations of the Occupational Safety and Health Administration (OSHA)
- IEEE — Switchgear and transformers
- NEMA Standards — Motors, starters, distribution panels, lighting and electrical materials
- Uniform Building Code
- National Electrical Code (NEC)
- National Fire Protection Association (NEPA) Standards
- Lightning Protection Code, NFPA No. 78 (ANSI C5.1-1969)
- IEEE Recommended Practice for Grounding of Industrial and Commercial Power Systems
- Public Service Company of New Mexico Power Plant Standards

4.5 CIVIL, STRUCTURAL, ARCHITECTURAL DESIGN

4.5.1 SUBSOIL CONSIDERATIONS

4.5.1.1 SITE LOCATION AND CONDITIONS

Reeves Station is located on approximately 60 acres north of the Albuquerque city limits, south of Los Angeles Boulevard, west of Interstate 70, and east of the northern diversion channel of the Albuquerque Metropolitan Arroyo Flood Control Authority. The plant site is in the foothills of the Sandia Crest, between the Crest and the Rio Grande River. The site slopes gently toward the north and west, to the Rio Grande about three miles from the site. Vegetation is sparse and there are no nearby bodies of water, the nearest being the Rio Grande.

4.5.1.2 SUBSOIL CONDITIONS

The entire area is overlaid with a thick layer containing lensatic strata of dry, sometimes porous, silty sand or sandy silt. This material generally has sufficient fines to have a low plasticity binder. This layer ranges in depth from six to twenty-six feet occasionally containing some small gravel. It is subject to small to moderate amounts of consolidation when wetted since the materials are all very frictional. Settlement conditions are controlling.

Underlying the near-surface layer is a thin stratum (one to four feet thick) of a very fine uniform sand. The sand layer is clean and generally in a medium dense state. Below this is a thick, dense sand and gravel layer. The sand and gravel is fairly well graded, and sub-angular, with a predominance of the smaller sand-sized particles and with a maximum gravel size of about three inches. The sand contained in this sand and gravel bed appears to be essentially the same as to particle size and shape as the thin sand bed immediately above. No ground water is evident to a depth of 50 feet.

4.5.1.3 GENERAL CONSIDERATIONS

To adequately support any structure, it is necessary that the soils beneath the foundations be safe against settlement in excess of the amount permissible for the particular structure and shear displacement of soils from beneath the foundations. For the sandy foundation soils in question, there is no danger of shear displacement of the soils under any practicable pressures in the design of the three

units at Reeves Station. It is expected that the information is reliable, for the entire site due to the highly uniform nature of the soils in the area. However, in design for final construction purposes, a full scale soils investigation will have to be made to confirm reliability of this information, particularly where major structures are concerned.

The previous soils information was extracted and extrapolated from the "Foundation Investigation for the Proposed Reeves Power Plant" by Woodward, Clyde and Associates, March 26, 1957.

4.5.1.4 FOUNDATIONS FOR OPERATING UNITS

Previous experience with materials of these types causes Stearns-Roger to recommend several general foundation alternatives. Final selection should be based upon comparative cost studies.

- Foundations of heavy structures (receiver tower) to rest on well compacted fill extending down to the dense sand and gravel stratum. The upper silty sand would be removed and replaced with required sandy backfill.
- Foundations of lesser structures, which are not critical with respect to settlement, should be founded on the undisturbed upper silty sands
- Drilled pier foundations should be considered for heliostat foundations because loading is largely lateral and substantial economies may be achieved.

4.5.2 FOUNDATION AND STRUCTURAL DESIGN

4.5.2.1 HELIOSTAT FOUNDATIONS

Heliostat foundations should be given careful scrutiny before final selection because of their possible high impact on overall cost of the heliostat field. Review of previous foundation studies indicates two candidate foundation types subject to final review based on heliostat type and size, plus complete soils data:

DRILLED PIER

A 24-inch diameter drilled pier embedded about 22 feet in the recommended

heliostat foundation. In situ testing is recommended to determine if pier length can be reduced.

Cast-in-place concrete pier foundations can be used with a variety of soil conditions. The pier hole can be excavated by drilling an open hole, if the sidewalls do not cave, placing the required reinforcing, and placing concrete as required to fill the hole. The pier can also be placed by the Intrusion-Prepakt method, regardless of the sidewalls standing or not. In this method, a hollow auger is rotated into the soil the required depth and sand cement mortar placed through the auger to the hole bottom, the auger displaces the soil as it is withdrawn from the hole in a single operation. Reinforcing must be forced into the grouted hole before the mortar hardens.

The length of the drilled pier foundations can be varied as required by differing soil conditions to attain the required foundation stiffness.

CONICAL PRECAST CONCRETE FOUNDATION

This foundation is inherently very stable. Some unaccountable deviation rotation will occur at the time of placement as the material upon which the foundation rests will not make complete intimate contact with the foundation without excessive fine grading. Also as this particular site has soils which are moisture sensitive, this is not recommended foundation.

FOUNDATION PEDESTAL JOINT

The large number of heliostat pedestal/foundation joints makes them very cost sensitive. Design simplification studies should be included in the Detailed Engineering phase to optimize expenditures and joint integrity.

A complete detailed study cannot be made until selection of a heliostat type; however, one method to be considered is as follows:

The pedestal of the heliostat would be constructed of structural tapered tube and the foundation extension constructed of structural reinforced concrete formed by light gage tapered tube. The foundation extension form is to be placed over reinforcing extended from the drilled pier concrete. The extension is then

filled with concrete to provide the structural connection to the foundation. The tapered heliostat pedestal would then be force mounted over the foundation extension.

FOUNDATION DESIGN CRITERIA

The preliminary criteria resulting in the recommended drill pier foundation are as follows: limitation of allowable total rotation of the foundation/pedestal system was based on a 36 mph wind on a 520 square foot surface. Rotation was limited to 2.3 milliradians. Soil conditions were based on a southwest desert site. Analysis assumed no passive restraint by the top 5 feet of soil. Values of the coefficient of horizontal subgrade reaction were obtained from "Drilled Pier Foundations" by Woodward, Gardner, and Greer.

4.5.2.2 RECEIVER TOWER AND FOUNDATION

A comparative study was made to decide if a reinforced concrete receiver tower or a structural steel receiver tower would be the most economical and satisfactory. For this height, weight, and wind and seismic conditions, the reinforced concrete tower proved to be the most economical. It was also more satisfactory for providing sheltered interior work space as an adjunct to the method of construction.

CONCRETE RECEIVER TOWER AND FOUNDATION

The concrete tower developed in the preliminary conceptual design, shown in Figure 4.5-1, extends 413 feet above grade. The top of the tower has an outside diameter of 33 feet with a nominal 9-inch wall thickness. The base of the tower, measured at the top of the foundation mat, has an outside diameter of 50 feet with wall thickness of 12 inches. The slope of the vertical face of the tower is approximately 1 H to 50 V. The foundation, which is located 10 feet below the finished grade, is a solid concrete mat of 85 feet diameter with a uniform thickness of 8 feet.

Design references:

- Uniform Building Code
- Building Code Requirements for Reinforced Concrete (ACI 318-71)

CONCRETE SOLAR RECEIVER TOWER

DESIGN DATA

1. WT. OF RECEIVER 1500K
2. WIND LOADS = OPERATIONAL 36 MPH
SURVIVAL 90 MPH
3. SEISMIC LOADS = GROUND ACCELERATION 0.125 G
4. SOIL BEARING PRESSURE = 4 KSF ON COMPACTED FILL
5. CONCRETE STRENGTH = $f'_c=4000$ PSI
6. REINFORCEMENT - INTERMEDIATE GRADE $f_y=60,000$ PSI

MATERIAL QUANTITIES

1. CONCRETE TOWER
CONCRETE 1855 CY
REBAR 75 TONS
2. FOUNDATION MAT
CONCRETE 1765 CY
REBAR 93 TONS

Figure 4.5-1. Concrete Receiving Tower

- Specification for the Design and Construction of Reinforced Concrete Chimneys (ACI 307-69)
- Design Response Spectra for Seismic Design of Nuclear Power Plants (NRC Regulatory Guide 1.60)
- Damping Values for Seismic Design of Nuclear Power Plants (NRC Regulator Guide 1.61)
- Building Code Requirements for Minimum Design Loads in Buildings and Other Structures (ANSI A58.1-72)

The concrete tower was designed to resist stresses resulting from the weight of the receiver, the weight of the tower, and the effect of wind or earthquake, whichever is critical. The design loads are as follows:

Receiver weight	1,500,000 pounds
Seismic loads	0.125 g maximum ground acceleration in both the vertical and horizontal directions at survival condition
Operation wind	36 mph
Vortex shedding	48 mph
Survival wind	90 mph

The effective wind velocity pressures were obtained from ANSI A58.1-72. A gust factor of 1.062 was applied.

Stresses: The strength design provisions of ACI 318-71 were employed for design of the reinforcement in the concrete tower. A load factor of 0.9 was applied to dead load and a factor of 1.43 to seismic loads. Vertical seismic loads were conservatively assumed to oppose the tower and receiver dead load; i.e., to cause uplift.

Analysis Studies: The Stearns-Roger G163 computer program was used to perform the analysis and reinforcing steel design of the concrete tower. A fixed base model was employed and the receiver support structure was considered to be infinitely rigid due to the lack of information on the nature of the support structure. Dead load combined with the survival seismic loads governs the design

Lateral deflection of the receiver centerline under survival earthquake conditions is 7.25 inches which ensures that the deflection under operational wind (36 mph) will be less than the allowable limit of 7 inches. Lateral acceleration at the receiver centerline is 0.227 g's. Vertical acceleration at the receiver centerline is 0.434 g's. Fundamental frequencies are 0.378 cps in the lateral direction and 5.69 cps in the vertical direction.

Materials: The concrete used for constructing the tower shall conform to ACI Code and shall have a minimum ultimate compressive strength of 4000 psi at 28 days. Concrete for the foundation mat shall be 3000 psi minimum ultimate compressive strength at 28 days. Reinforcing bars shall be intermediate grade conforming to ASTM A615, Grade 60.

Allowable Soil Pressure: The Soil Report for Reeves Power Plant, prepared by Woodward-Clyde, dated March 1957, was referenced for the foundation design. A 4000 psf maximum allowable bearing pressure was assumed, allowing a one-third increase for dead load combined with earthquake.

STEEL RECEIVER TOWER

The steel tower developed in the preliminary conceptual design extends 423 feet above grade. An octagonal structure was selected because this shape provides great stiffness of the tower. The top of the tower is 33 feet diagonally to 30 feet-6 inches between the two opposite faces. The base of the tower is measured 75 feet diagonally or 70 feet between the two opposite faces. The slope of the vertical face of the tower is approximately 1 H to 21 V. The legs of the steel tower will be supported by a concrete ring wall which will rest on a 10 foot thick ring mat foundation with 110 feet outside and 40 feet inside diameters respectively. The top of the mat will be 10 feet below the grade.

Design References:

- Uniform Building Code
- AISC Manual of Steel Construction
- Design Response Spectra for Seismic Design of Nuclear Power Plants (NRC Regulatory Guide 1.60)

- Damping Values for Seismic Design of Nuclear Power Plants (NRC Regulatory Guide 1.61)
- Building Code Requirements for Minimum Design Loads in Buildings and Other Structures (ANSI A58.1-72)
- Guide for Design of Steel Transmission Towers (ASCE Manuals & Reports on Engineering Practice No. 52)

The structural members of the steel tower were designed to resist the stresses resulting from the weight of the receiver, the weight of the tower, and the effect of wind or earthquake, whichever is crucial. The design loads are as follows:

Receiver weight	1,500,000 pounds
Seismic loads	0.125 g, maximum ground acceleration in both the vertical and horizontal directions at survival conditions. Use response spectra from NRC Reg. Guide 1.60 with 7 percent damping
Operational wind	36 mph
Survival wind	90 mph

The effective wind velocity pressures were calculated in accordance with the provisions provided by ANSI A58.1-72. In calculating the solid exposed area of the structural member, the actual exposed area of one face has been increased by 100 percent to allow for the pressure on the opposite face.

Stresses: Structural members of the steel tower were sized conforming to AISC requirements. Dead load combined with survival wind load of 90 mph governs the design. The allowable stresses were increased one-third for that load combination in selecting the member sections.

Analysis Studies: The STARDYNE computer program was used to perform the analysis of the steel tower for dead load combined with wind load conditions. For the analysis of dead load combined with seismic load condition, the Stearns-Roger G163 computer program has been employed. A fixed base model was assumed and the receiver support structure was considered to be infinitely rigid due to a lack of information on the nature of the support structure. Lateral deflection of

the receiver centerline under survival earthquake condition is 7.10 inches and that under operational wind (36 mph) condition is 2.88 inches which is less than the allowable limit of 7 inches. Lateral acceleration at the receiver centerline is 0.063 g's and the vertical acceleration at the receiver centerline is 0.337 g's. The fundamental frequencies are 0.303 cps in the lateral direction and 3.670 cps in the vertical direction.

Materials: All structural steel members for the solar receiver tower shall be ASTM A36 steel. All primary field connections shall be made with 7/8-inch diameter ASTM A325 high-strength bolts. Concrete for the foundation ring wall and mat shall be 3000 psi minimum ultimate compressive strength at 28 days. Reinforcing bars shall be intermediate grade conforming to ASTM A615, Grade 60.

Allowable Soil Pressure: The Woodward-Clyde Soil Report for Reeves Power Plant, dated March 26, 1957, was referenced for the foundation design. A 4000 psf maximum allowable bearing pressure was used, allowing a one-third increase for dead load combined with wind or earthquake load conditions.

TOWER ECONOMIC STUDY

The cost breakdown in Table 4.5-1 shows the concrete tower to be more economical than the structural steel tower in direct field cost by nearly \$360,000.

BUILDING EXTENSION

The main building will be extended as shown on the General Arrangement drawings in order to house the majority of the new solar repowering equipment. The structure will be approximately 80 by 50 feet and be three stories high. Construction will match that of the existing plant, will consist of a structural steel frame supported on spread concrete footings; the building will abut the existing structure, but will not be attached to it.

Architectural treatment will match the existing structure with walls being of concrete block and fluted metal siding. The roof will be constructed of metal decking with insulated built-up roofing placed over it.

TABLE 4.5-1. TRADE STUDY--CONCRETE VERSUS STEEL TOWERS

CONCRETE TOWER											
		Mat'l		Manhours							
		Unit	Cost	Unit	Total	\$/MH	Labor	Material	Other	Total	
25 MW solar repowering station											
A	Excavation and Backfill	2800	CY						9,800	9,800	
B	Concrete										
	Foundation Mat	1765	CY	50	5	8,825	12	105,900	88,250		194,150
	Foundation Rebar	93	T	400	inc'l				37,200		37,200
	Tower Concrete	1855	CY	50	27	50,085	12	601,020	92,750		693,770
	Tower Rebar	75	T	400	inc'l				30,000		30,000
	TOTALS							706,920	24,8200	9,800	964,920
STEEL TOWER											
		Mat'l		Manhours							
		Unit	Cost	Unit	Total	\$/MH	Labor	Material	Other	Total	
25 MW solar repowering station											
A	Excavation and Backfill	4600	CY						16,100	16,100	
B	Concrete										
	Concrete	3054	CY	50	5	15,270	12	183,240	152,700		335,940
	Rebar	168	T	400	inc'l				67,200		67,200
C	Steel										
	Structural	660	T	1100	18	11,880	15	178,200	726,000		904,200
	TOTALS							361,440	945,900	16,100	1,323,440

The floor supporting the control equipment will consist of metal decking with a concrete wearing surface. This floor should be designed with vibration dampeners and isolation equipment in order to protect the control equipment from the heavy rotating equipment housed on the ground floor.

Receiver feed pump foundations will be spread footings on structural backfill.

4.5.3 FIELD SIZING AND SHAPE

The size and shape of the heliostat field have an overriding effect on site design. A field modified to meet site requirements was chosen. The field was extended as far north as possible in order to limit process and electrical runs and also to utilize land currently owned by PNM but used only as pole storage. Western field limits were established by the large physical barrier of the flood control drainage structure.

The heliostat field requires acquisition of about 130 acres of land south of the existing plant. Purchase of an additional strip of land of equal length on the eastern edge of the field is contemplated for use as a construction contractor's laydown area.

The MIRVAL computer code, along with two preprocessor codes, was used to size the field and locate the heliostats in order to obtain the desired station power output. A deployment of 4289 heliostats met this requirement. The field is shown on drawings Y1-1 and Y1-2. The MIRVAL program is described in Section 4.6.1 as are subsequent parametric analyses of the heliostat field.

4.5.4 CIVIL SITE DESIGN

A pervasive design feature of the solar-repowering at Reeves Station is the retrofit aspect of the work. This particular feature has a sustained impact on the Civil Engineering efforts often forcing solutions that are at best only compromises. The compromises, while not altogether acceptable for a new plant site, are solutions which become palatable when adding new equipment not anticipated in the original plant design.

4.5.4.1 HELIOSTAT FIELD LAYOUT

The size and shape of the heliostat field have an overriding effect on site design. An idealized heliostat field such as that planned for Barstow would be unwieldy and inefficient on this site. Such a field placed as close as possible to the south fence line (to limit steam lines) would spread across the drainage structure to the west and create access problems within the field.

Fortunately, other major physical items that could affect the heliostat field (cooling towers, oil tanks, substations, maintenance and storage structures) were located in a relatively convenient situation at Reeves Station. This cannot be expected at a majority of repowering sites. As it is, relocation of the transmission line is a requirement of the Reeves Site since it would divide the field.

A surrounding field modified to meet site requirements was chosen. The field was located as far north as possible in order to limit process and electrical runs and also to utilize land currently owned by PNM but used only as pole storage. Western field limits were established by the large physical barrier of the flood control drainage structure. As the field was to be symmetrical, this also established the eastern boundary.

The MIRVAL computer program, along with two preprocessor codes, was used to size the field and locate the heliostats in order to obtain the desired unit power output. The programs were used to establish the site results in an array of 4289 heliostats. This field was intentionally sized roughly 10 percent higher than necessary to allow for interferences with existing fuel storage tanks, steam line runs, roads and other obstacles to heliostat placement. This field is shown on Drawings Y1-1 and Y1-2. The heliostat field for the solar subsystem and the MIRVAL program are described in Section 4.6.1 as are subsequent parametric analyses and program runs that take into account heliostats deleted from earlier results. The field requires acquisition of about 110 acres of land south of the existing plant. Purchase of an additional strip of land of equal length on the eastern edge of the field is contemplated for use as a construction contractor's laydown area.

4.5.4.2 SITE DESIGN CONSIDERATIONS

The layout of the heliostat field should provide for ready access to the tower and heliostat field for maintenance and safety purposes. The field should slope sufficiently for drainage so that there will be no standing water about the heliostat foundations. If possible the field should be essentially in the same plane to avoid complications in heliostat siting.

Each site will dictate the best solution to that site's drainage problems; crowning slopes, one-way slopes, varying slopes, as well as differing levels for various heliostat areas. This site allows a nearly ideal approach.

Crowning the site with a center ridge was considered but abandoned for a uniform slope of 1 percent in the direction of the natural slope of the land. The lay-down area was sloped at 2 percent. This system provided a closely balanced cut and fill. A drainage ditch was provided running south to north on the western boundary in order to protect the concrete lining of the flood control structure.

4.5.4.3 FLOOD CONTROL

In the past decade, Albuquerque experienced severe flooding in the plan below the Sandia Crest. As a result, the Albuquerque Municipal Arroyo Flood Control Authority was formed. Through it the Corps of Engineers designed and constructed an extensive flood control system. The Authority now administers this system and controls all planning and development in the area which could effect storm water runoff in periods of high intensity storm. Any work on the site which could affect flooding will need approval by the Authority. Figure 4.5-2 shows design storm intensity for the Albuquerque area.

As noted previously, one of the two main flood control channels forms the western boundary of the site. A large concrete and stone inlet to that channel drains the Arroyo Domingo Baca and Arroyo Del Pino North across the center of the proposed heliostat field just south of the existing plant boundary. A second similar inlet structure exists immediately south of the proposed site draining the Pino Arroyo into the flood control system. See drawing Y4-3.

Figure 4.5-2. 100-Year, Six Hour Precipitation

Three concepts were explored to cope with the drainage problem. In order to distinguish the concepts, they have been arbitrarily assigned the various titles:

- Concept (1) Underground Diversion (Drawings Y4-1 and Y4-2)
- Concept (2) Northerly Diversion (Drawings Y4-3 and Y4-4)
- Concept (3) Southerly Division (Drawings Y4-5 and Y4-6)

The following design parameters are common to all three diversion schemes; Q_{100} equals 1,300 cfs and a freeboard of at least 1.75 feet. The concepts are ranked in their order of preference and construction merit as follows:

Concept (1)--A twin, 10 foot-0 inch wide by 8 foot-0 inch high reinforced concrete box culvert with attendant inlet and outlet structures. The culvert will transverse the proposed site in a northwesterly direction. The inlet structure will be placed in the deeper portion of the flood pool formed by an earthen embankment. The earthen embankment will serve to collect and funnel the storm waters to the inlet structure of the box culvert, which in turn will transport the storm waters underground to the outlet structure, where the waters are shunted into the existing North Pino Arroyo inletworks of the North Diversion Channel.

This Concept (1) is feasible and aesthetically pleasing as the majority of the construction is buried and will not be visible from the ground. There will be no loss of acreage from the Solar Power Unit Site Area to accommodate the underground culvert. In addition, there will be a minimal of interference and reconstruction of the North Pino Arroyo inletworks to the North Diversion Channel. It is our understanding that the inlet works mentioned above is capable of accepting the design Q of 1300 cfs.

Concept (2)--A trapezoidal open channel (3900 feet plus or minus long) cut into the existing ground along the eastern and northern periphery of the site, at a constant slope and bottom width with side slopes of 2:1. The bottom width has been set at 14 feet-0 inches. The bottom of the channel and the side slopes up to a vertical height of 8 feet-0 inches are to be constructed of Soil-Cement. The remaining channel height will be constructed with suitable in situ soils.

It will cross under two access roads between the existing plant and the Solar Power Unit Site. At each of these crossings it will require a twin 10-foot 0-inch-wide by 8-foot 0-inch reinforced concrete box culvery with necessary transitions. The culverts will be approximately 50-feet 0-inches in length at the westerly access road and 100-feet 0-inches in length at the easterly access road.

Concept (2) entails a major portion of the construction to be visible from the surface. Since the Site is in an area of historically low rainfall precipitation the wind blown debris collected in the open ditch may not be flushed clean during annual storms and it may become aesthetically unacceptable unless frequent cleaning and maintenance are provided. Another disadvantage with this concept is that the trapezoidal channel will require approximately 5 acres of land area. In addition, this concept will entail more construction at the intertie with the North Pino Arroyo inletworks than Concept (1).

This Concept (2) would displace approximately 60 south-facing heliostats.

Concept (3)--A trapezoidal open channel (4500-feet plus or minus long) with the same typical channel cross section as in Concept (2), except it will be along the eastern and southern boundaries of the site and connecting to the existing Pino Arroyo inletworks.

Concept (3) will have similar aesthetic disadvantages as discussed in Concept (2) In addition, there are two more disadvantages for this concept: First, since the channel will run out of the County boundary, approval and a permit from the City of Albuquerque will be required; second, the existing Pino Arroyo inletworks has to be enlarged to carry the diverted storm inflow as required.

This Concept (3) will involve purchase of additional expensive land to the south of the site.

The following total site quantities were estimated for each of the concepts:

Concept No. 1 — Underground Diversion

<u>Item No.</u>	<u>Description</u>	<u>Quantity</u>	<u>Unit</u>
1	Excavation	646,000	CY
2	Embankment	593,000	CY
3 (a)	Structural Concrete	6,750	CY
4 (b)	Concrete Removal	100	SY

Concept No. 2 — Northerly Diversion

<u>Item No.</u>	<u>Description</u>	<u>Quantity</u>	<u>Unit</u>
1	Excavation	1,158,000	CY
2	Embankment	600,000	CY
3 (a)	Structural Concrete	530	CY
4 (c)	Soil Cement	6,000	CY
5 (b)	Concrete Removal	200	SY

Concept No. 3 — Southerly Diversion

<u>Item No.</u>	<u>Description</u>	<u>Quantity</u>	<u>Unit</u>
1	Excavation	1,186,400	CY
2	Embankment	612,000	CY
3 (d)	Concrete Paving	335	CY
4 (c)	Soil Cement	7,000	CY
5 (b)	Concrete Removal	900	SY

-
- (a) Formed structural concrete
 - (b) Paved invert and side walls of 2:1 — 8-inches plus or minus thickness
 - (c) 9-inch plastic soil cement, side slopes of 2:1
 - (d) Same as (b) only this is new rock

Total cut and fill are balanced in Concept (1) but this was not possible in the other two concepts.

Relative costs based only on the quantities shown are:

- Concept 1 \$3,140,000.00
- Concept 2 \$1,802,000.00
- Concept 3 \$1,753,000.00

Figure 4.5-3 shows a cost estimate breakdown by major job cost accounts for the project.

No allowance for additional land acquisition requirements has been made in Concept (3).

Operating and engineering viewpoints recommended Concept (1). It is the best solution. Two-thirds of its cost is caused by the concrete structure. This cost may be dramatically reduced after further hydrological studies.

At this point, the reliability of the basis for the design limited further study. The flows used were provided by the Authority but were based upon dated hydrology studies. Much of the land involved has since been developed and flows seriously changed. This conceptual work shows that the flood control problem is solvable. However, extended hydrology investigation will be necessary before further decisions can be reached as to the most feasible and economical concept.

SOLAR HYBRID REPOWERING REEVES UNIT 2

Figure 4.5-3. Cost Estimate Breakdown by Major Job Cost Account

4.6 PLANT PERFORMANCE--SOLAR SUBSYSTEM

The development of the conceptual design and the sizing and layout of the heliostat collector field to produce 25 MWe for the Solar Hybrid Repowered Plant at Reeves Station No. 2 necessitated the selection of several specific design parameters, including tower height, receiver length and diameter, solar insolation, and the size and shape of the available land area. The characteristics of the final conceptual design of the heliostat field, as well as pertinent information relating to the choice of the design parameters utilized, are described herein. In addition, the results of the heliostat field parametric analyses are also given.

Section 4.6.1 details the development of the conceptual design, including the assumptions relevant to the analysis and the initial choice of design parameters. Section 4.6.2 presents a discussion of the parametric analyses performed to yield a more cost effective system.

4.6.1 DEVELOPMENT OF THE CONCEPTUAL DESIGN

DESIGN PARAMETERS AND ASSUMPTIONS

The following design parameters and assumptions are relevant to the analyses:

- The design power level for the solar subsystem is 25 MWe at 2:00 p.m. winter solstice
- The solar insolation has been assumed to be 950 W/m^2
- The MIRVAL computer code, which has been developed by Sandia Livermore, along with two preprocessor codes, has been used to size and analyze the various heliostat field configurations
- The heliostat and central receiver employed in the analyses are the McDonnell Douglas Astronautics Company (MDAC) designs, as shown in Figures 4.6-1 and 4.6-2. It should be noted that the heliostat as modeled by MIRVAL is a square with a side length of 6.5 m (21.3-ft). Account was taken for light rays falling between facets, and hence, the total mirror area of each heliostat is 38 m^2 (455-ft²).
- The heliostats have been placed in a radial stagger arrangement so as to minimize the effects of blocking and shading

Figure 4.6-1. Heliostat Design (McDonnell Douglas) Modeled by MIRVAL

Figure 4.6-2. Tower and Receiver Design (McDonnell Douglas) Modeled by MIRVAL

AVAILABLE LAND

The initial area of available land identified by PNM for the solar collector (heliostat) field at Reeves Unit No. 2 is shown in Figure 4.6-3. In general, the land area to the north of a central receiver tower is more efficient in terms of solar energy collected. Moreover, the square area to the east, 609.6m x 609.6m (2000-ft x 2000-ft), would not be used unless the electric power requirement of the plant could not be met with the remaining land available. This would insure the use of a symmetric solar collector field, and hence would tend to more evenly distribute the energy incident on the receiver. However, an analysis was made utilizing some land to the east, so as to give an indication of the power produced with this configuration.

