DOE/JPL 955456-1
Distribution Category UC-97c

MONITORING AND CONTROL REQUIREMENT DEFINITION STUDY FOR DISPERSED STORAGE AND GENERATION (DSG)

FINAL REPORT

Volume II

October 1980

Prepared for

JET PROPULSION LABORATORY
CALIFORNIA INSTITUTE OF TECHNOLOGY

and

NEW YORK STATE ENERGY RESEARCH AND DEVELOPMENT AUTHORITY

Submitted by

GENERAL ELECTRIC COMPANY
CORPORATE RESEARCH AND DEVELOPMENT

GENERAL ELECTRIC

(NASA-CR-164052) MONITORING AND CONTROL REQUIREMENT DEFINITION STUDY FOR DISPERSED STORAGE AND GENERATION (DSG). VOLUME 2, APPENDIX A: SELECTED DSG TECHNOLOGIES AND THEIR GENERAL CONTROL REQUIREMENTS (General G3/44

N81-20539

Unclas
18901

JPL 9950-419
NYSERDA 80-15

DOE/JPL 955456-1
Distribution Category UC-97c

MONITORING AND CONTROL REQUIREMENT DEFINITION STUDY FOR DISPERSED STORAGE AND GENERATION (DSG)

SRD-80-042-II

FINAL REPORT

Volume II

October 1980

Appendix A

SELECTED DSG TECHNOLOGIES AND THEIR GENERAL CONTROL REQUIREMENTS

Prepared for

JET PROPULSION LABORATORY
CALIFORNIA INSTITUTE OF TECHNOLOGY

(Contract No. 955456)

and

NEW YORK STATE ENERGY RESEARCH AND DEVELOPMENT AUTHORITY

(Agreement No. ER 320-78/79 EUET)

Submitted by

GENERAL ELECTRIC COMPANY
CORPORATE RESEARCH AND DEVELOPMENT
Schenectady, New York 12301

GENERAL ELECTRIC

FOREWORD

This Final Report is the result of a year-long effort on Monitoring and Control Requirement Definition Study for Dispersed Storage and Generation (DSG) conducted by the General Electric Company, Corporate Research and Development, for the Jet Propulsion Laboratory, California Institute of Technology, and the New York State Energy Research and Development Authority.

Dispersed storage and generation (DSG) is the term that characterizes the present and future dispersed, relatively small (<30 MW) energy systems such as those represented by solar thermal electric, photovoltaic, wind, fuel cell, battery, hydro, and cogeneration. To maximize the effectiveness of alternative energy sources such as these in replacing petroleum fuels for generating electricity and to maintain continuous reliable electrical service to consumers, DSGs must be integrated and cooperatively operated within the existing utility systems. To effect this integration may require the installation of extensive new communications and control capabilities by the utilities. This study's objective is to define the monitoring and control requirements for the integration of DSGs into the utility systems.

This final report has been prepared as five separate volumes which cover the following topics:

VOLUME I - FINAL REPORT

Monitoring and Control Requirement

Definition Study for Dispersed Storage and Generation

VOLUME II - FINAL REPORT - Appendix A

Selected DSG Technologies and Their General Control Requirements

VOLUME III - FINAL REPORT - Appendix B

State of the Art, Trends, and Potential Growth of Selected DSG Technologies

VOLUME IV - FINAL REPORT - Appendix C

Identification from Utility Visits of Present and Future Approaches to Integration of DSG into Distribution Networks

VOLUME V - FINAL REPORT - Appendix D

Cost-Benefit Considerations for Providing Dispersed Storage and Generation of Electric Utilities

PRECEDING PAGE BLANK NOT FILMED

ACKNOWLEDGMENTS

Throughout this study we have benefited greatly from the help offered by many people who are knowledgeable in specific areas of the dispersed storage and generation technologies studied and in the fields of communications, control, and monitoring. We particularly wish to acknowledge the efforts of and discussions with Dr. Khosrow Bahrami and Dr. Harold Kirkham, each of whom have served as technical manager in the Jet Propulsion Laboratory, and Dr. Fred Strnisa, project manager, New York State Energy Research and Development Authority.

We also wish to thank the various people with whom we met during our utility visits. The following utilities have provided useful information regarding DSG activities at their organizations:

Niagara Mohawk Power Corporation, Syracuse, New York

San Diego Gas and Electric Company, San Diego, California

Blue Ridge Electric Membership Corporation, Lenoir, North Carolina

Public Service Electric and Gas Company, Newark, New Jersey

In addition, we thank our many associates in General Electric Company who have helped so much in our understanding of the selected DSG technologies and in the integration of DSGs into the existing electric utility system. In particular, we thank J.B. Bunch, A.C.M. Chen, M.H. Dunlap, R. Dunki-Jacobs, W.R. Nial, R.D. Rustay, and D.J. Ward.

The help of Dr. Roosevelt A. Fernandes of Niagara Mohawk Power Corporation in several phases of the work covered in this report is acknowledged with thanks. Also, Dr. Fred C. Schweppe, consultant, has been of considerable benefit in the conduct of this project and his efforts have been appreciated.

Harold Chestnut

Robert L. Linden

PRECEDING PAGE BLANK NOT FILMED

ABSTRACT

A major aim of the U.S. National Energy Policy, as well as that of the New York State Energy Research and Development Authority, is to conserve energy and to shift from oil to more abundant domestic fuels and renewable energy sources. Dispersed Storage and Generation (DSG) is the term that characterizes the present and future dispersed, relatively small (<30 MW) energy systems, such as solar thermal electric, photovoltaic, wind, fuel cell, storage battery, hydro, and cogeneration, which can help achieve these national energy goals and can be dispersed throughout the distribution portion of an electric utility system.

The purpose of this survey and identification of DSG technologies is to present an understanding of the special characteristics of each of these technologies in sufficient detail so that the physical principles of their operation and the internal control of each technology are evident. In this way, a better appreciation can be obtained of the monitoring and control requirements for these DSGs from a remote distribution dispatch center. A consistent approach is being sought for both hardware and software which will handle the monitoring and control necessary to integrate a number of different DSG technologies into a common distribution dispatch network. From this study it appears that the control of each of the DSC technologies is compatible with a supervisory control method of operation that lends itself to remote control from a distribution dispatch center.

TABLE OF CONTENTS

PRECEDING PAGE BLANK NOT FILMED

TABLE OF CONTENTS (Cont'd)

TABLE OF CONTENTS (Cont'd)

TABLE OF CONTENTS (Cont'd)

LIST OF ILLUSTRATIONS

LIST OF ILLUSTRATIONS (Cont'd)

LIST OF TABLES

Section A1

INTRODUCTION

A1.1 IDENTIFICATION OF DSG TECHNOLOGIES

A major aim of the U.S. National Energy Policy is to conserve energy and to shift from oil to more abundant domestic fuels and renewable energy sources. Dispersed Storage and Generation (DSG) is the term that characterizes the present and future dispersed, relatively small (<30 MW) energy systems, such as solar thermal electric, photovoltaic, wind, fuel cell, storage battery, hydro, and cogeneration, which can help to achieve these national energy goals. A great deal of the national energy research and development effort is being devoted to energy systems of these kinds which, because of their small size, can be dispersed throughout the distribution portion of an electric utility system.

The purpose of this survey and identification of DSG technologies is to present an understanding of the special characteristics of each of these technologies in sufficient detail so that the physical principles of their operation and the internal control of each technology are evident. In this way, a better appreciation can be obtained of the monitoring and control requirements for these DSGs from a remote distribution center. An objective is that a consistent approach for both hardware and software can be identified which will handle the monitoring and control necessary to integrate a number of different DSG technologies into a common distribution dispatch network.

In performing the survey, the DSG technologies have been considered in terms of their potential contribution to the effectiveness of the electric utility power distribution network. These technologies have been viewed as possible means for enabling the persons responsible for supervision of the electric power distribution system to operate that distribution system, as well as the associated generation and transmission equipment, more effectively.

A1.2 IDENTIFICATION OF POSSIBLE DSG TECHNOLOGIES

There are numerous technologies which may be considered as candidates for DSG application. Often there are basic system variations within technologies and thus the number of candidate DSG systems compounds. Both conventional technologies and alternative energy technologies are considered candidates and represent a range of readiness from conceptual or experimental status to being "available for commercial application." Since the renewed concept of dispersed storage and generation is expected to grow for the remainder of this century and into the next, DSG technologies presently in various stages of readiness or availability are compatible with this concept. Some candidate DSG technologies will fail to meet general screening criteria and for the present will be set aside. Later in this report, and in other portions of the program report, the matters of selection and feasibility of DSG technologies will be considered.

From a wide range of technologies, a list was compiled for consideration. The candidate technologies considered in the survey consisted of the following:

- Fusion
- Magnetohydrodynamics
- Biomass/Biofuels
- Geothermal
- Hydroelectric Pumped Storage
- Compressed Air Storage
- Superconducting Magnetic Storage
- Solar Thermal Electric
- Photovoltaics
- Wind
- Fuel Cell
- Storage Battery
- Hydroelectric (small, low head)
- Cogeneration

A brief description of each technology is given as a basis for later explanations of the selection of DSGs for this Monitoring and Control Requirements Definition Study.

Fusion Energy Conversion

A fusion reaction results in the formation of a heavier nucleus from two lighter ones with the attendant release of energy. There is less energy release per fusion reaction than there is per fission reaction, but the reactants are more plentiful and easier to handle. From this simplified definition, a perspective on this technology can be gained from a direct quotation.

> The search for economical controlled fusion power is a scientific hunt for the Lost Dutchman Mine. Only a few true believers are absolutely certain that the goal exists, but

> the search takes place over interesting terrain, and the rewards for success are overwhelming. In the case of fusion power, the potential long term societal rewards are so enticing, and the possibility of success is so high that a major, truly international research effort has developed over the last two decades. The United States has allocated over $400 million for research in controlled thermonuclear reactors (C.T.R.) to date, and the U.S.S.R. more than twice that amount. There seems little question that eventually either fusion energy or solar energy will be called upon to deliver the enormous quantities of "environmentally gentle" power that people will need. We should be able within five years to say whether significant amounts of energy can be obtained from controlled fusion within the next 20 to 30 years (before an irreversible commitment to an economy based on fission breeder reactors) or whether fusion power development will have to wait much longer until the technological and economic considerations are even more favorable than they are at this moment.(50)

Another opinion which puts fusion power in perspective is provided in the EPRI Research and Development Program Plan for 1979-1983.

> Fusion: Although considerable technical progress has been made in fusion research, the possibility of generating electricity still remains to be proven. Fusion was shown to be theoretically feasible more than 25 years ago, but by common estimate it will be another 20 years before the first token electricity will flow from a fusion reactor. At least another 10 years will be required before the first utility prototype fusion power plant will be on line. This technology, which will use abundantly available isotopes of hydrogen for its fuel, will not likely contribute to the generation mix before 2010.(51)

With these perspectives, the application of fusion energy conversion appears to be an energy source for the 21st century and not this century. Further present indications are that economy-of-scale principles will apply when commercial viability is reached, tending to make this technology more suitable for station type applications.

Magnetohydrodynamic (MHD) Energy Conversion

Magnetohydrodynamic (MHD) electric power generation is a promising technique for improving the efficiency of converting heat into electricity. The concept has been explored extensively, and experiments on major components and systems are being conducted world-wide. The basic principle of generating electric power from MHD systems is to extract direct current electrical power from the interaction of a moving, electrically conducting fluid passing through a magnetic field. The type of cycle receiving the most development effort is a fossil fueled/open cycle system because it is the most readily achieved of the three fundamental cycle alternatives (open cycle, closed cycle plasma, and closed cycle, liquid metal). In the United States efforts are being concentrated on direct coal-fired open-cycle (regenerative Brayton type) MHD topping units combined with a relatively conventional steam turbine-generator plant used as a bottoming unit. Efficiencies in the order of 47 to 50% are the goals for large central station type plants (1000 MW) using this cycle. Future improvements in technology could increase efficiency to 60%.

In this configuration the direct current output from the MHD generator is inverted to alternating current power to supply the electric utility network, and the output of the steam turbine generator is connected in the conventional way to the utility system. Major program milestones(51) and schedules are represented by: (a) DOE's MHD Component Development and Integration Facility (CDIF) with testing scheduled in 1980, (b) DOE's pilot-scale MHD Engineering Test Facility (ETF) scheduled for 1984, and (c) complete prototype commercial-scale (500 MW) MHD plant scheduled for 1989. Availability for commercial orders is anticipated as early as 1995. As an alternative some utilities are proposing that existing steam electric generating plants be retrofitted with MHD topping units in an effort to shorten the development time to commercialization. These plants would be in the 100 MW or larger class. Thus, MHD applications in the United States are planned for large 1000 MW or medium sized (100-500 MW) central station installations and are expected to reach commercial viability in the 1995 to 2000 period.

Biomass/Biofuels

All plant matter is called biomass. Biofuels are renewable energy sources from living things. (Fossil fuels are of biological origin but are nonrenewable.) All biofuels are ultimately derived from plants which capture the sun's energy, convert it to chemical energy of protoplasm by photosynthesis, and thereby provide storage of solar energy. The biofuel may be directly derived from the plant matter or derived from wastes of animals. Compared to direct solar energy conversion methods such as solar thermal electric, photovoltaic, and wind, plants are very inefficient at converting solar energy into useful forms of energy. However, only plants can convert solar energy into chemical (biomass) energy. With regard to electric utility electrical energy production from biomass sources, the concept of "Energy Plantations" and burning the biomass in conventional power plants to produce electricity has been proposed. To obtain the efficiency and economy of scale, these would be relatively large plants with large land area requirements devoted to single "biomass fuel crops." The overall efficiency from solar input to electrical output of a wood burning steam-turbine-generator plant would be in the range of 0.4 to 0.8%. In comparison other "direct" solar energy conversion systems have much higher efficiencies: photovoltaics, 10%; solar thermal electric, 3 to 15%; and wind, 25 to 35%. Another biomass/biofuel production method proposed is the growing of aquatic plant life (e.g., sea kelp) in off-shore waters, specifically California waters. It is proposed that the dried biomass would be digested and converted to methane gas. This would presumably involve large scale operations also.

In contrast with the "Energy Plantation" concept, the incineration or anaerobic digestion of organic wastes provides a means of using biofuels to generate electric power in relatively conventional steam-electric power plants. Where sufficient quantities of these biofuels are available, they provide an alternative means of electric power generation. Organic wastes could be forest or agricultural wastes for direct combustion, and animal wastes for methane gas fuel production.

Municipal incineration plants which produce electric power and heat from urban refuse are similar to a forest or agricultural waste combustion-electric power generation process. The separation and reclamation of noncombustible material make the materials handling much more complicated, however. In addition to the primary biomass organic wastes contained in urban refuse, there are also complex manufactured materials (e.g., plastics) which require special combustion arrangements.

Geothermal Energy Conversion (52)

The generation of electric power from heat supplied from the interior of the earth is produced from geothermal reservoirs where it is accumulated and stored through geological processes. Where the earth's crust, composed of several rigid plates, separates or converges along plate boundaries, abnormal terrestrial heat flow occurs. At these boundaries, mass transfer of heat from the earth's inner mantle, by magma filling the gaps, takes place. This brings heat to the shallower levels of the earth's crust. From these heat sources, geothermal systems are developed. All the prospective high-enthalpy geothermal areas of the world are found within the belts of geographically young volcanism and crustal deformation produced by the moving plates. The useful geothermal fluid (water, containing dissolved minerals and salts) is heated. Where favorable conditions of fractured rocks and or porosity exist along with the geothermal fluid, geothermal reservoirs are formed. There are vapor-dominated and liquid-dominated reservoirs. The vapor-dominated reservoirs are preferred and are most amenable to producing electric power by using the steam to drive steam turbine-generators. Liquid-dominated systems with high enthalpy can produce a mixture of water and steam, with the steam used for operating steam turbine generators. Low-enthalpy liquid-dominated systems are most useful for other purposes as an alternative to other forms of energy. However, in the upper temperature range for low-enthalpy fluids, it may be possible to produce electric power by exchanging heat from the geothermal fluid to a higher vapor pressure working fluid, such as isobutane, which is used to drive a turbine generator unit.

Because the geologic conditions described above are uncommon, geothermal energy is not commonly available. Furthermore, it must be utilized near its source, even if it is a remote location, or it must be of sufficient magnitude to warrant construction of transmission lines to supply electric energy to the utility grid. In the latter case the plants tend to be of the large central station type. The Geysers plant in California had 500 MW installed capacity in 1976 and has steam capacity for further expansion. It is at present the only commercial geothermal power plant in the United States. Various estimates have been made of possible geothermal energy electric power plant capacity by the year 2000, using both vapor-dominated and liquid-dominated geothermal sources. The latter have greater potential but more technical problems. Including both types, EPRI[51] has estimated that between 14 and 25 GW of capacity may be possible by the end of this century. This capacity would be located in the Western states.

Hydroelectric Pumped Storage[53]

Pumped storage hydroelectric power plants are peak-load plants which pump all or a portion of their own water supply. Essentially they consist of a tailwater pond, which may take the form of a river or a natural lake, and a higher "headwater pond" for storage. There is also serious consideration being given to surface headwater storage and underground tailwater reservoirs. During times of peak load, water is drawn from the headwater storage pond through the pentstocks to operate hydroelectric generating units during the peak of the electric utility system load curve. During the off-peak hours pumps (most often reversible pump-turbine, motor-generator units) are operated to transfer water from the tailwater pond to the headwater storage pond. Power for operating the pumping cycle is furnished by off-peak energy from other generating units such as fossil-fired or nuclear steam turbine generator units. The reservoir of a pumped hydro plant is usually sized to provide for the plant's operation during the peak load period of the system it is designed to serve. Sometimes margin is included to permit using the plant for system reserve short-time service. Reservoir capacity that will permit full capacity operation of the plant for 4 to 10 hours is usual.

There are three basic types of pumped storage hydroelectric plants: (a) pumped storage combined with conventional hydroelectric generation, (b) pumped hydro only, and (c) pumped storage with diversion for irrigation. The type most compatible with DSG applications would be the "pure" pumped hydro only. The advantages of this type of plant are its flexibility of location, in that the upper reservoir need have no source of water other than what is pumped into it, and the possibility of developing large plants with a small reservoir and high head. Historically, however, the size of these pumped storage plants has tended to become relatively large, rated several hundred MW or more. This is to obtain economy of scale and low operating costs for the function of system peak-load shaving.

Compressed Air Storage

This method of energy storage utilizes off-peak power to compress air in underground reservoirs. The compressed air provides pressurized air for a combustion turbine-generator to produce electric power during system peak load periods. The major features of this energy storage system have been described as follows:

> Compressed air storage, as currently conceived, uses a modified combustion turbine, uncoupling the compressor and turbine so that they can operate at different times and incorporating the intermediate storage of compressed air. During off-peak load periods, the turbine is disengaged and the compressor is driven by the generator, used as a motor, taking its power from other units through the interconnection. The compressed air may be stored in (1) naturally occurring caverns, porous ground reservoirs and depleted gas or oil fields or (2) manmade caverns such as dissolved out salt caverns, abandoned mines or mined hard-rock caverns.
>
> The stored compressed air is subsequently used during peak load periods when it is mixed with fuels in the combustion chamber, burned and expanded through the turbine. During the peak load periods, the compressor clutch is disengaged and the entire output of the turbine is used to drive the generator, feeding power to the electrical system. Since in normal operation the compressor consumes about 2/3 of the power output of the turbine, the rating of the gas turbine operating from the stored compressed air is increased by roughly a factor of 3. Air storage may be accomplished either at variable pressure or, through the use of a hydrostatic leg, at constant pressure.[54]

This can be considered a "near term" (i.e., 1985) technology. The economic plant size for this technology has been assessed in the range of 200 to 1000 MW.[55] It is of primary importance to note that this technology requires liquid petroleum and gaseous fuels, both of which are expensive and currently being discouraged for power generation use.

Superconducting Magnetic Energy Storage

This technology is considered as a possibility for the "long-term" future (beyond year 2000). Much development and engineering work is needed to make this technology practical and economically viable. This energy storage technology is described in a recent ERDA/EPRI study as follows:

Superconducting magnetic energy storage (SMES) systems store electrical energy in a magnetic field produced by a circulating current in the winding of a magnet. Essential for SMES success are superconductive magnet windings and the operation in a persistent mode, otherwise there is quick self-discharge.

The proposed use of a superconducting inductor for energy storage makes use of the principle that energy can be stored in an inductor of zero resistance, theoretically, forever. A superconducting inductor stabilized with a normal conductor is housed in a Dewar. The inverter used during discharging is used as a rectifier during charging.

For a utility size superconducting magnetic energy storage system, the magnet would be located several hundred feet below ground in solid bedrock. The bedrock is used as low cost reinforcing to absorb the forces developed by the magnet. The magnet requires leads to the power conversion equipment, a superconducting switch to limit energy loss during hold periods, a large refrigeration system located in a low magnet field area and large storage tanks for the helium refrigerant. While the magnet itself may not be very large, the total area required for refrigeration equipment, cryogen (He) storage and shield magnet rings could be quite large.[56]

The physical relationships and economics of scale would probably favor relatively large installations.

Solar Thermal Electric

Solar thermal electric energy conversion systems collect solar radiation and convert it into high temperature heat. The heat is transferred to a working fluid, often water or steam, for use in a mechanical-electrical generation system. Solar thermal electric energy may be used in an energy system providing both electricity and thermal energy. Energy storage may also be included as part of the thermal energy system.

Photovoltaics

Photovoltaic power generation systems convert light energy to electrical energy. This conversion takes place by the "photovoltaic effect," whereby a voltage is produced between dissimilar materials when their junction is illuminated (irradiated) by the light-band portion of the electromagnetic spectrum. There are a limited number of materials which exhibit photovoltaic properties. The relatively low power intensity of sunlight (0.100 watt per square centimeter), and the relatively low efficiency of photovoltaic conversion (5 to 20%), inherently require considerable land area to obtain kilowatt or megawatt power levels. Since photovoltaic power is in the form of direct current, dc-to-ac inverters are required to interconnect photovoltaic generation to an electric utility ac distribution system. The basic daily insolation cycle and variable weather conditions limit the availability and amount of potential photovoltaic power generation. Thus, photovoltaic generation systems must be used in conjunction with other firm power sources on an electric utility system.

Wind

Wind generation systems, by means of a bladed propeller, convert wind energy to shaft mechanical energy to electrical energy via a conventional electric alternator. Wind generation systems for electric utilities are likely to consist of one or more modest size units (0.2-3.0 MW) making up an integrated installation. Wind generation is available only when the wind is blowing at speeds above a certain threshold velocity and at speeds below a certain maximum velocity at which damage to the installation might occur. Therefore, with wind generation, additional generation by other means is generally required by the utility.

Fuel Cell

Fuel cell energy systems consist of an electric power generation device in which hot fuel gas is passed over a fuel electrode and heated air is passed over an adjacent air electrode, separated from the fuel electrode by an electrolyte, so as to produce a dc power output and an exhaust of carbon dioxide and water. The direct current electric power produced by the fuel cell is connected to a dc/ac inverter which in turn supplies the distribution network with alternating current at the proper voltage and frequency.

Storage Battery

Storage battery energy systems have as their inputs dc electrical energy which is converted electrochemically to chemical energy during charging of the battery and is electrochemically converted to dc electrical energy during the discharging of the battery. Operation of a storage battery with the conventional ac electric distribution system requires the use of power conditioning equipment which can accept the alternating current from the distribution network and convert it to the dc required to charge the battery and invert the dc electrical energy provided from the battery to ac suitable for the distribution network. Care must be taken so that the timing of battery charging and discharging is economically beneficial to the overall electric power system operation.

Hydroelectric (Small, Low Head)

Hydroelectric generation converts the energy of falling water into electrical energy by means of mechanical-electric machinery. Flowing water, pressurized by gravity, drives a hydraulic turbine which is coupled to an electric generator. The electric generator driven by the turbine produces alternating current electric power which is supplied into the electric utility power system.

Cogeneration

Cogeneration is the combined production of process heat and electricity. Industries and/or utilities which need both of these forms of energy potentially have net operational cost savings available through an efficient coordinated facility which fully utilizes the total heat of combustion. Various manufacturing, commercial, and district heating applications utilize medium and/or low pressure steam. These comprise the largest percentage of potential cogeneration applications. For these applications, the most common configuration for generating electricity and "process steam" has been to use fossil-fuel-fired steam boilers producing high temperature, high pressure steam to drive steam turbine-generator set(s). Electricity is produced directly by the turbine-generator, and the steam from the turbine, with its remaining energy, is delivered to the "process." This is called a topping cycle. Electricity is produced at the highest temperature part of the thermal cycle. Bottoming cycles, obtaining electric power from the low temperature process "waste heat" or exhaust, are also possible configurations for cogeneration. Thus, cogeneration covers a very wide variety of energy conversion and utilization cycles and applies various equipment combinations to provide the desired match of electric power and process heat requirements at one site from one combination plant.

A1.3 ISSUES FOR SELECTING DSG TECHNOLOGIES

From the perspective of electric utility companies, there are principal issues which would be considered and evaluated in the process of selecting DSG technologies to be integrated into utility distribution systems. In addition to the principal issues, each utility tends to have unique characteristics which directly influence and have a major impact on the selection process. Examples of utility characteristics are: geographical location, size, energy resources, bulk energy system composition and configuration (generation and transmission), interconnections with other utilities, system load characteristics, economic conditions and type of utility (public or private).

Thus, the selection process and influence factors must be examined on an individual utility basis since each utility tends to be unique.

From an initial screening standpoint, the principal issues to be considered in selecting one or more DSG technology are: commercial availability of DSG, economics, DSG size and total capacity, energy resources, operational features, technical factors, and institutional and regulatory requirements. These issues will be considered in detail in subsequent parts of this study, principally in the section on "Feasibility of DSG Alternatives." These issues will be briefly described here for the purpose of clarifying the selection process described in Section A1.4, which summarizes the selection of DSG technologies to be used in this monitoring and Control Requirement Definition Study.

A1.3.1 COMMERCIAL AVAILABILITY

In the context of electric utility system planning for generation and transmission expansion, it is fundamental that any technology included in expansion plans must be commercially available, or that planners have reasonable assurance that it will be available when needed. From the standpoint of this study, it is not necessary to have this assurance but rather indications that a DSG technology has promise of becoming viable in the future time frame under consideration. Therefore DSG technologies may be included even though their commercial availability is not foreseen until the 1990s. However, if the technology is in an extremely early stage of development and technical or economic viability cannot be predicted, it is better to set this technology aside for purposes of this study.

A.1.3.2 ECONOMICS

To an electric utility company, the economics of any proposed system generation, transmission, or distribution expansion is of vital concern, since it directly affects revenue requirements and the cost of producing electrical energy. In analyzing the overall economic viability of a DSG technology, the cost of producing electric energy is fundamental in comparing it to other means of supplying the need. When the DSG technology uses a consumable fuel which must be obtained at direct cost, the DSG can be compared rather directly with other technologies by conventional cost comparison methods. When the primary energy input to a DSG is "free" as in the case of sun, wind, and to some extent water, a more complex analysis which compares "benefits" to "costs" over the lifetime of the plant must be made. The principal benefit will often be the displacement of "conventional" (i.e., fossil) energy by the renewable energy source. The nature of the renewable energy source, its availability and dependability, will determine if any system capacity credit can be assigned to it in the benefit/cost evaluation. There are additional factors which also must be considered.

In evaluating DSG technologies, all benefits such as reduced bulk transmission and distribution system losses should be credited to the DSG and added costs such as those required for Monitoring and Control should be charged to the DSGs.

A1.3.3 SIZE

Dispersed storage and generation has been defined as being located in and connected to the distribution portion of the electric utility system. Thus, it will be connected to the distribution system at some point between the secondary side of bulk power substations and the customer's premises. Generally the point of electrical connection will relate to the size (MW rating) of the DSG unit. In the broadest sense, DSGs may therefore range in size from a few kW, located on single residences or farms, to large units of many MW, which may have their own substation connected to the subtransmission circuit in the utility distribution system. A wide range of electrical ratings are possible for DSG applications and to some degree relate to the nature and characteristics of the type of DSG plant. As foreseen for the purposes of this study, the size range will be from 10 kW to 30 MW. In general the DSGs will be plants capable of automatic or semiautomatic unattended operation. This will be necessary to keep the operating costs low to achieve economic viability. However, certain DSGs such as a cogeneration plant will have operating personnel present for other portions of the plant and process, and the generation equipment will incur only incremental personnel operating costs. In contrast, central station plants connected to the bulk power transmission system are large complex plants which require continuous-duty operating personnel and staff and tend to be from 50 MW to several thousand MW in size.

A1.3.4 ENERGY

DSGs may be characterized by the type of energy they utilize in producing electricity. The type of energy in turn will have a major effect on DSG operational characteristics, as well as all the other selection issues. DSG technologies are divided into two basic categories: those that use nonrenewable fossil fuels and those that use renewable energy sources such as sun, wind, or water.

A third DSG category is that of energy storage in which electrical energy is withdrawn from the system at a time of low incremental cost and returned at a time of high incremental cost.

Fossil fuels inherently have the property of energy storage and thus can provide variation in electrical energy production on demand. In contrast, renewable sources tend to be periodic and/or variable in supply and are less convenient and less reliable as a source for a utility system which has a continuous need for electrical energy. Sunshine as used in solar thermal electric and photovoltaic plants is partially available on a 24 hour cycle; water is generally available on a variable seasonal basis with surges due to storms; and wind is randomly available with seasonal variations. Other renewable energy sources can provide continuous energy supply and are represented by sources such as geothermal and biomass/biofuel. The latter, however, is a form of stored chemical energy quite similar to fossil fuels. The constancy and predictability of an energy supply source for electric energy production have a significant effect on its value to a utility with regard to the overall system generating capacity which must be maintained to meet system load demands. Energy storage has the basic role of reducing energy production costs by more effectively utilizing large central station units which have low-incremental-cost of energy production and returning (supplying) the electrical energy to the power system during times of peak load to replace energy which would be produced by higher-incremental-cost (less efficient) peaking generation units. Storage can also be used as generation reserve to replace units which are out of service due to an unscheduled outage. Thus, the inherent nature and characteristics and supply quantity of the energy supply source are major issues in selecting DSGs for application on a specific utility.

A1.3.5 OPERATIONAL

Operational characteristics can have a significant influence on the suitability of specific DSGs for application on an electric utility system. As was described in the previous subsection, the most important operational characteristic regarding overall system operation is the reliability/availability of the DSG source. The ability to schedule the source, either continuously or periodically, with a high degree of dependability has definite generation capacity displacement value to a utility. On the other hand, if the electrical power output of a DSG is completely random, then it has no capacity displacement value and may actually require a greater amount of spinning reserve, depending on the total amount of connected random DSG generation. Other operational issues involve system operation and scheduling regarding the DSG's startup and shutdown time requirements. These will vary widely for different types of DSGs and have an influence on their flexibility for system-wide energy management functions.

A.1.3.6 TECHNICAL

Technical issues concern the complexity, reliability, and application of DSGs.

Complexity will primarily affect operation and maintenance requirements and costs. If a plant is extremely complex, it may require full time operators and considerably larger plant size than other DSGs in order to be economically viable.

Complexity will also affect the reliability of a plant since these technical issues are related. This in turn affects the availability of a plant and its value to the utility.

Application issues concern the matters of power quality and control, physical and electrical location within the distribution system, and integration of the DSGs into the distribution system. These application issues concern technical matters such as power flow, voltage level, and wave form control. The application of DSGs requires consideration of the conditions and characteristics of the particular part of the distribution system to which the DSG will be connected, and with which it must be compatibly integrated. Voltage, power flow, and system protection are of primary importance and require coordination for a successful DSG application.

A.1.3.7 INSTITUTIONAL REGULATION

Institutional and regulatory issues can have a major impact on DSG selection. For relatively small generating sources like DSGs, complex operating rules and procedures, lengthy and costly licensing procedures, and environmental constraints place disproportionate costs on these plants. By contrast, large plants with much larger capital investment can bear essentially the same costs more easily because they represent a lower percentage of total plant cost.

Other matters, such as favorable tax policies regarding write-off/depreciation and investment tax credits, can have a major impact on economic incentives and decisions regarding the viability of DSG technologies.

The recent (February 25, 1980) ruling of the Federal Energy Regulation Commission regarding PURPA Section 201 and 210 has made a significant step in the direction of helping to bring about the acceptance of small, customer-owned DSGs by the electric utility companies. Under the new regulations, electric utilities must purchase the electric energy and capacity made available by qualifying facilities at rates equal to the utility's generation cost or the cost of buying electric energy from other utilities. It would appear that institutional regulations are being brought in as an ally to assist in the acceptance of DSGs.

A1.4 SUMMARY OF REASONS FOR DSG SELECTION IN THIS REPORT

The emphasis of this report is on the monitoring and control requirements definition for DSG. Thus, it is worthwhile to be aware of the characteristics of the many possible DSG technologies which may be used within an electric utility distribution network. However, since what is needed is an understanding of the monitoring and control requirements for many DSG technologies, it is not essential that all possible DSG technologies be considered in detail. It is important that the key monitoring and control requirements include those characteristics which are common to all of the DSG technologies. Thus, in selecting the seven DSG technologies covered in this report, other DSG technologies from the total list in Section A1.2 were either eliminated by major screening issues, or else they were considered to be similar enough in monitoring and control requirements to be accommodated by the requirements of the seven selected DSG technologies.

DSG technologies which were set aside are:

- Fusion
- Magnetohydrodynamics
- Biomass/Biofuels
- Geothermal
- Hydroelectric Pumped Storage
- Compressed Air Storage
- Superconducting Magnetic Storage

DSG technologies which were retained for description are:

- Solar Thermal Electric
- Photovoltaics
- Wind
- Fuel Cell
- Storage Battery
- Hydroelectric (small, low head)
- Cogeneration

A brief explanation of the reasons the first set of DSG technologies were deleted will be given. This will basically include the screening issues described in Section A1.3 and/or similarities to The selected DSGs which will be described in detail in Sections A2.0 through 8.0 and therefore will not be discussed in this section. Table A1.4-1 provides a summary of the issues involved in determining elimination of the following candidate DSG technologies and where applicable their similarity to the selected DSG technologies.

<u>Fusion</u>

This technology was eliminated based on the selection issues of technology availability, which appears to be in the 21st century, and the anticipated MW size and complexity of commercial units, which will probably place them in the central station category.

Table A1.4-1

COMPARISON OF SELECTED DSG TECHNOLOGIES
AND ELIMINATED CANDIDATE TECHNOLOGIES

INDICATION OF SIMILARITIES BETWEEN DSG TECHNOLOGIES ELIMINATED AND DSG TECHNOLOGIES SELECTED

DSG TECHNOLOGIES SELECTED	DSG TECHNOLOGIES ELIMINATED						
	Fusion	MHD	Biomass	Geothermal	Hydro Pumped Storage	Compressed Air Storage	Superconducting Magnetic Storage
Solar Thermal Electric				X			
Photovoltaic							
Wind							
Fuel Cell							
Storage Battery					X	X	X
Hydroelectric					X		
Cogeneration		X	X	X			

INDICATION OF RELATION OF NON-DSG ISSUES TO DSG TECHNOLOGIES ELIMINATED

NON-DSG ISSUES	DSG TECHNOLOGIES ELIMINATED						
	Fusion	MHD	Biomass	Geothermal	Hydro Pumped Storage	Compressed Air Storage	Superconducting Magnetic Storage
Central Station Size	X	X	X	X	X	X	X
Long-Term Research and Development Required	X						X

Magnetohydrodynamics

All efforts and indications of the present U.S. programs are aimed at MHD plants which will be in the 100 to 1000 MW size range. This classifies this technology as central station size rather than DSG.

Biomass/Biofuels

This technology, which includes the combustion (or conversion to gas) of organic plant material, is quite similar to fossil fuel conventional power plants in that the primary energy source is in the form of stored chemical energy. For this reason and because of the similarity of this technology to the DSG technology of co-generation, it was decided that all biomass/biofuels monitor and control requirements would not be included in the seven selected DSG technologies.

Geothermal

This technology with its relatively constant energy supply was considered similar to conventional steam electric plants, and its monitor and control requirements were considered similar to those of the cogeneration DSG technology. Further, indications are that geothermal plants will tend to be large in order to justify the exploration and source development costs.

Hydroelectric Pumped Storage

The combined characteristics of small low head hydro and energy storage DSG technologies were considered sufficient to cover the monitor and control requirements of this technology. Further, the hydroelectric pumped storage plants tend to be large capacity plants which are connected directly to the bulk transmission system.

Compressed Air

The economics of this technology favor units rated 200 MW or larger. As such they would be connected directly to the bulk transmission system and not be considered a DSG technology.

Superconducting Magnetic Storage

This technology was considered to be too far from commercial availability to be included in this study. Further indications are that the economy-of-scale principles will apply to this technology, and the size will be in the several hundred MW range. Thus, it will be beyond DSG technology size.

A1.5 DESCRIPTIONS OF SEVEN SELECTED DSG TECHNOLOGIES

The common functions of the monitoring and remote control of DSGs are similar in several of the selected DSGs. They include such functions as being on or off, power output level, and the conditions of the subsystems. An effort has been made to emphasize the external monitoring and control similarities for the selected DSG technologies rather than to stress the individual differences between them at the subsystem and sub-subsystem level of detail.

In identifying each selected DSG technology, an effort has been made to define the technology in a generic sense and to explain its function, operation, feasibility, availability, and cost. This report also describes the physical and chemical principles of each technology, including those that limit when and where each is limited in the energy output it can provide. In each case the more important characteristics of the internal controls necessary to make the particular technology operate are described.

The first technology discussed (Section A2.0) is solar thermal electric conversion (STE). The description is presented in greater detail than for the other technologies in order to illustrate the extent to which the designers of each technology must go to make that particular DSG operate effectively. It was not considered appropriate to expound on each technology in such great detail. Nevertheless, from the descriptions given it is possible to identify a similar monitoring and control hierarchy as perceived by the human operator at the distribution dispatch center.

Some of the technologies described are new and experimental, and there may be a period of a decade or more before commercialization can be realized. Other technologies, such as hydro, are mature and may be put into service in a much shorter time. This report has placed emphasis on the basic characteristics of each of the DSGs. The future trends and growth potential of each of the DSGs during the near term, 1980-1985, and the longer term, 1985-2000, are discussed in Appendix B entitled, "State of the Art, Trends and Potential Growth of Selected DSG Technologies."

Section A2

SOLAR THERMAL ELECTRIC CONVERSION TECHNOLOGY

A2.1 DEFINITION AND DESCRIPTION OF PHYSICAL PRINCIPLES

Solar Thermal Electric energy conversion systems collect solar radiation and convert it into high temperature heat. The heat is transferred to a working fluid, often water or steam, for use in a mechanical-electrical generation system. Solar thermal electric energy may be used in an energy system providing both electricity and thermal energy. Energy storage may also be included as part of the thermal energy system.

A2.1.1 DESCRIPTION OF PHYSICAL PRINCIPLES

Solar Thermal Electric systems are in the early design stage in the United States, and developmental systems and equipment are being planned for the mid 1980s. For small (1 MWe) solar power systems three systems concepts are being analyzed:

- Central receiver
- Point focusing, distributed collector, central power conversion
- Point focusing, distributed collector, and distributed power conversion

Reference 2 presents a summary of EEI Contractor Reports covering the work being done by McDonnell Douglas Astronautics, General Electric, and Ford Aerospace and Communications respectively for each of these three systems concepts. Although the three concepts are different in detail, from a control point of view they have common principles because they depend primarily on automatic operation.

Preliminary work has emphasized systems which convert solar energy to steam (850 ^{o}F-1050 ^{o}F) for use with conventional steam turbine generators providing an ac output to a utility network. The Ford Autonutronics approach, which involves point focusing, distributed collectors, and power conversion, uses a Stirling Engine instead of a steam turbine generator, with sodium at 1382 ^{o}F as the heat transfer medium and helium as the working gas.

To achieve high temperatures concentrator-type collectors are required, and both distributed-collector and central-receiver options are being considered. The distributed collector systems may use many individual elements (e.g., 150), each element consisting of a central boiler and a concentrating collector. The central receiver system may use a number of heliostats which reflect sunlight to a central receiver located at the top of a tower. For either type of system, tracing of the sun by the collector is required to improve performance.

Common to all of the solar thermal electric systems are control subsystems for collectors, power conversion, energy transport, and energy storage. Also common to all of the solar thermal electric systems is the fact that sunlight is available for only a limited amount of time. Utility systems should be able to supply the customer's electrical needs whenever they exist and not only when the sun is shining. One alternative is to generate electrical energy from the sun and store it to meet customer needs when the sun is not shining. Another alternative is to use the electrical energy generated from the solar thermal electric system and to use other energy sources such as coal, nuclear, or oil when the sun is not available.

Detailed engineering studies of these alternatives have been made. The choice between the two depends on the values of the various design parameters and on the choice of decision criteria used in making the judgment. It is evident that the monitoring and control requirements for the solar thermal electric system may differ in detail depending on the concept chosen. However, a number of the monitoring and control requirements are quite similar in function and equipment despite the differences in the specific hardware implementation of the solar thermal electric system.

A2.2 DESCRIPTION OF AN ILLUSTRATIVE SOLAR THERMAL ELECTRIC SYSTEM AND CONTROLS

The solar thermal electric system described as an illustrative example is a 1 MWe unit proposed by the General Electric Company in Reference 1. The system has no storage and delivers approximately 2,800,000 kWh annually at approximately 1 MWe. The design concept proposed utilizes collectors of two types:

- A saturated steam field (approximately 80% of the collectors - about 200 in number)
- A superheated steam field (approximately 20% of the collectors - about 50 in number)

The two fields are connected by a steam accumulator as shown schematically in Figure A2.2-1. Basically, the system operates by generating saturated steam, collecting this saturated steam (quality varying with insolation) in a steam accumulator, and then superheating the steam from the accumulator in the superheated field prior to entry into the steam turbine. This concept requires only the turbine control valves for controlling the collector field.

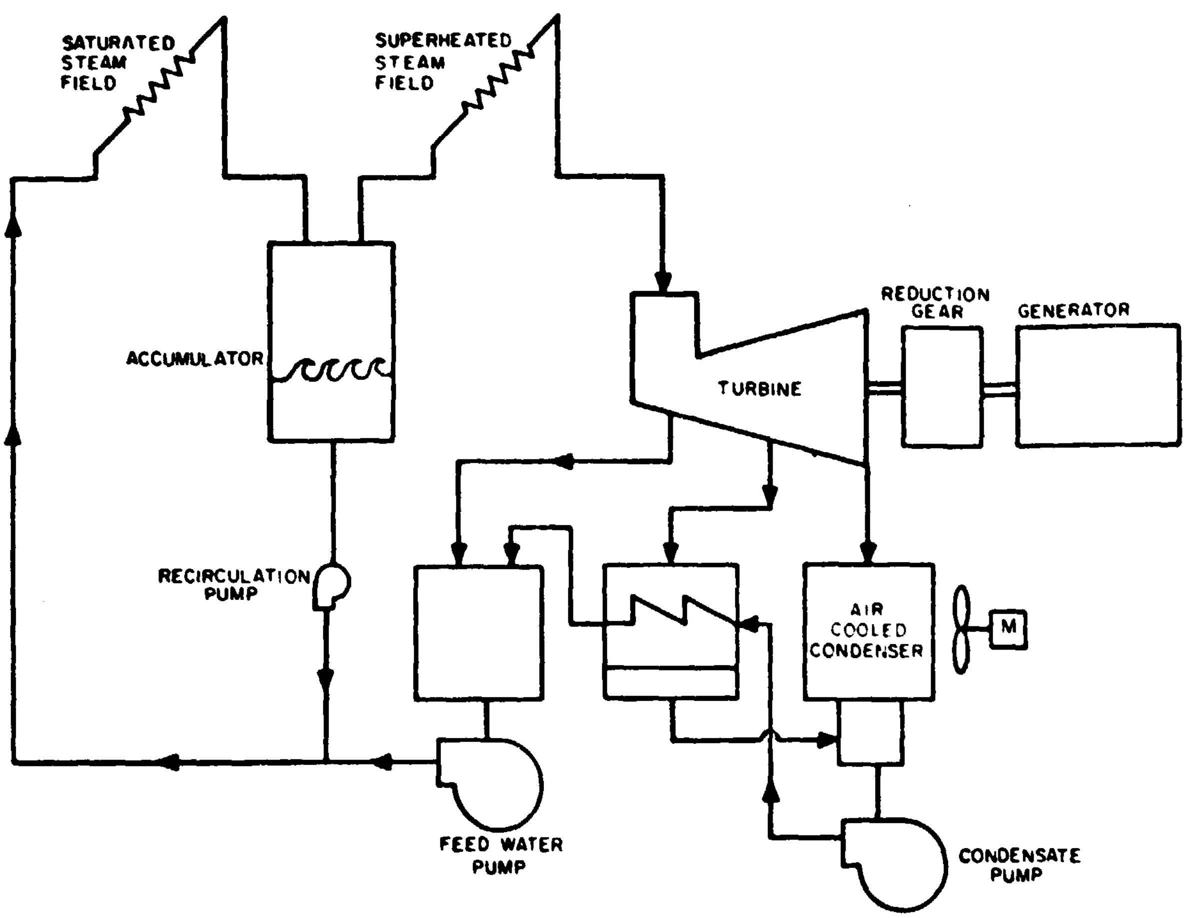


Figure A2.2-1. Basic System Schematic

The master control subsystem directs and monitors all control functions within the solar plant using a fully automatic control technique. A computer system performs process calculations, interfaces with other plant subsystems, coordinates control action, and monitors and records data, thus allowing automatic unattended operation of the plant while providing reliable system protection. This control concept is especially suited for a solar thermal electric power plant where variations in the heat source intensity during the course of the day require continuous adjustments to the process flow rates. The use of a master computer control minimizes the length of time that the plant operates in less than an optimum condition.

