Chapter 4

New Technologies for Generating and Storing Electric Power

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INTRODUCTION

A number of new technologies for generating and storing electricity are being developed as alternatives to large-scale, long lead-time conventional powerplants. Of increasing interest are technologies which are small scale and highly efficient, which are capable of using alternative fuels, and/or which impose substantially lower environmental impacts than conventional generating options.

This chapter focuses on new technologies which, while generally not fully mature today, *could figure importantly in the electric-supply technologies insta//ed in the 7990s.* Not examined in detail are those technologies which already are considered technically mature or those which are very unlikely to achieve wide deployment during that time. Only grid-connected applications are considered. The chapter also does not examine closely technologies which recently have been covered in other OTA reports.[1]

The new technologies covered in this report are summarized in table 4-1. In table 4-2, the technologies are grouped according to size and application, along with their primary competitors. They range in size from units less than 1 MWe to units greater than 250 MWe. The technologies can be divided between those in which the electrical power production is available upon utility demand (dispatchable) and those where it is not. In the table, dispatchable applications are further broken down according to base, intermediate, and peak load applications. Among applications where the utility cannot summon electrical power on command are intermittent technologies (e.g., wind turbines and direct solar equipment), when they have no storage capacity, as well as any other technologies not controlled by utilities.

Table 4-1 .—Developing Technologies Considered in OTA's Analysis[a]

Photovoltaics:
Flat plate systems (tracking and nontracking)
Concentrators
Solar thermal electric:
Solar ponds
Central receivers
Parabolic troughs
Parabolic dishes
Wind turbines
Geothermal:
Dual flash
Binary (large and small)
Atmospheric fluid ized-bed combustors
Integrated gasification combined-cycle
Batteries
Lead acid
Zinc chloride
Compressed-air energy storage (large and small)
Phosphoric-acid fuel cells (large and small)

[a]For description see box 2A, ch. 2 and table 3-9, ch. 3.

The chapter discusses estimates of the typical cost and performance of these technologies *in the 1990s.* The estimates and extensive references are presented in appendix A. In presenting the estimates, the chapter seeks to explain and justify them, and to point out the expected, most important determinants of the technologies' cost and performance during the 1990s. Technology-specific research and development (R&D) opportunities to accelerate the deployment of the technologies in the 1990s are also addressed.

The cost and performance estimates presented here are based on the current status of the technologies and the context within which they are developing. Information on technical, economic, political, and other areas was analyzed and interpreted. The levels of uncertainty which varied by technology are also discussed.

[1]These include nuclear power, convent io na l technologies used in cogeneration, and conventional equ ipment which uses biomass; see p. iv of this report.

Table 4-2.—Selected Alternative Generating and Storage Technologies: Typical Sizes and Applications

Typical configurations in the 1990s

Installation size (MW)	Dispatchable applications[a]			Nondispatchable applications[b]	
	Base load (60-70% CF)	Intermediate load (30-40% CF)	Peaking load (5-15%)	Intermittent (w/o storage)	Others (not utility controlled)
Greater than 250 MWe	Coal gasification/ combined-cycle	Coal gasification/ combined-cycle	n.a.		
	Conventional coal				
51-250 MWe	Geothermal Atmospheric fluidized-bed combustor	Atmosphere fluidized-bed combustor Compressed air storage (maxi CAES) Solar thermal (w/storage)	Compressed air storage (maxi CAES) Solar thermal (w/storage)	Solar thermal Wind	Atmospheric fluidized-bed combustor Solar thermal (w/storage)
	Combined-cycle plants	Combined-cycle plants	Combustion turbine		
1-50 MWE	Geothermal Atmospheric fluidized-bed combustor Fuel cells	Fuel cells Compressed air storage (maxi CAES) Solar thermal (w/storage)	Compressed air storage (mini CAES) Battery storage Fuel cells Solar thermal (w/storage)	Solar thermal Wind Photovoltaics	Atmospheric fluidized-bed combustor Geothermal Fuel cells Solar thermal (w/storage) Battery storage Compressed air storage (mini CAES) Geothermal
			Combustion turbine		Combustion turbine
Less than 1 MWe				Solar thermal Wind Photovoltaics	Fuel cells Battery storage

NOTES: For each unit size and application, new technologies are shown above the dotted line and conventional technologies are shown below the dotted line. CF = capacity factor and n.a. = not applicable.
[a]Dispatchable technologies may not be utility-owned.
[b]Note that nondispatchable technologies may serve base, intermediate, or peaking loads.

SOURCE: Office of Technology Assessment.

GENERATING TECHNOLOGIES

Solar Technologies

Introduction

In seeking ways to directly exploit the Sun's energy to produce electric power, two alternatives are being pursued. Solar thermal-electric technologies rely on the initial conversion of light energy to thermal energy; the heat typically is converted to mechanical energy and then to electric power. Alternatively, photovoltaic cells may be used to directly convert the light energy into electrical energy. Between the two technologies, many variations are being developed, each with its own combination of cost, performance, and risk, and each with its own developmental hurdles.

Most solar electric technologies promise noteworthy advantages over conventional technologies.[2] These include:

1. *Free, secure, and renewable energy source:* These are especially important attributes when contrasted with price and availability uncertainties of oil and natural gas.
2. *Widely available energy source:* Figure 7-11 in chapter 7 illustrates the distribution of the solar resource in the United States.

[2]Note that some solar technologies may use a supplemental fuel such as oil, gas, or biomass. In such instances, the hybrid system will not have some of the advantages and disadvantages listed; and the system will possess some advantages and disadvantages *not* listed.

3. *No off-site, fuel-related impacts:* The delivery of solar energy imposes no environmental impacts off-site, unlike the delivery of conventional fuels which frequently require a series of steps (exploration, extraction, refining, transportation, etc.) which each impose environmental impacts quite distinct from those at the power plant site itself.
4. No *fuel supply infrastructure required:* The delivery of solar energy does not require the development of an ancillary fuel-supply infrastructure as is the case with conventional fuels. A solar plant can operate remotely at any site; a coal plant could not do so without the prior development of an infrastructure which extracts, refines, and transports the coal to the plant.
5. *Short lead-times.*
6. *Wide range of installation sizes.*
7. *Dec/ining costs:* Many of t he solar thermal systems are experiencing declining costs, a fact which reduces risk in any plans to invest in the technologies.
8. *Relative/y small water needs: Some* of the solar technologies require little water beyond that used for cleaning.
9. *Litt/e or no routine emissions:* Other than thermal discharges and other than run-off from washing operations, most solar technologies do not routinely emit large quantities of wastes into the air, water, or soil. j
10, *Siting flexibility.*

Though graced by many advantages, solar electric systems–like any other generating technologies—also have disadvantages. Among them are:

1. */intermittent supp/y of energy:* Solar energy is subject to uncontrollable and sometimes unforeseeable variations. It is not always there when needed. Most obviously, it completely ceases to be available every day for extended periods (night) or its power is considerably diminished anytime clouds pass between the Sun and the surface of the Earth. in addition, seasonal and annual fluctuations in average solar radiation can be significant.[4] And these fluctuations put stress on hardware and can cause control problems.
2. *Capita/ intensive:* Current solar electric technologies are characterized by very high capital costs per kWe.
3. *Land extensive:* Solar systems use a lot of land per unit of power. where land is expensive, land acquisition can greatly increase installation costs. where solar concentrators are spread over a large surface area, soils and microclimates and local ecosystems can be affected.
4. *Water usage:* Some solar thermal systems routinely require large quantities of water; and all likely will require periodic cleaning. Where units are used in arid areas, this may be a problem.
5. *Exposure to the elements and to malevolence:* Many of the system components are fully exposed. They therefore suffer from erosion, corrosion, and other damage from the wind, from moisture (including hail) and contaminants in the air, and from temperature extremes. The systems also may be easy targets for vandals or saboteurs. For these reasons most solar electric installations are enclosed by fences, often with some kind of barrier for wind protection. And where reflective mirrors are used, they frequently are designed not to shatter and to withstand the elements. A permanent security force also may be required where the systems are deployed, but their land extensiveness makes security difficult.
6. *Cost and difficuky of access:* The likelihood that the systems will be built in remote locations raises problems relating to site access during construction and for maintenance. Transmission access may also be difficult or expensive to obtain.

Photovoltaics

introduction.–A photovoltaic (PV) cc// is a thin wafer of semiconductors material which con-

[3]Disposal of the technology at the end of its useful lifetime may, however, create serious waste problems.

[4]It was reported, for example, that the solar flux at Solar One, a solar-thermal central receiver plant in California, has been 25 percent lower than in the base year (1 976) used for planning purposes for the plant, This may be due to the increased atmospheric particulate load imposed by recent volcanic eruptions.

[5]A semiconductor is a material characterized by a conductivity lying between that of an Insulator and that of a metal.

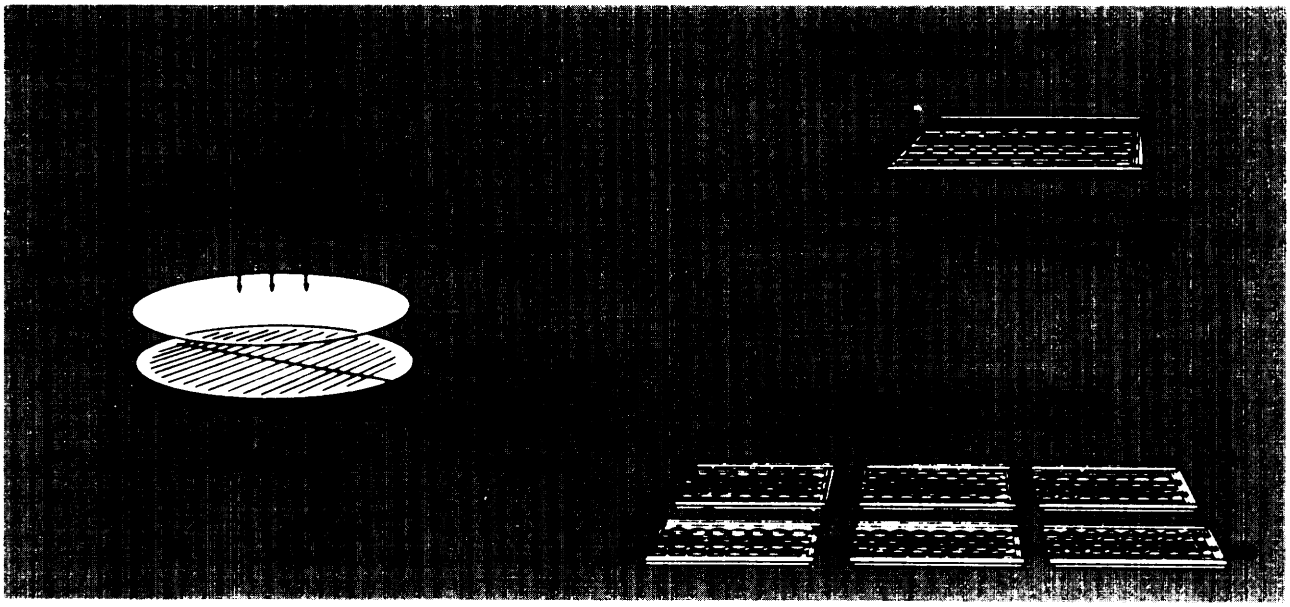
verts sunlight directly into direct current (DC) electricity by way of the photoelectric effect, Cells are grouped into modules, which are encapsulated in a protective coating. Modules may be connected to each other into panels, which then are affixed to a support structure, forming an array (see figures 4-1 and 4-2). The array may be fixed or movable, and is oriented towards the Sun. Any number of arrays may be installed to produce electric power which, after conversion to alternating current (AC), may be fed into the electric grid. I n a PV installation, all the components other than the modules themselves are collectively termed the balance-of-system.

At present, PV systems are being pursued in many different forms. Each seeks some particular combination of cost and performance for the module and for the balance-of-system. In a concentrator module, lenses are used to focus sunlight received at the module's surface onto a much smaller surface area of cells (see figure 4-2); all available concentrator systems follow the Sun with two-axis tracking systems. A flat-plate module is one in which the total area of the cells used is close to the total area of sunlight hitting the exposed surface of the module. Various mechanisms such as mirrors can be used to divert light from adjacent spaces onto the exposed surface of the modules. Flat-plate systems may be fixed in position or may track the Sun with either single or two-axis tracking systems.

The parallel development of these two types of PV modules and systems reflects a basic technological problem: it is difficult to produce PV cells which are *both* cheap and highly efficient. Cheap cells tend to be inefficient; and highly efficient cells tend to be expensive. Some PV systems which are being developed for deployment in the 1990s are emphasizing cells which are relatively cheap and inefficient; such cells are used in flat-plate modules. Others are using a smaller number of high-cost, high-efficiency cells in concentrator systems.

In either case, if PV systems are to compete with other grid-connected generating technologies in the 1990s, their cost and overall risks will have to come down and their performance will

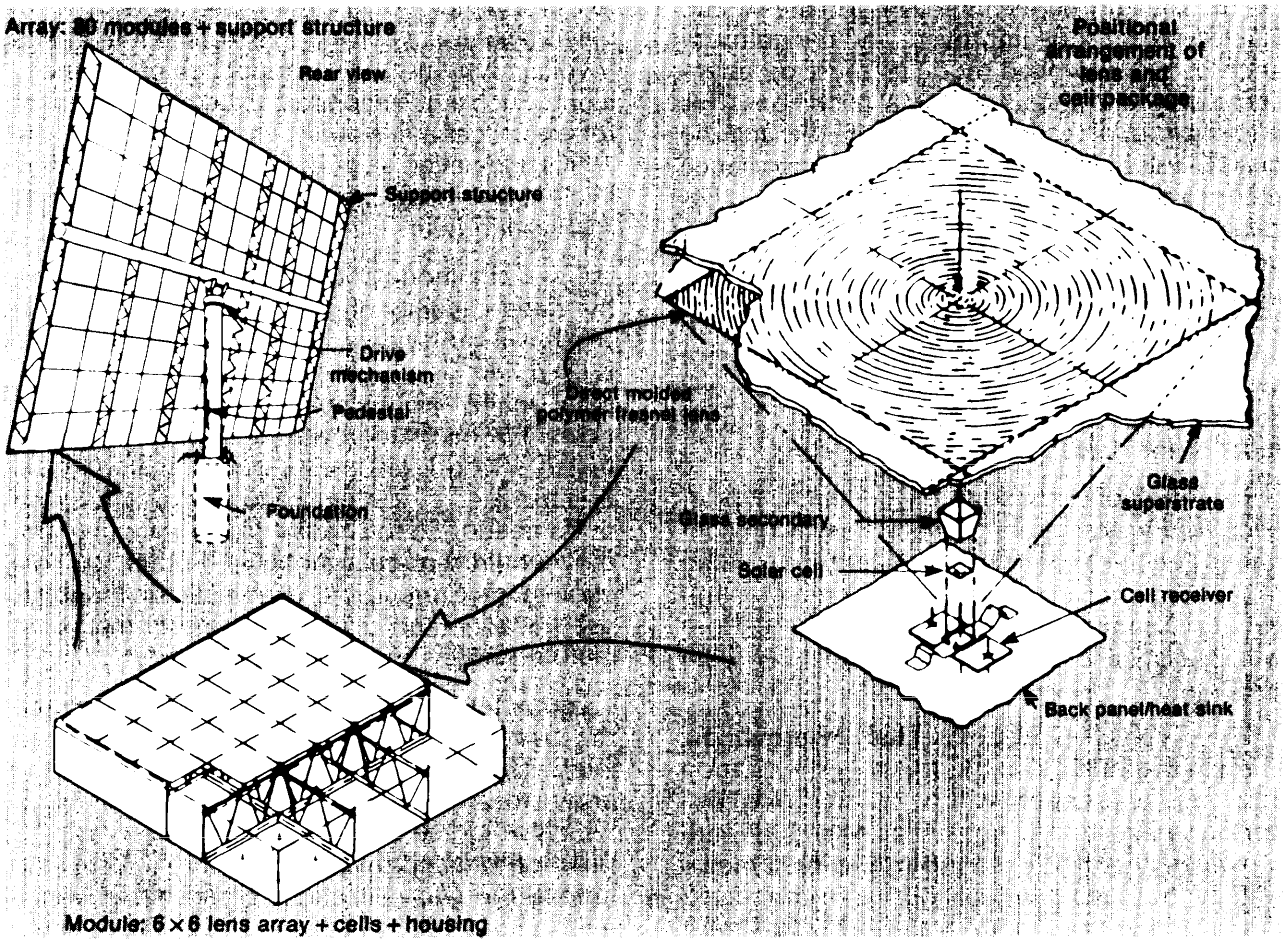
Figure 4.1.—Features of a Flat-Plate Photovoltaic System



The basic hierarchy of a PV generator is the solar cell; the module, or group of cells connected in series or parallel; and the array, or group of modules connected in series or parallel.

SOURCE: Solar Energy Research Institute (SERI), *Photovoltaics: Technical Information Guide* (Golden, CO: SERI, 1985), SERI/SP-271-2452.

Figure 4-2.—Schematic of a Conceptual Design for a High Concentration Photovoltaic Array



SOURCE: Black & Veatch, Engineers-Architects, *Conceptual Design for a High-Concentration (500X) Photovoltaic Array* (Palo Alto, CA: Electric Power Research Institute, 1984) EPRI AP-3263

have to improve. There is considerable disagreement over which particular PV system is the strongest contender for this market. Market penetration will depend on the current state of the particular variety of PV system; the potential for cost reductions and performance improvements; and on the reduction in risk perception among prospective investors in grid-connected installations.

At present, two types of modules appear to be the leading contenders. One is the flat-plate module based on tandem cells made from amorphous silicon; the other is the concentrator module, probably using crystalline silicon.

There are a number of reasons why the concentrator module could be the photovoltaic technology of choice in central station applications in the *near term.* The crystalline silicon cell is *relatively* well understood, as are the techniques for making such cells. The cells have been manufactured for many years, and information on cell performance after extended exposure to the elements is rapidly accumulating. Concentrator modules may offer a favorable combination of cost and performance in the Southwest, where early central station deployment probably will be greatest. And the prospects are good that cost and performance improvements can be made during the balance of the century. Many of the improvements do not appear to require basic technical advances but rather incremental improvements and mass production.

Flat-plate modules using amorphous silicon meanwhile are expected to continue to develop. But basic technical improvements must be made before extensive grid-connected deployment will occur. The current technology is too inefficient. Efficiencies must be improved, and the performance of the improved modules must be established over time and under actual conditions. This combination of technical improvements and the need to establish a clear, long-term performance record will take a substantial period of time. Because of this, amorphous-silicon flat-plates may not offer a superior choice for central station applications until the latter part of the 1990s or later. There is a small possibility, however, that rapid improvement in the cost and performance of amorphous modules is likely and that they will compete successfully with concentrators during most of the 1990s.

Regardless of technology, the commercial prospects for PV systems will depend heavily on continued technical development and the volume of production. Factors influencing either technical development or production levels therefore will strongly affect cost and performance in the 1990s.

The Typical Grid-Connected Photovoltaic Plant in the 1990s.—In the 1990s, central station applications probably will be favored over dispersed applications. Indeed, by May 1985, approximately 19 MWe of PV power in multimegawatt central station installations were connected to the grid in the United States—this was most of the grid-connected PV capacity in the country. This capacity was divided roughly equally between concentrator and flat-plate modules. By 1995, as much as 4,730 MWe could be located in such installations nationwide.b Capacity probably will be concentrated in California, Florida, Hawaii, Arizona, and New Mexico.[7]

In this analysis, it is assumed that the typical grid-connected photovoltaic system in the 1990s is a centralized photovoltaic system (see figure 4-3). Unless otherwise stated, the numbers referred to in this discussion are drawn from table A-1 in appendix A, where full references are provided. The discussion emphasizes the use of photovoltaic systems for the production of electricity alone. Such applications are expected to account for most central station photovoltaics in the 1990s. However, a significant share of photovoltaic systems may cogenerate both electric power and usable heat.

Given the modularity of photovoltaic systems, the rated capacity of central PV facilities in the 1990s will vary widely. An installation of 10 MWe is used here as a typical plant. This 10 MWe PV plant might occupy approximately 40 to 370 acres. The installation would consist of approximately 500 to 1,250 arrays, each of which would be supported by a structure resting on some kind of foundation. If the arrays are to track the Sun, they would require a motor and other tracking equipment. Currently, all central station PV plants use trackers, and evidence suggests that most central stations in the 1990s will too.[8]

Equipment also would be required to ground the arrays, to detect faults, and protect against faults. Direct-current wiring would connect the arrays to power-conditioning subsystems (PCS) which would control the arrays, convert the DC power produced by the arrays into a form suitable to the grid—constant voltage AC power—and regulate the switchgear.[9] (See figure 4-4.)