MIRVAL

The evaluation of the heliostat fields considered was accomplished with the MIRVAL computer code. MIRVAL is a Monte Carlo program in which the interaction of light rays from the sun with an arbitrary array of mirrors and a solar energy receiver is simulated. Several different types of mirrors and receivers can be analyzed. Phenomena whose effects are simulated include shading, blocking, mirror tracking, detailed optics of the reflective surfaces, insolation and the angular distribution of incoming sun rays.

RECEIVER AND TOWER SIZING

In order to size and make a layout of the heliostat collector field for a 25 MWe Solar Hybrid Repower Plant at PNM Reeves Unit No. 2, preliminary sizes for the diameter and length of the receiver and for the tower height at the centerline of the receiver were required. Basically, the external receiver and tower designs for this analysis can be scaled from the McDonnell Douglas Astronautics Company (MDAC) design for the 10 MWe Solar Central Receiver Pilot Plant.

Calculations indicated that a thermal power of approximately 92 MW would be required to yield the proper level of electrical generation. In addition, initial values for receiver diameter and length, as well as tower height, were computed. These were a receiver diameter of 12m (39.4-ft), a length of 21m (68.9-ft) and a height to the centerline of the receiver of 135m (443-ft).

Figure 4.6-3. Initial Area of Available Land Identified for the Heliostat Field at Reeves Unit No. 2

The following discussion illustrates the calculational methodology by which the receiver and tower sizing was accomplished.

THERMAL POWER ABSORBED INTO STEAM

The thermal power absorbed into the steam at the solar receiver for Reeves Unit No. 2 is a function of the turbine heat rate and the auxiliary (parasitic) power losses. The percent auxiliary power for the Reeves Unit No. 2 as it exists today was derived from two sources. Using primarily heat balance computations dated August 15, 1958, the auxiliary power requirements at full load were evaluated as 5.82 percent. Based on the past performance tests for Reeves Unit No. 2 at full load for the 1975/1977 time period, an auxiliary power of 5.08 percent was quoted. A nominal value of 5.4 percent was taken for this analysis. Also, an additional auxiliary power requirement of 4.6 percent was estimated to convert the unit to a solar plant and to cover the thermal and pressure losses in the piping run from the base of the tower to the existing turbine/generator at Reeves Unit No. 2. Combining these auxiliary power losses yields an estimated value of 10 percent, or an auxiliary "efficiency," η_a , of 0.90.

The turbine heat rate, HR_T , for Reeves Unit No. 2 to be used for this analysis is 9333 Btu/kW-hr. Thus, the net turbine efficiency, η_T , is:

$$\eta_T = 0.329$$

For an electrical power output, P_e , of the solar portion of a hybrid repowered plant of 25 MWe, the thermal power, P_t , absorbed into the steam is:

$$P_t = \frac{P_e}{\eta_T} = 76.0 \text{ MWt}$$

THERMAL POWER INCIDENT ON THE RECEIVER SURFACE

The required thermal power incident on the receiver surface is based on the above thermal power absorbed into the steam, the losses that account for re-radiation and convection from the receiver, and the loss due to the absorptivity of the receiver surface. The efficiency that accounts for most of the re-radiation and

convection losses from the receiver, $\eta_{r\&c}$, was taken as 0.887 and was based on the MDAC efficiency chart for the 10 MWe Pilot Plant design. Additional losses from the receiver were taken into account by an efficiency, η_r , of 0.98 to cover the balance of the re-radiation and convection losses from the external surface of the receiver. The efficiency due to the absorptivity of the receiver surface, η_a , was taken as 0.95.

Thus, the required thermal power incident on the receiver surface for the 25 MWe plant, $P_{t,r,25}$, is:

$$P_{t,r,25} = \frac{P_t}{(\eta_{r\&c}) (\eta_r) (\eta_a)} = 92.0 \text{ MWt}$$

This value is comparable to the thermal power incident on the receiver surface for the MDAC 10 MWe Pilot Plant Design, $P_{t,r,10}$, of 38.7 MWt.

TOWER HEIGHT AT THE CENTERLINE OF THE RECEIVER

The height of the tower at the centerline of the receiver for a solar central receiver varies approximately as the square root of the thermal power incident on the receiver surface. This tower height for the MDAC 10 MWe Pilot Plant, H_{10} , ft , is 80.0m (262-ft). Therefore, the tower height at the receiver centerline for the 25 MWe Reeves Unit No. 2 solar hybrid repowered unit is approximately:

$$H_{25}, \text{ ft} = H_{10}, \text{ ft} \left[\frac{P_{t,r,25}}{P_{t,r,10}} \right]^{1/2} = 123\text{m (404-ft)}$$

RECEIVER SIZE (DIAMETER AND LENGTH)

The diameter, D_{10} , and length, L_{10} , of the external receiver for the MDAC 10 MWe Pilot Plant Design are 7.0 m (23.0-ft) and 12.5 m (41.0-ft), respectively.

In order to retain an approximate maximum thermal flux on the outside surface of the receiver of about 0.30 MW/m^2 (corresponding to the 10 MWe Pilot Plant) for the 25 MWe Solar Hybrid Repowering Plant at Reeves Unit No. 2, the diameter and length need to be increased. Preliminary sizing of this 25 MWe receiver suggested

that each of these dimensions be increased in equal proportions. Thus, the receiver diameter for the 25 MWe plant, D_{25} , is approximately:

$$D_{25} = D_{10} \left[\frac{P_{t,r,25}}{P_{t,r,10}} \right]^{1/2} = 10.8\text{m (35.4 ft)}$$

and receiver length, L_{25} , is:

$$L_{25} = L_{10} \left[\frac{P_{t,r,25}}{P_{t,r,10}} \right]^{1/2} = 19.3\text{m (63.3 ft)}$$

ANALYSIS

Three MIRVAL analyses were initially made in an attempt to bound the required design parameters. The first case employed the aforementioned values for receiver diameter [12m (39.4 ft)] and length [21m (68.9 ft)] and tower height [135m (443 ft)]. The land area utilized is shown in Figure 4.6-4. Note that this is a symmetric collector field. The number of heliostats placed in the field is 4153, and the thermal power incident on the receiver at 2:00 p.m. winter solstice is 87 MW.

The second case run was identical to the first, except that an additional strip of land ~150m (492 ft) wide was added to the east. This land area is shown in Figure 4.6-5. The number of heliostats in this configuration is 4730, and the power into the receiver at 2:00 p.m. winter solstice is 102 MWt.

The third case in the initial series of computer runs was also identical to the first, except that the height to the centerline of the receiver is 155m (508 ft). At 2:00 p.m. winter solstice the power into the receiver is 93 MWt. The 4488 heliostats are deployed in the same area shown in Figure 4.6-4.

A summary table of the above results is given in Table 4.6-1.

Figure 4.6-4. Initial Land Area Used in the Analysis

Figure 4.6-5. Asymmetric Heliostat Field with Additional Land to the East

TABLE 4.6-1. INITIAL MIRVAL RESULTS

<u>Case</u>	<u>Centerline (m)</u>	<u>Receiver Diameter and Length (m)</u>	<u>Number of Heliostats</u>	<u>Thermal Power Into Receiver at 2:00 p.m. Winter Solstice (MW)</u>
1	135 (443 ft)	D = 12 (39.4 ft) L = 21 (68.9 ft)	4153	87
2	135 (443 ft)	D = 12 (39.4 ft) L = 21 (68.9 ft)	4730	102
3	155 (508 ft)	D = 12 (39.4 ft) L = 21 (68.9 ft)	4488	93

The above results indicated that a thermal power incident on the receiver of 92 MW would be achievable. Only the combination of design parameters remained to be chosen.

Consultation with PNM indicated that an additional parcel of land to the north was also available for the Solar Hybrid Repowered Plant, as shown in Figure 4.6-6. Therefore, the decision was made to utilize only the symmetric portion of the field illustrated in the figure. This would have the affect of distributing the reflected solar insolation on the receiver more evenly during the course of a day. In addition, the height to the centerline of the receiver was chosen to be 150m (492 ft). Receiver dimensions remained the same; i.e., length = 21m (69 ft) and diameter = 12m (39 ft).

The final MIRVAL run yielded a thermal power incident on the receiver of 92.2 MW at 2:00 p.m. winter solstice at a design insolation value of 950 W/m^2 .

The initial conceptual design of the heliostat field is shown in Figure 4.6-7. The number of heliostats required is 4289. The circular exclusion area at the base of the tower is approximately $38,000 \text{ m}^2$ ($4.09 \times 10^5 \text{ ft}^2$), corresponding to a radius of 110m (361 ft).

Table 4.6-2 is the thermal power incident on the receiver at various times of the year.

Figure 4.6-6. Final Area of Available Land Identified for the Heliostat Field at Reeves Unit No. 2

Figure 4.6-7. Heliostat Arrangement for Initial Baseline Conceptual Design (Total Number of Heliostats: 4289)

TABLE 4.6-2. POWER INCIDENT ON RECEIVER AT SELECTED TIMES OF THE YEAR
FOR INITIAL BASELINE CONCEPTUAL DESIGN WITHOUT ROADS
(4289 HELIOSTATS)

<u>Time of Year</u>	<u>Power (MW)</u>
2:00 p.m. Winter Solstice	92.2
Noon Winter Solstice	102.8
Noon Vernal Equinox	112.8
Noon Summer Solstice	114.0
Annual Average	100.5

Figure 4.6-8 is a detailed (1,000,000 Monte Carlo trials) flux map on the receiver at noon summer solstice based on the initial baseline conceptual design with 4289 heliostats.

UPDATED CONCEPTUAL DESIGN

The preprocessor code originally utilized to lay out the collector field for the conceptual design described above was found to not completely eliminate possible heliostat interference. Figure 4.6-9 illustrates the potential interference problem. For example, note the potential interference problem between row #8 (a slip plane) and rows #7 and #9; e.g., between heliostats #411 and #353, and heliostats #411 and #469. This problem persists between slip planes and the rows preceding and following the slip plane rows until such time that the heliostats are placed far enough apart to completely avoid interference, as is the case when heliostat blocking causes adjacent rows to be widely separated. Additional interference problems were noted at slip plane rows #16 and #27 with their adjacent rows, respectively (see Figure 4.6-9).

The design as given initially was considered to be undesirable and work was geared toward correcting the preprocessor code. This was accomplished by a trial and error procedure that produced a satisfactory heliostat configuration. A more rigorous correction of the code is expected from Sandia Livermore in the near future.

Figure 4.6-8. Flux (MW/m^2) on McDonnell Douglas Receiver at Noon Summer Solstice for Initial Baseline Conceptual Design (4289 Heliostats)

The updated conceptual design of the solar hybrid repowered plant utilizes 4185 heliostats. The heliostats are deployed in the same area as before (see Figure 4.6-7). An enlargement of a sector of the field is shown in Figure 4.6-10, which shows that the heliostat interference problem has been corrected. This heliostat configuration produces 91.8 MWt incident on the receiver at 2:00 p.m. winter solstice.

NORTH-SOUTH ACCESS ROADS

Access to all heliostats in the field is required to perform routine maintenance and repair. This is accomplished by the inclusion of north and south access roads. A 50-ft wide south road was selected. Allowance for steam and feedwater lines along the north road necessitates an overall width of 68-ft for this road. The resulting heliostat field, shown in Figure 4.6-11, contains 4086 heliostats. The deployment produces 89.5 MWt incident on the receiver at 2:00 p.m. winter solstice. Utilizing an overall conversion efficiency of ~ 0.28 calculated by Stearns-Roger, 25.0 MWe will result from this configuration. Table 4.6-3 is the thermal power incident on the receiver at various times of the year, and Figures 4.6-12 through 4.6-16 are flux maps on the receiver at these times.

TABLE 4.6-3. POWER INCIDENT ON RECEIVER AT SELECTED TIMES OF THE YEAR FOR FINAL BASELINE CONCEPTUAL DESIGN WITH ROADS (4086 HELIOSTATS)

<u>Time of Year</u>	<u>Power (MW)</u>
2:00 p.m. Winter Solstice	89.5
Noon Winter Solstice	98.0
Noon Vernal Equinox	108.2
Noon Summer Solstice	107.5
Annual Average	96.9

It should be noted that the receiver as modeled by MIRVAL is a right circular cylinder. The aim point for a mirror lies on the cylindrical surface and in a vertical plane through the center of the mirror and the receiver centerline. The aim point for the mirrors lies 1/4, 1/2 or 3/4 of the way up the cylindrical

Figure 4.6-10. Detailed Heliostat Plot from Updated Conceptual Design (4185 Heliostats) Showing Elimination of Interference

Figure 4.6-11. Heliostat Deployment for the Final Baseline Conceptual Design with North-South Access Roads
(Total Number of Heliostats: 4086)

Figure 4.6-12. Flux (MW/m^2) on McDonnell Douglas Receiver at 2:00 p.m. Winter Solstice for Final Conceptual Design with North and South Access Roads (4086 Heliostats)

Figure 4.6-13. Flux (MW/m^2) on McDonnell Douglas Receiver at Noon Summer Solstice for Final Conceptual Design with North and South Access Roads (4086 Heliostats)

Figure 4.6-14. Flux (MW/m²) on McDonnell Douglas Receiver at Ncon Vernal Equinox for Final Conceptual Design with North and South Access Roads (4086 Heliostats)

Figure 4.6-15. Flux (MW/m^2) on McDonnell Douglas Receiver at Noon Winter Solstice for Final Conceptual Design with North and South Access Roads (4086 Heliostats)

Figure 4.6-16. Flux (MW/m^2) on McDonnell Douglas Receiver on an Annual Average Basis for Final Conceptual Design with North and South Access Roads (4086 Heliostats)

surface in this plane, representing an overall three-point aiming strategy; every third heliostat is aimed at one of these locations. This aiming strategy serves to distribute the thermal power incident on the receiver surface more evenly and thereby avoid any local hot spots on the receiver.

4.6.2 PARAMETRIC ANALYSES

Various parametric analyses have been performed in an attempt to produce a more cost effective system. Tower location and tower height, as well as selective field trimmings, have been analyzed with respect to savings in total plant cost and net electric power output. The analyses have been keyed to the final conceptual design with access roads included (4086 heliostats), and with a tower height to the centerline of the receiver of 150m, which produces a net electric output of 25.0 MW.

TOWER HEIGHT

Two cases were considered in which the height to the receiver centerline could be evaluated with regard to its impact on the system at the design point of 2:00 p.m. winter solstice. First, a height to the centerline of the receiver of 135m (443 ft) was investigated, while the land area was held fixed. Then a height to the centerline of the receiver of 165m (541 ft) was examined. Both situations resulted in a net reduction in field performance, based on the percent changes in cost and power output, as shown in Table 4.6-4.

HEIGHT TO RECEIVER CENTERLINE = 135m

For a height to the receiver centerline of 135m, the number of heliostats placed in the same field area is 3910, and 85.6 MWt is incident on the receiver at 2:00 p.m. winter solstice. This is equivalent to 23.9 MWe electrical output.

In this example, a net loss in field performance of 2.2 percent (see Table 4.6-4) results when the height to the centerline of the receiver is reduced from 150m to 135m. In other words, the decrease in net electric power output (4.4 percent) is not accompanied by a greater decrease in the percentage of total plant cost (only 2.2 percent). Hence, this method of improving plant performance is deemed to be unacceptable. (Note that it has been assumed for this analysis that the effects of a reduction in plant cost due to a shorter tower are minimal.)

TABLE 4.6-4. FIELD PERFORMANCE, TOWER HEIGHT VARIATION

	Reference Case* (4086 Heliostats)	Height to Centerline = 135m	Net Savings/ Change in Power Output (Percent)	Height to Centerline = 165m	Net Savings/ Change in Power Output (Percent)
Total Plant Cost** (Millions of Dollars)	80.0	78.2	+2.2	81.2	-1.6
Net Electric Output (MWe)	25.0	23.9	-4.4	25.4	+1.6
Net Change in Performance (Percent)			-2.2		0.0

*Height to centerline of receiver = 150m

**Cost estimates were based on data given in Section 4.7 of this Report

HEIGHT TO RECEIVER CENTERLINE = 165m

The number of heliostats deployed in the (fixed) available land area when the height to the centerline of the receiver is increased to 165m is 4212. Note that the number of heliostats utilized has increased because the higher receiver height allows the heliostats to be deployed with a higher overall packing fraction. In this instance, 90.9 MWt is incident on the receiver surface at 2:00 p.m. winter solstice, which leads to a net electrical output of 25.4 MWe, as shown in Table 4.6-4.

No net change occurs when the height to the receiver centerline is increased to 165m. Since this net change is zero, some optimum height to the receiver centerline between the reference value of 150m and 165m may yield a very slight overall net increase in field performance. These effects are expected to be marginal, however. As before, it has been assumed that the additional cost of a higher tower does not significantly change the results derived.

FIELD TRIMMING

Two examples of field trimming were evaluated to determine the effect on field performance. First, an analysis was done wherein the southern corners of the

field were "clipped," yielding a small reduction in heliostats. Next, a relatively large clipping of the southern corners of the field was examined. Both situations resulted in a net loss in field performance at 2:00 p.m. winter solstice, as is shown in Table 4.6-5.

TABLE 4.6-5. FIELD PERFORMANCE, FIELD TRIMMING

	Reference Case (4086 Heliostats)	Small Field Trim	Net Savings/ Change in Power Output (Percent)	Large Field Trim	Net Savings/ Change in Power Output (Percent)
Total Plant Cost* (Millions of Dollars)	80.0	78.1	+2.3	71.4	+10.8
Net Electric Output (MWe)	25.0	24.1	-3.7	20.6	-17.4
Net Change in Performance (Percent)			-1.4		-6.6

*Cost estimates were based on data given in Section 4.7.

Small Field Trim

When the southern corners of the heliostat field are removed, the number of heliostats in the configuration is 3904, which in turn produce 86.2 MWt incident on the receiver at 2:00 p.m. winter solstice. This leads to a net output of 24.1 MWe. As can be seen, the overall field performance is reduced by ~1.4 percent with respect to the design point of 2:00 p.m. solstice.

Large Field Trim

When the southern corners of the heliostat field are grossly clipped, only 3226 heliostats are deployed and 73.9 MWt are incident on the receiver at 2:00 p.m. winter solstice. The net electric output is 20.6 MWe. Clearly this example illustrates that gross trimming of the southern heliostat field results in a large net loss (~7 percent) in field performance. Comparison of the field

trimming cases above indicates that selective trimming of the extreme southern corners of the field may lead to a slight net increase in performance at the design point.

TOWER LOCATION

Several tower locations were considered in the parametric analyses of the conceptual design of the heliostat field for 2:00 p.m. winter solstice. Tower locations of 30, 40, 50, 75 and 100m south of the original location and a location 50m north of the conceptual design location were examined. Indications are that an improvement in the field performance can be obtained by relocating the tower south of the reference position. This is illustrated by Table 4.6-6.

Tower 30m South

With the tower relocated 30m south of the final baseline conceptual design location, the number of heliostats deployed is 4032, yielding 89.3 MWt on the receiver at 2:00 p.m. winter solstice, which in turn produces 24.9 MWe. Note that a relatively modest improvement in field performance results.

Tower 40m South

In this case, 4006 heliostats are located in the field; 90.2 MWt are incident on the receiver at 2:00 p.m. winter solstice, resulting in 25.2 MWe. A more significant improvement in field cost effectiveness is provided.

Tower 50m South

The number of heliostats is 3986 and the power incident on the receiver is 90.2 MWt, which again yields 25.2 MWe. Note that this heliostat field is more efficient in its production of electricity, and hence, compared to the reference configuration, this field also performs significantly better.

Tower 75m South

The heliostat field is comprised of 3916 heliostats. The power incident on the receiver is 89.0 MWt at 2:00 p.m. winter solstice, and this yields 24.9 MWe. This deployment also outperforms the reference case.

TABLE 4.6-6. FIELD PERFORMANCE, TOWER RELOCATION

	Reference Case (4086 Heliostats)	TOWER SOUTH										TOWER NORTH	
		Net Savings*		Net Savings*		Net Savings*		Net Savings*		Net Savings*		Net Savings*	
		30m	Percent	40m	Percent	50m	Percent	75m	Percent	100m	Percent	50m	Percent
Total Plant Cost** (Millions of Dollars)	80.0	79.4	+0.7	79.2	+1.0	79.0	+1.2	78.3	+2.1	77.5	+3.1	80.5	-0.6
Net Electric Output (MWe)	25.0	24.9	-0.4	25.2	+0.8	25.2	+0.8	24.9	-0.6	24.7	-1.1	24.4	-2.2
Net Change in Performance (Percent)			+0.3		+1.8		+2.0		+1.5		+2.0		-2.8

*Net Savings/Change in Power Output (percent)

**Cost estimates were based on data given in Section 4.7.

Tower 100m South

In this case, 3838 heliostats are deployed. The power incident on the receiver at 2:00 p.m. winter solstice is 88.5 MWt and the electric output is 24.7 MWe. This configuration is more cost effective than the reference case, and in fact is virtually as efficient as the case where the tower is located 50m south of the original position. Hence, in this sense, both deployments appear to be equally attractive. However, the thermal flux incident on the receiver in this case tends to exceed by a relatively large degree the desired 0.3 MW/m^2 maximum flux levels, specifically on the panels facing the northern part of the field. This is to be expected, since most of the field is north of the receiver. Hence, receiver design requirements may impose a limit on how far south the tower may be moved, and therefore the situation where the tower is 50m south of the reference position may be a more suitable alternative.

Tower 50m North

In this arrangement the tower has been relocated 50m north of the original position. The number of heliostats deployed in the land area available is 4134; the power incident on the receiver is 87.5 MWt, yielding 24.4 MWe net output. Obviously, this is not a cost effective system. It is clear that moving the tower north degrades the overall cost effectiveness of the plant.

DESIGN POINT CONSIDERATION

If the design requirement was to maximize the amount of solar energy collected on an annual basis, then the conceptual design as it now stands would be very close to the most cost effective system, as is shown in Figure 4.6-17. Note that this design stipulation might lead to a tower location approximately 10 to 20m south of the reference position.

CONCLUSIONS

The parametric analyses of the PNM conceptual design demonstrate that a better performing, more cost effective plant can be designed with the proper heliostat deployment. Indications are that moving the tower 40m to 100m south of the reference position yields the highest performing plant (see Table 4-6-6).

Figure 4.6-17. Change in Average Annual Power Output and Change in Total Cost Versus Tower Location

Changing the receiver height appears to produce no significant benefits. In fact, the two situations considered, both increasing and decreasing the receiver height, actually tended to degrade the performance of the plant. Trimming the southern corners of the field also appears not to yield significant improvement in cost effectiveness of the plant, although selected trimmings of the extreme southern corners may lead to a slight improvement in performance.

It should be noted that the MIRVAL code is a Monte Carlo code and as such the results presented are subject to statistical uncertainties. Hence, it is not practical to identify any one given heliostat field configuration as the "best." However, inasmuch as certain inferences can be made from the results of the analyses, it is probably a valid statement that moving the tower south will tend to result in a more cost effective system. It also should be pointed out that fairly small percentage changes from the conceptual design result from the southern relocations of the tower. From an absolute point of view, the performance of the various heliostat fields where the tower has been relocated toward the south actually does not change significantly. This is a rather important observation, since it indicates that, all other things being equal, perturbations of the conceptual design considered here do not have an extreme effect on the performance of the solar subsystem.

4.7 CONCEPTUAL DESIGN COST ESTIMATE

The conceptual design cost estimate covers those costs that can be reasonably anticipated for the solar hybrid repowering of Reeves Station Unit No. 2 in Albuquerque, New Mexico. (See Appendix for the Cost Estimate printout.) ✓

Because the technical design of the Project has not proceeded beyond the conceptual stage, which covers the major concepts but does not address all of the particulars, detailed estimating information is not available. Thus, a cost estimate derived from a conceptual design must be expected to be somewhat broad in nature. In general, it is assumed that the accuracy of this cost estimate is within ± 25 percent. In certain areas where the design is more detailed, or the technology dictates the design, the cost estimate will reflect that exactness. This includes the following:

- Earthwork ± 15 percent
- Few changes are anticipated as long as Conceptual Design 1 is used
- Piping ± 15 percent

The estimate addresses those costs that are reasonably expected to be incurred in this project. Management, contingency and escalation are not included at this time; such costs will be added when definite program dates, and government and other management policies are established. New Mexico use tax is not included as a separate line item at this time. Since Government funding is anticipated, when that level of participation is established, this tax account will provide for such visibility.

EQUIPMENT

Except for the Receiver and Collectors, many of the mechanical equipment items are relatively standard for power plants. For these "standard" components, an accuracy of ± 15 percent is expected. For the most costly items, the Receiver and the Collectors, accuracy is questionable due to state of the art technology and the limited sources of procurement. As an example, the Collectors were initially priced on a capital cost basis of \$250.00 per square meter, excluding field wiring. That figure comes from the Barstow Pilot Plant estimate. A

later figure obtained by PNM was lower. This lower quotation appeared to leave certain questions unanswered, however, so a revision of the original price was used in the cost estimate. The Receiver price was obtained by PNM and does not include escalation.

CONCRETE

In the tower, an accuracy ± 15 percent can be anticipated because the basic design is quite refined. For the underground diversion box culvert, an accuracy of ± 10 percent, ± 25 percent seems probable. Due to the length of the culvert (2800-feet), we believe that production line methods would be developed that could save substantial costs when compared to more conventional methods of concrete placement for smaller quantities.

In this estimate all costs are based on 1978 dollars and no allowances for escalation has been made. Certain construction items are generally estimated and contracted for as a package. That is, the labor, material, equipment and mark-up are included in one Contract package. Much of this cost estimate is based upon an approach wherein the printout shows the entire Contract amount in the "other" column with no costs indicated in the labor and material columns.

Although a column has been left on the printout for labor hours, no hours are shown. These figures can be inserted when that information is complete, but at present, hours are known for items totaling only minor percentages of the total cost.

The format of the estimate with a revision column included will increase the flexibility and traceability of the inevitable cost changes that occur. For example, when a change to the estimate is necessary, the revision number of that change would then print next to the changed item at the base level as well as next to all other figures that were modified by that change.

The attached summary, Table 4.7-1, has been extrapolated from the detailed cost breakdown to show the major areas of expenditure. It is noteworthy that the collector and receiver systems, accounting for more than 80 percent of the total

Project cost, are the areas where the greatest variables in cost data occur. Thus, the accuracy of the total cost estimate cannot be more exact than those estimates. A cost estimate graphical presentation is given in Figure 4.7-1.