A.2.2.1 CONTROL PHILOSOPHY

The primary objective of the small solar power plant is to maximize the plant's energy output. Therefore, electrical power generation commences as soon as and continues as long as insolation levels permit. If insolation levels become too low to support power generation, the plant is placed in a standby mode and electrical power generation recommences when insolation levels increase sufficiently. The generator is disconnected from the grid as soon as it stops producing power. No-load operation to maintain grid synchronization is not utilized, and the generator is not allowed to "motor" off-grid on battery power. The plant is shut down only if an end-of-day or emergency condition exists, or if so directed by the utility or local operator.

A2.2.2 OPERATION WITH ENERGY STORAGE

The manner in which the plant is operated depends, to a large degree, on whether energy storage is utilized. If dedicated energy storage is used, all of the power output is directed to the utility grid until the output to the grid reaches 1 MWe. As soon as this occurs, power in excess of 1 MWe is used to charge the energy storage subsystem. Conversely, when the output falls below 700 kWe, power from storage, if available, is directed to the grid in an attempt to maintain a combined generator and storage output of 700 kWe. Electricity is always discharged from storage to the grid as soon as the generator output falls below 700 kWe and continues until the generator output increases above 700 kWe or until the storage subsystem is discharged. This means that the electrical storage subsystem is always discharged at the end of the day rather than storing energy overnight for service power or for startup the next day. If there is no energy storage in the power plant, however, there is no power-leveling capability and the power supplied to the utility grid is just the output of the turbine-generator less auxiliaries.

There are times when a defocus of a portion or all of the collector field is necessary. Collectors are defocused to prevent overheating if the turbine capacity is exceeded or to shut the plant down in response to an emergency condition. Defocus of collectors is also necessary when the turbine-generator output to the grid exceeds 1 MWe while the energy storage subsystem is fully charged or when there is no energy storage. The limit of 1 MWe to the grid is an artificial boundary. In a commercial solar power plant, there probably would be no limit on the amount of power that could be supplied to the grid.

Finally, the type of control used to accomplish the above objectives is automatic with unattended operation and system protection at the local plant site and with remote monitoring and control at the utility dispatch level. Most of the master control functions at the plant, including all of the more complex control tasks, are performed by a microcomputer system. Other sequencing and simpler control functions are provided by programmable logic controllers. The data acquisition and alarm system is centered in a standard, self-contained, key-programmable microprocessor and various peripheral devices. All of this equipment, although designed for remote automatic operation, is capable of local, on-site operation to facilitate checkout and maintenance procedures and to allow local control of the plant during severe environmental conditions.

The remote control provided at the utility is minimal, consisting essentially of ON PERMISSIVE/SHUTDOWN/AUTOMATIC functions. Key parameters are monitored at the utility location. However, an alarm condition requires the dispatching of a troubleshooter to the plant site. This remote monitoring and control is accomplished using a Supervisory Control and Data Acquisition (SCADA) system.

A2.2.3 MASTER CONTROL SUBSYSTEM

Within the master control subsystem, as shown in Figure A2.2.3-1, the operating mode control establishes the necessary valve positions and switches pumps, fans, and breakers on and off for the various operating modes of the plant. This control function also determines, by sensing key plant parameters, when to switch from one mode to another.

Data acquisition and alarm, local operator controls and utility control and monitoring are three other interfaces within the master control subsystem. The data acquisition and alarm function is provided by a standard, self-contained, key-programmable, miniprocessor-based data acquisition/alarm system complete with on-board printer. The system monitors and records identified key operating parameters periodically and records certain signals when they exceed a predetermined value. The location and identification of the instrumentation for the data acquisition system is shown in Figure A2.2.3-2. The local operator control panel is an on-site console where manual operation of the plant may be established, plant parameters monitored, and system checkout and troubleshooting performed. Normally, however, the local operator control is unmanned, with supervisory control being provided by the utility. The utility control consists of a relatively few overall plant control functions and monitoring of certain key parameters. Alarm signals require dispatching of troubleshooting personnel to the power plant site for the necessary checkout and repairs. The instrumentation shown in Figure A2.2.3-2 is

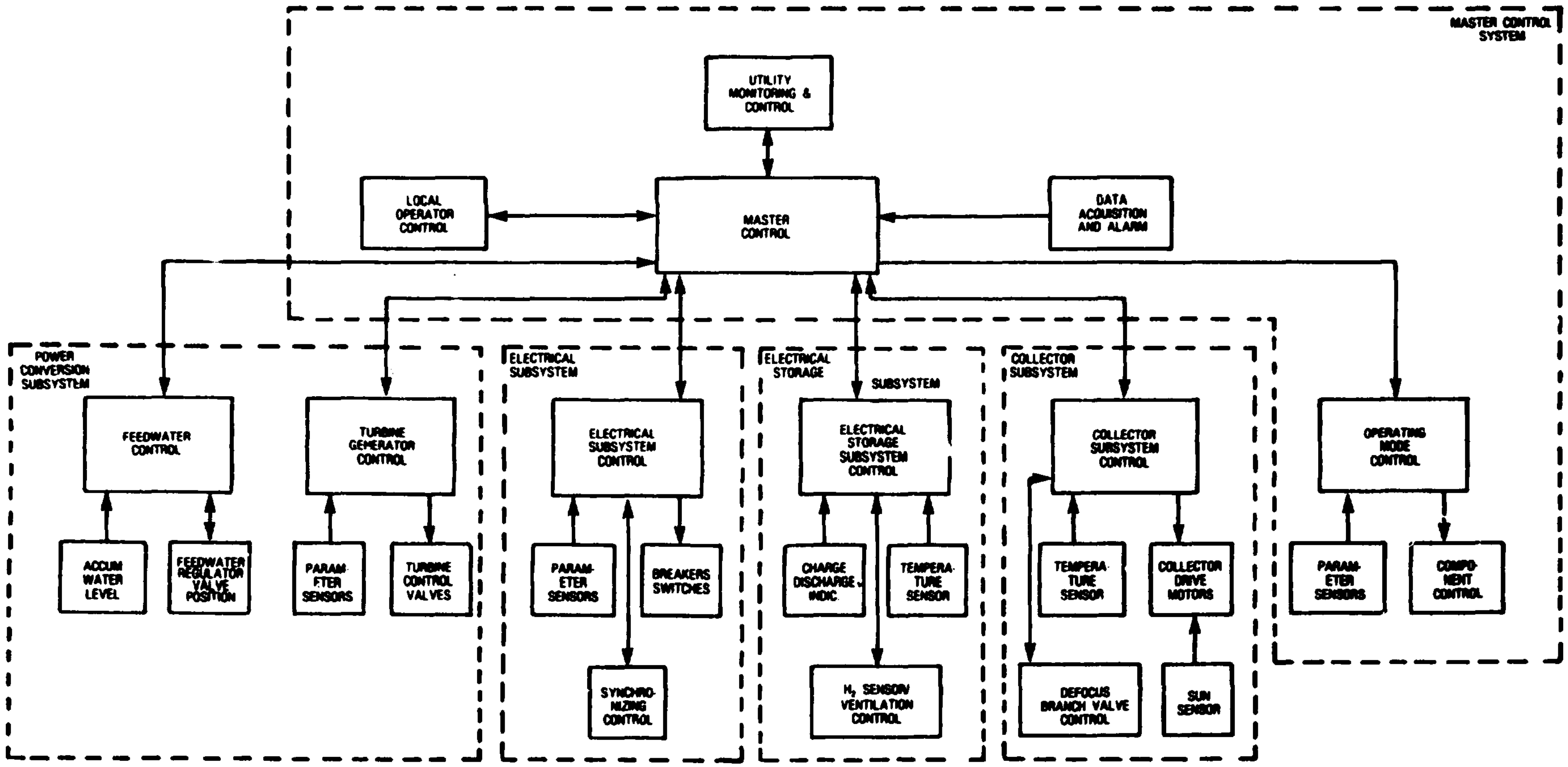


Figure 2.2.3-1. Master Control Functional Diagram

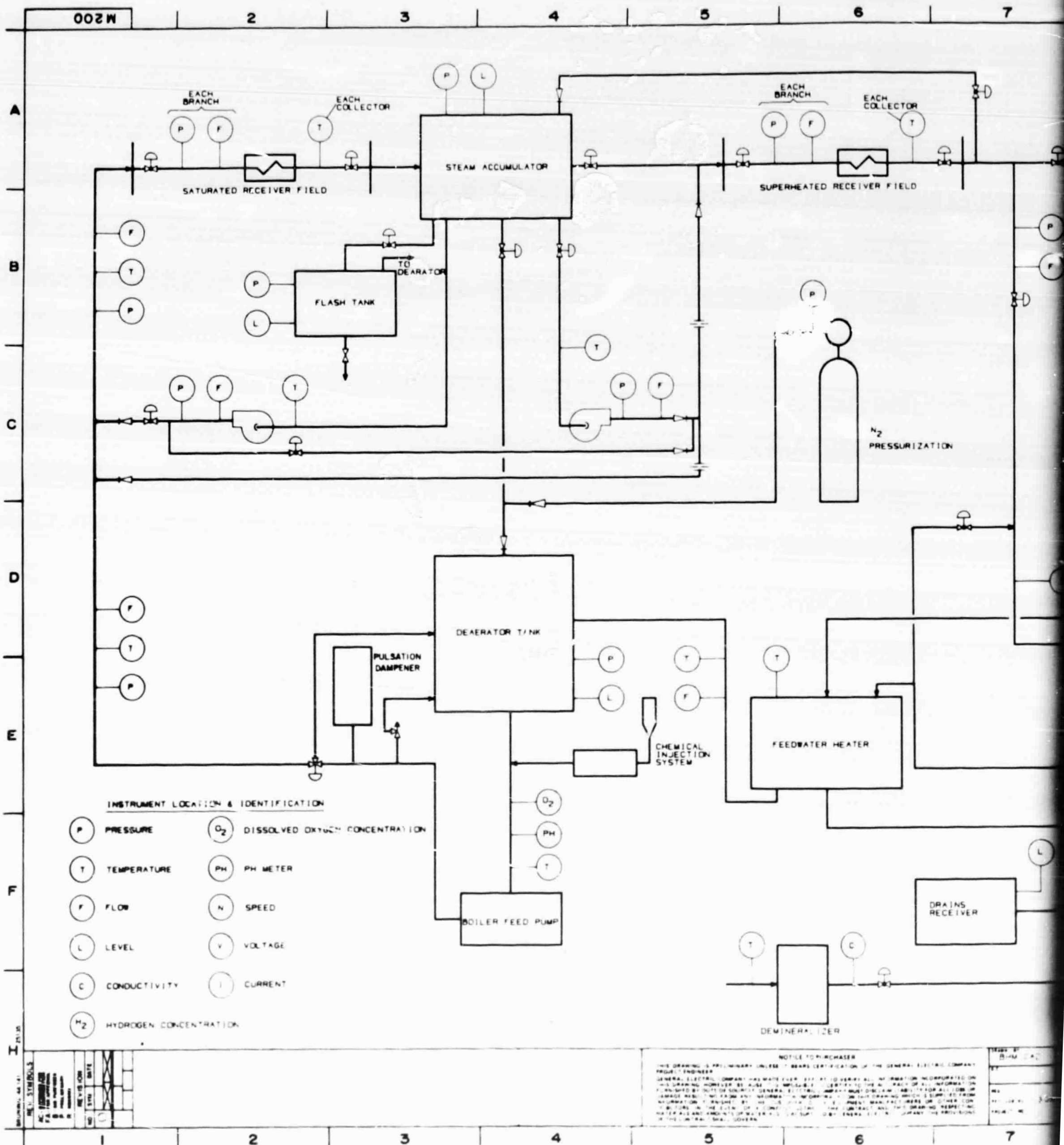
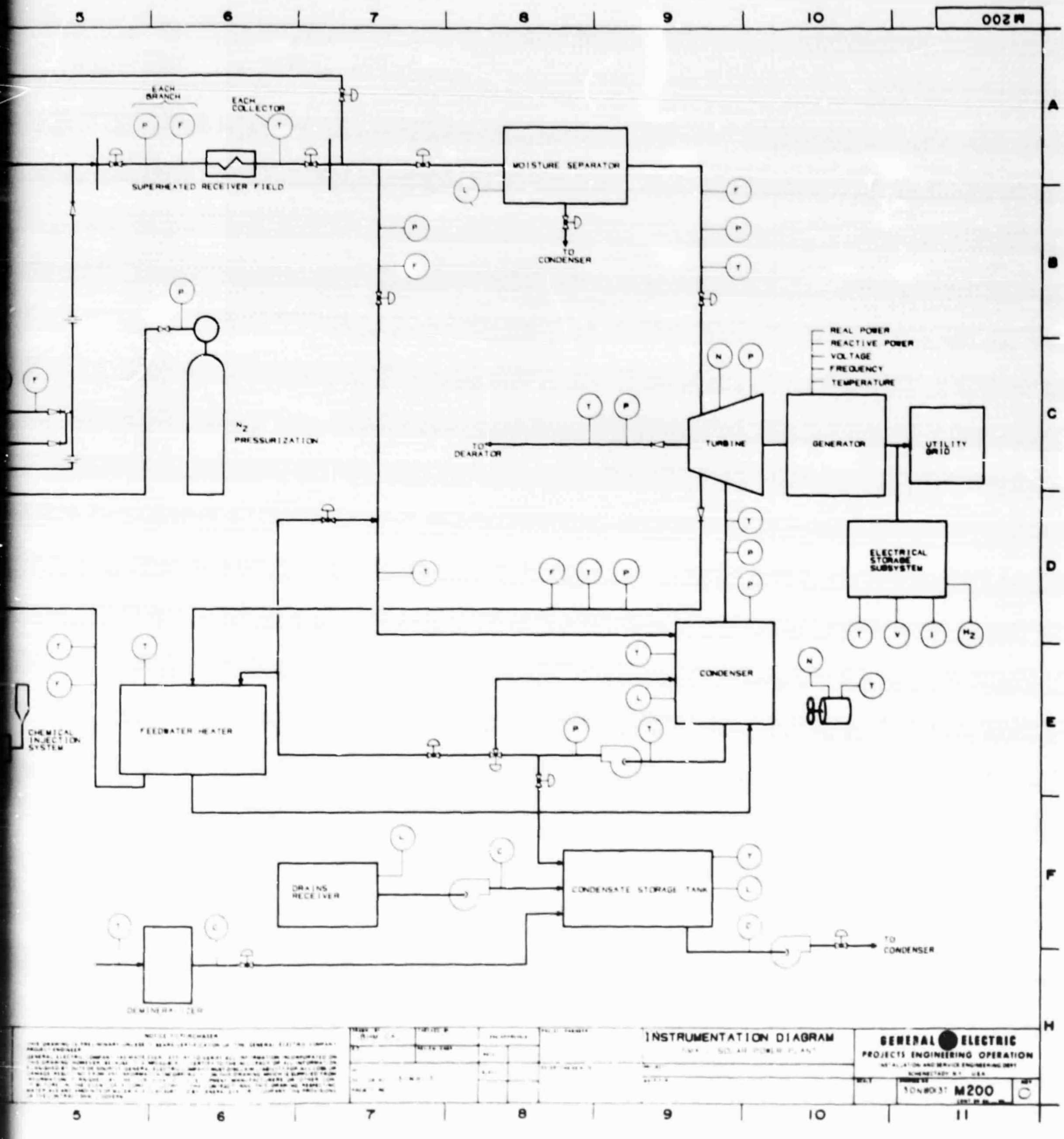


Figure A2.2.3-2. Instrumentation Diagram for
System of a Small Solar Pow

FOLDOUT FRAME



-2. Instrumentation Diagram for the Data Acquisition System of a Small Solar Power Plant

FOLDOUT FRAME 2

applicable only to the experimental system (EE-1). A commercial plant would probably not be as heavily instrumented.

The power plant control interfaces for the subsystems described above are shown in Figure A2.2.3-3. Also shown in the figure are the local control functions (provided by logic controllers) from an individual parameter sensor to a control component. Examples of this type of local control are various component water levels and the desuperheating water flow control to the turbine bypass line.

The master control subsystem interfaces with the power conversion, electrical, electrical storage, and collector subsystems in implementing automatic control of the power plant. Each of these interfaces is discussed in more detail below.

A2.2.3.1 Power Conversion Subsystem Control Unit

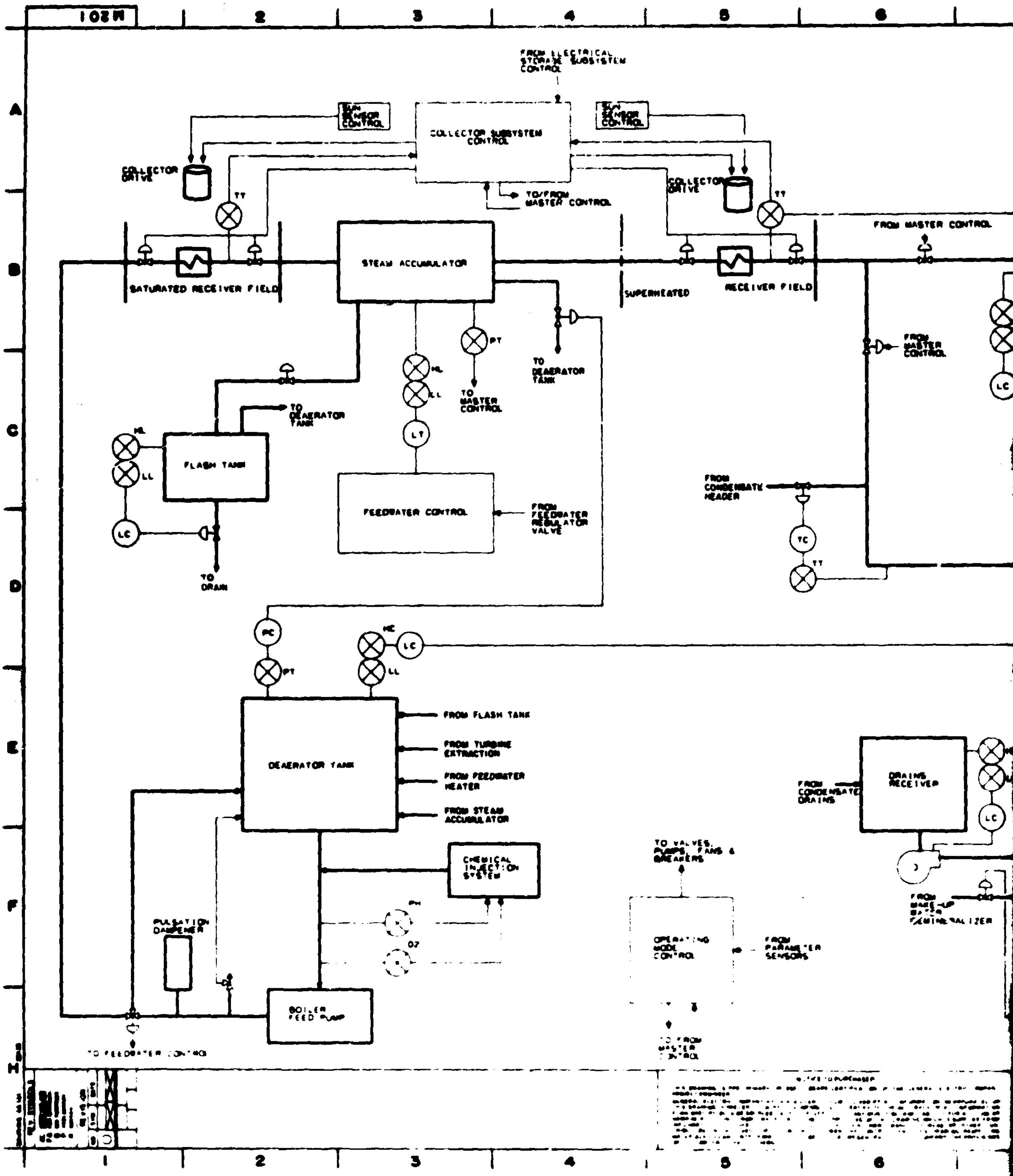
Within the power conversion subsystem control unit, the turbine-generator control has the following functions:

- To operate the turbine control valves to maintain desired pressures in the collector fields during both transient and steady-state operation and to open the turbine control valves to provide increased steam flow to the superheated receiver field during periods of increasing insolation

- To generate a partial collector defocus signal when thermal energy input exceeds the turbine capacity

- To initiate emergency control actions for fault conditions of the turbine-generator unit

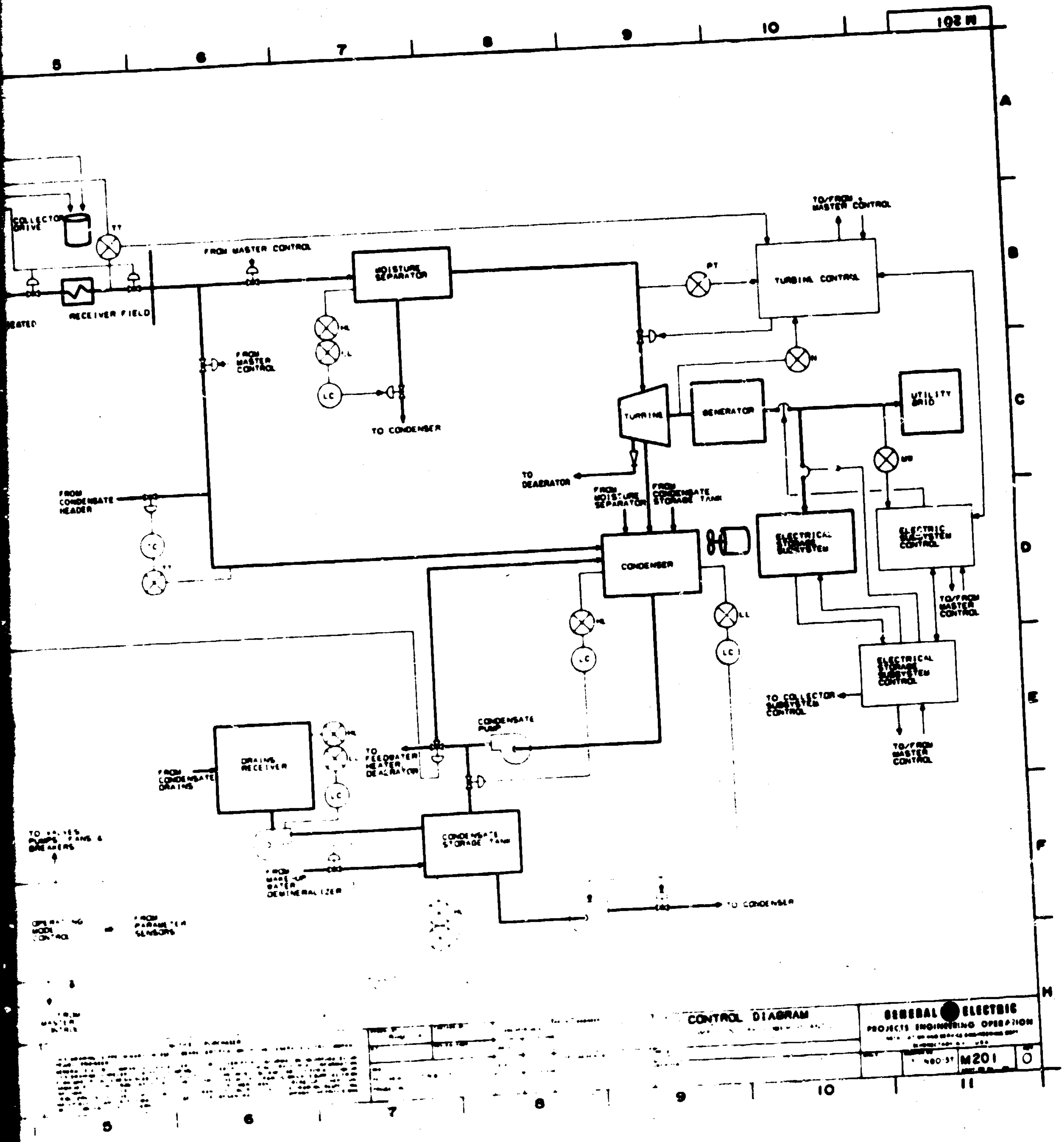
The first function is necessary for transient control during periods of varying insolation. If the plant is operating at a reduced steady-state insolation level and insolation suddenly increases, the transient combination of low steam flow rates through the receivers with increased energy input may result in unacceptably high temperatures at the receiver outlets before new steady-state conditions can be established. This is primarily a problem in the superheated collectors where saturated steam enters the receivers. A small amount of superheating is allowable in the saturated field receivers, but outlet temperatures will be low compared to those in the superheated field receivers since the inlet water to the saturated receivers is subcooled. To minimize the problem, the turbine control valves are operated to maintain an essentially constant pressure in the steam accumulator. As the insolation level increases, the temperature and pressure of the steam leaving the superheated receivers starts to increase because of the relatively low flow rate. The turbine control valves open to maintain pressure at its original value, which increases the steam flow through the receivers and thus decreases temperatures. To insure that an individual receiver does not exceed a metal temperature limit, a temperature indicator is located in the outlet of each superheated



PRECEDING PAGE BLANK NOT FILMED

FOLDOUT FRAME

Figure A2.2.3-3. Control Interfaces fo



fo

.3-3. Control Interfaces for Power Plant Subsystems

FOLDOUT FRAME

receiver. Thus, when a high temperature condition is sensed at one or more superheated receiver outlets, the turbine control valves are opened further, which causes steam pressure to drop in the steam accumulator and water to flash to additional steam. The increased steam flow carries away more heat and causes the receiver outlet temperatures to decrease to acceptable levels.

It is anticipated that this scheme will adequately control the receiver metal temperatures during transient conditions. If, however, subsequent dynamic simulation indicates a problem will be encountered during this condition, an alternative design, such as injecting desuperheating water into each superheating field receiver, may be required. The control of such a design would be relatively straightforward, using the receiver outlet metal temperature to determine the amount of water to be sprayed into the receiver inlet piping. Note that a sudden decrease in insolation results in a suppression of steam generation (since there will transiently be more feedwater flow than steam flow) but that this condition, although undesirable, is safe in that metal temperatures are not elevated.

The second function of the turbine-generator control becomes necessary when the total thermal energy gathered by the collector field exceeds the turbine-generator capacity. This occurs on days of maximum solar insolation since the turbine capacity is somewhat less than that required for the annual peak insolation value. For this situation, a portion of the collector field is defocused so that the thermal energy gathered by the collector field does not exceed the rated turbine capacity. Defocusing is accomplished by transmitting steering signals to selected collector drive motors which cause the collectors to defocus to a position 2 to 5^{o} behind the coarse tracking azimuthal position of the remaining focused collectors. The defocusing steering signal automatically deactivates the individual sun sensor fine focus control, which would tend to return the collector to its focused position. During this period of defocus, care is taken to insure that the focused image of the sun does not fall on a structural member of the concentrator or a receiver component, such as a valve or piping.

During a partial defocus of collectors an unbalanced flow condition may result. For this reason, the energy transport piping of the defocused collectors is isolated from the remainder of the field. In order to maintain the proper balance between saturated and superheated collectors, collectors are defocused and isolated in the ratio of approximately 4:1 in the saturated and superheated fields, respectively. In the saturated field, defocusing and isolating occurs in blocks of six collectors, which represent a single branch, to minimize the number of automatic isolation valves. In the superheated field, control is based on blocks of six collectors (i.e., one branch) except that the collectors in approximately two branches have individual isolation control in order to achieve an acceptable saturated-to-superheated collector ratio.

The second control within the power conversion subsystem unit, the feedwater control, regulates the position of the feedwater regulator valve (and hence the feedwater flowrate) based on the water level in the steam accumulator. The feedwater flowrate is adjusted as necessary to maintain the water level in the steam accumulator within a prescribed band. Thus, an increase in the flowrate of steam from the accumulator results in a lowered water level in the accumulator, which in turn causes the feedwater regulator valve to open and admit more feedwater. The net effect is to match the feedwater flow with the steam flow from the steam accumulator.

A.2.2.3.2 Electrical Subsystem Control

The electrical subsystem control functions are:

- To synchronize the generator electrical output with the utility grid when coming on-line
- To open the breaker between the generator and the utility grid when the turbine-generator power output becomes so low that synchronization with the grid is jeopardized
- To open the appropriate breakers when fault conditions occur within the electrical subsystem
- To start the emergency fossil generator upon loss of electrical power to the plant from the utility grid in order to establish or maintain a controlled and safe shutdown procedure
- To provide a defocus signal to the collector subsystem control when the plant output to the utility grid exceeds 1 MWe

Most of these functions have been discussed previously as part of the plant control philosophy. One additional function is that of providing a backup emergency power source to the plant. While the plant is producing power during the day, electrical power for the various auxiliary loads (such as pumps, enclosure fans, collector drive motors, and control equipment) is supplied by the generator output. During periods of no power generation (such as at night or during loss of insolation in the day) these electrical loads are supplied by a service connection to the utility grid. If this service connection to the grid itself is lost, an emergency power generator provides backup power for essential plant functions. This is especially critical to insure that the plant is not left in an unsafe condition when power is lost. In addition, a complete loss of power would result in a loss of memory function in the master control subsystem, such that the master control would be inoperative even if service power returned at a later time. The size of the emergency generator is minimized to reduce fuel costs and storage capacity. The emergency generator starts automatically when it senses an underfrequency condition in the bus and sheds all but the most essential loads by operating the proper breakers.

A2.2.3.3 Storage Battery Subsystem Control

The storage battery subsystem control has five functions:

- To terminate battery charging when voltage/temperature sensors indicate a fully charged condition
- To terminate battery discharge (i.e., open breaker) when voltage/temperature sensors indicate a fully discharged condition as established for maximum battery life
- To sense hydrogen level in the battery enclosures and to ventilate as necessary
- To provide a "fully charged" signal to the collector and power conversion subsystems to effect a partial defocus if necessary
- To commence storage battery charge/discharge operations as conditions permit

One important function of the storage battery subsystem control is to prevent a dangerous accumulation of hydrogen in the battery enclosures. The hydrogen level is monitored and maintained below an established limit by ventilating as necessary. Hydrogen production is a problem only during charging, and then occurs only during the last 10-20% of the charge. However, the potential for an explosion requires special precautions. Arsine (arsenic hydride) and stibine (antimony hydride) are also produced during battery charging. Although the amount of arsine and stibine produced relative to the amount of hydrogen is quite small, their high toxicity levels may require even more ventilation than is required to reduce the hydrogen concentration to a safe level. Since arsine, stibine, and hydrogen are produced in fixed relative amounts, monitoring for hydrogen and ventilating sufficiently insures that arsine and stibine levels remain below their environmental limits.

A2.2.3.4 Collector Subsystem Control

The collector subsystem control has the following functions:

- To provide steering signals to the collector drive motors as a function of time-of-day and day-of-year (coarse focus control)
- To provide local individual collector fine focus control using sun sensors
- To provide receiver outlet temperature signals for turbine-generator control and for out-of-limit indications
- To defocus and isolate collectors based on out-of-limit temperature pressure indications

- To defocus and isolate collectors when excess energy is supplied to the turbine or when more than 1 MWe is being supplied to the utility grid

The defocus of collectors for an alarm condition (e.g., high temperature or low pressure) differs from the defocus scheme previously described in that the collectors are directed to the stow position rather than being defocused about 2 to 5^{o} from the rest of the field. Their isolation valves are shut off in the same manner, however, in order to maintain the desired ratio of saturated to superheated collectors. Defocus and shutdown of one or more collectors in one field due to an abnormal condition may require the defocus and shutdown of an appropriate number of collectors in the other field to maintain the balance between the two fields.

A2.2.4 OPERATING MODES

A description of the major operating modes, from a process flow standpoint, for a small solar power plant is presented in the following sections. A brief summary of the various operating modes is presented in Table A2.2.4-1.

In the nighttime/recirculation mode, Figure A2.2.4-1, the plant is shut down, the collectors are moved to the stow position, and electrical power for various auxiliary loads is supplied by the grid. If freeze protection of the saturated and superheated receiver fields is required, a small recirculation pump is operated. If freeze protection is not required, the pump is shut off and the system remains idle. A positive pressure of nitrogen is maintained in both the steam accumulator and the deaerator tank to prevent oxygen entry into these tanks and into the collector fields. With the exception of the collector and energy transport subsystems, the small solar plant is totally contained within submodule enclosures which provide environmental protection (from freeze, wind, hail, sand, etc.) for the components therein.

Based on clock time and sun declination/rise time data, the master control initiates the first phase of startup as shown in Figure A2.2.4-1. The larger recirculation pump is started (after the smaller recirculating pump is secured, if necessary) and cooling to the condenser is begun. The condenser vacuum pump is also switched on to start drawing a vacuum in the condenser. The collectors are directed to the coarse tracking position by steering pulses from the master controller. Fine focusing of the collectors is provided by the individual collector sun sensors. The water in both the saturated and superheated receiver fields is heated and steam is produced during this phase until a predetermined pressure is attained in the steam accumulator. If this pressure is not reached within a fixed time period, as might be the case with very low insolation levels, the plant is switched to the standby mode.

If the prescribed pressure is reached in the steam accumulator within the time limit, the master control switches to phase II of startup as shown in Figure A2.2.4-1. Recirculation through the larger pump is secured; the smaller saturated receiver field recirculation pump is started; and steam is bled from the superheated receiver field to the condenser via the turbine bypass line. The condensate, boiler feed, and chemical injection pumps are all started, thus establishing a normal flow of steam or water through most of the plant components. Condensate is chased from the steam lines as the steam lines are heated up. Steam is also bled to the deaerator tank to commence deaeration of the boiler feed water. At the same time, the steam is desuperheated as required in the turbine bypass line prior to admission to the condenser. This phase of startup continues until steam conditions at the superheated receiver outlet are correct for turbine operation.

Table A2.2.4-1

SUMMARY OF OPERATING MODES

OPERATING MODE	CONTROL FUNCTIONS
Nighttime/Recirculation	• Plant shutdown; collectors in stow position
	• Electrical power for auxiliary loads provided by grid with diesel-generator backup
	• Positive nitrogen pressure in steam accumulator and deaerator
	• Small recirculation pump operating for freeze protection of field, if required
Startup (Phase I)	• Collectors coarse tracking per steering signals from master control
	• Collectors fine focused using individual sun sensors
	• Water circulated in both saturated and superheated receiver fields using large recirculation pump to charge accumulator
Startup (Phase II)	• Large recirculation pump secured; recirculation through saturated receiver field only using small recirculation pump
	• Steam from accumulator superheated and routed to condenser via turbine by-pass line
	• Condensate, feedwater and chemical injection pumps started (normal condensate/feedwater flow established)
	• Steam bled to deaerator
Normal	• Steam admitted to turbine
	• Generator synchronized to grid
	• Excess power used for battery charging
	• Steam accumulator periodically blown down to flash tank
	• Partial defocus and isolation of collectors if: - Energy to turbine exceeds turbine capacity - Power to grid exceeds 1 MWe with batteries fully charged.
	• Generator disconnected from grid if power output drops to zero; resynchronized when power output increases due to insolation fluctuations
	• Battery commences discharging to grid when generator power output to grid drops below 700 kWe
Shutdown	• Occurs when insolation level decreases to point of no electrical power generation and master control indicates end of day
	• Batteries continue to discharge to grid
	• Sequence of shutdown is reverse of startup, with plant ending in nighttime mode

Table A2.2.4-1 (Cont'd)

SUMMARY OF OPERATING MODES

OPERATING MODE	CONTROL FUNCTIONS
Emergency Shutdown	• Actuates for major malfunction or alarm indication • Initiates emergency shutdown sequence similar to normal shutdown • Plant control must be reset prior to plant startup
Standby	• Occurs with loss of insolation during day • Auxiliary power requirements minimized • Collectors continue to coarse track • Plant returns to normal operating mode when insolation returns

When steam conditions permit, normal operation per Figure A2.2.4-4 is commenced. Steam is admitted to the turbine and the turbine started. As steam passes through the turbine, steam is extracted for feedwater deaeration and for feedwater heating. When steam flow is sufficient, the generator is synchronized to the utility grid and electricity supplied to the grid. Excess power is used to charge the storage battery subsystem as soon as the generator output exceeds 1 MWe. Since the steam accumulator tends to concentrate impurities in the feedwater (due to the recirculation flow and steam generation), a portion of the water in the accumulator is blown down to a flash tank. Steam drawn off from the flash tank is directed to the deaerator tank, while the liquid water is discharged to the waste drain system.

Operation continues in this manner as long as sufficient solar insolation exists, with the various subsystem controls and logic controllers maintaining normal conditions in the individual components. If insolation decreases temporarily, the steam accumulator water level indication causes the feedwater regulation valve to close down so that new steady-state conditions are established at a lower power level and flow rate. If the generator output falls below 700 kWe, additional energy will be drawn from the storage battery subsystem to maintain a plant output of 700 kWe. If the insolation level decreases below that required to maintain synchronization with the grid, the master control will initiate a controlled plant shutdown to the standby mode. When sufficient insolation returns, the plant is started up from the standby mode to the normal operating mode.

Although the normal operating philosophy is to charge the storage battery subsystem as soon as plant output exceeds 1 MWe and to start discharging the storage battery to the grid as soon as the solar plant power output drops below 700 kWe, this is not the only mode that may occur. If the storage battery subsystem is out of commission, operation from only the turbine-generator occurs. If a loss of insolation occurs before a sufficient charge has been accumulated in the storage battery subsystem, the same situation exists, and power to the grid is only that value put out by the generator. Similarly, there are times when power to the grid is supplied only by the storage battery, such as at the end of the day when insolation has ceased and the storage battery is charged. Finally, if lead-acid batteries are used in the storage battery subsystem, an equalization charge is required every one to two weeks to insure that all cells are at the same charge condition. Depending on plant and grid conditions, this charge could be supplied by either the turbine-generator or the grid. The important point is that there are a number of different electrical line-ups possible with the generator, electrical storage and utility grid, and the particular combination in use at a given time is determined by the conditions that exist at that time. Table 2.2.4-2 is a summary of the various possible electrical alignments and the conditions that would cause each to occur.

Table A2.2.4-2

SUMMARY OF ELECTRICAL ALIGNMENTS

ALIGNMENTS	OCCURS FOR FOLLOWING CONDITIONS:
Generator output to grid only	• Before sufficient power is generated to charge storage (power to grid <1 MWe)
	• If storage battery is out of commission
	• If not storage battery is utilized
Generator output to grid and storage	• When generator output ≥ 1 MWe and storage battery is not fully charged
Generator output to storage only	• When batteries require equalization charge and connection to grid is not possible
Generator and storage output to grid	• When generator power output <700 kWe and storage battery is partially charged
Storage output to grid only	• When generator is disconnected from grid and storage is at least partially charged (i.e., end of day, during temporary loss of insolation)
Grid to storage only	• When batteries require equalization charge and insolation is too low to generate power
Grid to plant	• To supply auxiliary power loads to plant during periods of no insolation
Storage to plant	• To supply auxiliary power loads to plant during periods of no insolation if grid connection is not possible and storage is at least partially charged
Emergency generator to plant	• When neither grid nor storage nor turbine generator energizes vital services bus bar

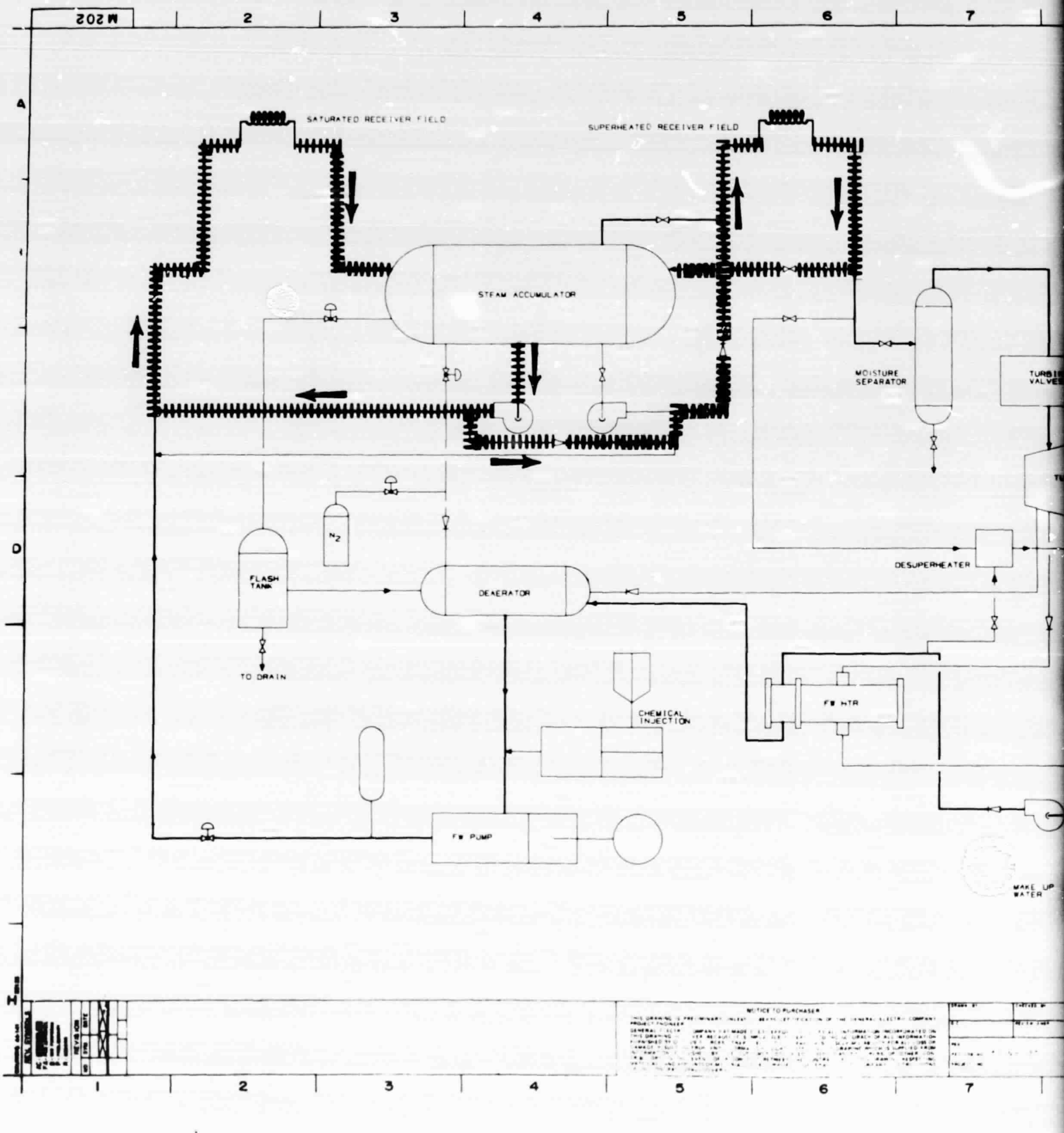
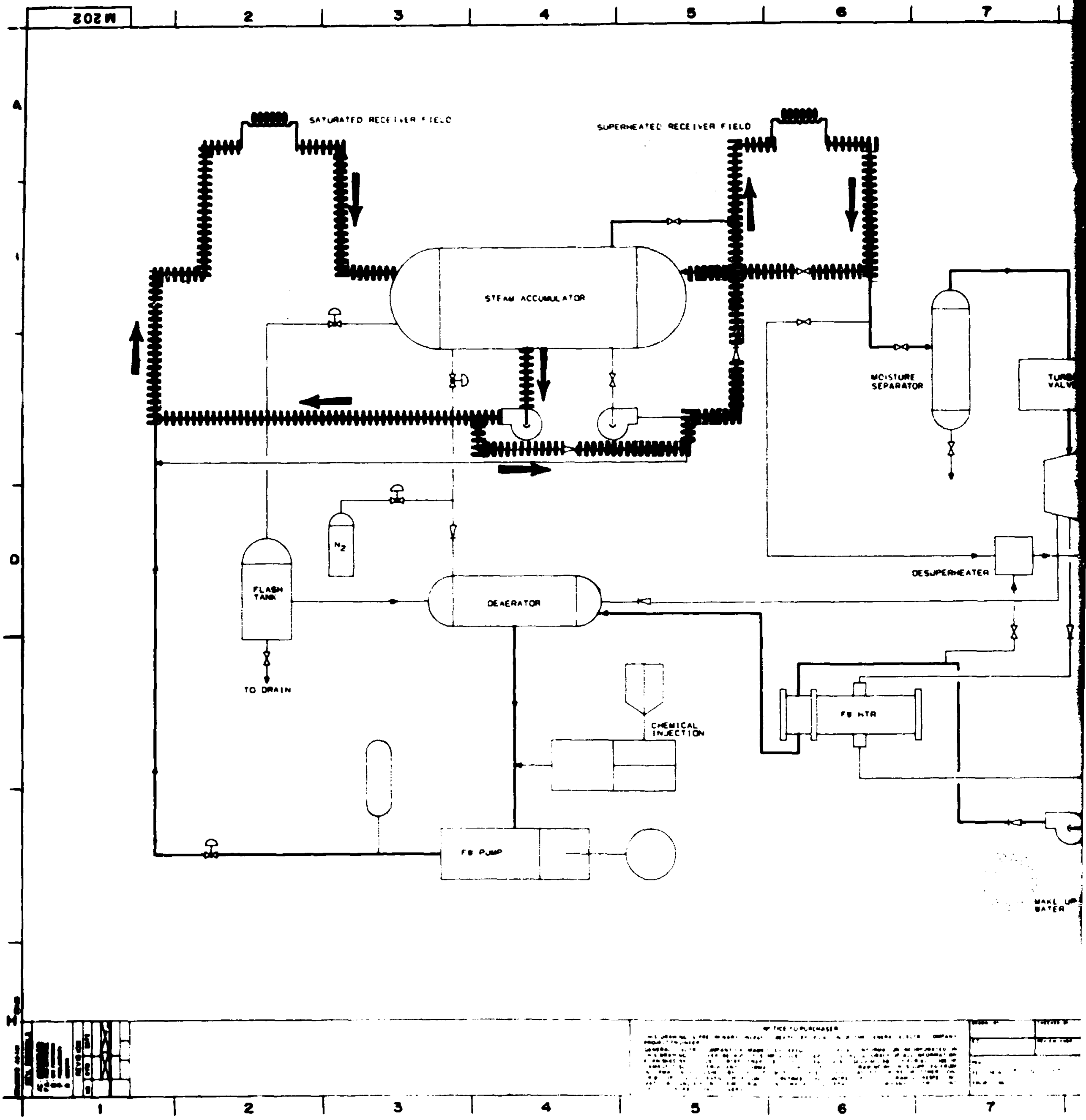
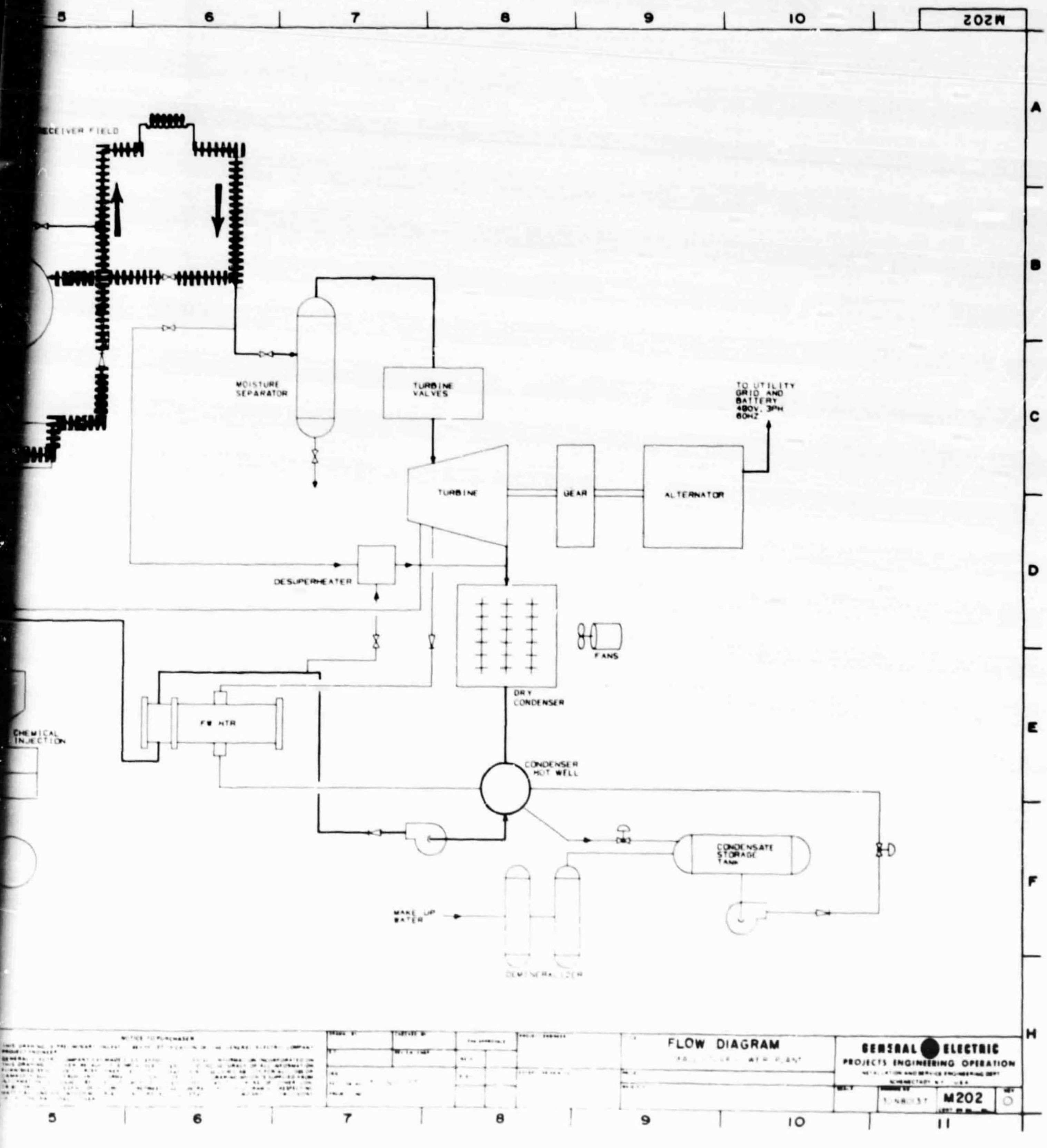