The environmental impact of large PV plants is likely to be extensive (see figure 4-5). During construction, impacts will result mostly from disruption of the soils, vegetation, and wildlife by the heavy machinery. Impacts after construction will relate to changes in the microclimate, ecology and appearance of the area from the simple presence of the large arrays and from routine maintenance. The latter could include activities

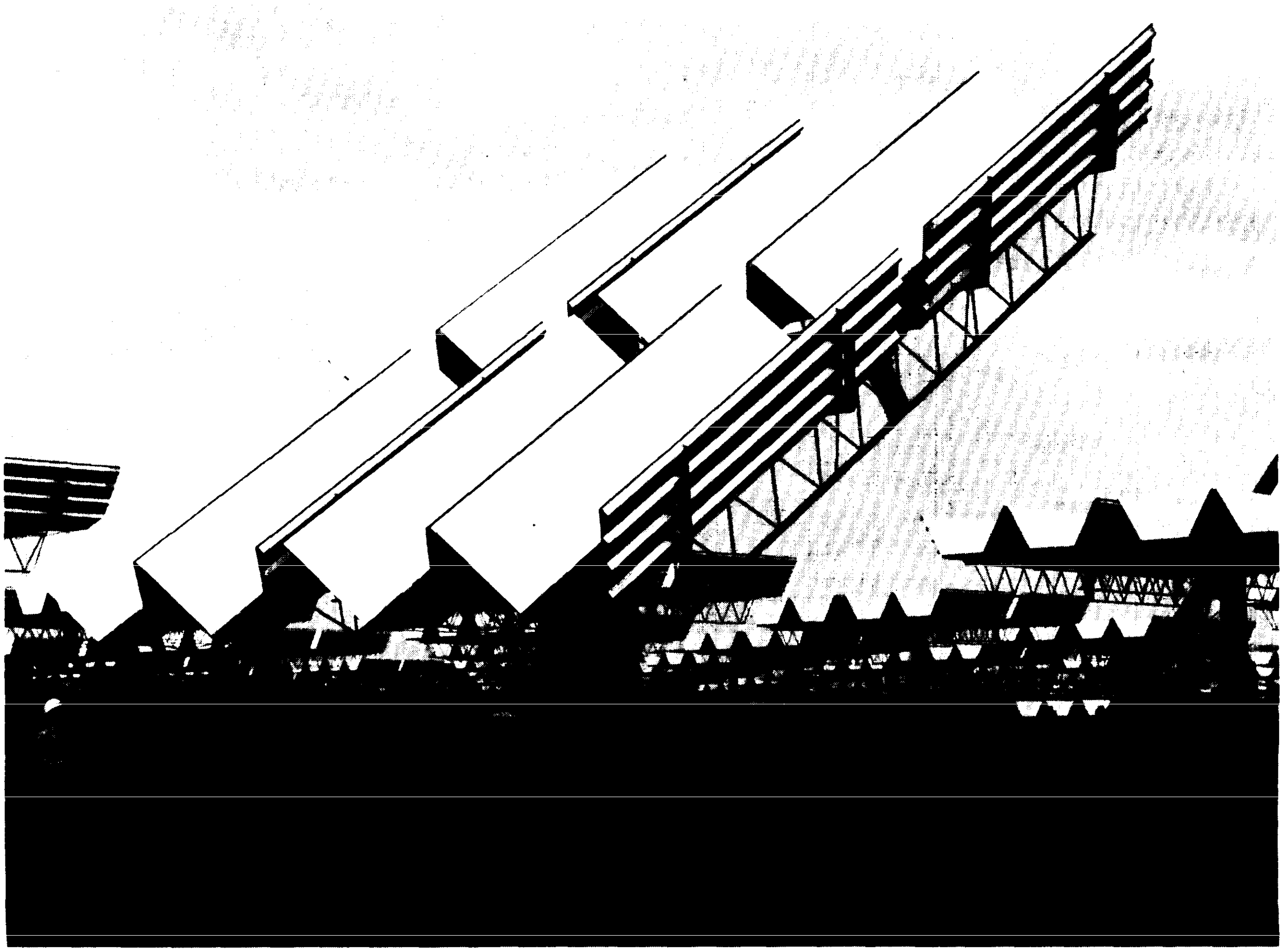
[6]This is the range provided by Pieter Bos (Polydyne Inc.), as estimated in a submission at the OTA Workshop on Solar Photovoltalc Power (Washington, DC, June 12, 1984) and discussed by Maycock and Sherlekar (Paul D. Maycock and Vic S. Sherlekar, *Photo\ 'oltaic Technology, Performance, Cost and Market Forecast to 1995. A Strategic Technology& Market Analysis* (Alexandria, VA: Photovoltaic Energy Systems, Inc., 1984), pp. 130-1 36.),

[7]Ibid.

[8]See for example: Gary J. Jones, *Energy Production Trade-Offs in Photovoltaic System Design* (Albuquerque, NM: Sandia National Laboratories, 1983), SAND82-2239. One reason for this is that trackers allow for higher electricity production and permit capital investment to be amortized more rapidly.

[9]For a good discussion of the basic components of a PV installation, see: Paul D. Sutton and C.J. Jones, "Photovoltaic System Overview," *Advanced Energy Systems—Their Role in Our Future: Proceedings of 19th Intersociety Energy Conversion Engineering Conference, August 19-24, 1984* (San Francisco, CA: American Nuclear Society, 1984), paper 849251.

Figure 4-3.—A View of a Recently Installed Photovoltaic Central Station



SOURCE ARCO Solar, Inc

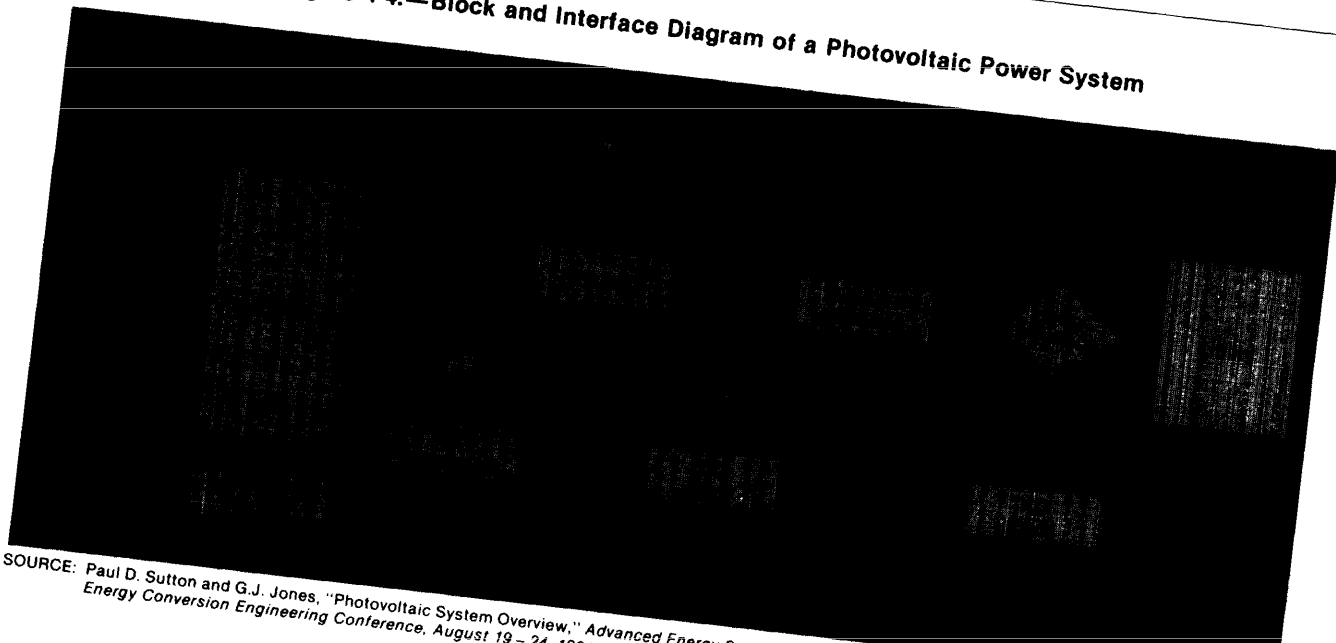
such as dust abatement measures, vegetation control efforts, and periodic cleaning of the modules.

The lead-time required to deploy a PV plant is potentially quite short, perhaps 2 years—including planning, licensing, permitting, construction, and other elements. Construction itself should be quick and simple. Licensing and permitting should proceed very rapidly because many of the environmental impacts are low relative to those associated with conventional technologies. However, large PV plants will be new to most areas in the 1990s; and the land-extensive character of the technology raises problems which could engender controversy, leading to regulatory delays.

System Cost *and* Performance.–Operating availabilities of 90 to 100 percent are anticipated for the multimegawatt PV installation of the 1990S.[10] This will be affected primarily by the number of PCSS required and their quality. Most operating large PV systems today are characterized by operating availabilities below this—between 80 and 90 percent–usually as a result of problems with the PCSS. I n order to reach the expected range of operating availabilities, PCSS must be developed which can operate reliably.

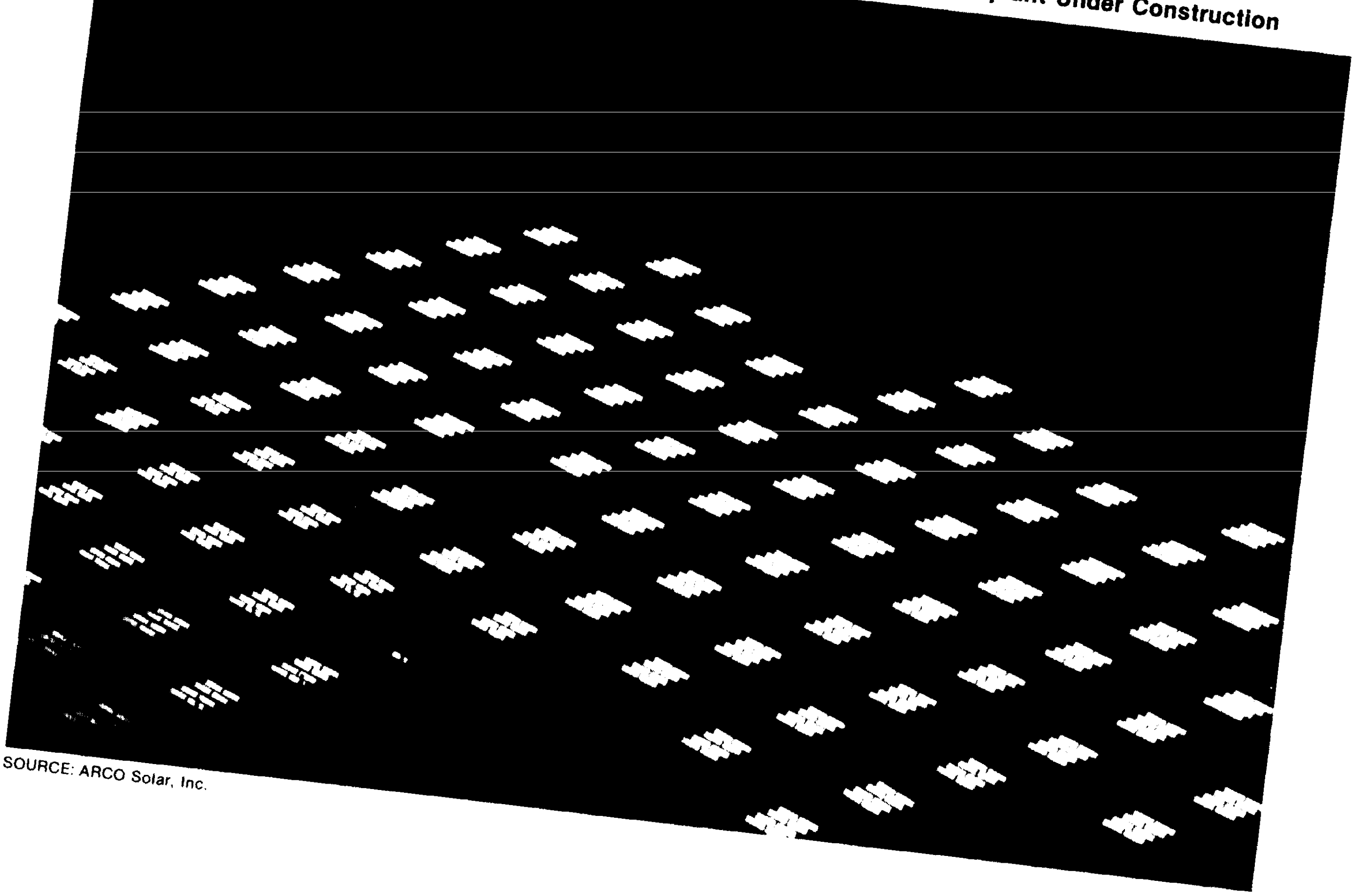
[10] Operating availability of individual arrays will be between 95 and 100 percent, depending mostly on the performance of trackers, if they are used. Recent experience with trackers suggests that their operating availabilities should not fall below that range.

Figure 4-4.—Block and Interface Diagram of a Photovoltaic Power System



SOURCE: Paul D. Sutton and G.J. Jones, "Photovoltaic System Overview," *Advanced Energy Systems—Their Role in Our Future: Proceedings of the 19th Intersociety Energy Conversion Engineering Conference, August 19 – 24, 1984* (San Francisco, CA: American Nuclear Society, 1984), Paper No. 849251.

Figure 4-5.—Aerial View of a Multi-Megawatt PV Central Station Powerplant Under Construction



SOURCE: ARCO Solar, Inc.

Such systems now are being developed and may be available during the 1990s.

Equipment lifetimes of up to 30 years are anticipated, but they will depend mostly on the lifetime of the modules, the trackers (if they are used) and the PCS, and the lifetimes for all three types of equipment are still uncertain. By far the most important component in this regard is the module; degradation and failures may seriously shorten its life.

Capacity factors will differ noticeably from system to system, depending on the general design features as well as on the location of the system and atmospheric conditions. In this analysis, capacity factors[11] for fixed flat-plate systems vary little–they range from 20 to 25 percent in Boston to 25 to 30 percent in Albuquerque. The capacity factors for tracking flat-plate systems are assumed to range from 30 to 40 percent,[12] though, this has yet to be verified nationwide. The capacity factor for concentrator systems varies by a larger margin by location—from 20 to 25 percent in Boston and Miami, to 30 to 35 percent in Albuquerque.

The modules and the balance of system (BOS) jointly determine capital costs and efficiency. Module cost and efficiency, as discussed above, depends on whether the system utilizes flat-plate modules or concentrator modules. Regardless of module or whether the array is fixed or tracking, BOS efficiencies are likely to fall within the same rough range. The costs of the BOS, however, will vary greatly, depending on whether or not a tracking system is used.

The typical multimegawatt flat-plate module PV station in the 1990s probably will produce electric power with an efficiency between 8 to 14 percent. Capital costs are expected to range between $1,000/kWe and $8,000/kWe in Albuquerque, and higher elsewhere in the country. Installations using concentrator modules should be more efficient-with a 12 to 20 percent efficiency. Capital costs for concentrator modules in Albuquerque should be between $1,000/kWe and $5,000/kWe; costs will be higher in areas with lower levels of direct sunlight.

Cost reductions and performance improvements in PV systems will require the deployment of highly automated processes capable of mass producing cells as well as efficiently producing other components, such as tracking equipment and lenses for concentrators.

Another important element of cell costs will be the cost of silicon. If cell costs are to be driven down, either the quantity of silicon consumed per kilowatt-electrical of cell produced must be reduced; or silicon costs must be lowered either through new production techniques or by an expansion of silicon production capacity. More material-efficient cells are being developed which require less silicon per kilowatt-electrical produced.[13] Efforts are also underway to develop silicon production processes which can produce low-cost silicon. There is a fair chance that these silicon production processes will be successfully developed and available in the 1990s.[14] And evidence indicates that the additional silicon production capacity will be built when needed.[15]

PV plants should have low operating and maintenance costs—probably ranging from 4 to 28 mills/kWh in the 1990s. These estimates are highly uncertain, though, and will only become more definite as more systems are placed in the field. Questions about module lifetimes, tracker problems, and difficulties with the PCS make operating and maintenance (O&M) cost projections uncertain.

Two other areas of uncertainty may increase O&M costs. The first is that dirt accumulating on the modules may reduce their efficiency.[16] Rain

[11] Capacity factor is the ratio of the annual energy output (kWe (AC)) of a plant to the energy output (kWe (AC)) it would have had if it operated continuously at its nominal peak operating conditions.

[12] OTA staff interview with D.G. Schueler, Manager, Solar Energy Department, Sandia Laboratories, Albuquerque, NM, Aug. 7, 1984.

[13] A good discussion of silicon and its importance as a driving force behind the development of alternative PV technologies can be found in: Paul D. Maycock and Vic S. Sherlekar, *Photovoltaic Technology, Performance, Cost and Market Forecast to 199.5. A Strategic Technology & Market Analysis,* op. cit., 1984.

[14] Leonard J. Reiter, *A Probabilistic Analysis o?' .$ilicon Cost* (Pasadena, CA: Jet Propulsion Laboratory, 1983), DOE/JPL/1012.

[15] Robert V. Steele, "Strategies On Poly," *Photo voltaics International,* vol. II, No. 4, August/September 1984, pp. 6-8.

[16] For example, in a module performance evaluation program conducted by the MIT Lincoln Laboratory and the Jet Propulsion Laboratory, "the greatest single cause of power loss has been soil accumulation." (Edward C. Kern, Jr., and Marvin D. Pope, *Development and Evaluation of Solar Photovoltaic Systems: Final Report* (Lexington, MA: MIT, 1983), DOE/ET/20279-240.

has been found to be an effective cleaner, but often the best areas for photovoltaics have little rain. With flat-plate systems, dirt does not seem to be as much of a problem as with concentrators. The second problem is wind damage. Most existing photovoltaics and solar thermal plants have suffered damage from wind blown sand, though methods to prevent this are being developed.

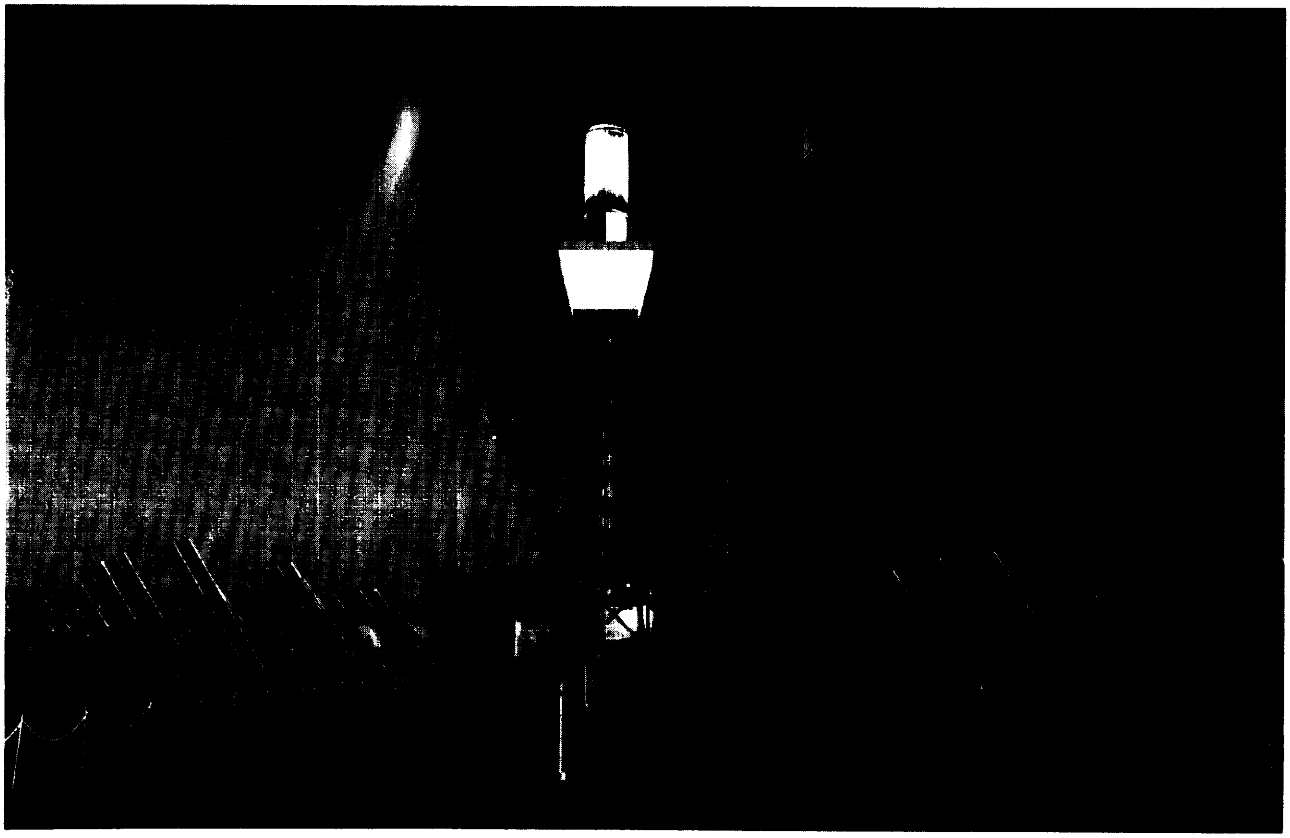
Solar Thermal= Electric Powerplants

Technology Descriptions. -Solar thermal-electric plants convert radiant energy from the Sun into thermal energy, a portion of which subsequently is transformed into electrical energy. Among the systems, there are four which, with some feasible combination of reduced costs and risks and improved performance, could be deployed within the 1990s in competition with other technologies and without special and exclusive Government subsidies. They are central receivers, parabolic troughs, parabolic dishes, and solar ponds. Brief descriptions of these technologies are provided below.