TABLE 4.7-1. COST ESTIMATE SUMMARY

<u>COST ESTIMATE BREAKDOWN</u>	<u>% OF TOTAL</u>	<u>SUBTOTALS</u>	<u>TOTALS</u>
1. <u>Solar Collectors</u>	51%		\$40,916,200
Engineering coordination of collectors with remainder of Project		\$ 50,000	
Furnish and install solar collectors and associated controls		38,817,000	
Installation of solar collector control and power wiring		1,862,200	
Checkout collector system		187,000	
2. <u>Receiver</u>	31%		23,706,750
Engineering coordination of receiver with remainder of Project design of tower, tower piping and electrical up to existing building		1,759,000	
Furnish and install solar receiver and receiver controls		16,960,000	
Tower for Receiver - includes earthwork, concrete, foundation and tower, elevator, platforms and painting		1,647,050	
Piping from receiver to existing building		3,209,500	
Electrical from receiver to existing building		81,200	
Checkout Receiver System		50,000	
3. <u>Thermal Storage</u>	0%		0

TABLE 4.7-1 (Cont'd)

<u>COST ESTIMATE BREAKDOWN</u>	<u>% OF TOTAL</u>	<u>SUBTOTALS</u>	<u>TOTALS</u>
4. <u>Controls and Instruments</u>	4%		\$ 3,530,800
Engineering and integration of controls, instrumentation and master control system		\$ 322,000	
Purchase and install controls and instrumentation		3,162,400	
Checkout controls and instrumentation		46,400	
5. <u>Balance of Plant</u>	8%		6,411,400
Engineering and integration of these components that are not part of the electrical power generating system		224,000	
Civil/structural work including underground diversion culvert site grading, warehouse and new building, complete		4,426,300	
Equipment - purchase and install		338,000	
Piping - purchase and install		712,700	
Electrical - purchase and install		415,800	
Other construction work		282,300	
Checkout balance of plant		12,300	

TABLE 4.7-1 (Cont'd)

<u>COST ESTIMATE BREAKDOWN</u>	<u>% OF TOTAL</u>	<u>SUBTOTALS</u>	<u>TOTALS</u>
6. <u>Electric Power Generating System (EPGS)</u>	4%		\$ 3,350,600
Engineering and integration of the EPGS components with the remainder of the system		\$ 321,000	
Equipment - purchase and install		1,060,800	
Piping construction work		1,218,200	
Electrical construction		415,800	
Other construction work		322,500	
Checkout EPGS		12,300	
7. <u>Distributables</u>			1,920,000
Field expense, all risk insurance, payroll taxes, bonds		1,447,700	
Construction supplies and temporary facilities		<u>472,300</u>	
	<u>100%</u>	\$79,835,750	\$79,835,750

SOLAR HYBRID REPOWERING REEVES UNIT 2

COST ESTIMATE BREAKDOWN BY MAJOR JOB COST ACCOUNTS

Figure 4.7-1. Cost Estimate Breakdown

4.8 ENVIRONMENTAL CONSIDERATIONS

A summary of the major environmental considerations for the solar hybrid repowering facility at Reeves Unit No. 2 is presented in Section 4.8.1. Section 4.8.2 below describes the site as it pertains to these environmental considerations. Discussions of the environmental impacts of construction and of the environmental impacts of operation are covered in Sections 4.8.3 and 4.8.4, respectively. The references cited in Section 4.8 are listed in Appendix C of this Report.

4.8.1 SUMMARY OF MAJOR ENVIRONMENTAL CONSIDERATIONS

Based upon a preliminary assessment of the major environmental considerations, it appears that there will be no major environmental impacts resulting from construction and operation of the Solar Hybrid Repowered Reeves Station (Unit No. 2) at Albuquerque, New Mexico.

The major potential environmental impacts on air are:

- For both normal and adverse operating conditions, the maximum calculated ground-level concentrations of pollutants will be due to the oil-fired operation of the facility and are expected to be well below the State of New Mexico and National Ambient Air Quality Standards.
- The emissions produced by the solar/oil facility are approximately 40 percent lower than the emissions produced by a facility operating on oil alone.

The major environmental impacts on water are:

- Water Use - Water needs for this facility are expressed in the need for approximately 15 gallons of water per heliostat per month (approximately 800,000 gallons of water per year) for washing and rinsing the heliostats during the operation phase and drinking water for the construction crew during the construction phase. Water needs are anticipated to be met without affecting existing local water users. Conservation and recycling will be practiced wherever feasible.
- Water Quality - Operation of the solar hybrid repowering facility will produce discharges of cooling waters and discharges of the heliostat washing solutions. Neither are expected to have a significant effect on local surface or groundwater resources. During construction, runoff could have a temporary effect on the local streams.

The major environmental impacts on the terrestrial resources, human resources and ecology are:

- Vegetation - No significant loss of grassland
- Wildlife - No significant habitat loss
- Endangered Species - Based upon a literature survey, no endangered plants are known to be present on-site; some endangered animals may migrate through the area
- Land Use - Land in this area could be used for power generation, industrial park or housing, but is generally unfit for other uses. Proximity of two small locally used airports may pose some hazard to pilots due to glint, glare and tower height. This would be worked out with FAA authorities.
- Mineral Resources - There will be no impact to existing mineral resources.
- Seismology - Slight to moderate damage could occur, depending on location of epicenter of earthquake.
- Demographic-Socioeconomic - No significant demands on schools, housing or municipal services are anticipated for the construction and operation phases of the proposed project. Some temporary increase in traffic congestion and increased demands on retail services in the immediate site vicinity may occur during the construction period.

4.8.2 ENVIRONMENTAL SITE DESCRIPTION

This section provides a description of the solar hybrid repowering site in terms of relevant environmental considerations. Included are discussions of the site location (Section 4.8.2.1), physiography (Section 4.8.2.2), geology and mineral resources (Section 4.8.2.3), seismology (Section 4.8.2.4), soils (Section 4.8.2.5), and hydrology (Section 4.8.2.6). Ecology and climatology are reviewed in Sections 4.8.2.7 and 4.8.2.8, respectively. Also included are discussions of land ownership and use (Section 4.8.2.9), transportation (Section 4.8.2.10), historical and archaeological sites (Section 4.8.2.11), demography and socioeconomics (Section 4.8.2.12), and ambient sound levels (Section 4.8.2.13).

4.8.2.1 SITE LOCATION

The solar hybrid repowering site is located on the south side of the Reeves power plant which lies approximately two miles north of Albuquerque's city

limits in Bernalillo County, New Mexico. Figures 4.8-1 through 4.8-3 depict the proposed facility in relation to the state, the county and the city of Albuquerque. As evidenced in Figure 4.8-3, the site lies approximately one-half mile west of Interstate 25 and is bounded on the south by Osuna Road and on the west by the Albuquerque Metropolitan Arroyo Flood Control Authority (AMAFCA) North Diversion channel, and to the north by Los Angeles Boulevard.

4.8.2.2 PHYSIOGRAPHY

The site lies in the southern portion of the Basin and Range Physiographic Province in the Mexican Highland Section, which is characterized by isolated dissected block mountain ranges separated by aggraded desert plants. The Sandia Mountains' crestline lies approximately 10 miles east, reaching 10,678 feet above sea-level (MSL) at Sandia Crest. Westward from these mountains elevations decrease to 5000 feet MSL at the Rio Grande River which lies approximately three miles west. The site has a surface that slopes gently westward from an elevation of 5130-feet MSL on the east to 5070-feet MSL on the west near the AMAFCA drainage canal. Topography at the site is shown in Figure 4.8-1.

4.8.2.3 GEOLOGY AND MINERAL RESOURCES

The site is located in the Albuquerque-Belen Basin, that is a north-trending basin 90-miles long and 30-miles wide in the Rio Grande trough. The area is covered mainly with Quaternary alluvium and with rocks of the Santa-Fe formation.⁽¹⁾ Figure 4.8-4 depicts a stratigraphic column of the Albuquerque area.⁽²⁾

On site there are no known:^(3,4,5,6)

- Oil, gas or coal resources
- Oil or gas pipelines
- Metal or non-metal resources

Figure 4.8-2 indicates that the closest coal field, the Rio Puerco coal field, is located approximately 13 miles west of the site and the small Tijeras coal field is located approximately 15 miles east of the site.⁽⁴⁾

Figure 4.8-1. Map of New Mexico State

Figure 4.8-2. Map of Bernalillo County

Figure 4.8-3. General Location of the Solar Hybrid Repowering Site

ERA	SYSTEM	SERIES	AGE (M.Y.)*	FORMATIONS	THICKNESS
CENOZOIC	Quaternary	Holocene		Gravel, sand, mud in low-lands, arroyos, low terraces and alluvial fans	5-100
		Pleistocene	1	Gravel, sand, caliche; lava flows	10-50
		Pliocene	12	<i>Santa Fe Formation</i> : sand, clay and gravel	10,000+ _—
	Tertiary	Eocene		<i>Galisteo Formation</i> : red and buff sandstone and mudstone	1000+ _—
	Cretaceous	Upper	90	<i>Mesaverde Formation</i> : shale, sandstone, and coal	1500
				<i>Mancos Shale</i> : shale with thin limestone and sandstone beds	1500
		Lower	125	<i>Dakota Formation</i> : sandstone, conglomerate, shale	5-100
MESOZOIC	Jurassic	Upper	165	<i>Morrison Formation</i> : variegated mudstone and sandstone	400-800
				<i>Summerville Formation</i> : red and buff mudstone and sandstone	200
				<i>Todilto Formation</i> : gypsum and limestone	100-200
				<i>Entrada Sandstone</i> : red and buff sandstone	150-200
	Triassic	Upper	185	<i>Chinle Formation</i> : red and tan mudstone and claystone	1500
				<i>Santa Rosa Formation</i> : sandstone and conglomerate	200-400
	Permian	Upper	215	<i>Bernal Formation</i> : sandstone, siltstone, and limestone	100
				<i>San Andres Formation</i> : limestone	30-100
		Middle	225	<i>Glorieta Sandstone</i>	50-100
				<i>Yeso Formation</i> : red and tan sandstone, limestone, and gypsum	600-800
PALEOZOIC		Lower	235	<i>Abo Formation</i> : red sandstone and mudstone	600-900

Figure 4.8-4. Stratigraphic Column of Albuquerque Area⁽²⁾

PALEOZOIC	Pennsylvanian	270	<i>Madera Foundation</i> : limestone, shale, and sandstone	100+
			<i>Sandia Foundation</i> : sandstone, shale, and limestone	100-200
	Mississippian	300	<i>Terrero Formation</i>	0-100
	Precambrian	1400-3000	<i>Sandia Granite</i> : gneiss, quartzite greenstone, and schist	

*M.Y. = millions of years from the beginning of the system or series.

A formation is a number of beds that are distinguishable from others above and below because of differences in composition, color, or other features. Series and systems are larger groupings of formations based on fossils, age, etc. Definitions of rocks comprising the formations may be found in any standard dictionary.

Stratigraphic Column of Albuquerque Area⁽²⁾

The closest prospects for uranium mines are located approximately 18 miles southwest of the site, approximately 17 miles northeast of the site, or approximately 13 miles southeast of the site,⁽⁴⁾ as indicated in Figure 4.8-2.

4.8.2.4 SEISMOLOGY

The site is located in Zone 2 of the U.S. Seismic Risk map,⁽⁷⁾ as shown in Figures 4.8-5 and 4.8-6. This indicates that earthquakes of intensity VII on the Modified Mercalli Scale (Table 4.8-2), which corresponds to an earthquake of the magnitude of five to six on the Richter scale, could occur on the site or its vicinity. This was confirmed by a recent detailed study⁽⁸⁾ that tabulated the recorded earthquakes in the general vicinity of the site.

Seismic events are rated according to the maximum intensity in the area of the epicenter (originating location). The intensity follows the Modified Mercalli Intensity Scale and is a measure of the damage caused by the event. Table 4.8-1 gives the Mercalli Intensity Scale and the expected damage for each intensity. Damage done by an earthquake is related to the energy released at the epicenter and the distance from the epicenter. Other important factors include the geologic setting of the area, the frequency of the seismic waves, the depth of the epicenter and the amount of earthquake resistance built into man-made structures. The more commonly known Richter Magnitude Scale is a measure of energy released at the epicenter of the earthquake. Table 4.8-2 gives a comparison between the Mercalli Intensity Scale and the Richter Magnitude Scale. Figure 4.8-7 gives the magnitude of an earthquake as a function of the maximum distance from the epicenter to observed structural or ground damage.

A detailed tabulation and graphical depiction of earthquakes felt prior to 1962 and instrumentally recorded earthquakes from January 1, 1962 through June 30, 1976 in the Albuquerque area is provided in the Western Area Survey, Public Service Company of New Mexico, 1978. Data in this study indicate that earthquakes of magnitude 5 on the Richter scale could occur at the site or its vicinity. Damage from such an earthquake at the epicenter may result in broken masonry, small landslides and collapse of tall weak structures. (Table 4.8-1) within 10 to 50 km or 6 to 31 miles.

Figure 4.8-5. Seismic Risk Map of the United States⁽⁷⁾

NOTE: Roman Numerals indicate earthquake intensity levels on the Modified Mercalli Scale. For instance, Mercalli Scale VII corresponds to an earthquake of magnitude 5 to 6 on the Richter Scale.

Figure 4.8-6. Seismic Risk Map for Southwestern United States⁽⁷⁾

TABLE 4.8-1. MERCALLI INTENSITY SCALE AND EXPECTED DAMAGE FOR EACH INTENSITY (AFTER C. F. RICHTER, 1958)(9)

- I. None felt. Marginal and long-period effects of large earthquake.
- II. Felt by persons at rest, on upper floors, or favorably placed.
- III. Felt indoors. Hanging objects swing. Vibration like passing of light trucks. Duration estimated. May not be recognized as an earthquake.
- IV. Hanging objects swing. Vibration like passing of heavy trucks; or sensation of a jolt like a heavy ball striking the walls. Standing motor cars rock. Windows, dishes, doors rattle. Glasses clink. Crockery clashes. In the upper range of IV wooden walls and frame creak.
- V. Felt outdoors; direction estimated. Sleepers wakened. Liquids disturbed, some spilled. Small unstable objects displaced or upset. Doors swing, close, open. Shutters, pictures move. Pendulum clocks stop, start, change rate.
- VI. Felt by all. Many frightened and run outdoors. Persons walk unsteadily. Windows, dishes, glassware broken. Knickknacks, books, etc., off shelves. Pictures off walls. Furniture moved or overturned. Weak plaster and masonry D cracked. Small bells ring (church, school). Trees, bushes shaken.
- VII. Difficult to stand. Noticed by drivers of motor cars. Hanging objects quiver. Furniture broken. Damage to masonry D, including cracks. Weak chimneys broken at roof line. Fall of plaster, loose bricks, stones, tiles, cornices (also unbraced parapets and architectural ornaments). Some cracks in masonry C. Waves on ponds; water turbid with mud. Small slides and caving in along sand or gravel banks. Large bells ring. Concrete irrigation ditches damaged.
- VIII. Steering of motor cars affected. Damage to masonry C; partial collapse. Some damage to masonry B; none to masonry A. Fall of stucco and some masonry walls. Twisting, fall of chimneys, factory stacks, monuments, tower, elevated tanks. Frame houses moved on foundations if not bolted down; loose panel walls thrown out. Decayed piling broken off. Branches broken from trees. Changes in flow or temperature of springs and wells. Cracks in wet ground on steep slopes.
- IX. General panic. Masonry D destroyed; masonry C heavily damaged, sometimes with complete collapse; masonry B seriously damaged. (General damage to foundations). Frame structures, if not bolted, shifted off foundations. Frames racked. Serious damage to reservoirs. Underground pipes broken. Conspicuous cracks in ground. In alluviated areas sand and mud ejected, earthquake fountains, sand crater.
- X. Most masonry and frame structures destroyed with their foundations. Some well-built wooden structures and bridges destroyed. Serious damage to dams, dikes, embankments. Large landslides. Water thrown

TABLE 4.8-1 (Continued)

on banks of canals, rivers, lakes, etc. Sand and mud shifted horizontally on beaches and flat land. Rails bent slightly.

XI. Rails bent greatly. Underground pipelines completely out of service.

XII. Damage nearly total. Large rock masses displaced. Lines of sight and level distorted. Objects thrown into the air.

Masonry A, B, C, D are specified by Richter as follows:

Masonry A. Good workmanship mortar and design; reinforced, especially laterally, and bound together by using steel, concrete, etc.; designed to resist lateral forces.

Masonry B. Good workmanship and mortar; reinforced, but not designed in detail to resist lateral forces.

Masonry C. Ordinary workmanship and mortar; no extreme weaknesses like failing to tie in at corners, but neither reinforced nor designed against horizontal forces.

Masonry C. Weak materials, such as adobe; poor mortar; low standards of workmanship; weak horizontally.

Figure 4.8-7. Magnitude of Earthquakes as a Function of the Maximum Distance from the Epicenter

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BKD--Bluepoint-Kokan Association, hilly. Runoff is slow, and the hazard of water erosion is moderate or severe.

EmB--Embudo gravelly fine sandy loam, 0 to 5 percent slopes. Runoff is medium, and the hazard of water erosion is moderate.

EtC--Embudo-Tijeras complex, 0 to 9 percent slopes. Runoff is medium and the hazard of water erosion is moderate.

WeB--Wink fine sandy loam, 0 to 5 percent slopes. Runoff is medium and the hazard of water erosion is moderate.

SURFACE WATER HYDROLOGY

Surface water supplies in the Albuquerque area are largely confined to the Rio Grande River and include the water flowing through irrigation and drainage ditches or standing in low areas on the floodplain. A small quantity of ephemeral surface flow occurs in several arroyos draining from the mountains.⁽²⁾

The U.S. Geological Survey has been measuring the flow of the Rio Grande River at Albuquerque (Station 08330000) since October 1941. Table 4.8-3 lists the daily flow at this station in cubic feet per second (cfs) for the water year 1976 (October 1, 1975 through September 31, 1976) as well as total maximum and minimum monthly flows. The extremes for the period of record are: maximum discharge of ~25,000 cfs, which occurred on April 24, 1942, and minimum flows of "no flow," which occur at times. Since November 1973 the flow is completely regulated by Cochiti Dam located approximately 50 miles upstream.

Measurements of suspended sediment loads, temperatures and concentrations of total dissolved solids are taken at this station. It appears that the major water quality concern at this location is in the area of the inflowing suspended solids.

An arroyo passes through the southern part of the solar hybrid repowering site. A playa (a shallow central basin of a desert plain in which water gathers after a rain and is evaporated) is located near the eastern boundary of the site.

GROUNDWATER HYDROLOGY

Much of Albuquerque's water comes from the subsurface at or beneath a level of soaked sand and gravel known as a water table (see Figure 4.8-3). In the Rio Grande trough, nearly all the subsurface beds are fairly porous and permeable enough to allow slow movement of groundwater. Since all the rocks in the trough are permeable, the ground water is unconfined and the groundwater level may fluctuate up and down, depending upon the amount of rainfall, the river flow, or the use of water from wells and ditches. Being unconfined, the subsurface ground water has complete connection, or freedom of movement, with the river surface water. Thus, with sufficient rain, the water table can rise to coincide with the surface of the earth.⁽²⁾

TABLE 4.8-3. DISCHARGES OF RIO GRANDE RIVER AT ALBUQUERQUE, NEW MEXICO
(U.S.G.S. STATION 08330000), cfs(13)

DAY	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP
1	244	800	1670	1660	333	820	874	1950	1170	463	417	514
2	242	836	1650	1550	290	774	744	2170	1290	545	1170	555
3	245	862	1660	1500	288	804	653	2160	1250	624	1330	541
4	242	883	1660	1480	249	838	700	2220	884	635	848	464
5	312	1120	1660	1550	654	930	626	2490	648	549	666	499
6	362	1670	1440	1590	1190	967	537	2550	570	451	335	659
7	326	1680	1680	1520	1030	969	705	2710	924	411	258	782
8	247	1670	1730	1510	770	852	799	2450	1210	452	123	721
9	208	1670	1440	1550	742	760	1040	2940	950	554	45	669
10	205	1710	1710	1620	734	815	1080	2930	1050	517	15	648
11	229	1750	1760	1740	689	901	1080	2900	1310	442	15	599
12	259	1680	1410	1620	716	832	1190	2610	1190	521	40	647
13	267	1670	1900	1880	779	841	1270	2540	1070	770	251	610
14	279	1450	1730	1920	842	923	1290	2620	999	647	228	500
15	235	1350	1710	1880	880	908	1430	2580	855	1550	180	478
16	237	1400	1720	1770	930	872	1480	2490	731	651	515	488
17	264	1650	1690	1360	833	667	1400	2450	579	773	913	523
18	279	1730	1680	1160	815	715	1070	2390	584	544	922	600
19	281	1730	1440	1180	821	601	984	2620	543	490	881	676
20	306	1660	1690	1110	840	620	911	3140	529	425	1740	626
21	315	1690	1740	902	835	670	730	3170	460	582	1240	532
22	326	1640	1750	779	853	724	629	2900	385	895	797	672
23	326	1650	1870	708	889	701	499	2600	345	1370	625	484
24	350	1710	1440	445	826	650	351	1910	510	1090	1230	478
25	362	1550	1880	637	749	615	817	1940	623	1360	1320	400
26	362	1440	1790	626	765	710	1110	1880	556	1070	1230	370
27	358	1280	1790	613	780	593	1110	1210	469	647	1460	340
28	334	1370	1810	635	830	542	1100	938	628	649	754	496
29	240	1650	1710	468	824	845	1360	794	645	745	657	606
30	265	1540	1690	707	---	698	1660	810	558	596	596	580
31	461	---	1780	468	---	811	---	978	---	494	519	---
TOTAL	8977	44491	53430	38860	21780	23808	29229	70480	23515	21838	21722	16757
MEAN	290	1443	1736	1254	751	768	974	2274	784	704	701	559
MAX	461	1750	1940	1920	1190	969	1660	3170	1310	1550	1740	782
MIN	205	800	1640	613	249	542	351	794	345	411	15	340
AC-FT	17810	88250	106800	77080	43200	47220	57940	139830	44640	43320	43090	33240
(t)	14430	1430	1180	982	857	6230	14200	16320	17480	19500	15240	14420
CAL YR 1975	TOTAL	564435	MEAN	1557	MAX	5800	MIN	160	AC-FT	1127000	(t)	111500
OTH YR 1976	TOTAL	375287	MEAN	1025	MAX	3170	MIN	15	AC-FT	744400	(t)	122300

Before large water usage occurred and before the digging of drainage ditches, the water table in the valley bottom coincided with the surface in many places to make water-logged soils or rose above the surface in lower areas to cause swamps and lakes. The drainage ditches did away with these conditions by lowering the water table. It continues to be lowered, especially near Albuquerque where well withdrawals are large.⁽²⁾

The Rio Grande trough is filled with at least several thousand feet of sand and gravel very much like that seen at the surface (Figure 4.8-4). Sand, gravel and mud brought into the trough by water, along with part of the water itself, were deposited and buried.

There is little chance of a water shortage in the Albuquerque area. Probably no other large city in the arid Southwest has such a bountiful supply of good water as Albuquerque has. Water everywhere in the trough is no more than a few hundred feet beneath the surface. With population projections of nearly 1,000,000 by the year 2000, hydrologists estimate that the water table around Albuquerque would be lowered no more than 80 feet.⁽²⁾

WATER USE

Surface and groundwater resources are utilized by municipalities and for industrial and agricultural purposes. The New Mexico State Engineer regulates both surface and groundwater uses and limits the amount of water rights on the basis of purpose of use, location and nature of the surface or groundwater availability and the demonstrated or established need or use of the water.⁽²⁾

4.8.2.7 ECOLOGY

Local terrestrial flora and fauna as well as aquatic ecology are described in this section as they apply to this facility.

TERRESTRIAL FLORA

Native vegetation around the solar hybrid repowering site is low in profile principally because of low rainfall, 7 to 10 inches annually, and high elevation.

5000 to 6000 feet above MSL. The plant community at a typical site in this part of the county is mainly comprised of grasses mixed with some shrubs and herbaceous plants. Vegetation covers only approximately 15 percent of the soil surface. The most abundant grass is usually black grama (*Bouteloua eriopoda*), which may comprise approximately 35 percent of the total vegetation by weight. Less abundant species are sand dropseed (*Sporobolus cryptandrus*), mesa dropseed (*Sporobolus flexuosus*), galleta (*Hilaria jamesii*), three awn (*Aristida glauca*), blue grama (*Bouteloua gracilis*), alkali sacaton (*Sporobolus airoides*), bush muhly (*Muhlenbergia porteri*), Indian ricegrass (*Oryzopsis hymenoides*), and fluffgrass (*Tridens pulchellus*). In places, there are broom snakeweed (*Gutierrezia sarothrae*), broom dalea (*Dalea*, sp.), pricklypear cactus (*Opuntia*, sp.), small soapweed (*Yucca glauca*), cholla cactus (*Opuntia*, sp.), and winterfat (*Eurotia lanata*). Annual plants which increase during years of above average precipitation are tansymustard (*Descurania*, sp.), Indian paintbrush (*Castilleja leonardi*), woolly Indian-wheat (*Plantago purshii*), lambsquarters (*Chenopodium album*), and Russian-thistle (*Salsola kali*). Woody plants such as Apache plume (*Fallugia paradoxa*) may occur in the drainage ways.⁽¹¹⁾

The vegetation of the site is characterized principally by black grama, sand dropseed, three awn, bush muhly, Indian ricegrass, fluffgrass, broom snakeweed, pricklypear, cholla cactus, tansymustard, Russian-thistle and bladderpod.⁽¹²⁾ When such a plant community is disturbed, annual plants increase. Vegetation of the site has already undergone some disturbance because of the existing power plant and is also affected by several small washes that dissect the proposed plot for the solar collector field.

Of the Federal threatened and endangered plant species^(14,15) and the plants protected by the State of New Mexico,⁽¹⁶⁾ none are known to occur on the site at this time. Of those listed, only a few species could potentially occur at the site, such as grass cactus (*Pediocactus papyracantus*),⁽¹⁹⁾ and only a more detailed study could verify their presence or absence. Should these species be present, they would be moved away from the site prior to construction.

TERRESTRIAL FAUNA

The faunal components of the area around the solar hybrid repowering site have been strongly influenced by man's activities; interstate highways, drainage canals, etc. The area is considered poor to very poor for potential habitat elements required by wildlife and thus for wildlife itself.⁽¹¹⁾

Mammal species residing in the site potentially include several small mammals such as the ord kangaroo rat (*Dipodomys ordii*), silky pocket mouse (*Perognathus flavus*), desert cottontail (*Sylvilagus auduboni*), blacktail jackrabbit (*Lepus californicus*) or least chipmunk (*Eutamias minimus*). Larger mammals are likely to occur at the site only during forays for food. Predators such as the raccoon (*Procyon lotor*), skunk (*Mephitis mephitis*) or coyote (*Canis latrans*) may pass through occasionally but most larger mammals, such as deer (*Odocoileus hemionus*) would be inclined to avoid man's activity and remain closer to the Rio Grande River floodplain.

Bird activity at this site would be limited to those few song birds that make this type of habitat home. Species such as the raven (*Corvus corax*), horned lark (*Eremophila alpestris*), western meadowlark (*Sturnella neglecta*) or vesper sparrow (*Poecetes gramineus*) may be seen in this area and raptors such as the marsh hawk (*Circus cyaneus*) may hunt here. Waterfowl may be observed nearby because of the proximity to the Rio Grande River, but no habitat is available for these species on the site.

Reptiles comprise another component of the fauna of the site. Several desert species could potentially occur here.

Within the proposed site no rare, threatened or endangered species are known to occur at this time. Several Federally or state endangered species that may migrate through the Rio Grande Valley but are unlikely to use the site are the whooping crane (*Grus americana*), bald eagle (*Haliaeetus leucocephalus*), little blue heron (*Florida caerulea*), and American peregrine falcon (*Falco peregrinus anatum*).^(17,18,19) The presence or absence of additional endangered or threatened species on the state list would have to be confirmed by on-site studies. The site is not located in the direct path of migratory birds.

4.8.2.8 CLIMATOLOGY

Monthly mean and annual climatological data for a 29-year period are available for Albuquerque⁽²⁰⁾ and temperature and precipitation for Los Lunas⁽²¹⁾ and Bernalilli.⁽²²⁾ The climatological data from these cities should more than adequately characterize the climate in the vicinity of the proposed site. A summary of relevant climatological data for the three locations mentioned is provided in Table 4.8-4.