Figure A2.2.4-1. Nighttime/Recirculation



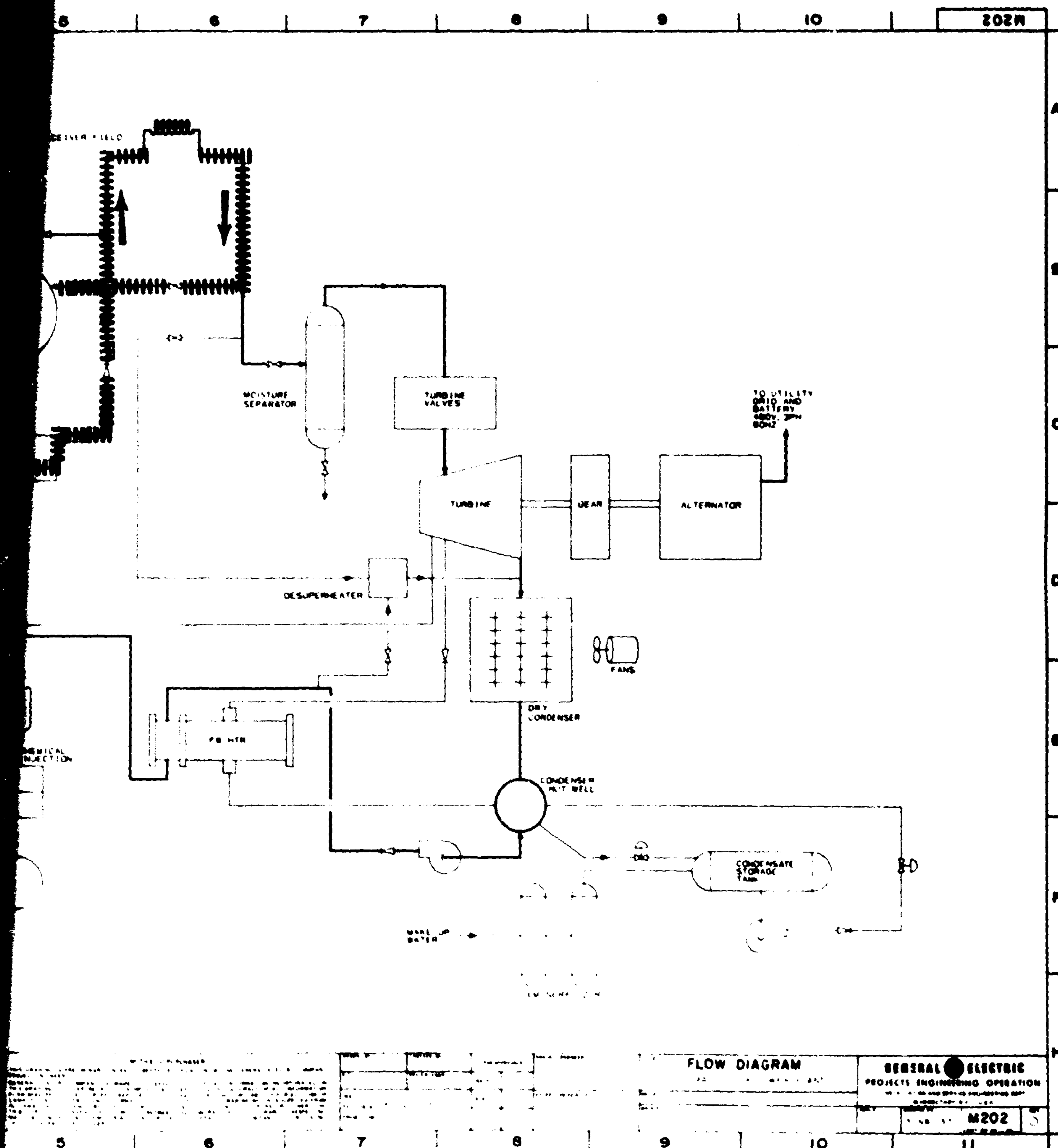
FOLDOUT FRAME

Figure A2.2.4-1. Nighttime/Recirculation



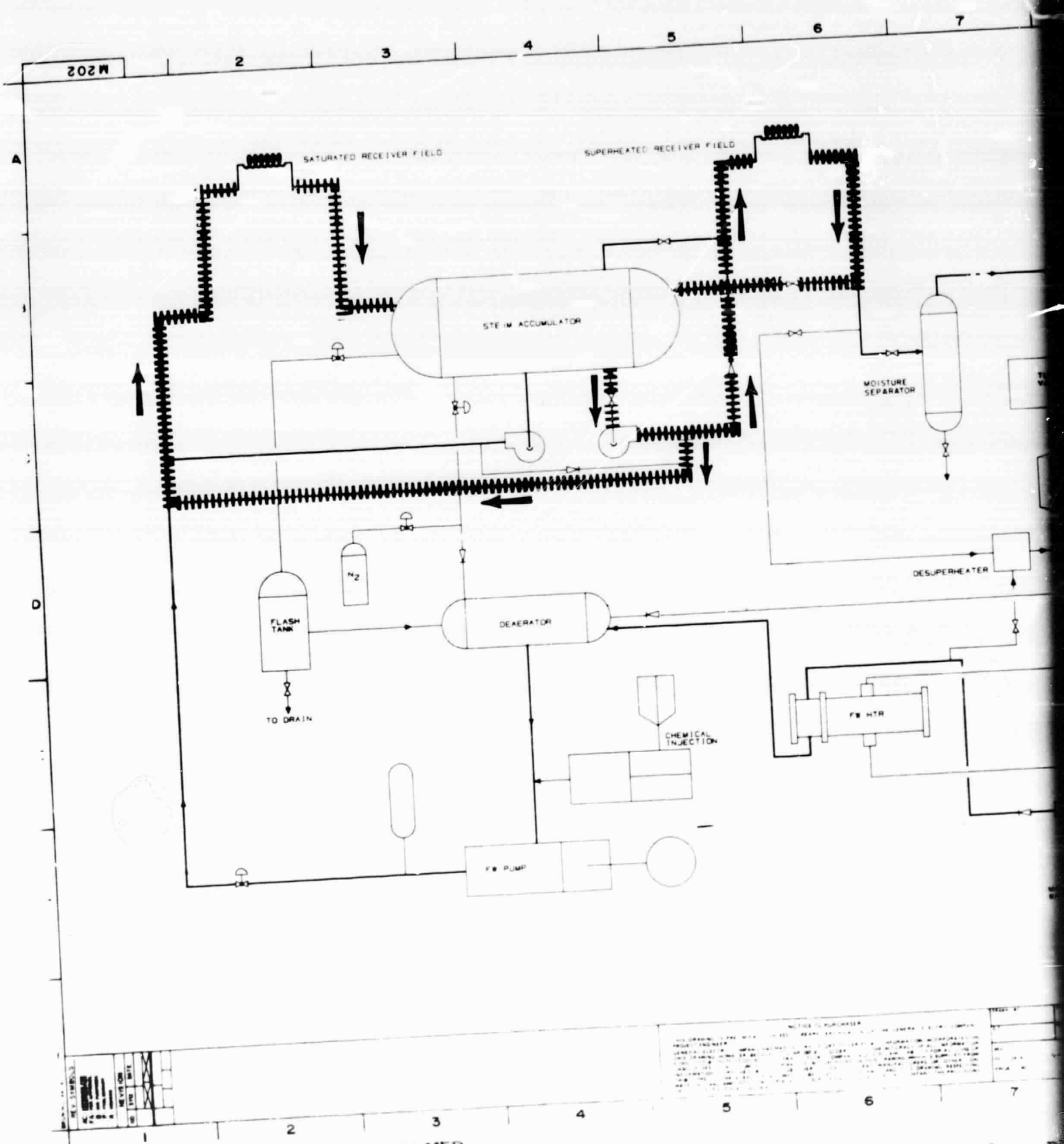
A2.2.4-1. Nighttime/Recirculation Mode

FOLDOUT FRAME



A2.2.4-1. Nighttime/Recirculation Mode

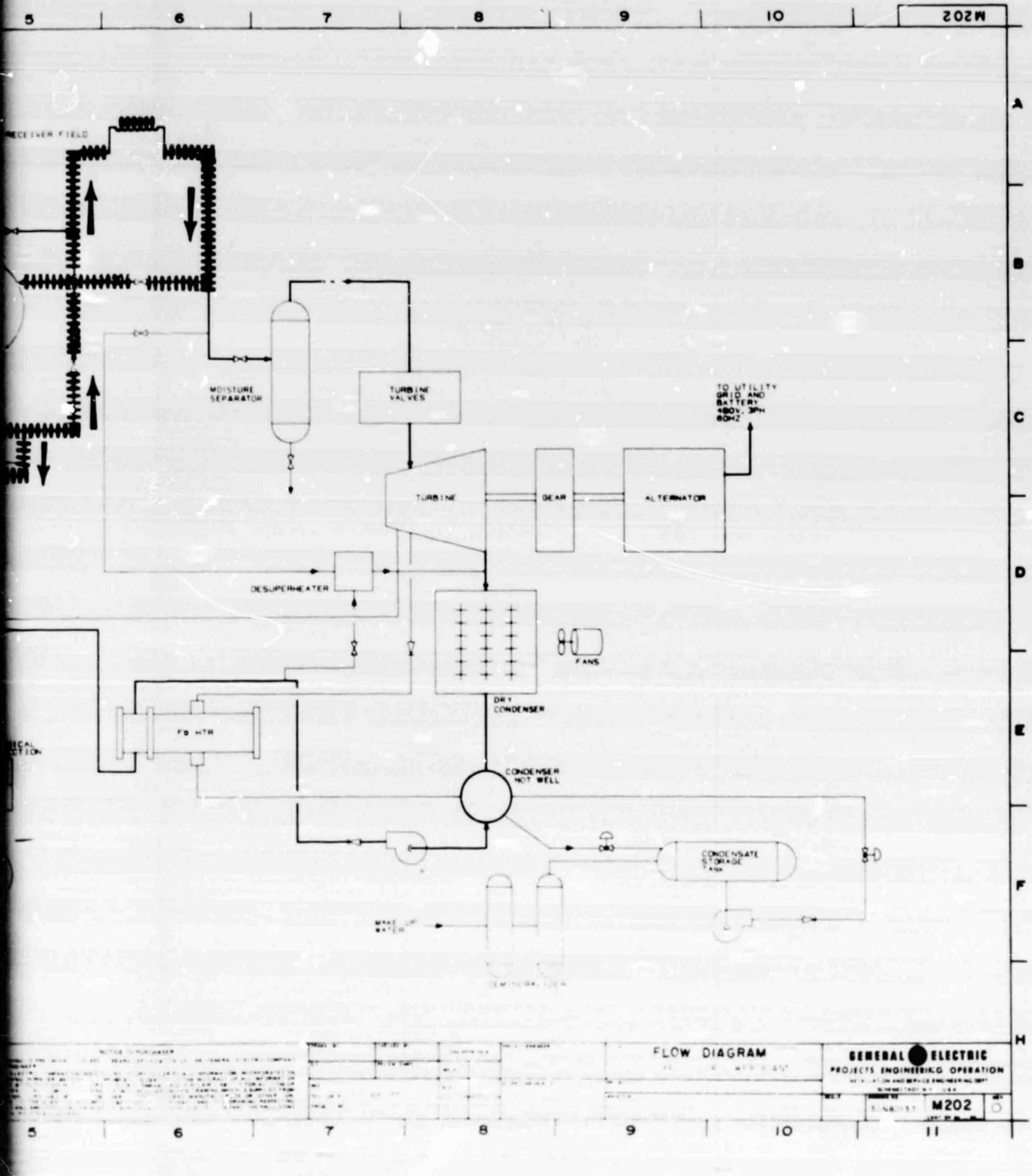
FOLDOUT FRAME



PRECEDING PAGE BLANK NOT FILMED

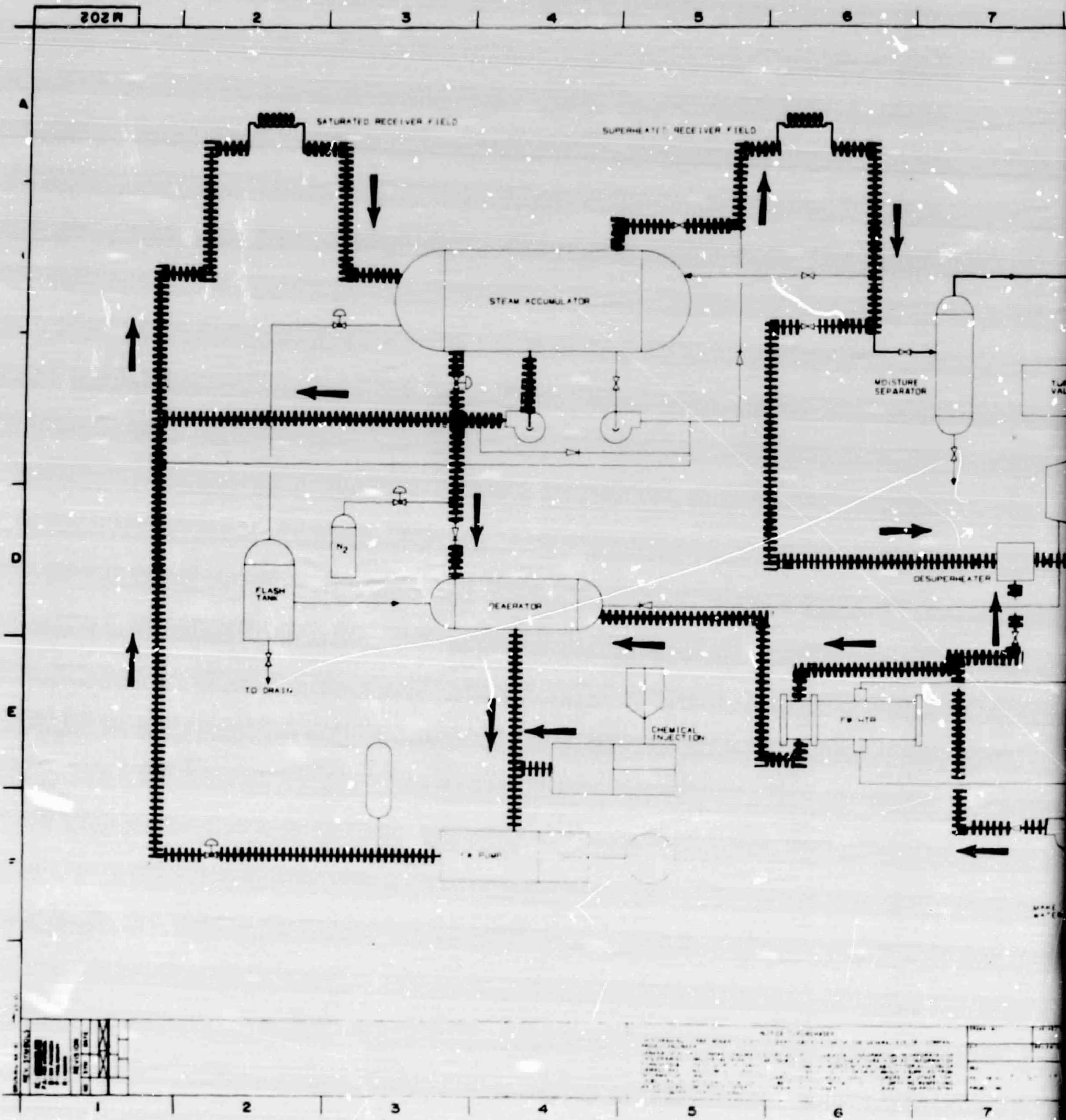
Figure A2.2.4-2. Startup Mode - P

FOLDOUT FRAME



A2.2.4-2. Startup Mode - Phase I

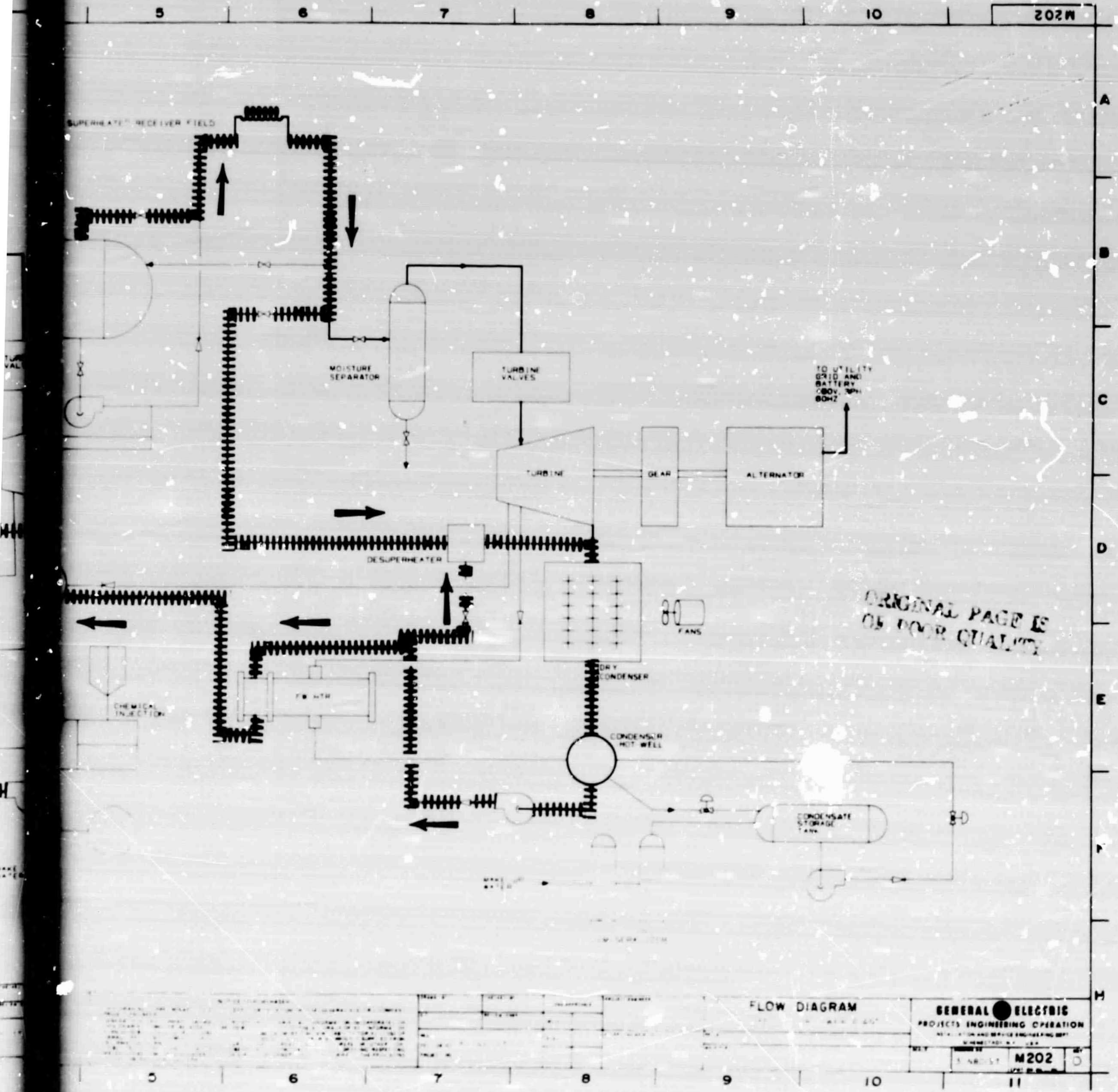
FOLDOUT FRAME 2



PRECEDING PAGE BLANK NOT FILMED

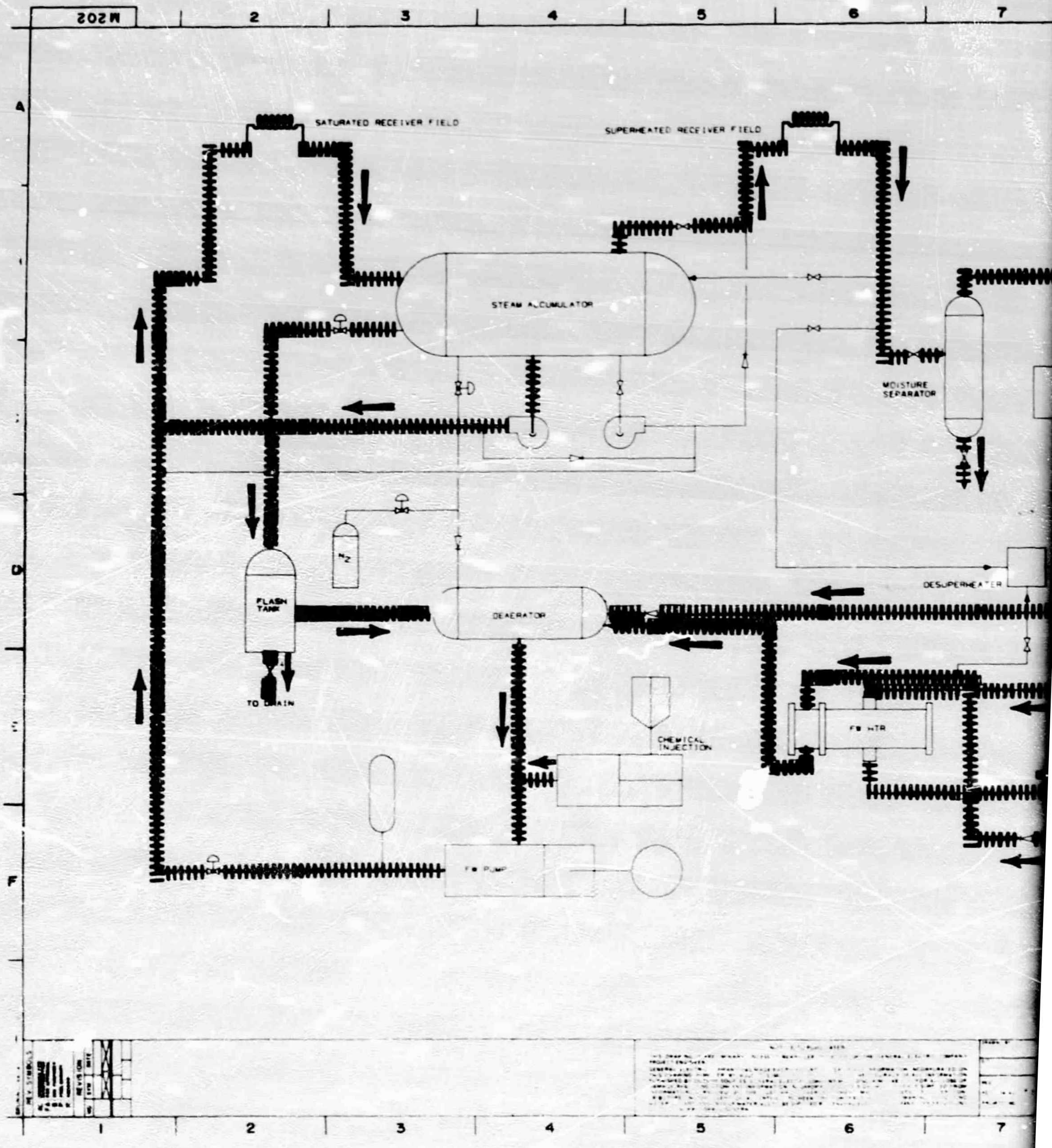
FOLDOUT FRAME

Figure A2.2.4-3. Startup Mode - Phas



igure A2.2.4-3. Startup Mode - Phase II

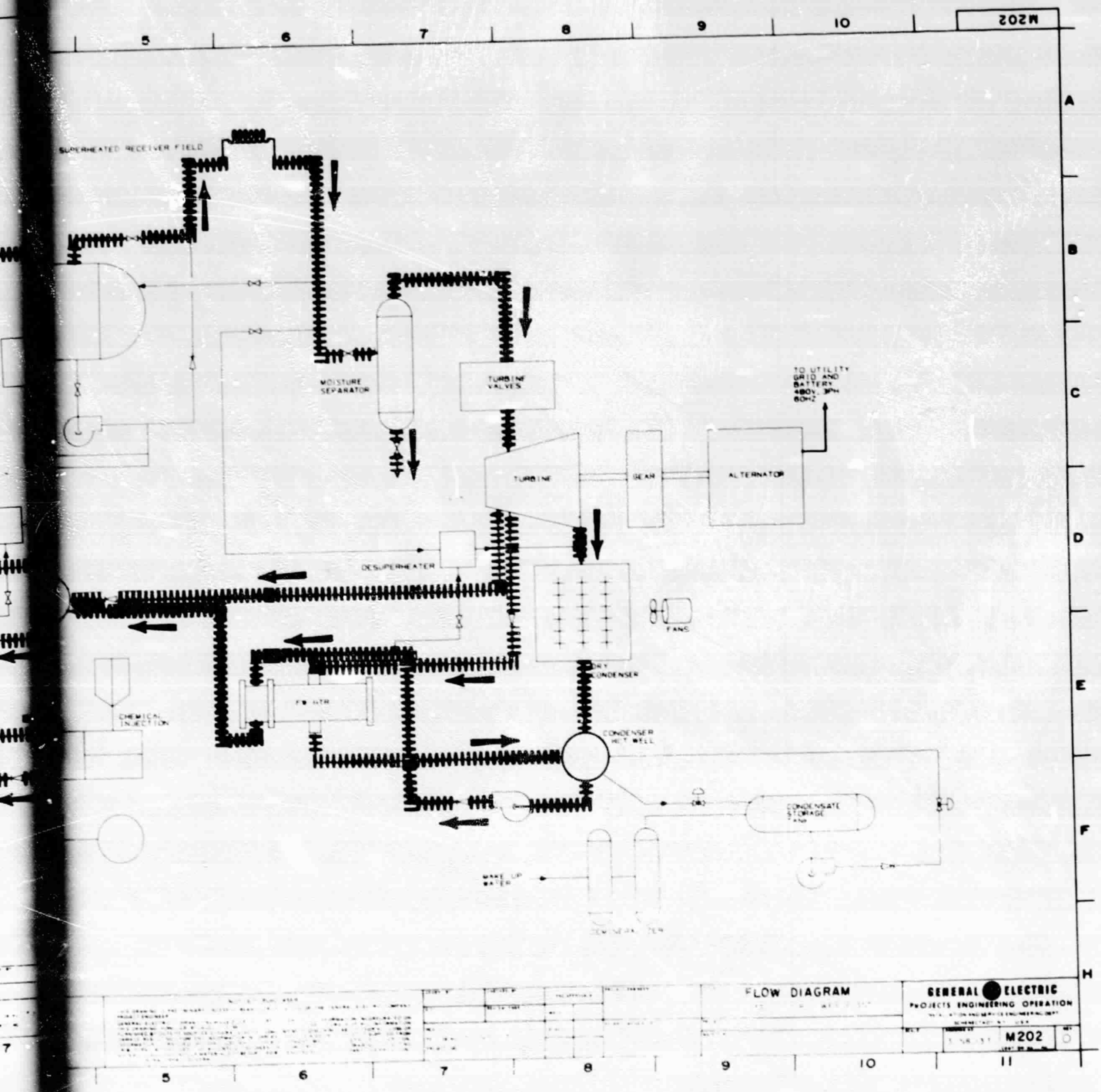
FOLDOUT FRAME



PRECEDING PAGE BLANK NOT FILMED

Figure A2.2.4-4. Normal Operating

FOLDOUT FRAME



ing

Figure A2.2.4-4. Normal Operating Mode

FOLDOUT FRAME 2

When the sun goes down or when the utility or the local operator directs, the plant is placed in the shutdown mode. The sequence of shutdown is essentially the reverse of the startup sequence. As insolation decreases, the power output from the generator decreases and the generator is disconnected from the grid. When this occurs, the plant is placed in phase II of the startup mode, with steam bypassing the turbine and being condensed in the condenser. This mode continues until there is essentially no more steam being generated in the steam accumulator, as indicated by steam accumulator pressure. The plant is then placed in the nighttime/recirculation mode, with recirculation being used if freeze protection is required. Coincident with the above actions, the collectors are returned to the stow position and the electrical storage, if available, is discharged to the utility grid.

If there is a loss of insolation during the day, or if there is insufficient insolation to commence plant startup in the morning, the plant enters the standby mode. In this mode, the collectors continue to coarse track, so that plant startup can commence as soon as insolation returns. All other auxiliary power requirements are minimized, however. Thus, except for the fact that the collectors are coarse tracking, the plant configuration is essentially identical to the nighttime/recirculation mode. Upon loss of insolation during the day, the transition from normal operations to the standby mode is the same as described for shutdown, except that the collectors continue to track.

The final mode to be considered is the emergency shutdown mode. The emergency shutdown sequence is initiated for major malfunctions or alarm indications such as the following:

- Generator breaker trip at power
- Turbine overspeed trip
- Steam header overtemperature
- Steam header overpressure/loss of pressure
- Steam header loss of flow
- Loss of feedwater flow
- Loss of steam accumulator recirculation flow
- Loss of condenser vacuum
- Condenser high/low level limits exceeded
- Loss of condensate flow
- High pH or O_2 in feedwater
- Environmental peril to unenclosed collectors (i.e., wind, hail, sand, etc.)

Each of these situations will result in a rapid but controlled shutdown of the plant. The collectors will be defocused and returned to the stow position thereby interrupting the heat source to the plant. The plant will shutdown in a manner similar to that used in the shutdown sequence. A local reset will be required prior to recommencing plant startup to insure that the cause of the emergency shutdown has been corrected and to insure that no plant damage has been incurred.

A2.2.5 MASTER CONTROL SUBSYSTEM DESIGN DESCRIPTION

A detailed design description of the master control subsystem is not possible at this time since only a conceptual design has been established. However, since all of the components are expected to be off-the-shelf items, a brief description of candidate components is possible. It should be emphasized that these items are not necessarily the ones that would be utilized in a final design.

The heart of the master control subsystem is a microcomputer system. This system performs process calculations based on measured plant parameters and determines transitions between operating modes; performs calculations and provides steering signals to the distributed solar collector drives; matches steam flow from the accumulator with feedwater flow; and sequences and coordinates other control functions. The system currently being considered is a Hewlett-Packard 9800 series microprocessor-based system. Features include a 64 K random access memory (RAM), analog and digital input/output, peripheral interface, hard copy output, and interrupt capability. In addition to these standard features, a number of custom options are also available, such as autoinitialization and uninterrupted power supply. These, plus the standard and custom software packages engineered for this application, make this system a powerful, reliable, and cost-effective control unit for the small solar power plant.

The data acquisition and alarm system monitors and records key plant operating parameters periodically and records certain signals whenever they exceed a predetermined value. These functions can be accomplished by a programmable data system such as the Esterline Angus Model PD2064. This model is a standard, self-contained, key-programmable, 64-channel, microprocessor-based unit with expansion to 248 channels included. It features an onboard printer, analog and digital input circuitry, and alarm options, such as set point dump and initialization. It is also capable of interfacing with a data link system so that signals can be transmitted to a remote location by standard telephone circuits or specific signals can be requested by the remote operator.

The programmable logic controllers perform specific control functions primarily associated with individual plant components, such as water level control. Two programmable controllers, such as General Electric's Logitrol 550 model, can be used. Each controller has 128 inputs and 128 outputs, with functions for relays, latches, timing, counting, and arithmetic operations. Options include switchable dual RAM/PROM CPU (for program development capability), programmable read-only memory (ROM) for on-line control, and a separate CRT programmer module with a five-inch CRT display and capability for data exchange with the serial interface data part of the controllers.

The main components of the master control subsystem are contained in a control module as shown in Figure A2.2.5-1. The master control subsystem occupies only about one-third of the module space, the remainder being used for office and storage areas. All of the control components discussed above require control of the room ambient conditions (both temperature and humidity), which is provided by the air conditioner shown in the figure. Heating, cooling, humidification, and dehumidification functions may all be required, depending on the environmental conditions existing at the plant site. All of the control system components operate on standard 120 VAC, 60 Hz power.

The remote control and monitoring of the small solar power plant is accomplished using a Supervisor Control and Data Acquisition (SCADA) system. There are several methods which could be used for this system, the primary ones being radio telemetry, telephone (both dedicated and commercial), and distribution carrier (multiplexing control signals over the electric distribution system). At present, more information is needed to determine which method is most reliable and cost effective.

A2.2.5.1 Maintenance Requirements

The solar power plant is always shut down at night. This provides a period of time in which maintenance operations may be performed without interfering with normal plant operations. The master control subsystem consists, to a maximum extent, of modular components and elements that can be replaced quickly and without the need for extensive troubleshooting at the component location. The defective modules can then be repaired at a central location, as time permits. Even if a component fails during the day, it may be possible to operate the plant in a manual mode for the rest of the day and then repair or replace the defective item that night. A schedule of periodic preventive maintenance checks cover the individual components of the subsystem.

A2.2.5.2 Development/Verification Requirements

All of the components of the master control subsystem, with the exception of some software pieces, are off-the-shelf items and require essentially no development effort. In addition, this subsystem changes very little whether it is used for a 3.5-, 4.5-, or 6.5-year experimental plant or for a commercial plant. It is anticipated that a commercial plant will be somewhat less instrumented than an experimental plant, but the control scheme should remain unchanged.

For any plant considered it is necessary that dynamic computer modeling of the control system be performed prior to establishing the plant's final design. In addition, it is also recommended that a breadboard verification of the control concept be performed, perhaps as part of a test of a few full-size collectors. This could be done by testing, say, four full-size saturated collectors and

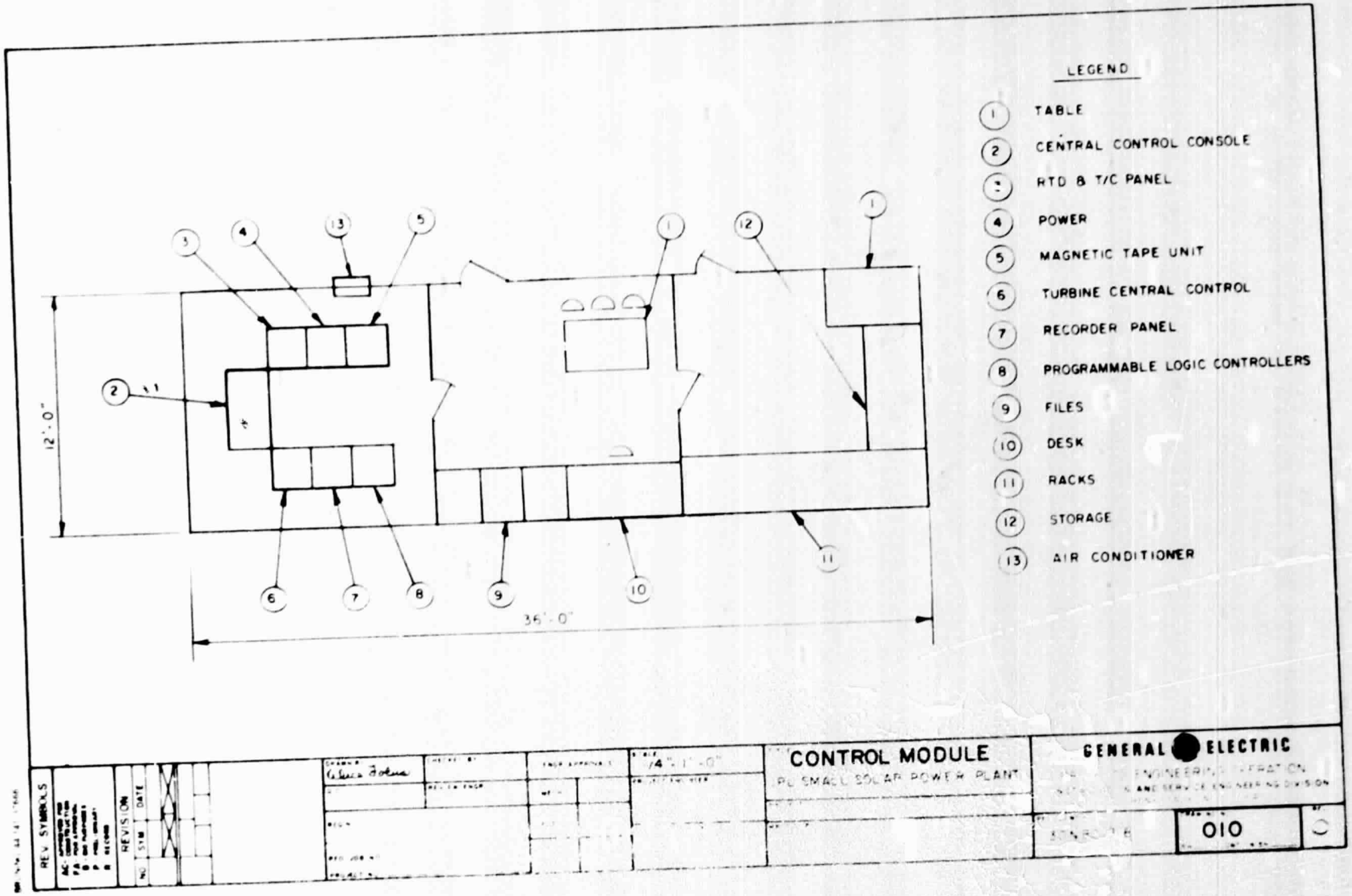


Figure A2.2.5-1. Control Module for a Small Solar Power Plant one superheated collector connected by a prototypical steam accumulator. This would demonstrate the proof-of-concept of both the master control subsystem and the collector subsystem with a relatively small capital expenditure.

A2.3 SOLAR THERMAL ELECTRIC PLANT SIZE, EFFICIENCY, AND OPERATIONAL AVAILABILITY

This subsection discusses an appropriate size range, the anticipated efficiency, and the likely operational availability, of a solar thermal electric plant.

A.2.3.1 SIZE

The size of solar thermal electric generation plants can easily be in the range from 1 to 10 MWe because, even though the individual collector units are considerably smaller in rating, the total plant is made up of a large number (50-200) of these smaller units. A certain amount of land area is necessary for the solar collectors for a specified electric power rating, MWe, and the unit designed has emphasized a 1 MWe rating. To obtain a larger plant it is necessary to increase the land area proportional to the desired amount of power.

Depending on whether a central receiver or a distributed collector with central energy conversion or energy conversion at the collector is used, the land area and topographic requirements may differ for different sized electric generating units. Present thinking is directed at 1-10 MWe size units, which are suitable for dispersed generation, with or without storage, at the distribution network level.

The amount of insolation, i.e., the amount of sunlight which reaches the ground, varies, and due attention must be given to this factor. For the EE-1 Study, the location selected was Barstow, California, which might reasonably be expected to have a high amount of sunlight per year. Figure A2.3.1-1 shows the distribution of available solar energy expressed in terms of kW/m^2 for the year 1976 at Barstow, and indicates that a direct normal insolation of 950 W/m^2 represents a good design point.

An associated size factor is the land area required per 1 MWe of electrical generation. For the General Electric 1 MWe design for the EE-1 study, the land area required for the 4.5 year plant with storage is approximately 9 acres for a "tight" perimeter around the collector field. With 100 foot spacing around the perimeter of the collector field, approximately 16 acres are required. Figure A2.3.1-2 shows an artist's sketch of a commercial solar power plant and provides an indication of the land space required for a nominal 1 MWe solar thermal electric plant.

A2.3.2 EFFICIENCY

In considering the efficiency of the solar thermal electric system, one must consider the following factors:

- total incident solar energy
- collector efficiency

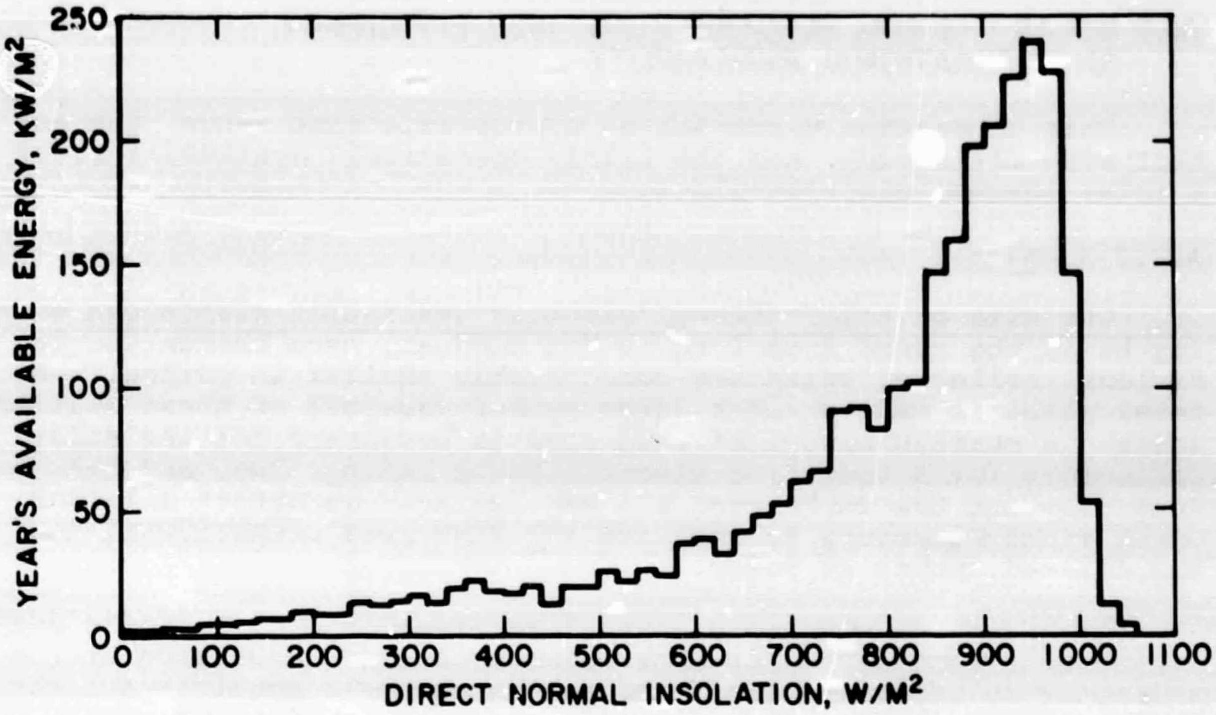


Figure A2.3.1-1. Distribution of Available Energy for 1976 at Barstow, California

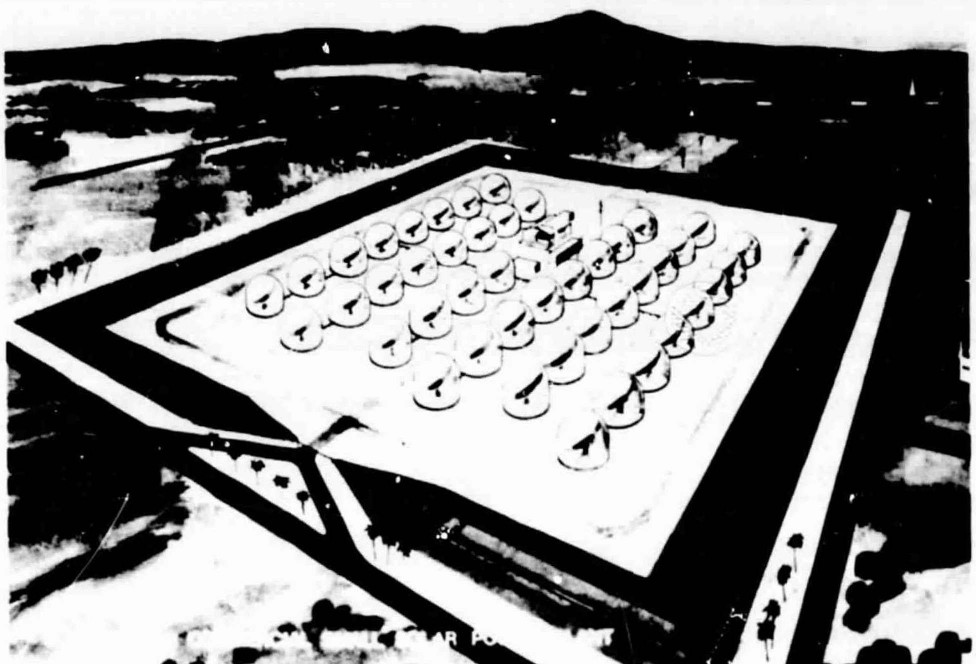


Figure A2.3.1-2. Commercial Small Solar Power Plant

- steam transport efficiency
- power conversion efficiency
- gross electric power generated
- auxiliary power efficiency

The result of such a study indicates that about 12 to 15 percent of the solar energy available can be converted into useful electric power at the generator busbar.