Centra/ Rece;ver.–A central receiver is characterized by a fixed receiver mounted on a tower (see figure 4-6). Solar energy is reflected from a large array of mirrors, known as heliostats, onto the receiver. Each heliostat tracks the Sun on two axes. The receiver absorbs the reflected sunlight, and is heated to a high temperature. Within the receiver is a medium (typically water, air, liquid metal, or molten salt) which absorbs the receiver's thermal energy and transports it away from the receiver, where it is used to drive a turbine and generator, though it first may be stored.

Parabo/ic Dishes. –parabolic dishes consist of many dish-shaped concentrators, each with a re-

F gu e 4 6 The So a One Powe p an



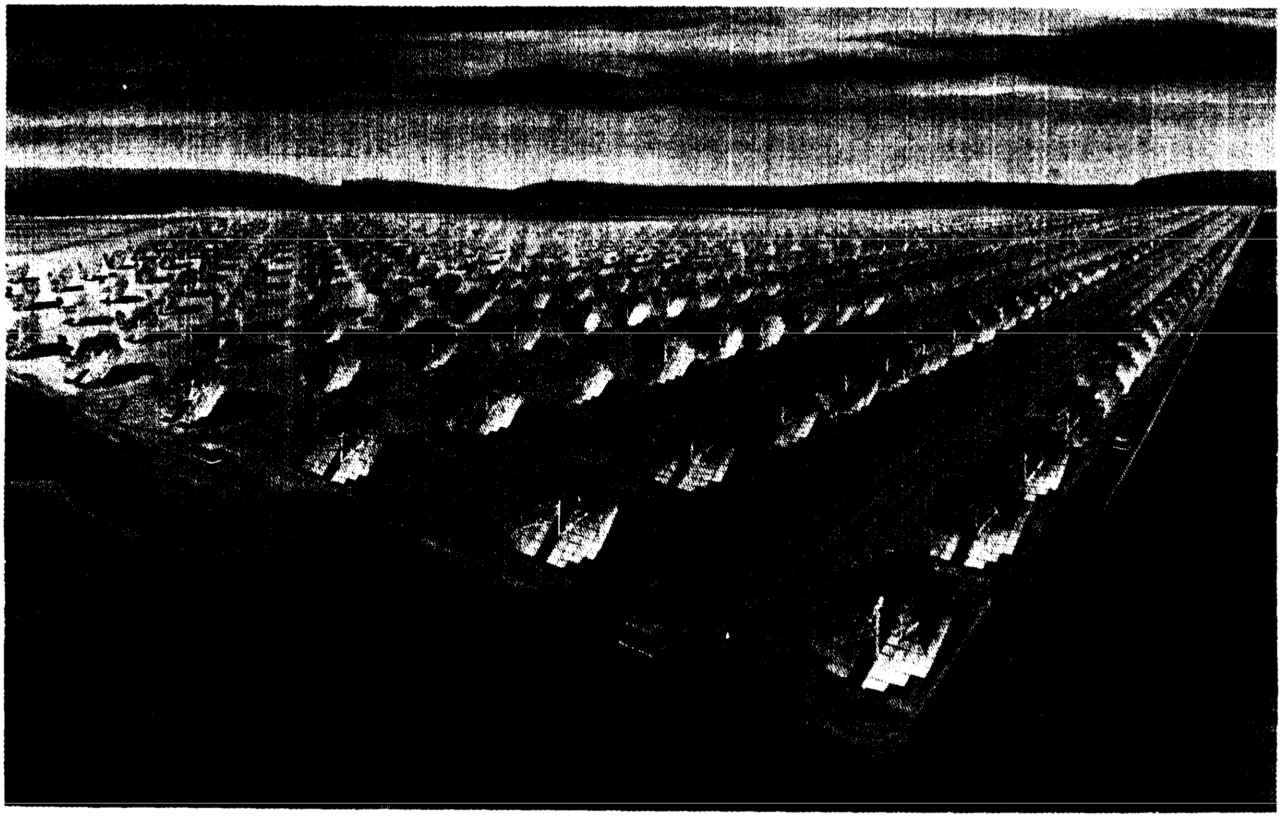
ceiver mounted at the focal point. The concentrated heat may be utilized directly by a heat engine placed at the focal point (mounted-engine parabolic dish); or a fluid may be heated at the focal point and transmitted for remote use (remote-engine parabolic dish). Each dish/receiver apparatus includes a two-axis tracking device, support structures, and other equipment (see figures 4-7, 4-8, and 4-9).

Solar Troughs.–With a parabolic trough, the concentrators are curved in only one dimension, forming long troughs. The trough tracks the Sun on one axis, causing the trough to shift from east to west as the Sun moves across the sky. A heat transfer medium, usually an oil at high temperature (typically 200 to 400° C), is enclosed in a tube located at the focal line. The typical installation consists of many troughs (see figure 4-1 O).

The oil-carrying tubes located at their focal lines are connected on each end to a network of larger pipes. The oil is circulated through the tubes along the focal lines, flows into the larger pipes, and is pumped to a central area where it can be stored in tanks or used immediately. In either case, it ultimately passes through a heat exchanger where it transfers energy to a working fluid such as water or steam which in turn is routed to a turbine generator. At the Solar Energy Generating units in southern California, the only large trough installations in the United States, the oil's heat is supplemented with a natural gas-fired combustion system to obtain adequate steam temperatures to drive the turbine. After passing through the steam generator. The oil is used to preheat water destined for the steam generator; the oil may be returned to the trough field.

So/ar Pond.–In an ordinary body of open water, an important mechanism which influences the thermal characteristics of the reservoir is natural convection. Warmer water tends to rise to

Figure 4-7.—An Artist's Conception of a Multi-Megawatt Parabolic Dish Installation



SOURCE: McDonnell Douglas Corp. brochure.

F gu e 4 8 V ew o he LaJe Ene gy Co s So arp an n Sou he n Ca o n a

F gu e 4 9 An Emp oyee o he LaJe Ene gy Co nspec ng One o he 24 M o s Wh ch A e Assemb ed Be ow Each nd dua Rece e

the surface; and if the water is warmer than the ambient air, it tends to lose its heat to the atmosphere. A solar pond (see figure 4-11) is designed to inhibit this natural process. The creation of three layers of water, with an extremely dense layer at the bottom and the least dense layer at the top, interferes with the movement of warmer bottom waters toward the surface. Salt is used to increase the density of the bottom layer, forming a brine, to the point where its temperature can go as high as 227° F. The heat in this bottom layer can then be drawn off through a heat exchanger, where the brine transfers its heat to an organic working fluid which in turn can drive an engine to produce electric power.

General Overview.–Within most of the above mentioned technologies, many variations now exist or could exist. The discussion here is confined to those variations which appear to affect prospects for solar thermal-electric systems in the 1990s. The discussion is intended to be a brief survey rather than exhaustive examination of the technologies.

Each technology is characterized by a particular set of advantages and disadvantages (see table 4-3) which together define its prospects this century. All of the technologies share a principal disadvantage in that costs and performance are currently uncertain. The level of uncertainty can only be reduced sufficiently as commercial-sized units are deployed and operated. In some cases, research and development hurdles must still be solved before commitments are likely to be made to early commercial units, Until this occurs, the chances for widespread commercial application for any one technology during the 1990s are quite small, regardless of the technology's ultimate promise. At least one operating system is required to reduce cost and performance uncertainty to a level where it no longer is a primary impediment to extensive investment; and perhaps several units—including early commercial units—would be necessary. The time and expense associated with these early demonstration and commercial units are critical elements in determining the commercial prospects of the solar thermal technologies in the 1990s.

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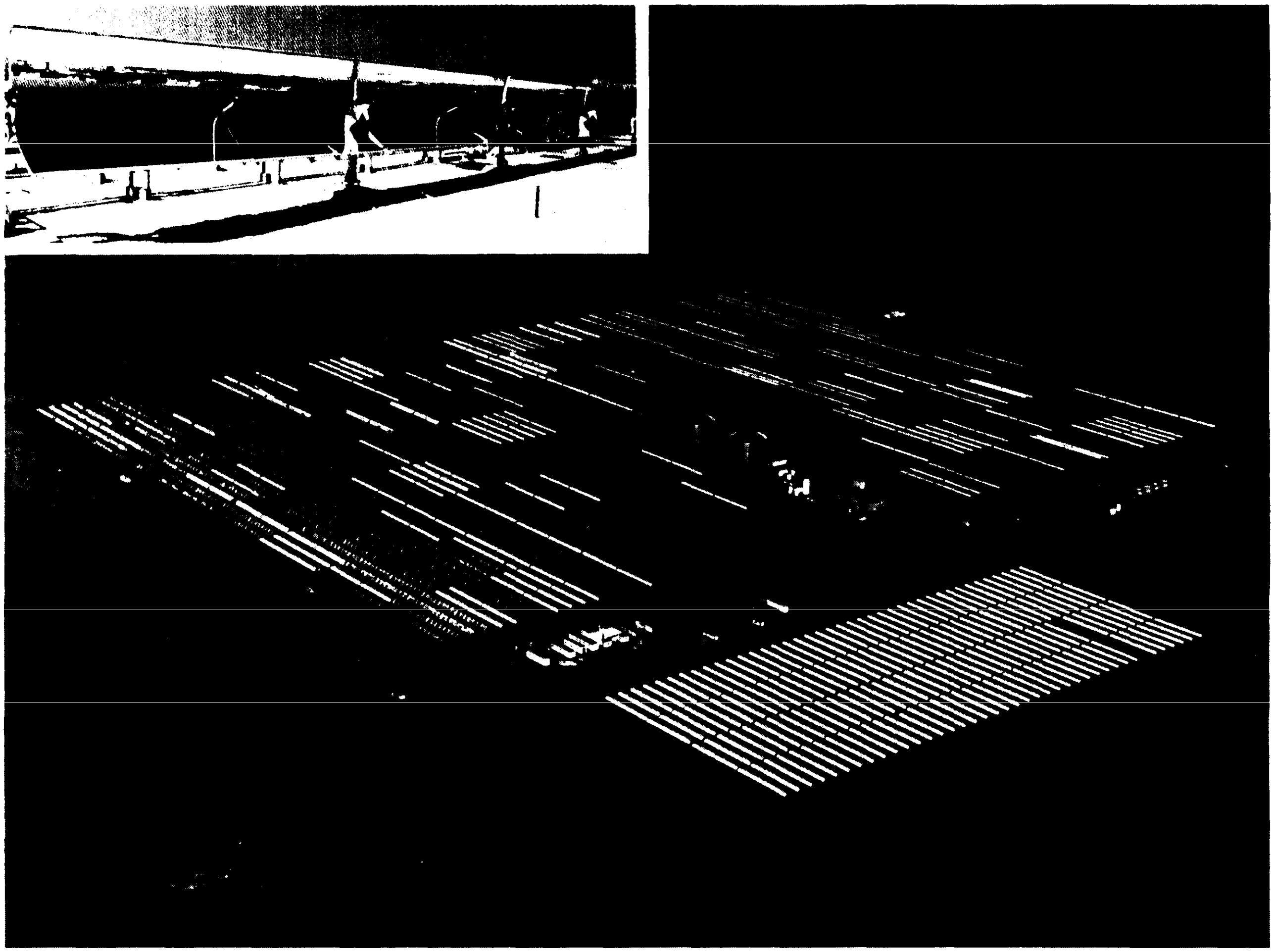

SOURCES: Southern California Edison Co. and LUZ Engineering Corp

While the need to reduce uncertainty is of prime importance, efforts to improve cost and performance through continued research and development also could enhance the prospects for the technologies in the 1990s. The primary R&D needs are different for each technology though generally efforts directed towards the development of low-cost, durable, and efficient concentrators, receivers, and heat engines are most important. '[7] Also very important will be the need for adequate data on the solar resource across the country.[18]

Solar Ponds and Centra/ Receivers.– Neither solar ponds nor central receivers appear to require major technical breakthroughs before they can be commercially applied. But because no commercial-scale solar ponds or central receivers are now operating in the United States, because none are now under construction in this country, and because of the long lead-times expected for the installations, it will be very difficult to deploy enough demonstration and early commer-

'7More detailed information on R&D needs for solar thermal technologies can be tou nd in Sandia National Laboratories, U.S. Department of Energy, *Fi\ e Year Research and Development Plan 1985-1989,* draft (Livermore, CA: Sandia National Laboratories, December 1984); and Edw a rd 1, t+. Li n, *A Re\ iew of the Salt Gradient Solar Pond Technology* (Pasadena, CA: Jet Propulsion Laboratory, 1982), DOE/SF-2 2252-1

18B.p.G u pta, *Solar Thermal Research Program,* Annual Researc h Plan, Fiscal Year 1985 (Golden, CO Solar Energy Research I nsti - tute, 1984).

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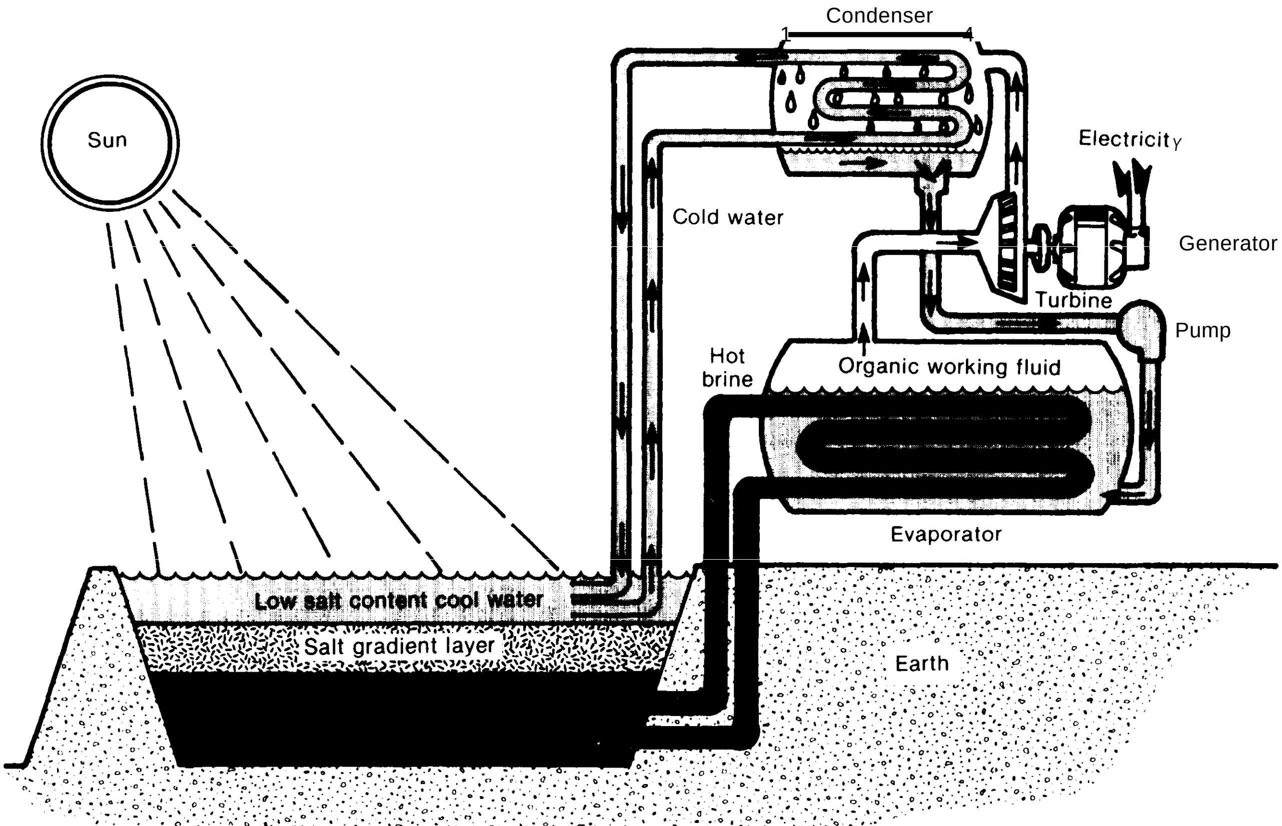
Figure 4-il.—Solar Pond Powerplant Concept



SOURCE: E. I. H. Lin and R. L. French, *Regional Applicability and Potential of Salt-Gradient Solar Ponds in the United States* (Pasadena, CA: Jet Propulsion Laboratory, 1982).

Table 4-3.—Advantages and Disadvantages of Solar Thermal Electric Systems

	Technology				
Characteristic	Solar ponds	Solar troughs	Parabolic dishes (mounted-engine)	Parabolic dishes (remote engine)	Central receiver
1. Demonstrated in U.S. at commercial scale?	No (–)	Yes (+)	Yes (+)	Yes (+)	No (–)
2. Privately financed plants now operating?	No (–)	Yes (+)	No (–)	Yes (+)	No (–)
3. Nonelectric/repowering/cogeneration market?	Yes (+)	Yes (+)	No (–)	Yes (+)	Yes (+)
4. Overall efficiency	very low (–)	low (–)	high (+)	low (–)	med (0)
5. Number of engines/kWe	low (+)	low (+)	high (–)	low (+)	low (+)
6. Degree of modularity	low (–)	low (–)	high (+)	low (–)	low (–)
7. Able to use indirect or diffuse sunlight?	yes (+)	no (–)	no (–)	no (–)	no (–)
8. Thermal storage capability of 1 hour or more?	yes (+)	yes (+)	no (–)	yes (–)	yes (+)
9. Supplementary fuel required?	no (+)	yes (–)	no (+)	no (+)	no (+)
10. Water requirements	high (–)	med (0)	low (+)	med (0)	med (Ž)
Total, all categories:					
+ (major advantages)	5	5	5	5	5
– (major disadvantages)	5	4	5	4	4
• (moderate advan/disadvan)	0	1	0	1	2
Total, categories 3-10:					
+ (major advantages)	5	3	4	3	4
– (major disadvantages)	3	4	4	4	2
• (moderate advan/disadvan)	0	1	0	1	2

SOURCE: Office of Technology Assessment

cial units quickly enough to sufficiently reduce uncertainty about cost and performance. Furthermore, the expense of such early units is high enough that it is very unlikely that any entity or group of entities outside of government presently would invest in such units without special government incentives. In short, the time and expense associated just with reducing risks for these two technologies strongly mitigate against the provision of sizable amounts of electric power by the technologies within the 1990s. It is likely that only a sizable and immediate government intervention to encourage rapid deployment of demonstration units and subsequent units could reduce uncertainty to the point where it no longer is a major impediment to commercial investment in the 1990s.

Should such intervention occur and if the potential advantages of the solar ponds and central receivers are realized, both technologies offer favorable balances of advantages and disadvantages which could stimulate considerable private investment in the 1990s. Between the two technologies, the central receiver probably would be most widely deployed. Solar ponds must be located in areas where land, water, and salt are plentiful. Such sites are far less common than the sites available to central receivers, which require considerably less land, less water, and do not require such large quantities of salt. Siting options therefore are greater with the central receiver. [19]

Furthermore, the central receiver is a more mature technology. A 10 MWe (net) pilot facility, Solar One, has operated successfully in southern California since 1982; and a small experimental facility, rated at 0.75 MWe (gross) has been operated in New Mexico .*" Small central receivers also have been built and operated overseas, but no solar pond has ever produced electric power in the United States. However, a 5 MWe unit is in operation in Israel and several ponds have been built and operated in the United States and elsewhere for applications other than the production of electricity. The solar pond *concept* however is considered to be well established and the successful commercial deployment of the technology is not expected to require any major technical breakthroughs. *1

Parabolic Troughs and Dishes.– Unlike the ponds and central receivers, parabolic dishes and parabolic troughs already have been deployed in commercial-scale units. Indeed, commercial installations financed by private investors assisted by the Renewable Energy Tax Credits now are operating. Further demonstration and early commercial units are being planned over the next 5 years, though the extent to which the plans are realized depends heavily on Government tax policies or funding, As current units continue to operate, and as new units are added, the level of uncertainty and risk associated with the technologies will continue to drop.

At present, the **parabolic trough is the most mature of the solar thermal electric technologies, with commercial units operating, under construction, and planned. Nearly 14** MWe (net) of privately financed capacity already is operating in southern California at the Solar Electric Generating System-1 (S EGS-I); an additional 30 MWe (net), the Solar Electric Generating System-n (SEGS-11), now is being built. Additional capacity— 150 MWe or more—may be added by early 1989. if the energy tax credits are extended in some form. Whatever the case, by 1990 more commercial experience will have been logged with this technology than any other solar thermal-electric alternative. The resultant low level of risk will constitute an important advantage for this technology. Other important advantages will be the technology's inherent storage capacity and the relatively wide variety of markets to which it could be applied—including industrial process-heat applications.