Monthly mean temperature and relative humidity data depict the climate of the site as arid continental. Temperatures around the area are those characteristic of high altitude, dry climate. The average daily range of temperatures is relatively high, with the daytime summer maxima averaging higher than 90°F and the nights are cool. The demands for energy to heat during the winter and cool during the summer can be evaluated by degree days. These values are presented in Table 4.8-4.

The annual average wind speed for the proposed site is approximately nine miles per hour with the prevailing direction from the southeast. The average monthly precipitation in the vicinity of the site varies from less than one-half inch during the winter months to over an inch and a quarter during July and August. Snow rarely remains on the ground in the valleys for more than 24 hours. The July-September period furnishes almost half of the annual moisture with most of it due to heavy thundershowers. Thunderstorms occur on the average of 43 days per year. Severe weather such as tornadoes rarely occur in the area but occasional dust storms occur.

Another feature of the climate is the high percentage of sunshine. Monthly and annual solar radiation data, expressed as percentage of possible sunshine, are available for Albuquerque and are listed in Table 4.8-4. Sunshine is recorded during more than three-fourths of the hours from sunrise to sunset and this high percentage carries through the winter months. Frequencies of fractional cloud cover from sunrise to sunset are also available on a monthly and annual basis for Albuquerque (Table 4.8-4). These frequencies, along with the possible percentages of sunshine, serve as a valuable estimate of the solar input at the proposed site of the solar hybrid repowering facility.

TABLE 4.8-4. SUMMARY OF CLIMATOLOGICAL DATA FOR
ALBUQUERQUE AND VICINITY

<u>Parameter</u>	<u>Meteorological Stations</u>		
	<u>Albuquerque</u> ⁽²⁰⁾	<u>Los Lunas</u> ⁽²¹⁾	<u>Bernalilli</u> ⁽²²⁾
<u>Temperature, °F</u>			
Annual Average	56.8	54.6	54.5
Maximum	78.7	77.2	75.8
Minimum	35.2	32.6	34.6
Degree Days - Heating	4292	4830	--*
Degree Days - Cooling	1316	--	--
<u>Precipitation, inches</u>			
Annual Average	7.77	7.15	8.41
Monthly Maximum	3.33	--	--
Monthly Minimum	0.00	--	--
24-hour Maximum	1.92	1.50	--
<u>Snowfall, inches</u>			
Annual Average	10.4	4.7	--
Monthly Maximum	14.7	8.0	--
24-hour Maximum	14.2	8.0	--
<u>Wind, mph</u>			
Annual Average Speed	9.0	--	--
Prevailing Direction	SE	--	--
Fastest:			
Speed, mph	90	--	--
Direction	SE	--	--
<u>Relative Humidity, %</u>			
Annual Average at:			
0500 hour	58	--	--
1100 hour	37	--	--
<u>Solar Radiation</u>			
Annual Percentage of Possible Sunshine	77	--	--
Maximum	83	--	--
Minimum	72	--	--

TABLE 4.7-4 (Continued)

<u>Parameter</u>	<u>Meteorological Stations</u>		
	<u>Albuquerque</u> ⁽²⁰⁾	<u>Los Lunas</u> ⁽²¹⁾	<u>Bernalillo</u> ⁽²²⁾
<u>Mean Annual--No. of Days</u>			
Precipitation $\geq$.01 in.	59	--	--
Snow, sleet, hail ($\geq$ 1.0 in.)**	4	--	--
Thunderstorms	43	--	--
Heavy Fog	5	--	--
Maximum Temperatures $\geq$ 90°F	61	84	--
Minimum Temperature $\geq$ 32°F	121	157	--

*Data not available

**Total Precipitation

4.8.2.9 LAND OWNERSHIP AND LAND USE

Much of the following discussion on land use is based on a study conducted by the Environmental Affairs Department of the Public Service Company of New Mexico.⁽¹²⁾

This site is located in an area of rapid urban development activity. The Metropolitan Areas and Urbans Center Plan of the Albuquerque/Bernalillo County Comprehensive Plan⁽²³⁾ classifies the area of the proposed solar hybrid repowering site as established urban land. Established urban land is land suited for development as there exists financing and public services that would permit higher densities.

The solar hybrid repowering site is bounded by two established industrial parks, Academy Industrial Park to the south and Loop Industrial Park north of Los Angeles Boulevard. The area between these two industrial parks is vacant land with the exception of the heavy industry activity of the Public Service Company of New Mexico (PNM) Reeves Station and American Gypsum, both located south of Los Angeles Boulevard. Albuquerque's suburbs have been rapidly spreading northward, and several new housing plans and trailer parks lie within two miles of the site on the northeast, east and southeast.

West of the site, between the AMAFCA North Diversion Channel and North Edith Boulevard, the land is classified as developing urban which is land that has not been platted extensively and is presently acceptable for low level urban development. Albuquerque Gravel Products occupies most of this land. Small portions of land adjacent to Edith Boulevard are designated as semi-urban and rural, suitable for low density residential development.

Most of the projected industrialization in the vicinity of the site will be related to Loop Industrial Park and a speculative and yet to be designed industrial community east and south.

4.8.2.10 TRANSPORTATION

As shown in Figures 4.8-1 through 4.8-3, the site is bounded by Los Angeles Boulevard to the north, I-25 and the Frontage Road that parallels the interstate

to the east, Osuna Road to the south and the AMAFCA North Division Channel to the west. Edith Boulevard lies west of the drainage channel.

Daily traffic flow statistics for 1976 and projected for 1995 are given in Table 4.8-5. Traffic flow statistics were obtained from the Middle Rio Grande Council of Government.^(24,25) Projected increases in traffic flow over the next 20 years will be greatest for Los Angeles Boulevard, 3200 vehicles per day in 1976 to 10,700 vehicles per day in 1995. Increases in traffic flow will also be substantial for I-25. Current traffic statistics are not available for the Frontage Road, but 1995 projections estimate average daily traffic flow at about 5000 vehicles.

TABLE 4.8-5. AVERAGE DAILY TRAFFIC^(24,25)
AT SOLAR HYBRID REPOWERING SITE

<u>Corridor</u>	<u>1976</u>	<u>Projected 1995</u>
Los Angeles Boulevard	3,200	10,700
I-25	17,556	44,000
Osuna Road	12,900	17,300
North Edith Boulevard	6,700	4,100

Extensive improvement and expansion of transportation networks are planned for northwest Albuquerque. Within the vicinity of the site, Frontage Road will be improved, running in a north to south flow west of I-25, and a south to north flow east of I-25 and an I-25 interchange will be constructed at Los Angeles Boulevard. A major improvement will be the construction of a North Valley River Crossing which will follow the alignment of either Montano Road, Los Angeles Boulevard or Richfield Avenue. At the present time Montano Road is the favored alignment. If Montano Road is not feasible, Los Angeles Boulevard is the likely alternative. All of these improvements to the circulation system will increase the opportunities for large scale development in the early to mid-1980's for this area through increased accessibility and visibility of the area.

There are four airports in and around Albuquerque, as shown in Figures 4.8-1 through 4.8-3. The city's Sunport International Airport lies eight miles south, adjacent to the Kirtland Air Force Base. Closer to the site there are two smaller local airports; Coronado Airport, which lies two miles north north-east, and Alameda Airport, which lies four miles northwest.

4.8.2.11 HISTORICAL AND ARCHAEOLOGICAL SITES

There are eight historical sites listed in the National Register of Historic Places for Bernalillo County as of December 31, 1977.⁽²⁶⁾ Three additional sites were added as of March 7, 1978.⁽²⁷⁾ None of these historical places are located on or near the proposed solar hybrid repowering site. It is not known whether archaeological artifacts are located within the proposed site boundaries. Prior to construction of this facility an on-site survey will be performed.

4.8.2.12 DEMOGRAPHY AND SOCIOECONOMICS

The solar hybrid repowering site lies within the Albuquerque Standard Metropolitan Statistical Area (SMSA) which coincides with Bernalillo County's boundary. The county's population has grown steadily from a population of 316,800 in 1970 to 365,200 in 1975, and is by far the most populated county in the state.⁽²⁸⁾ It is a highly urbanized county (94.2 percent in 1970) with a 1970 population density of 270 persons per square mile. The City of Albuquerque, Bernalillo County area had in 1974, a population of 286,300, which is over six times larger than either Santa Fe or Las Cruces, New Mexico's second and third largest cities, respectively. The population of this city is expanding rapidly: during an eight-year period, from 1970 through 1978, there was an increase of over 35 percent, from 243,751 to 330,242. A recent July 1978 publication⁽²⁹⁾ of the Albuquerque Urban Observatory, University of New Mexico, contains projected demographic changes to 1980 based on past demographic changes in the Albuquerque/Bernalillo County area. The population growth in the Albuquerque/Bernalillo County is expected to continue for the period between 1975 through 1985; it is expected to increase by 23 percent.⁽²⁹⁾ During the same period the number of households is forecasted to increase in this area by 38 percent.⁽²⁹⁾

The 1976 annual average size of the civilian labor force in the Albuquerque SMSA was 171,815, with 154,971 persons employed and 16,844 persons unemployed giving

an average unemployment rate of 9.8 percent of 1976.⁽³⁰⁾ Contract construction employment accounted for 9800 jobs out of the total (~155,500) non-agricultural jobs in the Albuquerque SMSA in 1976.⁽³¹⁾ Construction employment is expected to reach 13,779 by 1980 and 15,069 by 1985. Housing units are expected to grow from 126,400 units in 1975 to 150,00 units by 1980 and reach 174,000 units by 1985.⁽²⁹⁾

4.8.2.13 AMBIENT SOUND LEVELS

Noise levels at the site are affected by various existing activities that contribute to the total noise level. These activities include: (1) mobile sources on the nearby roads and Interstate 25, (2) the two small nearby airports, (3) the existing PNM Reeves Station, and (4) the gypsum plant.

Noise levels at this site are typical of those occurring at other industrial sites.

4.8.3 ENVIRONMENTAL IMPACTS OF CONSTRUCTION

In this section the environmental affects during the construction phase are described. All applicable Federal, state and local laws and regulations will be followed to minimize and to avoid undesirable environmental effects. Included are discussions of air quality effects (Section 4.8.3.1), effects of sound (Section 4.8.3.2), effects on land use (Section 4.8.3.3), ecological effects (Section 4.8.3.4), hydrological effects (Section 4.8.3.5), and social and cultural effects (Section 4.8.3.6).

4.8.3.1 EFFECTS ON AIR QUALITY

Dust formation and motor machinery emissions are the major potential impact to the local air quality during the construction phase. Clearing and regrading the heliostat field could cause the dust formation and machinery employed for construction would emit some gases and particulate matter. Levels of fugitive dust formed will be comparable to those associated with the construction of similar size projects. Dust suppression techniques (such as frequent surface wetting) may need to be employed to reduce dust levels.

4.8.3.2 EFFECTS OF SOUND

Machinery employed during construction could increase noise levels at the construction site; however, the heliostats will be prefabricated and will only be assembled on site. In addition, noise levels at the site are presently influenced by a variety of noise causing functions as described in Section 4.8.2.13.

4.8.3.3 EFFECTS ON LAND USE

The area designated for the solar hybrid repowering site is presently vacant land, and no homes or other buildings would have to be relocated, purchased or destroyed.

During construction, there probably will be increased traffic volume and congestion in the immediate vicinity of the site during morning and afternoon rush hours. Increased congestion may occur at the Osuna Road interchange of I-25, along Los Angeles Boulevard in the vicinity of Osuna Road and Los Angeles Boulevard.

Traffic congestion may be mitigated by staggering the starting and quitting times of the construction workforce.

4.8.3.4 ECOLOGICAL EFFECTS

Construction activities will result in the removal of vegetation from the site prior to installation of the heliostats. The removal of the existing vegetation during construction will promote the growth of annual plants and perennials such as sand dropseed, cactus, and catclaw mimosa. These species and various grasses may thrive under the shade of the heliostats. Control of these shaded area micro communities through various techniques such as cutting or spraying may prove necessary. If seeding is not utilized to reestablish vegetation on disturbed sites, then dormant perennials may be expected to eventually revegetate these sites. (32)

The removal of vegetation will result in increased siltation during construction. This runoff could affect the aquatic communities in local water bodies off site. However, collection of runoff and sediments in a retention pond could allow the sediments to settle prior to allowing excess water to be discharged into the natural drainage system. Construction of such a pond would be considered if found necessary. High sediment loads are a naturally occurring phenomenon in the local small streams and in the Rio Grande River Wildlife habitat will be destroyed with the removal of the vegetation. Many wildlife species will move to surrounding areas. The less mobile and burrowing species are likely to experience some mortality.

The potential for impacts to endangered flora or fauna must be determined by additional studies conducted on site prior to construction. These studies will be conducted on a seasonal basis by experts to determine the presence or absence of endangered or threatened flora or fauna on the site. The presence of migratory birds could be determined at the same during the appropriate season. Should floral endangered species be found on-site, they will be relocated to another site in the general vicinity without affecting the construction of the facility.

4.8.3.5 HYDROLOGICAL EFFECTS

Degradation of the quality of the local water resources through increased siltation and runoff over construction areas is of environmental concern. Construction of a retention pond could help mitigate this potential impact.

Drinking water for the work force and waters needed for construction will probably be supplied by the wells that supply the potable water needs of the existing power plant. Should the yields of these wells not suffice, an additional well could be dug after obtaining approval from the New Mexico State Engineer.

4.8.3.6 SOCIAL AND CULTURAL EFFECTS

The construction force is anticipated to range between 250 and 350 persons.

Construction of the solar facility at the proposed location should not create any long-term adverse social, economic or cultural impacts. This conclusion is based on several factors, which relate to the following: (1) the overall population of Albuquerque, (2) the size of the civilian labor force, (3) percentage of the local unemployment, (4) size of the construction force required, and (5) duration of the construction period.

Generally speaking, a large city with a growing population such as Albuquerque does not experience the typical social-economic "boom-town" effects associated with construction projects in small isolated communities. With Albuquerque's average size of its civilian labor force of about 170,000 people, and a near 10 percent or close to 17,000 unemployed people, it is possible to conclude that most of the 250 to 350 construction workers will be local inhabitants.

Therefore, there will not be a large influx of people from outside the Albuquerque SMSA. Some specialized construction workers, technical people and project managers will move into Albuquerque from outside areas, but their numbers will be small, and they will not cause any adverse impact to schools, housing, or utility systems, since Albuquerque will easily be able to absorb these people. There may be some increased demands placed on local restaurants, gasoline service stations and shops in the immediate vicinity of the site during construction. Also, the existing package sanitary waste system at the existing power plant may have to be increased during construction to accommodate the work force.

Positive socioeconomic benefits would be increased tax revenues through wages and salaries, employment for several hundred workers in an area where unemployment is rather high (10 percent), and additional jobs created through a multiplier effect during construction.

An archaeological survey of the site, performed prior to construction, will ensure no loss of potential archaeological information.

4.8.4 ENVIRONMENTAL IMPACTS OF OPERATION

The environmental effects during the operation of the solar hybrid repowered site are described in this section. Included are discussions of the air quality effects (Section 4.8.4.1), sound effects (Section 4.8.4.2), land use effects (Section 4.8.4.3), ecological effects (Section 4.8.4.4), hydrological effects (Section 4.8.4.5), social and cultural effects (Section 4.8.4.6), and visual impacts (Section 4.8.4.7).

4.8.4.1 EFFECTS ON AIR QUALITY

Air quality impacts of the solar portion of the proposed facility will be minimal. Potential air quality effects could result from the conventional equipment associated with power generation.

In assessing the air quality effects of the proposed facility for this study, assumed emissions and assumed adverse meteorological conditions were used. When the actual evaluation of the environmental impacts will be done, it would be more accurate to use actual on-site meteorological data. Results of this assessment were compared to Class II PSD (Prevention of Significant Deterioration) increments for information only and not because the proposed facility will necessarily be subject to the PSD provisions of the Clean Air Act amendments of 1977.

Fuel and stack characteristics are required to assess the potential impact of a new or modified facility on air quality. In this particular case, the maximum continuous rating of the power plant is 50 MWe. The power plant is currently operating on natural gas but has a backup fuel of residual oil number 6 or number 5. In the future, the facility will use residual oil which will most likely be number 6 blended with number 2 in some proportion.

In this section the following three cases are discussed:

- Power plant operation for peaking requirements — normal conditions — spinning reserve mode at nighttime
- Power plant operation under adverse conditions and spinning reserve mode at nighttime

- Power plant operation — normal/adverse conditions and cold start-up mode at nighttime

Figures 4.8-9 through 4.8-11 represent schematically these three cases and the following three paragraphs describe them in detail.

The first case deals with the power plant operating for peaking requirements under what will be termed normal conditions. Thus, for twelve hours during the day, 25 MWe of power is assumed to be generated by solar energy and 25 MWe is oil fired.

In the second case, the operation of the power plant under adverse conditions is discussed. An example of such adverse conditions could be several consecutive days of overcast skies in which the power plant would be forced to generate the total 50 MWe by oil firing. In both cases, one and two, the boiler is assumed to be in a spinning reserve mode at 5 to 25 percent of full power at nighttime.

Case 3 considers the situation in which the boiler must undergo a cold start-up period for twelve hours previous to daytime use. For case three, the boiler is assumed to operate at 25 percent of full power. This third case would be responsible for greatest emissions of SO_2 , NO_2 and particulates under adverse daytime conditions and correspondingly, higher ground-level concentrations than maintaining the boiler in a spinning reserve mode. A range of values for SO_2 , NO_2 and particulate emissions given in later tables for the nighttime case should provide a conservative estimate for both the spinning reserve and cold start mode.

Parameters used in the air quality assessment along with an explanation of their characteristics are summarized in Table 4.8-6. The percentages of emission for SO_2 , NO_2 and particulate matter are also presented in this table. Regardless of the residual oil type or blend, the proposed solar/oil facility is assumed to comply with the maximum allowable State of New Mexico emission standards presented in Table 4.8-6. Should the facility use only this oil, it should meet the State of New Mexico ambient air quality standards.

Daytime (12 hours)
Operation

Nighttime (12 hours)
Operation

Spinning Reserve
Mode -- oil fired
at 5 to 25% full power

Figure 4.8-9. Case I - Operation of a 50 MWe Solar/Oil Facility under Normal Conditions

Daytime
Operation (12 hours)

50 MWe generated
by oil firing

Nighttime
Operation (12 hours)

Spinning Reserve
Mode -- oil fired
at 5 to 25% full power

Figure 4.8-10. Case II - Operation of a 50 MWe Solar/oil Facility Under Adverse Conditions (i.e., Several Consecutive Days of Overcast Skies)

Figure 4.8-11. Case III - Operation of a 50 MWe Solar/oil Facility under Normal or Adverse Daytime Conditions and Cold Start-up of the Boiler at Nighttime

TABLE 4.8-6. FUEL AND STACK CHARACTERISTICS CONSIDERED
IN AIR QUALITY IMPACT CALCULATIONS

<u>Power Plant Characteristics</u>	<u>Description</u>
Fuel Types	No. 2 residual oil No. 6 residual oil
Fuel Consumption	3.15×10^7 gal/yr (3600 gal/hr)
Stack Height	120 feet
Exit Diameter	10.5 feet
Effluent Flow Rate	1.174×10^5 cfm
Exit Temperatures	200-260°F
<u>Fuel Characteristics</u>	
Heat Input	545×10^6 Btu/hr
State of New Mexico Sulfur Dioxide Emission Standard	≤ 0.34 lb/ 10^6 Btu
State of New Mexico Particulate Emission Standard	≤ 0.005 lb/ 10^6 Btu
State of New Mexico Nitrogen Dioxide Emission Standard	≤ 0.3 lb/ 10^6 Btu

The modified facility will be classified as a fossil-fuel plant and will be responsible for an increased amount of pollutants emitted. This increase is a result of the conversion from natural gas to residual oil which has characteristically higher emission factors for SO_2 and particulates. This modified source is defined as a major point source since it causes emissions in excess of 100 tons per year of any pollutant for which there is a national standard.⁽³³⁾

It is evident from the calculated emission values presented in Table 4.8-7 and Table 4.8-8 that this solar/oil facility can be considered a major point source. Since this facility will emit more than 100 tons per year of any pollutant and will operate a fossil-fuel boiler of more than 250×10^6 Btu thermal per hour, it may also require a prevention of significant deterioration (PSD) permit.⁽³⁴⁾ However, at this time it is not clear that the facility will definitely be subject to the PSD provisions of the Clean Air Act amendments of 1977.

Table 4.8-7 presents the emissions (pounds per day) of SO_2 , NO_2 and particulate matter from the solar/oil facility under normal operating, daytime and nighttime conditions (Case I). Two values are presented under nighttime operation and each were calculated based on a different reduced percentage of full power to simulate either the spinning reserve or cold start-up mode.

The total emissions for normal conditions are thus presented as a range of values; 2376 to 3239 lb/day of SO_2 , 1078 to 1469 lb/day of NO_2 and 18 to 24 lb/day of particulate matter.

Table 4.8-8 presents similar emissions for the power plant under adverse meteorological conditions (Case II) such as several consecutive days of overcast skies. In this case, the total 50 MWe is generated by oil firing during the daytime while the nighttime power output remains at the same reduced percentage as in the normal operating conditions.

Emissions under adverse conditions are approximately 40 percent higher than those emissions produced under normal conditions. The emissions produced

TABLE 4.8-7. CASE I. THE OPERATION OF A 50 MWE SOLAR/OIL FACILITY
UNDER NORMAL CONDITIONS*

Pollutant	Emissions (pounds per day)			Total Range**
	Daytime (12 hours)	Nighttime (12 hours)		
		5%	25%	
SO ₂	2160	216	1079	2376 to 3239
NO ₂	980	98	489	1078 to 1469
Particulate Matter	16	2	8	18 to 24

*Case I assumes 25 MWe generated by solar energy and 25 MWe oil fired

**Total Range - lower limit = daytime + 5% full power value at night
upper limit = daytime + 25% full power value at night

TABLE 4.8-8. CASE II. THE OPERATION OF A SOLAR/OIL FACILITY
UNDER ADVERSE CONDITIONS*

(i.e. Several Consecutive Days of Overcast Skies)

Pollutant	Emissions (pounds per day)			Total Range**
	Daytime (12 hours)	Nighttime (12 hours)		
		5%	25%	
SO ₂	4316	216	1079	4532 to 5395
NO ₂	1962	98	489	2060 to 2451
Particulate Matter	33	2	8	35 to 41

*Case II assumes the total 50 MWe generated by oil firing

**Total Range - lower limit = daytime + 5% full power value at night
upper limit = daytime + 25% full power value at night

under adverse conditions and a cold start-up of the boiler during the night-time are therefore good estimates of the worst possible emissions. It is important to note once again, that the emissions obtained in Tables 4.8-7 and 4.8-8 were calculated using the maximum allowable emission factors for SO_2 , NO_2 and particulate matter that the State of New Mexico permits. For further information, Class II significant deterioration increments are presented in Table 4.8-9.

TABLE 4.8-9. CLASS II SIGNIFICANT DETERIORATION INCREMENTS⁽³⁾

<u>Pollutant</u>	Maximum Allowable Increase
	<u>$\mu\text{g}/\text{m}^3$</u>
Sulfur Dioxide:	
Annual arithmetic mean	20
24-hour maximum	91
3-hour maximum	512
Particulate Matter:	
Annual geometric mean	19
24-hour maximum	37

Maximum ground-level concentrations for SO_2 , NO_2 and particulates and applicable ambient air quality standards are presented for both cases (Case I and II) in Tables 4.7-10 and 4.7-11. These maximum calculated values are based upon conservative considerations including meteorological conditions conducive to high ground-level concentrations and were obtained by using a Gaussian formulation as discussed by Turner.⁽³⁵⁾ The terrain was assumed to be flat from the stack to the downwind distance of the predicted maximum ground-level concentration. The distance to the maximum was determined from the graphs presented by Turner⁽³⁵⁾ and an effective plume height calculated from Briggs' equation. This terrain consideration along with the assumptions that a given atmospheric stability and wind speed will exist for approximately six hours serve as the basis for the calculations of SO_2 , NO_2 and particulate concentrations shown in Tables 4.8-10 and 4.8-11. For comparison, the State of New Mexico ambient air quality standards

TABLE 4.8-10. MAXIMUM GROUND-LEVEL CONCENTRATIONS* FOR SO₂, NO₂ AND PARTICULATE MATTER UNDER NORMAL OPERATING CONDITIONS ASSUMING UNLIMITED MIXING (CASE I) AND APPLICABLE AIR QUALITY STANDARDS

	Maximum Calculated		State of New Mexico Standards				EPA-National Primary Standards			
	24-hour		24-hour		Annual†		24-hour		Annual†	
	μg/m ³	ppm	μg/m ³	ppm	μg/m ³	ppm	μg/m ³	ppm	μg/m ³	ppm
SO ₂										
A Stability, 3m/s**	24 to 32	0.009 to 0.01	261	0.10	52	0.02	365	0.14	80	0.03
E Stability, 2.5m/s	17 to 23	0.006 to 0.009								
NO ₂										
A Stability, 3m/s	11 to 15	0.006 to 0.008	188	0.07	94	0.04	---	---	100	0.04
E Stability, 2.5m/s	8 to 11	0.004 to 0.006								
Particulate Matter (μg/m ³)										
	24-hour		24-hour	7-day	30-day	Annual†	24-hour		Annual†	
A Stability, 3m/s	0.18 to 0.23		150	110	90	60	75		60	
E Stability, 2.5m/s	0.13 to 0.17									

*Maximum ground-level concentration calculated assuming persistancy of the stability class and wind speed for six out of 24 hours. Calculations assumed flat terrain which is 8 km of the stack.

**These wind speeds were assumed and were not based on actual on-site data

†Annual arithmetic mean for SO₂ and NO₂ and geometric mean for particulate matter

TABLE 4.8-11. MAXIMUM GROUND-LEVEL CONCENTRATIONS* FOR SO₂, NO₂ AND PARTICULATE MATTER UNDER ADVERSE OPERATING CONDITIONS ASSUMING UNLIMITED MIXING (CASE II) AND APPLICABLE AIR QUALITY STANDARDS

	Maximum Calculated		State of New Mexico Standards				EPA-National Primary Standards			
	24-hour		24-hour		Annual†		24-hour		Annual†	
	<u>µg/m³</u>	<u>ppm</u>	<u>µg/m³</u>	<u>ppm</u>	<u>µg/m³</u>	<u>ppm</u>	<u>µg/m³</u>	<u>ppm</u>	<u>µg/m³</u>	<u>ppm</u>
SO ₂										
A Stability, 3m/s**	45 to 53	0.009 to 0.02	261	0.10	52	0.02	365	0.14	80	0.03
E Stability, 2.5m/s	34 to 40	0.013 to 0.015								
NO ₂										
A Stability, 3m/s	20 to 24	0.001 to 0.013	188	0.07	94	0.04	---	----	100	0.04
E Stability, 2.5m/s										
Particulate Matter (µg/m ³)										
	<u>24-hour</u>		<u>24-hour</u>	<u>7-day</u>	<u>30-day</u>	<u>Annual†</u>	<u>24-hour</u>		<u>Annual†</u>	
A Stability, 3m/s	0.30 to 0.5		150	110	90	60	75		60	
E Stability, 2.5m/s	0.25 to 0.3									

*Maximum ground-level concentration calculated assuming persistancy of the stability class and wind speed for six out of 24 hours. Calculations assumed f at terrain within 8 km of the stack

**These wind speeds were assumed and were not based on actual on-site data

†Annual arithmetic mean for SO₂ and NO₂ and geometric mean for particulate matter

for SO_2 , NO_2 and particulate matter ⁽³⁶⁾ as well as the Environmental Protection Agency (EPA) Regulations on national ambient air quality standards ⁽³⁷⁾ are presented in the same tables.