The total incident normal radiation is the amount available at the collector location based on the aperture area of the collector. The collector field collects energy only when the insolation levels are above certain values. During some particularly high insolation level hours, the thermal energy collected in the field may exceed the capability of the power conversion subsystem. In such circumstances part of the collector field is defocused to reduce the thermal energy input to the accumulator and the turbine. About 95 percent of the total solar energy can be considered available on an annual basis which covers about 3500 hours per year.

The collector subsystem efficiency is defined as the energy collected divided by the incident solar energy during collection. The collector efficiency is the weighted average between the efficiencies of the saturated steam collectors and the superheated steam collectors. The losses of the collector subsystem include shadowing by neighboring collectors, transmissivity loss through enclosure, blocking by the receiver and its supporting structure, concentrator reflectivity loss, receiver intercept losses, and receiver thermal losses. A figure of about 72 percent can be used to represent the collector subsystem efficiency.

The collected energy is transported through the pipe-field network and fed into the turbine. The losses incurred include the heat losses during steady-state operation and the heat lost in warming up the thermal mass in the pipe field. An efficiency figure of 91 percent for the energy transport subsystem represents a realistic objective.

The efficiency of the power conversion subsystem is given by the ratio of the gross electric energy generated by the steam turbine generator unit divided by the thermal energy fed into it. Power conversion subsystem efficiency varies with load, as well as with ambient conditions which affect the condenser back pressure. A figure of 23 percent on an annual basis is used for this power conversion subsystem efficiency.

Part of the gross electric power generated is used to supply the plant auxiliary power. The auxiliary power includes power for the feedwater pump, the condensate pump, the recirculation pumps, the condenser fan, and for the drive motor and control of the collectors. For an enclosed collector, power for the blower which maintains the pressure inside the enclosure is also included. Eighty-seven percent efficiency for the auxiliary power has been used.

In systems with energy storage, losses are incurred in the batteries and the ac/dc conversion equipment. The energy storage subsystem efficiency is defined as the electric energy extracted during discharging periods divided by the energy fed to the batteries during charging periods, and a figure of 72 percent is representative.

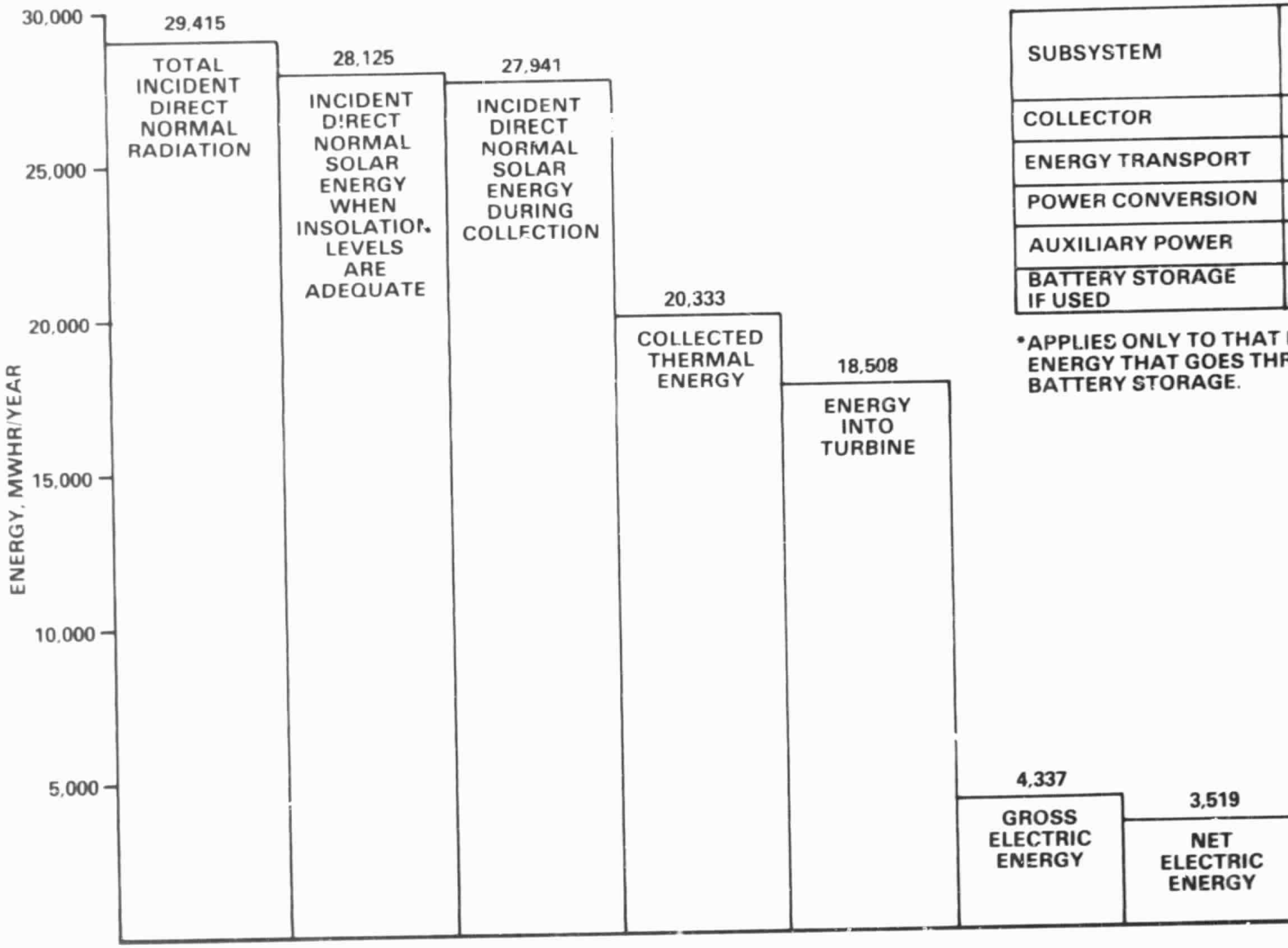
Since the several subsystems and other losses operate in series, the net result of these cascading efficiencies can be represented on an annual basis by the system annual power flow as shown in Figure A2.3.2-1. The annual efficiency for each of the major elements is indicated in the box located in the upper right. Since the electric generator is rated at 1 MWe nominal, the net electric energy of 3519 MW hr/yr represents 3500 hours of operation in an 8760 hour year. Using the 27,941 MW hr/yr as input and 3519 MW hr/yr as output gives an overall efficiency of 12.6 percent.

A2.3.3 OPERATIONAL AVAILABILITY

For solar thermal electric power to achieve its role in providing power for utility use and distribution, it must have an inherent high availability. Since the solar power plant can only operate during sunlight hours over an average of 3500 hours per year, it is of prime importance that the plant be operational during these hours. The 3500 hours availability per year amounts to a figure of 3500/8760 = 0.400 gross availability factor that defines the nominal annual performance of the system.

One way of looking at the solar power plant's importance in the utility system is that it is comparable to gas turbines which have an availability of 90% using fuel oil and an availability approaching 93% using natural gas. Although an availability goal for the mature commercial solar power plant is 95%, a more conservative figure of 90% probably should be used for utility planning purposes.

Another measure of availability is the average direct insolation value of energy which is available at different times of day for the different seasons of the year. Figure A2.3.3-1 shows typical quarterly average direct insolation values for Barstow, California, and indicates the variations in the magnitude of the solar energy that may be expected.



SUBSYSTEM	ANNUAL EFFICIENCY (%)
COLLECTOR	72.7
ENERGY TRANSPORT	91.0
POWER CONVERSION	23.4
AUXILIARY POWER	87.1
BATTERY STORAGE IF USED	72.0

*APPLIES ONLY TO THAT PORTION OF ENERGY THAT GOES THROUGH THE BATTERY STORAGE.

Figure A2.3.2-1. Typical System Annual Power Flow (4.5-year system)

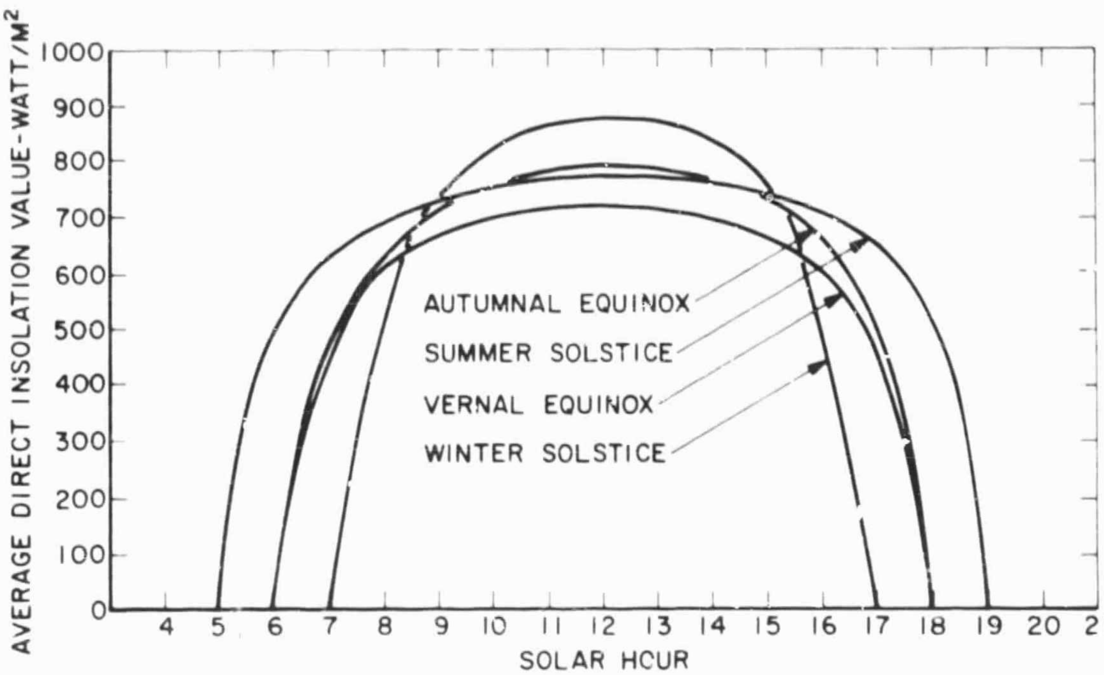


Figure A2.3.3-1. Typical Quarterly Average Direct Insolation Values, Barstow, California - Latitude = 35°

A2.4 ECONOMIC CONSIDERATIONS OF EQUIPMENT COST AND SYSTEM VALUE

In view of the developmental status of solar thermal electric equipment it is worthwhile to describe the learning curve process whereby the cost of solar thermal electric equipment is reduced with time as experience is gained. This experience process has been referred to as the "road-map to commercialization." Another important economic consideration is the value to an electric utility system of a solar thermal power generation plant that is available only on a part-time basis.

A.2.4.1 ROAD MAP TO COMMERCIALIZATION

The process of evolution from an experimental plant to a commercial prototype or demonstration-unit to a full commercial production plant is referred to as a road-map to commercialization. There are a number of possibilities for the time and risks associated with each of the three types of plant. The longer the experimental design takes, the more it costs initially. However, the final commercial cost should ultimately be lower. Thus, as summarized in Table A2.4.1-1, there is a range of cost alternatives from almost $9000/kWe for a quickly developed 1 MWe experimental unit to $1300/kWe for a commercial plant in mass production by 1990. More detailed information on the features of the alternative designs is available in Reference 1.

Table A2.4.1-1

COMPARISON OF PLANT COSTS IN 1978 DOLLARS

EXPERIMENTAL PLANTS	Initial Cost ($/kWe) (1979 start)	Commercial Production Plant Cost ($/kWe)** (1990 start)
3.5 year system*	8780	2600
4.5 year system	7265	2000
6.5 year system	6235	1800
1985 COMMERCIAL DEMONSTRATION PLANT	Initial Cost	1990 Cost
Like 4.5 or 6.5 year system	6000	1500
1990 COMMERCIAL PLANT	1300 for 1 MWe plant	1000 for 1 MWe plant

*A "3.5 year system" is permitted 3.5 years for development.
**1990 Cost ($/kWe) assumes production of 1000 plants at 1 MWe nominal plant size.

It will be noted from Table A2.4.1-2 that installed cost with storage outweighs the increase in the capacity factor and the mills/kWh are considerably greater for the storage case than for the no-storage case.

Table A2.4.1-2

ESTIMATED COST OF SOLAR THERMAL ELECTRIC POWER

	No Storage	Storage
Solar Multiple	1.0	1.3
Installed Cost $M (1-1-78)	2.2	3.51
Rating (MW)	1.3	1.3
$/kW (1-1-78)	1692	2700
Service Hours	2385	2650
Capacity Factor (%)	27	30
Mills/kWh	78.0	112.1

where the $\text{Mills/kWh} = \$/\text{kW} \times 0.11 \frac{(\text{Fixed Charge Rate})}{\text{Year}}$

$$\times \frac{1}{\text{hr/yr}} \times \frac{10^3 \text{ mills}}{\$}$$

Consider the costs for a nuclear power plant and for a combustion turbine. The nuclear power plant which might cost 1020 $/kW (1/1/79), with production cost (fuel and O&M) of 11 mills/kWh, has a busbar cost at 11 percent fixed charge rate, 80 percent capacity of

$$1020 \ \$/\text{kW} \times 0.11 \frac{\text{p.u.}}{\text{yr}} \times \frac{1}{8760 \text{ hr/yr}}$$

$$\times \frac{1}{0.80} \times 10^3 + \frac{11 \text{ mills}}{\text{kWh}} = \frac{27 \text{ mills}}{\text{kWh}}$$

A combustion turbine, used for peak loads, which might cost 160 $/kW (1/1/79), with production cost (fuel and O&M) of 40 mills/kWh, has a busbar cost at 11 percent fixed charge rate, 5 percent capacity factor, of

$$160 \ \$/\text{kW} \times 0.11 \frac{\text{p.u.}}{\text{yr}} \times \frac{1}{8760 \text{ hr/yr}}$$

$$\times \frac{1}{0.05} \times 10^3 + \frac{40 \text{ mills}}{\text{kWh}} = \frac{80 \text{ mills}}{\text{kWh}}$$

Although the preceding material provides a useful overview of some cost elements involved in the use of solar thermal electric generation, a system annual performance model program has been used for annual performance calculations on an hour-by-hour basis using given design parameters and a weather data tape for a representative location. Three modes of system operation are considered, namely, normal, pipe field warmup, and pipe field cooldown. For specific conditions and designs, specific cost results have been obtained.

A2.4.2 SYSTEM COST TO THE CUSTOMER

One of the important bases for judging the cost of electric power generation is the mills/kWh which the customer must be charged. There are many factors which enter into such an evaluation. Section 9 of the Final Technical Report on "The First Small Power System Experiment, EE-1, Phase I," presents a more comprehensive treatment of those factors. A simple comparison of a solar thermal electric power plant with and without storage is presented in Figure A2.4.2-1.

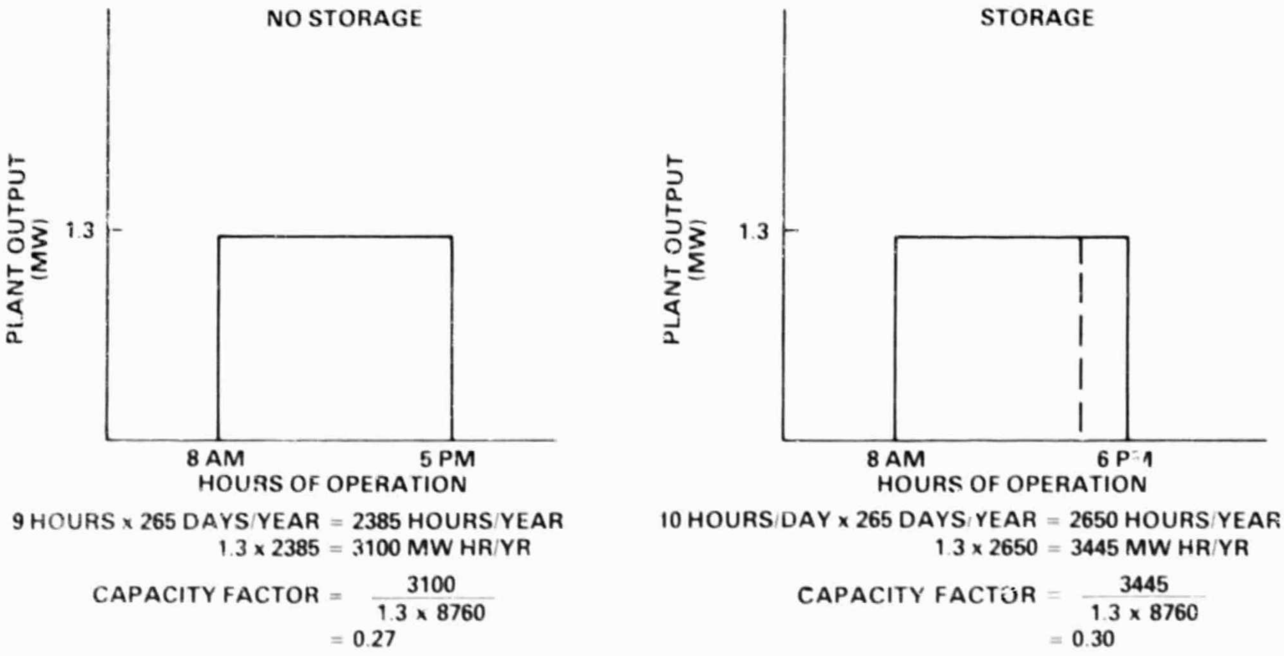


Figure A2.4.2-1. Comparison of Solar Thermal Electric Power Plants With and Without Storage

A2.5 ACTIVE PARTICIPANTS

The following organizations and companies are representative of those active in the development of solar thermal energy systems:

- Jet Propulsion Laboratory, California Institute of Technology
- General Electric Company, Energy Systems Programs Department
- McDonnell Douglas Astronautics
- Ford Aerospace and Communications Corporation
- Pacific Northwest Laboratory
- Westinghouse Electric

Section A3

PHOTOVOLTAIC POWER GENERATION TECHNOLOGY

A3.1 DEFINITION AND DESCRIPTION OF PHYSICAL PRINCIPLES

Photovoltaic power generation systems convert light energy to electrical energy. This conversion takes place by the "photovoltaic effect" whereby a voltage is produced between dissimilar materials when their junction is illuminated (irradiated) by the light-band portion of the electromagnetic spectrum. There are a limited number of materials which exhibit photovoltaic properties. The relatively low power intensity of sunlight (0.100 watt per square centimeter), and the relatively low efficiency of photovoltaic conversion (5 to 20 percent), inherently require considerable land area to obtain kilowatt or megawatt power levels. Since photovoltaic power is in the form of direct current, dc-to-ac inverters are required to interconnect photovoltaic generation to an electric utility ac distribution system. The basic daily insolation cycle and variable weather conditions limit the availability and amount of potential photovoltaic power generation. Thus, photovoltaic generation systems must be used in conjunction with other firm power sources on an electric utility system.

A3.1.1 DESCRIPTION OF PHYSICAL PRINCIPLES

As in the case of solar thermal energy, the inherent attractiveness of photovoltaic energy is that the energy source is "inexhaustible," free, nonpolluting, and widely available. Impeding its widespread utilization is the high cost of the photovoltaic system, relatively large area (land) requirements, and the variableness of the available energy. "State-of-the-art" technology for producing photovoltaic cells is relatively high in cost.

The dc current produced by a photovoltaic cell is proportional to the intensity of the incident light. Therefore, light-concentrating methods are being employed in photovoltaic conversion systems to replace "high cost" material with lower cost material which concentrates the light energy. There is no reduction in land area required by concentrating methods, however, since the intensity of the available sunlight still remains at the same value. Concentrating devices inherently require direct rays to effectively concentrate the sunlight whereas "flat plate" nonconcentrating arrays intercept both direct and diffused (random direction) light rays. Whereas concentrating arrays inherently require tracking, nonconcentrating arrays can be stationary. Tracking mechanisms, structures, and controls add considerably to the cost and complexity of photovoltaic systems. Generally concentrator systems require somewhat more area per watt output since tracking the sun inherently requires more spacing between collector devices as compared to nonconcentrating arrays.

The generic degrees of concentration for which designs have been developed are: (a) Nonconcentrating, (b) Low, (c) Medium, (d) High and (e) Very High Concentrating. Approximate concentration ratios (CR) for these are (a) 1 (b) 2 to 5 (c) 5 to 100 (d) 100 to 1000 (e) 1000 to 10000. Examples of (a), (b), (c), and (e) designs are shown in Figure A3.1.1-1 from Reference 9.

Photovoltaic arrays using nonconcentrating and low to medium concentrating collectors can be passively cooled by air convection in conjunction with heat sinks.

Additional cost and complexity are incurred for photovoltaic concentrators with higher concentration ratios, (i.e., CR above 50:1). The concentrated sunlight on a relatively small area requires that the heat be removed to avoid degradation (or destruction) of cell material, and to maintain reasonable cell efficiency. Cell efficiency decreases with increasing temperature. Since concentrator designs usually employ tracking and movement of the concentrator (or assemblies of concentrators), an added degree of complexity is incurred if liquid cooling is employed. Some applications are being investigated which make use of the low grade heat collected by the coolant.

There is a practical limit to the cell area for which a photovoltaic cell can effectively function. Currently photovoltaic cells of 100 square centimeters are common for nonconcentrating applications. These cells have rated voltages of less than one volt and low current values. For a concentration ratio of 1, a single crystal silicon cell would produce approximately .030 ampere cm^2 at rated conditions. Thus to produce kilowatts or megawatts of power requires that many photovoltaic cells be connected in series to obtain practical levels of input voltage for dc-ac inverters, and many cell banks or arrays in parallel are needed to provide the current magnitudes for the required power levels. These fundamental facts (many cells in series - parallel combinations) combined with the large area from which this low density power must be collected results in considerable interconnection cost.

To maintain a relatively high degree of plant availability, many parallel power circuits are used, each capable of being protected and isolated during fault conditions. An example for a 5 MW photovoltaic power plant showing multi cells in series - parallel connections, parallel dc power circuits, inverter equipment, and ac switching equipment - is shown in Figure A3.1.1-2.

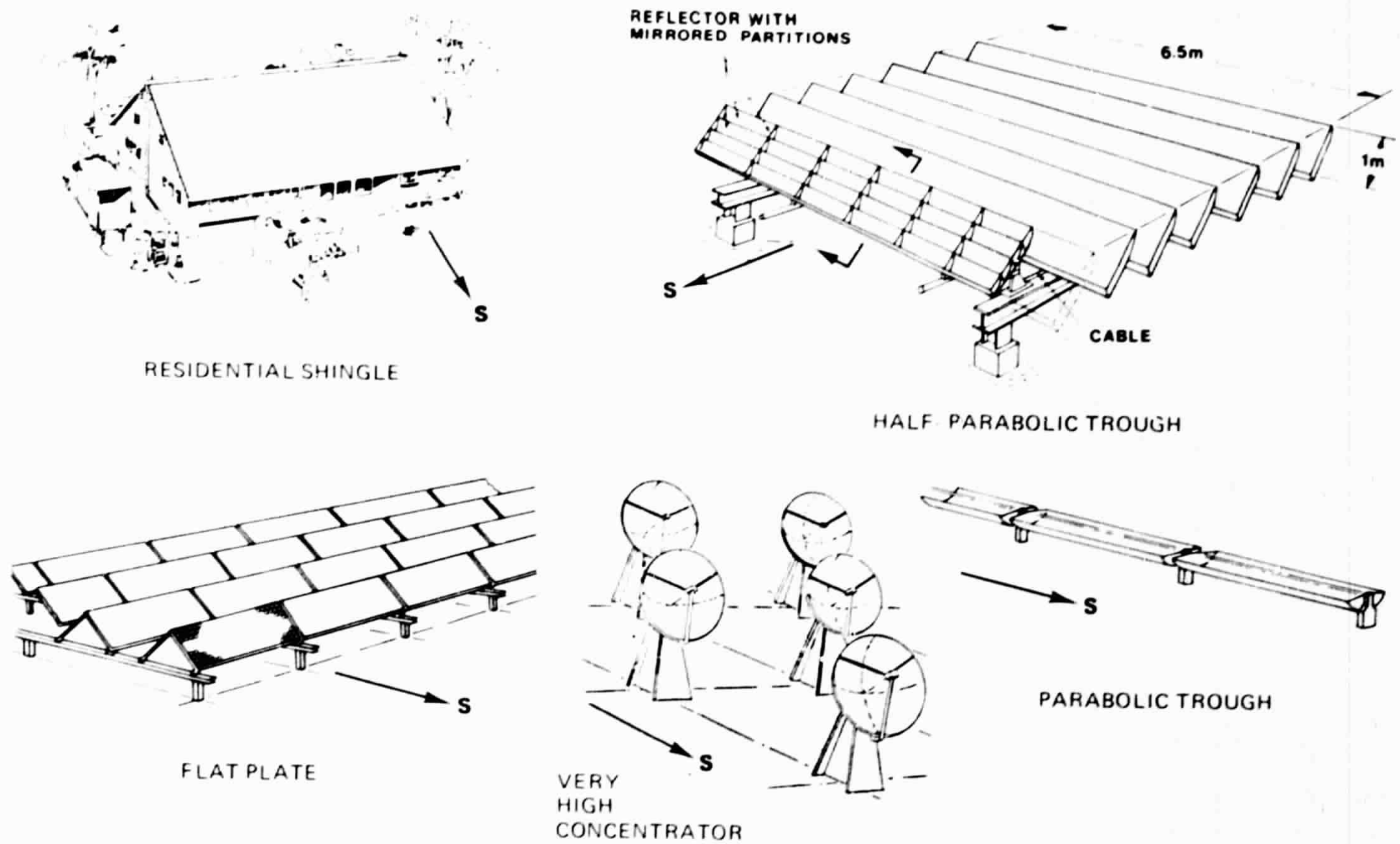
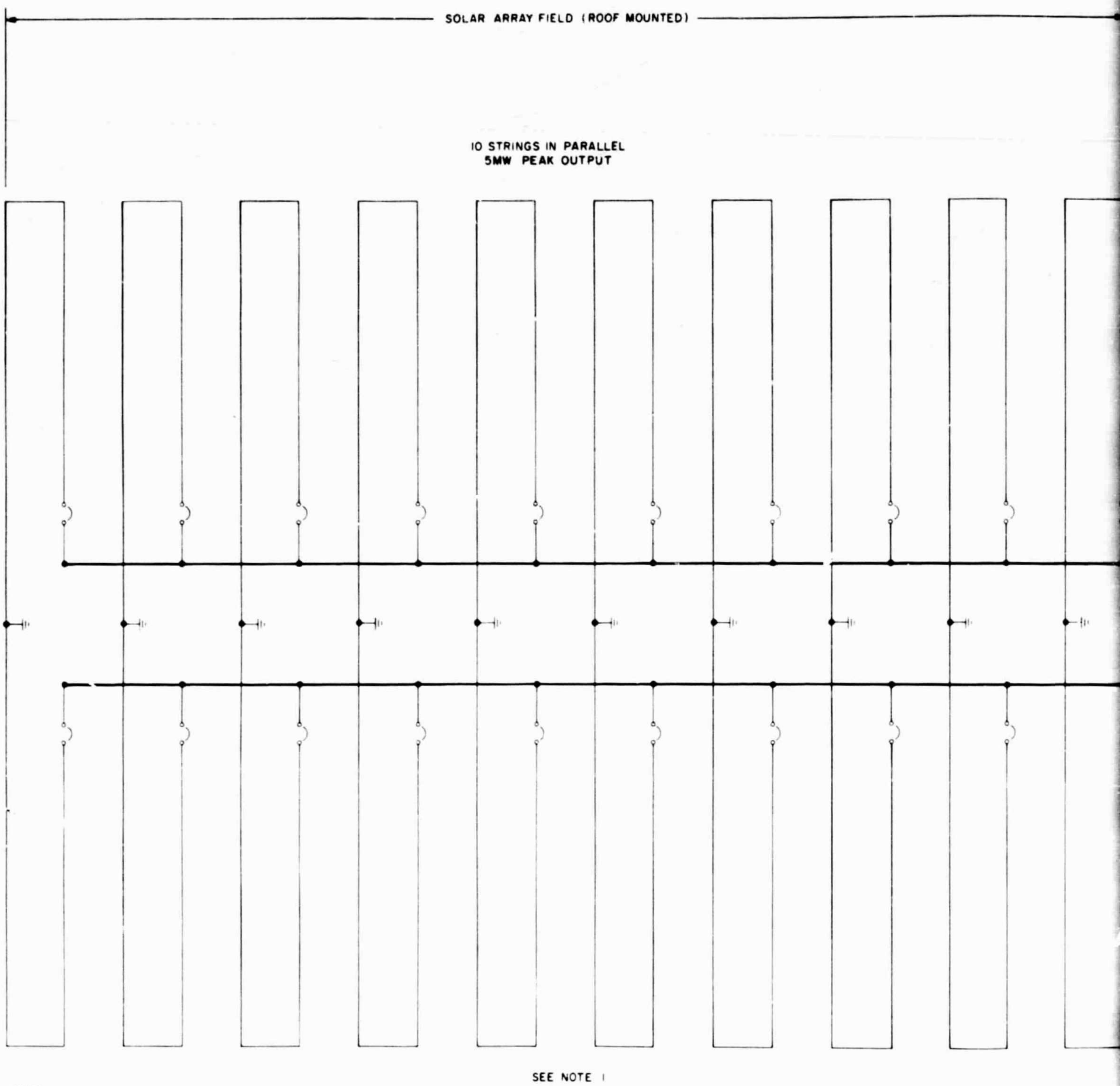


Figure A3.1.1-1. Candidate Plant Designs

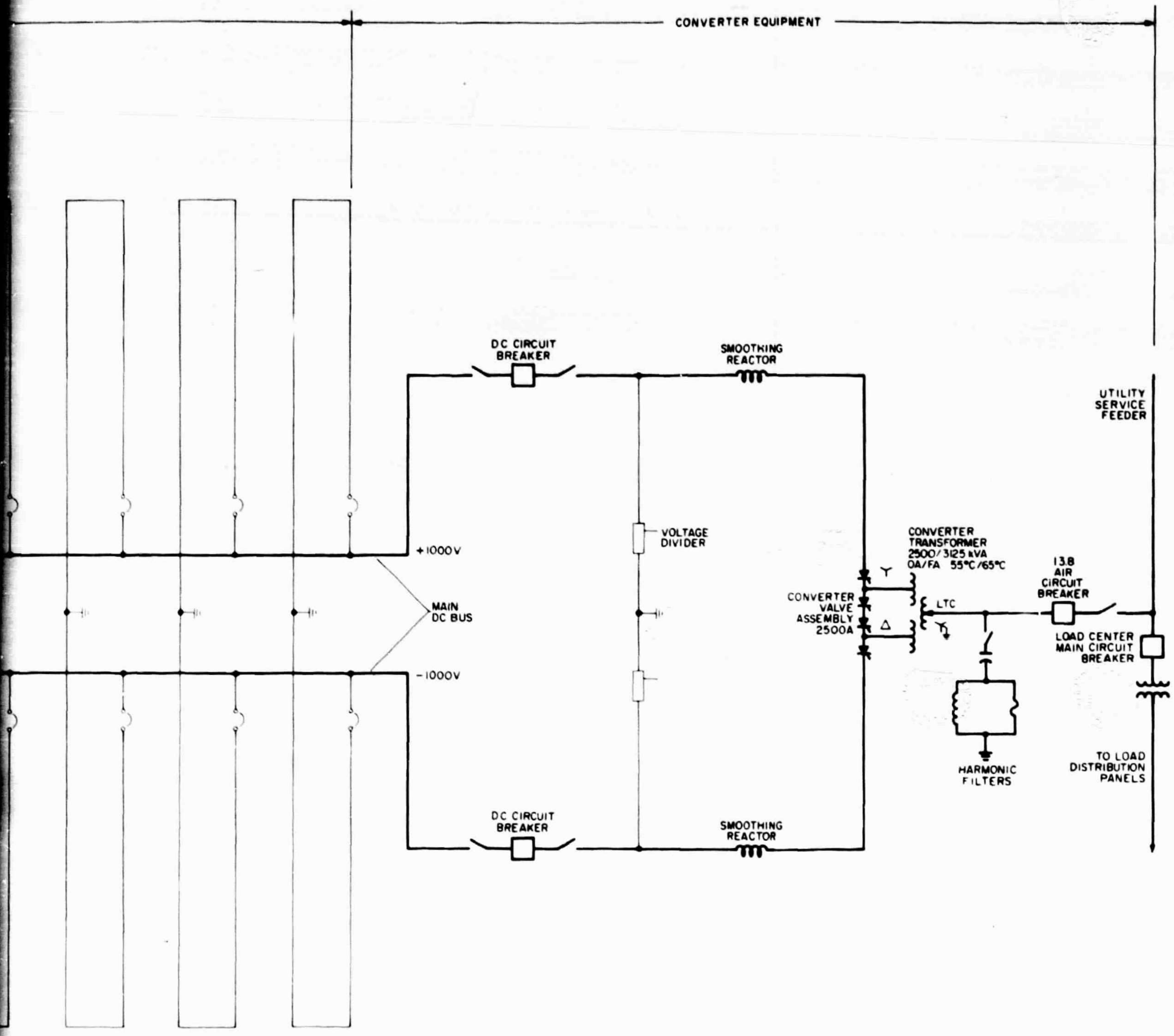


NOTES
1. ONE STRING = 5 ARRAYS IN PARALLEL, 40 ARRAYS IN SERIES (200 ARRAYS/STRING)
ONE ARRAY = 3 PANELS IN PARALLEL, 10 PANELS IN SERIES (30 PANELS/ARRAY)
ONE PANEL = 12 CELLS IN PARALLEL, 12 CELLS IN SERIES (144 CELLS/PANEL)

Figure A3.1.1-2. A 5 MW Photovo

PRECEDING PAGE BLANK NOT FILMED

 FOLDOUT FRAME



A3.1.1-2. A 5 MW Photovoltaic Power Plant

FOLDOUT FRAME 2

A3.2 DESCRIPTION OF SYSTEM CONTROL

In general, utility size photovoltaic power plants should be designed for unattended automatic operation. However, on occasion (startup, testing of maintenance operations) the plant will be controlled by a local operator. During unattended operations, the plant automatically performs normal startup and shutdown and emergency shutdown and is self-protecting from all types of electrical, and mechanical failures. Protective subsystems detect faults, protect and isolate equipment which has incurred a fault, and, if required, initiate plant shutdown. Control commands from the Distribution Dispatch Center are executed through and by the plant control equipment which also monitors plant conditions. The type, amount, and degree of monitoring are related to the rating of the plant. Larger plants have more components and require some means of identifying normal and abnormal conditions in circuits and equipment to assist in operation and maintenance activities.

Because of their lesser impact on an electric utility system, small plants require less monitoring and basically only have to identify major generic malfunctions and basic measurements.

Larger plants, especially as the number installed on a utility system becomes appreciable, require that normal and abnormal conditions be reported to the distribution dispatch office.

Protection, control, and monitoring requirements for photovoltaic plants require a hierarchy of plant protection control and monitoring equipment. Figure A3.2-1 is a simplified block diagram of protection, control, and monitoring for a photovoltaic plant of megawatt size.

The plant control, monitoring, and display equipment is a small computer-based system. It provides plant sequencing operations, control instructions to the major subsystem control equipment, coordination between various control and protection subsystems, monitoring of important status and operating parameters, display of plant status and conditions, and a means of communicating with local and remote operators.

The other control and protection subsystems perform control and protective functions with only basic inputs from the plant control equipment. Examples of such subsystems are:

- Auxiliary power
- AC switchgear and filters
- Inverter
- DC switchgear
- DC power circuits
- Photovoltaic array

PRECEDING PAGE BLANK NOT FILMED

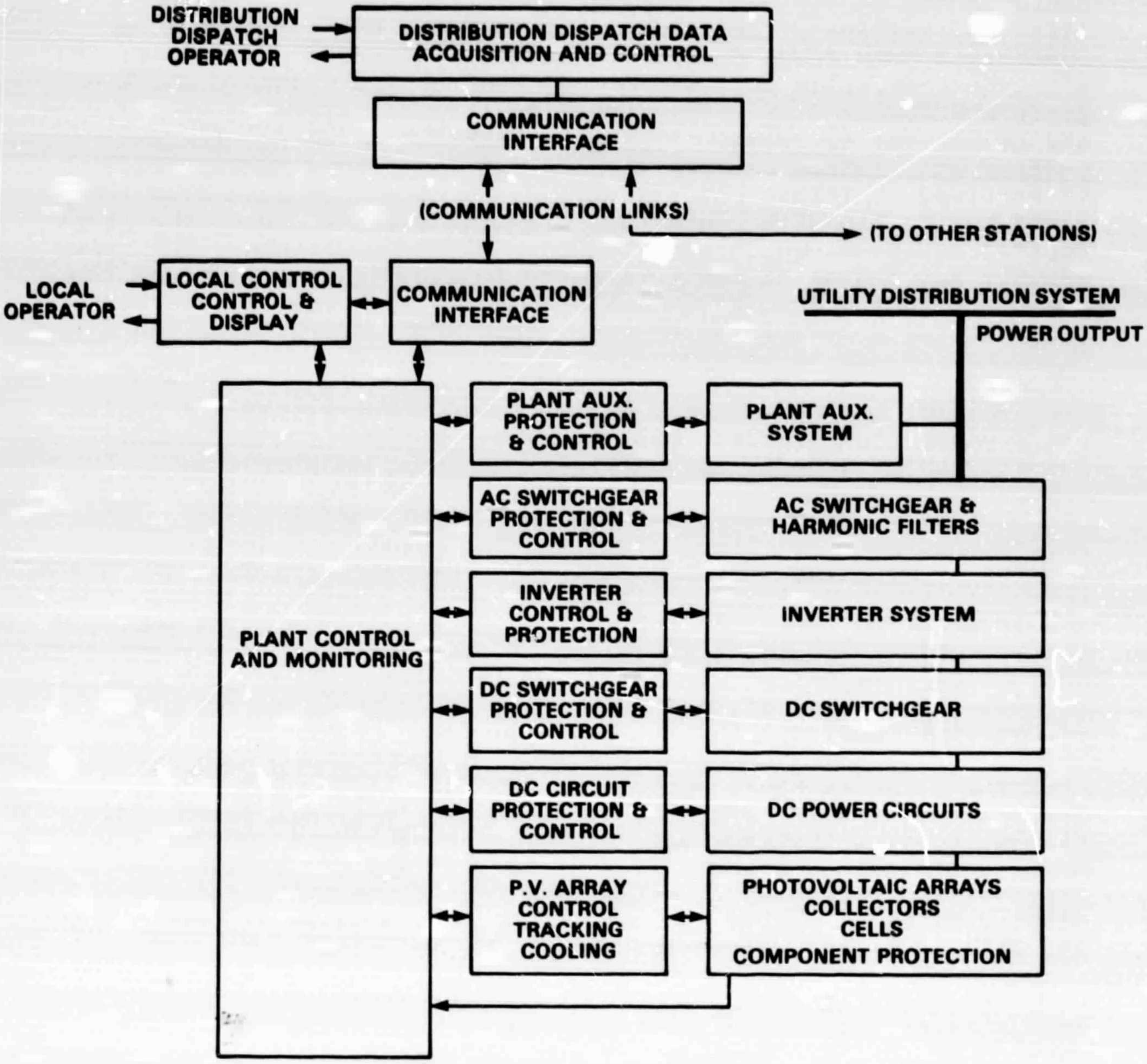


Figure A3.2-1. Block Diagram of a 5 MW Photovoltaic Power Plant

The major control subsystems are the photovoltaic array control and the inverter control.

If the photovoltaic array is a tracking system, its control system acts to optimize the available insolation unless it receives override commands from the plant control equipment.

The inverter control system normally adjusts ac current flow to achieve maximum power output. If other than maximum power output is desired by the local or remote operator or utility dispatch system, a modified setpoint is imposed on the inverter control via the plant control equipment. Sequencing of inverter equipment for normal startup and normal and emergency shutdown is performed by the inverter control equipment.

Other subsystem controls provide the usual functions for the type of equipment involved by means of relatively conventional electromechanical controls.

A3.3 PHOTOVOLTAIC GENERATION PLANT SIZE, EFFICIENCY, AND AVAILABILITY

This subsection discusses factors influencing the kW rating of photovoltaic generation plants, probable efficiencies, and some considerations with respect to availability.

A3.3.1 SIZE

Photovoltaic (PV) conversion systems of a wide range in size (kW rating) are possible for DSG applications. These applications might include such things as residential units of 10 kW, individual load centers of several hundred kW for small industrial applications, or stations ranging from a few to many MW for larger load centers or centralized power generation.

Area requirements, rather than equipment or photovoltaic system design factors, are likely to be a limiting factor in the size or (electrical output) rating of a PV system. The larger photovoltaic systems can be designed and built in modular form which provides operating flexibility and inherently higher system availability.

The following example gives an indication of the area required for multi-array plants. Assume a median overall sunlight-to-high voltage busbar conversion efficiency of 10 percent, an array packing factor of 50 percent and a peak solar insolation value of 1 kW per square meter. Then twenty square meters (218 square feet) of area are required for each kilowatt of peak power output.(9) If rooftops can be utilized, land area can serve dual purposes, but using rooftops places a finite limit on the kW rating possible. This example is for a fixed flat plate array. Arrays (collectors) which use two-axis tracking require approximately double this amount of area because of increased spacing for non-interference (shadowing effect). For a single array residential roof installation, packing factors of 75 to 90 percent are possible.

A3.3.2 EFFICIENCY(9)

The predominating factor in photovoltaic system efficiency is the photovoltaic cell conversion efficiency. For the materials presently under investigation theoretical cell conversion efficiencies from a few percent to 30 percent have been identified. At present, practical producible limits for each of the various materials is somewhat less than the theoretically obtainable efficiency (in some cases only a few percent and in others more than half the theoretical efficiency can be demonstrated). Examples of efficiency for present technology are given in Table A3.3.2-1.

While the spectral content of the irradiant energy affects the efficiency of the cell, cell temperature has a larger effect. Efficiency decreases with an increase in temperature. Photovoltaic materials have different temperature-efficiency characteristics (some more tolerant to high temperatures).

Table A3.3.2-1

PHOTOVOLTAIC CELL EFFICIENCY

Photovoltaic Cell Material	PERCENT CONVERSION EFFICIENCY	
	Commercial or Repetitive	Highest Reported (1978)
Single Crystal Silicon	12 - 15	19
Polycrystalline Silicon (Thin Film)	-	10
Cadmium Sulfide/Copper Sulfide	3 - 5	9
Gallium Arsenide	-	24.5

Other losses in the sunlight-to-high voltage ac busbar chain are incurred in dc interconnections and cable, inverter, station, and array auxiliary power, ac cable, transformer, harmonic filter, and switchgear elements of the system. Generally, however, these losses will amount to only 5 or 10 percent of the plant's rated output. Thus, by comparison, the photovoltaic cell conversion efficiency is the predominant factor in the performance chain.

A3.3.3 AVAILABILITY

The largest factor in the overall availability of a photovoltaic system's power output is sunlight. In addition to the daily cycle (which varies seasonally), weather conditions affect the output as they modify the available intensity and type of insolation, direct and diffuse. Table A3.3.3-1 lists annual sunlight energy available at 26 sites.[12] Various types of array, from low concentration to very high concentration, are affected differently by diffuse solar irradiation. Generally high concentration collector designs are much less able to utilize diffuse irradiation (they require direct irradiation) and are, therefore, more adversely affected by clouds. Thus available weather records are an important consideration in choosing a geographical location and type of photovoltaic collector design.[9,12]

In addition to the basic sunlight availability, intensity and type, equipment/system availability affects overall plant availability. However, the high availability of solid state photovoltaic, dc to ac inverter, and other relatively standard, reliable equipment makes this factor less significant than sunlight availability. Further, in medium to large PV systems, sectionalizing and modular design will permit isolation of faults and operation of the plant at partial output, thus providing greater equipment/system availability than is found in fossil plants, in which all power is concentrated in a single, large, prime-mover generator.