[19] For a discussion of the solar pond's prospects in California, and of the limitations regarding sites, see Marshal F. Merriam, *Electricity Generation from Non-Convective Solar Ponds in California* (Berkeley, CA: Universitywide Energy Research Group, December 1983), UER-109,

[20] John T. Holmes, "The Solar Molten Salt Electric Experiment, " *Advanced Energy Systems–Their Role in Our Future: Proceedings of the 19th Intersociety Energy Conversion Engineering Conference,* Aug. 19-24, 1984, (San Francisco, CA: American Nuclear Society, 1984), Paper 849521,

21 See: 1) Massachusetts Institute of Technology, *A State-of-the-Art Study of Nonconvective Solar Ponds for Power Generation* (Palo Alto, CA: Electric Power Research Institute, January 198S), EPRI AP-3842. 2) Edward I.H.Lin, *A Review of the Salt Gradient Solar Pond Technology,* op. cit., 1982,

But the troughs are saddled with several serious disadvantages which to some extent will constrain deployment. The technology's low efficiency is its most serious disadvantage. Another is the need by the SEGS units for a supplementary fuel such as oil or gas, and for considerable volumes of water. Finally, the system of conduits through which the heat-absorbing oil flows may develop problems or the oil itself may degrade at an excessive rate; these potential problems have not yet materialized at the SEGS-I installation, but further operating experience is required before long-term performance can be proven.

Two types of **parabolic dishes may be deployed in the 1990s: the mounted-engine parabolic dish and the remote-engine parabolic dish. Each offers many design options.** The primary advantages of the mounted-engine units are their high efficiencies, low water consumption, and ability to operate without supplemental fuel. The small size of the basic electricity-producing module also carries with it advantages. The system may be installed in many sizes, and multi module installations may produce electric power long before the full installation is completed; individual modules or groups of modules may begin operating while others are being installed. Together these advantages provide the technology with considerable siting flexibility and potentially very short lead-times.

The largest disadvantage of the mounted-engine unit is the relatively high level of uncertainty about its performance, and the possibility that the engines may require an excessive amount of maintenance. Only three commercial-scale demonstration units—at about 25 kWe (net) each—had been deployed by May 1985, and few are scheduled to be deployed by 199o; no commercial installation yet exists, or is under construction. Other disadvantages include the lack of storage capacity and the inability to readily adapt the technology to cogeneration or nonelectric applications.

The remote-engine dishes, like the troughs, enjoy the advantage of being used at present in a commercial installation. A 3.6 MWe system, built by LaJet, Inc., now is operating in southern California. Also, like the troughs, the remote-engine technology may use as few as one or two engines; engine-related O&M costs therefore could be much lower than those of the mounted-engine parabolic dishes. The remote-engine technology in addition may be easily used for nonelectric applications. The LaJet design at present does not require a supplemental fuel.

But the remote engine technology is inefficient; much heat is lost as the heat transfer fluid is pumped from the collector field to the turbines. Also, the system has little storage capacity; electricity production therefore cannot be deferred for very long. And unlike the mounted-engine units, the remote-engine technology consumes sizable volumes of water.

Both dishes and troughs suffer from the same serious problem—they lack the cost and performance certainty which can only be gained through more commercial-size operations. This mitigates against private sector investment which is not in some manner accompanied by government support. At the current pace, it is uncertain whether the situation will change over the next 5 to 10 years.

Generally, capital costs will have to be reduced and performance improved if the technologies are to be deployed. To some extent this can be fostered by research oriented towards incremental improvements of the commercial-scale systems now operating. The most useful research would concentrate on low-cost, durable, and highly reflective reflector materials and inexpensive, long-lasting receivers and engines. But if the technologies are to be extensively deployed in the 199os, the greatest overall need is to reduce uncertainty and thereby increase demand to the point where economies of scale can drive costs down.

By virtue of the fact that commercial-scale systems now are operating for troughs and dishes, the level of cost and performance uncertainty among the troughs and dishes will be considerably lower than the uncertainty associated with the central receiver and ponds in the 1990s. Between troughs and dishes, uncertainty will be lowest for troughs, highest for the mounted-engine dishes, and somewhere in between for remote-engine dish systems.

The mounted-engine dishes, in particular could benefit from greater deployment of commercial-scale units. A considerable reduction in uncertainty and greatly improved commercial prospects might result. Under such conditions, the mounted-engine parabolic dishes could eliminate the current lead enjoyed by parabolic troughs among the solar thermal technologies. If the engines perform well, the parabolic dish technology could well become the prevalent choice for solar thermal electricity production in the 1990s.

Typical Solar Thermal-Electric Installation for the 1990s.—The precise cost and performance of the solar thermal-electric systems in the 1990s will vary widely according to system design, location, overall market size, risk, and many other factors. No attempt here is made to fully discuss the cost, performance, and uncertainty of all the many solar thermal technologies. Rather, a single technology–the mounted-engine parabolic dish–is examined in fuller detail and used for reference purposes. The cost and performance numbers shown in appendix A, table A-2 for the mounted-engine parabolic dish installation in the 1990s represent reasonable estimates, but obviously should be viewed with caution.

By 1995, mounted-engine parabolic-dish plants might account for up to 200 MWe of installed capacity, The deployment level depends mostly on the extent of Government support over the next 5 to 10 years–primarily the Renewable Energy Tax Credit—and avoided cost rates.

The reference plant used in this analysis consists of 400 electricity producing modules, each independently tracking the Sun and producing electric power. The plant would have a gross capacity of 10.8 MWe and a net capacity of 10.2 MWe–the 0.6 MWe difference goes primarily to driving the tracking motors which keep the dish properly oriented toward the Sun during the day, and to cooling the engine. Other equipment required on the site include a central control unit, electric power subsystems, buildings, maintenance facilities, and other equip ment.[22]

The amount of time required to build the plant should be very short, perhaps 2 years. The greatest uncertainty in this estimate lies with permitting and licensing. A large area of land—approximately 67 acres—would be required for the installation; the impacts of the development would be extensive. The most obvious impact would be visual, arising from the modules, roads, and transmission lines (see figure 4-7). Serious impacts on the soil and vegetation of the area could also occur. Installations in the 1990s **probably would be concentrated in arid areas which have fragile soil and plant communities. Regulatory delays could result from concerns over all these impacts. Indeed,** such problems reportedly have delayed the planned expansion of LaJet's Solarplant 1 facility in southern California (see box 7B in chapter 7).

The overall operating availability[23] of the installation could be quite high for several reasons. Routine maintenance could be conducted at night. Should a module not be working during the day, its incapacity would not impede the operation of other modules. As long as large numbers of unpredictable failures do not occur (as for example might happen after a severe and damaging storm), then high operating availabilities for the system as a whole can be maintained. The reference system used in this analysis is characterized by operating availabilities of 95 percent.

The expected plant lifetime is 30 years. Many of the components are relatively simple and durable. The power conversion unit (PCU) located at the focal point, which uses relatively unproven technology, is the component which creates the greatest uncertainty about plant lifetime, It is anticipated, however, that with a regular and perhaps expensive maintenance pregram, this uncertainty can be greatly reduced, although further development is needed to assure this.

[22]Where Stirling engines are used, the other equipment includes systems which pressurize hydrogen for use in the Stirling engines,

[23]Operating availability here refers to the average percentage Of modules capable of operating between sunrise and sunset. A 95 percent availability indicates that during the average day, 5 percent of the modules are not operating.

Wind Turbines

Introduction

A wind turbine converts wind into useful mechanical or electrical energy. Wind turbines may be classified according to the amount of electricity they generate under specified wind conditions. A small turbine generates up to 200 kWe, an intermediate-sized turbine can deliver from 100 to 1,000 kWe, and a large system may produce more than 1 MWe.

Since the early 197os, the development of wind technologies for electric power production has followed two relatively distinct paths–one directed towards small turbines and the other towards the large machines. As the efforts relating to the large turbines bogged down with technical and economic problems, the small turbines —aided by State and Federal tax incentives— progressed very rapidly. In the early 1980s, wind turbines were extensively deployed, mostly in California, where 8,469 turbines were operating by the end of 1984. The total capacity of these units was approximately 550 MWe. Almost all were erected at windy locations, in clusters called "wind farms. " By the end of 1984, many thousands of wind machines, with a total installed capacity of over 650 MWe, were producing electric power in the United States, and almost all were small turbines (see figure 4-l 2).

As operating experience accumulated with the small machines, both manufacturers and investors began to gravitate towards intermediate-sized machines. By the end of 1984, intermediate-sized machines were being deployed in small numbers. It is widely believed that if large numbers of wind turbines are to be manufactured and deployed in the 1990s, in free competition with other generating technologies, intermediate-sized machines probably will be favored over both small and large machines. Only the intermediate-sized machines promise sufficiently cheap power without imposing unacceptable risks (figure 4-13 illustrates a intermediate-sized vertical-axis wind turbine).

While it appears that the total installed capacity of wind turbines in the United States may exceed 1,000 MWe by 1985, the rate of subsequent deployment is a matter of speculation. Given the short time within which a wind farm can be deployed and operated–from 1 to 2 years, excluding wind data gathering—growth u rider favorable circumstances could be extremely rapid. it is possible that the market potential for wind turbines could be as high as 21,000 MWe for the 1990-2000 period.[24]

The areas most favored for wind farms are those with good wind resources, heavy reliance on oil or gas, and with an expected need for additional generating capacity. They are located mostly in California, the Northeast, Texas, and Oklahoma. There are, however, less extensive but nevertheless promising opportunities elsewhere in the country, especially in parts of the Northwest, Michigan, and Kansas.[25] Most–though not all–

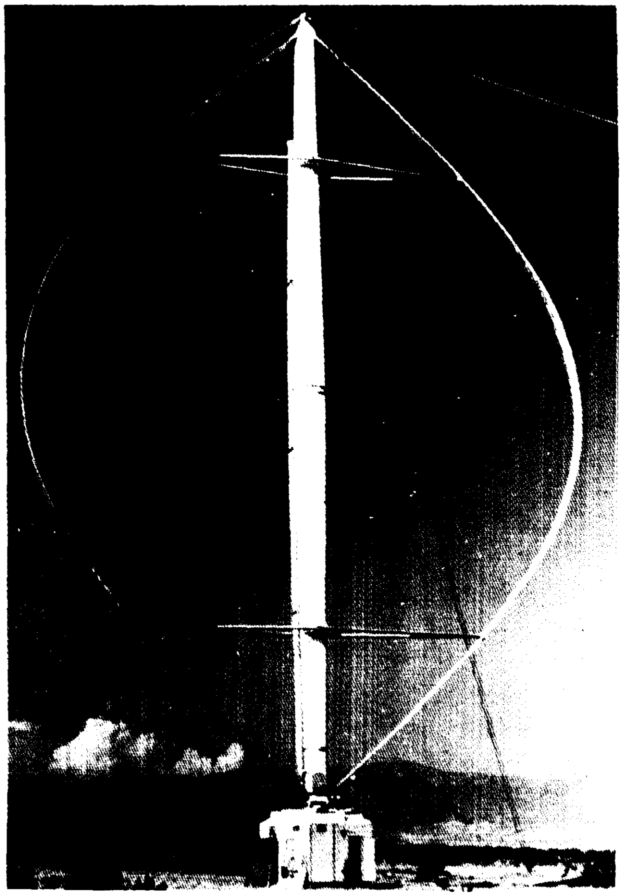
Figure 4-12.—Maintenance Crews Performing a Routine Inspection of a Small Wind Turbine

SOURCE: U.S. Windpower, Ed Linton, Photographer

[24]Science Applications International Corp., *Early Market Potential for Utility Applications of Wind Turbines, Preliminary Draft* (Palo Alto, CA: Electric Power Research Institute, December 1984), EPRI Research Project 1976-1.

[25]Ibid.

Figure 4-13. —A 500 kW Vertical"Axis Wind Turbine



SOURCE Southern California Edison Co.

turbines probably will continue to be installed in relatively large wind farms rather than individually or in small clusters. Figure 7-10 in chapter 7 indicates the distribution of the wind resource and the areas of the United States where wind development is most favored.

A Typical Wind Farm in the 1990s

The reference wind farm used in this analysis is summarized in appendix A, table A-4. A typical wind farm in the 1990s may consist of up to several hundred, 200 to 600 kWe wind turbines; the reference wind farm consists of 50 turbines with ratings of 400 kWe each. Installations could vary widely in the number of turbines deployed or in their exact ratings. But based on current projections, the important cost and performance characteristics would be common to the average facility considered by investors during that decade.

In addition to the turbines themselves, related equipment will be necessary at the site, including power conditioning equipment, system protection devices, security fencing, metering devices for measuring turbine output, wind measuring equipment for monitoring site conditions and equipment performance, control buildings, and a fabrication yard where equipment is stored and assembled .[26]

The turbines of the reference wind farm would be distributed over an area of anywhere from 300 to 2,000 acres, depending on the topography, prevailing wind direction, the shape and orientation of the property on which the farm is located, and the size of turbines being used. The turbines are spaced to avoid excessive interference with each other. Because installation and maintenance of the turbines requires vehicular access, at least one road leads to a wind farm and to each individual wind turbine (see figure 4-14) unless topography, surface characteristics, and regulations allow access without roads. Since the performance of the turbines and the cost of their power depends directly on wind exposure, all major obstructions such as trees would be removed.[27]

It is evident that the major environmental impacts of wind farms will result from their initial construction as well as from their high visibility, their extensive road networks, and from the activities of maintenance crews on the roads and around the turbines.[28] Among the other impacts, the severity of which may be assessed less readily but which nevertheless are considered potentially serious, are those associated with the noise created by turbine operation.

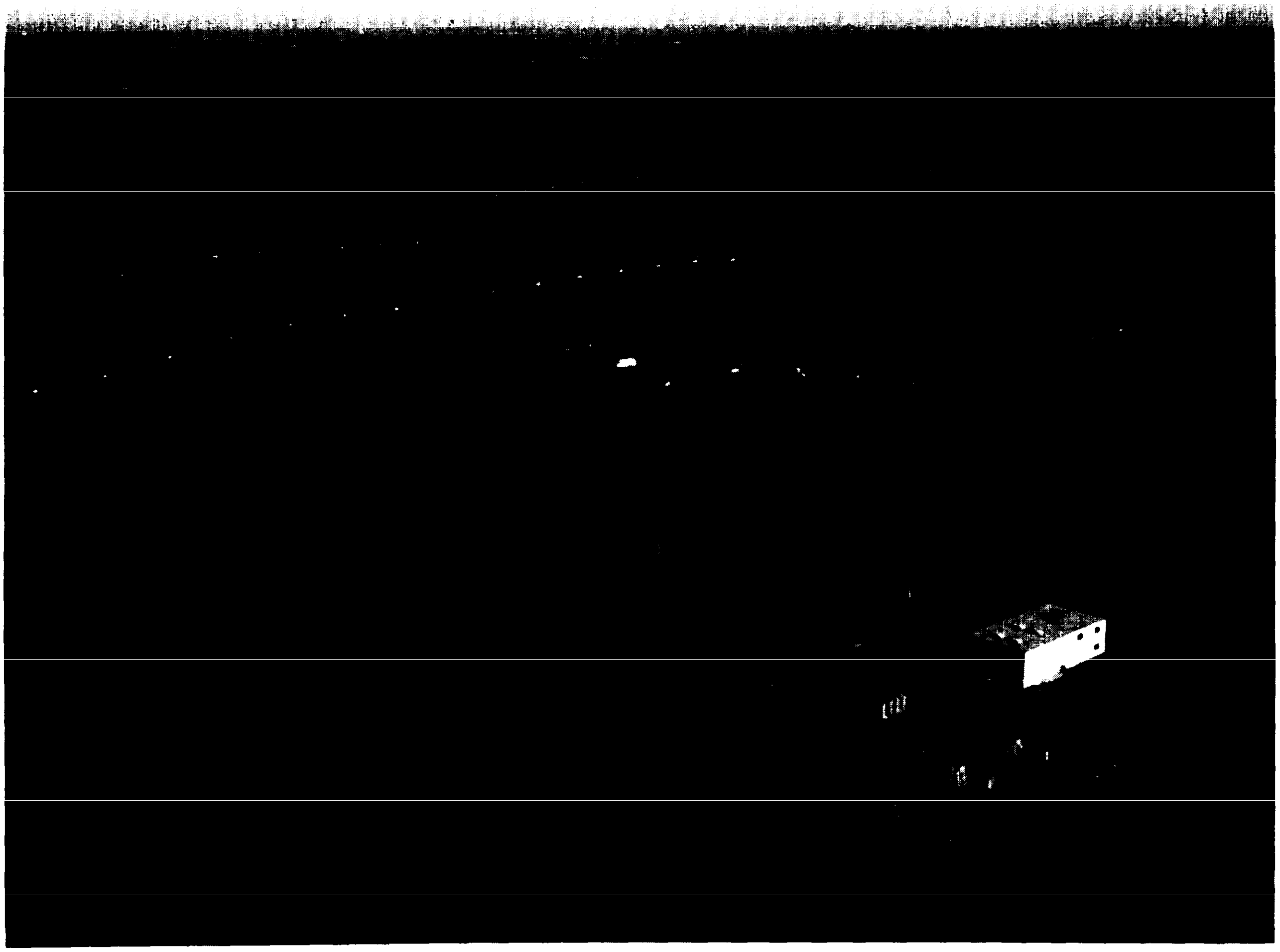
Concern over environmental impacts could seriously delay the deployment of wind turbines.

[26]Sam Sadler, et al., *Windy Land Owners' Guide* (Salem, OR: Oregon Department of Energy, 1984), p. 17,

[27]It should be noted that many prime wind sites, being exposed to frequent high velocity winds, are inhospitable environments for trees and therefore frequently are devoid of large, upright trees which could be considered serious obstructions.

[28]"Wind Farms, Timber Logging May Have Similar Environmental Impacts, Harvard's Turner Says, " *Solar Intelligence Report*, Nov. 26, 1984, p. 375,

Figure 4-14.—Aerial View of a Wind Farm in the Altamont Pass in California



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W nd Fa m Perfo man e O m
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m p d m h d
g d p g b
h q h b w d d
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sited in windy areas. Under these favorable conditions, typical capacity factors between 20 and 35 percent are expected in the 1990s as the intermediate-sized turbine technology matures.

As the performance of wind turbines improves and is better understood, one especially large uncertainty still remains in estimating the annual outputs of turbines in the 199os: the quality of the wind resource to which the turbines will be applied. Today's turbines are exploiting some of the best wind resources available. But new sites will be required, and the average quality of new sites probably will decline. High capacity factors will be progressively more difficult to maintain. At present, it is difficult to predict what wind regimes will characterize new sites exploited in the 1990s, because sufficiently detailed, site-specific wind data are not yet available in most instances. Information is accumulating, however, and it suggests that there remain considerable areas of land available with high-quality wind resources.

The lifetime of a wind farm is somewhat difficult to determine because individual turbines and even components of turbines can be replaced as needed; in a sense, the wind farm itself can outlive any of its individual components. Generally, the components of a wind farm in the 1990s will be designed to last 20 to 30 years, though some key components–such as the rotor–may fail and be replaced before that time.

Wind Farm Costs.–The average capital cost for wind turbines installed on California wind farms in 1984 was $1,860/kWe.[29] This capital cost however is heavily inflated as a result of the financing arrangements associated with current projects; one observer has estimated that in fact actual costs would be closer to $1,330/kWe if the financing mechanisms typical of utilities were used.[30]

The capital costs of the typical wind farm in the 1990s may range from $900 to $1,200/kWe. The reduced capital cost will result both from design improvements and from the more competitive market expected when the current favorable tax treatment is phased out. Termination or phase-out of the Federal and California State tax credits, for example, would very likely contribute to decreases in the capital costs.

Operating and maintenance costs for the wind farms of the 1990s could range between 6 and 14 mills/kWh. Available evidence indicates that costs for small turbines in 1984 ranged between 15 and 25 mills/kWh.[31] The high O&M costs which thus far have been incurred can be attributed to the fact that the first generations of machines, those deployed in the early 1980s, were plagued with mechanical problems. Changes in two areas will stimulate the reduced O&M costs: smaller numbers of turbines per kilowatt-hour generated and improved turbine design, Of central importance will be the maintenance of high operating availability.

An important cost associated with wind-generated electric power is the cost of access to the wind itself—if indeed access can be gained at any cost. The fee charged by the landowner typically is either in the form of a minimum rent, royalty payments, or some combination of the two.[32] Costs of access have increased substantially; landowners have already begun to appreciate the value of prime sites, particularly in California.[33] There, in 1984, annual land charges commonly amounted to 6 to 13 percent of gross revenues from the sale of the electricity over the lifetime of the contract negotiated between the developer and the landowner.[34]

The prospects for wind turbines in the 1990s would be enhanced by research and development. Among the most important R&D items are the need to better understand turbulence and predict its effects; to more readily and accurately

[29]Conversation between Mike Batham, California Energy Commission, and OTA staff, Feb. 5, 1985. See also "California Adds 366 MWe of Wind Capacity; Size, Capacity Factor Up," *Solar Energy Intelligence Report,* Jan. 28, 1985, p. 30.

[30]Donald A. Bain, Wind Energy Specialist, Renewable Resources, Oregon Department of Energy, conversation with OTA staff, June 11, 1985.

[31]"Wind Turbine Operating Experience and Trends," *EPRI Journal,* November 1984, pp. 44-46.

[32]For a discussion of the determination of wind resource value and contractual arrangements see: Sam Sadler, et al., *Windy Land Owners' Guide,* op. cit., 1984.

[33]Teknekron Research, *Cost Estimates and Cost-Forecasting Methodologies for Selected Non-Conventional Electrical Generation Technologies* (Sacramento, CA: California Energy Commission, May 1982).