A comparison of the short-term (24-hour) calculated averages and applicable ambient air quality standards indicate that the concentrations of pollutants produced by this modified facility would be expected to be in compliance with the State of New Mexico and national air quality standards. Even when the existing 24-hour background concentration of $15 \mu\text{g}/\text{m}^3$ ⁽³⁸⁾ for both SO_2 and NO_2 are added to these values, the standards would be met with a large margin of safety.

Since concentrations also decrease with sampling time, annual calculated ground-level concentrations will be less than the short-term 24-hour values and will also be less than annual national and state standards.

As well as meeting national and state air quality standards, this proposed solar/oil facility may be expected to comply with Class II significant deterioration increments for SO_2 . Under normal conditions, the maximum calculated 24-hour SO_2 concentration will be less than $91 \mu\text{g}/\text{m}^3$ above the background 24-hour SO_2 concentration thus complying with Class II significant deterioration increments (see Table 4.8-9 for reference). Since the proposed site is in a non-attainment area for particulates, Class II significant deterioration increments cannot be applied to this pollutant. It should be noted that the Albuquerque area is also a non-attainment area for oxidants and carbon monoxide. Should this facility be subject to PSD requirements, emission offsets might have to be obtained for oxidants, carbon monoxide and TSP (total suspended particulates).

In summary, it is clear that the proposed stack emissions and resulting concentrations of concern (SO_2 , NO_2 and particulates) are less than the national and state standards with a large margin of safety. Furthermore, based on this assessment, the calculated 24-hour SO_2 concentrations under normal or adverse conditions will comply with Class II significant deterioration increments.

4.8.4.2 EFFECTS OF SOUND

Sound levels at the solar hybrid repowering site are anticipated to be the same as present ambient sound levels. The low levels of noise generated by the boilers, the turbogenerators and the cooling towers that are presently at the site are not expected to change significantly with the introduction of the solar modification. The solar heliostat field will not generate any sounds.

4.8.4.3 EFFECTS OF LAND USE

There are several advantages or positive land use aspects of locating the solar facility on the proposed site. Suburban residential development has been concentrated east of Interstate 25. The area already has several industrial facilities around it that would be compatible with the solar facility. These include the Reeves power plant, two industrial parks, American Gypsum and Albuquerque Gravel Products. In addition, since the facility would be used for educational and research purposes, proximity to the interstate would allow good access to the site from downtown Albuquerque.

The 130 acres to be used for the solar facility will be precluded from being used for other purposes for which this land is fit such as expansion of existing industrial parks. Since some type of buffer zone is usually required around this type of facility, a total of more than 130 acres may be affected directly and indirectly. Since this area has been designated as "established urban area" in Albuquerque/Bernalillo County's Comprehensive Plan, and two industrial parks are already in this area with speculation for a third industrial park, the potential for a land use conflict may exist between these industrial uses: industrial parks and power production.

This land is not fit for agricultural purposes but could be used for industrial purposes.

4.8.4.4 ECOLOGICAL EFFECTS

As described in Section 4.8.2.7, the terrestrial ecology at the solar hybrid repowering site is typical to the local desert conditions: only approximately

15 percent is covered with flora, which provides relatively little habitat to the local desert fauna. Although approximately 130 acres will be affected directly by the solar heliostat field, the disruption of the local ecosystem on these 130 acres in this location (Section 4.8.29, Land Use) cannot be considered significant. This is especially true considering that the land has been designated for industrial purposes (Section 4.8.2.9), and the disruption of this ecosystem has been designated to occur by the local inhabitants.

In addition to the affect of the local existing terrestrial flora and fauna, operation of this could affect nearby communities through: (1) emissions to the air, (2) cooling tower drift and (3) impacts caused by the heliostat field.

TERRESTRIAL EFFECTS CAUSED BY AIR EMISSIONS

Since the site will have been significantly altered during construction, the operational impacts to vegetation will be to the surrounding area. Emissions to the atmosphere will meet all local and Federal standards, and the use of the solar portion would reduce emissions by 40 percent as compared to using oil. In addition, levels of emitted pollutants will be below those that are known to cause harm to the local flora and fauna. Thus, impacts should be insignificant.

IMPACTS FROM COOLING TOWER DRIFT

Drift from cooling towers is being deposited in the surrounding vicinity and whether this deposited material could have an impact on the local soils, vegetation and waters is of environmental concern.

Since groundwater is used in the cooling towers, the major ionic constituents consist probably of bicarbonate, calcium and magnesium, and the drift probably consists mainly of calcium and magnesium carbonates.

Cooling towers are presently employed at the existing power plant and no change in the quantity of waters used, in the number of cycles of concentration applied, nor the amount or type of chemical additives should occur. Thus, no change in impact of the cooling tower drift to the local soils should occur.

Cooling tower drift may affect vegetation in two main ways: (1) any affect on the local soils may affect the vegetation these soils support, and (2) deposits on the leaves may reduce photosynthesis and/or cause burns to leaves. Since the soils will not be affected and since the drift will be mainly composed of calcium and magnesium carbonate, no harm to the local vegetation should be caused by the cooling tower drift.

HELIOSTAT FIELD IMPACTS

Operational effects to terrestrial wildlife will relate primarily to birds and particularly during migratory periods. It is expected that some birds could die from impact with the heliostats and the tower. Birds and other flying creatures such as moths and butterflies may be attracted to the reflective surfaces and may be killed on impact or they may be burned as a result of such contacts. It must be noted at this point, as mentioned in Section 4.8.2.7, Terrestrial Fauna, that this solar hybrid repowering site is not located directly in the path of the majority of migratory birds.

To prevent the entrance of wandering larger animals into the collector field, the field will probably need to be fenced. This precaution will also avoid the possibility of animal-caused accidents. Impacts to most animals will be limited because of the current lack of adequate habitat. However, rodents may increase with an increase of forbs and grasses under the shaded heliostat.⁽⁴⁰⁾

The potential for impacts to endangered flora or fauna can be determined by on-site studies. At this time no aquatic or terrestrial endangered species are known to be present on the site nor in the vicinity of the site.

4.8.4.5 HYDROLOGICAL EFFECTS

Local water resources could be affected by the operation of the solar hybrid repowering system through six major sources:

- Flooding due to increased runoff
- Oil spills
- Cooling tower blowdown
- Sewage discharges
- Heliostat washing/rinsing
- Impact on water availability

IMPACTS DUE TO RUNOFF

Since no paving is planned on the heliostat field, the quantity of runoff over this field should not increase significantly in comparison to present conditions. Some increase in erosion may occur as a result of soil manipulation and removal of the local vegetation cover. Should mitigation of this occurrence be required, a collecting pond could be constructed to collect the runoff that will drain the field.

EFFECTS OF COOLING TOWER BLOWDOWN

Blowdown from the solar hybrid repowering station cooling tower will contain chemicals that serve to prevent scaling, corrosion and biological fouling and will be of the same type presently used at the existing power plant cooling system. Blowdown will be combined with other discharges and treated, if needed, to meet NPDES (National Pollution Discharge Elimination System) requirements prior to discharge. All discharges would comply with current EPA regulations and would be discharged to the Alameda Drain of the Middle Rio Grande Conservancy District. Effluent waters that would not comply with EPA discharge regulations would be contained in an evaporation pond.

EFFECTS OF HELIOSTAT WASHING/RINSING FLUIDS

Periodically the heliostats will be washed probably with a diluted weak ammonia solution and then rinsed with deionized water. A total of approximately 15 gallons of water would be required per heliostat per washing of which approximately five gallons are the wash solution and 10 gallons are deionized water.⁽¹¹⁾ Washing of heliostats is expected to take place at a frequency of one washing per month. For the 4289 heliostats expected for this solar hybrid repowering site, approximately a total of 800,000 gallons of water per year could be required of which two-thirds will be deionized water. Collection and recycling of washing and rinsing solutions will probably be done if found to be practical and feasible.

Ammonia is found in equilibrium in water as shown in the following equation:

The equilibrium is driven to the right with the increase in pH. Since the make-up water has a basic pH (Section 4.8.2.6, Groundwater Hydrology), some of the ammonia will dissipate as gaseous ammonia (NH_3). (The concentration entering the atmosphere should be too small for environmental concern.)

Conservation methods will be employed and it is expected that no wash water from this facility will be discharged into surface or groundwater bodies.

EFFECTS OF OIL STORAGE AND SPILLS

Oil will be stored on site in accordance with the December 1973, Environmental Protection Agency Regulations on Oil Pollution Prevention⁽⁴³⁾ which will minimize the potential impacts of oil contamination on the local surface and groundwater resources.

EFFECTS OF SEWAGE DISCHARGES

Approximately 25 to 35 people will comprise the operational work force of the solar hybrid repowering site (Section 4.8.4.6). Sewage effluents from such a work force will be absorbed by the existing package sewage facility with no difficulty. The existing system, as described in Section 4.8.3, meets regulatory requirements.

IMPACT OF WATER AVAILABILITY

Water requirements for the operation of the solar hybrid repowering system should reduce or equal water requirements of presently used systems (Section 4) and therefore no impact on local water availability should occur. Water needs for operating personnel (approximately 25 to 35 people) should also not pose a hardship on the potable water availability at the site. As described in Section 4.8.2.6, groundwater is available in the Albuquerque area, and should there be a total net increase in water requirements, those should be met without affecting existing local water users.

4.8.4.6 SOCIAL AND CULTURAL EFFECTS

The operating force for the solar plant will range between approximately 25 and 35 employees. This is a small number of people when comparing to the overall population of Albuquerque, to the total labor force, and when considering the growth rate of the area. Thus, this small operating force will not cause any noticeable adverse socioeconomic effects.

Positive socioeconomic benefits from this facility will be increased tax revenues through taxes on the facility, wages and salaries, personal property tax, sales tax and other similar taxes. In addition, this facility will allow PNM to provide the electric power to the increasing number of residents in the Albuquerque/Bernalillo County area (see Section 4.8.2.12).

4.8.4.7 AESTHETIC EFFECTS

It is generally accepted that industrial intrusions that interfere with the far-reaching natural landscape are considered unattractive and constitute an adverse impact.

Visibility of the heliostat field would be from Los Angeles Boulevard to the north, and I-25, the Frontage Road and the planned extension of Jefferson Road to the east. Visibility from Osuna Road would generally be impaired by development, and from North Edith Boulevard visibility would be obstructed by the rise in elevation and the drainage channel. Travelers viewing the site from Los Angeles Boulevard would have their view intermittently obstructed by the Reeves Station and the Gypsum Plant. Viewing of the site from I-25 and the Frontage Road with present developments would be relatively unobstructed due to the higher elevation to the east of the site and lack of development. Future development may obstruct this line of sight. Since the receiver tower will rise approximately 530 feet (160 meters), it will be visible from several miles away and from residences and highways that have long viewing ranges. This will be a dominant visual element in the Albuquerque area and will require further evaluation as to its impact.

4.9 SAFETY CONSIDERATIONS

One of the developmental areas in the conceptual design of a 25 MWe solar hybrid repowered plant at PNM Reeves Unit No. 2 is the investigation of safety aspects associated with the application of a solar central receiver design. Some of these health and safety considerations are unique to a solar central receiver design while others are relevant to the existing power plant. Section 3.6, Safety Considerations, discusses some of the safety aspects evaluated in selecting a specific unit to be repowered on the PNM system. This section reviews certain hazards that are associated with locating a solar central receiver system at an existing facility and these 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 such a facility.

A number of reports have been issued that address the safety aspects that are unique to the application of a solar central receiver system. Among these are three reports that deal with the 5 MWt Solar Thermal Test Facility (STTF) which has been constructed at the Sandia Laboratories in Albuquerque, New Mexico. (44, 45, 46) The tower, heliostat field and control building for this test facility covers approximately 10 acres of land. The height of the tower is 60m (~200-feet) and the heliostat collector field contains ~366 heliostat foundations. Several prototype heliostats and types of central receivers located at the top of the tower will be evaluated at the facility.

Several safety aspects were discussed in the MITRE Report. 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 STTF 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 vision was expected to be slight, similar to

flying across the choppy water of a lake. The Martin-Marietta heliostat design for the STTF consists of 25 individual facets or mirrors to produce the 37 m² of reflective surface and each of these facets are slightly dished and can be individually focused.

An additional consideration with regard to air traffic in the Sandia area is the 200 foot tall tower. Since this tower needed to conform to FAA regulations for aircraft safety, any danger was expected to be minimal. Moreover, the tower location needed to be noted on the pilot's instrument approach plates (Jepson Charts) for Albuquerque so that all aircraft can avoid it. Some thermal turbulence will also be created by the heat plume rising from the tower. The combination of these three potential safety impacts (glare, obstruction, and turbulence) on air traffic may necessitate slight modifications in the flight paths over the Sandia Laboratories area. Similar solar reflectance/tower height/heat plume assessments will be required in the development of a 25 MWe solar hybrid repowered plant at Reeves 2.

Significant efforts have been performed in assessing the eye hazards and evaluating the glint aspects in the development of this 5 MW STTF.⁽⁴⁵⁾ 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 have been 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 discussed. Certain beam control modifications which needed to be incorporated so as to minimize the altitude at which over-flying aircraft could encounter unsafe levels were described. Recommendations were made in Reference (45) with respect to the 5 MW STTF 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 affects.

Excerpts from some of the conclusions drawn in Reference (45), along with additional specific notations which apply, in general, to a solar hybrid repowered plant, are as follows:

- With regard to the application of the 25 faceted heliostat design by Martin-Marietta at the STTF, 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 heliostat designs being developed by MDAC, Martin-Marietta, or others which might be used for the 25 MWe solar hybrid repowered plant at Reeves 2.
- 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 STTF, 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 if a MDAC/Rocketdyne external receiver design is employed in the 25 MWe solar hybrid repowered plant.
- 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 for the conceptual design of a solar hybrid repowered facility has been completed. In developing preliminary health and safety considerations, initial evaluations call for the

identification of potential hazards and the corresponding subsystem(s) in which these hazards can occur. 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 complete health and safety assessment of the solar hybrid facility at PNM Reeves 2 will be required in subsequent phases of this program. This assessment will be based on the final design of the solar subsystem as well as on the specific components and working fluids selected for the solar hybrid repowered unit.

In developing an approach to specifying the health and safety considerations appropriate to the solar hybrid repowering program, several items will need to be delineated and/or evaluated: 1) the objectives of the health and safety program, 2) the applicable design guidelines, requirements and regulations for health and safety, 3) the types of hazards which need to be considered during the subsequent phases of the program and 4) the definition of a recommended set of safety related categories to be utilized in the analysis. A detailed health and safety analysis which will need to be performed will treat the following types of hazards associated with the solar hybrid repowering application at Reeves 2: solar reflectance; working fluid (steam and hot water) and oil fuel; electrical; mechanical; malfunction; and maintenance hazards. In addition, several other potential problems which extend beyond the normal health and safety of operating personnel will require investigation. These include a) the health and safety considerations of the general public, as well as visitors to the facility, b) transportation (both vehicular and airline modes) and its impact on safety, and c) the environmental and reliability considerations. The preliminary conclusions with regard to assessing health and safety considerations which can be drawn from this conceptual design phase for the solar hybrid repowering program are: 1) numerous hazards, causes of potential hazards and possible corrective actions can be identified, and 2) all potential problems are amenable to solution.

Preliminary health and safety considerations have been developed for a 25 MWe solar hybrid repowered plant at Reeves 2. This development effort is consistent with the conceptual design phase of the Technical and Economic Assessment of Solar Hybrid Repowering. Some of these considerations will be applicable not only to the design of the solar/hybrid subsystems being proposed for repowering, but also may be appropriate to the general solar central receiver programs being developed by the Department of Energy. The preliminary design guidelines and the safety analysis for the identification of potential hazards discussed below will relate specifically to the PNM design for the solar hybrid repowered unit, to the working fluids required for the system and to the appropriate components currently envisioned for use by the system.

4.9.1 OBJECTIVES

With respect to safety considerations in the development, construction, start-up, test and operation of a solar hybrid repowered facility at Reeves 2, the complete system must be designed to fulfill a number of the following objectives:

- Protect the health and insure the safety of the general public.
- Protect the health and insure the safety of the PNM Operating personnel and of visitors to the solar hybrid repowered facility.
- Protect the health and insure the safety of the construction, testing, 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 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, health and safety of the living environment identified herein will need to be evaluated further as part of the complete

environmental assessment. The above criteria, possibly complimented by others yet to be identified, have been set forth as the preliminary health and safety objectives in future phases of this program.

4.9.2 DESIGN GUIDELINES

Numerous guidelines, requirements and regulations are applicable to the health and safety considerations which will be assessed during the development of the solar hybrid repowered facility at Reeves 2. Special attention will be devoted to the design of the solar collector (heliostat) field and the central receiver/tower subsystems because of the relatively less mature technology of these components in solar central receiver systems. The electrical power generation subsystem (consisting of piping, components, controls and wiring for fluid power and electrical power generation), the fossil boiler subsystem and the auxiliary subsystems are based on a more mature technology and, in fact, are mostly in existence at Reeves 2. Accordingly, the applicable codes and standards which are now available for the electrical power generation and auxiliary power subsystems will be observed for the new construction or modifications to these subsystems. These same codes and standards, appropriately applied, will serve to ensure safe design of the components and subsystems unique to solar central receiver hybrid repowering systems.

An extensive list of standards, regulations, manuals and codes has been compiled which may comprise some of the design guidelines and requirements for the solar hybrid repowering project. These include:

- American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code:
 - Section I, Power Boilers
 - Section II, Material Specifications
 - Section V, Nondestructive Examination
 - Section VIII, Pressure Vessels
 - Section IX, Welding and Brazing Qualifications

- National Fire Protection Association (NFPA):
 - Fire Protection Handbook
- National Fire Protection Association (NFPA) National Fire Codes (NFC):
 - Volume 2, Water Spray Fixed Systems
 - Volume 5, Explosion Prevention Systems
 - Volume 6, National Electrical Code
- American National Standards Institute (ANSI):
 - ANSI A13.1, Scheme for the Identification of Piping Systems
 - ANSI A58.1, Building Code Requirements for Minimum Design Loads in Buildings and other Structures
 - ANSI B31.1, Power Piping Code
 - ANSI Z53.1, Safety Color Code for Marking Physical Hazards and Identification of Equipment
- Occupational Safety and Health Administration (OSHA):
 - OSHA 2206, General Industry Standards
- American Society of Heating, Refrigerating and Air Conditioning Engineers (ASHRAE):
 - ASHRAE Standards for Design of HVAC Equipment
 - ASHRAE Standard 90-75, Energy Conservation in New Building Design
- Air Conditioning and Refrigeration Institute (ARI):
 - Standards for Cooling Towers and Condensers
- National Board of Fire Underwriters (NBFU):
 - Codes for Buildings and Equipment
- National Electric Manufacturers Association (NEMA):
 - Standards for Electrical Equipment and Controls

- Safety Rules for the Installation and Maintenance of Electric Supply and Communication Lines
- Steel Boiler Institute (SBI):
 - Codes for Boilers
- Tubular Exchanger Manufacturers Association (TEMA):
 - Standards for Heat Exchangers
- Underwriters' Laboratory (UL) Standards
- Uniform Building Code
- Standards of American Institute of Steel Construction and American Concrete Institute
- Interstate Commerce Commission (ICC) Shipping Standards and Regulations
- National Safety Council
 - Accident Prevention Manual for Industrial Operations

These standards and codes, and possibly others, will be utilized as the controlling design guidelines and requirements during future phases of the solar hybrid repowering project, as appropriate.

PNM also intends to review and utilize, where appropriate, the health and safety assessment being prepared for the 10 MWe Solar Central Receiver Pilot Plant to be constructed at Barstow, California. In addition, it is anticipated that further design guidelines and safety criteria will be developed by the Department of Energy in other solar central receiver and solar hybrid programs which may be appropriate to incorporate into the solar hybrid repowering project. Finally, further technology development and testing efforts at Sandia Albuquerque and Sandia Livermore in the safety area are expected and these results will need to be considered.

4.9.4 SAFETY HAZARD CATEGORY DEFINITIONS

The conventional definitions by which possible hazardous conditions can be categorized for severity during subsequent phases of the project are as follows:

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

4.9.4 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 subsystem. Thus, a potential safety hazard associated with the solar hybrid repowering site could stem from emergency or accidental 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 severe eye hazard exists for those personnel whose eyes are looking at, and happen to be 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 hybrid repowered facility.

A skin hazard (concentrated sunburn) is also a consideration for the design of a solar central receiver system. 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 collector subsystem, is an additional consideration.

While not as hazardous as burns or fire, glare is a potential problem resulting from misaligned or even properly aligned heliostat collectors. This is due to its ability to impact both on- and off-site receptors as well as those in overflying 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 will decrease.

Nuisance glare and glint caused by reflected sunlight from the heliostats may affect nearby residents, aircraft pilots and passengers and highway travelers. Several studies have been conducted which describe the potential environmental and safety hazards that exist for solar plants. A few of these studies were discussed above at the beginning of Section 4.9. One of the safety considerations most frequently cited is variously termed distractive glint, nuisance glare, misdirected light or spurious reflections. These can result during normal operations, 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 occurrence 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. 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 aircraft pilots and airline passengers due to glint and glare from the heliostats and the 530 foot height of the receiver tower, since four airports are within ~10 miles of the proposed site. Specific evaluations of flight paths, aircraft altitudes, types and sizes of aircraft, and air traffic volumes would have to be 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, and these can be determined 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 hybrid repowered facility. Techniques which might be used 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 personnel on the methods to avoid these hazards; proper design of the controls for the collector subsystem (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.

4.10 PRELIMINARY NOTES ON INSOLATION PREDICTION FOR SOLAR ELECTRIC POWER PLANTS

This section discusses insolation prediction in terms of its importance to solar power plants, factors controlling insolation, cloud characteristics, and other weather situations that affect insolation.

4.10.1 THE NEED FOR LOOK-AHEAD REQUIREMENTS

There are three major types of look-ahead or insolation prediction requirements for solar electric power plants:

- Short-term, minutes to hours
- Intermediate, several hours to several days
- Long-term, average monthly to annual values

Short-term prediction of heliostat field outputs is especially necessary for solar repowered stations that do not have thermal storage. Typical thermal response time of such stations is in the order of a few minutes, and back-up boilers require a minimum build-up warning time of 10 minutes for load following. It is also desirable to have warning times of an hour or more to come up from cold conditions. Predictions of up to 10 to 15 minutes will be of value, and a look-ahead capability of one hour should meet most short-term needs.

Intermediate prediction of one-half to three days will be of value in determining how much of a solar capacity can be anticipated, and if it is likely to be uninterrupted.

Long-term prediction is of value in determining the economic worth of a plant, as well as how much energy will be available from a solar plant on a month-by-month basis, which can assist in determining likely fuel usage.

4.10.2 FACTORS CONTROLLING INSOLATION

The diurnal and seasonal variation in the direction of arrival of the sun's direct rays as a function of location for observations above the earth's surface is well established. The effects of the atmosphere in modifying the sun's radiation available at the earth's surface is much more complex. A

model has been developed that allows the prediction of the direct normal term with a good degree of accuracy based on atmospheric parameters. (See, for example, "On the Nature and Distribution of Solar Radiation," Report HCP/T2552-01, U.S. Department of Energy, Division of Solar Technology, Environmental Resource Assessments Branch, March 1978.) The variation in the direct normal term caused by changes in aerosols and atmospheric water vapor can be accounted for and, in general, predicted with a good degree of accuracy particularly since their characteristics do not vary rapidly. The major problem in look-ahead capability is the ability to predict the presence of clouds over the solar energy site.

The general insolation model employed is illustrated in Figure 4.9-1, which indicates the variation in insolation values above the atmosphere due to varying sun-earth distance, and then the reduction in the direct normal term due to the various atmospheric constituents.

The major problem, particularly as far as short term prediction, involves the motion, formation and dissipation of clouds. In general, there may be a short boundary of the clouds where the direct normal term is reduced, but this is usually followed by an essentially complete blockage of the direct term as the cloud moves across the observing point. In view of the importance of clouds in determining the ability to predict insolation, particularly on a short term basis, the following section will treat in some detail the characteristics of clouds as they are important to the prediction problem.

4.10.3 CHARACTERISTICS OF CLOUDS

CLOUDS IN GENERAL

Many different ways have been proposed to describe cloud types. F.H. Ludlam has proposed four basic classes of clouds based on the formation process:

- Orographic clouds, which are formed as a result of vertical motion caused by mountains or hills
- Layer clouds formed by widespread irregular stirring of the air

Figure 4.10-1. Insolation model showing: solar flux outside the atmosphere, I_0 ; absorption and scattering by various layers; the direct normal term at the earth's surface, I_{DN} ; and the downward scattered term.

- Layer clouds formed by widespread regular ascent of air
- Cumuliform clouds formed by "penetrative convection"

Strahler has classified clouds into families based on height and vertical development. He has suggested high clouds, in the region of 20,000 feet and above; middle clouds for 6,000 to 20,000 feet; and low clouds below about 6,000 feet. The types and examples of clouds are shown in Figure 4.9-2, which is obtained from Strahler (1963). The types of clouds typical to a given region vary with the time of year as well as location. In many of the northern regions the typical clouds are of the lower nimbo stratus type, while in the Albuquerque, New Mexico region a great deal of the cloudiness is in the form of cumulus clouds, particularly in the summer months. A fair amount of cirrus clouds can be present at some times of the year. The amount of cirrus appears to be quite variable from year to year.

The greatest emphasis in short term prediction should probably be placed relative to cumulus type of clouds which are of the fair weather nature. The clouds are broken up into small cellular structures and account for periods when a significant amount of radiation is available that is interrupted for short periods of time. Insolation records at Albuquerque show that very frequently in summer afternoons this type of cloud pattern is present. The cumulus clouds start out as small sized structures, with dimensions in the order of meters, and can grow to dimensions of several kilometers. The initial phases are usually such that the horizontal extent of the cloud is larger than the vertical extent, but once a cell grows to the large cumulonimbus stage, its height is often several times the horizontal extent.

The formation of cumulus clouds occurs with the upward motion of moist air into colder regions. Often at the same time some of the clouds are dissipating as the air moves downward into warmer regions. It is important to note that clouds of this nature are not predictable on a simple horizontal motion of uniform cloud cell types. Careful observations of clouds indicate that on some days the changes of shading on a local basis are more influenced

Figure 4.10-2. Cloud Forms Classified by Height and Vertical Development, from A. N. Strahler, 1963

by the growth and decay of individual clouds than by their horizontal motion. In view of this, it is important to note that short term predicting capability will require, in addition to horizontal wind speed and remote sensors, some indication of vertical motion of the air and temperature vs. height information. When the gross temperature decreases with increasing height greater than the dry adiabatic rate, there is a tendency for moist air to move upward and produce clouds. If the moist air moves up to a height where condensation occurs, the lapse rate will be significantly greater than the wet adiabatic rate, and a large cellular build-up usually occurs.

Vertical wind speeds of up to 30 or more mph can occur, and cloud heights may extend from 5,000 to 50,000 feet, with horizontal extents of several miles for well developed cumulus clouds.

Once a cloud is fairly well developed, then prediction is possibly by tracing its horizontal motion. On the other hand, during periods when only small cells are built up, a significant part of the prediction problem is determining when a cloud is likely to form or dissipate as opposed to a simple horizontal drift of the cloud.

High level cirrus clouds are likely to move horizontally at a much higher rate due to the greater wide speeds at high altitudes. The prediction of such clouds will likely be significantly different than for the cumulus type. In view of this, it is apparent that a determination of actual cloud height is important.