Table A3.3.3-1 (12)

TYPICAL METEROLOGICAL YEAR ANNUAL ENERGY
AVAILABILITY FOR THREE SURFACE TYPES

SOLMET SITE	TOTAL HORIZONTAL	TOTAL LATITUDE TILT	DIRECT NORMAL
	kWh per m^2		
Albuquerque	2116	2401	2566
Apalachicola	1735	1866	1639
Bismark	1452	1707	1641
Boston	1265	1421	1160
Brownsville	1803	1868	1587
Cape Hatteras	1583	1747	1504
Caribou	1227	1418	1183
Charleston	1542	1690	1354
Columbia	1524	2058	1552
Dodge City	1789	2055	2103
El Paso	2193	2434	2631
Ely	1919	2230	2377
Fort Worth	1711	1877	1764
Fresno	1987	2169	2243
Great Falls	1452	1715	1641
Lake Charles	1557	1652	1285
Madison	1367	1554	1304
Medford	1562	1699	1582
Miami	1706	1802	1418
Nashville	1460	1589	1279
New York	1255	1402	1087
Omaha	15[illegible]7	1767	1652
Phoenix	2154	2394	2496
Santa Maria	1837	2039	1947
Seattle	1186	1299	999
Washington, DC	1397	1559	1287

A3.4 ECONOMIC CONSIDERATIONS OF EQUIPMENT COST AND SYSTEM VALUE

Electric power production by photovoltaic conversion in kW or larger sizes is in its very early stages. However, a number of systems from a few kW to several hundred kW are either operating or in the design and construction stages. These are experimental or demonstration type systems.

Following general patterns for Federal Power Commission (FPC) and Atomic Energy Commission (AEC) Code of Accounts, a Code of Accounts has been suggested for Photovoltaic Power Plants[1]

Major direct cost categories are:

- Land and Land Rights
- Structures and Site Facilities
- Solar Array Equipment
- Power Conditioning Equipment
- Electrical Plant Equipment
- Miscellaneous Plant Equipment
- Storage Equipment

Indirect costs and other costs generally have the same titles as those of fossil fuel plants.

Taking into account expected improvements in cell efficiency and reductions in cell costs, a range of "Installed Costs" for photovoltaic power plants projected for 1995 installation is forseen as 2000 to 4000 dollars per kW, in 1995 dollars.[1] These figures include favorable (and hopefully realistic) assumptions regarding progress in cost reductions (i.e., cell costs of $\$40/m^2$ in 1976 dollars). Table A3.4-1 shows a breakdown of the direct costs, on a relative basis, for 1995 conditions based on 1976 dollars.

Table A3.4-1

PHOTOVOLTAIC POWER PLANT DIRECT COST ESTIMATES
(Costs Expressed as a Percent of Total Direct Cost)

Account No.	Account	Range of Costs for Various Type Arrays
10	Land and Land Rights	0.1 - 0.2 (2)
11	Buildings and Site Facilities	0.8 - 2.3 (2)
12	Solar Array Equipment	79. - 89.4 (3)
13	Power Conditioning Equipment	5.2 - 21. (4)
14	Electric Plant Equipment	4.7 - 7.9 (2)
15	Miscellaneous Plant Equipment	(Note 5)
16	Storage Equipment	(Note 6)

Notes:

(1) Based on plant size of 200 MW installed 1995 (residential size 10 kW, 20,000 units).

(2) For residential roof installation these accounts were zero.

(3) Based on assumed solar photovoltaic cell costs of $\$40/m^2$ ($\$3.72/ft^2$), excluding encapsulation and mounting.

(4) 21% figure was for residential units which had higher relative $/kW power conditioning costs. For large plants the range was 5-6 percent.

(5) Miscellaneous plant equipment included in Account Nos. 12, 13, 14.

(6) No storage included in these examples.

(7) Reference 9 is source of data.

When PV plant costs are compared to PV plant value for a utility system, projections for the 1995 period do not appear optimistic.(9) Depending on a number of factors, total value to a utility system compared to total PV system costs appears to be in the range of 0.33 to 0.75. However, future cost and technology projections are subject to inaccuracies and therefore must be carefully evaluated as changes occur. A prime example of circumstances that may affect projections is the rapid escalation of fossil fuel costs.

A3.5 ACTIVE PARTICIPANTS[11]

The following companies are representative of those active in development of photovoltaic technology:

- ARCO - Solar
- Bell Labs (AT&T)
- General Electric Company, Corporate Research and Development
- Honeywell
- Hughes Research
- IBM
- Motorola
- RCA
- Rockwell International
- Solarex
- Texas Instruments

Section A4

WIND GENERATION TECHNOLOGY

A4.1 DEFINITION AND DESCRIPTION OF PHYSICAL PRINCIPLES

Wind generation systems, by means of a bladed propeller, convert wind energy to shaft mechanical energy to electrical energy via a conventional electric alternator (see Figure A4.1-1). Wind generation systems for electric utilities are likely to consist of one or more modest size units (0.2-3.0 MW) making up an integrated installation. Wind generation is available only when the wind is blowing at speeds above a certain threshold velocity and at speeds below a certain maximum velocity at which damage to the installation might occur. Therefore, with wind generation, additional generation by other means is generally required by the utility.

A4.1.1 DESCRIPTION OF PHYSICAL PRINCIPLES

Power generated by the wind is a function of a number of parameters including the following:

Wind speed. The power developed, by a propeller with a fixed angle of attack, is proportional to the cube of the wind speed along the axis of rotation.

Direction of wind. For a wind turbine with a horizontal axis, the power decreases as the wind direction departs from coincidence with the axis of rotation of the propeller.

Pitch angle of the propeller. The power developed by a propeller in a wind of a constant velocity and a given wind direction is a function of the pitch angle of the propeller.

Height of the propeller axis of rotation. Wind velocity increases as the height above the ground increases. The power from a wind generator can be increased to a certain extent as the height of the hub is increased.

Diameter and number of blades of the propeller. The power developed by a propeller, is a function of the diameter and number of blades of the propeller. To obtain a greater amount of power from a horizontal axis wind turbine by the use of a larger diameter propeller, it may be necessary to increase the height of the propeller axis above the ground.

Some of these quantities are fixed by the characteristics of the initial design and are not changeable under load or other conditions of operation. The height of the propeller axis above ground level and the diameter and number of blades of the propeller are representative of such fixed parameters.

Other quantities are controllable under load to maintain synchronous frequency with the electric utility system or to orient

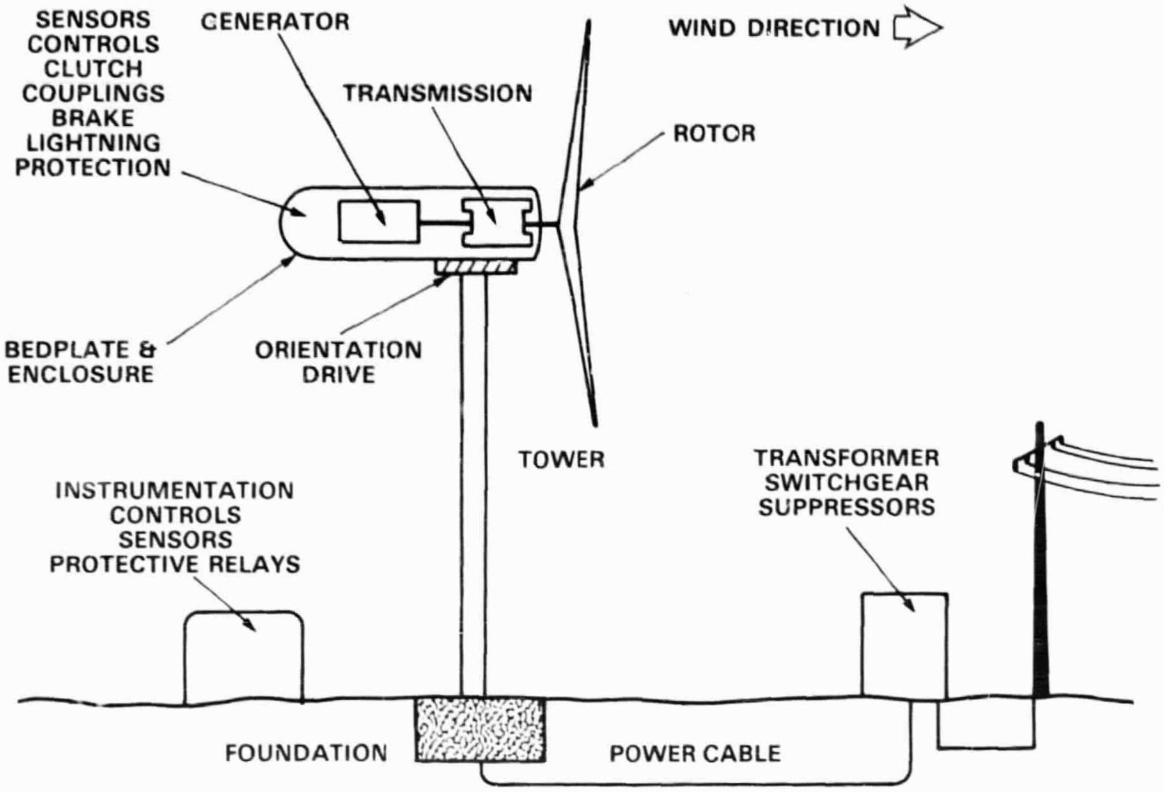


Figure A4.1-1. Elements of a Wind-Driven Generator System

in yaw the horizontal axis of the propeller to get the full energy from the wind. In particular, control of the pitch angle of the propeller is necessary to accommodate changing wind speed and the electric utility load as well as the frequency and power angle of the electric utility system.

Still other quantities, such as the magnitude of the wind speed and the direction of the wind, are not controllable at all, and their values must be sensed and accommodated by the variables which are controllable.

Although there are a number of different wind turbine designs that have been proposed and considered,(17,18) some with a horizontal axis for the propeller rotation and others with a vertical or darrieus-type axis,(17) the following discussion concerns the horizontal-axis propeller-type wind turbine.

The power which can be derived from the wind varies according to the cube of the wind speed along the axis of rotation. Thus, the basic equation for power, P, is:

$$P = 1/2 \ \rho \ V^3 \ Cp \ A$$

where ρ = air density

V = wind speed

C_p = coefficient of power

A = area swept out by rotor

The theoretical limit for extraction of energy from the wind by a propeller-type rotor is 59.3 percent. In practice, well-designed rotors are able to extract between 40 and 45 percent of the wind energy. An expression for the power density extraction capability of a propeller-type windmill is given by the following equation:

$$P = 2.08 \times 10^{-6} V^3 \text{ kW/ft}^2$$

where V = wind velocity in miles per hour

Area in square feet is that area swept out by the rotor diameter.

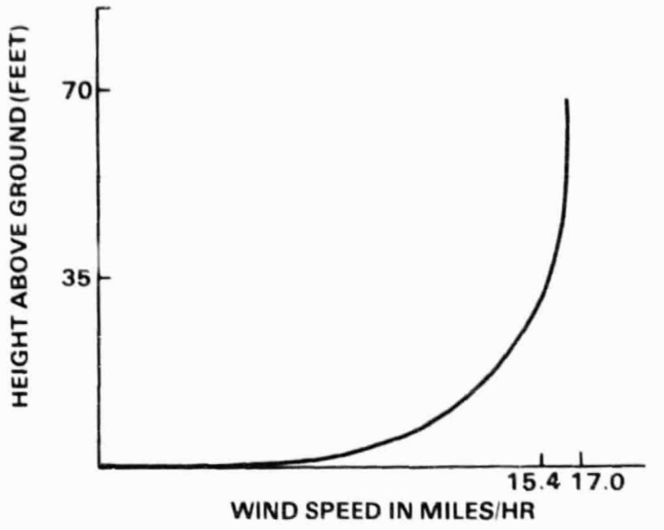
Thus, for a rated speed of 20 miles per hour the extractable power density is 0.017 kW per ft^2 of swept area. For a 1 MWe windmill, the rotor diameter would be approximately 274 feet, and the blade tip should clear the ground by about 50 feet.

Further, wind exhibits a vertical escalation in speed with height (caused by vertical wind shear) that is a function of such factors as the gross terrain features, atmospheric stability, and ground friction. For wind over water or a flat terrain, a reasonable conservative model of wind shear is given by the equation:

$$V = V_o \left(\frac{h}{h_o}\right)^{1/7}$$

where Vo is the velocity at a reference height, ho. Figure 4.1.1-1 shows the shape of this wind velocity profile as a function of hub height above ground and indicates the desirability of having the hub well above ground level. Representative values for ho and Vo are 35 feet and 15.4 mph respectively.

Since the wind speed is generally uncertain in both magnitude and direction, it is interesting to note the relationship between generated power and wind speed expressed in terms of rated wind speed. The wind energy system design may be such that the generator must run synchronously with the electric utility frequency so that a constant rotation speed of the mechanical shaft is required. Figure A4.1.1-2 is based on a simplified model of power output versus wind speed in which the power output (up to rated speed) is taken as proportional to the cube of the speed less a fixed loss which would yield zero power at 1/2 rated speed. Beyond rated wind speed, pitch control of the blades permits the shedding of excess power up to a wind speed beyond which power should not be generated because of structural limitations. Beyond this maximum wind speed, of say 300 percent, the blades should be feathered. Since the direction from which the wind may come is likewise subject to frequent change, it is desirable that an additional angular



FigureFigure A4.1.1-1. Height Above Ground versus Wind Speed

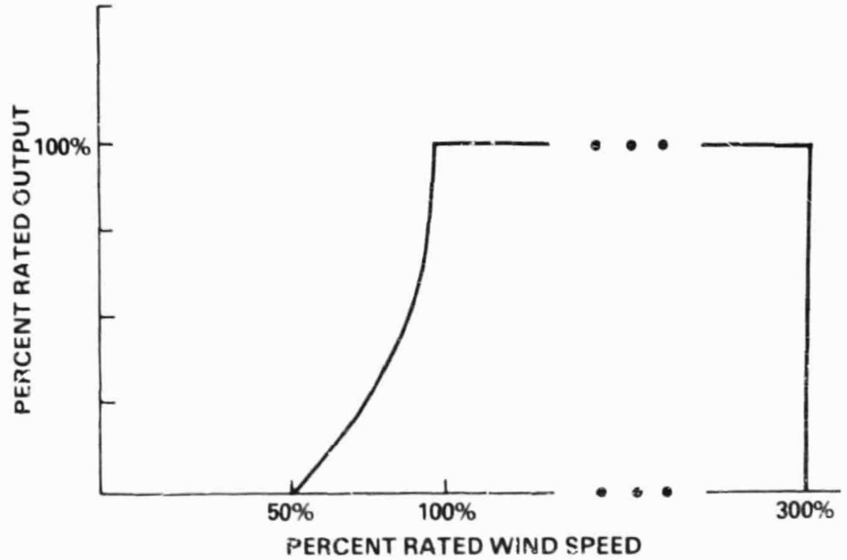


Figure A4.1.1-2. Power versus Wind Speed for Wind Energy System

control in yaw be available to direct the orientation of the plane of the propeller to be perpendicular to the direction of the wind.

Another version of wind turbine generator using electrical power conversion equipment can modify variable frequency alternating current to fixed frequency alternating current which is compatible with the requirements of the electric power distribution system.

As a measure of the uncertainty of the speed of the wind, one can measure the actual wind speed as a function of time throughout a year and determine the frequency of occurrence of different wind speeds. Representative of such a curve of frequency of occurrence of wind speed is Figure A4.1.1-3. From such data, one can estimate the number of hours per year when the wind is lower in speed than the cut-in velocity (below which the generator is not able to generate power), and the number of hours when the wind may exceed the maximum speed at which it is no longer safe to operate because of possible damage to the equipment. Figure A4.1.1-4 shows a power duration curve for a particular wind generation site. It indicates for an average year (after conversion losses have been accounted for), the number of hours per year that various amounts of electric power can be generated. The shaded area indicates the total energy that on the average should be available from the wind generator.

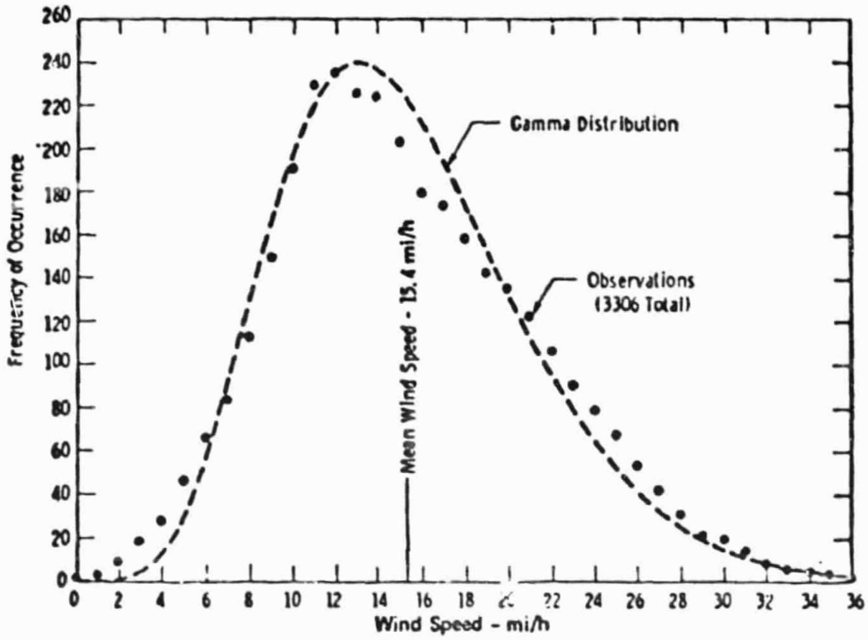


Figure A4.1.1-3. Frequency of Occurrence versus Wind Speed

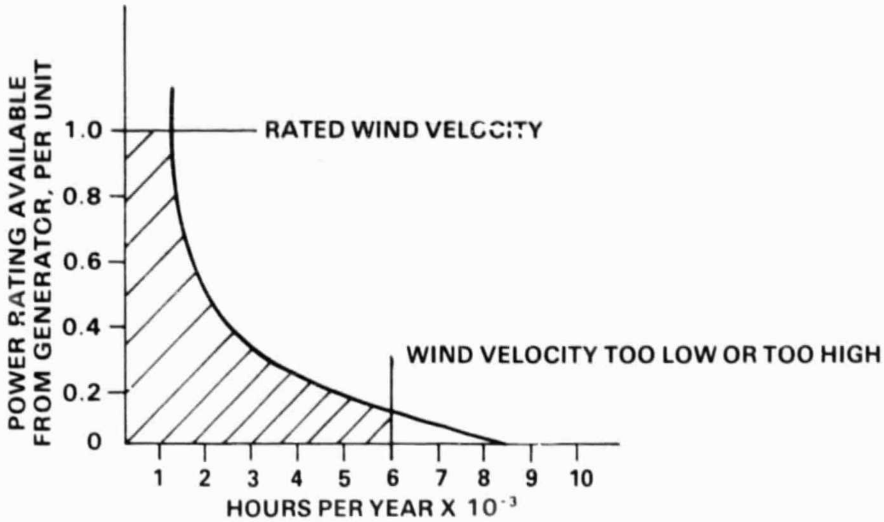


Figure A4.1.1-4. Typical Power Duration Curve

A4.2 DESCRIPTION OF SYSTEM CONTROL

A Wind Turbine Generator (WTG) control system should be designed for operation at a remote, unattended site. The system must be fail-safe and self-monitoring. It must be capable of detecting any failure within the WTG which may cause secondary damage to associated equipment. It must also be able to take the appropriate protective action. The control equipment must be capable of maintaining proper operation of the WTG under extreme environmental conditions, such as wind gusting and wide temperature ranges. Safety and protective functions must be capable of being executed without external power. The WTG control system must be conservatively designed to maintain high reliability and be properly protected against induced transients from the power line or from lightning strikes.

The following criteria have been recommended(14) to guide the conceptual design processes:

1. The concepts must be acceptable to the utility.

2. Preference should be given to equipment with which utilities have had previous experience in remote-site applications.

3. Concepts must be compatible with climatic conditions ranging from arctic to tropical, as well as lightning and power line transients.

4. To assure low cost and high reliability, the selected concepts must be as simple as possible to do the required task.

5. Control functions performed under emergency conditions must be able to be executed with minimum power demands on the emergency battery supply.

6. Critical functions must have readily predictable failure modes and must be easily amenable to automatic failure mode detection.

7. Preference should be given to concepts which have inherently long life with minimum maintenance.

The control system which has evolved from the above design criteria utilizes a microprocessor for data telemetry and for startup and shutdown sequencing of the wind-driven generator with hydraulic servos and analog equipment for the primary rotor controls. A mechanical backup is provided for safe emergency shutdown of the rotor.

A4.2.1 PRIMARY ROTOR CONTROLS

There are two primary control requirements for a horizontal axis WTG. The first requirement is to control the yaw orientation of the rotor to maintain the plane of the rotor disc perpendicular to the average wind vector. The rotor disc is normally positioned downwind of the rotor to allow the rotor to be operated as close as possible to the tower, and hence to reduce yawing movements on the tower.

The second requirement is to control and limit rotor revolutions per minute and power output under varying wind conditions. This control is most readily provided by varying the pitch angle of the rotor blades around their longitudinal axis. The WTG can be operated at relatively constant rpm under varying wind conditions by control of the rotor blade pitch. This same control can be used to synchronize the generator with the utility network. Once the generator has been synchronized with the network, the blade pitch control is used to limit power output of the WTG under high wind conditions and to limit the adverse effects of wind gusts on the system.

Figure A4.2.1-1 shows a control block diagram for the yaw position control and the rotational speed control, each of which is provided with signal information from wind sensors. In addition, the rotational speed control is provided with utility load data from the electrical load on the alternator.

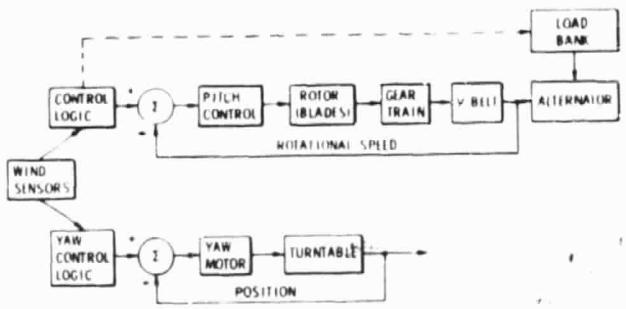


Figure A4.2.1-1. Rotor Control Block Diagram

A4.2.2 PITCH CONTROL SYSTEM

The pitch control system must operate in a satisfactory manner during the following operational modes of the WTG system:

1. Startup: programmed pitch change for rotor acceleration

2. Standby/Synchronize: pitch controlled to regulate shaft rpm

3. Operate: pitch controlled to regulate power output

4. Normal Shutdown: programmed pitch change for rotor deceleration

Continuous fault monitoring of the pitch servo during the startup, standby/synchronize, and operate modes is required to prevent possible overspeed/underspeed and/or reverse thrust on the rotor due to pitch servo failures. The monitoring device must be capable of differentiating between pitch control failures and sudden or unusual motion of the controls due to wind gusts. This is accomplished by a monitoring device which checks for proper blade pitch position via an independent feedback sensor. The average position of blade pitch should bear a direct relationship to wind speed in the standby/synchronize and operate modes, and should be a predictable function of rotor rpm and wind speed in the startup mode. Comparison with the actual blade pitch position from an independent feedback sensor allows monitoring for proper operation of the servo. Backup fault sensing is provided by additional sensors such as redundant rotor overspeed sensors, redundant wind sensors, monitoring of generated power, and monitoring of pitch control forces.

A4.2.3 YAW ORIENTATION CONTROL

Turntable yaw orientation is accomplished by means of a hydraulic motor driving through a gear train. The worm gearbox is irreversible so that the turntable will be rigidly held against wind load, unless the wind load is assisting the hydraulic motor. This arrangement provides yaw restraint for the rotor even if the hydraulic supply should fault. The speed of the motor is restrained by hydraulic flow control valves, so that turntable rotation will be held to 1/3 rpm even with assisting wind. This is required to limit rotor gyroscopic forces. The yaw servo is intended only to trim the system to the average wind direction, not to follow sudden wind direction changes.

Continuous fault monitoring of the yaw servo during WTG operation is provided by independently monitoring the average wind direction error and checking for proper servo response to changes in the average direction of the wind. Backup fault sensing is also provided for the yaw servo, as in the pitch system described above.

A4.2.4 OPERATING MODE CONTROL FOR SEQUENCING AND SUPERVISORY CONTROL

The sequencing control of the WTG during startup and shutdown and the signals for the synchronizing and normal operating modes are contained in the Operating Mode Control. Critical sequencing functions may be provided by redundant signal sources so that a suitable reliability capability is available.

A4.2.5 EMERGENCY CONTROL FOR OVERSPEED LIMITING AND OTHER ABNORMAL CONDITIONS

Overspeed of the WTG in high winds due to control failure or a sudden loss of load is of concern because of the potential equipment damage which could occur. Alternative speed controls to the normal ones should be available, and a completely redundant mechanically actuated rotor blade feathering system to dump excess rotor energy, backed up by a parking brake of moderate capacity, may be employed for emergency conditions.

A4.2.6 MASTER CONTROL

In addition to the individual controls for the WTG noted above, there is need for a master control which will integrate the separate controls and make them responsive to the local control, the utility dispatch, and the data and alarms as shown in Figure A4.2.6-1. The local control station is required because the WTG must be capable of being operated locally as well as remotely.

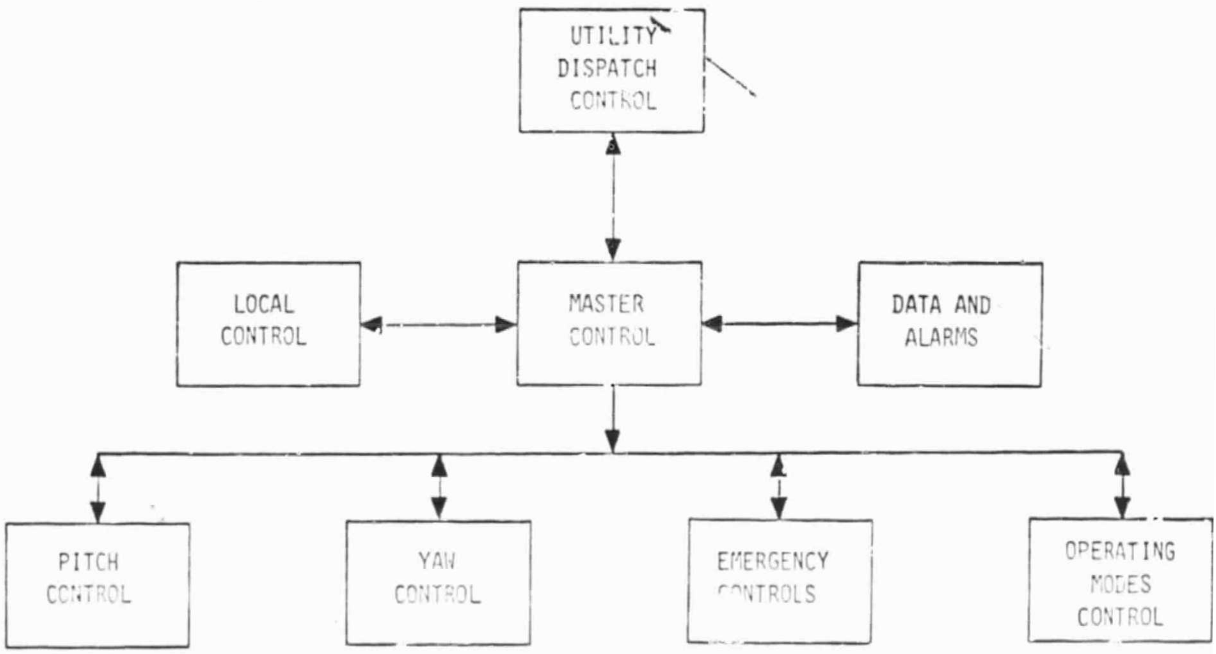


Figure A4.2.6-1. Wind Driven Generator Control System

Data and alarms are needed locally and at the remote utility dispatch control. A limited amount of routine information should be available on a periodic or an as-required basis remotely when all is operating well. When operation is abnormal, more detailed information should be available to the remote operator to help in the decision process to restore the WTG to normal operation.

Another function of the master control may be to serve as a common control point for several wind-driven generators to operate in parallel when such a grouping of generators exist in close proximity.

A4.3 WIND GENERATION POWER PLANT SIZE, EFFICIENCY, AND AVAILABILITY

In this subsection the size, efficiency, and availability of wind generation power plants are discussed.

A4.3.1 SIZE

The earlier description of the power capable of being generated by the wind indicated that a 1 MWe windmill would require a structure with a rotor axis located about 275 feet above the ground and a wind velocity of 20 miles per hour. Considering the unlikelihood of regularly having winds greatly in excess of this speed, and considering the undesirability of having support structures much higher than 300 feet from the ground, one arrives at the conclusion that the rating of a wind generation power source will probably not exceed 5 to 10 MWe. The NASA Lewis Research Center Wind Energy Project for 1975[14] included industry-designed and user-operated wind generators up to 3.0 MWe in size.

To get a larger amount of energy from the wind at any particular locality requires two or more wind generators acting in parallel on the same electrical network. This arrangement necessitates supplemental control capability through which it may be possible to share control functions such as startup or synchronizing between two or more wind generator units. Thus large wind generator systems lead naturally to complex control systems.

A4.3.2 EFFICIENCY

Considerable effort over the years has been devoted to improving the efficiency of propellers, and the rotors of wind-driven generators are described as approaching an efficiency of 70 percent of their theoretical value of 59.3 percent. The associated gearing efficiency is in the 90 percent range. Likewise the efficiency of the electrical generator is about 90 percent. The combined efficiency should amount to 30-35 percent at rated power which represents a reasonably attractive figure that is not likely to be greatly improved in the near future. Analyses have shown the annual efficiency to be about 20-25 percent.

A4.3.3 AVAILABILITY

Figures A4.1.1-3 and A4.1.1-4 have indicated that there are periods of the day and year when there is either too little or too much wind for safe, efficient operation. Compared to the reliability and availability of the hardware and the software of the wind generator system, the wind is probably the largest single reason for the unavailability of a wind generator system at any particular time.

A basic factor in the availability of wind power is the density of the available wind energy for the particular location.

Figure A4.3.3-1 is a U.S. wind chart in which the available wind energy at 50 meters is shown in units of $MWh/m^2/yr$. With the use of maps such as these, one is better able to identify those localities which are likely to have the desired wind energy.

For the 274 ft. diameter rotor considered earlier, and for a location having an energy density of 10 $MWh/m^2/yr$, the number of MWh/yr =

$$10 \times \frac{\pi}{4} \times \left(\frac{274}{3.3}\right)^2 = 54{,}150 \text{ MWh/yr.}$$

Assuming that the wind is available 5415 hours per year, i.e., 62 percent of the 8760 hours total, this means that 10 MW of power are theoretically available. The earlier calculations had indicated that with this 274 ft. diameter rotor and a speed of 20 miles per hour, the power generated would be 1 MWe. Taking into account the various efficiencies involved as well as the nominal wind energy available, one may relate in a reasonable fashion the wind energy data with the rating of the wind turbine generators noted above.

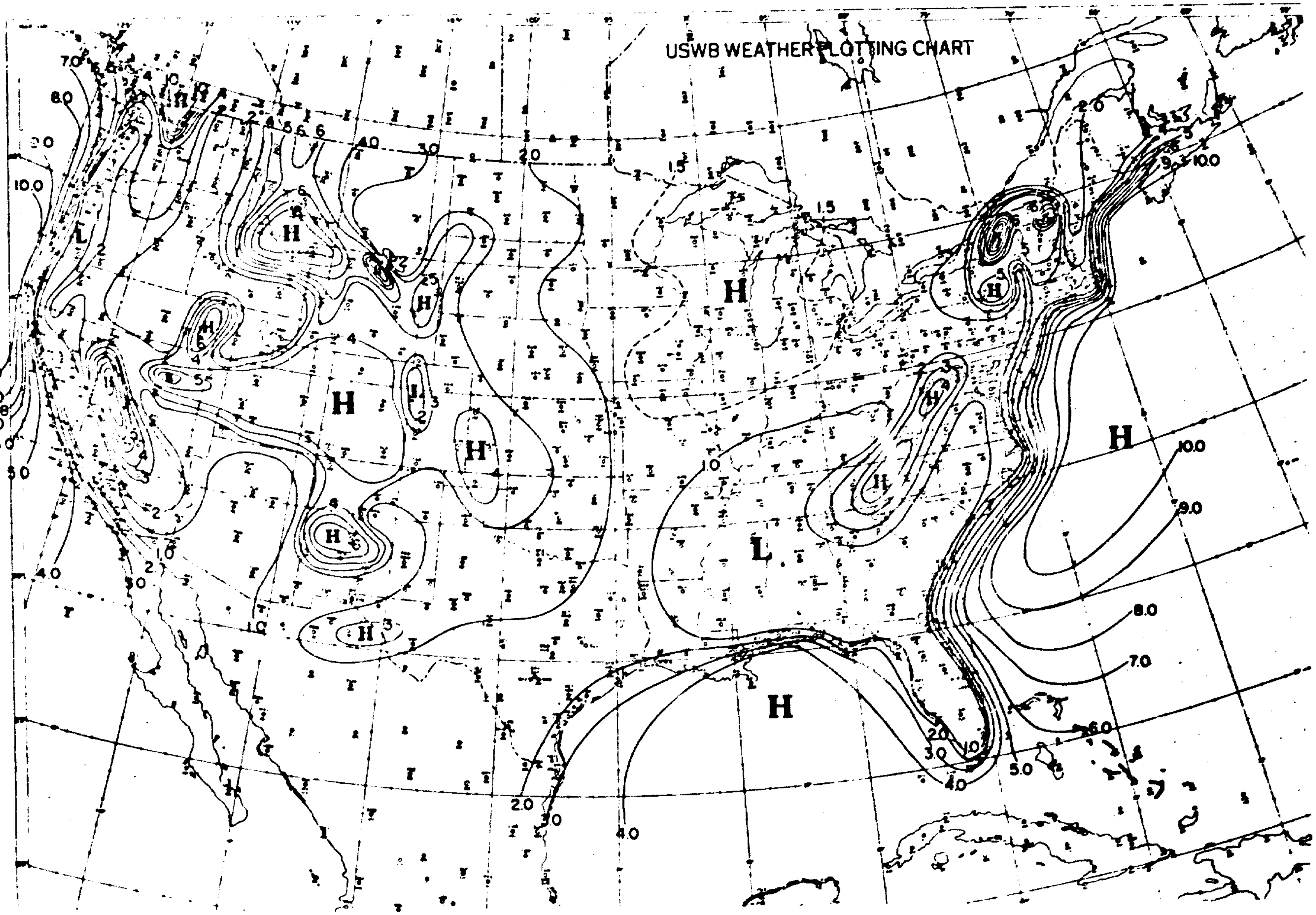


Figure A4.3.3-1. Distribution of Wind Energy at 50 Meters over the U.S.; Isopleths Are in MWh/m^2/year.

A4.4 ECONOMIC CONSIDERATIONS

At present, some wind-driven generators are under test in electric utility operation[19] and other installations are approaching operational status. As such, the WTG can be considered to be in the initial portion of a cost learning curve. From this point of view, the costs for wind-driven generator installations should decrease as the number of units installed increases.

The major elements of a WTG system include the following:

- Land
- Tower and Building
- Generator
- Propeller rotor
- Switchgear
- Control

Those elements with the greatest amount of uncertainty include the tower, propeller rotor, and control. As such, those are the items for which the costs are least well known and most subject to change.

Informal estimates have been obtained[21] which indicate that wind plant costs were and will be:

1,500 kW	= \$590/kW in '76 for wind generators to be put into production in 1990. (Note: Inflation of costs '76 to '90 must be included.)
200 kW (horizontal axis and constant speed)	= \$970/kW in '76 and '90 production

Another factor to be considered is a "transmission interconnection" cost which is to be added to the basic costs listed above. That may amount to \$100/kW to \$300/kW.

Two elements which influence cost and time factors are:

- The time required to select, design, and construct a wind-driven generator installation.
- The way the costs per wind-driven generator installation will change over the next two decades. These costs are related to the learning curve.

The value of a wind-driven generator can be measured by the value of displaced conventional power plants.[21] Cost consists of the capital investment and the operating and maintenance costs of the wind plant. For wind generation the saving in fuel cost is a predominant factor.

A4.5 ACTIVE PARTICIPANTS

The following organizations and companies are representative of those active in the development of wind-driven generation systems:

- General Electric Company
- Kaman Aerospace Corporation
- NASA Lewis Research Center
- Northeast Utilities Service Corporation
- Oklahoma State University
- Public Service Electric & Gas
- Pennsylvania Power Company
- Westinghouse Electric
- Pennsylvania Power and Light
- Southern California Edison
- Boeing

FUEL CELL TECHNOLOGY

A5.1 DEFINITION AND DESCRIPTION OF PHYSICAL PRINCIPLES

Fuel cell energy systems consist of an electric power generation device in which hot fuel gas is passed over a fuel electrode and heated air is passed over an adjacent air electrode, separated from the fuel electrode by an electrolyte, so as to produce a dc power output and an exhaust of carbon dioxide and water. The direct current electric power produced by the fuel cell is connected to a dc/ac inverter which in turn supplies the distribution network with alternating current at the proper voltage and frequency.

A5.1.1 DESCRIPTION OF PHYSICAL PRINCIPLES

Fuel cell plants for use at dispersed sites on a distribution network are just entering the experimental testing stage. Fuel cells operate at different temperature ranges depending on the type of fuel cell. These include low temperature cells (up to 200 °C) using phosphoric acid and medium temperature cells (up to 650 °C) using molten carbonate. Fuel cells operating at still higher temperatures (1000 °C) are in the conceptual stage. As shown in Figure A5.1.1-1, the fuel gas may be generated from oil, steam, and air, which are processed in an oil fired gas source. The fuel gas and air used in the fuel cell develop direct current electrical energy which must be converted into the alternating current of the distribution network. An electrical inverter is required to perform the necessary electrical conversion.

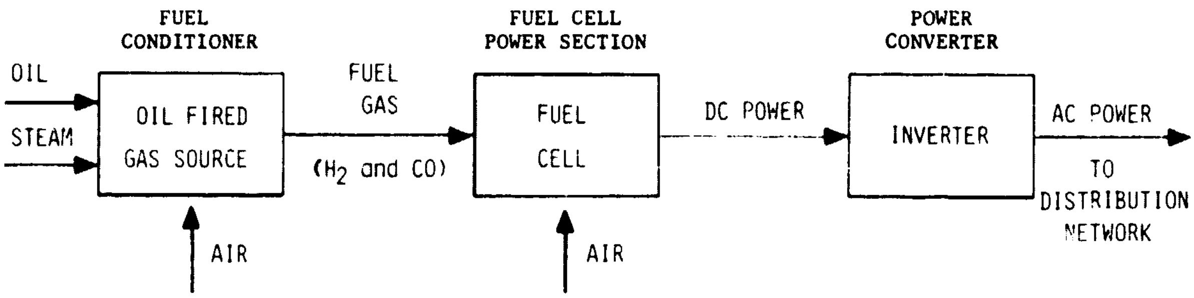


Figure A5.1.1-1. Distribution Fuel Cell Power System

Cited as being favorable characteristics for the fuel cell are the following:

- High efficiency (40-45%) which is relatively independent of load
- Flexibility of modular design
- Easily dispersed, low temperature exhaust

- Doesn't depend on availability of sun, wind, or water to supply distribution power
- Low noise
- Minimum environmental pollution

The fuel cell powerplant concept consists of three major subsystems: a fuel conditioner, a fuel cell power section, and a power conditioner.[22] Functionally, the fuel conditioner processes a hydrocarbon fuel into a product gas rich in hydrogen. The power section, comprising groups of single fuel cell elements, electrochemically combines this hydrogen with oxygen from the air to produce dc power. The power conditioner subsystem then converts the dc power to ac power of the proper voltage and frequency.

Figure A5.1.1-2 is a simplified schematic of such a fuel cell power plant. The fuel conditioner concept shown utilizes the steam-reforming process for generating the hydrogen-rich process gas. In this subsystem, either a liquid or a gaseous hydrocarbon fuel is mixed with steam and passes over a catalytic bed in the reformer. The product gas from the reformer contains hydrogen along with considerable amounts of carbon dioxide, carbon monoxide, and water vapor. This stream is cooled and then passed through a catalytic shift converter in which most of the carbon monoxide is further converted to hydrogen and carbon dioxide. This gas is then fed to the fuel cell power section. A portion of the fuel stream is vented from the cells and recirculated back to the burner of the reformer where it is burned to provide the endothermic heat required for the reforming reaction. Process steam is generated by utilizing waste heat from the fuel cell. A preprocessing step which employs hydrogenation of the fuel and subsequent removal of H_2S is added for operation on heavier fuels with high sulfur content.

The overall process in the fuel cell power section consists of the continuous electrochemical reaction of hydrogen and oxygen from the air to produce power and by-product water and heat. The fuel cells generate electricity on demand as long as fuel and air are supplied. The by-product water is removed with the excess air vented from the cells and this along with the water produced in the reformer exhaust is recovered in air-cooled condensers. Sufficient water is recovered to supply the complete process needs of the fuel cell power plant. Waste heat is removed from the cells by a recirculating coolant loop. Some of this heat is utilized to generate steam for the fuel conditioner, and the remainder is rejected in an air-cooled heat exchanger.

Unit cells are connected electrically in series to form "stack" assemblies. The stacks are in turn connected in a series-parallel arrangement to obtain the desired power and voltage requirements.

The power conditioning subsystem converts the dc current from the fuel cell stacks to alternating current and controls its flow

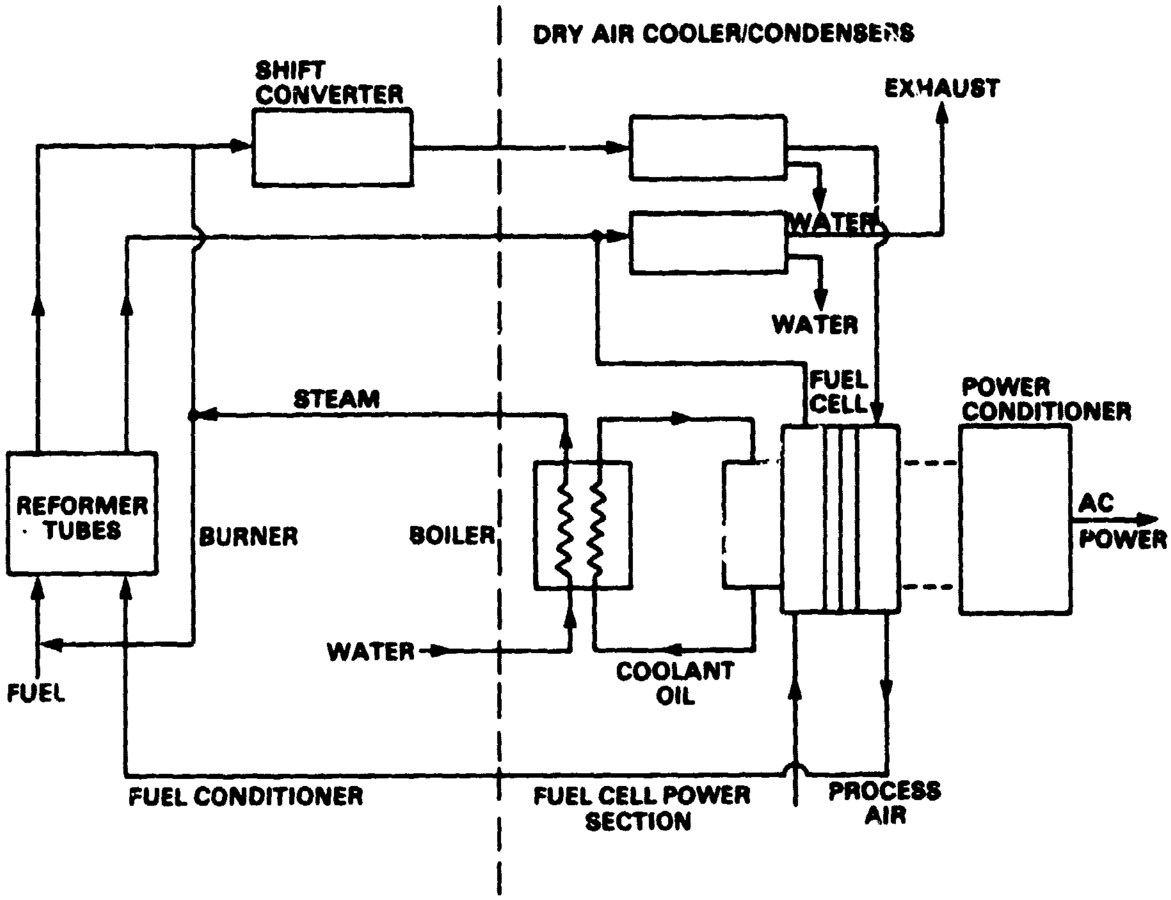


Figure A5.1.1-2. Fuel Cell Generator

into the utility network. This function is accomplished through the use of solid-state inverters with components similar to those being used for high-voltage dc transmission links. This provides for high power-conversion efficiency and reliability with the potential for low cost. The ac voltage output from the inverters is stepped up through a transformer to the desired level for utility distribution.

Further information on fuel cells and their operation in small utilities is contained in such references as the following:

46. Economic Assessment of the Utilization of Fuel Cells in Electric Utility Systems, EPRI EM-336. Final Report of RP 729-1, Public Service Electric and Gas Co., Jan. 1977.