[34]Conversation between Mike Batham (California Energy Commission) and OTA staff, Nov. 30, 1984.

model structural dynamics; to better predict noise problems; to accurately model wind farm cost and performance; and to develop, test, and characterize materials and components. The development of cheap, reliable, and accurate wind measurement instruments as well as better understanding and prediction of the wind's characteristics also are needed. Detailed and accurate assessments of the wind resource nationwide are necessary too.[35]

Geothermal Power

Introduction

Geothermal energy is heat stored beneath the Earth's surface. The U.S. Geological Survey (USGS) estimates as much as 1.2 million quads (a quad is 10^{15} Btu and is equal to 293 billion kWh) of accessible geothermal resources underlie 3.4 million acres of U.S. land, mostly within the western third of the country.[36] Only a small portion of the resource—approximately 3.8 percent of the total—occurs as hydrothermal resources—superheated water contained in a permeable rock formation and trapped below a layer of impermeable rock. The locations of major hydrothermal resources in the United States are provided in figure 7-9 of chapter 7. Steam (vapor-dominated resources) or water (liquid-dominated resources) convectively circulates towards the surface within the permeable rock formation. It is the hydrothermal resources which will continue to provide most of the geothermal electric development in the 1990s.

The temperature and quality of hydrothermal resources vary greatly. While a portion of the hydrothermal resource is very hot, most—roughly two-thirds of the identified resources—are in the moderate temperature range (1 50 to 250°F).[37] Geothermal development has in the past focused on the high-quality, vapor-dominated reservoirs, which are confined to limited areas of the United States,

The equipment required to exploit these high-quality resources is commercially available, and no major changes in the basic characteristic of the technology is likely during this century. There are available improved technologies, however, which not only could more economically exploit the high-quality resource, but also may economically tap the much more plentiful resources of lesser quality. Among these are single-flash, dual-flash, binary, and total flow systems.

The single-flash technology has been commercially deployed in the United States. Because this analysis focuses on technologies which are not already technologically mature, the single-flash technology will not be examined here. The total flow systems also will not be discussed, since they either require considerable further technical development, or will be applied only to a small number of high-quality sites i n the United States. The total flow systems therefore are unlikely to constitute more than a small fraction of geothermal capacity additions in the 1990s. The dual-flash and binary systems will constitute the most important new technologies applied to the liquid-dominated geothermal resource in the 1990s, and, therefore, are the subject of this analysis.

Geothermal Power Technology

Before the resource is exploited to produced electric power, it must be located and assessed. This itself is a time-consuming, expensive process involving its own particu tar set of technologies and problems. Ultimately, resource assessment requires building roads, transporting drilling equipment to the site, constructing the rigs and drilling. Once the resource has been satisfactorily measured, the thermal energy next must be brought to the surface where it can be used. This too involves particular technologies and difficul-

[35] For a more detailed discussion of R&D needs and plans, see: 1) Solar Energy Research Institute, *Wind Industry R&D Planning Workshops: Summary Report* (Washington, DC: U.S. Department of Energy, July 1984. 2) State of Oregon, Department of Energy, *Final Report of the Wind Energy Task Force To the Oregon Alternate Energy Department Commission* (Salem, OR: Oregon Department of Energy, 1980), pp. 50-52. 3) U.S. Department of Energy, Wind Energy Technology Division, *Federal Wind Energy Program: Five Year Research Plan, 1985-1990 (Draft)* (Washington, DC: U.S. DOE, 1984).

[36] U.S. Geological Survey (USGS), *Assessment of Geothermal Resources of the United States—1978*, L.J.P. Muffler (ed.) (Washington, DC: U.S. Department of the Interior, 1979), USGS circular 790.

[37] M. Nathenson, "High-Temperature Geothermal Resources in Hydrothermal Convection Systems in the United States, " *Proceedings of the Seventh Annual Geothermal Conference and workshop*, Altas Corp. (cd.) (Palo Alto, CA: Electric Power Research Institute, 1983), EPRI AP-3271 , pp. 7-1 to 7-2.

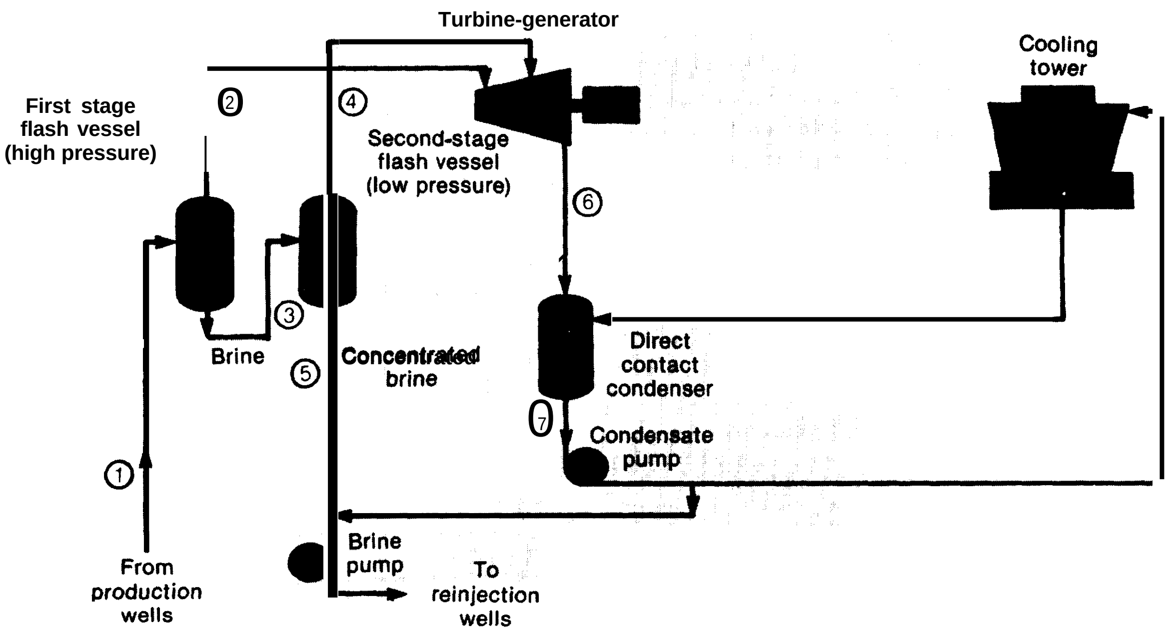
ties. An especially important technological hurdle which remains to be satisfactorily overcome is the development of cheap, reliable "downhole" pumps capable of moving the brine from the underground reservoir, and subsequently reinfecting it. While the brine is at the surface, a portion of its thermal energy is drawn off and used to produce electric power.

Dual-Flash Systems.–Figure 4-15 illustrates the typical dual-flash unit. When liquid-dominated, high temperature brine–300 to several thousand pounds per square inch (psia) and 410 to 6000 F —reaches the surface, a portion of the brine "flashes" into steam. First, a high pressure flash-tank processes the geothermal brine into saturated steam and spent brine, The steam enters one inlet of a dual-inlet turbine, while the unflashed brine goes on to a second, lower pressure flash-tank. The second-stage flash-tank produces further steam which is routed to the other inlets of the turbine. The remaining unflashed brine then is reinfected underground.

After exiting the turbines, the steam passes through a condenser, where it transfers its heat to a stream of cooling water. The cooling water is then routed to a cooling apparatus. Current designs use "wet cooling" devices in which the hot water is sprayed into the air and discharges its heat mostly through evaporation, The remaining water is recirculated to the condenser to repeat the cycle, along with "make-up" water required to compensate for evaporative losses. The condensed steam from the turbine is reinfected into the geothermal reservoir to help maintain reservoir pressure.

The make-up water requirements may be extremely large. The 50 MWe reference plant used in this analysis would require about 3 million gallons of make-up water daily, roughly six times the amount of water required by an atmospheric fluid ized-bed combustor of comparable net generating capacity. The water requirements could be reduced with "dry-cooling" systems; but these are very expensive and reduce the plant's overall efficiency.

Figure 4-15.—Schematic of Dual-Flash Geothermal Powerplant



SOURCE: Peter D. Blair, et al., *Geothermal Energy: Investment Decisions and Commercial Development* (New York: John Wiley & Sons, 1982). Copyright 1982 Reprinted with permission of the publisher.

Alternatively, the water requirement could be greatly reduced by meeting it in part with the condensed steam from the condenser (instead of re-infecting it into the reservoir). This can only be done, however, to the degree allowed by contractual agreements and regulations. The field developer may require that all or part of the condensed steam be reinfected into the geothermal reservoir to maintain the quality of the resource. Or regulators may require some degree of reinfection in order to reduce subsidence problems.

The basic turbine, condenser, and cooling tower subsystem are similar to traditional steam powerplant designs, although there are significant differences. An important factor in the use of flash technology is the existence of noncondensable gases and/or entrained solids in the brine. These contaminants can cause scaling, corrosion, and erosion within the flash equipment, surface piping, and reinfection well casing. Development of highly saline resources has been slowed by these problems. Considerable research has been conducted to develop and demonstrate reliable removal technologies for these resources.

Although, operational dual-flash units abroad total 396 MW,[38] there is little commercial experience with these systems in the United States. None is now operating, and only one 47 MWe (net) dual-flash unit is under construction (see figure 4-1 6). Neverti~eless, the dual-flash system will be used increasingly to exploit moderate to high temperature hydrothermal resources because it is more efficient than the single-flash system .39

Appendix A, table A-5 contains cost and performance estimates for dual-flash units in the 1990s. By the reference year 1995, dual-flash geothermal units will most likely range in size from 40 to 50 MWe. The expense of smaller units would be higher than would in most cases be justified by the advantages they might provide.[40 41]

The units will require little land. Total acreage (including the geothermal wellhead, surface piping, and the powerplant) will not exceed 20 acres for a 50 MW plant. Directional drilling techniques[42] which tap various parts of a reservoir, allow the wellhead and the plant to be confined to a small area.

The total lead-time required to bring a plant online typically should be 3 years, including licensing and permitting. Delays may be occasioned by concern over water requirements and various other environmental impacts. The latter could include atmospheric emissions, pollution or disruption of the watershed, and land impacts resulting from the construction and routine operation of the plant. This lead-time figure assumes that the geothermal resource has already been confirmed and developed, and that transmission facilities are available. Actual construction activity should take 1½ to 2 years. The first dual-flash unit at a resource could take as long as 5 years to establish, due to the initial permits and licenses that would be required.

Geothermal units are designed to operate on base load duty cycles. Operating availability is expected to run between 85 and 90 percent, and capacity factor should be between 75 and 80 percent.[43] The efficiency of geothermal technologies are measured in terms of resource utilization efficiency; i.e., net brine effectiveness—watt-hours per pound (Wh/lb) of steam. Typical net brine

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[38]R. Dipippo, "Worldwide Geothermal Power Development: 1984 Overview and Update," Altas Corp. (cd.), Proceedings of the *Eighth Annual Geothermal Conference and Workshop* (Palo Alto, CA: Electric Power Research Institute, 1984), EPRI AP-3686, pp. 6-1 through 6-15.

[39]The Electric power Research Institute (persona! communication between E. Hughes (EPRI) and OTA staff, Oct. 4, 1984) predicts that most of the planned flash plants at the Salton Sea and Brawley resources will use dual-flash technology.

[40]Based on:

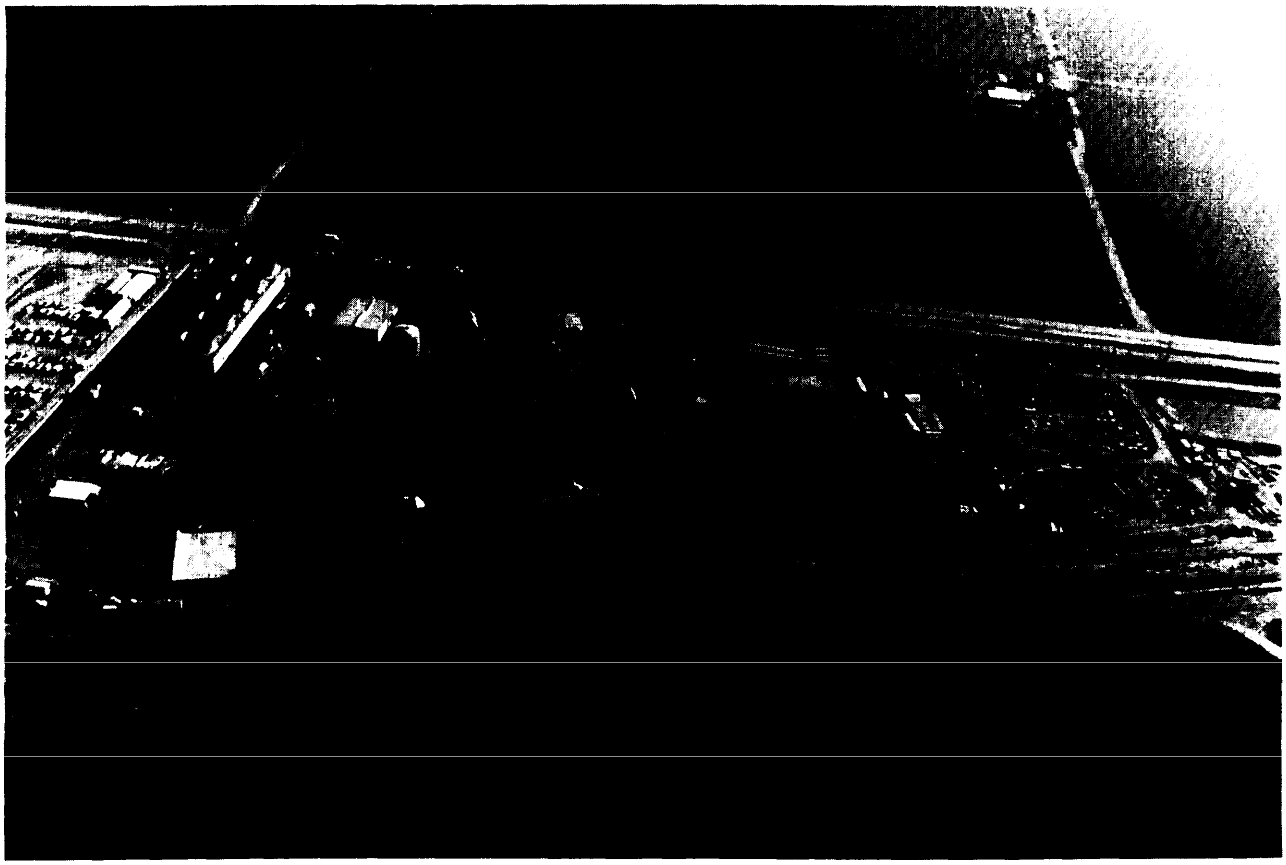
1. *Sourcebook on the Production of Electricity From Geothermal Energy*, J. Kestin (ed.) (Washington, DC: U.S. Department of Energy, March 1980), ch. 4, DOE/RA/4051-1.
2. Personal communication between Janos Laszlo (Pacific Gas & Electric) and OTA staff, Oct. 10, 1984.

[41]California Energy Commission, Systems Assessment Office, *Preliminary Energy Commission Staff Price Forecast for California Utilities* (Sacramento, CA: California Energy Commission, March 1984).

[42]Directional drilling involves a well bore that deviates from vertical. This form of drilling is used where the resource area underlies built-up areas, valuable cultivated land, and other difficult and expensive terrains.

[43]Estimate based on views expressed by participants at the Office of Technology Assessment's Workshop on Geothermal Power, Washington, DC, June 5, 1984.

F gu e 4 6 Ae a V ew o he Hebe CA Dua F ash Geo he ma ns a a on



At the time the photo was taken, the plant was under construction.

SOURCE: Dravo Constructors, Inc.

effectiveness figures for dual-flash at 400° F resources will be 7 to 8 Wh/lb.[44 45] At 600° F resources, net brine effectiveness may be as high as 25 Wh/lb.[46]

Typical capital costs for dual-flash units will probably run from $1,300 to $1,600/kWe. Actual costs will vary based on reservoir temperature, salinity, and the amount of noncondensable gases. The California Energy Commission[47] predicts that plants at highly saline resources could cost as much as $2,000/kWe.

Operation and maintenance costs will vary widely from resource to resource, ranging from 10 to 15 mills/kWh. Fuel (brine) costs are in large measure dependent on negotiations between the brine/steam supplier and the powerplant developer. Future brine fuel costs should be in the range of 50 to 70 mills/kWh.

Binary Cycle Systems.—In a binary plant (see figure 4-17), the brine is used to heat and vaporize a secondary working fluid with a lower boiling temperature than water. The secondary fluid then drives a turbogenerator to produce electricity. The use of a secondary working fluid complicates the design of the plant—it requires pumps to maintain brine and hydrocarbon pressure; special hydrocarbon turbines; heat exchangers; and

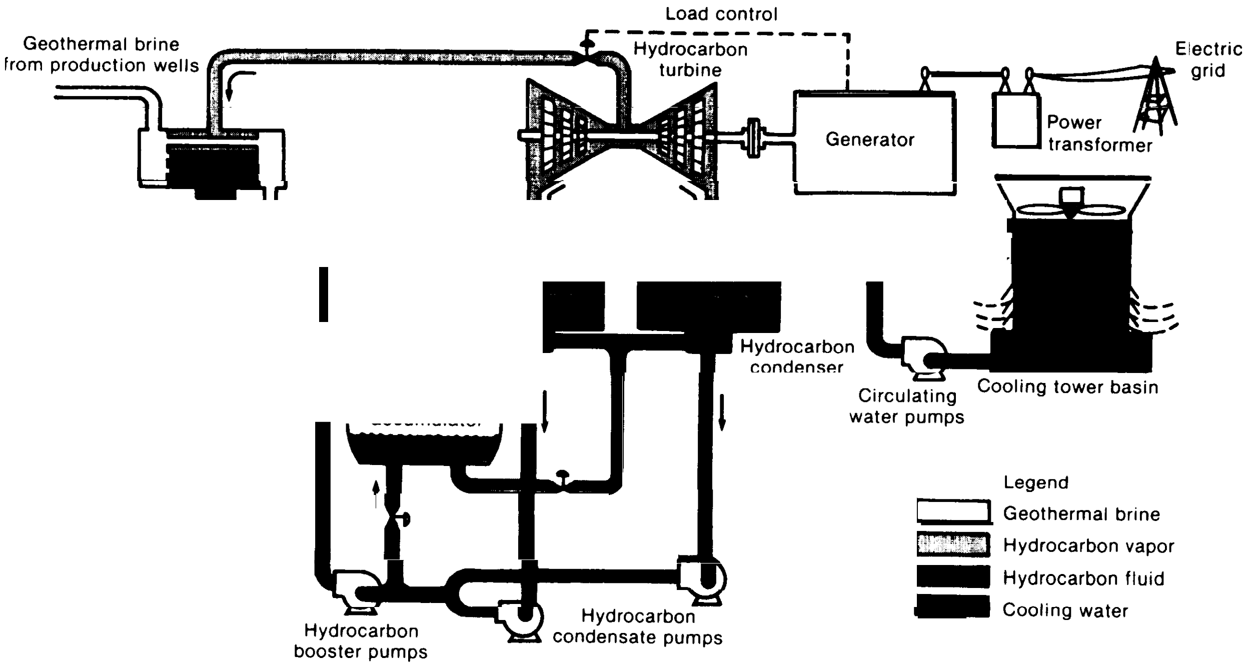
[44] T. Cassel, et al., *Geothermal Power Plant R&D, An Analysis of Cost-Performance Trade-offs and the Heber Binary Cycle Demonstration Project* (Washington, DC: U.S. Department of Energy, 1983), DOE/CS/30674-2.

[45] Evan E. Hughes, "EPRI Geothermal Wellhead Projects," *Proceedings: Eighth Annual Geothermal Conference and Workshop*, Altas Corp. (ed.) (Palo Alto, CA: Electric Power Research Institute, 1984), EPRI AP-3686, pp. 4-9 through 4-19.

[46] Ibid.

[47] California Energy Commission, *Capital Cost of a Hydrothermal Flash Power Plant*, draft staff issue paper (Sacramento, CA: California Energy Commission, August 1984).

Figure 4-17.–Simplified Process Flow Diagram of Binary Cycle Technology



SOURCE: San Diego Gas & Electric Co., *Heber Binary Project: Briefing Document* (San Diego, CA: San Diego Gas & Electric Co., 1984), p. 5.

surface condensers (instead of direct contact condensers).

The major advantages of binary cycles relate to efficiency, modularity, and environmental considerations. First, working fluids in binary cycles can have thermodynamic characteristics superior to steam, resulting in a more efficient cycle over the same temperature difference.[48] Second, binary cycles operate efficiently at a wide range of plant sizes. Especially attractive are small plants which, in addition to encouraging short lead-times, have many other important advantages as well. Third, since the brine is kept under pressure and reinfected after leaving the heat exchanger, air pollution, e.g., hydrogen sulfide, from binary plants can be tightly controlled. There are also several other cost and efficiency advantages of binary technology over the clual-flash systems. Nevertheless, the dual-loop design of binary cycles is more complex and costly than a flash design.

Binary cycle technology is in developmental stages with few large operational generating units. By the end of 1985, one large 45 MWe (net) binary plant will have been installed near Heber, California (see figure 4-18); in addition, small binary plants, with a total capacity of about 30 MWe, will be operating.[49] This will account for most of the binary capacity installed worldwide. Development is expected to proceed, and extensive commercial deployment is feasible in the 1990s.