ANTICIPATED CLOUD CHARACTERISTICS AT THE REEVES STATION

One of the features of the Albuquerque climate is the large number of clear days and resulting high percentage of sunshine. The average percentage of possible sunshine ranges from a low of 72 percent in December to a high of 83 percent in June. The Reeves site, which is located in the Rio Grande River Valley north of the city of Albuquerque, Figure 4.10-3, is expected to have sunshine characteristics similar to that observed by the Weather Bureau at the airport. The gross motion of air is predominantly from the south in the

Figure 4.10-3. Locations of Reeves Plant and Weather Service Site

summer months, with northwesterly winds in February and March. The normal surface wind velocities are in the order of 10 mph. The local wind directions are variable enough that prediction sites will have to be spaced in most directions around the station to account for the changes in air flow.

The presence of the Sandia Mountains to the east of the site can have some influence; however, in general the main pattern, particularly during the summer months when the flow of air is from the south, is one of a slow gradual rise as the air flows up the valley. A significant increase in cloudiness does not occur until one gets much closer to the mountains. For air motion from the east, some of the moisture is removed from the air as it flows over the Sandia Mountains. This can result in less cloud cover at the Reeves site with wind from the east. July and August are the months with the heaviest precipitation and the greatest number of partly cloudy days. This is caused by the flow of moist air from the Gulf of Mexico in the summer "monsoon season." During these months, the wind is largely from the south or southeast.

A condensed view of the direct normal radiation observed for June 1962 is shown in Figure 4.10-4. On a number of days it is clear that there are numerous dropouts occurring in the afternoon. See, for example, June 1, 2, 8, 10, 23, 24 and 29. These values shown are the 10 minute average values. The original strip chart records show many more fades all the way to zero on these days. It appears that these fades result from a significant build-up of cumulus cloud forms in the afternoons. The dropout statistics are shown in Figure 4.10-5 for periods of four hours in the afternoon for three different days. It is apparent that a large number of the fades are four minutes or shorter in duration. The surface wind velocity and direction are shown in the calculation for each of the days. The effective projected width of the clouds for the case of horizontal motion is $W_e = t/v$.

For a median dropout time of 3 minutes (180 seconds) and an average wind speed of 6 knots (2.7 meters/sec) the median effective width for the days analyzed appears to be about 70 meters. The 20 minute dropouts could

DIRECT NORMAL
SOLAR RADIATION
ALBUQUERQUE

MATT ENG. LTD.

Figure 4.10-4. Direct Normal Solar Radiation (Albuquerque)

Figure 4.10-5. Dropout Length Distributions of Direct Normal Insolation at Albuquerque, New Mexico, Dropout Level = 300 W/m²

result from a 500 meter effective width. It should be noted that the effective width is the actual width plus the height times the tangent of the sun's zenith angle. It is important to note that the formation and dissipation times of small cumulus clouds is often in the order of 5 to 15 minutes, so it is possible that the variations observed are not all associated with horizontal cloud motion.

In any event, it appears desirable to examine carefully the cloud structures with due regard to the vertical, as well as horizontal, components of wind in determining the best type of prediction system to employ.

Intermediate term variations of cloud cover can, in some cases, be predicted several days in advance with a fair degree of certainty. As an example, in April 1971, the weather patterns over the western U.S. are shown in Figure 4.10-6. The lower left-hand track, with dates of 2, 13, and 14 of April, show a storm starting out of the Gulf of Alaska and approaching the western U.S. with a swerve down to the California coast on the 14th. Cloud cover photos for the days of April 11 through 16 are shown in Figures 4.10-7 through 4.10-12. On the 11th, the skies over Albuquerque were clear and both the direct normal radiation values and total horizontal radiation values were high for that date, as shown in Table 4.10-1.

TABLE 4.10-1. DIRECT NORMAL (LANGLEYS/MINUTE) AND
TOTAL HORIZONTAL (LANGLEYS/DAY) OBSERVED
AT ALBUQUERQUE, NM, APRIL 1971

<u>April</u>	<u>I_D (60°)</u>	<u>I_{TH}</u>
11	1.17	683
12	1.27	699
13	1.1 clds	681
14		514
15		228
16		652
17	1.06 clds	584

Circle indicates position of center at 7:00 a.m. E.S.T. Figure above circle indicates date, figure below, pressure to nearest millibar. Dots indicate intervening 6-hourly positions. Squares indicate position of stationary center for period shown. Dashed line in track indicates reformation at new position. Only those centers which could be identified for 24 hours or more are included.

Figure 4.10-6. Cyclone Tracks for April 1971

Figure 4.10-7. Cloud Cover, 11 April 1971

Figure 4.10-8. Cloud Cover, 12 April 1971

Figure 4.10-9. Cloud Cover, 13 April 1971

Figure 4.10-10. Cloud Cover, 14 April 1971

Figure 4.10-11. Cloud Cover, 15 April 1971

On April 12, it can be seen that the band of clouds is approaching the west coast of the U.S. and Albuquerque is still in the clear. On April 13, it is apparent that although the cyclone is dissipating, the cloud structure is still sweeping inland and approaching Albuquerque. By April 14, the cloud cover has reached Albuquerque. It can be seen in Table 4.10-1 that the direct normal values are missing for this date (this omission occurs on cloudy days) and that there is a significant decrease in the total horizontal radiation values. By the 15th, the cloud cover over the Albuquerque area is well established, and even the total horizontal value has dropped to a very low amount. By the 16th, the clouds are dissipating and the total horizontal radiation is back to normal. There is some cloud cover in the area so that the direct normal reading at 60° zenith angle was not available. By the 17th, the cloud cover has decreased to the point where direct values are again available.

This type of frontal storm, which is typical of the winter and spring conditions, can be observed and prepared for with the aid of satellite information. This simple sweeping in of cloud cover does not always occur. In fact, during the summer months an appreciably different pattern is observed. Clouds frequently disappear from storms moving in off the southern California coast due to the warm dry desert air. If enough moisture is carried along, they re-appear over the Rocky Mountains. A significantly different type of prediction method is required for this type of cloud cover.

4.10.4 SHORT-TERM LOOK-AHEAD SYSTEMS

There are a number of cases where it is believed that short term look-ahead systems will be feasible. Figure 4.10-13 shows a typical size heliostat field about 1 kilometer across, with two examples of clouds approaching. In case A, the large cumulonimbus clouds are shown as approaching from the southwest. If they are approaching at a velocity of three meters per second, which corresponds to a wind of seven knots, the times of passage for radial inflow is shown. Since the lifetime of large clouds of this type will be in excess of 20 to 30 minutes, it is possible to predict the degree of coverage and likelihood of encounter from each of the clouds shown which are approximately one kilometer across.

Figure 4.9-13. Plan View of a Heliostat Field Showing 2 Examples of Clouds Approaching the Site.

It becomes apparent that any simple vertical looking photoelectric system must be spaced at least two to four kilometers away from the station, and preferably some information should be received from sites as far as six to eight km away. It can also be seen that the horizontal resolution must be significant to keep the number of observing sites to a reasonable value. At a six km distance, if the horizontal detection capability is limited to one km, there would be a requirement for about 18 stations. This would not give sufficient resolution to determine whether or not a particular cloud would, in fact, cross the site, and it would be necessary to have an additional set of stations at a distance of two km from the field center.

Next, consider case B, with small cumulus clouds having widths in the order of 50 to several hundred meters. It is apparent that a simple vertical looking station or ring of stations is not likely to be of much value. In addition, when it is noted that the lifetime of the small cumulus clouds is frequently in the order of 5 to 15 minutes, it is obvious that any attempt to track small clouds at distances in excess of one to two km from the site will be of little value under most conditions.

It soon becomes apparent that an ideal look-ahead system should present a view with the heliostat field in the center and showing clouds for a distance of out to eight km. It is possible that a presentation to four or five km will be of great value in short term prediction. One possible approach would be to have a scanning all sky type camera to determine the location of clouds around the station. If the scanner is in the form of a lidar or some similar device, the actual height and distance can be determined.

SYSTEM LAYOUTS

A desirable look-ahead system will provide a visual presentation of clouds and their motions, including direction, speed, and height information for a distance of several km from the heliostat field. It is believed that a system could be constructed around a mini computer which would take the optical data and present it in visual form, as well as provide alerting information based on logic built into the computer. A measure of the moisture

content of the air above the station is also desirable in that increasing values would aid in alerting to the onset of condensation and the growth locally of clouds over the heliostat field.

INSTRUMENTATION

There will be a need for several types of instruments including local wind velocity, air temperature, humidity, absolute moisture content, and optical scanning systems. These instrumental inputs would then be employed, with suitable computer software, to arrive at both a visual presentation and alerting system for the look-ahead system. At this time, it is difficult to estimate the best mix of instruments to employ or to arrive at the cost of the system. It may, however, be possible to give some very rough order of magnitude guesses which should be subsequently modified after a more detailed analysis is carried out of the look-ahead problem.

4.10.5 INTERMEDIATE TERM LOOK-AHEAD SYSTEMS

The intermediate term look-ahead systems would likely be based about the existing satellite pictures and other prediction methods used by the Weather Bureau and other predictors. This type of system will rely on trained personnel and methodology development, rather than in instrumentation.

4.10.6 LONG RANGE LOOK-AHEAD SYSTEMS

It is known that climatic change often follows general trends, with some variation in the annual patterns. Year to year variations can also be anticipated. Initially, the emphasis will be on analyzing past changes, and then attempting to determine what the driving forces were that caused the variations observed. Again, the major cost would be in the research effort involved, as opposed to instrumentation.

THE ORDER OF MAGNITUDE COSTS (SHORT TERM SYSTEM)

The order of magnitude costs can perhaps be arrived at by assigning three subtotals; one for basic weather and optical instrumentation at \$20,000 to \$50,000, a PDP 11 type computer with extra storage, at \$25,000 to \$35,000,

and system design and integration at \$50,000 to \$75,000. It should be emphasized that there can be a wide range of costs, depending on the degree of system complexity. Initially it may be possible to start with some of the inputs from a nearby weather station and relatively simple optical systems to determine the type of prediction reliability attainable.

5.0 UNIT ECONOMIC ANALYSIS

This section presents the detailed economic analysis of the solar repowered Reeves No. 2 Unit operating on the PNM system. The analysis is based on the conceptual design of the repowered unit described in Section 4.0. The methodology used to perform the analysis is discussed in Section 2.5. The analysis described herein is similar to the analysis performed in Section 2.5 except that the following changes have been incorporated:

- Reference plant description has been revised consistent with the conceptual design presented in Section 4.0
- The insolation data base has been updated consistent with the 1978 version of the Aerospace tapes for Albuquerque, New Mexico
- The PNM system description has been revised to reflect the July 1978 plan for future power generation capability
- The economic scenario has been modified to approximate PNM system changes
- The cost of the repowered plant has been revised consistent with the data presented in Section 4.7

The intent of the analysis presented is to realistically assess the economics of the "first" repowered plant using present cost data for a limited production level for the solar hardware. The results therefore are not indicative of the economic potential of solar repowering but rather only of the economics of the "first demonstration" plant; the economic potential of solar repowering was presented in Section 2.5.

This section of the report includes a brief description of the unit, a discussion of the economic basis for the analysis, a description of the PNM system, and the results of the analysis.

5.1 UNIT DESCRIPTION

A reference solar hybrid repowered plant concept has been established for the Reeves Unit No. 2 for the purpose of performing the unit economic analysis. The reference plant concept for Reeves Unit No. 2 is based on the conceptual design presented in Section 4.0 and utilizes the solar hardware and technology being developed for the 10 MWe solar central receiver pilot plant to be built near Barstow, California. Table 5.1-1 summarizes the characteristics of the reference Reeves Unit No. 2. The capital cost data are given in Section 4.7. The solar subsystem has been sized to provide 25 MWe (50 percent repowering) at 2 P.M. winter solstice based on an insolation level of 950 watts/m^2 . The following changes were incorporated in the Reference Plant description described in Section 2.5 to yield the model summarized in Table 5.1-1 for Reeves Unit No. 2:

- Solar subsystem was revised consistent with the conceptual design presented in Section 4.0
- Net plant efficiencies were revised based on the heat balance calculations for the Reeves Unit No. 2
- Part load performance of the turbine generator was revised consistent with Reeves Unit No. 2 data
- The part and full load efficiency of the fossil boiler was revised to represent the Reeves Unit No. 2 boiler data

The solar system design is characterized by an external receiver mounted on a tower, and located in a 360° array of two axis sun-tracking heliostats which comprise the collector subsystem. Feedwater from the electrical power generation subsystem is pumped through a riser to the receiver and converted to superheated steam in a single pass through the tubes of the receiver panels. The steam from the receiver is routed through a downcomer to ground level and transported from the tower base to the turbine through horizontal steam lines.

The collector field has been sized to provide for 50% repowering of the 50 MWe fossil plant and is comprised of 4086 heliostats having a total mirror area of $155,268 \text{ m}^2$. The 950 Watts/m^2 insolation level assumed for sizing the collector fields is representative of 2 P.M. winter solstice conditions; the design point for the solar repowering project being used by PNM.

TABLE 5.1-1. REFERENCE REEVES UNIT NO. 2 PLANT PARAMETER SUMMARY

● Plant Type	Steam Turbine/Non-Reheat
● Plant Rating	50 MWe (25 MWe Solar)
● Plant Repowering Percentage*	50%
● Plant Operating Scenario	Maximize solar benefit Fossil operation - full time, part time, and only on cloudy days Economic dispatch fossil energy
● Collector Subsystem	
- Field Configuration	360°
- Field Area	130 Acres
- Heliostat Area	155,268 m ²
- Number of Heliostats	4086
● Receiver/Tower Subsystem	
- Receiver Type	External (single pass to superheat)
- Receiver Size	12 M dia by 21 M long
- Tower Height	150 M
● Electric Power Generation Subsystem	
- Cycle	Steam Rankine
- Net Plant Efficiency	33.5% Solar, 34.7% Fossil
- Turbine Inlet	950°F/1250 psi
- Heat Rejection	Wet Cooling Tower
● Fossil Boiler	
- Type	Oil
- Rated Load Efficiency	86%
- Start Up	Warm

*Based on an insolation level of 950 Watts/M²

The ability to operate on fossil fuel has been maintained in the repowered plant concept. The plant can therefore operate and produce 50 MWe using steam generated from the fossil boiler or a combination of both fossil and solar. It is assumed that the plant will always operate on fossil only or a combination of solar and fossil produced steam during cloudy days - a cloudy day for the purpose of the unit economic analyses is defined as a day during which the sky cover exceeds 0.5 for two or more consecutive hours (see Section 2.5).

The operation scenario assumed for the fossil boiler is important in determining the economic benefit of solar hybrid repowering. Two different scenarios were analyzed as discussed in Section 5.4. In order for the fossil boiler to be capable of responding to insolation variations during periods of intermittent cloud cover, the boiler must be operating at a minimum of approximately 25 percent of rated thermal output. The boiler response time to achieve 100 percent rated output from an operating level of 25 percent of rated output is approximately 10 to 15 minutes.

During those periods of the day when the plant is operating from solar generated steam, the fossil boiler is maintained in the warm standby condition for one of the scenarios analyzed. The other scenario assumes the fossil boiler is providing steam to produce 25 MWe.

At the end of the day, however, the boiler is "banked" and maintained in a warm standby condition overnight. The boiler is also "banked" during days when it is not economical to operate the plant from either solar or fossil energy. In order to account for scheduled and forced plant outages throughout the year, three "cold" starts of the boiler have been included in the unit economic analysis.

5.2 ECONOMIC BASIS

For the Task 1400 analysis, the economic assumptions were adjusted to a set of parameters provided by Public Service Company of New Mexico, whereas in Task 1100 the base economic assumptions were EPRI RP 648-1 (see Tables 5.2-1 and 5.2-2).

Among the new parameters were those reflected by the design study results for the repowering of Reeves Unit No. 2. The revised plant characteristics were discussed in the previous section (5.1) and include a smaller collector area, revised boiler efficiency curves, higher repowering cost and different operating and maintenance cost assumptions.

Regarding the higher capital cost assumptions, it is important to note that the Task 1400 results reflect demonstration plant cost assumptions, whereas with Task 1100 DOE heliostat goal costs were used assuming commercial penetration. The repowering direct cost for 25 MWe solar capacity in the demonstration phase (Task 1400) was assumed to be 82.8M\$ (1978), where in Task 1100 the commercial direct cost for 25 MWe was 25.2M\$. The operating and maintenance costs produced in Task 1400 were derived from separately estimated fixed and variable costs. In Task 1100 a simple percentage of the repowering capitalization was used for the total of fixed and variable O and M.

The fuel costs, escalation rates and other assumptions were changed from Task 1100 to 1400 as shown in Table 5.2-1. Three fuel escalation scenarios were investigated as will be described in Section 5.4.

Several changes were made affecting the capacity credit calculations. One was that the credit was taken effective in 1997 representing the anticipated retirement date of the Reeves No. 2 plant, rather than the prior assumption of 1995. Per Public Service of New Mexico expansion studies, the capacity displacement used in this task was 25 MWe of pumped storage hydro rather than 50 MWe of peaking (combustion-turbine) plants. Other changes are shown in Table 5.2-1.

TABLE 5.2-1. TASK 1400 ASSUMPTION CHANGES

REPOWERED PLANT CHARACTERISTICS

- Collector Area - Smaller
- Boiler Efficiency - Flatter
- Repowering Cost - Higher
- Solar O&M - Variable and Higher

ECONOMIC ASSUMPTIONS

	<u>1400</u>		<u>1100</u>
● Levelized Fixed Charge Rate	14.6%	vs	18%
● Oil Escalation Rates	7%, 15.5%	vs	12%
● Other Fuel Escalation Rates	7%	vs	10%
● O&M Escalation Rates	7%	vs	8%
● Base Fuel Costs	(See Table 5.2-2)		
● Capital Escalation Rate	7%	vs	10%

CAPACITY CREDIT

● Reduced MWe Credit	25 MWe	vs	50 MWe
● Different Unit Displacement	P.S. Hydro	vs	Pkg.
● Different Year	1997	vs	1995
● Different \$/kWe (1985)	675	vs	300
● Fixed Charge Rate (%)	14.6	vs	20

OPERATING STRATEGY

- 1982 - 84 25 MWe Fossil All times
- 1985 - 86 25 MWe Fossil 50% Time
- Warm Start Operation

TABLE 5.2-2 Fuel Cost Assumptions (\$/MBTU)

	<u>TASK 1400</u>			<u>TASK 1100</u>
	<u>(1977)</u>	<u>(1985 @ 7%)</u>	<u>(1985 @ 15.5%)*</u>	<u>(1985)</u>
#2 Oil	2.697	4.63	8.54	5.50
#6 Oil	1.762	3.02	5.58	5.00
Coal	.872	1.49	1.49	2.00
Nuclear	.343	.59	.59	1.25

*Oil escalated at 15.5%/year from 1977 to 1985,
other fuels escalated at 7%.

For the Task 1400 analysis, detailed modelling of the operation of the repowered plant and the PNM system was performed for several discrete years, beginning in 1981. The penalty for the loss of the Reeves No. 2 unit during repowering was estimated. Also, the operating strategy was varied from year to year, requiring 25 MWe of fossil firing any time the solar side was being used in years 1982-1984, and requiring the same operating strategy 50 percent of the time in the years 1985-1986. Beyond 1986 the repowered plant was allowed to operate in the most economical mode. In Task 1100, economic mode operation was assumed throughout the life of the plant. Also in Task 1100, 1985 plant introduction was assumed. For Task 1400, a detailed PNM expansion plan for conventional generation was used.

The methodology developed by Westinghouse for EPRI under study RP 648-1 was used for the analysis in Task 1400 as well as 1100. However, in this task much more detailed simulation was utilized.

5.3 PNM SYSTEM DESCRIPTION

The detailed analysis reported in this section was performed based on a model of the Public Service Company of New Mexico system. As reported in Section 2, this is a summer peaking system with a moderate nuclear/coal base (see Figure 2.5-1).

In the years from 1982 through 1987, most of the capacity additions were in the form of nuclear and coal plants with a pumped storage hydro facility being added toward the end of that period. The 1985 peak demand was estimated to be around 1500 MWe.

An example of the fuel displaced by the repowered plant, for economic operation in 1985, is shown in Table 5.3-1. Because the repowered plant operates on weekends and during low load seasons of the year, it displaces energy generated by coal as well as oil plants, as shown in the table. During these periods, the repowered plant is still more economical to operate than the competing coal plants because of the minimal solar operating cost.

TABLE 5.3-1. CONVENTIONAL ENERGY DISPLACEMENT

Task 1100 Methodology
(1985 Installation)

<u>Plant Type</u>	<u>% Energy Displaced</u>	<u>% \$ Value</u>
Coal	23	15
Oil	77	86

5.4 RESULTS

Several analyses were performed in this task using the methods and assumptions previously described. Sensitivities were performed on several critical parameters as shown in Table 5.4-1. These include oil escalation rate, repowered plant life, repowering cost and alternate methods of analysis. The latter sensitivity was to use the methods used in 1100 with the 1400 assumptions to compare with the more detailed 1400 analysis.

The results given in this section will be presented primarily in 1978 dollars as opposed to the 1985 dollars used in Section 2.5.

The impact of varying the repowering capital cost is shown in Table 5.4-2. This table shows the reference given in Section 5.1 and a deviation of plus and minus 25 percent. The cost numbers shown are the present worth of the revenue requirements to support the repowering investment. A 30-year repowered life is assumed.

Three different fuel escalation scenarios were evaluated. For each of the scenarios, fuels other than oil were escalated at 7 percent per year. For the first scenario oil was also escalated at 7 percent. For the second scenario oil was escalated at 15.5 percent per year from 1977 to 1985, and then at 7 percent from 1985 on. The third scenario assumed a 15.5 percent escalation rate for oil from 1977 through the life of the repowered plant. The results are given in Table 5.4-3.

Even though the oil escalation rate is changed significantly, the cost/benefit is altered only slightly. The change in cost/benefit will not be significant as long as the oil displaced by the repowered plant is approximately equal to that consumed. With the 15.5 percent oil escalation rate the nature of the present worth calculation emphasizes the latter years of plant operation. During these years the oil displaced by the repowered plant is slightly smaller than that consumed. Therefore, the fuel cost increases more than the fuel savings, resulting in a slightly smaller overall plant value. In the 15.5/7 percent case the early years of plant operation are emphasized, again due to the nature of the

TABLE 5.4-1. TASK 1400 CASES

FUEL ESCALATION RATES

- Oil - 7% Post 1977
- Oil - 15.5% Post 1977
- Oil - 15.5% 1977-85, 7% 1985-

REPOWERED PLANT LIFE EXPECTANCY

- 30 Years Post Repowering
- 20 Years Post Repowering
- 15 Years Post Repowering

REPOWERING COST

- Reference
- Reference + 25%
- Reference - 25%

ALTERNATE METHODS OF ANALYSIS

- Detailed Annual, 1981-
- Detailed 1985, Projections

TABLE 5.4-2. COST/VALUE VS REPOWERING CAPITAL COST
 30 Year, 7% Escalation, 1978 M\$
 (Present Worth of Revenue Requirements)

	<u>-25%</u>	<u>Ref</u>	<u>+25%</u>
Solar Plant Cost			
STC Plant Cost	93.6	124.8	156.0
STC Plant O&M	5.9	5.9	5.9
STC Total	<u>99.5</u>	<u>130.7</u>	<u>161.9</u>
Solar Plant Value			
Fuel Value	16.9	16.9	16.9
Variable O&M	1.7	1.7	1.7
STC Fuel Cost	-8.4	-8.4	-8.4
Capacity Credit	5.7	5.7	5.7
Total Value	<u>15.9</u>	<u>15.9</u>	<u>15.9</u>
Net Value	-83.6	-114.8	-146.0
Cost/Benefit	6.3	8.2	10.2

TABLE 5.4-3. COST/VALUE VS FUEL OIL ESCALATION RATE
 30 Year, 1978 M\$
 (Present Worth of Revenue Requirements)

	<u>7%</u>	<u>15.5/7%</u>	<u>15.5%</u>
Solar Plant Cost			
STC Plant Cost	124.8	124.8	124.8
STC Plant O&M	5.9	5.9	5.9
STC Total Cost	<u>130.7</u>	<u>130.7</u>	<u>130.7</u>
Solar Plant Value			
Fuel Value	16.9	23.3	33.2
Variable O&M	1.7	1.7	1.7
STC Fuel Cost	-8.4	-14.4	-24.9
Capacity Credit	5.7	5.7	5.7
Total Value	<u>15.9</u>	<u>16.3</u>	<u>15.7</u>
Net Value	-114.8	-114.4	-115.0
Cost/Benefit	8.2	8.0	8.3

present worth calculations. However, during these years the repowered plant displaces more oil than it consumes, resulting in a slightly higher total value. This change in net oil savings is due to the significant amount of coal added in the latter years. In all cases investigated, the combined savings in coal and oil justified the oil consumed by the solar repowered plant.

The sensitivity of cost and value to repowered plant life is given in Table 5.4-4. Life expectancies of 15, 20, and 30 years past repowering were investigated. A strong incentive to assure substantial plant life is seen.

The detailed methodology used in Task 1400 is compared with that used in Task 1100, in Table 5.4-5. The 1400 methodology assumed beginning operation in 1982 with phasing in of the economic dispatch mode. The 1100 methodology assumed 1985 operation with immediate economic dispatch. This difference in operating mode during the early years of plant life is one of the reasons why the 100 methodology produced a better cost/benefit. The capacity credit differs between the two methodologies because the number of years of capacity displacement are different. There are 18 years of capacity displacement in the 1100 methodology and only 15 years in the 1400.

For comparison with the repowering cost assumptions used in Task 1100, the same capital cost basis was used (DOE heliostat goal) and the cost/benefit calculated using the detailed modelling from Task 1400. A comparison of results using the demonstration (1400) and commercial (1100) cost assumption is shown in Table 5.4-6. The substantial difference in the repowered plant cost is the reason for the significant change in cost/benefit. In the commercial/DOE goal cost assumption, the repowered plant O&M was assumed to be the same as that revised for Task 1400. Both plant values reflect restrained operation in the early years of plant life.

Again, one should be conscious of the fact that the repowering costs used in the Task 1400 analysis were based on a first demonstration plant, and that economic dispatch was restrained for the first few years.

TABLE 5.4-4. COST/VALUE VS REPOWERED PLANT LIFE
7% Escalation, 1978 M\$
(Present Worth of Revenue Requirements)

	<u>30 Yr</u>	<u>20 Yr</u>	<u>15 Yr</u>
Solar Plant Cost			
STC Plant Cost	124.8	119.6	109.4
STC Plant O&M	<u>5.9</u>	<u>4.7</u>	<u>3.8</u>
STC Total Cost	130.7	124.3	113.2
Solar Plant Value			
Fuel Value	16.9	14.1	12.2
Variable O&M	1.7	1.3	1.0
STC Fuel Cost	-8.4	-7.5	-6.9
Capacity Credit	<u>5.7</u>	<u>2.9</u>	<u>0.0</u>
Total Value	15.9	10.8	6.3
Net Value	114.8	113.5	-106.9
Cost/Benefit	8.2	11.5	18.0

TABLE 5.4-5. COST/VALUE VS METHODOLOGY
 30 Year, 7% Escalation, 1978 M\$
 (Present Worth of Revenue Requirements)

	<u>Task 1400</u>	<u>Task 1100</u>
Solar Plant Cost		
STC Plant Cost	124.8	111.9
STC Plant O&M	5.9	5.6
STC Total	<u>130.7</u>	<u>117.5</u>
Solar Plant Value		
Fuel Value	16.9	20.5
Variable O&M	1.7	1.1
STC Fuel Cost	-8.4	-10.1
Capacity Credit	5.7	6.1
Total Value	<u>15.9</u>	<u>17.6</u>
Net Value	-114.8	-99.9
Cost/Benefit	8.2	6.7

TABLE 5.4-6. COST/VALUE VS PLANT COST
 30 Year, 7% Escalation, 1978 M\$
 (Present Worth of Revenue Requirements)

	<u>Demonstration</u>	<u>Commercial/DOE Goal</u>
Solar Plant Cost		
STC Plant Cost	124.8	40.6
STC Plant O&M	5.9	5.9
STC Total Cost	130.7	46.5
Solar Plant Value		
Fuel Value	16.9	16.9
Variable O&M	1.7	1.7
STC Fuel Cost	-8.4	-8.4
Capacity Credit	5.7	5.7
Total Value	15.9	15.9
Net Value	-114.8	-30.4
Cost/Benefit	8.2	2.9

The work performed and results from this task point to the necessity for detailed modelling of the specific power system (utility) involved to determine the impact of solar repowering.