47. An Assessment of the Fuel Cell's Role in Small Utilities, EPRI EM-696. Final Report of RP 918, Burns and McDonnel Engineering Co., Feb. 1978.

48. "A Giant Step Planned in Fuel-Cell Plant Test," E.P. Barry, R.L.A. Fernandes, and W.A. Messner. IEEE Spectrum, Vol. 15, No. 11 (Nov. 1978).

49. "Fuel Cell Power Plants," A.P. Fickett, Scientific American, Vol. 239, No. 6 (Dec. 1978).

A5.2 DESCRIPTION OF SYSTEM CONTROLS

As shown in the Master Control Functional Diagram (Figure A5.2-1), the Master Control for the fuel cell serves as the interface between the utility dispatch control center and a number of other controls located at the fuel cell itself. Typical of these other controls are the following:

- Operating Mode Control - to coordinate the startup, standby, operate and other possible modes of operation. Since the fuel cell operation requires that a suitable temperature be maintained and that adequate fuel gas be available, a proper sequencing and set of interrelationships among the various controls must be established. An important part of this coordination function is performed by the operating mode control.

- Fuel Gas Supply Control - to provide the fuel cell with the proper amount of fuel gas and air to handle the required electrical output. For the case of an oil-fired gas source shown in Figure A5.2-1, control of this gas supply is required.

- Fuel Cell Control - to provide the necessary flows of fuel gas and air to the fuel cell to develop the desired voltage and current for the inverter to meet the distribution network needs. Although the inverter and the gas source have their own controls, control of the fuel cell inputs and outputs can be beneficial.

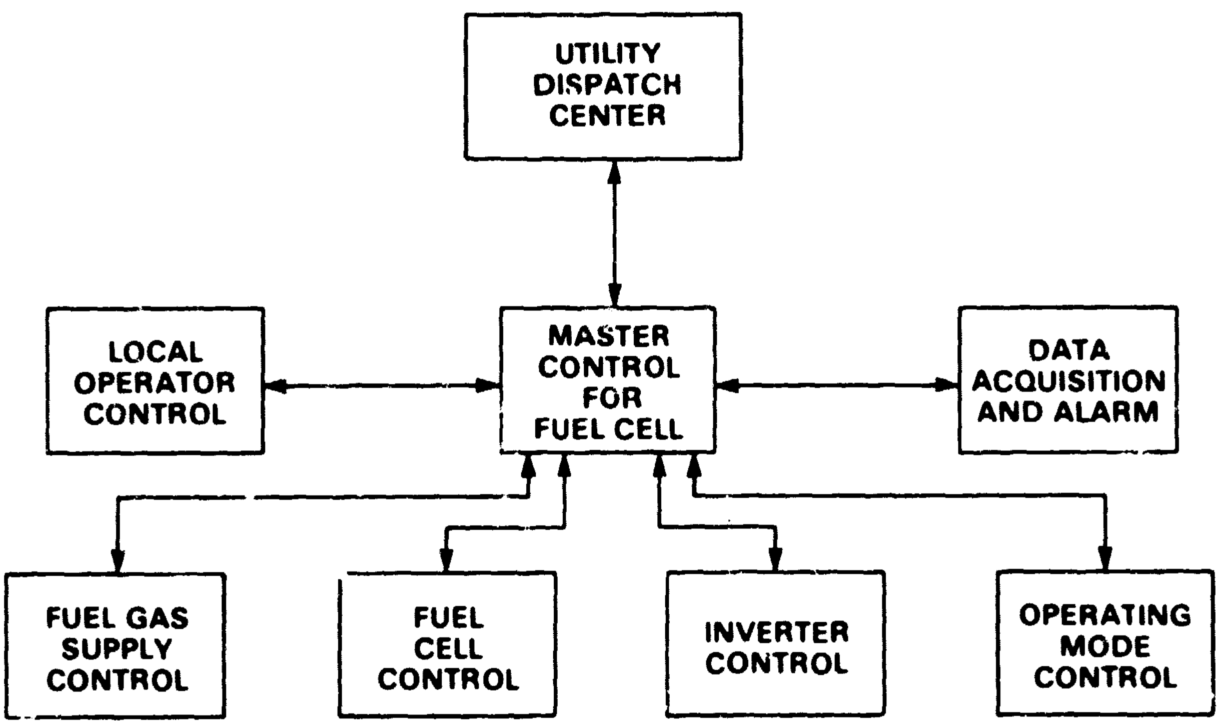


Figure A5.2-1. Master Control Functional Diagram

- Inverter Controls - to control the necessary match between the electrical energy output from the fuel cell and the electrical energy required by the utility distribution network.

As previously noted for other DSG technologies, the plant master control must be capable of independent control of this electrical power source. The remote utility dispatch control sends reference commands for the desired power generation and performs more of a supervisory than an operational control function. Remote monitoring capability must also be available at the utility dispatch control so that the remote power dispatcher has knowledge of when the fuel cell is generating power or is able to generate power.

A5.3 FUEL CELL SIZE, EFFICIENCY, AND AVAILABILITY

A fuel cell of approximately 5.0 MW using phosphoric acid is scheduled to be on line in 1979 for experimental testing. This should provide information on efficiency and reliability. The cost of construction and operation of this first unit should be useful in estimating the future costs, efficiency, and availability of fuel cell units.

A5.3.1 SIZE

The second generation of fuel cells will use molten carbonate electrolyte and should be in the 5-10 MW size range. Such fuel cells are planned to be available in the mid 1980s.

Considering fuel cell size in a physical sense, one can find a description[1] of a 26 MW fuel cell power plant that "could be situated on less than half an acre of land and would have a maximum height of 18 feet." It would appear that fuel cells have a relatively small space requirement compared with some other power generation concepts such as solar.

A5.3.2 EFFICIENCY

Another attractive feature credited to fuel cells is their low heat rate. Figures of 9300-9000 Btu/kWh are listed[22], and these values are indicated not only at rated power but at decreasing power down to 20 percent of rated power. Whereas other sources of electric generation may decrease in efficiency (i.e., increase in heat rate) significantly when the power generated departs from the rated power range, this appears not to be the case for fuel cells.

A5.3.3 AVAILABILITY

A fuel cell generator provides for a much greater inherent power availability than solar or wind generators which require the presence of the sun or the wind to generate power. Fuel cells are estimated to require a startup period of about 60 minutes after which they should be able to deliver any amount of power from 10 percent to 100 percent of rated power as long as fuel is available. In this sense of availability, fuel cell generators should provide a greater measure of predictable availability than several of the other dispersed electric power generators.

A5.4 ECONOMIC CONSIDERATIONS

Because of the early developmental status of fuel cells for electric utility power distribution service, a satisfactory base of economic data from normal operation does not presently exist. It has been necessary, therefore, to approach the subject of economic considerations from the viewpoint of determining those capital and operating and maintenance costs which, if obtained by fuel cell designs, would represent a financially attractive opportunity from an electric utility viewpoint. The General Electric Optimum Generation Program (OGP) has been used to identify the capital cost objectives at which fuel cell purchases by the electric utilities would be attractive.

A target figure of $300/kW for the capital costs expressed in 1978 dollars has been established, and cost estimates have been made for each of the subsystems and components involved to determine whether this cost objective can be achieved. In considering the capital cost elements for an oil-fired fuel cell plant, the subsystems listed in Table A5.4-1 have been included in the cost calculations. A fuel cell system designed to meet this cost objective seems feasible.

It is necessary to have cost-control-oriented studies from the outset to determine the potential of new power plant systems, subsystems, and components for achieving cost competitiveness in the early 1990s which is the time frame for commercial units. The molten carbonate fuel cell modules lend themselves to the learning curve concept where the typical cost reduction curve from early development to large scale production brings about a significant decrease in unit price.

Table A5.4-1

OIL-FIRED FUEL CELL PLANT SUBSYSTEMS

Gasification Subsystem
- Auto Thermal Reformer
- Air Supply System
- Preheat Heat Exchangers
- Steam Flashing System

Gas Cleanup Subsystem
- Zinc Oxide Catalytic Reactor

Fuel Cell Subsystem
- Fuel Cell Module
- Air Compressor
- Catalytic Burner

Electrical Subsystem
- Inverter
- Electrical Collection and Distribution System

Condensate Subsystem
- Condenser
- Feedwater Pump
- Heat Exchangers

Balance of Plant
- Service Buildings
- Normal Support Services

Plant Control Subsystem

A5.5 ACTIVE PARTICIPANTS

The following organizations and companies are representative of those engaged in the development of fuel cells:

- Electric Power Research Institute (EPRI)
- Energy Research Corporation
- General Electric Company
- Institute for Gas Technology
- United Technologies, Incorporated
- Westinghouse Electric

Section A6

STORAGE BATTERY TECHNOLOGY

A6.1 DEFINITION AND DESCRIPTION OF PHYSICAL PRINCIPLES

Storage battery energy systems have as their inputs dc electrical energy which is converted electrochemically to chemical energy during charging of the battery and is electrochemically converted to dc electrical energy during the discharging of the battery. Operation of a storage battery with the conventional ac electric distribution system requires the use of power conditioning equipment which can accept the alternating current from the distribution network and convert it to the dc required to charge the battery and invert the dc electrical energy provided from the battery to ac suitable for the distribution network. Care must be taken so that the timing of battery charging and discharging is economically beneficial to the overall electric power system operation.

A6.1.1 DESCRIPTION OF PHYSICAL PRINCIPLES

Storage batteries for use as dispersed storage and generation are presently receiving considerable attention. An economic attraction is that they use electrical energy at off-peak-load hours supplied by the lowest-cost generation units and supply power to the system during the peak-load hours when the cost of generation is higher. Another attractive feature is that electrical energy generated from coal or nuclear fuel can be used to charge the battery, thus avoiding the use of oil or gas for peaking generation.

Several different combinations of chemicals are under development for use in advanced storage batteries, and it will probably be 5 to 10 years before commercial storage battery equipment will be available at prices competitive with other peak generating means. Table A6.1.1-1 compares three advanced batteries with lead-acid types[30] and indicates the projected test date for a 5-MWh system.

In some cases, the batteries operate at elevated temperatures, in the range of 300-350 °C for the sodium-sulfur battery, so that battery temperature controls are required. Elevated temperatures are necessary to keep the reactants molten and to ensure high battery efficiency.

A battery is comprised of a pair of electrodes that contain an active material, a separator, an electrolyte, and a case.[30] For a sodium-sulfur battery, molten sodium (Na) and sulfur (S) are the active negative and positive materials. These materials are maintained in the molten state by control of the operating temperature. The electrolyte and separator are typically beta

Table A6.1.1-1

LOAD-LEVELING BATTERY CANDIDATES AND CHARACTERISTICS

Characteristic	Battery Candidates			
	Lead-Acid (Pb/PbO_2)	Sodium-Sulfur (Na/S)	Lithium-Metal Sulfide (Li/FeS_2)	Zinc-Chlorine (Zn/Cl_2)
Operating temperature, °C	20-30	300-350	400-500	25-50
Electrolyte	Sulfuric acid	Ceramic	Molten salt	Aqueous zinc chloride
Design modular energy density, Wh/kg*	20	44	53	84
Design modular volumetric energy density, Wh/cm^3*	0.046	0.06	0.049	0.06
Utilization of active material, during charge/discharge, percent	25	85	80	100
Current density (5-h discharge), mA/cm^2	10-15	100	30	40
Active materials cost, $/kWh	8.5	0.49	4.27	0.74
Operating potential, V	1.9	1.8	1.4	1.9
Battery size goal, kWh	>20	10	40	50
Cell life goal, cycles	>2000	1300(30 Wh)	1000(150 Wh)	800(1.7 kWh)
Costly or critical materials	Lead	β-alumina	Lithium	Graphite
Projected test date for 5-MWh system	-	1984	1985	1981

*These figures represent different cooling arrangements: water cooling for lead-acid, gas cooling for sodium-sulfur and lithium-metal sulfide, and a refrigeration system for zinc chloride. Liquid-cooled designs for sodium-sulfur have about 40-50 percent higher energy densities per unit weight and unit volume than corresponding values for gas cooling.

alumina, a solid ceramic material capable of conducting sodium ions. Sodium polysulfide (Na_2S_x) is created during the electrical discharge of a sodium-sulfur battery cell.

Individual cells operate at 1.8-2.0 V and typically 40 of them may be configured in parallel to make up a submodule or bundle. Nine of these bundles in series make up a module (100 kWh), the building block of a battery energy system. A number of these modules are connected in series to build up the voltage to an operating voltage in the 1000-2000 V range. A number of these strings of modules are connected in parallel to build up the energy level to the range of 40-100 MWh, depending on the battery design requirements.

A6.2 DESCRIPTION OF SYSTEM CONTROL

A sodium-sulfur battery system for load-leveling, as shown in Figure A6.2-1, can be represented as being made up of four parts: the sodium-sulfur battery, the switchgear and protection, the power conditioning equipment, and the electric utility network. Each of these parts has its own individual control system, and there is an integrated battery control system which combines all the various individual controls. Although early installations of the battery system will doubtless be under local manual control, it is anticipated that future battery systems and their tie with the electric utility network control, say the distribution dispatch control, will be automatic. In the case where a sodium-sulfur battery system is located at a distribution substation, the relationship of the battery power and control equipment to the substation bus and to the division load dispatch center may be as shown on Figure A6.2-2.

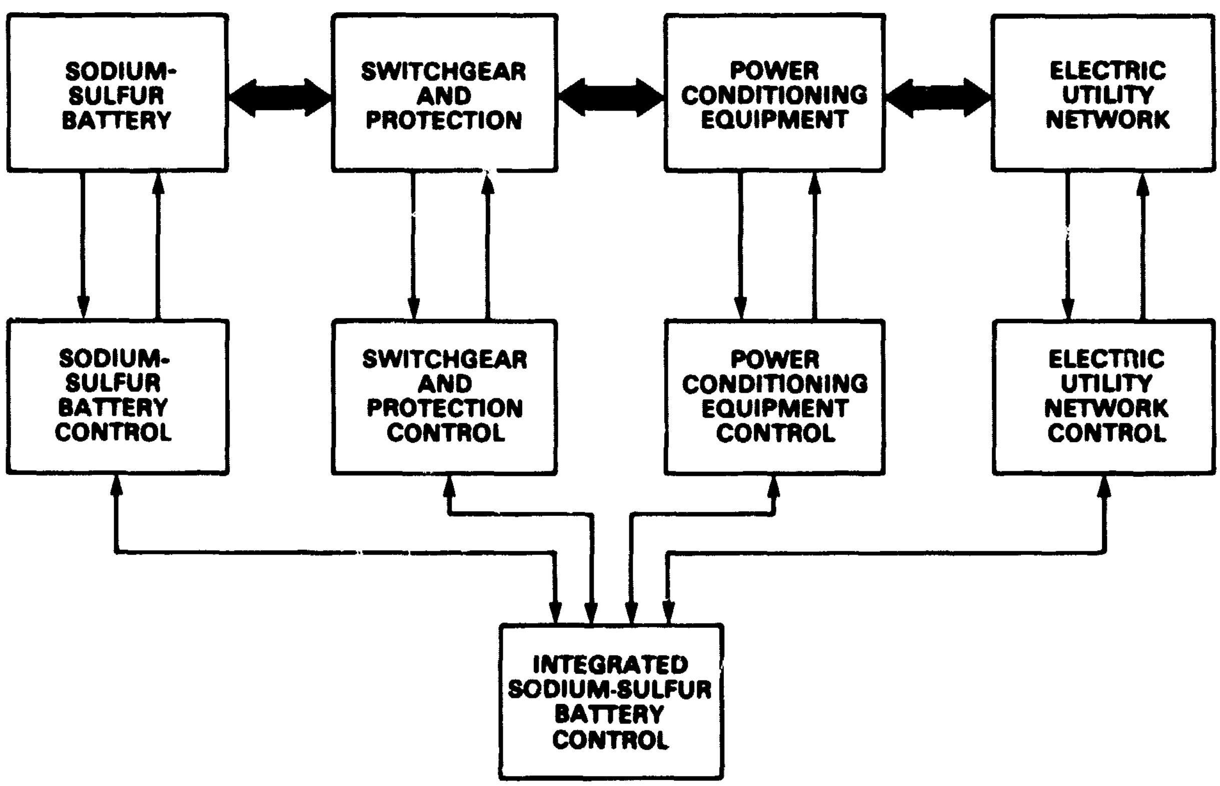


Figure A6.2-1. Sodium-Sulfur Battery System with Controls

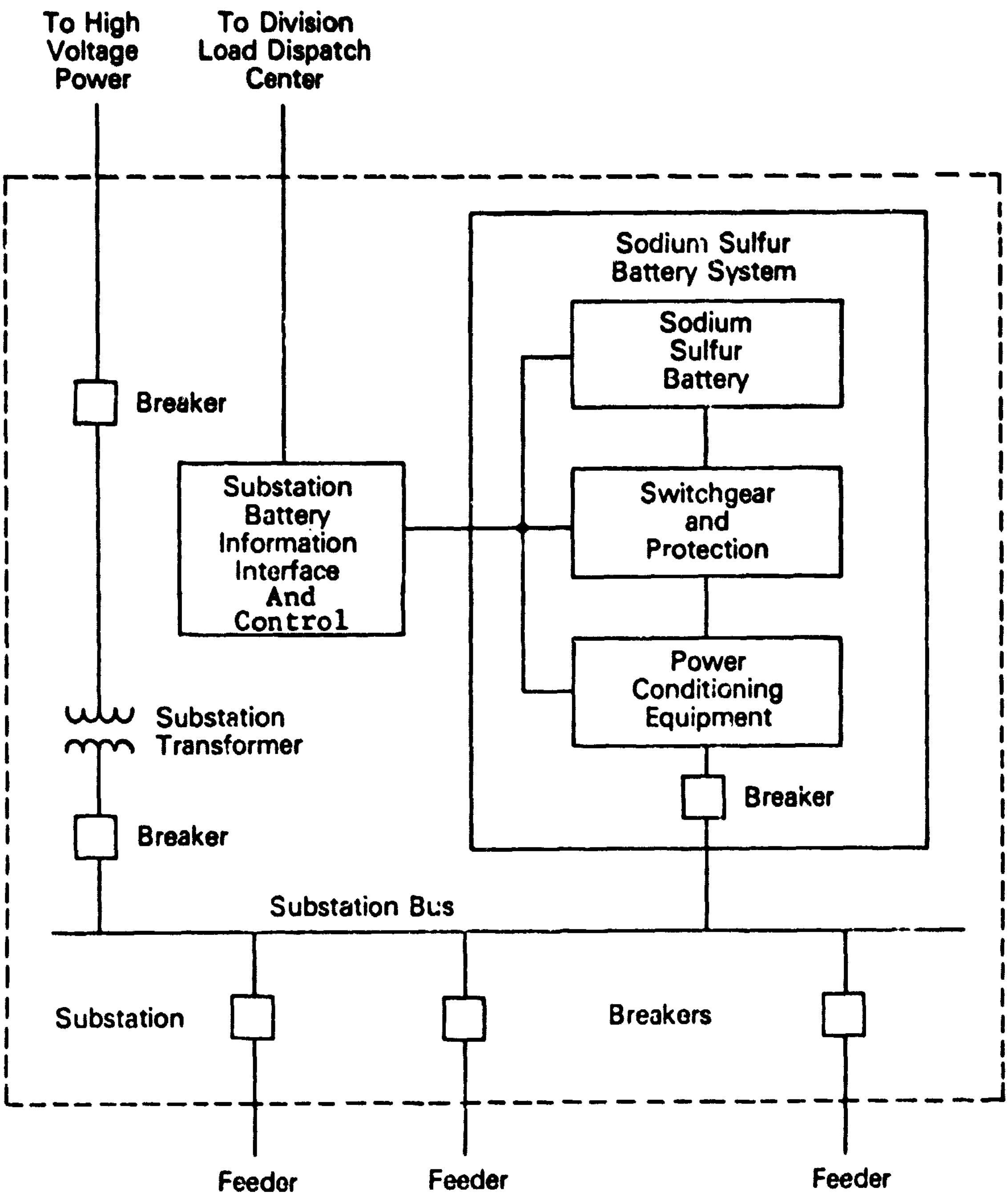


Figure A6.2-2. Sodium-Sulfur Battery System Connected to Substation Bus

Referring to Figure A6.2-1, one notes that the integrated sodium-sulfur battery control serves as a master control to co-ordinate the other controls which serve as subcontrols in a control hierarchy. Included in these subcontrols to the master control are the following functions:

- Operation Mode Control - to organize the startup, standby, normal operation, and other modes of operation. For the battery operating modes, these include:

  - Battery Off
  - Battery Startup
  - Battery Cool Standby
  - Battery Warm Standby
  - Battery Charging
  - Battery Discharging
  - Battery Module Replacement
  - Battery Shutdown

- Power Conditioning Equipment Control - to prepare and control the power conversion equipment to match the battery dc characteristics and the ac network load needs as indicated by the distribution dispatch center commands.

- Switchgear and Protection Control - to permit the power equipment to change satisfactorily from battery charge to discharge and to reduce the danger of battery damage due to faults in the power conditioning equipment.

- Battery Control - to control the battery temperature and other auxiliaries to achieve suitable environmental conditions for the battery under the appropriate operating mode.

A6.3 BATTERY SIZE, EFFICIENCY, AND AVAILABILITY

The electric storage battery system is a collection of a large number of individual battery cells which are connected in a number of parallel and series groupings to reach the desired ratings, which may fall in the 1 to 10 MW range for dispersed storage/generation use. Of importance in the sizing of an electric storage battery is the number of hours needed to charge the battery from a discharged condition and to discharge the battery from its charged condition. Thus megawatt-hour (MWh) rating of the battery is a significant rating parameter. Charging periods of 5 to 10 hours with comparable times for discharge are reasonable.

A6.3.1 SIZE

The battery's size is governed by the substation's size and location. The goal is a battery that fits unobtrusively into the local surroundings.

A6.3.2 EFFICIENCY

The two major factors influencing the overall plant efficiency are the power conversion equipment and the efficiency of the battery itself. The in-out efficiency for the conversion equipment and the battery combined (the turn-around efficiency) is approximately 75 percent.

A6.3.3 AVAILABILITY

Availability of the battery is influenced significantly by the daily load cycle expressed in terms of the generation equipment availability and incremental generation cost. Since a major objective of using battery storage is to charge the battery when generation costs are low and to discharge the battery when generation costs are high, the time of battery operation is strongly influenced by the daily cycle characteristics.

Reliability data on the power conditioning equipment is available and indicates a high reliability. In the case of the storage battery, there is relatively little operational data. However, the subject of reliability is receiving increasing attention in cell testing activities. There are times when the equipment is at standby so that preventive maintenance of the electronic components can be attended to.

A6.4 ECONOMIC CONSIDERATIONS

Advanced storage batteries are presently in the development stage. Production costs of commercial batteries have yet to be established for the 1985 to 1990 time period when commercial batteries are scheduled to be available. The projected market in 1985 has been estimated to range from 10 to 2000 MW/year for a battery system costing between $350 and $450 for production of a kilowatt of power.[30] The results of a study done by Arthur D. Little, Inc., for the same range of capital costs are shown in Figure A6.4-1. A number of assumptions regarding the 5-hour storage capacity of the battery, the fuel cost escalation rate, and the requirement that a demonstration plant be included are noted. It is evident that the market for advanced battery storage systems is large and in a very dynamic state as far as the technical and economic ability to meet production and cost targets.

An EPRI report[32] looks to the year 2000 and recognizes that coal and nuclear power will be required to replace much oil and gas as a source of energy. It is estimated that with the use of 90 GWe of installed storage batteries it should be possible to meet the anticipated U.S. electrical energy needs. "The net result of deploying 120 GW of new energy storage equipment installed between 1985 and 2000 is that energy storage will directly substitute for petroleum.... Coal will supply the bulk of the energy for storage."[32]

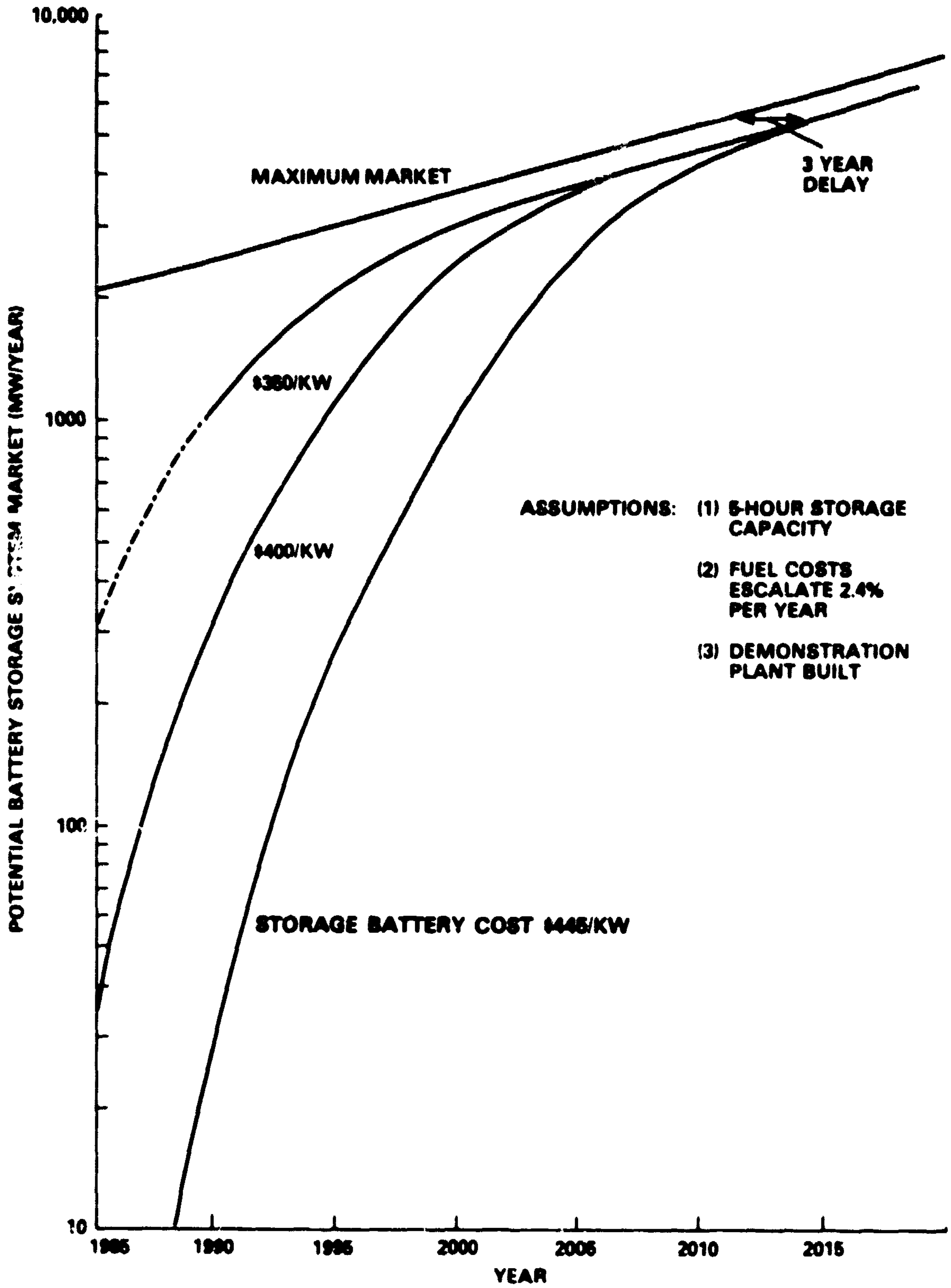


Figure A6.4-1. Effect of Storage Battery Cost on Potential Battery Storage System Market

A6.5 ACTIVE PARTICIPANTS

The following organizations and companies are representative of those active in the development of battery technology:

- Brown Boveri & Cie (Switzerland)
- Chloride Ltd. (U.K.)
- Dow Chemical
- Ford Motor Company
- General Electric Company
- Public Service Electric and Gas
- Yuasa (Japan)
- Energy Development Associates
- Gould, Inc
- Eagle-Picher Industries, Inc.
- Globe-Union, Inc.
- ESB, Inc.

Section A7

HYDROELECTRIC GENERATION TECHNOLOGY

A7.1 DEFINITION AND DESCRIPTION OF PHYSICAL PRINCIPLES

Hydroelectric generation converts the kinetic energy of falling water into electrical energy by means of mechanical-electrical machinery. A water turbine is coupled to an electric generator. The electric generator driven by the turbine produces alternating current electric power which is fed into an electric utility power system.

A7.1.1 DESCRIPTION OF PHYSICAL PRINCIPLES

Water, as motive power, is ancient in origin. The basic design of "modern" hydraulic turbines dates back to the mid 1800s. The basic design variations have been continually improved and retained. Electric power produced from water power dates from the 1880s. Thus, hydroelectric generation is a mature technology.

Water stored in a reservoir has potential energy which is a function of its weight and height above a reference elevation. This potential energy can be used to perform work when the water is released to the lower level. Thus, water released through hydraulic turbines is used to produce work. Power is the rate of doing work and the fundamental relationship which defines the power which can be produced is expressed as:

$$P = \frac{Q\,(H-h_f)\,\eta}{11.8} \text{ kilowatts}$$

where:

Q = Water flow, in cubic feet per second

H = Gross head (differential height) in feet

h_f = Head loss, in feet

η = Efficiency of conversion of potential energy to electrical energy

P = Power in kilowatts

The magnitude of power which can be produced is directly proportional to the volumetric flow rate and the differential effective height (head) of the water body. Great natural variations are found in the flow and head conditions (i.e., differences in the size of rivers and in the height of falls. Dams are built to provide increased head and to provide water storage to whatever degree is practical for the site. Different fundamental hydraulic turbine designs provide optimization of overall electromechanical efficiency for various conditions and combinations of flow and head.

While elementary, low power waterwheels may be of interest to individual residential or farm applications, they inherently operate at very low speed, have relatively poor efficiency, and are not well suited to producing constant-frequency 60 Hz power. They are more applicable to producing direct mechanical drive power.

Commercial hydraulic turbines are generically of two basic types: impulse and reaction. The impulse type uses only the kinetic energy of the water, whereas the reaction type uses both the kinetic and pressure energy.

Impulse turbines are of two basic designs which are called the "Michell [cross flow] turbine" and the "Pelton wheel." (There are other designs in addition to these two.) Pelton impulse turbines are generally used for medium-to-high head applications, i.e., 230 to 4000 feet (although there have been designs made for very small power Pelton wheels for heads of 50 feet). Michell turbines accommodate low-to-medium heads, i.e., 15 to 300 feet.

Reaction-type turbines are of two fundamental designs: Francis and propeller type. There are variations within each of these types to accommodate various flow and head combinations. In addition, adaptations and variations have been invented to improve performance.

The distinguishing difference between the Francis and the propeller turbine is that the Francis turbine runner (rotating part) has a shroud or circumferential band around the runner discharge area which is attached to the buckets or blades. The propeller type has no shroud attached. Francis turbines with runner design variations can accommodate a wide range of low (80 ft.),* medium (300 ft.), or high (2000 ft.) head hydro site conditions. Propeller turbines with a variety of designs can accommodate a wide range of low (6 ft.) to medium (200 ft.) head applications.

A major refinement of the propeller type turbine was the development of adjustable pitch blades. A further refinement was the addition and coordination of adjustable wicket (flow control) gates with the adjustable propeller blade. The Kaplan turbine is named for the inventor of this design.

The "bulb" turbine is a unique design of the propeller-type turbine in which the ac generator is submerged and contained within an enlarged "bulb" and connected to the propeller as a single assembly. This design can be used for heads of 12 to 50 feet.

*Installations as low as 20 ft. head have been reported by Niagara Mohawk Power Corp.

The "Rim" type turbine generator is a unique design of the propeller type where the generator rotor rim is attached to the outer diameter of the turbine propeller blades.

"Tube-type" horizontal, axial-flow, propeller turbines are an innovation wherein practically all of the turbine generator unit, including pipe-type water casings, can be factory-built and prefabricated into major modules. This permits lower equipment, plant, and installation costs. Tube-type turbines are typically small, and used for low-head (6 to 50 ft.) applications.

The various hydraulic turbine designs discussed above accommodate a wide range of hydroelectric plant site flow and head conditions. Figure A7.1.1-1 shows common application ranges for various turbine types vs. head.

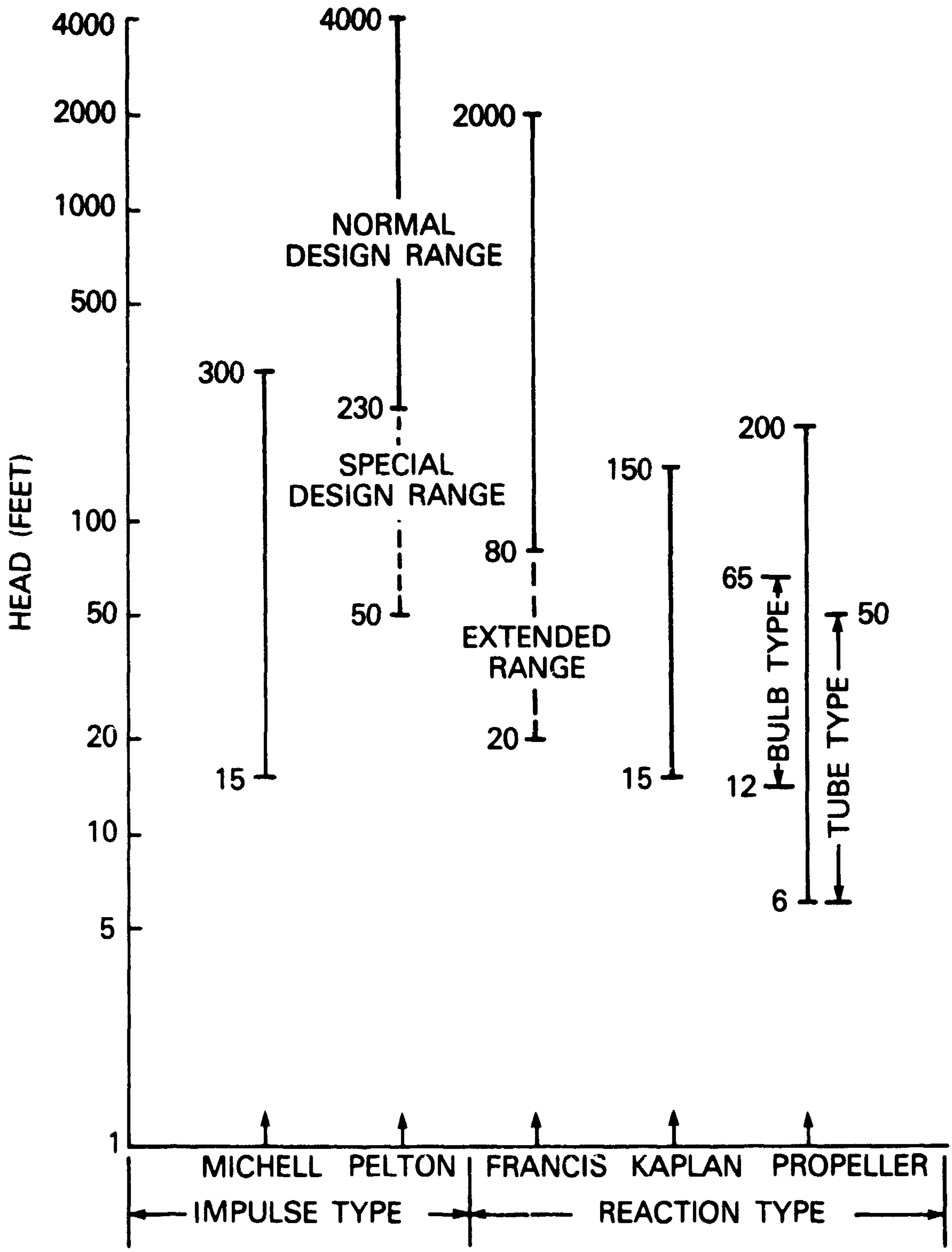


Figure A7.1.1-1. Common Head Application Range for Major Hydraulic Turbine Types

A7.2 DESCRIPTION OF SYSTEM CONTROL

In general, hydroelectric plants of the size associated with Dispersed Storage and Generation (DSG) projects are normally unattended. During periodic maintenance, testing, or repairs, an operator controls the plant locally. Thus, provision for automatic plant operation with either remote or local control initiation may be required for DSG hydro plants. Operating modes which may be involved are:

- Automatic operation - startup/shutdown initiated by local sensor (water level) or device (timer)
- Automatic operation - startup, loading and shutdown initiated by remote dispatch center (or dispatcher)
- Automatic operation - startup, loading, and shutdown initiated by local operation
- Manual operation - all functions initiated by local operator

Existing DSG-size hydroelectric plants have a wide range of control and data acquisition equipment, from local operator controlled only to remote automatic controlled. Data acquisition may include: (a) local indicators, recorders, and meters, (b) same as (a) plus a few analog-telemetered quantities, or (c) digital data and status acquisition and transmission.

As the number of DSG stations on a utility system increases, it is anticipated that DSG data and control will become more important to the dispatch center. Thus, existing hydro stations may have to be converted from local manual control to automatic remote-control. For discussion purposes, unattended operation with its associated automatic operation and data acquisition are assumed. This type of operation requires interfacing local plant control and data acquisition with the remote dispatch center. Functional relationships are shown in the block diagram of Figure A7.2-1.

Basically, the plant must be provided with automatic control equipment which can safely and reliably perform startup, run, and shutdown functions. Equipment or control abnormalities must be detected and safe action (i.e., shutdown if necessary) initiated. Data acquisition will be performed, presented, and/or recorded locally, and transmitted to the dispatch center.

The functional block diagram of Figure A7.2-1 provides for the operating modes described above, with overall control and data acquisition concentrated at the Plant Master Control. The specific type of control and data acquisition equipment determines the degree of modularity and/or commonality; thus Figure A7.2-1

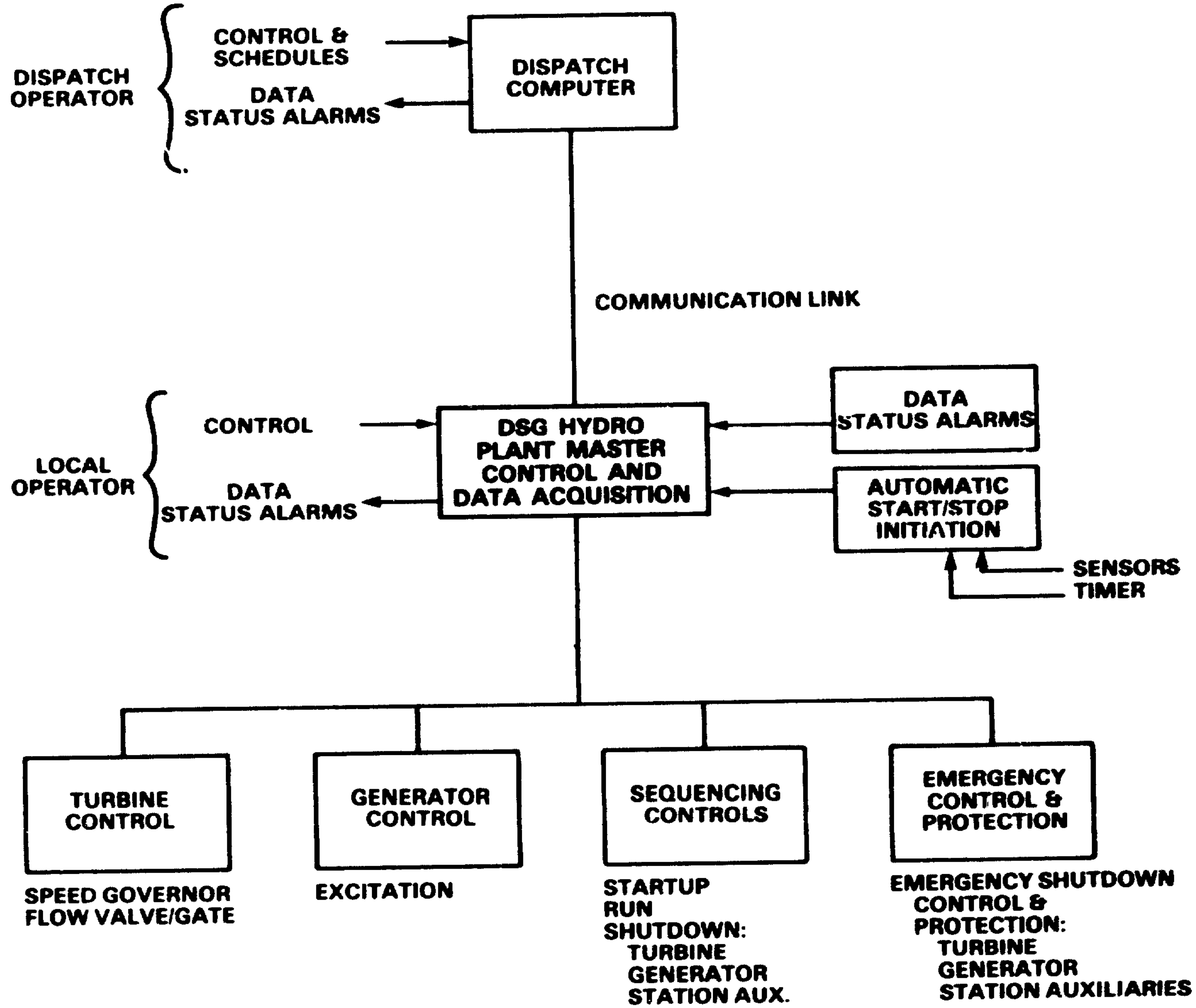


Figure 7.2-1. Block Diagram - Hydroelectric DSG Control and Data Acquisition

identifies only major functional control and data areas. Existing plants may have some degree of automation such as automatic startup and shutdown sequencing implemented with electromechanical relay logic. This could involve coordination, modification, and retrofitting if the station is to be included in an overall system DSG control and data acquisition system.

The Plant Master Control, which serves as the nerve center, directs (or possibly performs) local automatic control and data acquisition functions. As shown in Figure A7.2-1, the Plant Master Control interfaces with the following major subsystems:

- Turbine Governor and Gate Control for controlling water flow, speed, and/or power output. These controls are furnished as part of the turbine and hydraulic system.

- Generator Control (excitation system) controls synchronous generator voltage/reactive volt amperes/power factor. This excitation system is usually furnished by the generator manufacturer. Induction generators do not require this control.

- Sequencing Controls basically provide step-by-step action-initiation, and checking logic, for automatic startup and shutdown operations. Sequencing Controls direct and coordinate all of the major and minor systems and equipment operation in the plant in response to start-up/shut-down commands from either local or remote sources. For normal conditions, a hydroelectric turbine-generator unit is automatically sequenced through its startup steps, synchronized with the power system, and then the water flow is adjusted to achieve the desired power output. When normal shutdown is required, the load is reduced to zero and then the shutdown sequence is performed.

- Abnormal and Emergency Control and Protection provides sensing, action initiation, and sequencing to protect against conditions which could damage equipment. For abnormal or emergency conditions requiring immediate disconnection and shutdown, the emergency shutdown sequence is initiated. This can be initiated by protective relay or sensor devices in the plant which detect serious problems.

- Data and status acquisition functions include the collection, processing, presentation and transmission of measured data and status information, both normal and abnormal. The amount of data retained locally is more than that transmitted to the dispatch center. Local data provides records and information to operating and maintenance personnel. Data and status transmitted to the dispatch center are of a more basic and general nature.

- When alarm conditions exist, the category and nature of the alarm are recorded locally and transmitted to the dispatch center to permit the dispatchers to determine the urgency of the problem and what type of maintenance personnel are needed to correct it.

- Normal data (and status) are scanned at regular intervals to detect trends. Selected normal data is transmitted periodically to the dispatch center. Abnormal conditions are logged and transmitted to the dispatch center immediately.

A7.3 HYDROELECTRIC GENERATOR SIZE, EFFICIENCY, AND AVAILABILITY

This subsection discusses the size, efficiency, and availability of hydroelectric generators which would be used at DSG hydroelectric plants.

A7.3.1 SIZE

One may make some general observations concerning the size range of DSG hydroelectric plants associated with electric utility distribution systems. DSG hydroelectric plants range in size from a few hundred kW up to 15, or perhaps 30 MW. The streams used for DSG hydroelectric plants are small to medium in size and have relatively low head, i.e., up to 50 ft. Research,[34] has identified existing dams which do not presently have hydroelectric power generation facilities. These existing dams present the most economical potential hydroelectric development sites. The cost of civil works including dam construction usually is in the order of half the total cost of a hydroelectric project. Since these dams already exist, the environmental concerns associated with adding hydroelectric generation facilities are minor in comparison to projects which require new dams.

The main factors which affect the size (i.e., kW rating) of a hydroelectric plant are:

- Hydrological Conditions
- Site Conditions
- Economic Considerations
- Regulatory Requirements
- Environmental Concerns

Hydrological conditions govern the potential water flow at the hydroelectric site. These conditions are rainfall and watershed area. Annual rainfall which occurs in the stream's watershed area and the seasonal variations of the rainfall determine amount and time distribution of water. Flood and drought conditions must also be known. The area of the watershed (along with the rainfall) determines the volume of water available. The nature of the watershed's soil, vegetation, and weather patterns affects water runoff characteristics. Historical records of stream flow conditions are vital to the planning of a hydroelectric plant site and selecting its kW rating. Historical records provide the data necessary to determine seasonal variations, with maximum and minimum flows, and from this a stream "Flow Duration Curve" can be developed. Figure A7.3.1-1 presents an example of the relationship between stream flow and month, and Figure A7.3.1-2 presents a typical flow duration curve.