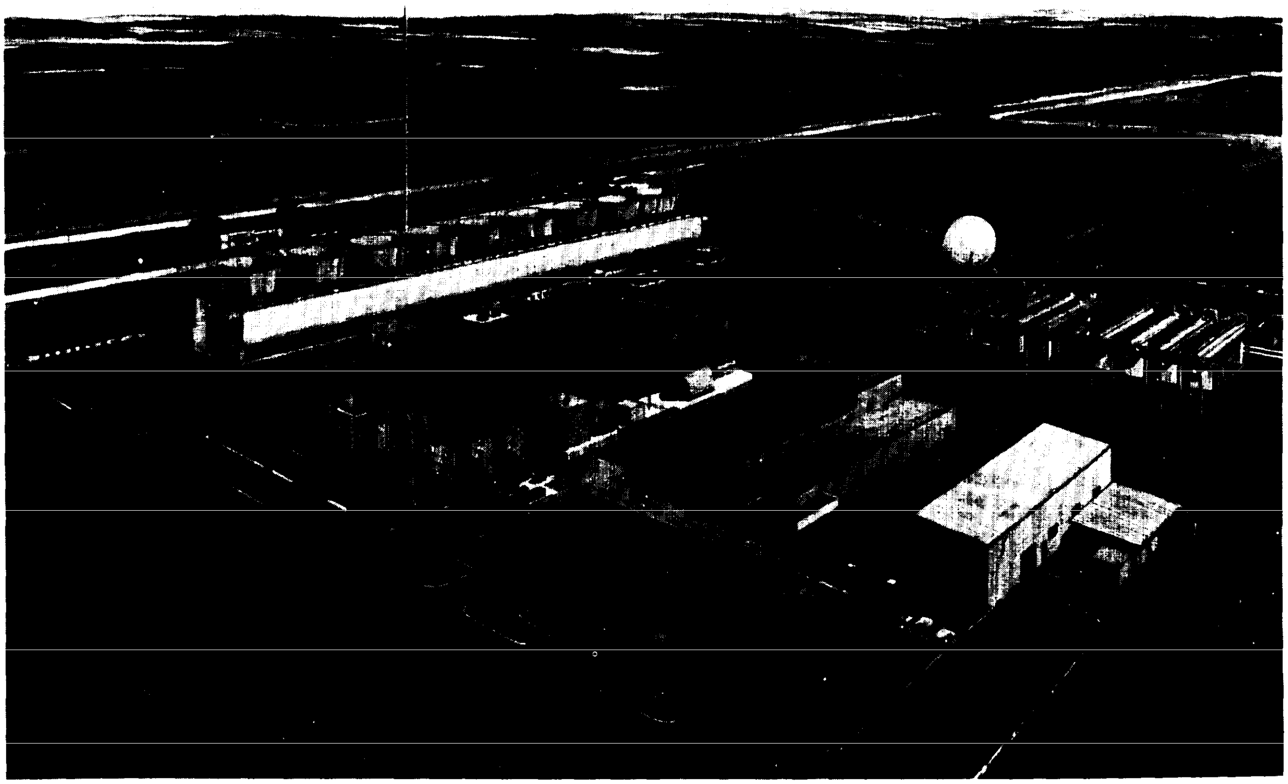
The expected cost and performance of binary geothermal plants in the 1990s are summarized in appendix A, table A-5. Data is provided for two reference plants, a large plant of about 50 MWe (net) and a small plant of about 7 MWe (net). The large plant could require up to 20 acres of land for the powerplant and for the maze of piping required for both the brine and the working fluid. The small unit might occupy 3 acres or less.[50] As with the the dual-flash technology, very large

[48] P. Blair, et al., *Geothermal Energy. Investment Decisions and Commercial Development* (New York: John Wiley & Sons, 1982).

[49] Ronald DiPippo, "Worldwide Geothermal Power Development: 1984 Overview and Update," op. cit., 1984.

[50] Personal communication between H. Ram (Ormat, Inc.) and OTA staff, Oct. 6, 1984.

Figure 4-18.—Artist's Conception of the Heber, CA, Binary Geothermal Installation



SOURCE San Diego Gas & Electrlc Co

volumes of cooling water are required; indeed, the water requirements are even larger than the dual-flash units. The large plant would require over 4 million gallons each day. The smaller plant would need about 0.6 million gallons per day.

Small plants of about 5 to 10 MWe (net) can be erected and operating on a site in only 100 days. But prior licensing, permitting, and other preconstruction activities could extend the lead-time to 1 year.[51] Construction of larger binary units should take only 1 ½ to 2 years.[52] But here too, overall lead-times will be longer because of preconstruction activities, including licensing and permitting. About 5 years total might be required for the first plant at a resource, and 3 years might be necessary for subsequent additions. With both small and large plants, problems about water requirements and environmental impacts could seriously extend the licensing and permitting process.

Binary cycle plants are designed to operate continually in base load operation. Availability is expected to be between 85 and 90 percent, and capacity factors are likely to be in the 75 to 80 percent range. Binary plants should last at least 30 years.

The net brine effectiveness of binary cycle plants may vary between 7 and 12 Wh/lb of steam at a 4000 F resource. Advanced binary technology in the larger sizes should increase present effectiveness values at Heber from 9.5 to 12 Wh/

[51] Wood & Associates, a geothermal energy developer, has had permitting problems at the county, State, and Federal level at its site near Mammoth Lakes, CA.

[52] San Diego Gas & Electric also had problems getting their large binary plant through the permitting process, Its problems, however, were encountered during the California Public Utilities Commission's plant approval process.

lb,[53] while smaller modular plants will probably have a net brine effectiveness between 7 and 9 Wh/lb.[54]

Capital costs for large binary cycle geothermal plants could range from $1,500 to $1,800/kWe in the 1990s. The smaller, wellhead units will probably vary from $1,500 to $2,000/kWe. The lower part of this range should be associated with the truly modular designs, which require little on-site construction, while the semimodular wellhead units (those which require a greater amount of onsite fabrication) should tend towards the higher part of this range. The capital cost estimates for both large and small units are lower than those which are expected to characterize early demonstration units.

Operation and maintenance costs are expected to range between 10 and 15 mills/kWh for all except the modular units. The simpler and smaller units should show O&M costs of 4 to 6 mills/kWh. Fuel, i.e., brine, costs will vary significantly by resource and resource developer. A range of 20 to 70 mills/kWh is most likely.

Fuel Cells

Introduction

A fuel cell produces electricity by an electrochemical reaction between hydrogen, supplied by a hydrocarbon fuel, and oxygen. Neither combustion nor moving parts are required in the conversion process. Fuel cell powerplants are expected to generate electrical power very efficiently and with modest environmental impacts relative to those of combustion technologies. Fuel cell installations may be capable of being deployed economically in a wide variety of sizes, ranging from small cogeneration units to large central power stations. In addition, they can be installed in many locations, including areas where both available space and water are limited. Among the other advantages which have attracted strong interest with investors are:

- responsiveness to changes in desired output,
- short lead-times,
- easily recovered waste heat,
- fuel flexibility,
- off-site manufacturing, and
- ability to operate unattended.

Most of the commercial demonstration plants crucial to the future of the fuel cell will *not* begin operations until the late 1980s, though by May 1985, a 4.5 MWe demonstration plant was operating successfully in Japan and thirty-eight 40-kWe demonstration units were operating in the United States.[55] Should the performance of the demonstration units be very good, limited quantities of commercial fuel cells may be produced at the earliest at the end of this decade or the beginning of the next.[56 57]

The level of deployment depends heavily on the success of the demonstration units; the period of time deemed necessary to generate investor confidence; and the willingness of the vendors to share the risk and cost of the early units, The perceptions and decisions of investors, vendors and buyers cannot be accurately and confidently predicted, but current evidence suggests that the early 1990s may see the beginnings of fuel-cell mass production and the first commercial applications. As much as 1,200 MWe of fuel cell powerplant capacity may be operating by 1995.

The low production levels will drive installed capital costs down somewhat, but they will remain far above possible costs in a mature market. High-volume mass production is unlikely to occur until a sizable market is anticipated—in the mid-l990s at the earliest. Such a market may develop as investors observe the continued operation of the demonstration units and the initial operation of the early commercial installations.

Most important to the prospective investors will be operating and maintenance costs, economic

[53] T. Cassel, et al., *Geothermal Power Plant R&D, An Analysis of Cost-Performance Trade-offs and the Heber Binary Cycle Demonstration Project*, op. cit., 1983.
[54] Personal communication between H. Ram (Ormat, Inc.) and OTA staff, Oct. 6, 1984.

[55] J.W. Staniunas, et al., United Technologies Corp., *Follow-On 40-kWe Field Test Support, Annual Report (July 1983 -June 1984)* (Chicago, IL: Gas Research Institute, 1984), FCR-6494, GRI-84/0131.
[56] Peter Hunt, *Analysis of Equipment Manufacturers and Vendors in the Electric Power Industry for the 1990s as Related to Fuel Cells* (Alexandria, VA: Peter Hunt Associates, 1984), OTA contractor report OTA US-84-1 1.
[57] Battelle, Columbus Division, *Final Report on Alternative Generation Technologies* (Columbus, OH: Battelle, 1983), vols. I and II, pp. 13-11.

life, and reliability. In particular, investors are likely to be sensitive to the rate at which fuel cell performance degrades over time under various operating conditions as well as the cost and difficulty of replacing cells when their performance becomes unacceptable. There is uncertainty among investors over these two points, both of which are crucial to the fuel cell's ultimate commercial prospects. Should problems be encountered in either area in early commercial prototypes, commercial deployment will be delayed. If powerplant operation is favorable, subsequent market growth in the latter half of the 1990s could be very rapid.

Basic Description

The typical fuel cell powerplant will consist of three highly integrated major components: the fuel processor, the fuel cell power section, and the power conditioner. The fuel processor extracts hydrogen from the fuel which can be any hydrogen-bearing fuel, though most installations in the 1990s are expected to employ natural gas.

The hydrogen is then fed into the fuel-cell power section, the heart of which are "stacks" of individual fuel cells. The operation of a single fuel cell is schematically illustrated in figure 4-19, The cells are joined in series (the stacks), which, in turn, are combined to form a powerplant. There are several types of fuel cells being developed. These are categorized according to the type of electrolyte-the medium in which the electrochemical reaction occurs—they use. The first-generation fuel cells use phosphoric-acid as the electrolyte. These cells are the most developed and are likely to account for most of the fuel cells deployed in the 199os.

Other less mature, fuel cell designs which employ alternative electrolytes promise superior performance; molten carbonate cells are the closest to commercial application, but are not expected to be commercially deployed until the late 1990s at the earliest. They therefore are not likely to account for an important share of fuel cell powerplants installed in the 1990s. M w

S8Peter Hunt, *Analysis of Equipment Manufacturers and Vendors in the Electric Power Industry for the 1990s as Related to Fuel Cells,* op. cit., 1984.

[59]U.S. Congress, Office of Technology Assessment Workshop on Fuel Cells, Washington, DC, June 5, 1984.

The electrical power which flows from the fuel cell stacks is direct current (DC). With some voltage regulation, this DC power can be used if the load is capable of operating with direct current. Otherwise, a power conditioner is required to transform the direct current into alternating current. This allows it to be fed into the electrical grid and to be used by alternating-current electrical motors.

The components of the fuel cell plant are tightly integrated to reduce energy losses through the proper management of fuel, water, and heat (see figure 4-20). Various parts of the plant benefit from the byproducts of other parts of the installation. Further efficiency gains result when byproduct heat from different parts of the plant are tapped for external use. The fullest exploitation of the fuel cell's heat may yield total energy efficiencies of up to 85 percent for the entire plant. The heat can be used for domestic hot water, for space heating, or to provide low-level process heat for industrial uses.

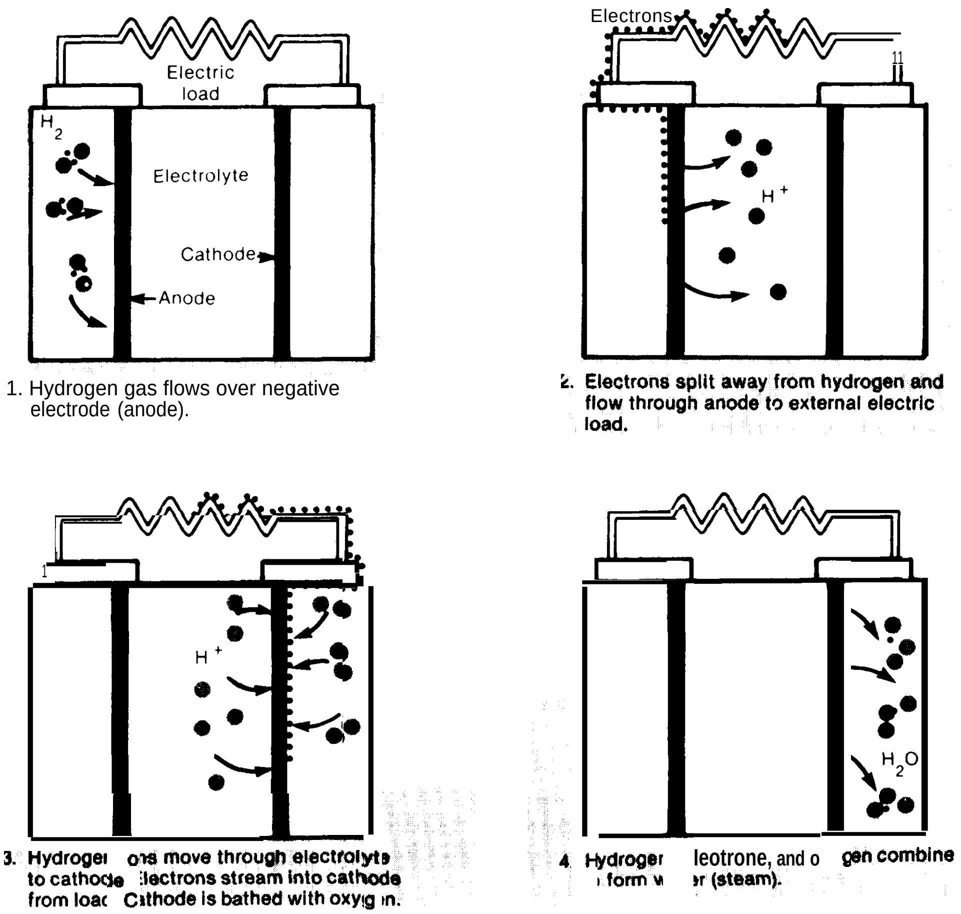
Typical Fuel Cell Powerplants for the 1990s

The expected cost and performance of typical fuel-cell powerplants for the reference year 1995 are summarized in appendix A, table A-7. Because no complete powerplants identical to those which might be deployed at that time exist today, these values remain estimates.

The units deployed in the 1990s probably will be built around two sizes of fuel cell stacks. The larger stacks are likely to be capable of generating approximately 250 to 700 kWe (gross, DC) each and the smaller stacks about 200 to 250 kWe (gross, DC) each. The plants built around the small stacks will be installed mostly in large multifamily dwellings, commercial buildings, and in light industries; most will probably be used to cogenerate both electricity and useful heat. The typical system would consist of at least two complete self-contained modules (see figure 4-21), each of which might produce about 200 kWe (net, AC).

Plants using the larger fuel cell stacks most likely will be deployed primarily by electric utilities, and by industries which would use them in cogeneration applications. Installation capacities probably

Figure 4-19.—Schematic Representation of How a Fuel Cell Works



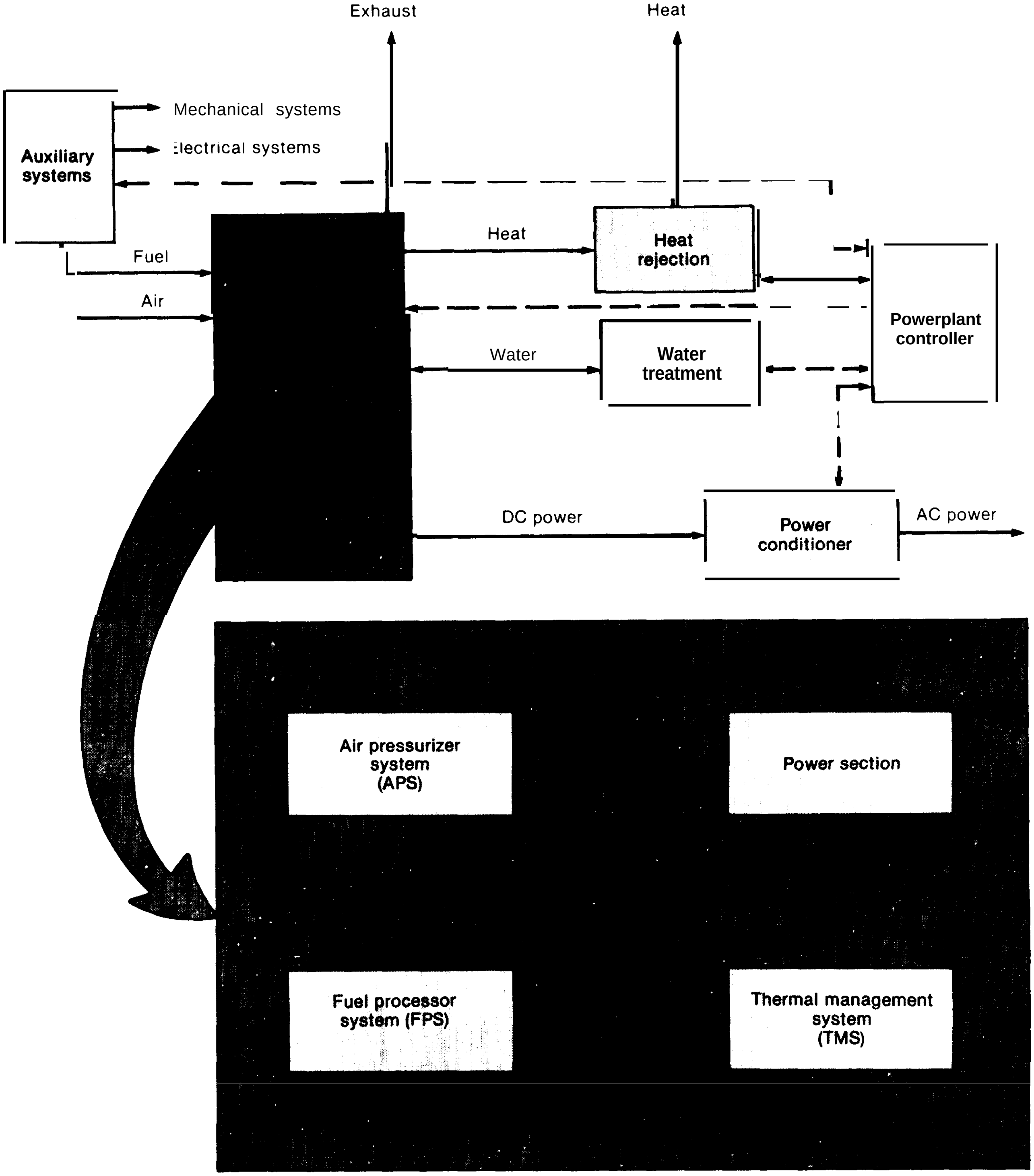
SOURCE: Ernest Raia, "Fuel Cells Spark Utilities' Interest," *High Technology*, December 1984.

will range from several megawatts on up. The reference installation used in this analysis is 11 MWe (net). Many of the major components would be fabricated in factories and shipped to the site on pallets.

The lead-time of a small fuel cell powerplants should be about 2 years. These units are relatively small, unobtrusive, and quickly and easily erected. Modules subsequently added at the same site could require as little as a few months. Regulatory delays are unlikely because of relatively minor siting and environmental considerations.

Installations utilizing the larger stacks, however, may encounter more serious regulatory problems, Unlike the approximately 480 to 600 square feet required by an installation of two, 200 kWe units, an 11 MWe installation would occupy about 0.5 to 1.2 acres of land (see figure 4-22). Because the plants frequently may be located in the midst of populated areas, the opportunity for regulatory conflicts with these larger plants is considerably greater. Partly offsetting these factors, though, are the environmental advantages associated with fuel cell powerplants. Hence, a lead-time of 3 to 5 years is anticipated with the larger units, considerably longer than the small plant's lead-time, but also much shorter than that of most conventional powerplants. As with the smaller fuel cell installations, capacity subsequently added to an already existing fuel cell plant should require considerably shorter lead-times.