6.0 PROGRAM PLANNING, FUTURE PHASES

The results of the market survey of southwestern utilities (Section 2.0) indicate that a large potential market exists for the solar hybrid repowering concept if the approach can be successfully demonstrated and proven to be economically attractive. Likewise, the cost/benefit analysis results (Section 2.0) have indicated that the solar hybrid repowering concept has the potential to be economically attractive for utility applications when compared with conventional methods of electric power generation. PNM therefore believes that a timely demonstration of the solar hybrid repowering concept is mandatory to the acceptance and future commercialization of solar energy within the utility industry. In addition, PNM believes the demonstration can ultimately provide the stimulation needed for solar energy to enhance the conservation of our dwindling oil and natural gas reserves to reduce our nation's severe foreign oil dependence, achieve the earliest commercialization of solar components as well as to introduce earliest direct utility participation in commercializing solar energy, extend the life and use of existing generation equipment, utilize present generation sites wherever adjacent land is available, reduce fossil fuel emissions at existing sites, improve present generation mix, determine hybrid operating principles, and minimize backup requirements for early solar thermal electric plants.

The program plan presented in this section to implement the factors noted above includes the objective, project and major task description, the management plan and work breakdown structure.

The program plan is structured to provide appropriate visibility and control of all technical effort, schedules and costs. It utilizes the Work Breakdown Structure approach and anticipates control documents, such as design requirements and interface control drawings, to assure a successful demonstration of the solar hybrid repowering concept. It recognizes and accommodates the acquisition, analysis and reporting of data vital to the repowering program.

6.1 OBJECTIVE

The principal objective is to establish the technical viability and economic attractiveness of the solar hybrid repowering concept and widespread utility application. The specific objectives are:

- Preparation of the detailed design of the solar repowered plant.
- Construction of the solar repowered plant.
- Successful start-up and operation of the solar repowered plant for a period of two years, with five years optional.
- Timely dissemination of the progress and the results of the program to other utilities, industries, and government agencies to enhance the early commercialization of solar repowering.

6.2 PROJECT AND MAJOR TASK DESCRIPTION

The program to implement the solar hybrid repowering concept is divided into six principal phases: These phases are:

- Phase 1 - Technical/Economic Assessment
- Phase 2 - Design
- Phase 3 - Procurement
- Phase 4 - Construction
- Phase 5 - Checkout
- Phase 6 - Operation

Figure 6.2-1 presents the schedule for the proposed program.

The Phase 1 portion of the program is completed with the issuance of this final report; the following output will be available to initiate the Phase 2 Design:

- A market survey and cost/benefit analysis.
- A specific site selected for the solar repowering program.
- A conceptual design of the solar repowered unit.
- A cost estimate for the unit.

Phase 2 through Phase 5 are scheduled over a 42 month period. A two year operating period (Phase 6) is also planned, the option for DOE to continue the operations period for a longer time period should be reevaluated once successful operation of the unit has been achieved.

The foundation of the proposed program is Phase 2, Design. The solar repowering system for Unit No. 2, located at Reeves Station, will be designed, fabricated and constructed on the basis of the central receiver technology. Major components such

Figure 6.2-1. Detailed Schedule for Solar Hybrid Repowering Program

as the heliostat system, the receiver system, and potentially the master control system will have been operationally demonstrated to varying degrees of maturity as part of the solar central receiver 10 MWe Pilot Plant Program. Successful and timely accomplishment of project objectives requires detailed technical and programmatic coordination during the project and, in particular, during Phase 2 Design. A project management organization will, therefore be established at project initiation to provide necessary technical and programmatic coordination.

Early in the first quarter of the first year, the Project Plan, which includes the Work Breakdown Structure (WBS) will be finalized and submitted to DOE for approval. The Project Plan will be updated/revised during the performance of the project. As a minimum, the plan will be updated at the end of preliminary engineering prior to the start of construction and prior to unit checkout.

PNM will secure use of the required adjacent land for the life of the project during Phase 2. The necessary plans, including site preparation and site access will be formulated. PNM is measuring the direct normal insolation and other climatological data at the site; this is being performed as a portion of the West Solar Resource Data Evaluation Project. This effort will be continued and it is further planned that all data collected will be transferred to the SERI data bank for utilization and integration into that program.

The preliminary design for the solar subsystem, the master control subsystem, the modifications to the existing plant equipment, and support facilities is to be prepared during Phase 2; this effort will require coordination with the DOE, 10 MWe Pilot Plant design teams throughout this project, particularly during preparation of a preliminary design document. Two preliminary design reviews are contemplated during Phase 2 to afford DOE maximum project visibility. Specifications parameters for the plant equipment and support facilities will be defined during Phase 2.

A unit layout will be prepared based on the conceptual design resulting from the Phase 1 Assessment. The preliminary design requirements for the plant and support facilities will be defined. A preliminary system design will be prepared from which design specifications for the component hardware can be formulated. An interface control drawing will be maintained throughout the project and will be modified to incorporate mandatory plant design changes.

An environmental assessment will be made within the scope of Phase 2. Furthermore, during Phase 2, all aspects of the solar plant designs and development data of the 10 MWe Pilot Plant will be considered. The findings at this review will be utilized in the selection of components and systems for the design of the pre-commercial unit.

Phase 3 will commence with the preparation of specifications for the solar subsystem, the master control subsystem, the modification to the existing plant equipment, and the support facilities.

Procurement will be initiated early to allow for long lead times. Activities will include vendor surveys, bid package preparation, vendor selection, purchasing, expediting, inspecting, and quality assurance. Special attention will be given to the procurement of potentially long lead items such as heliostats, receiver and control system components.

Phase 4 encompasses the construction which could start as early as May 1979. A detailed construction schedule for Phase 4 will be prepared to cover the solar subsystem, the master control subsystem, the modifications to existing plant equipment and support facilities. Principal items of work will be incorporated in this schedule. Additional charts will be prepared, as considered necessary, to schedule the construction of particular areas in greater detail.

Phase 5 involving checkout of the unit and all support subsystems, is scheduled to occur during the first two quarters of the fourth year. The solar subsystems will be checked out during this time. The unit startup tests will be performed during the fourth quarter of the fourth year.

The repowered unit, although intended to operate as an on-line power unit in the PNM system, is a first-of-a-kind system. In formulating this program plan, therefore, a number of tests have been identified which encompass the regime from component and subsystem operation verification to unit checkout and test and to normal and emergency operating performance tests. A test plan will be prepared with appropriate revisions being incorporated as required during subsequent phases. The test plan will include:

- Startup tests and checkout
- Acceptance tests for the solar subsystem
- Data acquisition system validation
- Modification of computer simulation model
- Steady state and transient performance tests

Phase 6 Operation will be defined in detail during Phase 2 of the program. However, the operation task of the program has been considered in sufficient detail to permit base estimates of manpower requirements to summarize the effort needed during the initial phases. It is currently envisioned that the utility operations would be studied by PNM and DOE for approximately two years.

Personnel for the operation and maintenance crews will be selected, utilizing a thorough screening and testing process. The test engineering team, a necessary requirement during the operations task, will be selected from personnel having extensive backgrounds in the startup and testing of a first-of-a-kind power plant. Training of supporting PNM personnel will be an objective of the team effort.

The operation, maintenance, and testing crews will be given thorough training and testing during the startup task in preparation for their responsibilities. The actual equipment manuals will be used by the operators in the preparation for checkout as well as plant operation, and maintenance crews will work with the construction, installation and erection crews as components and subsystems are completed and operated in their respective checkout modes. Hence, as

larger subsystems are made operational and until the total pilot plant has been carried through the checkout and startup mode, the operation crew will be assuming greater responsibility and acquiring full familiarity with their assignments.

Pertinent data will have been generated during the startup and checkout activities and these data will be recorded, analyzed and reported. Technology transfer, Public Relations, and other like functions assisting and promoting the commercialization efforts are also included.

HELIOSTAT MARKETING PRODUCTION SCHEDULE

Utility response to the survey presented in Section 2.0 indicates a definite interest in solar hybrid repowering of existing power plants. Section 2.0 further defines this interest to show that 82 units corresponding to approximately 5189 MWe (≤ 200 MWe unit size) are considered as candidates for solar repowering efforts. Heliostat production capability must be developed to allow accomplishment of such an endeavor. The approximate level of heliostat production required to achieve solar repowering within a ten year time frame (1980 to 1990) has therefore been determined. Due to unique plant site constraints and criteria, approximations and assumptions must be introduced into any heliostat production level number.

The baseline for the number of heliostats required per MWe is derived from the equinox noon insolation heliostat requirement for the 100 MWe Commercial Plant. Solar multiples for thermal storage capability have been removed to provide a net of approximately 13,500 heliostats for 100 MWe (net). Naturally, other plants may be designed for either winter or summer solstice.

In such cases, heliostat quantities may vary considerably. Solar insolation available at each plant site and solar field optimization studies may also have an impact on the levelized heliostat production requirement. Figure 6.2-2 indicates the approximate heliostat quantities per MWe (net) that could be experienced based on an insolation level of 950 W/m^2 .

Figure 6.2-2. Number of Collectors vs. Power Output

Figure 6.2-3. Average Annual Heliostat Production Range
(Based on Solar Hybrid Repowering of 5189 MWe in Ten Years)

Efficiencies of the larger plants (~ 100 MWe) can be considered higher than those in the lower MWe ranges. These efficiency variations have been accounted for in the range of average annual heliostat production shown in Figure 6.2-3.

Productivity of heliostat installation will be determined by such considerations as plant location, labor availability, local weather conditions during construction, etc. Applying an arbitrary productivity factor to heliostat installation time produces the curve "Estimated Productivity Adjusted Line" shown in Figure 6.2-4.

The MDAC Preliminary Report for the 100 MWe Commercial Plant optimized onsite heliostat assembly at 60 per day. The values in Figure 6.2-5 were determined using the 60 heliostat per day per plant site capability to estimate time durations for the 82 units. The figure is not an attempt to schedule particular plants for solar repowering, but an indication of quantities of engineering and construction starts per year to fully utilize the levelized heliostat yearly production.

An average annual heliostat production level of between 70,000 to 80,100 could be anticipated in order to accomplish solar repowering of 82 units representing approximately 5189 MWe.

Thermal storage capability, unique efficiencies that vary with plant site and operating characteristics, locale, and local solar insolation levels will vary heliostat requirements and consequently have an impact on the annual heliostat production level. Productivity for smaller unit heliostat installation would not be anticipated to be as high as for the larger units; it will also vary by locale.

With an annual heliostat production of 80,100 and single plant unit installation capability of 60 heliostats per day, five different sites could be simultaneously under construction for solar repowering. Figure 6.2-5 tends to indicate a heliostat production dropoff in the tenth year. The variables previously mentioned would tend to increase the tenth year production by increasing either installation time or heliostat quantities per unit.

Figure 6.2-4. Helikostat Installation Time vs Plant Size

Figure 6.2-5. Heliostat Installation Durations

6.3 MANAGEMENT PLAN

Public Service Company of New Mexico will manage the Solar Repowering Program with the objective of:

- Full compliance with contractual and reporting commitments.
- Implementation of the technology of solar repowering.
- Strict cost and schedule control.
- The widest practical dissemination of results and data.

The organization structure for performing the program is shown in Figure 6.3-1. The Public Service Company of New Mexico will be responsible for the project and will conduct the project in a manner consistent with other successful utility oriented development projects. PNM will identify a Project Manager who will be responsible for the technical and programmatic direction of the project through all aspects. In addition he will be responsible for all utility operations which will primarily include the preparation of functional design requirements, the preparation of the environmental impact assessment and the overall program technical, cost and schedular control. He will have single-point management responsibility and commensurate authority for the project.

The Project Manager's responsibilities are to meet all technical, cost, and schedular objectives. Within the scope of the contract, he will have complete freedom and flexibility to allocate his assigned resources to meet program goals, and he is the principle PNM decision-maker for daily project activities. He will be supported by an architect engineering firm who will be responsible for the architect-engineer services which will include the preparation of the engineering design (including site preparation, facility layout, civil structural work, balance of plant, and arrangement/piping), equipment procurement, construction management/construction, modifications to the existing plant and facilities, plant checkout quality assurance, and project planning and scheduling.

Figure 6.3-1. OVERALL PROGRAM ORGANIZATION

The Project Manager also will be supported by a system engineering firm who will be responsible for the system engineering and project integration which will include the system design and integration, the solar system design coordination, technical inputs to the master control and data acquisition system design, the turbine generator and turbine generator control system design modification, the performance of impact assessments including safety, operational, and network, the test engineering in support of the unit operation, and the project integration including maintaining the work breakdown structure.

It is suggested that to effectively accomplish the program a cooperative agreement be executed between PNM and DOE for the direction of the project. A Solar Project Operating Committee (SPOC) will be formulated as part of the cooperative agreement to assist the PNM Project Manager in his direction of the project. Membership of the SPOC will consist of key management personnel from PNM. The SPOC is responsible for the overall project as a joint DOE-utility endeavor in accordance with the terms of the contract. It is the executive decision-making authority for all matters not specifically delegated and entrusted to the PNM Project Manager. The committee, in addition to its role to direct, advise, and counsel, represents the project administratively to other functional elements of PNM. The committee is the decision-making authority for the project on all matters referred to it, including those which cut across functional or departmental lines. The Operating Committee will receive periodic reports from the Project Manager and will regularly review project progress.

A number of utilities will participate in an advisory capacity to PNM as part of the utility council. PNM recognizes that one of the most important objectives of the project is the timely dissemination of the progress and results of the project to the utilities committed to the solar repowering program. The direct participation by the utilities in the project will assure that the required technical expertise within the utility industry exists in order to achieve an aggressive fossil fuel displacement goal. In addition, direct utility participation, particularly during the engineering stage, is mandatory to ensure that the design of the repowered unit does not restrict its applicability to other utility systems.

Major functions of program management are:

- Program Plan
- Work Initiation
- Monitoring of Project Progress
- Variance (from Plan) Resolution
- Reporting (to DOE)

These principal elements of successful program management are performed in accordance with the logic illustrated in Figure 6.3-2. The Program Plan provides definition of the program effort in detail in the Work Breakdown Structure. This, along with the schedules and budgets for these subtasks, will provide a consistent set of directions for all program participants.

There also will be related technical direction and control documents that are important parts of the planning element. These include the Design Requirements, which translate the contractual requirements into design directives, and the Interface Control Drawings, which define the physical and other interrelationships between subsystem responsibilities. These also become control documents and are updated, as required, as the program proceeds.

The monitoring effort by PNM will encompass management reviews at each sub-contractor organization, analysis of technical progress against the Program Plan and Design Requirements to identify any variance, and cost/schedule analysis against the Program Plan milestones and budgets. The results of the monitoring activities will be provided to the Project Managers.

The results of the monitoring activity will be reviewed at Project Manager review meetings. In addition to a project status review, the Project Managers will take action to resolve the delinquent items. In the event that the needed corrective action impacts the contract requirements, schedule or budget; the recommended change will be submitted to DOE. On receipt of

Figure 6.3-2. Program Management and Control Logic

DOE approval, the Program Plan and other affected control documents will be updated and the change will be implemented.

6.3.1 WORK BREAKDOWN STRUCTURE

A preliminary Work Breakdown Structure (WBS) developed on a subsystem basis is provided in Tables 6.3-1 and 6.3-2 to define the content of the Solar Hybrid Repowering Program. PNM has overall responsibility for all work performed as previously indicated in the project organization.

6.3.2 PROGRAM PLAN

PNM will prepare a Program Plan reflecting the contractual commitments as negotiated. The Program Plan will consist of the management plan, the work breakdown structure, the schedule and milestone chart, and the cost schedules, and manpower control plan. The Plan will be submitted to DOE within 45 days after contract initiation. When approved by DOE, the Plan will be utilized as a "controlled document" under which the project will be executed. The Plan will be updated, as required, through the procedure described in Subsection 6.3.5. The Plan will define the Work Breakdown Structure, schedules and milestones, and budgets for each level two WBS tasks. Further detail breakdowns into manageable work packages (levels three and four) will be implemented for internal management and control of the work.

SCHEDULE

The project schedule is presented in Section 6.2. A further breakdown of schedules and milestones will be prepared, as necessary, for use in managing and controlling the program. PNM will hold periodic review meetings consisting of discussions of the program status relative to achieving the milestones, the technical status including the resolution of interface problems, and a detailed review of the technical work completed. In addition, the PNM Project Manager will hold project review meetings as required to resolve major issues impacting the milestone schedule.

TABLE 6.3-1. WORK BREAKDOWN STRUCTURE OUTLINE

11 SOLAR COLLECTORS

111 Engineering

111211 General

111211J001 Preliminary Design of Collectors

111221 Heliostat Equipment

111221J001 Prepare Specs

111221J002 Equipment Selection

111221J003 Procurement

111222 Heliostat Controls

111222J001 Prepare Specs

111222J002 Equipment Selection

111223 Heliostat Foundations/Pedestal

111223J001 Detail Design

111223J002 Prepare Specs

111223J003 Procurement

112 Construction

112221 Heliostat Equipment

112221D001 Fabrication and Installation

112222 Heliostat Controls and Power

112222F001 Electrical

112222N001 Instrumentation

112223 Heliostat Foundations/Pedestal

112223A001 Earthwork

112223B001 Concrete

112223C001 Steel

112241 Quality Assurance

112241H001 Quality Assurance

12 RECEIVER

121 Engineering

121211 General

- 121211J001 Preliminary Design CF Receiver
- 121211J002 Preliminary Design of Tower

121221 Engineering - Receiver

- 121221J001 Prepare Spec
- 121221J002 Equipment Selection
- 121221J003 Procurement

121224 Engineering Tower

- 121224J001 Detail Design
- 121224J002 Prepare Spec
- 121224J003 Equipment Selection
- 121224J004 Procurement

121225 Engineering - Piping and Pipe Rack

- 121225J001 Detail Design
- 121225J002 Prepare Spec
- 121225J003 Equipment Selection
- 121225J004 Procurement

121226 Engineering - Auxiliary Equipment

- 121226J001 Detail Design
- 121226J002 Equipment Selection
- 121226J004 Procurement

122 Construction

122222 Receiver

- 122222C001 Structural Steel
- 122222D001 Equipment
- 122222E001 Piping
- 122222G001 Painting

122224 Tower

- 122224A001 Earthwork
- 122224B001 Concrete
- 122224C001 Steel
- 122224C002 Elevator
- 122224E001 Main Stream Piping

- 122224E002 Feedwater Piping
- 122224E003 Other Piping
- 122224F001 Electrical
- 122224G001 Painting

122226 Auxiliary Equipment

- 122226001 Auxiliary Equipment

122241 Quality Assurance

- 122241H001 Quality Assurance

122251 Checkout/Startup

- 122251M001 Checkout/Startup

13 THERMAL STORAGE

131 Engineering

131211 General

- 131211J001 Preliminary Design CF System

131221 Thermal Storage Equipment

- 131221J001 Prepare Specs
- 131221J002 Equipment Selection
- 131221J003 Procurement

132 Construction

132221 Thermal Storage Unit

- 132221A001 Earthwork
- 132221B001 Concrete
- 132221C001 Steel
- 132221D001 Equipment
- 132221E001 Piping
- 132221F001 Electrical
- 132221G001 Painting
- 132221N001 Instruments
- 132221P001 Insulation

132241 Quality Assurance

- 132231H001 Quality Assurance

132251 Checkout

- 132251M001 Checkout

14 CONTROLS AND INSTRUMENTS

141 Engineering

141211 General

- 141211J001 Preliminary Design of Control Systems
- 141211J002 Preliminary Design of Instrumentation

141228J1 Control System

- 141228J101 Master Control Computer - Design & Prepare Specs
- 141228J102 Data Acquisition System - Design & Prepare Specs
- 141228J103 Analog System Design and Prepare Specs
- 141228J104 Interface Logic System Design and Prepare Specs
- 141228J105 Control Systems Procurement

14228J2 Instrumentation

- 141228J201 Control Panel - Design and Prepare Specs
- 141228J202 Turbine Control System - Design & Prepare Specs
- 141228J203 Annunciator - Design and Prepare Specs
- 141228J204 Boiler Combustion Controls - Design & Prepare Specs
- 141228J205 Other Instrumentation - Design and Prepare Specs

142 Construction

14228 Installation of Controls and Instrumentation

- 142228N001 Control Systems Installation
- 142228N002 Instrumentation Installation and Hookup

142241 Quality Assurance

- 142241H001 Quality Assurance

142251 Checkout

- 142251M001 Checkout

15 BALANCE OF PLANT

151 Engineering Balance of Plant

151212 Systems Engineering

- 151212J101 Prepare Functional Design Requirements
- 151212J102 Prepare System Design Specs
- 151212J202 Prepare Integrated Plant Layout
- 151212J203 Prepare Interface Control Drawings
- 151212J204 Prepare Overall System Flow Diagram
- 151212J301 Perform Systems Studies and Transient Analysis

- 151212J401 Perform Reliability Studies
- 151212J402 Perform Transient Analysis
- 151212J501 Prepare Design Plans
- 151212J502 Prepare Quality Assurance Plans
- 151212J503 Prepare Procurement and Construction Plans
- 151212J504 Prepare Plant Checkout Plan
- 151212J505 Data Acquisition Plan
- 151212J506 Prepare Operations Test Plan

151213 Site Engineering

- 151213J001 Permits and Approvals
- 151213J002 Prepare Site Preparation Plan
- 151213J003 Prepare Facility Plan
- 151213J004 Prepare Public Awareness Plan
- 151213J005 Periodic Review and Update of Plan
- 151213J006 Prepare Site Specs
- 151213J007 Prepare Facility Specs
- 151213J008 Facility Design
- 151213J009 Prepare Test Plan to Acquire Site Data
- 151213J010 Perform Tests
- 151213J011 Analyze and Report Data
- 151213J012 Establish/Maintain Site Data Bank
- 151213J013 Site Data Dissemination
- 151213J014 Site Data Preparation
- 151213J015 Perform Environmental Assessment
- 151213J016 Prepare Impact Statement

152 Construction Balance of Plant

152229 Demolition

- 152229T001 Demolition

152230 Modifications to Existing Structures and Equipment

- 152230F001 Electrical
- 152230F002 Relocate Transmission Lines

152231 New Work

- 152231A001 Earthwork-Site Grading
- 152231A002 Earthwork-Underground Diversion
- 152231A003 Earthwork-Roadways and Fence
- 152231B001 Concrete
- 152231C001 Buildings
- 152231C002 Warehouse
- 152231D001 Equipment
- 152231E001 Piping
- 152231F001 Electrical
- 152231G001 Painting

152251 Checkout

152251M001 Checkout

16 ELECTRICAL POWER GENERATION SYSTEM

161 Engineering

161214 Preliminary System Design

161214J001 Prepare Design Requirements

161214J002 Prepare Preliminary Design of Existing System

161215 System Design and Modification

161215J001 Detail Design

161215J002 Prepare Specs

161215J003 Equipment Selection

161215J004 Procurement

161216 Component Design

161216J001 Mechanical

161216J002 Electrical

161216J003 Civil/Structural

161216J004 Piping/Instrument Design

161216J005 Control System Design

161216J006 Procurement

162 Construction

162229 Demolition

162229T001 Demolition

162230 Modifications to Existing Structures and Equipment

162230A001 Earthwork

162230B001 Concrete

162230C001 Buildings and Structures

162230D001 Process Equipment

162230E001 Piping

162230F001 Electrical

162230G001 Painting

162230L001 Plant Items

162230N001 Instrumentation

162230P001 Insulation

162231 New Work

162231AUU1 Earthwork

162231B001 Concrete

- 162231C001 Buildings and Structures
- 162231D001 Equipment
- 162231E001 Main Steam Piping
- 162231E002 Feedwater Piping
- 162231E003 Other Piping
- 162231F001 Electrical
- 162231G001 Painting
- 162231L001 Plant Item
- 162231N001 Instrumentation
- 162231P001 Insulation

162241 Quality Assurance

- 162241H001 Quality Assurance

162251 Checkout

- 162251M001 Checkout

17 DISTRIBUTABLES

173 Field

17300 Indirect Expense

- 173700H001 Field Expense
- 173700H002 All Risk Insurance Payroll Tax, Bond
- 173700K001 Construction Supplies
- 173700S001 Temporary Facilities

173900 Escalation, Contingency, Contractor's Fee

- 173900Y001 Escalation
- 173900Y002 Contingency
- 173900Y003 Construction, Contractor's Fee/G&A

176 Management

176771 Administration

- 176771J001 Project Management
- 176771J002 Cost/Schedule Control
- 176771J003 Engineering Change Control

176772 Planning

- 1761772J001 WBS Extension Review and Upgrade

176773 Reporting

- 176773J001 Technical Reports
- 176773J002 Financial Reports
- 176773J003 Topical Reports

176774 Overall Quality Control

176774J001 Design Review
176774J002 Meetings and Reviews

176775 Other Expenses

176775J001 Travel
176775J002 Communications
176775J003 Reproductions
176775J004 Computer
176775J005 Postage
176775J006 Other Expenses

176976 Fees

176776Y001 Participants' Fees/G&A
176976Y002 Engineering Fees/G&A
176976Y003 Consultants' Fees/G&A

18 PLANT OPERATION AND MAINTENANCE

184 Operation and Maintenance

184081 Operating Crew

1840810001 Define Requirements
1840810002 Operating Crew Cost Estimates
1840810003 Crew Selection
1840810004 Crew Training Manuals
1840810005 Crew Training

184082 Manuals

1840820001 Operating Plan and Manual
1840820002 Maintenance Plan and Manual

184083 Operation

1840830001 Total Plant Checkout and Startup
1840830002 Operations - Test and Power
1840830003 Operational Analysis and Reporting

184084 Spare Parts

184084U001 Spare Parts

184085 Special Equipment

1840850001 Heliostat Wash Truck

TABLE 6.3-2. EXPLANATION OF ACCOUNT NUMBER SYSTEM

Major Systems Number (Position 2):

- 1 Solar Collectors
- 2 Receiver
- 3 Thermal Storage
- 4 Master Control and Data Acquisition System
- 5 Balance of Plant
- 6 EPGS
- 7 Distributables
- 8 Plant Operations and Maintenance

Major Category Designation (Position 3):

- 0 Dummy
- 1 Engineering
- 2 Construction
- 3 Distributables
- 4 Operations
- 5 Land
- 6 Managerment

FPC Number (Position 4):

- 0 Dummy
- 1 Structures and Improvements
- 2 Process Equipment
- 7 Indirect Costs
- 9 Escalation, Contingency and Fee

Subsystem Numbers (Positions 5 & 6):

00	Dummy
11	General Engineering
12	System Engineering
13	Site Engineering
14	Preliminary System Design
15	System Design & Modification
16	Component Design
21	Major Equipment
22	Controls
23	Foundations
24	Tower
25	Riser/Downcomer
26	Other/Auxiliary Equipment
27	Steel
28	Master Control & Data Acquisition System
29	Demolition
30	Modification
31	New Work
41	Quality Assurance
51	Checkout
61	Distributables
71	Administration
72	Planning
73	Reporting
74	Overall Quality Control
75	Other Expenses
76	Fees
81	Operating Crew
82	Manuals
83	Operation
84	Spare Parts
85	Special Equipment

ABC Designation (Position 7):

A	Earthwork
B	Concrete
C	Buildings & Structures
D	Process Equipment
E	Piping
F	Electrical
G	Painting
H	Field Expense
J	Engineering
K	Construction Supplies
L	Plant Items
M	Startup
N	Instruments & Controls
P	Insulation
Q	Sales Taxes
R	Premium Pay
S	Temporary Facilities
T	Demolition
U	Spare Parts
V	Craft Personnel - Maintenance Cost
W	Construction Equipment
X	Extras
Y	Additional Expense

6.3.3 REPORTING

PNM will provide to DOE monthly reports on the technical and financial status of the project. The first report will be provided within 60 days of contract initiation. The format of these reports will include:

- A cover page designating the contract, the contract number, and the period covered by the report.
- A brief statement of the contract content.
- A summary of technical progress during the report period.
- An update of the schedule and milestone chart.
- A discussion of any anticipated problems along with a summary of action for their resolution.
- A financial tabulation comparing cost to budget for each of the nine WBS tasks.