Site conditions which have a major effect on the plant kW rating are the water flow duration curve, the available head (and head variation), and the water storage capacity. If the site has an existing dam, these conditions are fairly well fixed. The main

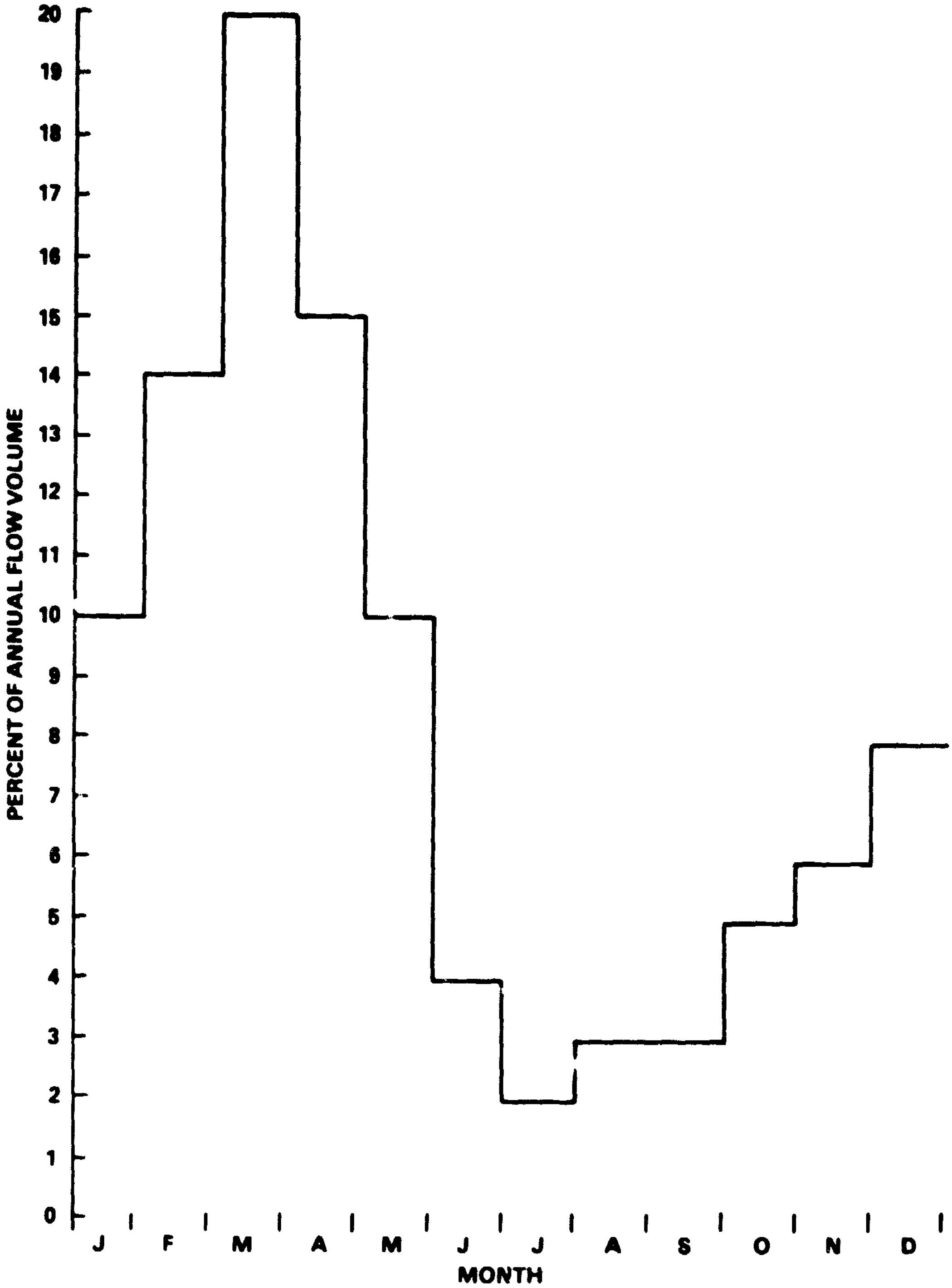


Figure A7.3.1-1. Percent of Annual Stream Flow vs. Month - Northeastern USA

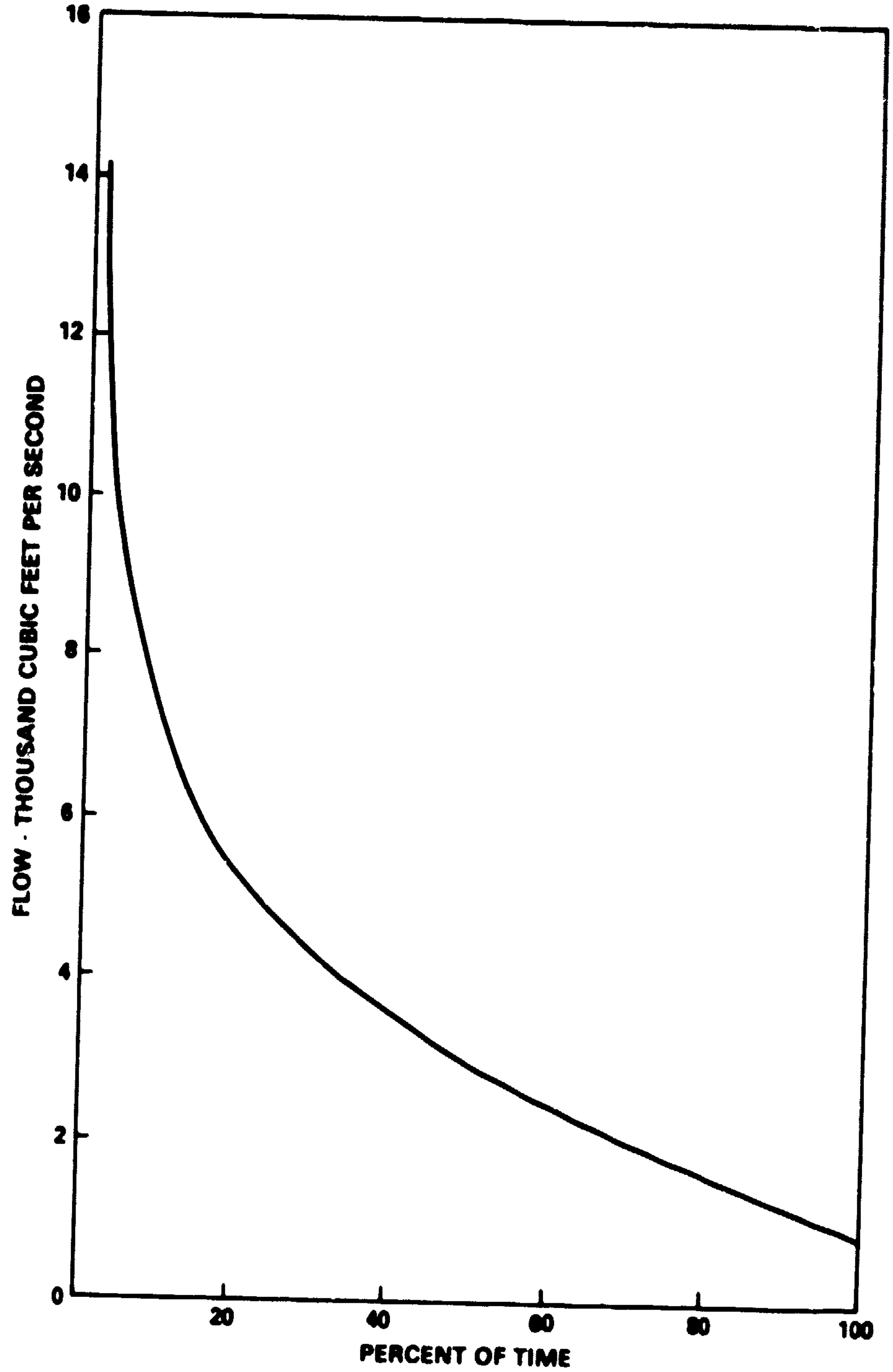


Figure A7.3.1-2. Typical Flow Duration Curve analysis is required in determining the kW rating of the plant is the economic trade-off of cost vs. value of the plant, for the utility system involved. For the development of a new site, regulatory requirements and environmental concerns also become major factors in determining kW rating.

Economic considerations in plant sizing are discussed more fully in subsection A7.4. However, the major factor is the optimization of total installed plant generating capacity to achieve the most beneficial relationship between hydroelectric plant costs and the plant's value to the utility system.

Regulatory requirements can affect plant size. Federal, state, and local laws, regulations, and licensing requirements can restrict or even prevent hydroelectric site development. Basic water rights involving the sharing or prior rights of other parties is usually involved to some degree regarding control/regulation of the stream. While water is not "consumed" by a hydroelectric plant, modification of stream flow is involved. There may be upstream and downstream constraints imposed by the rights of others, and the basic use of the stream or river. For streams in the DSG size category navigational constraints are not foreseen as a factor in the majority of plants.

Currently attempts are being made to simplify hydroelectric plant licensing by the Federal government. Initially this involves attempts to simplify rules and regulations for "small" hydroelectric plants up to 1.5 MW. The size range may be extended up to 15 MW if initial efforts are successful.

In addition to regulations pertaining to licensing and size, there are state regulations regarding purchase and sale of electricity by private owners connected to electric utilities. These may directly or indirectly affect size considerations of a plant, or even its economic viability.

Environmental concerns affecting hydroelectric plant size involve upstream and downstream effects of water impoundment, storage, and release. Upstream effects of the water storage impoundment created by the dam, and storage and release schedules, affect the land area inundated and the variable shoreline created by water level variations. For existing dams the inundation issue is resolved by its prior existance. The reservoir level variations, to advantageously schedule water usage, will have to be a compromise with other parties and potential environmental effects. These concerns will relate to the primary functions the existing dam serves and the imposed constraints. Thus upstream environmental concerns can affect reservoir size (water storage volume) and water level variation (permissible drawdown), which directly relate to plant size determination. Scheduled water release also causes downstream flow variations which must be reconciled with other users and/or environmental concerns. One of the major environmental concerns is that of maintaining "water quality standards." Complete hold-back of water to create maximum storage in a given time period can result in virtually no flow downstream of the plant, thus leading to a degradation of "water quality." If this degradation is considered substantial, the plant may be required to release a (minimum) continuous flow of water, resulting in a reduction of generating capacity.

A7.3.2 Efficiency

Hydroelectric plants have a relatively high energy conversion efficiency. Unlike thermal cycle plants, hydroelectric plants directly convert mechanical energy to electrical energy. Thus, there are no inherently high "cycle" losses. Further, plant auxiliary power is relatively small as compared to thermal-electric plants. Overall plant efficiency is primarily dependent upon the type of hydraulic turbine selected. Because most stream-watershed, reservoir combinations have unique flow characteristics, care must be taken in matching turbine type, size, and design to the water usage schedules. Variation in head, both seasonal and daily, may also be a consideration in selecting turbine type and design.

Hydraulic turbines (and their associated generators) have a maximum efficiency at some point on their load curve.

Operation below and above the "design" point is less efficient and wastes water. If the plant size warrants it, and large seasonal or scheduled release variations occur, multiple units may be employed to operate the overall plant more nearly at maximum efficiency for all flow conditions. The decision to install multiple units must also be based on economic considerations of cost vs. value, since multiple units generally will have a higher capital cost, as well as a higher operating and maintenance cost, than a single unit of the same total rating. Figure A7.3.2-1 illustrates separate turbine and generator efficiency curves and their combined efficiency. Auxiliary power which is in the order of 1 percent or less is omitted. At "design load" hydraulic turbine-generator sets have a combined efficiency of approximately 80 to 85 percent. Part load operation is less efficient, as shown in Figure A7.3.2-1. Large variations in head cause further efficiency reductions. Comparative efficiency curves of basic hydraulic turbine types are illustrated in Reference 1, Chapter 38, Figures 19, 20, and 21. It is noted that adjustable-blade, propeller-type turbines have a relatively flat (constant) efficiency over a wide load range.

7.3.3 Availability

Hydroelectric turbine-generator sets have a relatively high availability. Examination of EEI Report 77-64 [35] covering the period from 1967 to 1976 shows an aggregate availability of 95.4 percent for the hydro units. This figure includes the effects of both forced outages and scheduled outages. The sample is considered large enough to be reliable. The relatively simple and proven designs of hydroelectric units may be credited for this favorable availability performance. However, proper maintenance procedures are also required to achieve high availability figures.

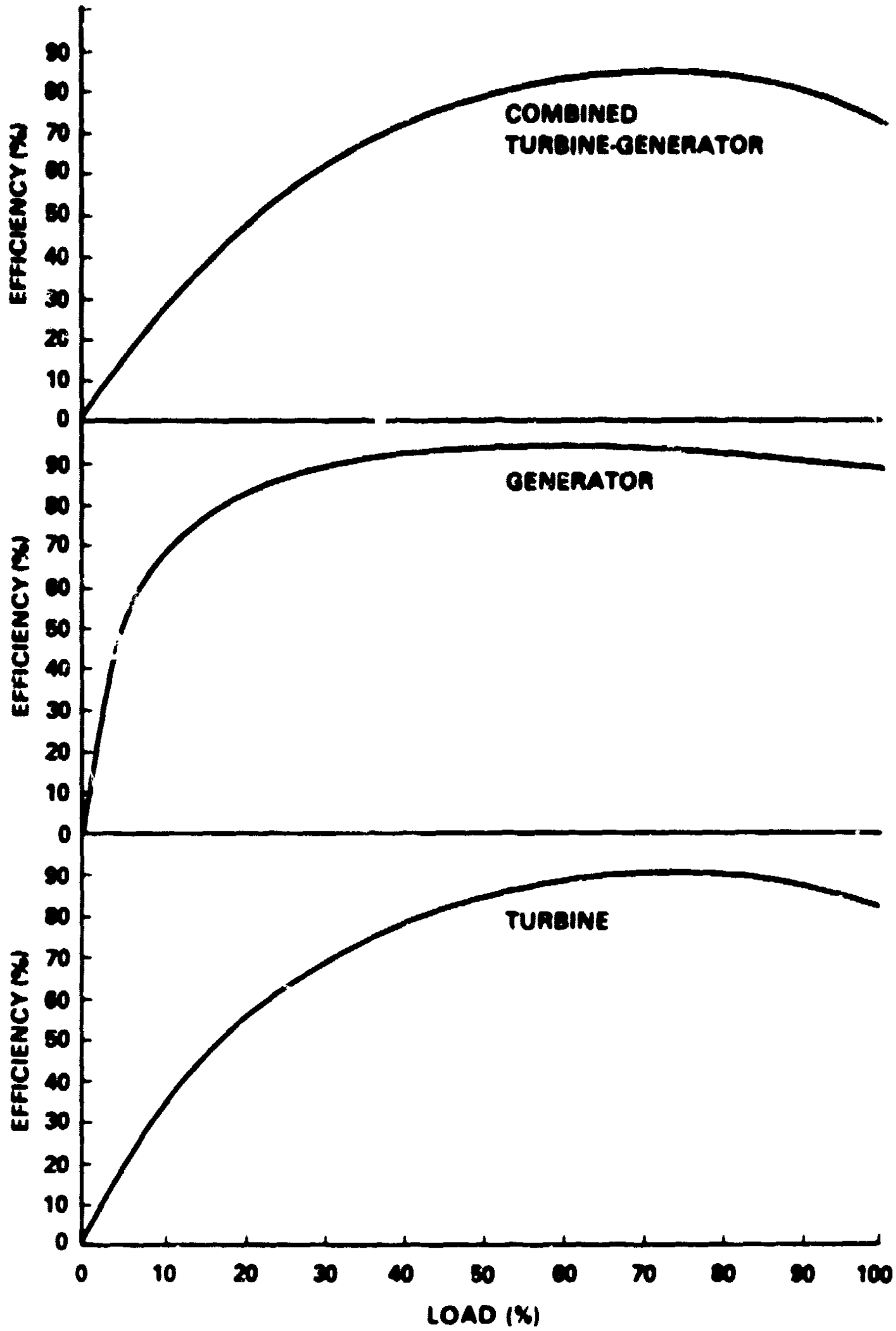


Figure A7.3.2-1. Efficiency vs. Load

A7.4 ECONOMIC CONSIDERATIONS

The driving force for evaluating undeveloped hydroelectric generation potential is the high and rising cost of fossil fuel. The disproportionate increase of oil and gas prices initiated the need to reexamine the relative economics of producing electricity by hydroelectric generation as compared to fossil fuel plants. Hydrogeneration also offers the incentive of using a renewable resource, water.

Since a large portion of the cost (approximately 50%) of a completely new hydroelectric development is for the dam and reservoir, the most economically attractive undeveloped potential hydroelectric sites are those with existing dams. Preliminary surveys of potential hydroelectric sites have been made and further definition and refinement studies are in progress. Federal, state, and regional agencies, and utility companies and organizations are involved in these studies. It must be recognized that there are constraints regarding the addition of hydroelectric generation to existing dams due to the precedence of the primary uses and other factors such as environmental concerns about water level and stream flow variations.

A preliminary study by the U.S. Army Corps of Engineers in 1977[34] identifies a total potential of 54,600 MW. Of this total potential, 26,600 MW has been identified as the potential at existing (non-hydroelectric) dams of less than 5000 kW capacity and 7000 MW at existing dams with greater than 5000 kW capacity. Preliminary utility feedback indicates that approximately 15,000 MW may be practical to develop. The Department of Energy[45] has tentatively identified low-head hydro goals of 1500 MW by the year 1985, and 20,000 MW by 2000. Unless site conditions permit relatively low cost dams, it appears that the emphasis will be on developing hydroelectric power at existing dams.

Hydroelectric turbine-generator manufacturing was once a flourishing business in the U.S.A. However, the very low level of installations has reduced the number of U.S. manufacturers to a few. While this is a mature technology, high capital cost has discouraged hydroelectric installations. Recent development work and equipment designs have focused on reducing equipment costs. It is of interest to note the allocation of costs for hydroelectric plants, to identify major cost areas, and to determine where cost reduction emphasis is worthwhile. According to the Federal Power Commission's Uniform System of Accounts[36] for hydraulic production, major electric plant accounts are:

- Land and land rights
- Structures and improvements
- Reservoirs, dams, and waterways
- Waterwheels, turbines, and generators
- Accessory electric equipment
- Miscellaneous power plant equipment
- Roads, railroads, and bridges

From Federal Power Commission reports, the cost breakdown for hydroelectric plant costs over a period from 1910 to 1972 is shown in Table A7.4-1 for heads up to 50 feet. The wide ranges of cost indicate the variableness of site conditions for hydroelectric installations. This information reinforces the desirability of developing hydroelectric power at sites with existing dams. If recent trends to reduce turbine generator equipment and installation costs can be realized, low-head hydro will begin to be a viable economic choice.

Historically, turbine-generators have been custom engineered and designed to the specific site conditions. This custom design and manufacturing is a major equipment cost item (up to 50%). Recent attention has been directed toward standardized designs of relatively simple turbine-generators for a range of flow and head ("small, low head") conditions. Both domestic and foreign manufacturers are concentrating on this approach in an effort to be cost competitive and enlarge the market. In summary, efforts to minimize or reduce hydroelectric plants costs are concentrating on the following major items:

- Utilize existing dams
- Utilize existing power plant structures
- Simplify hydraulic turbine-generator design
- Standardize turbine-generator design
- Reduce installation costs
- Simplify licensing procedures and reduce time required

Hydroelectric plant costs vary widely and are affected by site conditions of flow and head as well as the need for power plant structures (either renovated or new). Hydroelectric plant costs cover at least a three-to-one range even when there is an existing dam. Whereas turbine-generator units in the range of 25 MW size and reasonable head (30 to 50 ft.) may have an installed cost of $500/kW (excluding structural renovation costs), units of smaller size (i.e., 1 MW) and lower head can have installed equipment costs of $1000/kW or more. Thus, when site renovation or new buildings are included, a range of $700 to $2000 per kW installed cost is indicated for low-head hydro at existing dams.

Table A7.4-1

TYPICAL COST BREAKDOWN FOR
HYDRO PLANTS UP TO 50 FEET HEAD

	PERCENT OF TOTAL COST (%)	
	APPROXIMATE RANGE	APPROXIMATE MEAN
Power plant equipment	19-40	30
Reservoirs, dams, waterways	20-59	40
Structures and improvements	6-38	22

The relative value to a utility of a hydroelectric plant is measured by its total cost of producing electrical energy as compared to other types of generation. This cost per kWh is derived by dividing total annual cost by total annual energy produced and is commonly expressed in cents per kWh (¢/kWh). The two major elements of Total Annual Cost are the "fixed costs" and the "operating costs." Fixed costs are the major nonvariable charges (depreciation, taxes, insurance, cost of money, administrative, etc.). Operating costs include personnel, repair, and maintenance, and in the case of thermal plants, fuel cost.

Hydroelectric plants have relatively high fixed costs, (high capital cost) and low operating cost. Low operating costs are due to zero fuel cost* and unattended operation of these small low head hydro plants. Operating costs of attended small hydro plants are economically prohibitive. High fixed (capital) costs make it important to generate as much energy as possible with the installed hydroelectric capacity to minimize cost/kWh.

The type of plant against which the small hydro plant is economically compared depends upon the hydro plant's capacity factor and water availability. This in turn depends upon hydrological, site, storage, and water use/regulation constraints.

Hydro plants may be base-load plants (high-capacity factor), peaking plants (low-capacity factor), or intermediate-load plants (medium-capacity factor). The value of hydro plants thus depends on the type of capacity it displaces and the cost of the displaced fuel of that type of generation. There are computer programs** which analyze the operation of generating plants according to defined schedules and operating criteria on utility systems. These programs must be used to obtain quantitative evaluations of various generation types.

In these evaluations all conditions of system generation and hydrogeneration firm capacity are considered. The fact that a hydro plant may have a low capacity factor may not be a great disadvantage if it can displace peaking gas-turbine-plant energy that requires high production costs (high petroleum or gas costs). Based on this high value of replacement power during the peak periods, a hydro plant with a 30% capacity factor capable of generating during the same (peak) periods could prove to be economical. In economic studies it is important to establish a firm energy criterion. As an example, the NMPC criterion for dependable capacity requires that a plant be able to run for four full hours at rated load using available storage and the average flow for the month in which the system peak occurs. If a plant cannot meet this criterion, it has to be correspondingly derated, which

* Zero fuel cost may be debatable if other water consumption services are competing for the water which then has a "value."

** General Electric "Optimized Generation Planning Program."

could mean the difference between an economical and noneconomical hydro plant. A low capacity factor for a hydro plant can be the result of variable stream flow conditions during the year as illustrated in Figure A7.3.1-1.

Other costs not addressed in this discussion are costs identified as "Intangible Plant." Major items are:

Organization (incorporation costs)
Franchises and consents
Miscellaneous intangible plant

It is not the authors' intention to discuss these items here, but merely to call attention to the fact that these items can involve substantial cost. Under "franchises and consents," federal and/or state water power licenses and associated expense (such as environmental impact statements) can cost many thousands of dollars and must not be overlooked in evaluating the economics of small hydroelectric plant power.

A7.5 ACTIVE PARTICIPANTS

The following organizations and companies are representative of those active in the development of hydroelectric generation technology:

- Allis Chalmers Corporation
- Alstholm-Atlantique (France)
- Bofors-Nohab (Sweden)
- Dominion Engineering (Canada)
- General Electric Company
- KMW (Sweden)
- James Leffel & Company
- Ossberger Turbinen Fabrik (West Germany)
- Tampella (Finland)

Section A8

COGENERATION TECHNOLOGY

A8.1 DEFINITION AND DESCRIPTION OF PHYSICAL PRINCIPLES

Cogeneration is the combined production of process heat and electricity. Industries and/or utilities which need both of these forms of energy potentially have net operational cost savings available through an efficient coordinated facility which fully utilizes the total heat of combustion. Various manufacturing, commercial, and district heating applications utilize medium and/or low pressure steam. These comprise the largest percentage of potential cogeneration applications. For these applications, the most common configuration for generating electricity and "process steam" has been to use fossil-fuel-fired steam boilers producing high temperature, high pressure steam to drive steam turbine-generator set(s). Electricity is produced directly by the turbine generator, and the steam from the turbine, with its remaining energy, is delivered to the "process." This is called a topping cycle. Electricity is produced at the highest temperature part of the thermal cycle. Additional electric power and heat can be obtained by superimposing gas turbine-generators on the combustion portion of the cycle. In some cases, diesel engine-generators producing electric power and relatively low temperature water and steam provide a good match of power and heat to certain processes. Bottoming cycles, obtaining electric power from the low temperature process "waste heat" or exhaust, are also possible configurations for cogeneration. However, these have higher investment costs and often require more complex equipment. Processes requiring the direct heat of combustion can occasionally use the high temperature exhaust gas of oil or gas-fired gas turbines. The combustion turbines also drive electric generators in a topping configuration.

Thus cogeneration covers a very wide variety of energy conversion and utilization cycles and applies various equipment combinations to provide the desired match of electric power and process heat requirements at one site.

A8.1.1 DESCRIPTION OF PHYSICAL PRINCIPLES

Cogeneration (also called "combination plant," "in-plant generation," "on-site generation," "by-product power," "total energy concept," etc.) has been employed in the United States since the early 1900s. While it is a mature technology which utilizes proven energy conversion cycles, studies are being conducted to determine extended application and improved efficiencies which may be possible with advanced energy conversion cycles and equipment.[38]

While not a physical principle, the ownership-operation arrangement and objectives of a cogeneration plant have a fundamental effect on the most economic energy conversion cycle. The owner may be a private industry, an electric utility, a third party, or various combinations of these. Depending on ownership, the optimum ratio of electric power-to-process heat (P/H ratio) for the plant can have widely different values. Thus, while a solely owned private-industry cogeneration plant may have a relatively low P/H ratio for self-sufficiency, a combined utility/industrial cogeneration plant will usually have a much higher P/H ratio. Therefore, a cogeneration plant may have a deficiency, a match, or a surplus of electric power.

Various arrangements of cogeneration ownership and operation are possible. These ownership arrangements may be 100 percent industrial, 100 percent utility, shared industrial and utility, or third party ownership. Examples of ownership are:

- Privately owned industrial or commercial plant producing electricity which is less than, equal to, or more than the need of the industrial plant

- Utility-owned plant used for generating electricity for the utility grid and producing steam for district heating or sale to an industry

- Combined ownership arrangement between an industrial plant and utility; various combinations of heat and electricity production, utilization, ownership and control are possible

- Third-party-owned facility with sale of process heat and electricity to adjacent industrial plant(s) or utility system

In addition to basic ownership and operation of cogeneration facilities, other major considerations are:

- Contractual arrangements
- Regulatory constraints on power transfer
- Economic impact of tax incentives

Thus, overall technical, economic, ownership, operation, regulatory, and tax considerations must be examined and evaluated before making a decision on cogeneration facilities. Several of these can affect the operation and control of cogeneration facilities.

Expansion and elaboration of all the various combinations of ownership, energy conversion cycles, equipment, processes, technical, economic, and regulatory aspects of cogeneration are beyond the scope of this document. Only basic, common, state-of-the-art energy conversion cycles and equipment will be used for illustration.

As compared to separate facilities for producing process heat and electric power, cogeneration utilizes much of the energy that would otherwise be discharged to the environment. Thus, the overall efficiency of fuel utilization can be 60 to 80 percent as compared to 30 to 40 percent for an electric power generation plant alone. Savings are thus available in fuel costs and in capital equipment costs of these dual-function cogeneration systems.

In the most common cogeneration thermal cycle configurations, the high temperature portion of the cycle is utilized for the generation of electricity. However, some processes also require high temperature. The lower temperature heat discharged from the power generation prime movers is utilized for process heat. In a large portion of industrial processes, heat is utilized in the form of steam, and therefore, descriptions and analysis of cogeneration plants concentrate on cycles which produce high grade steam and/or heat for electric power generation, and medium and low temperature steam for industrial processes.

Many cogeneration thermal energy cycles are in use. However, regarding the production of electric power the cycles used are either "topping" or "bottoming" cycles. Topping cycles utilize high grade heat, and bottoming cycles use low grade or "waste" heat for electric power generation. Topping cycles typically involve the production of high temperature, high pressure steam, and its expansion through a steam turbine, and the extraction and discharge of the lower grade steam to the industrial process. Gas turbines produce either direct process heat from turbine exhaust or steam by means of heat recovery steam generators. Gas turbines have a higher P/H ratio than steam turbines. Diesel-generators have the highest P/H ratio (compared to steam and gas turbines). They receive consideration when a good P/H match exists and the process can use low temperature liquid from engine cooling and process steam from exhaust gas heat recovery equipment. Relative P/H comparisons of steam turbines, gas turbines, and diesel engines are shown in Figure A8.1.1-1.

Bottoming cycles involve the use of direct high temperature heat or high quality steam by the process, and the utilization of the low grade heat for power generation. Direct heat processes usually use waste heat boilers to generate steam for steam turbine-generators. Low grade process steam usually cannot be used directly in steam turbines because of the poor efficiency. However, low grade steam may be used to heat organic fluids in a Rankine cycle. The organic Rankine cycle has some serious economic and developmental problems. Demonstrations are in progress but no commercial "state-of-the-art" exists.

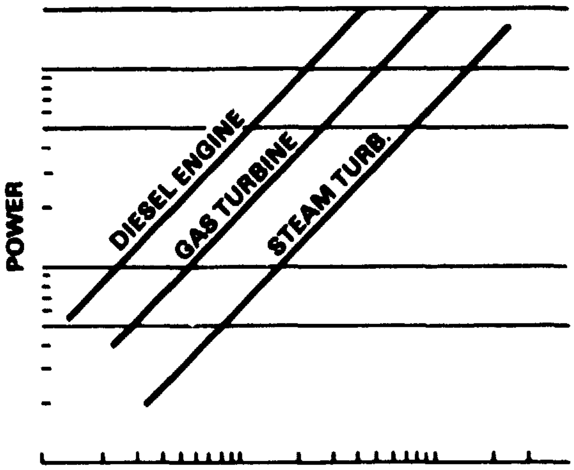


Figure A8.1.1-1. Relative Effect of Prime Mover on Electric Power Process Heat

State-of-the-art energy conversion systems (ECSs) for steam topping of cogeneration configurations either use conventional fossil-fuel-fired steam boilers, combustion turbines with heat recovery steam generators (HRSGs), or a combination of these. The process and electrical requirements plus economics usually dictate the equipment combinations and system configuration. Simple block diagrams of system configurations are shown in Figures A8.1.1-2, A8.1.1-3, and A8.1.1-4. In some special cases, diesel-generators may be a good P/H match. While steam boilers may burn a wide variety of solid, liquid, or gaseous fuel, gas turbines and diesels have thus far been limited to liquid and gaseous fuels which have been predominantly refined oil and gas.

Various steam turbine designs provide flexibility in obtaining process steam of the required temperature, pressure, and quantity by utilizing steam extraction ports and non-condensing and condensing steam turbines. Schematic diagrams of various designs are shown in Figures A8.1.1-5 and A8.1.1-6.

The industry groups which comprise the majority of potential cogeneration applications are: foods, textiles, pulp and paper, wood, chemicals, petroleum refining, primary metals, cement, and glass. Because the characteristics of these industrial processes are widely different, the energy cycles utilized are also quite different. In addition, each process and plant has a different economic P/H ratio. An economic balance requires tailoring combustion, heat, and power generation cycles to provide optimum economic results. From this standpoint, the following summary comments apply:

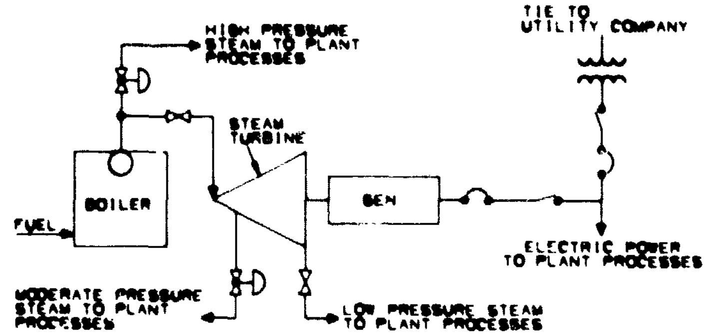


Figure A8.1.1-2. Block Diagram of an ECS Using Conventional Fossil-Fuel-Fired Boilers

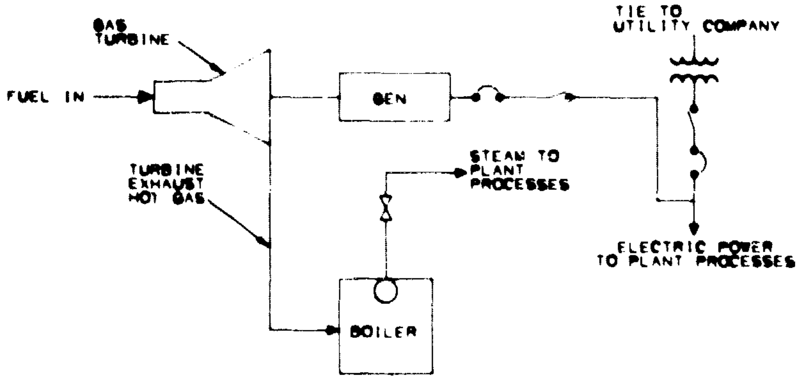


Figure A8.1.1-3. Block Diagram of ECS Using Combustion Turbines with Heat Recovery Steam Generators

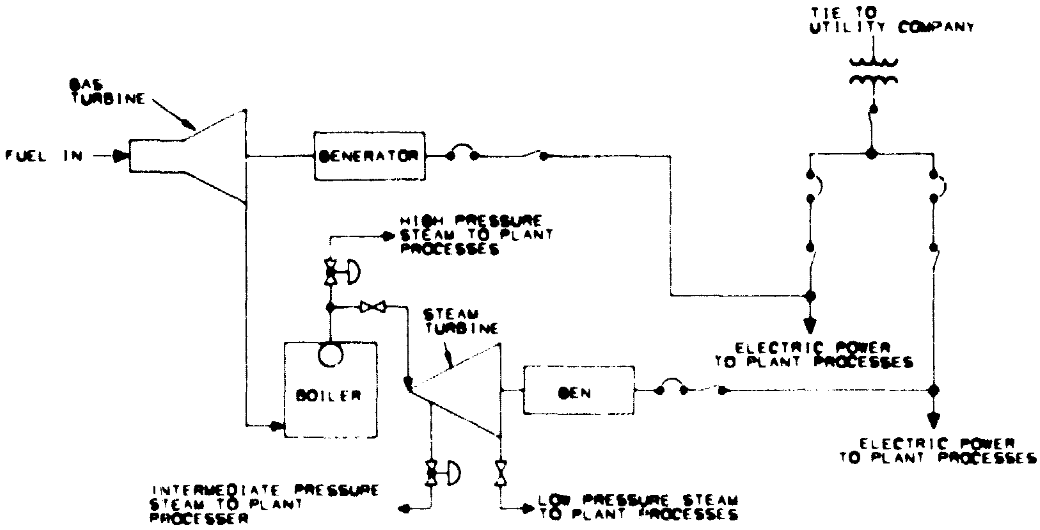


Figure A8.1.1-4. Block Diagram of an ECS Using Conventional Boilers and Combustion Turbines with HRSGs

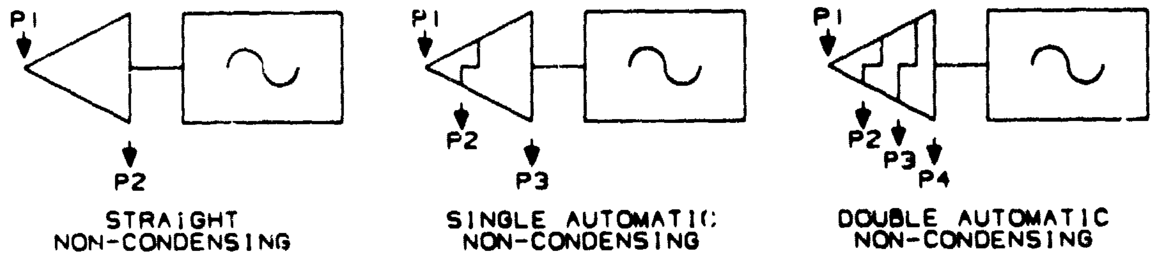


Figure A8.1.1-5. Typical Non-Condensing Cogeneration Turbines-The Basic Cogeneration Units

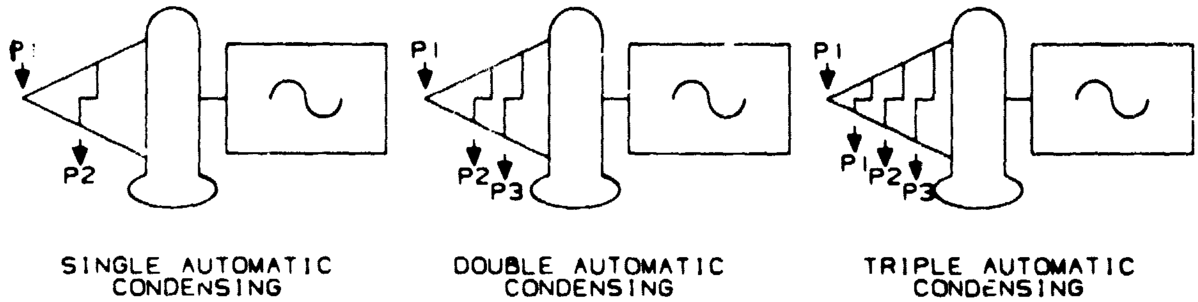


Figure A8.1.1-6. Typical Condensing Cogeneration Turbines-An Alternative Solution to Satisfying Variations in Both Steam and Electrical Power Requirements

- From a technical standpoint, each cogeneration application must be designed to optimize the energy conversion system configuration for the industrial process involved. Major considerations are: fuel type, fuel cost, purchased power costs, process heat quality and quantity, power/heat ratio, and capital cost.

- With "state-of-the-art" energy conversion systems, discontinuities usually exist in making an ideal P/H match for a given application. Thus purchase or sale of electrical energy is usually necessary.

- Historically, industry-owned cogeneration applications in the U.S. exhibit a net consumption of electrical energy.

- Paper making processes tend to provide a good match of P/H ratio with that of extraction steam turbine generators. This industry comes close to producing 100 percent of its electrical power requirements.

- It is anticipated that future energy conversion systems for cogeneration applications will permit a more favorable P/H ratio.

Major equipment types under consideration for future applications are:

- Atmospheric fluidized bed boiler
- Pressurized fluidized bed boiler
- Advanced combustion gas turbine designs
- Stirling engines
- Advanced diesel engines
- Fuel cells

A8.2 DESCRIPTION OF SYSTEM CONTROL

There are basic functions which make up a cogeneration plant control system. With regard to the production of electric power, however, it must be recognized that the cogeneration plant control system has primary responsibility for the correct, safe, and economic control of the plant's process heat needs. The electric power produced may be adjusted only insofar as the cogeneration plant configuration, equipment, and process permit.

Cogeneration plant controls, within constraints, operate to meet power and heat needs. Within the range of electric power and process heat adjustment provided in the system design, certain relationships of power to heat exist. There are normal limits to variations power and heat can have, relative to each other. Excursions from the optimum P/H ratio will result in poorer fuel utilization performance. For example, increased electric power may be obtained at the expense of increasing condenser flow and its additional heat rejection to the atmosphere. Electric power demands, beyond condenser or plant capability, would require greater tie line flow of purchased power from the utility system. Conversely, increased heat-to-process requirements beyond normal system operating range can only be achieved by added steam flow through (pressure reducing) bypass stations. (This assumes boiler capacity exists.) Thus excursions from the optimum plant P/H ratio incur higher heat rates and associated higher incremental costs.

While basic functional relationships exist, it should be recognized that a cogeneration plant control system philosophy cannot be generalized. Some comments to justify this statement are:

- The ownership - industrial, utility, third party, or some ownership combination - determines the priorities of electric power vs. process heat production. This in turn affects plant design.

- The cogeneration plant control system depends on the process, system configuration, basic prime mover-generator types, and ownership.

- The overall steam system configuration including steam boilers, associated steam turbines, and plant control system affect the flexibility of plant power and process heat.

- Electric power control flexibility varies widely in a steam turbine system depending on the type of turbine. In a steam turbine topping configuration, the type of turbine employed has a major effect on the ability to adjust electric power output. In ascending order of flexibility, the turbine types are:

- Straight noncondensing turbines
- Automatic extraction, noncondensing
- Automatic extraction, condensing
- Automatic extraction/admission, condensing

System control functions included in a cogeneration plant system control are illustrated in Figure A8.2-1. Note that this diagram is simplistic and does not show interrelationships between functions. Further, the functional block diagram should not be assumed to imply that hardware-oriented, completely integrated and coordinated, automatic control systems are common.

Many cogeneration control systems have been limited to coordinated packages of the Boiler-Turbine-Generator (BTG) control functions. BTG controls are the vital on-line control functions and, therefore, in the following descriptions, these functions are emphasized.

To assist in an overall understanding of equipment and control interrelationships, Figure A8.2-2 shows a simplified block diagram of a cogeneration plant and control system.

- The tie line power flow control function is the on-line control interface between the utility electric power system and the cogeneration plant. When normally connected and operating, the cogeneration electric power production can be adjusted within limits. Limits may be plant/process constraints or electric power demand/energy contract constraints. Depending on ownership and control/operational agreements, the utility dispatch center may exercise control over the tie line controller set point to adjust net power flow on the congeneration plant tie line. If solely industry-owned, tie line power is controlled to meet power and energy contract constraints.

  The tie line controller adjusts the turbine governor speed control to change generator output. In the event of tie line interruption, the load-frequency control can control the isolated cogeneration system, perform turbine governor control mode switching and, if necessary, perform process plant electrical load shedding to balance available generation with load, to avoid system collapse.

- Fuel system control can be relatively simple when the fuel is oil or gas, or may be complex when the plant uses coal or other solid fuels. The primary function of the fuel system is to monitor and control fuel storage, handling, forwarding, and supply to the boilers, gas turbines, or diesel engines. Fuel handling systems are quite varied and specifically plant related. Since they are strictly in the domain of plant control, they will not be described further.

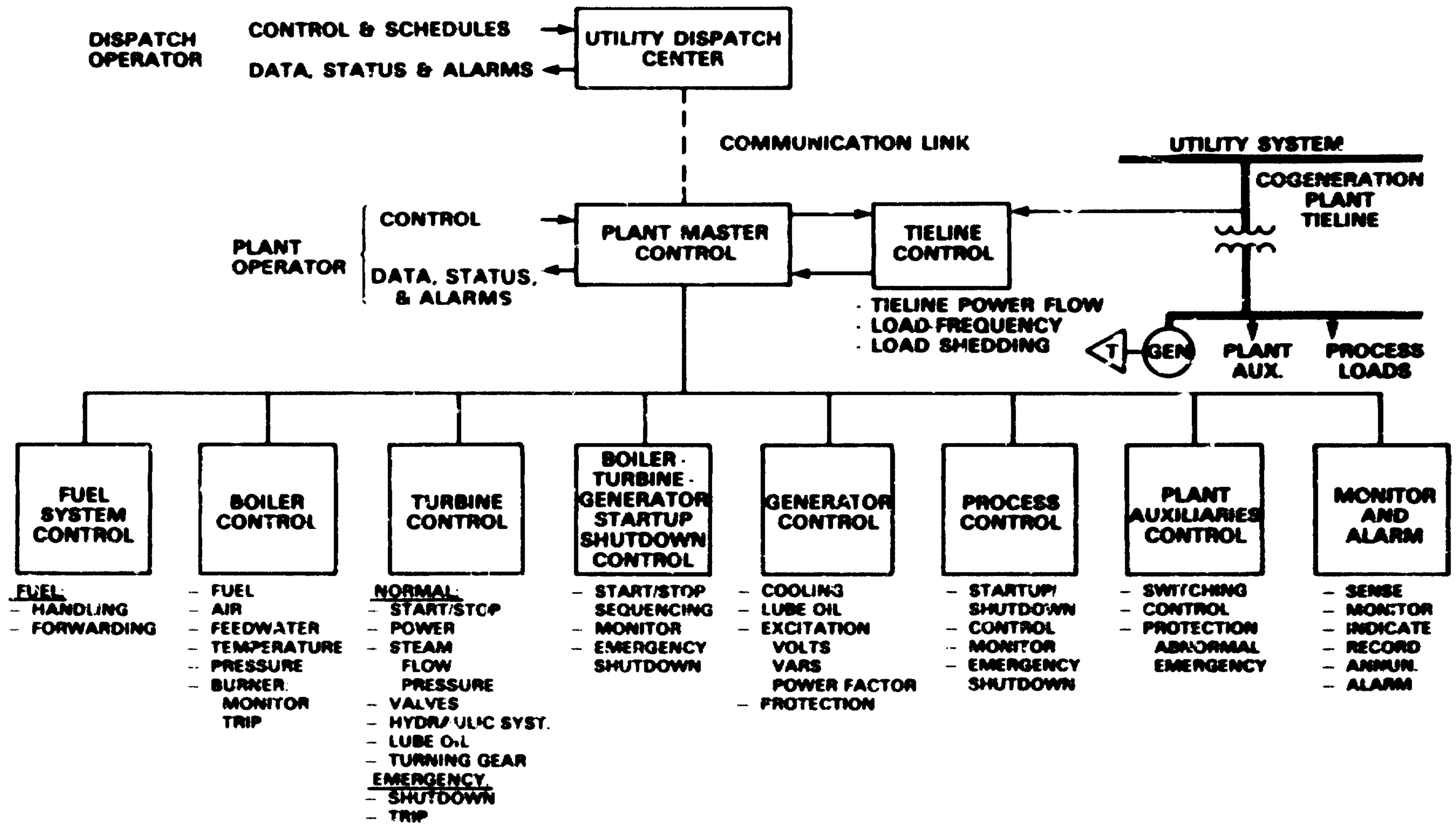


Figure A8.2-1 Cogeneration Plant System Control Functions

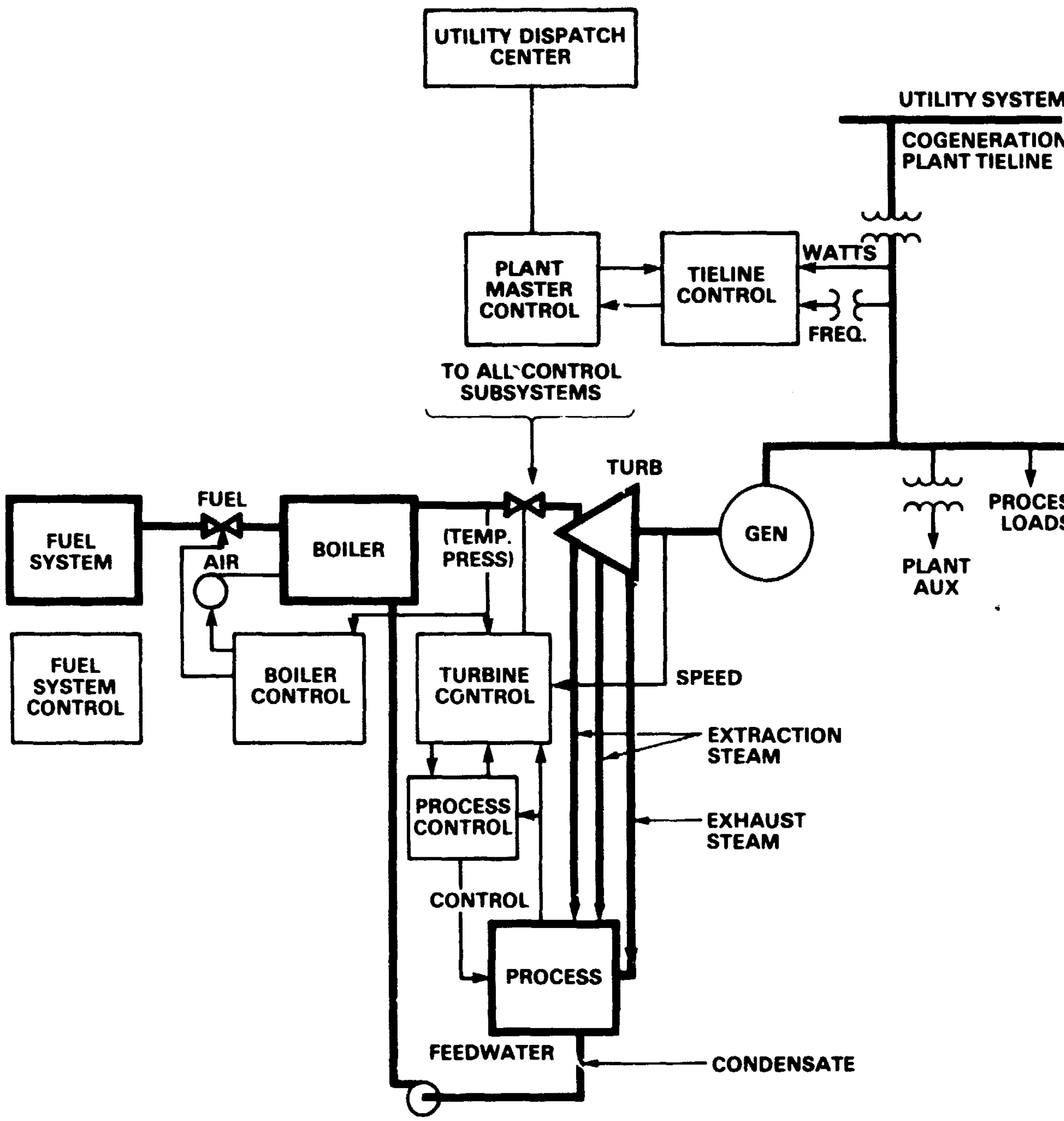


Figure A8.2-2. Simplified Block Diagram Cogeneration Plant and Control System

- The boiler control subsystem responds to disturbances internally and externally generated, in a manner which satisfies system demands, within limits of the boiler capability. The boiler control subsystem must perform in a fast, accurate, stable, safe, and reliable manner.