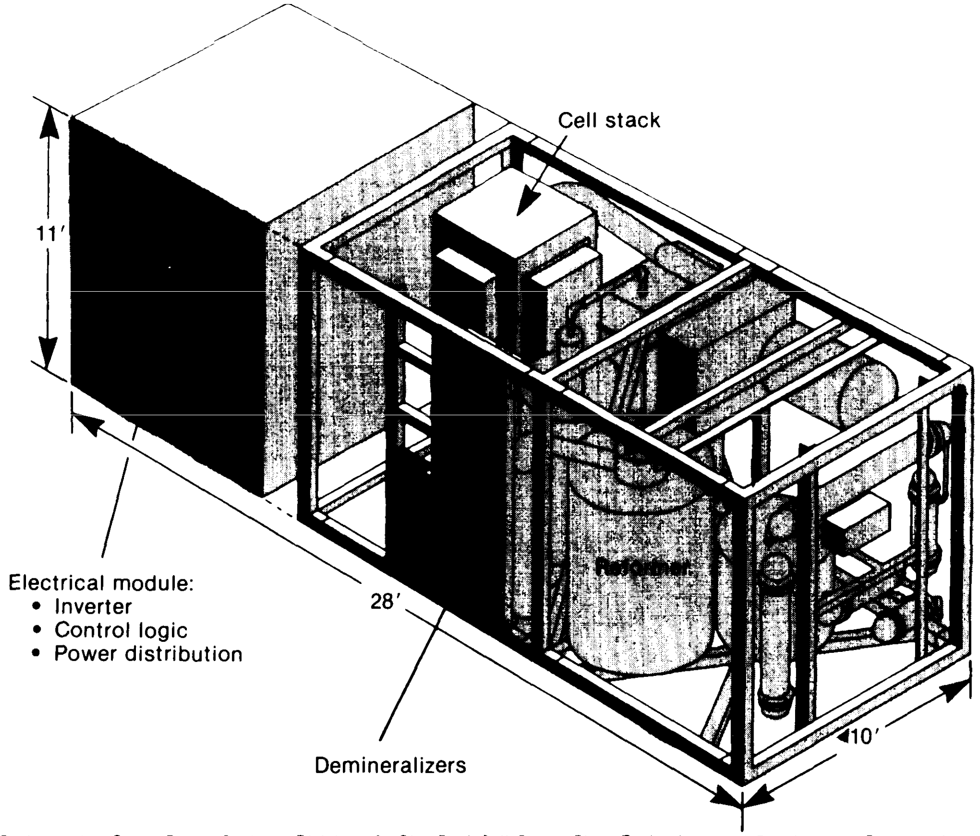
Figure 4-20.—Simplified Block Diagram of an 11-MWe Fuel Cell Plant. Detail of the DC Module is Provided Below.



SOURCE: United Technologies Corp., *Description of a Generic 11-MW Fuel Cell Power Plant for Utility Applications* (Palo Alto, CA: Electric Power Research Institute, 1983), EPRI EM-3161.

Figure 40-21.— Design for a 200 kWe Fuel Cell Module

While basically similar to units which might be deployed In the 1990s, this design differs in several important details,



SOURCE: United Technologies Corp., Power Systems Division, *On-Site Fuel Cell Power Plant Technology and Development Program Annual Report* (January-December 1983) (Chicago, IL: Gas Research Institute, 1984), FCR-6243 GRI-84/109.

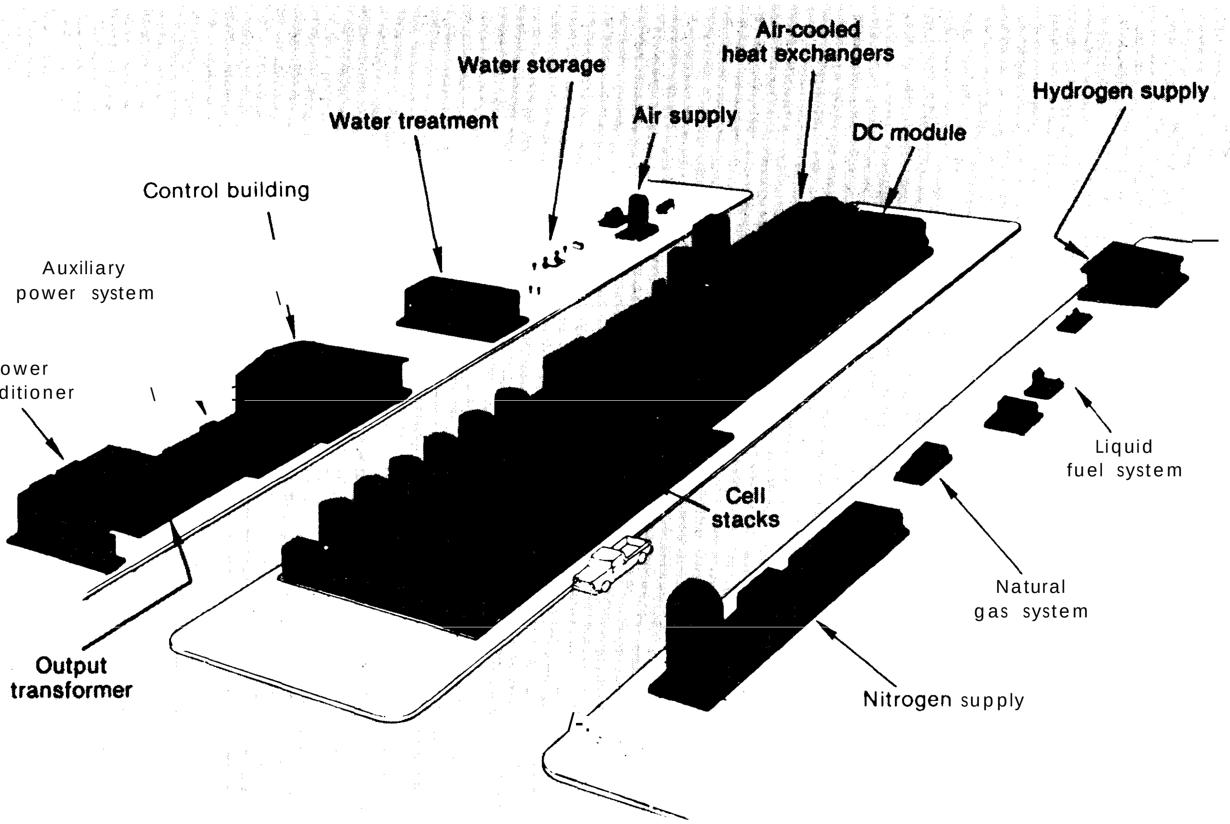
The operating availability of large fuel cell powerplants may range between 80 and 90 percent. Availability is heavily dependent on the quality of design—its simplicity, the extent to which it has redundant components, the number of parts, and their reliability—and on the availability of spare parts and repair people when they are needed.

The fuel cell can be applied to any duty cycle. The fuel cell has excellent load following capabilities and high efficiency over a wide variety of operating levels.

The fuel cell powerplant's lifetime is assumed to be approximately 20 to 30 years with periodic overhaul of the fuel cell stacks and other components. over time, the powerplant's efficiency drops. The timing of overhauls will vary; schedu les will be a function of the performance reduction over time and of other factors such as the cost of fuel .[60] I n some cases the stacks must periodically be removed and replaced with new ones. The old unit then is shipped back to a manufacturing plant where its catalyst (in the fuel processing section) and perhaps other components are removed, processed, and recycled. While the overhaul schedule and costs are uncertain, it is assumed here that all stacks are replaced after the equivalent of 40,000 hours of operation at full capacity.

[60] J. R, Lance, et al., Westinghouse Electric Corp., "Economics and Performance of Utility Fuel Cell Power Plants, " *Advanced Energy Systems– Their Role in Our Future: Proceedings of the 19th Intersociety Energy Conversion Engineering Conference, August 19-24, 1984* (San Francisco, CA: American Nuclear Society, 1984), paper 849133.

Figure 4-22.—Typical Arrangement of 11 MWe Fuel Cell Powerplant



SOURCE: Burns & McDonnell Engineering Co., *System Planner's Guide for Evaluating Phosphoric Acid Fuel Cell Power Plants* (Palo Alto, CA: Electric Power Research Institute, 1984), EM-3512.

Efficienciesbl for large fuel cell plants are expected to be between 40 and 44 percent. Small plants may have efficiencies of approximately 36 to 40 percent. The estimated efficiencies are those which might characterize a plant over its lifetime; efficiencies of new stacks could be higher while those of older stacks might be below that level.

The installed capital costs of fuel cell power plants are expected to range from $700 to $3,000/kWe for large units to $950 to $3,000/kWe for small plants; expected values for 1995 are $1 ,430/kWe and $2,240/kWe respectively. The low numbers can be expected where units are commercially produced in large numbers; the high numbers are representative of prototype units and include nonrecurring costs. By far the largest expense is the fuel-cell power section itself; it is expected to account for about 40 percent of the costs of a mature 11 MWe plant .62 The largest decrease in capital costs over the next decade will come from increases in the levels of fuel-cell production. However, technical improvements in the fuel-cell plant itself may substantially reduce costs as well. Already, over the past several years, design changes have reduced costs by an appreciable amount.

Operating and maintenance costs may range between 4.3 and 13.9 mills/kWh. The biggest element in O&M costs is the cost of periodically replacing cells stacks. For specific applications, the actual O&M costs will depend on the overhaul period for the cell stacks and the material and labor costs for each overhau 1.

[61]Based on higher heating-value

[62]United Technologies Power Systems, *Study on Phosphoric Acid Fuel Cells Using Coal-Derived Fuels* (South Windsor, CT: United Technologies Power Systems, Apr. 27, 1981), prepared for Tennessee Valley Authority, contract No. TV-52900A, FCR-2948.

Fuel costs are expected to be approximately 27 to 33 mills/kWh, accounting for the major portion of electricity costs from fuel cells. Fuel costs also constitute the fuel cell's greatest advantage over some of its competitors such as the gas turbine, due to the fuel cell's high efficiency which yields substantially lower per kilowatt-hour fuel costs. Major variations in fuel costs per kilowatt-hour will result primarily from fluctuations in fuel prices. Fuel cell efficiency variations, due to technical improvements or maintenance practices (especially stack reloading schedules), also would be reflected in different fuel costs. In the longer term, post-2000, it is expected that natural gas will have to be replaced with more abundant fuels. Primary candidates are synthetic fuels–especially methanol—from coal and biomass.

Stacks are of central importance in determining capital, O&M, and fuel costs. The development and extended demonstration of cheap (per kWe) and reliable stacks which can operate at high efficiencies for extended periods are critical to the success of the technology. Technological improvements which could be especially important in this regard are the development of inexpensive, corrosion-resistant cell structural materials and less expensive and more effective catalysts to operate at higher pressures and temperatures, and improved automated fabrication and handling processes for large area cells. Also important is the development of cheap, reliable and efficient small-scale reformers (fuel processing units) and the improvement of various other standard components.

Combustion Technologies

Integrated Gasification/Combined-Cycle Powerplants

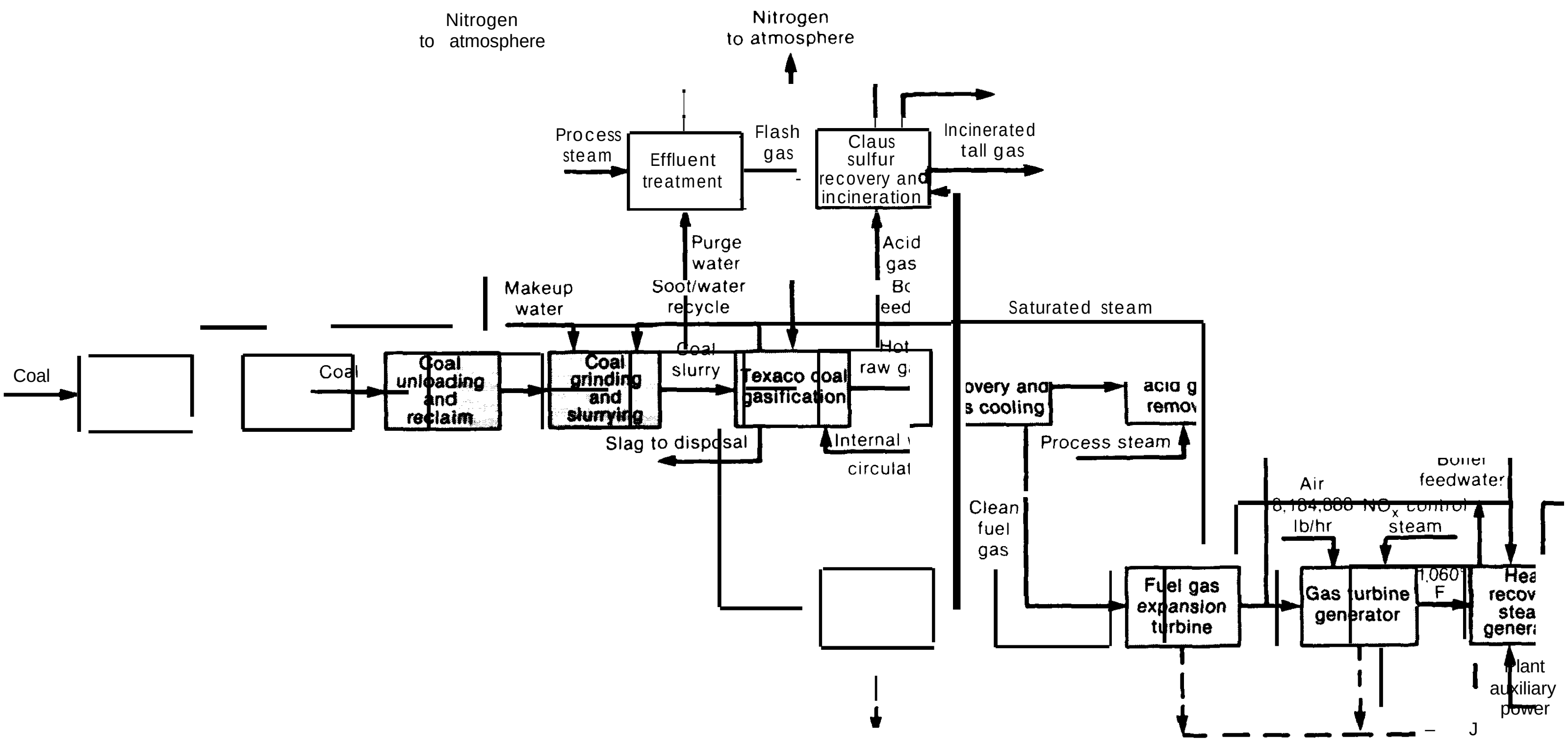
introduction.-A coal gasification/combined-cycle powerplant centers around two elements. First is a gasification plant which converts a fuel into a combustible gas; other equipment purifies the gas, Second is a combined-cycle powerplant in which the gas fuels a combustion turbine whose hot exhaust gases are used to generate steam which drives a steam turbine. While the gasification system can be quite separate and distinct from the combined-cycle system, they *can* be integrated so that some of the heat discharged in the gasification sequence is exploited in the combined-cycle system, and a portion of the heat discharged by the combined-cycle unit may be routed back for use in the gasification plant (see figure 4-23). This section focuses on such integrated units, commonly referred to as IGCCS.

The primary attractions of the IGCC are its fuel efficiency and its low sulfur dioxide, carbon monoxide, nitrogen oxide, and particulate emissions. The high efficiency allows for fuel savings and hence reduced operating costs. The potential for very low emissions makes the technology particularly attractive for using coal to generate electric power. Another advantage allowed by the IGCC is "phased construction. " Some parts of the plant may be installed and operated before the rest of the plant is completed;[63] this can be financially advantageous and is considered a major selling point for the technology. The IGCC also may be very reliable. In addition, the technology requires less land and water than a conventional scrubber-equipped, pulverized coal boiler powerplant. Furthermore, its solid wastes are less voluminous and less difficult to handle than those of its scrubber-equipped competitor and of the atmospheric fluidized-bed combustor (AFBC). Current estimates are that solid wastes from an IGCC will be 40 percent of a pulverized coal boiler and 25 percent of an AFBC of comparable size.

The evidence suggests that the IGCC offers a favorable combination of cost and performance when compared to its competitors (see also chapter 7). Nevertheless, a combination of two factors—lead-times and risk—may mitigate against its extensive deployment within the 1990s. Because of its modular nature and positive environmental features, potentially the IGCC has lead-times of no more than 5 to 6 years. It is likely, however, that the first plants, at least, will require longer times–up to 10 years–because of regulatory delays, construction problems and operational difficulties associated with any new, complex technology. It may take a number of

[63] For example, the gas-turbine/generator sets may be installed before the gasifiers and operated off of natural gas. When the gasifiers are completed, the synthetic gas then may be used instead.

Figure 4-23.—Simplified IGCC Flow



SOURCE: Argonne National Laboratory and Bechtel Group, Inc., *Design of Advanced Fossil Fuel Systems: A Study of Three Developing Technol... Power Generation* (Argonne, IL Argonne National Laboratory 1983) commercial plants before the short lead-time potential of the IGCC is met, unless strong steps are taken to work closely with regulators and to assure quality construction for these initial plants. Such steps may be facilitated if the early plants are in the 200 to 300 MWe range rather than the current design target of 500 MWe. Should the longer lead-times be the case, projects must be initiated no later than the end of 1991 and perhaps as early as the end of 1989 if they are to be completed within the 1990s.

In addition to these possible longer lead-times, limited experience with IGCC demonstration plants may also constrain extensive deployment in the 1990s. Although there has been extensive experience with the gasification phase, currently, there is only one IGCC plant in operation, the 100 MWe Cool Water plant in California (see figure 4-24). In addition, there is another demonstration plant using a different gasifier, under construction in a large petrochemical plant (discussed more in chapter 9). The Cool Water plant has been very successful in meeting its construction scheduled and budget, and in its early operation. As a result it has given confidence to utilities in their consideration of whether to commit to an IGCC. Despite this success, however, more operating experience is likely to be required before there will be major commitment to the IGCC by a very cautious electric utility industry. The Electric Power Research Institute, a major sponsor of the IGCC Cool Water project, anticipates three to four commitments by the end of 1986. If these projects go forward and the shorter lead-time potential of the IGCC is proven, then significant deployment in the mid to late 1990s is quite possible.

Description of a Typical IGCC in the 1990s.– Plausible cost and performance features of a representative IGCC are described in appendix A, table A-6. The reference year considered in the report is 1990, at which time two plants, generating altogether approximately 200 MWe probably will be operating in the United States. The reference plant capacity is 500 MWe, consisting perhaps of five gasifiers,[65] though installations as small as 250 MWe might be preferred. While capable of being built with capacities even smaller than 250 MWe, such smaller installations would be more costly per unit of capacity.[66] The plant would consist of three types of equipment: the gas production, cooling and purification facilities; the combined-cycle system (including gas turbines and steam turbines); and the balance of the plant. Included in the constituents of the latter are fuel receiving and preparation facilities, water treatment systems, ash and process-waste disposal equipment, and in most cases an oxygen plant.

[64] An interesting discussion of the planning and construction of an IGCC can be found in: Cool Water Coal Gasification Program & Bechtel Power Corp., Cool *Water Coal Gasification Program—Second Annual Progress Report,* interim report (Palo Alto, CA: Electric Power Research Institute, October 1983), EPRI AP-3232.

F gu e 4 24 The Coo Wa e GCC P an n Sou he n Ca o na

SOURCE: Southern California Edison Co.

[65] Zaininger Engineering Co., *Capacity factors and Costs of Electricity for Conventional* Coal and Gasification-Combined Cycle *Power Plants* (Palo Alto, CA: Electric Power Research Institute, 1984), EPRI AP-3551.

[66] According to one source (Electric Power Research Institute, *Economic Assessment of the Impact of Plant Size on Coal Gasification-Combined-Cycle Plants* (Palo Alto, CA: Electric Power Research Institute, 1983), AP-3084), the levelized cost of electricity for a variety of IGCCs using Texaco gasifiers increased as plant size decreased. The economies of scale were relatively small among plants of capacities greater than 250 MWe. But as plant size diminishes below 250 MWe, levelized costs increase very significantly. Selection of a 500 MWe module also was favored by participants in a June 1984 OTA-sponsored workshop on IGCCs, though it was suggested that installations as small as 250 MWe might seriously be considered.

The IGCC can be built in phases. The design permits the operation of portions of the plant before other segments are completed. The gas turbines could be installed first and operated with natural gas. The steam turbines then could be added, allowing the production of still more electric power. Finally, the gas facilities could be added to complete the plant and to allow its operation based on synthetic gas. Hence, some electrical power could be produced before the entire plant is completed.

The typical plant would require a rather large area of land and considerable quantities of water during its lifetime of approximately 30 years. An estimated 300 to 600 acres would be needed for the facilities, and for disposal of solid wastes. And 3 to 5 million gallons of water, on average, would be required to run the plant daily. These quantities are large, but as noted above, they are smaller than those which characterize conventional pulverized coal plants equipped with scrubbers.

The operating availability of the reference IGCC plant is 85 percent. There is uncertainty associated with availability estimates, as these plants would be the first commercial units and could experience problems which would result in lower availability rates. Of particular concern is the reliability of the combined-cycle system; combined-cycle system design as well as operating and maintenance practices will largely determine combined-cycle reliability.