PNM will also provide topical reports as may be required to document significant project accomplishments. In addition, PNM will provide a report summarizing the results of each of the major tasks as well as a final report discussing the overall accomplishments of the programs.

6.3.4 BUDGETARY COST ESTIMATE

A budgetary cost estimate has been developed as a subtask of the Technical and Economic Assessment of Solar Hybrid Repowering. It encompasses the detailed engineering design, procurement, construction and test operation of a solar hybrid precommercial unit at Reeves Unit No. 2. The cost estimate is based upon the conceptual design cost estimate discussed in Section 4.0. It was assumed the most desirable presentation of data for DOE planning purposes was to reflect costs in terms of annual cash flow.

Cash flow data were determined by PNM for architect/engineer functions, project engineering, system integration and utility management. The budgetary cost estimate was developed in 1978 constant dollars, therefore, these values may be escalated as deemed appropriate by the reader. No contingency values were assumed in addition to the overall project costs; this cost estimate is assumed

to be of plus or minus 25 percent accuracy, a nominal conceptual design value. It was assumed that an October 1, 1978 start date would be appropriate for the study as the current assessment phase ends on September 30. It was also assumed that an approximate two-year test/operation period occurs in the 1982 through 1983 time frame. PNM operation and maintenance costs were accounted for in this period. AFUDC was not accounted for, nor was escalation during construction.

Figure 6.3-3 presents the anticipated cumulative cash flow as a function of time; the cash flow, as a function of time, is presented in Figure 6.3-4. The approximate dollar value associated with the precommercial unit at the conceptual design stage is \$88,533,000. The assumptions above should be noted when utilizing this value for budgetary planning purposes.

6.3.5 FINANCIAL INCENTIVES

Financial incentives can produce economic favoritism for utility deployment of one generation alternative versus others. It appeared appropriate to address this in a cursory fashion to indicate the potential impact of a strong and weak incentive with respect to solar hybrid repowering.

An analysis was performed to determine the impact of two different tax incentive measures. The first involved a shortened tax write-off period, from 28 to 15 years, and the second assumed an increase in the investment tax credit rate from 10 percent to 20 percent for the repowered plant.

The results of this analysis are shown in Table 6.3-3. The effects of these tax incentives are to decrease the effective levelized fixed charge rates. Using as a reference the case shown in Table 2.5-8, the impacts upon fixed charge rate, revenue requirements associated with plant capital cost, and resulting cost/benefit ratios are shown.

As would be anticipated, the investment tax credit is a much more effective incentive approach. To achieve the benefits shown, the assumption is that the utility is in a position to take full advantage of the tax credit. That is, if the utility had other tax write-offs adequate to reduce its tax obligation for the year to zero, then the additional tax credit would be of less benefit.

Figure 6.3-3. Anticipated Cumulative Cash Flow as a Function of Time

Figure 6.3-4. Cash Flow as a Function of Time

TABLE 6.3-3. TAX INCENTIVE ANALYSIS

1. 15 Year vs 28 Year Tax Write-Off
2. 20% vs 10% Investment Tax Credit

Impacts:

<u>Case</u>	<u>Levelized Fixed Charge Rate</u>	<u>Present Worth RP Plant Cost</u>	<u>Cost/ Benefit</u>
Ref.	18%	126.8 M\$	1.5
1.	16.64%	117.2 M\$	1.4
2.*	8.26%	58.2 M\$	0.9

*Provided the utility can utilize the credit in the year the plant is put into service.

The basis for the calculations shown are fundamental tax formula developed by Paul H. Jaynes in his book on revenue requirements entitled, "Profitability and Economic Choice."* The specific formula used was an extension to this which reflects normalized accounting procedures and variations in tax life.** The precise capitalization and accounting assumptions used were defined by PNM.

*Paul H. Jaynes, Profitability and Economic Choice, Iowa State University Press, Ames, Iowa, 1968.

**J.T. Day and T.A. Ochs, Economics Correspondence Course, Westinghouse Electric Corporation, East Pittsburgh, Pennsylvania, 1972.

APPENDIX A

PNM SOLAR HYBRID REPOWERING PROJECT QUESTIONNAIRE

D.J. Groves, Public Service Company of New Mexico (PNM)
Letter to Distribution (78 Utilities), "PNM Solar Hybrid
Repowering Project Questionnaire," November 11 & 14, 1977

PUBLIC SERVICE COMPANY OF NEW MEXICO

Post Office Box 2267 / Albuquerque, New Mexico 87103

November 11, 1977

Mr. Eric R. Weber
Research Programs
Arizona Public Service Company
Post Office Box 21666
Phoenix, AZ 85036

Dear Mr. Weber:

Subject: PNM Solar Hybrid Repowering Project Questionnaire

Initial study efforts for the PNM Solar Hybrid Repowering Project are underway. The study will identify, from a utility point of view, if a cost-effective approach exists to repower existing steam or combustion turbine units with solar energy systems to reduce or supplant natural gas and/or oil boiler firing. Your utility is similar to PNM in that you utilize natural gas and/or oil for part of your electric generation. These fuels are increasing substantially in price and may be of questionable availability within your system as they are within PNM's.

The concept of solar repowering existing units might be accomplished to extend their operating life to a maximum, while greatly reducing future fossil fuel consumption. It will also help meet the legislative and administrative goal of conserving scarce natural resources, while potentially adding stability to your cost of power generation by reducing the impact of the oil/natural gas fuel component in your cost base.

The prime item which will enable PNM to assess the possible market and the impact on fuel consumption in the South and Southwest is the enclosed utility questionnaire. This is being sent to many utilities in order to obtain the most complete, up-to-date information available. It has been reviewed many times and simplified primarily to a checklist to reduce your efforts to supply the information needed.

In order to make this important study of maximum value, not only to all utilities, but your individual system, we urge your completion and return of the questionnaire before December 16, 1977. Note that additional pages 2 and 3 are enclosed if you have more than three units that are applicable. This will be the only request for information for the

Mr. Eric R. Weber

-2-

November 11, 1977

study required from you by PNM. Please complete and return the form in the enclosed, stamped envelope. Should you have any questions on the content of the questionnaire, or other matters related to the project, please phone at (505) 842-2606.

Thank you in advance for your timely response.

Very truly yours,

D. J. Groves
Project Coordinator
Solar Hybrid Repowering

DJG:dj
Enclosures

PNM SOLAR HYBRID REPOWERING PROJECT
UTILITY QUESTIONNAIRE

1. Utility Name: _____
2. Name, Title, and Address of contact on solar energy in your company
if different than addressee:

3. Has your utility considered the possibility of solar power generation
as a future alternative?

YES _____ NO _____

4. Would your company be interested in participating in a solar hybrid
plant program if financial incentives made it equivalent or superior
to existing generation alternatives?

YES _____ NO _____

5. Do you have any plans or interest in repowering any units of 200
MWe or less?

YES _____ NO _____

6. What is your approximate generation mix?

	<u>Oil/Natural</u> <u>Gas</u>	<u>Coal</u>	<u>Nuclear</u>
0 - 25%	_____	_____	_____
25 - 50%	_____	_____	_____
51 - 75%	_____	_____	_____
76 - 100%	_____	_____	_____

7. When is your system peak?

	<u>Summer</u>	<u>Winter</u>
12:00 p.m. - 8:00 a.m.	_____	_____
8:01 a.m. - 6:00 p.m.	_____	_____
6:01 p.m. - 12:00 p.m.	_____	_____

8. What are your availability requirements?

<u>Peaking</u>	<u>Intermediate</u>
70 - 80% _____	40 - 60% _____
81 - 90% _____	61 - 80% _____
91 - 100% _____	81 - 100% _____

9. Data on units less than 200 MWe:

A. Name:	_____	_____	_____
B. Size, MWe:	Nameplate	_____	_____
	Rated	_____	_____

CHECK ONE OF THE FOLLOWING FOR EACH ITEM:

C. Turbine Type:

Steam/Reheat	_____	_____	_____
Steam/No Reheat	_____	_____	_____
Combustion	_____	_____	_____
Combined Cycle	_____	_____	_____

D. Turbine Inlet Temperature:

150 - 300 ^o F	_____	_____	_____
301 - 600 ^o F	_____	_____	_____
601 - 900 ^o F	_____	_____	_____
901 ^o F +	_____	_____	_____

E. Turbine Inlet Pressure

150 - 300 psi	_____	_____	_____
301 - 600 psi	_____	_____	_____
601 - 900 psi	_____	_____	_____
901+ psi	_____	_____	_____

F. Year Built

before - 1941	_____	_____	_____
1941 - 1950	_____	_____	_____
1951 - 1960	_____	_____	_____
1961 - 1970	_____	_____	_____
1971+	_____	_____	_____

G. General Unit Condition:

New	_____	_____	_____
Good	_____	_____	_____
Fair	_____	_____	_____
Poor	_____	_____	_____

H. Current Use

Base	_____	_____	_____
Intermediate	_____	_____	_____
Peak	_____	_____	_____
Standby	_____	_____	_____

I. Estimated Retirement

1978 - 1980	_____	_____	_____
1981 - 1990	_____	_____	_____
1991 - 2000	_____	_____	_____
2001+	_____	_____	_____

J. General Plant Location

Industrial	_____	_____	_____
Suburban	_____	_____	_____
Urban	_____	_____	_____
Rural	_____	_____	_____

- K. Solar repowering would require adjacent land area near your plant(s) for the collector field. Based on a requirement of six acres of land per MWe, we estimate there is sufficient vacant area near the plant for solar repowering this percent of the unit:

0%	_____	_____	_____
1 - 25%	_____	_____	_____
26 - 50%	_____	_____	_____
51 - 75%	_____	_____	_____
76 - 100%	_____	_____	_____

- L. Estimated closest distance from unit to land parcels noted in Item (K) above:

0 - 1000 ft.	_____	_____	_____
1001 - 2500 ft.	_____	_____	_____
2501 - 5000 ft.	_____	_____	_____
5001 ft. +	_____	_____	_____

- M. General comments concerning solar hybrid repowering, if any:

9. Data on units less than 200 MWe:

A. Name: _____

B. Size, MWe: Nameplate _____
Rated _____

CHECK ONE OF THE FOLLOWING FOR EACH ITEM:

C. Turbine Type:

Steam/Reheat _____
Steam/No Reheat _____
Combustion _____
Combined Cycle _____

D. Turbine Inlet Temperature:

150 - 300°F _____
301 - 600°F _____
601 - 900°F _____
901°F + _____

E. Turbine Inlet Pressure

150 - 300 psi _____
301 - 600 psi _____
601 - 900 psi _____
901+ psi _____

F. Year Built

before - 1941 _____
1941 - 1950 _____
1951 - 1960 _____
1961 - 1970 _____
1971+ _____

G. General Unit Condition:

New _____
Good _____
Fair _____
Poor _____

H. Current Use

Base _____
Intermediate _____
Peak _____
Standby _____

I. Estimated Retirement

1978 - 1980

1981 - 1990

1991 - 2000

2001+

_____	_____	_____
_____	_____	_____
_____	_____	_____
_____	_____	_____

J. General Plant Location

Industrial

Suburban

Urban

Rural

_____	_____	_____
_____	_____	_____
_____	_____	_____
_____	_____	_____

K. Solar repowering would require adjacent land area near your plant(s) for the collector field. Based on a requirement of six acres of land per MWe, we estimate there is sufficient vacant area near the plant for solar repowering this percent of the unit:

0%

1 - 25%

26 - 50%

51 - 75%

76 - 100%

_____	_____	_____
_____	_____	_____
_____	_____	_____
_____	_____	_____

L. Estimated closest distance from unit to land parcels noted in Item (K) above:

0 - 1000 ft.

1001 - 2500 ft.

2501 - 5000 ft.

5001 ft. +

_____	_____	_____
_____	_____	_____
_____	_____	_____
_____	_____	_____

M. General comments concerning solar hybrid repowering, if any:

APPENDIX B

ECONOMIC ANALYSIS METHODOLOGY

A methodology developed by the Westinghouse Advanced Systems Technology Division in the performance of EPRI RP-648-1, "Requirements Definition and Impact Analysis of Solar Thermal Power Plants," was applied to the analysis required in this study. The applicable aspects included:

- A general methodology framework for assessment of solar-thermal electric plants
- A specific economic calculation methodology
- A process for modeling the interdependent operation of a solar plant and the balance of the utility system
- A procedure for reserve margin analysis that includes the vagaries of solar plants
- A method for solar plant penetration analysis as the utility system grows

The methodology includes a system of computer models and economic procedures specifically integrated to perform solar plant concept assessment and economic impact analysis. The framework of the specific methods employed involves the following sequence of analysis (see Figure B-1):

- Develop hourly projections for year and utility system of interest
- Simulate the operation of conventional units on utility system for that year, producing incremental operating cost tables
- Use incremental cost tables, hourly system loads, and hourly insolation to dispatch solar plant, subtracting solar plant electrical output from the load
- Use hourly load reduction to calculate solar plant capacity credit and conventional capacity displacement
- Resimulate operation of conventional generating units with reduced system load

Figure B-1. Model Usage Flow

- Use economic procedures to calculate resulting solar plant value

This framework allows the evaluation of a variety of solar plant concepts and configurations, in different operating and insolation environments. It also provides a vehicle for assessing the value of either a single solar plant or a number of them, independent of their cost projection.

These procedures were developed using conventional utility planning methods and tools as much as possible. This serves to enhance the ease of interpretation of results for those familiar with utility planning procedures and provides a level of confidence through the use of established, tested methods.

B.1 ECONOMIC METHODS

The economic methods developed use conventional Revenue Requirements analysis, recognizing both the time value of money and independent escalation of various cost elements. These methods are consistent with electric utility practice and provide the needed flexibility. The Revenue Requirements methodology is also consistent with the EPRI economic evaluation guidelines stipulated in the August 1977 EPRI "Technical Assessment Guide."*

The principal economic measures of solar plants implemented in this methodology are as follows:

- The value of the solar plant
- Solar plant busbar energy cost
- Net economic impact upon utility
- Cost/benefit of the solar plant

Because of the uncertainty of the costs of certain portions of the solar plant, particularly under mass production conditions, it was deemed important to assess the economic value of the solar plant independent of its costs. The value arises

*Technical Assessment Guide, Prepared by Electric Power Research Institute, June 1977.

potentially from both operating cost and capital cost savings to the balance of the utility system. The operating cost savings are derived from reductions in fuel consumption and variable operating and maintenance costs. The capital cost savings arise from reduced conventional capacity requirements and a potential shift in the mix of conventional units. The busbar energy costs, which are consistent with ERDA/EPRI guidelines, are a function of solar plant cost and electric energy production.

The net economic impact of a solar plant upon a utility system is calculated by simply subtracting the solar plant value from its estimated costs.

The cost/benefit ratio is calculated by dividing the present worth of solar plant lifetime costs (revenue requirements) by the present worth of its lifetime value.

The handling of the following areas is fundamental to the evaluations:

- Revenue requirement components
- Time value of money
- Escalation of different costs

The concept of revenue requirements includes cost components to support the capital investment and other expenses, which in this case are primarily operating costs. The concept may apply to a single project or to an entire system made up of many projects.

The revenue requirements to support the capital investment are primarily as follows:

- Adequate return on the investment to cover the cost of capital (similar to interest on money borrowed)
- Recovery of the amount invested (depreciation)
- Income taxes required
- Other taxes
- Insurance

The annual revenue requirements for the above can usually be expressed as a percentage of the capitalized investment.

Additional revenue requirements for a generating plant are other expenses, which are primarily as follows:

- Fuel costs
- Maintenance costs
- Other operating costs

These expenses are usually not expressed as a percentage of capitalized investment, and may escalate independently. For purposes of this analysis, operating costs and maintenance costs are lumped together as operating and maintenance costs.

The methods and the indices used provided an excellent basis for the economic analysis required in this study. An example analysis showing the various criteria is shown in Table B-1, a reproduction of the computer case analysis summary output.

B.2 ELECTRIC UTILITY SYSTEM MODELING

Two principal aspects of the potential impact of solar repowered plants upon utility systems required detailed modeling of the conventional generating capacity on the system. These two aspects are: 1) operational impact; and 2) reliability and/or capacity credit impact.

As shown in Figure B-1, the modeling of the operation of the utility system with and without the presence of the solar plant establishes the fuel savings and operating credit of the solar plant. For this purpose, the Westinghouse Detailed Production Cost Model was used to establish base-case (non-solar) utility system operating costs and other operating parameters, and for the balance-of-system simulation in cases including solar plant(s). It is an established computer program that simulates the operation of a utility system by performing economic dispatch on a bi-hourly basis. Minor modifications have been implemented to

TABLE B-1. EXAMPLE HYBRID ANALYSIS SUMMARY COMPUTER PRINTOUT

-ECONOMICS

-100 MW SOLAR HYBRID PLANT COLD START

-SOLAR PLANT VALUE AND COST TABLE ECONOMICS B METHOD 2
PRESENT WORTH OF REVENUE REQUIREMENTS 1985 MILLIONS

	<u>LO</u>	<u>REF</u>	<u>HI</u>
Solar Plant Cost			
● STC Plant Cost	290.4	341.8	431.8
● STC Plant O&M	104.0	122.4	154.6
● STC Total Cost	394.5	464.2	586.4
Solar Plant Value			
● Fuel Value	153.7	153.7	153.7
● Variable O&M	12.5	12.5	12.5
● STC Fuel Cost	-23.2	-23.2	-23.2
● Capacity Credit	111.9	111.9	111.9
● Total Value	254.9	254.9	254.9
Net Value	-139.5	-209.2	-331.4
Cost/Benefit	1.55	1.82	2.30
Breakeven \$/kW 1985	1199.6	1199.6	1199.6
Breakeven \$/kW 1977	698.1	698.1	698.1
Plant Cost \$/kW 1977	1080.2	1271.1	1605.8
STC Energy GWH/yr	206.9	206.9	206.9
Capacity Factor	0.236	0.236	0.236
Energy Cost mills/kWhr	232.2	270.9	338.9
Capacity Displacement Tables	<u>Megawatts</u>	<u>Value RR</u>	
● Peaking	64.0	34.6	
● Intermediate	9.0	8.9	
● Base Loaded	27.0	68.4	
TOTAL	100.0	111.9	

enhance communication with the solar model. This program contains the ability to represent various forms of hydroelectric generation and external system interchanges as well as fossil and nuclear plants.

The use of such a program that utilizes daily load cycle information facilitates impact analysis associated with daily, as well as seasonal, insolation correlations. It also allows examination of the impact upon the daily operating strategies of conventional units. Spinning reserve representation and explicit maintenance schedules are also part of this model.

A partial list of the inputs and outputs for the Detailed Production Costing is as follows:

- Input
 - Load/energy data
 - Unit availabilities
 - Unit incremental heat rates
 - Unit fuel and startup costs
 - Unit capacities (minimum and maximum)
 - Unit operating and maintenance costs
 - Pondage and pumped storage hydro energy
 - Pumped storage hydro cycle efficiency
 - System spinning reserve policy
 - System interchange limits
 - Unit transmission penalty factors
- Output
 - Amounts of fuels consumed by unit
 - Total fuel costs by unit
 - Total operating costs by unit
 - Energy generated by unit
 - Number of starts by unit
 - System interchange energy and costs
 - System fuel consumption
 - System generated energy
 - System total operating cost

- System generation by fuel class and station
- By-hourly loads

For reliability analysis, special modeling procedures have been developed by Westinghouse to handle insolation as well as equipment outages. However, with a solar repowered plant, the non-solar side of the plant can be called upon at the will of the system operator. Therefore, for reliability analysis, solar repowered plants are subject only to equipment-related outages and can be treated much the same as conventional plants.

To translate the capacity credit to dollars is more complicated in that generally a repowered plant will not operate purely as a peaking, intermediate, or base-load plant. Thus, an analysis of load curve alteration and breakpoint analysis is used to translate the megawatt credit to dollars. This usually results in displacement of a mixture of peaking, intermediate and base-load plants (see Table B-1).

Also involved with the reliability modeling analysis is the maintenance scheduling. An automatic scheduling routine that minimizes loss-of-load probability is used for conventional unit maintenance scheduling; however, the seasonal insolation variations are also considered for the solar hybrid scheduled outage. A period with a combination of relatively poor insolation and good utility system reliability is desired for maintaining the solar hybrid plant.

B.3 SOLAR HYBRID AND REPOWERED PLANT MODEL

The solar hybrid repowered plant model used for this analysis (see Section 3.0) is an outgrowth of the one developed by Westinghouse for EPRI in the performance of RP 648-1. This computer model has the capability of modeling the operation of a number of types and configurations of solar plants on an hourly basis. Included in the model is the economic operation of solar stand-alone plants with series or parallel storage and hybrid Brayton or Rankine systems.

The purpose of the model is to take solar design parameters as specified, site specific insolation and weather data, and simulate the operation of the solar

plant on an electric utility system. This operational modeling utilizes the plant in the most economic fashion recognizing the changes in incremental operating cost of the balance of the utility system on an hourly basis.

The model simulates, on an hourly basis, the energy flow within a solar-thermal electric generating plant. The program is constructed in a modular fashion to represent the major subsystems of such a plant. These subsystems are shown in Figure B-2.

The model takes as input the hourly incident normal insolation, and through a series of conversion efficiency and loss calculations develops the electrical output of the turbine generator. It accounts for the operation of thermal storage of fossil boilers and is capable of simulating a number of different solar plant concepts.

The concept simulated can be a system of parabolic trough distributed collectors, central-receiver parabolic dishes, or planar (Winston) collectors. The troughs can be east-west or north-south oriented.

The Collector Subroutine takes the input solar insolation and combines it with the effective collector area and appropriate factors to describe the loss due to shading, blocking, reflectivity and aiming. The resulting net collected thermal energy is then passed to the Receiver Subroutine.

The collected energy is next subjected to corrections for receiver efficiency and receiver heat losses. This is a simulation of the effects of receiver absorption efficiency, and convection and radiation losses.

The thermal energy leaving the receiver is next adjusted to account for pumping losses, and for line thermal losses. The net remaining energy is then transmitted either to thermal storage, if available, or directly to the turbine generator, or if the capacities of these subsystems are exceeded, to the condenser.

A number of input thresholds controls the actions of Valves A and B, shown in Figure B-2. Valve A determines whether the energy is directed to storage or

Figure B-2. Central Receiver Solar Plant Model Representation

TABLE B-2. SOLAR HYBRID PLANT MODEL DISPATCH

- Oil startup logic
- Oil buffer for insolation transients
- Closeup potential shutdown windows
- High wind speed solar shutdown
- Boiler efficiency corrections
- Oil recovery of low insolation
- Economic oil dispatch
- Hot standby oil (option)
- Economic shutdown at end of day
- Cost/benefit of daily oil use

RECOGNIZING

- Foreknowledge of day's insolation profile
- Foreknowledge of day's load profile
- Utility system incremental cost curve
- Fossil boiler limits and efficiency
- Turbine-generator limits and efficiency
- Insolation high transient conditions
- Operation wind limits

directly to the turbine generator. Valve B controls the withdrawal of energy from storage, which may be simultaneous with use of heat from Valve A. The control parameters define levels of system load below which plant output is not desired, and the minimum allowable heat in storage.

The energy passing from Valve A into storage is modified by a storage input efficiency factor. Thermal losses from storage, as a function of time, are also modeled. Should the energy in storage begin to exceed the maximum capacity stated by input, the limiting storage capacity is observed and the energy overflow noted in the printout.

The Turbine Generator Subroutine applies an efficiency factor to represent the losses in the process of conversion from input thermal energy to output electrical energy. This subroutine also incorporates limits for minimum and maximum levels of operation.

In summary, the basic approach of the model, is to account for energy flows by use of device efficiencies, some of which are directly input. Others are calculated through mathematical relationships in the program.

In some subroutines the user has the option of providing the input, a simple efficiency factor, or relying upon more complex internal calculations.

For the realistic representation of solar hybrid repowered plants and their most economical operation, a number of rules and considerations have been incorporated in the solar plant model, as discussed in Section 2.5.2, and briefly reiterated below.

For realism in the modeling of the operation of the hybrid plant, those items shown in Table B-2 included fossil fuel consumption to bring the boiler up to temperature, accounting for both fuel consumption and the time required. Operating scenarios where the boiler heat is maintained (standby) is an option in the program.

Logic requiring fossil boiler energy to buffer the turbine during insolation transients has also been incorporated. The skycover conditions are sampled hourly from the insolation tape to determine when insolation transient conditions apply.

To prevent excessive cycling of the turbine, the plant is fired to run through what otherwise would be a brief shutdown period. When wind speeds exceed the input design limits, the heliostats are assumed stowed and no solar energy is collected for that hour.

Both boiler and turbine generator part-load efficiency curves are incorporated in the solar plant model.

When the insolation is not sufficient to operate the turbine at its minimum level and a specified insolation threshold is exceeded, the boiler is fired to provide enough supplemental energy to salvage the insolation and operate the turbine generator.

The incremental cost of competing conventional plants is tested hourly to establish whether additional fossil firing is justified. Also, a test is made to determine whether it is worthwhile (economic) to start up the boiler at all, each day, or to leave the boiler cold and suffer the operating consequences (e.g., no electrical output during solar transients). The proper boiler shutdown hour is also established on an economic dispatch basis.

The ability of the model to examine alternate operating strategies as well as design parameters has been found to be extremely valuable. A list of some of the inputs and outputs of the solar plant model is given in Table B-3.

TABLE B-3. SOLAR PLANT MODEL INPUTS/OUTPUTS

● INPUT

- Site location and latitude
- Solar collector system type and orientation
- Hourly utility system demand
- Utility balance of system incremental cost
- Hourly insolation and meteorological data
- Collector field area
- Tracking efficiencies
- Reflectivity efficiencies
- Receiver thermal efficiency
- Pumping efficiency
- Line thermal power loss efficiency
- Storage input/output efficiency
- Thermal storage capacity
- Turbine generator efficiency
- Turbine generator operating limits
- Cooling tower type and efficiency
- Minimum usable insolation
- Startup/standby oil consumption
- Storage heat initialization
- Plant incremental fuel cost
- Plant availability (equipment-related forced outage table)
- Wind-speed design limit
- Skycover transient specification
- Turbine-generator output windows transient suppression

● OUTPUT

- Plant megawatt electric output (hourly)
- Modified utility system demand (hourly)
- Insolation energy (hourly)
- Energy in storage (hourly)
- Storage energy overflow (hourly)
- Intermediate power flows (hourly)
- Annual and monthly electric energy output
- Annual and monthly solar energy output
- Annual and monthly oil consumption output
- Operating mode transition summary
- Windy and cloudy days table
- Oil consumption
- Startup and buffer oil consumption
- Transient suppression oil consumption
- Average solar power availability by hour
- Average utility demand by hour
- Monthly peak utility demand

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