  Generally speaking, controls are required in most ambient air fired boilers to perform the following functions:

  - Supply the quantity of steam required at the desired pressure to the plant main steam header.
  - Properly proportion fuel and air flow.
  - Maintain the superheater outlet steam temperature within prescribed limits.
  - Maintain the steam drum water level within the range required for safe operation.
  - Assure safe boiler operation (Flame Safeguard Systems).

- Turbine control and governing subsystems play an important part in control of the cogeneration plant's over-all steam and power system. Industrial steam turbine governors can control many variables in the plant, including:

  - Electrical (or mechanical) power output
  - Speed
  - Pressure in as many as three process steam systems
  - Automatic extraction and/or admission of steam at one or more selected pressures
  - Boiler pressure for waste heat or waste fuel fired boilers
  - Turbine inlet flow
  - Condenser cooling water flow

  Electro-hydraulic governors have the additional capability of controlling other steam or gas turbines with a master-slave function.

  Basically the turbine governing system is comprised of speed (or steam flow) governing and steam pressure governing.

  "Speed governing" of industrial steam turbines can be divided into two modes of operation: Isochronous control, and speed regulation (droop) control. Isochronous speed control is used for turbine-generators operating in an isolated electric system. This mode of control may be required when a cogeneration plant, which is normally connected to a utility system, becomes disconnected from the utility grid.

When a turbine-generator operates electrically connected ("in parallel") with a utility system, the generator speed is synchronized or "locked into" the electrical system frequency. The turbine control mode can be one or more of the following: base (power) loaded, steam pressure control, or "slaved" to a plant master control.

A turbine-generator which is electrically connected in parallel and synchronized with an electrical system is normally base loaded by adjusting the speed/load reference while in the droop governing mode. The amount of load carried depends on the speed/load reference which is selected and the boiler pressure. This control mode is frequently called speed/load control. It may be operator adjusted or directly controlled by the Tie Line Control Subsystem.

A simplified block diagram of a turbine speed/load control is shown in Figure A8.2-3.

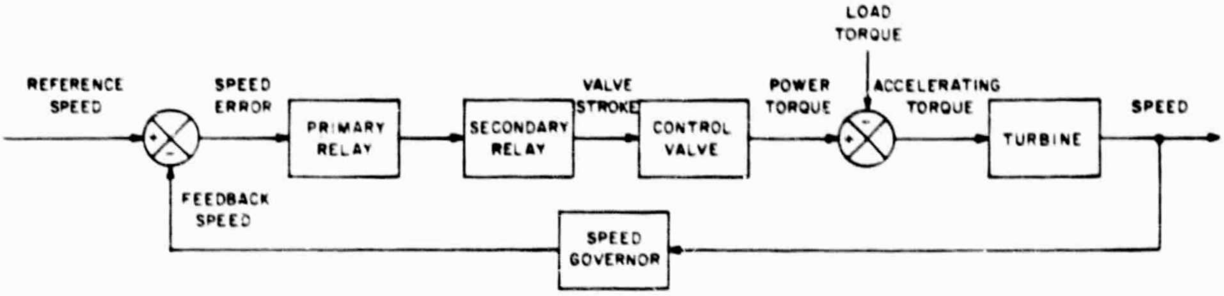


Figure A8.2-3. Block Diagram of a Turbine Speed Control

"Pressure governing" is used to control process steam conditions. A pressure governor controls the pressure of inlet steam, extraction steam, or exhaust steam according to its location in the control system. In each application, it senses changes in steam pressure and moves the control valves as required to maintain the pressure approximately constant. Pressure governing can be integrated into a speed governing system or it can be the exclusive turbine control in applications where turbine-generator speed is maintained by system electric frequency. The most common application of pressure governing is in conjunction with speed governing on automatic-extraction turbines. A block diagram of a pressure governing control system is shown in Figure A8.2-4.

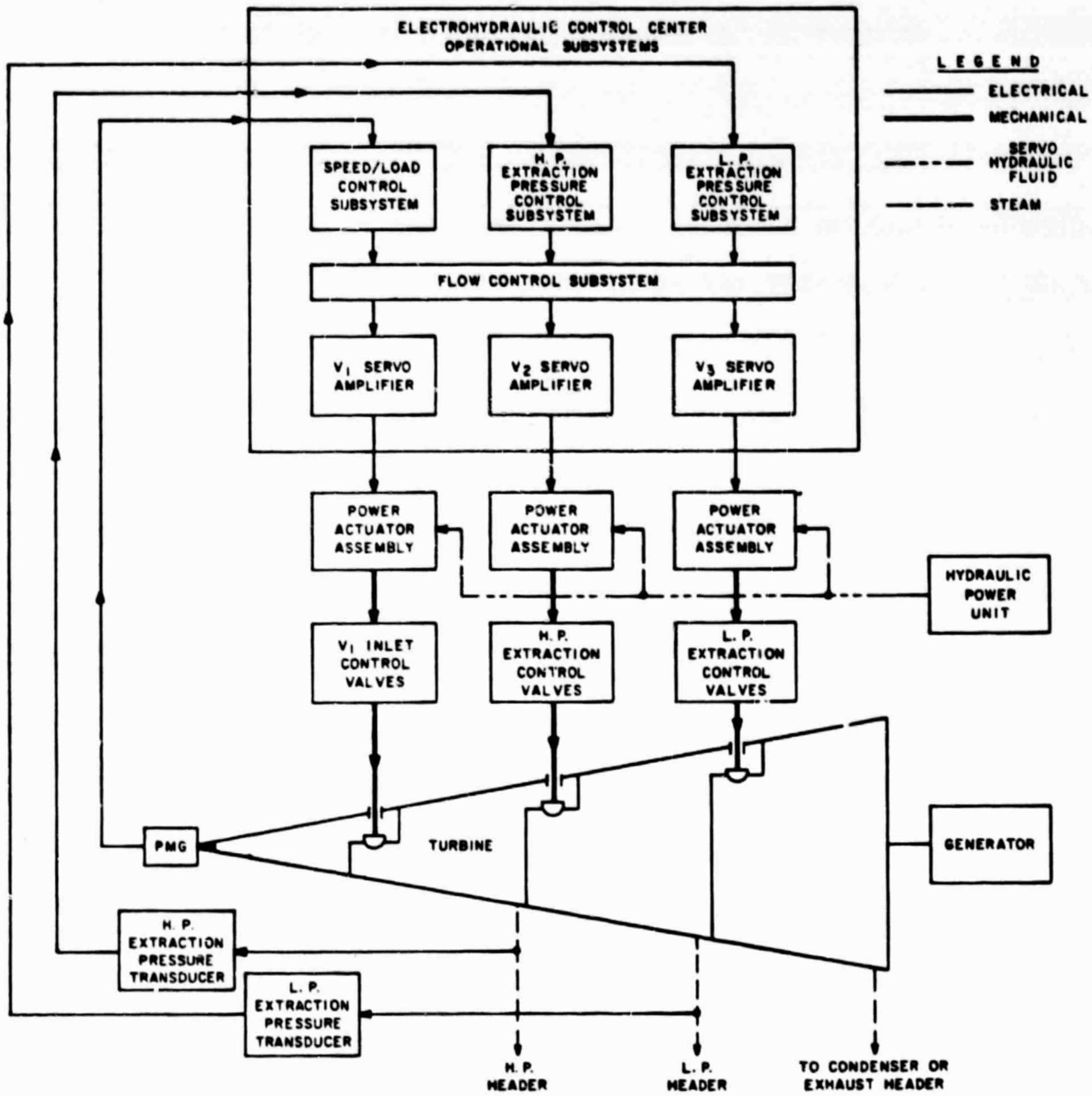


Figure A8.2-4. Double Automatic Extraction Electro-Hydraulic Control System

In addition to the normal turbine-generator control functions, it is also necessary to provide turbine-generator protection for abnormal or emergency conditions. Steam turbine-generators are designed with separate and distinct control systems for normal and emergency modes of operation. These systems are entirely independent of each other. The normal control system provides a means of starting and stopping the equipment, placing it in service, and controlling speed, load and extraction pressures while operating with normal system perturbations and excursions. The emergency control system provides protection against failure of the normal control system, some critical element of the machine itself, or some part of the related plant equipment or connected system. The primary functions of the emergency system are to prevent or minimize damage to the turbine-generator or associated plant equipment, to prevent personnel injury, and to maintain the equipment in condition for return to service with minimum delay.

- Boiler-turbine-generator startup/shutdown control provides the means of coordinating the startup and shtudown of these major plant subsystems. In earlier plants this was largely a manual step-by-step operator function. More modern plants incorporate interlocking and semi-automatic or fully automatic sequencing of mechanical and electrical plant equipment. Depending on the design and implementation, this may include both normal and emergency startup and shutdown functions.

- Generator control primarily includes the monitoring and control of basic generator cooling, lubrication, and excitation conditions. The excitation subsystem which controls the generator voltage, reactive volt-amperes, and power factor is complex. If the cogeneration plant is under joint utility-industrial ownership with an excess of electric power, the utility will probably want to exercise some degree of control over the generator excitation to assist in utility system voltage and reactive volt-ampere control. Industrial power contracts often require that the power factor be controlled within prescribed limits. Thus, the power factor is controlled using the local generation excitation system.

- Process control implies discrete mechanical-electrical control of the process startup, shutdown, normal process operation and emergency control. Since this is also specifically oriented to the process and in the domain of the plant control, further elaboration is not considered appropriate in this discussion.

- Plant auxiliaries control involves the actual control and switching of the plant electrical distribution system. In addition to normal switching and control, abnormal and emergency control and protection is included. This applies to all circuits supplied by the plant auxiliary electrical subsystem.

- Monitor and alarm functions for both boiler-turbine-generator and process conditions have been implemented with a wide range of equipment and subsystems. Earlier plants primarily used individual instrument displays, recorders, alarms, and annunciators all for local plant operator use. As solid state electronics have progressed, the monitor and alarm subsystems have more commonly been provided by automatic data acquisition systems. Modern computer-based plant controls have combined this function into overall master plant control, monitor and alarm, operator interface, and (where required) data transmission functions.

In summary, a modern cogeneration plant control system is a complex, integrated, coordinated arrangement of many control subsystems, which operates to maintain the plant integrity during normal operation and also during emergency or abnormal conditions. External control, such as might be exercised by a utility dispatch center, is limited to the degree provided by the basic cogeneration plant design and the constraints required by the associated process.

A8.3 COGENERATION PLANT SIZE, EFFICIENCY, AND AVAILABILITY

This subsection discusses the size, efficiency, and availability of cogeneration plants which would be connected to a utility distribution system.

A8.3.1 SIZE

Various studies[38,40,41,43] have examined and identified ranges of cogeneration plant size (electric power and process heat/steam). The range of kW rating identified varies from 0.5 MW[40,42] to 1000 MW.[38]

These cogeneration sizes covered equipment configurations ranging from reciprocating engines and small combustion turbines at the lower kW ratings[42] to advanced cycles such as molten carbonate fuel cells at the high end.[38] For the present and near term (1985), however, the greatest cogeneration potential appears to be in sizes above 5 MW. The size of cogeneration plant which would be connected to a utility distribution system at distribution substations or subtransmission voltage levels would be up to 30 MW, with the majority being in the 5 to 15 MW range. Plants of larger ratings would probably be connected to major substations, due to the need for reliable supply, voltage regulation, energy transmission efficiency, and system stability.

A8.3.2 EFFICIENCY (FUEL ENERGY UTILIZATION)

A high plant fuel energy utilization coefficient reduces total fuel cost and is the major economic advantage of cogeneration facilities. The overall plant efficiency is affected by the basic thermodynamic cycle of the plant, which in turn is influenced by the type of system, equipment, and process involved. For a large cogeneration plant using process steam and having a good balance of power/heat ratio, overall fuel utilization in the order of 80 to 84 percent may be obtained.[44] By comparison, the best modern coal-fired central station power plants with environmental protection constraints only expect about 35 percent efficiency. The difference is that the heat rejected to condensers in the central station power plant is largely wasted whereas it is put to productive use in the (cogeneration) process plant. The effect of this "dual" use of the heat derived from the fuel is that the fuel chargeable to power (FCP) in a steam producing cogeneration plant is in the range of 4200 to 5000 Btu/kWh as compared to 9700 to 10000 Btu/kWh for large central station plants. Reciprocating engine cogeneration plants tend to have somewhat lower overall efficiencies and higher FCP rates, i.e., 6500 Btu/kWh.[40,42]

A8.3.3 AVAILABILITY

In the moderate to large cogeneration plants where mature steam turbine, combustion turbine, and diesel equipment is applied, the availability of equipment is quite comparable to utility system experience. Regarding overall plant availability, the design and configuration of the plant's heat/steam producing equipments, common headers, spare units, and utility tie reliability all affect plant availability. It is obvious that where large manufacturing processes and material production are involved, availability is of prime importance and receives appropriate attention in the system design stages. Unscheduled shutdowns cause large losses of revenue and thus warrant capital investment in appropriate redundancy and backup features.

Since cogeneration is a mature technology, the required equipment and systems capability exist within the present industrial structure. The determining factors in the future growth of cogeneration will involve economics, the regulatory climate, fuel allocation/utilization rules, tax structures, and environmental constraints.

Various projections have been made regarding the potential for cogeneration expansion. Under present conditions of institutional regulations and incentives, it has been estimated by DOE that a total of 26,000 to 80,000 MW of generating capacity may be added by the year 2000. With incentives (i.e., favorable regulatory, tax, environmental, fuel policies, etc.), DOE has estimated that 57,000 to 190,000 MW is possible by the year 2000 in new cogenerations facilities.

A8.4 ECONOMIC CONSIDERATIONS

Economic analysis is much more complex for cogeneration plants than for plants dedicated solely to producing electric power. The cogeneration plant's viability from a profitability standpoint is a major concern of the owner(s). Depending on ownership, the incremental cost comparison methods used for analysis may be applied to: a) the incremental cost of producing electric power in addition to the primary plant function of producing process steam, (industrial ownership) or b) The incremental cost of producing steam from a plant primarily intended for electric power production (utility ownership). Historically, in the U.S., the situations described by (a) have been predominant.

To begin an investigation of a potential cogeneration facility, a set of four indicators give a general indication of the economic viability. These indicators are represented by a set of four charts shown in Figures A8.4-1, A8.4-2, A8.4-3 and A8.4-4.[(4] Additional considerations are:

- The utility's ability to reliably serve the kilowatt load
- The availability of waste or refuse fuels
- Boiler replacement
- Availability of a surplus of low-pressure steam in the process, i.e., 100,000 lb/hr at 5 to 100 psi
- Pressure reduction of over 150,000 lb/hr of steam

These indicators and additional factors permit preliminary conclusions and indicate whether a full feasibility study may be warranted. The detailed study should examine all aspects and factors included in determining the incremental costs of adding the power generation (or steam producing) capability to a single function plant. With rising fuel costs, potential cogeneration users will find the available reduction in overall fuel consumption increasingly valuable. From the standpoint of our national energy resources and supply, a net reduction of fuel consumption can be achieved by this "active" conservation method.

A8.4 ECONOMIC CONSIDERATIONS

Economic analysis is much more complex for cogeneration plants than for plants dedicated solely to producing electric power. The cogeneration plant's viability from a profitability standpoint is a major concern of the owner(s). Depending on ownership, the incremental cost comparison methods used for analysis may be applied to: a) the incremental cost of producing electric power in addition to the primary plant function of producing process steam, (industrial ownership) or b) The incremental cost of producing steam from a plant primarily intended for electric power production (utility ownership). Historically, in the U.S., the situations described by (a) have been predominant.

To begin an investigation of a potential cogeneration facility, a set of four indicators give a general indication of the economic viability. These indicators are represented by a set of four charts shown in Figures A8.4-1, A8.4-2, A8.4-3 and A8.4-4.[4] Additional considerations are:

- The utility's ability to reliably serve the kilowatt load
- The availability of waste or refuse fuels
- Boiler replacement
- Availability of a surplus of low-pressure steam in the process, i.e., 100,000 lb/hr at 5 to 100 psi
- Pressure reduction of over 150,000 lb/hr of steam

These indicators and additional factors permit preliminary conclusions and indicate whether a full feasibility study may be warranted. The detailed study should examine all aspects and factors included in determining the incremental costs of adding the power generation (or steam producing) capability to a single function plant. With rising fuel costs, potential cogeneration users will find the available reduction in overall fuel consumption increasingly valuable. From the standpoint of our national energy resources and supply, a net reduction of fuel consumption can be achieved by this "active" conservation method.

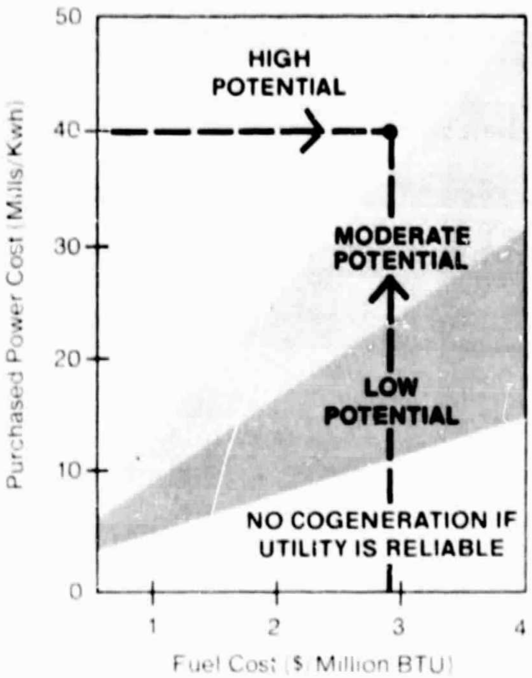


Figure A8.4-1. Fuel Cost and Purchased Power Cost Relationship

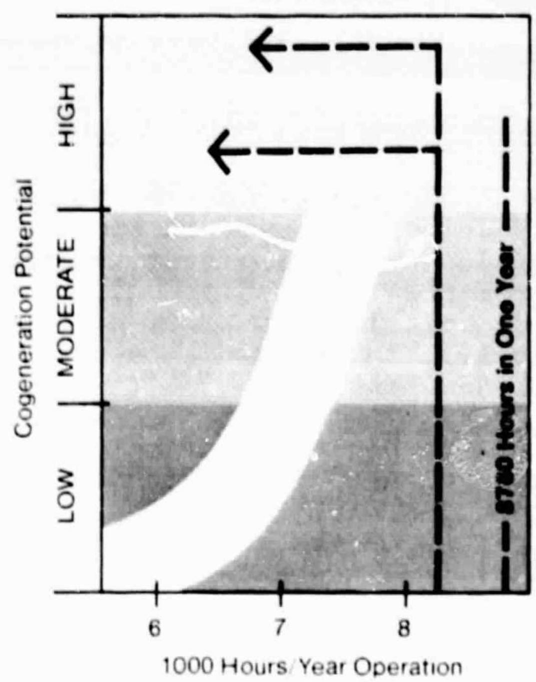


Figure A8.4-2. Plant Operation at Average Load Conditions

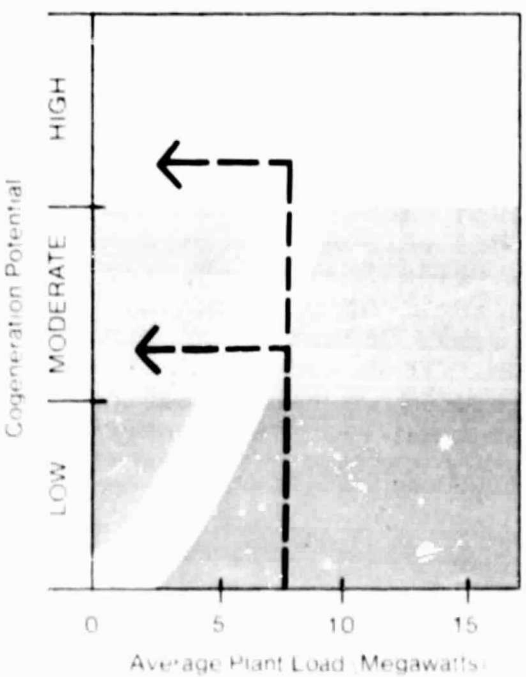


Figure A8.4-3. Plant Kilowatt Load

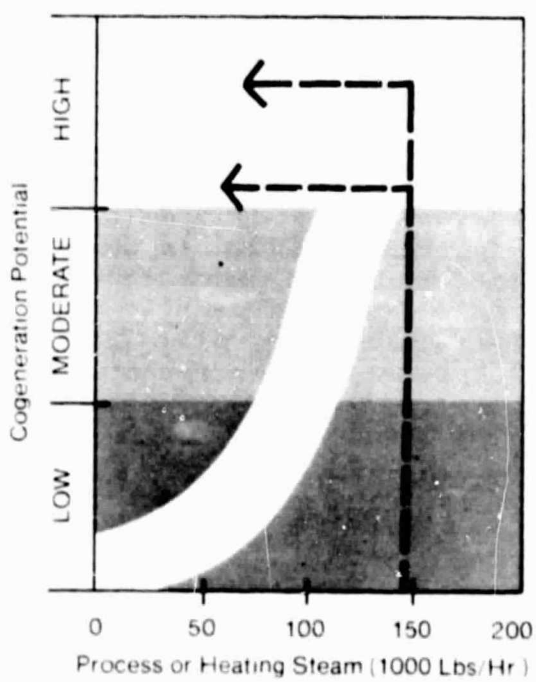


Figure A8.4-4. Process Steam Load

A8.5 ACTIVE PARTICIPANTS

The following organizations and companies are representative of those active in the development of cogeneration technology:

- ASEA (Sweden)
- Elliott Company
- General Electric Company
- Onan
- Skinner Engine Company
- Solar Turbines
- Terry Steam Turbine Company
- Turbodyne Corporation
- Westinghouse Electric Corporation

Section A9

OBSERVATIONS

A9.1 OBSERVATIONS OF IMPORTANCE TO DSG TECHNOLOGIES

The preceding descriptions of DSG technologies serve to bring out a number of significant observations of importance to the establishment of the monitoring and control requirements for DSG. These are:

1. Each DSG technology is a complicated system which has to be controlled locally to achieve satisfactory results.

Each DSG system has several control subsystems which must be integrated under a local master control and which must be responsive to normal and abnormal conditions as sensed locally. Figure A9.1-1 shows how a remote distribution dispatch center communicates through appropriate interfaces to a DSG to perform scheduling and control, as well as to monitor DSG system status. The DSG is under a local master control and may have local operator or automatic control, as well as local data acquisition and alarm functions.

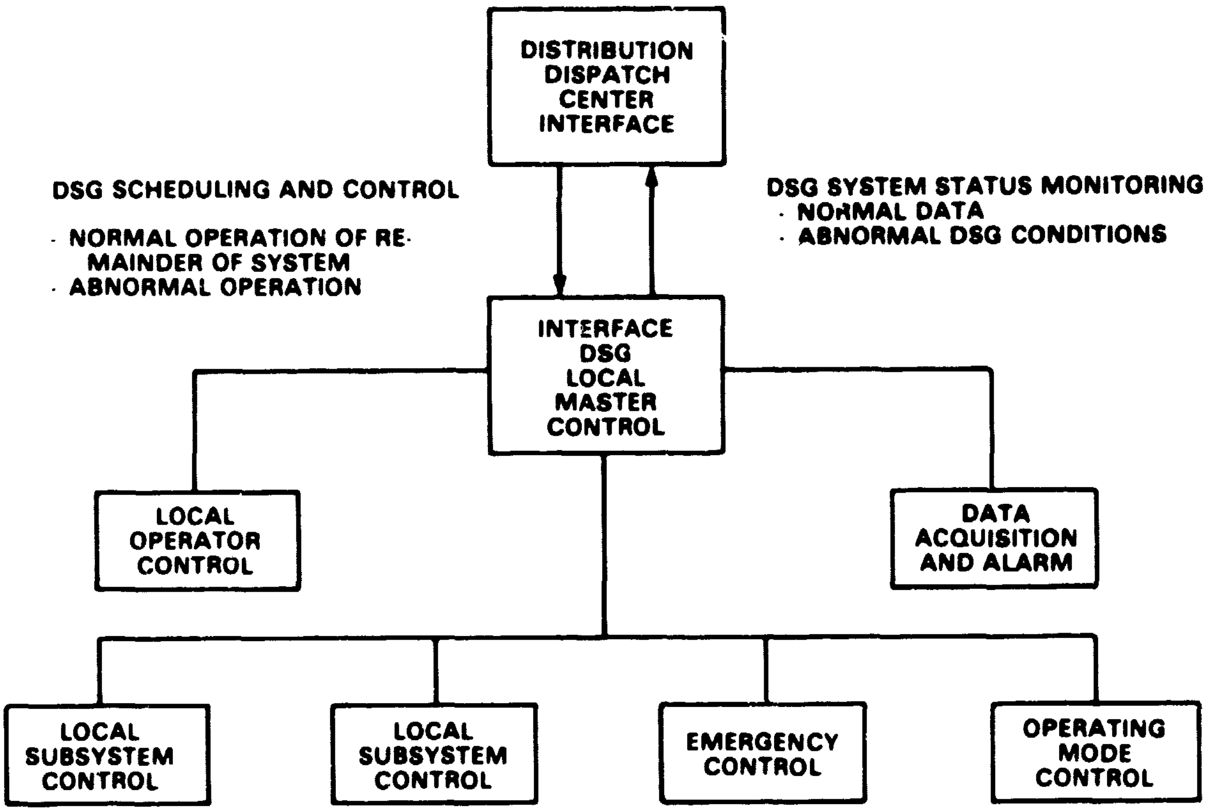


Figure A9.1-1. Relationship of Distribution Dispatch Center to a Typical DSG Showing Monitoring and Control Information Exchange

For proper stability and safety of each DSG, it is important that it be controlled locally. However, for each DSG to be able to contribute power to the electric distribution system as needed, it is desirable that remote supervisory control of the DSGs from the distribution dispatch center be available.

The remote monitoring and control of the DSG tends to be of a supervisory character. It establishes setpoints, monitors DSG conditions so that reasonable setpoints may be established, and identifies when conditions are normal or abnormal and what to expect from the remote DSG unit. Although the nature of the specific commands from the distribution dispatcher may be different in detail for each type of DSG technology, the resulting power input from each of the DSGs to the electric distribution network can be comparable in kind.

2. Since each technology has its own particular subsystems and characteristics, the communications to and from the DSG must be tailored to the needs of each DSG technology and may, therefore, differ in detail.

It may be necessary to have monitoring and control information in several categories: those of low, medium, and/or high precision, as well as those of slow, medium, and/or fast time response. The definition of low, medium, and high precision, and of slow, medium, and fast time response has not yet been finalized. It will be necessary to analyze in more detail these various requirements for each of the DSGs. An effort should be made to develop an appropriate modular approach to the hardware and software of the monitoring and control links to the various DSGs so that communicating to them appears the same to the distribution dispatcher, and yet each DSG component can have the specific instructions it requires.

3. From the dispatch center's point of view, DSGs appear to be remotely controlled activities like other bulk generation sources or transmission control points.

Since the dispatch centers already have existing supervisory control and data acquisition (SCADA) ties to the bulk generation and transmission equipment (see Figure A9.1-2) an effort should be made to determine whether the monitoring and control for the distribution system should be similar to or different from that for generation and transmission. Perhaps the existing choices of control and data for low, medium, and high precision and for slow, medium, and fast time response can be found to be acceptable for use with DSGs. If possible, generic means for monitoring and control of DSGs should be sought so that special custom-designed control means are not required for each DSG technology.

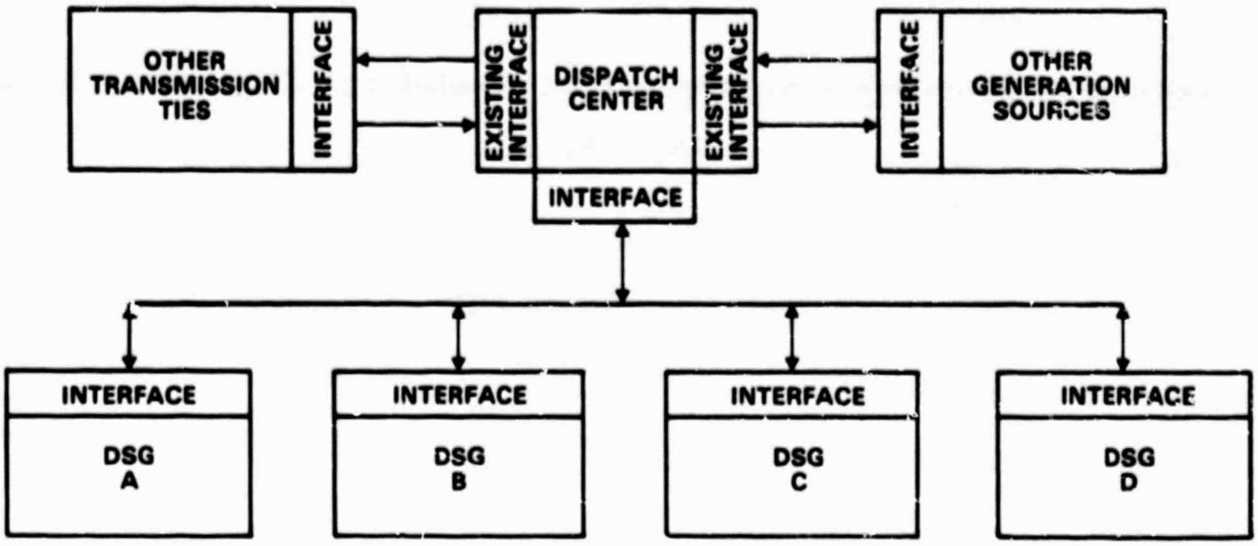


Figure A9.1-2. Dispatch Center's Interconnections with Generation Sources, Transmission Ties, and DSGs

4. Scheduling and control of remote DSG units should be based on the need to make the overall system service, i.e., generation, transmission, and distribution, most effective.

Scheduling of DSG power involves a measure of uncertainty, e.g., whether the sun is shining or what the wind speed is. Operation of the remainder of the system is also subject to some unforeseen changes with time because of load demand or equipment availability. The combination of monitoring and control of the DSGs' power contribution and the monitoring and control of the remainder of the generation and transmission system should provide the information base on which modifications to DSG generation and characterization of the remainder of the controllable system can be made.

5. The characteristics of the DSG technologies determine the electrical nature of the power generated and, therefore, the form and nature of local control required.

In addition, the extent to which the DSG scheduling can be performed is also influenced directly by the form of DSG and its energy source.

Table A9.1-1 shows the relationship between the type of DSG and the form of electrical energy which is produced. Based on the initial form of electrical energy produced, the actual control requirements will differ in the fashion indicated.

The type of DSG technology also has a definite bearing on the extent to which scheduling is possible. Table A9.1-2 indicates that certain technologies such as fuel cells, storage batteries, hydro, and cogeneration can be scheduled in advance.

Other DSG technologies, such as wind, and under some circumstances, hydro and cogeneration, have little possibility of being scheduled.

Table A9.1-2

RELATIONSHIP BETWEEN TYPE OF DSG AND FORM OF ELECTRICAL ENERGY

	INITIAL FORM OF ELECTRICAL ENERGY			
	AC		DC	
Type of DSG	Steam Generator	Mechanical Drive	Inverter	Converter-Inverter
Solar Thermal Electric	X			
Photovoltaic			X	
Wind		X		
Fuel Cell			X	
Storage Battery				X
Hydro		X		
Cogeneration	X			

Table A9.1-2

RELATIONSHIP BETWEEN TYPE OF DSG AND EXTENT TO WHICH SCHEDULING IS POSSIBLE

TYPE OF DSG	CAN BE SCHEDULED	POSSIBLY MAY BE SCHEDULED	LITTLE SCHEDULING POSSIBLE
Solar Thermal Electric		X	
Photovoltaic		X	
Wind			X
Fuel Cell	X		
Storage Battery	X		
Hydro	With Storage X	X	Run of River X
Cogeneration	Utility Owned X	When Process Known X	Industry Owned X
		Jointly Owned	

6. Monitoring of DSG should be done for both normal and abnormal operation.

Under normal operation, regular periodic reporting of the DSG power generated and energy available should be provided. Under abnormal conditions at the DSG or in the remainder of the system, it may be necessary to have data reported on a more frequent basis.

7. Information pertaining to DSG equipment size, efficiency, availability, and cost is useful in establishing whether, when, and where a DSG should be installed and dispatched.

Information of this sort also will have an influence on establishing the scheduling and/or control algorithms alluded to in observations 4 and 5.

The economics of DSG under production-lot conditions may at present not be sufficiently well-known or attractive to cause widespread electric utility acceptance. Nevertheless, in the long run, economic information must be incorporated into the scheduling and control decision-making process. This will permit the power dispatch operator in conjunction with the DSG automatic control to provide electric distribution system operation which will result in lower operating cost for the total system. The influence of these economic, performance, and availability characteristics on the monitoring and control requirements of each DSG has yet to be established. Ultimately, the bases for decision-making must be included as part of the scheduling, control, and monitoring of the DSG.

Section A10

REFERENCES AND BIBLIOGRAPHY

1. The First Small Power System Experiment,EE-1, Phase I, General Electric Company, ESPD, May 1979.

2. An Overview of Power Plant Options for the First Small Power System Experiment: Engineering Experiment Number 1, Jet Propulsion Laboratory, Pasadena, CA, JPL Document Number 5103-38, Nov. 9, 1978.

3. S. Karaki, D.S. Ward, and G.O.G. Lof, "Utilization of Solar Energy Today," IEEE Energy Development, 74 CH 0913-4-PWR, pp. 7, 9, 10.

4. A. Braunstein and D. Biran, "Solar-Electrical Systems - Theory and Applications," IEEE Energy Development II, 76 CH 1102-3-PWR, pp. 33-39.

5. Lloyd O. Herwig, "Solar Energy Systems for Electricity Production," IEEE Energy Development II, 76 CH 1102-3-PWR, pp. 92-95.

6. D.Q. Hoover and A.D. Watt, "Potential Role of Solar Thermal Electric Power in the U.S.," IEEE Energy Development II, 76 CH 1102-3-PWR. pp. 130-140.

7. J.W. Ballance and G.W. Braun, "Integration of Solar Generation into Electric Utility Systems," IEEE Energy Development IV, 78 TH 0050-5-PWR, pp. 6-12.

8. W.G. Pollard, "A General Method for the Evaluation of Possible Systems for Electric Generation with Solar Energy," IEEE Energy Development IV, 78 TH 0500-5-PWR, pp. 146-153.

9. Requirements Assessment of Photovoltaic Power Plants in Electric Utility Systems, General Electric Company, EPRI ER-685-SY, Project 651-1, June 1978.

10. Conceptual Design and System Analysis of Photovoltaic Systems, General Electric Company, Report No. ALO-3686-14, March 1977.

11. Assessment of the Solar Protovoltaic Industry Markets and Technologies, Booz-Allen and Hamilton, DOE Contract No. EX-77-C-03-1978.

12. Requirement Definition and Preliminary Design of A Photovoltaic Central Power Station Experimental Test Facility, General Electric DOE/Sandia, Report No. SAND 79-7022, 1979.

13. Frank R. Eldridge, "Wind Machines," MITRE, Oct. 1975, NSF-RA-N-75-051.

14. G. Elsoe Jorgensen, M. Lotker and R.C. Meier, "Design Economic, and System Considerations of Large Wind Driven Generators," IEEE Energy Development II, 76 CH 1102-3 PWR, pp. 54-62.

15. R. Thomas, R. Puthoff, J. Savins, and W. Johnson, "Plans and Status of the NASA - Lewis Research Center Wind Energy Project," IEEE Energy Development II, 76 CH 1102-3 PWR, pp. 173-186.

16. B.W. Jones and P.M. Moretti, "Evaluation of Wind Generator Economics in a Load Duration Context," IEEE Energy Development III, 77 CH 1215-3 PWR, pp. 25-29.

17. H.S. Kirschbaum, E.V. Somers, and V.T. Sulzberger, "Evaluation of Off-shore Site for Wind Energy Generation," IEEE Energy Development III, 77 CH 1215-3 PWR, pp. 108-114.

18. Robert L. Loftness, Energy Handbook, New York: Van Nostrand Reinhold Company, 1978, pp. 361-369.

19. James T. Yen, "Harnessing the Wind," IEEE Spectrum, Vol. 15, March 1978, pp. 42-47.

20. Thomas W. Reddock and John W. Klein, "No Ill Winds for New Mexico Utility," IEEE Spectrum, Vol. 16, March 1979, pp. 57-61.

21. Requirements Assessment of Wind Power Plants in Electric Utility Systems," EPRI ER-978-SY, Vol. 1, PROJ 740-1, January 1979.

22. W.J. Lueckel and P.J. Farris, "The FCG-1 Fuel Cell Power Plant for Electric Utility Use," IEEE Energy Development, 1974, 74 CH0913-4 PWR, pp. 42-46.

23. G.A. Phillips, J.H. Vogt, and J.W. Walton, "Inverters for Commercial Fuel Cell Power Generation," IEEE Energy Development II, 1976, 76 CH 1102-3-PWR, pp. 44-53.

24. L.H. Michaels, B.T. Fairchild, and S.T. Kohn, "Hybrid Simulation of Fuel Cell Power Conversion Systems," IEEE Energy Development III, 1977, 77CH 1215-3-PWR, pp. 34-41.

25. R.A. Fernandes and H.D. Philipp, "Hydrogen Cycle Peak-Shaving on the New York State Grid Using Fuel Cells," IEEE Energy Development III, 1977, 77CH-1215-3-PWR, pp. 92-100.

26. William Wood, Paul Yatcko, and M.P. Bhavaraju, "Economic Assessment of the Utilization of Fuel Cells in Electric Utility Systems," IEEE Energy Development IV, 1978, 78 TH0050-5-PWR, pp. 22-30.

IEEE Trans. Power Apparatus and Systems, Vol. PAS-97, No. 5, pp. 1805-13.

27. The Development of Molten Carbonate Fuel Cell Power Plants, GE Proposal ESPD-79-045, prepared for DOE and NYSERDA, May 7, 1979.

28. Robert Noyes, Fuel Cells for Public Utility and Industrial Power, Noyes Data Corp. Park Ridge, New Jersey, 1977.

29. An Assessment of Energy Storage Systems Suitable for Use by Electric Utilities, Vol. I, II, III, PSEG, January 5, 1976.

30. "Superbatteries: A Progress Report," IEEE Spectrum, March 1979, pp. 49-55.

31. A.D. Little, Parametric Analysis of the Electric Utility Market for Advanced Load-Leveling Batteries, HCP/T/5036, for DOE, February 1979.

32. J.R. Birk and J.W. Pepper, "Reducing Oil Requirements in the Electric Utility Industry: The Need for Energy Storage," March 1977. Electrochemical Society Meeting, October 1977.

33. William P. Creager and Joel D. Justin, Hydroelectric Handbook, 2nd Edition, John Wiley & Sons.

34. Estimate of National Hydroelectric Power Potential at Existing Dams, U.S. Army Corps of Engineers, Institute for Water Resources, July 20, 1977.

35. Report on Equipment Availability for the 10 Year Period 1967 to 1976, Edison Electric Institute EEI Publication No. 77-64.

36. "Uniform Systems of Accounts Prescribed for Public Utilities and Licensees," U.S. Federal Power Commission, April 1, 1973.

37. John D. Lawrence, "Small Hydro: Where Do We Go From Here?" Public Power, July-August 1977.

38. Cogeneration Technology Alternatives Study - CTAS, Contract No. DEN 3-31, General Electric Company, for NASA-Lewis/DOE, (To be published 1979).

39. W.B. Wilson, General Electric Company, "Cogeneration - Some Hardware and System Design Parameters," ASME Paper, 78-1PC-PWR6.

40. A Technical Overview of Cogeneration: The Hardware, The Industries, The Potential Development, ERDA Contract No. EY-76-C-03-1223 by Resource Planning Associates, Inc., for DOE, Dec. 1977, RPA Reference No. RA-77-3038A.

41. A Study of In-Plant Electric Power Generation in the Chemical, Petroleum Refining, and Paper and Pulp Industries, Contract No. 00-04-50224-00, March 1978, by Thermon Electron Corp., for Federal Energy Administration, Report FEA/D-76/321.

42. "Cogeneration," Power Engineering, March 1978, pp. 34-42.

43. "Energy Industrial Center Study," by Dupont Chemical Company, for National Science Foundation, June 1975, Reference No. PB 243823.

44. "Cogeneration: What It Means To Plant Engineers," Plant Engineering, Aug. 3, 1978, pp. 74-80.

45. Commercialization Strategy Report for Small-Scale Hydroelectric Power (Proposed report, DOE Commercialization Task Force, 1978), Report No. TID 28841.

46. Economic Assessment of the Utilization of Fuel Cells in Electric Utility Systems, EPRI EM-336. Final Report of RP 729-1, Public Service Electric and Gas Co., Jan. 1977.

47. An Assessment of the Fuel Cell's Role in Small Utilities, EPRI EM-696. Final Report of RP 918, Burns and McDonnel Engineering Co., Feb. 1978.

48. "A Giant Step Planned in Fuel-Cell Plant Test," E.P. Barry, R.L.A. Fernandes, and W.A. Messner. IEEE Spectrum, Vol. 15, No. 11 (Nov. 1978).

49. "Fuel Cell Power Plants," A.P. Fickett, Scientific American, Vol. 239, No. 6 (Dec. 1978).

50. Lawrence M. Lidsky, "Nuclear Energy Technology-Fusion Power," in Energy Technology Handbook, McGraw-Hill, 1977.

51. "Research and Development Program Plan for 1979-1983," EPRI Special Report PS-830-SR, July 1, 1978.

52. Information on geothermal processes paraphrased from "Geothermal Energy Technology," in Energy Technology Handbook, McGraw-Hill, 1977.

53. William P. Creager and Joel D. Justin, Hydroelectric Handbook, Second Edition, 1950, Chapter 11.

54. R.A. Fernandes, O.D. Gildersleeve, and T.R. Schneider, "Assessment of Advanced Concepts in Energy Storage and Their Application on Electric Utility Systems," Transactions: "Ninth World Energy Conference," Paper No. 6.1-12.

55. R.A. Herse, T.R. Schneider, R.V. Snow, V.T. Sulzberger, and J. Zemkoski-Public Service Electric and Gas, "Application of Energy Storage Systems to Electric Utilities in the United States," CIGRE, August 1976, Paper No. 31-07.

56. "An Assessment of Energy Storage Systems Suitable for use by Electric Utilities," Public Service Electric and Gas for ERDA/EPRI, Report No. EPRI-225, ERDA Contract E(11-1)-2501, 1976.