The IGCC facility commonly would be used to provide base load power at efficiencies ranging from 3s to 40 percent. This corresponds to a heat rate of between 8,533 and 9,751 Btu/kWe-hour.[67] It is worth noting that the Cool Water demonstration plant, which had a design heat rate of 11,400 Btu/kWh, has consistently met that target in operation to date. While the gasifier design certainly has an important effect on efficiency, the most important factor in efficiency within the anticipated range probably would be the gas turbines. To reach the high efficiencies projected for the IGCC will require high-temperature, advanced combustion turbines. The projected efficiency range is somewhat higher than the 35 to 36 percent efficiency expected for conventional plants with scrub bers.[68]

Conventional turbines would yield efficiencies at the low end of the efficiency range, while advanced turbines might yield higher efficiencies.[69] The choice of turbine type could significantly affect O&M costs in addition to efficiency. 'o For example, an advanced turbine design, while promising higher efficiencies could also entail greater technical problems and therefore higher O&M costs. The choice of turbine also would affect capital costs. Higher efficiency turbines would result in a higher electrical output for a given gasitier and feed system; and the steam plant would be relatively smaller. Both changes would reduce capital costs per kilowatt- hour.[71]

Capital costs probably will range from $1,200 to $1,350/kWe (net). For units in the 250 MWe range, costs are expected to be somewhat higher, about $1,600/kWe, By far the largest expense would be the gas production and purification facilities. These might account for approximately 40 percent of total costs. The cost would vary especially with gasifier design; there are indications that substantial capital cost differences may exist among leading gasifier designs,[72] though the magnitude of these differences not clearly established. Costs also will vary significantly according to the degree to which redundancy is designed into the system. Another 40 percent of the cost would include buildings, coal receiving and preparation equipment, an oxygen plant, waste handling equipment, water equipment, and the

[67] It is important to note that IGCC heat rates are particularly sensitive to ambient temperatures, Heat rates go down with ambient temperatures. See, for example, table 3-1 in: Zaininger Engineering Co., *Capacity Factors and Costs of Electricity for Conventional Coal and Gasification-Combined Cycle Power Plants*, op. cit., 1984. It is assumed here that ambient temperatures are held constant throughout the year at 88 F.

[68] B. M, Banda, et al,, "Comparison of Integrated Coal Gasification Combined Cycle Power Plants With Current and Advanced Gas Turbines, " *Advanced Energy Systems— Their Role In Our Future: Proceedings of the 19th Intersociety Energy Conversion Engineering Conference, August 19-24, 1984* (San Francisco, CA: American Nuclear Society, 1984), paper 849507.

[69] Ibid

[70] For a discussion of relevant turbine developments, see Eric Jetts "Tokyo Congress Highlights Efficiency and Nox Control, " *Gas Turbine World*, January-February 1984, pp. 26-30.

[71] General Electric Co, , *Review and Commentary* on Design of Advanced Fossil Fuel Systems (Fairfield CT: General Electric Co., 1982).

[72] OTA staff telephone conversation with Bert Louks, Electric Power Research Institute, June 6 1984

combined-cycle system .73 Finally there are access roads, site preparation, and various civil engineering tasks; together these might represent roughly 20 percent of capital costs.

Operating and maintenance costs could range from 6 to 12 mills/kWh, a figure roughly equivalent to the costs characteristic of a conventional pulverized coal plant. The greatest source of uncertainty in the estimate concerns the performance of the gasifiers, of the syngas coolers (if they are used) and of the gas turbines.

Fuel costs for the reference plant are projected to range from 15 to 17 mills/kWh based on 1990 coal costs of $1 .78/MMBtu (see "Definitions" in appendix A for discussion of fuel costs). It is here where the possible cost advantage of the IGCC over the conventional scrubber equipped plant is greatest. Because of its higher efficiency, the IGCC's fuel costs would be less than those of its conventional counterparts. As discussed above, an important determinant of overall efficiency is the gas turbine's efficiency. Advanced turbines which are expected to be available by the early 199os would be much more efficient than present turbines. Their use could allow fuel costs to fall to the low end of the estimated range. Since fuel costs account for a large portion of the cost of generating electricity from the IGCC, the anticipated improvement in turbine efficiency will affect the competitive position IGCC significantly .74

Atmospheric Fluidized=Bed Combustion

Introduction.–The AFBC is a combustion technology which will provide an economic alternative to conventional pulverized coal plants in the 1990s. Its relatively low volumes of sulfur dioxide and nitrogen oxide emissions, great fuel flexibility, small commercially available size (< 100 MWe), easily handled solid wastes, responsiveness to demand changes, and other features offer advantages which may allow it to compete successfully with conventional plants, particularly in areas where high sulfur coals are used. Investment outside the utility industry in AFBC cogeneration units already is growing rapidly, Greater investment by utilities is likely in the 1990s, though various factors may keep the number of large utility-owned AFBCs operating by the end of the century below that which cost alone would set (see chapter 9).

There are two basic types of fluid ized-bed combustors: the atmospheric fluid ized-bed combustor (AFBC) and the pressurized fluidized-bed combustor (PFBC). The PFBC operates at high pressures, and therefore can be much more compact than the AFBC. The PFBC also may produce more electricity for a given amount of fuel. Despite these potential advantages, the PFBC has more serious technical obstacles to overcome and is less well developed than the AFBC. It has not yet been successfully demonstrated on a commercial scale, nor are any commercial-scale demonstrations now under construction in the United States. It is unlikely that more than a few commercial units could be completed and operating before the end of the century, though the PFBCs longer term potential is quite promising.

The AFBC, the focus of this analysis, operates at atmospheric pressures. Small-scale AFBCs already are used commercially around the world for process heat, space heat, and in various other industrial applications; and are producing electrical power abroad as well as in very small amounts in the United States. Three types of AFBC installations may be important over the next 15 years: large electric-only plants (100 to 200 MWe), cogeneration installations, and nonelectric systems. The electric-only units are likely to be deployed by utilities, whereas the cogeneration and nonelectric units probably would be built and operated by others.

The cogeneration unit is an installation operated to provide both electricity and usable thermal energy, while the nonelectric systems are used to supply usable heat only. Electric-only AFBCs may be new "grass-roots" plants built from the ground up; or they may be "retrofits" to existing plants which have been modified to

[73] H G Hemphill and M, B, Jennings (Raymond Kaiser Engineers, Inc.), "Offsites, Utilities, and General Facilities for Coal Conversion Plants, " *Advanced Energy Systems— Their Role in Our Future: Proceedings of the 19th Intersociety Energy Conversion Engineering Conference, August 19-24, 1984* (San Francisco, CA: American Nuclear Society, 1984), paper 849195.

[74] B. M. Banda, et al., "Comparison of Integrated Coal Gasification Combined Cycle Power Plants With Current and Advanced Gas Turbines, " op. cit., 1984.

accommodate an AFBC instead of the old conventional boilers.[75] A retrofit may allow the life of a powerplant to be prolonged, reduce emissions, and increase the rating of a powerplant. Retrofits also are cheaper and faster to build than completely new AFBCs. See chapter 5 for a more detailed discussion of retrofits.

While this discussion centers on the large, grass-roots electric-only plants, the other three types of installations—retrofit, cogeneration, and nonelectric units—are important for several reasons. First, they constitute the most immediate market for the AFBC; and may very well dominate the market in the 1990s (see chapter 9). This prospect is enhanced by their short lead-times—substantially shorter than those which would characterize large grass-roots, electric-only units.[76]

Second, operation of these units may provide valuable experience which can be used to rapidly refine the technology, to reduce cost uncertainties and to improve its competitive posture. Thus, even with very few grass-roots, electric-only plants in operation, their design can be continuously and quickly improved and risks reduced as a result of experience gained in other applications. Furthermore, where utility retrofits are concerned, utilities directly can gain operating experience and confidence in the technology at a cost and risk considerably smaller than that associated with a new grass-roots electric-only plant.

General Features of the AFBC.—A fluidized-bed is a mass or "bed" of small particles—solid fuel, ash and sorbents used for sulfur removal—through which flow large volumes of air and combustion gases. The gases move through the bed at velocities sufficient to cause the mass of particles to behave like a fluid; hence the term "fluidized-bed." In the AFBC, one or more fluidized-beds are used to perform two key functions: combustion of the fuel and capture of sulfur carried in the fuel. Some AFBCs perform both functions in a single bed. Other systems use several sequentially linked beds, each of which has a different design and performs a different function. For the sake of simplicity, this discussion focuses on AFBCs which require only one bed.

In the typical AFBC, unburned solid fuel regularly is fed into the bed and mixed with the bed's hot particles bringing about combustion. Thermal energy is removed from the bed by heat transfer to water carried in tubes passing through the bed. The resultant steam can be used indirectly for space or process heat, to drive a steam turbine, or both. If the fuel contains substantial quantities of sulfur, a chemically active "sorbent" such as limestone also is fed into the bed to react with the sulfur while it is still in the bed. The sorbent captures the sulfur before it escapes from the bed with the combustion gases. This capability to capture sulfur "in situ" reduces or eliminates the need for expensive add-on sulfur-removal equipment and is perhaps the most attractive feature of the AFBC.

Air is injected from below the fuel and sorbent mixture and "fluidizes" it. Depending on the velocity and volume of the air, and the size of the fuel and sorbent particles, a portion of the particles and combustion byproducts are entrained in the flow of air and "elutriated" *from the bed.* A cyclone[77] separates the larger entrained particles from the gases. The gases and smaller particles are cooled and discharged into a baghouse[78] where the remaining particles are removed from the gas before it is exhausted to the atmosphere. The solids removed in the cyclone meanwhile are recycled through the bed—to improve fuel and sorbent utilization—or discharged. Some solids also may be discharged from the bottom of the bed. The effective recycling of sorbent and of unburnt materials is crucial in maintaining a highly efficient combustion process and minimizing sorbent consumption.

[75]The retrofit can take one of two forms. The old boiler may be *modified* with the addition of an AFBC; or the old boiler may be removed in its entirety and replaced with an entirely new AFBC boiler. In either case the old turbine and other equipment may be used.

[76]Retrofit units in many cases involve very little regulatory delay, as they are deployed at preexisting plants. Cogeneration units and nonelectric units commonly are very small, and are not owned by utilities, and are are not subject to the same extensive regulatory delays which characterize large utility-owned projects.

[77]A cyclone is a mechanical device which separates particles from gases by using centrifugal force.

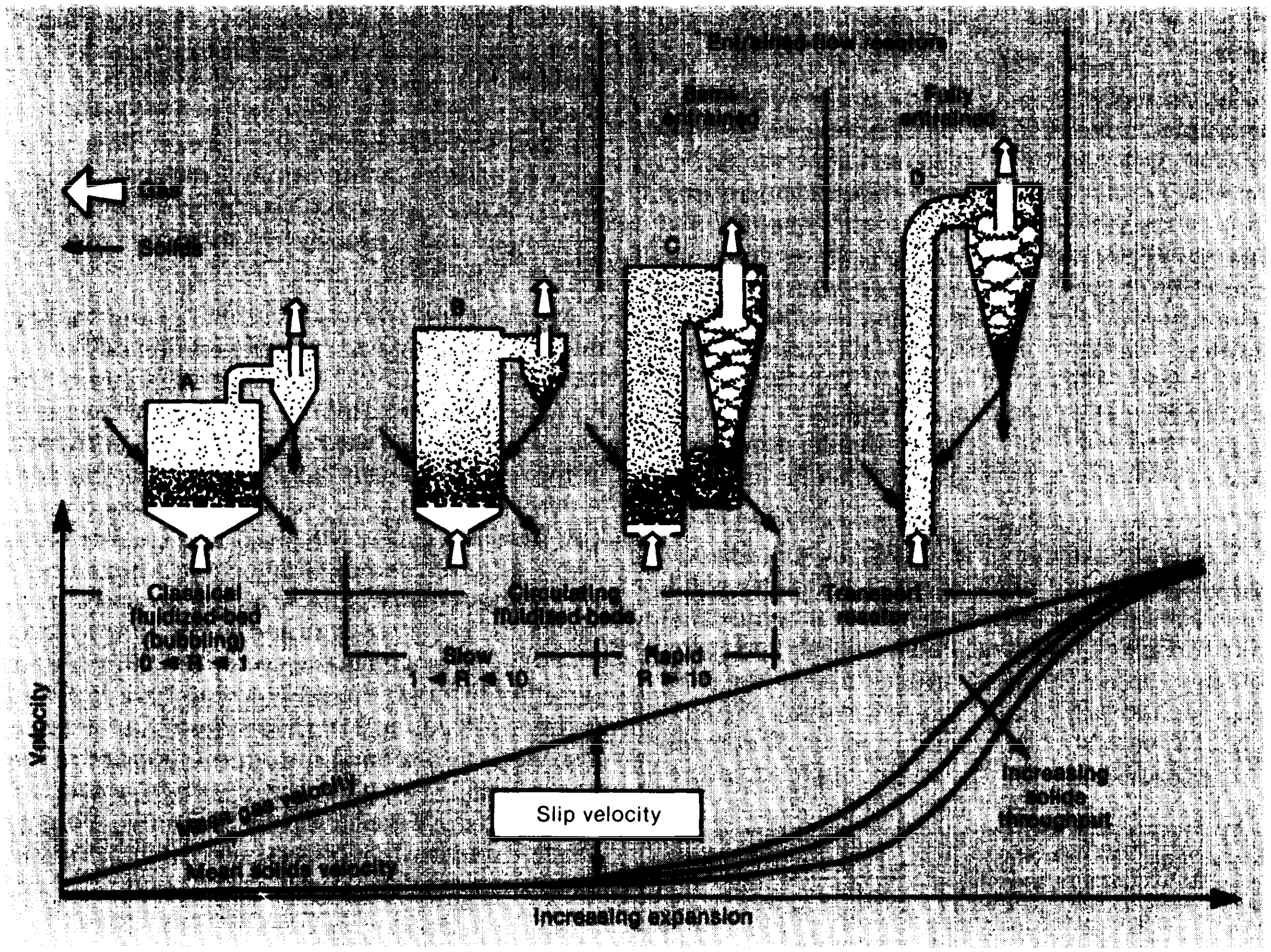
[78]A system of fabric filters (bags) for dust removal from stack gases.

Fluidized-bed combustors are commonly categorized by the degree to which solids are entrained in the gas-flow through the bed and to which solids are recycled to the bed after passing through the cyclone. The primary types of fluidized-beds are illustrated in figure 4-25; among these, bubbling beds and the circulating beds are the most important.[79]

The *bubbling bed* AFBC is characterized by low gas velocities through the bed. The result is a bed from which only the smaller particles are entrained with the gas; after being entrained, the solids on the average are recycled through the bed less than once. Conversely, the gas flow velocities through the circulating bed are rapid. The bed itself becomes less distinct with greater en-

79 These in turn can be further subdivided. Among the bubbling beds are the conventional bubbling bed, multibed and in-bed circulating models. Circulating systems include conventional and multisolids bed (or hybrid} systems. (Bruce St. John, NUS Corp., *Analysis and Comparison of Five Generic FBC Systems,* paper presented at Fluidized Bed Combustion Conference, sponsored by the Government Institutes, May 1984.)

Figure 4-25.—Types of Fluidized Gas-Solid Reactors With Different Regimes of Particle Slip Velocity and Degrees of Flyash Recycle (with Reh) Showing Proposed Terminology



$$R = \frac{\text{Mass flow rate of solids returned to bed}}{\text{Mass flow rate of solids entering bed}}$$

SOURCE: Leon Green, Jr., *Value Derivable From Coal Waste by Entrained-Flow Combustion,* presented at the Fifth ICU Symposium, Pittsburgh, PA, June 1983.

trainment levels, as larger portions of the fuel and sorbent repeatedly are cycled through the combuster. The fuel and limestone are thoroughly mixed as combustion of the fuel takes place.

Each of the two types of AFBC possesses certain operating characteristics and peculiarities. An important shortcoming shared by both technologies is the fact that neither have been built to produce electric power on a scale–100 to 200 MWe—attractive to utilities. And both face serious technical challenges in moving from the very small nonelectric industrial boilers which have typified AFBC applications so far to these larger sizes.

The bubbling bed has an important advantage in that it is the older of the two types and there is greater operating experience in the United States (in small, nonelectric, industrial applications). The bubbling-bed combustor can more readily be retrofitted to some preexisting conventional boilers, But the design also has its drawbacks. perhaps the most serious are the fuel-feed problems encountered as the unit is scaled-up. it is difficult to design a reliable feed mechanism that adequately distributes fuel to the bed; the problem becomes progressively more difficult as the bed is enlarged. An elaborate feed design is required; and the size and moisture content of the fuel must be carefully controlled.

By the end of this decade several large bubbling-bed AFBCS will be operating in the United States. One is a grass-roots, 160 MWe demonstration plant in Paducah, Kentucky (see figure *4-26).* Two others are retrofit units. Among the units, two different feed systems will be used. Should serious problems be encountered in the feed systems of the units, the deployment of the bubbling beds with capacities between 100 and *200* MWe in the 199os may be seriously delayed. Favorable operation would encourage commercial orders of large units. Other problems associated with some bubbling bed designs, which may impede commercial deployment, are erosion and corrosion of materials which are in contact with the bed itself or particulate laden gases. These difficulties, should they persist, could result in unacceptably high O&M costs.

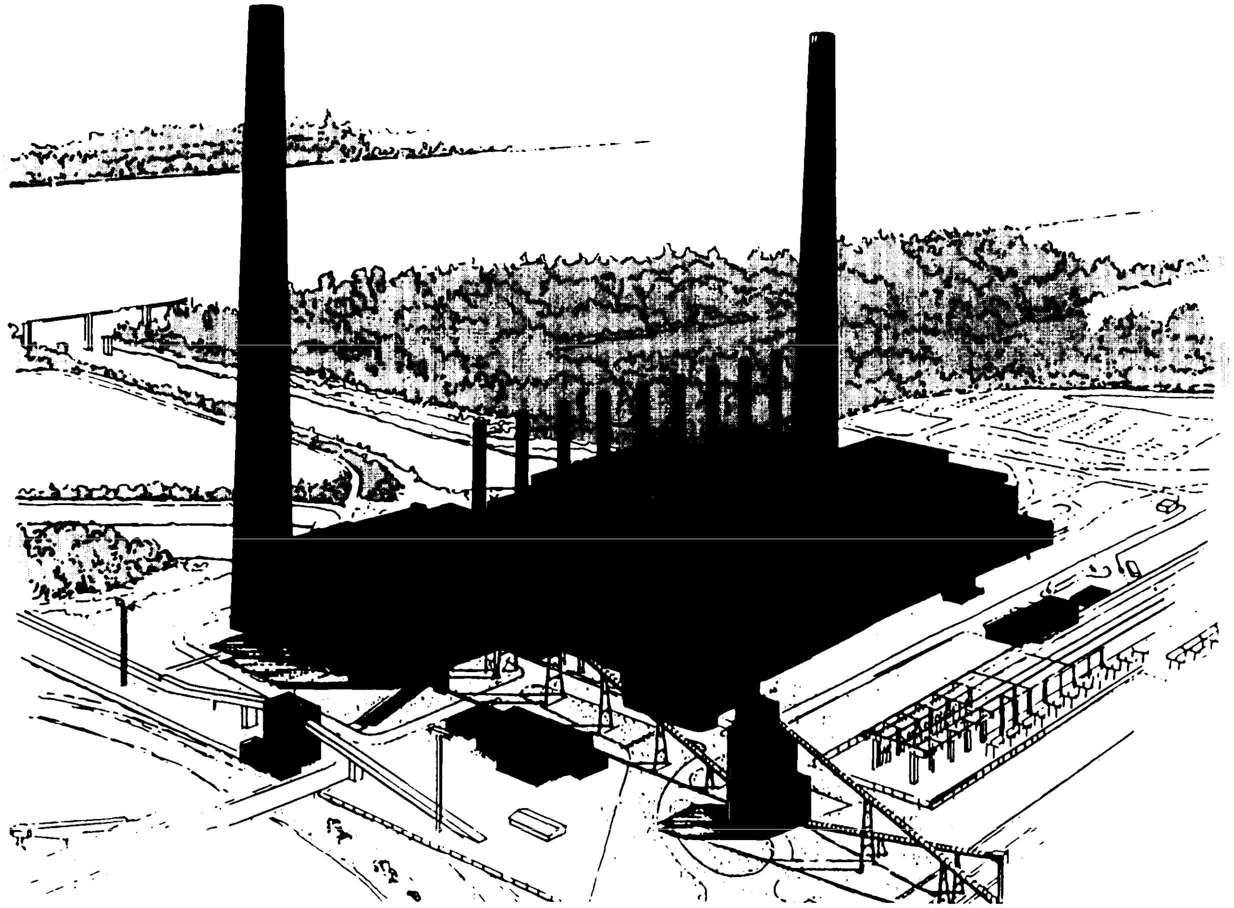
With the *circulating bed,* by virtue of its greater gas' velocities and higher levels of particulate recycling, the fuel-feed problem may be far less of a problem, at least with smaller units. A simpler feed mechanism can be used, and larger variations in fuel size and moisture are tolerated. Efficient combustion and sorbent utilization is more readily achieved. Nitrogen oxide and carbon monoxide emissions also tend to be lower.

Being a newer "second-generation' technology, there is less experience operating even small circulating-bed AFBCs. But this disadvantage is rapidly disappearing. Many vendors now are offering circu lating beds; and almost all the major cogeneration units and many of the nonelectric AFBC projects now being built employ circulating beds.

While it is not clear whether plants using bubbling beds, circulating beds, or some hybrid of the two will be favored for large grass-root plants in the 1990s, **the recent commercial trends indicates that the circulating beds are becoming the technology of preference for small cogeneration uses and a sizable share of nonelectric applications. Favorable experience with these units, as well as the single large retrofit unit using the circulating bed, could decisively favor the competitive position of large circulating bed AFBCs in the 199os. As with the large bubbling bed demonstration units, however, difficulties with** the demonstration retrofit unit could seriously retard the commercial deployment of large units.

Typical AFBC Plant for the 1990s.–A large AFBC plant typical of the kind which might might be deployed for electricity production in the 1990s is described in appendix A, table A-5. The table and the following discussion focus on all-electric, grass-roots plants. By the early 1990s, U.S. utilities will have only one such plant on which to base evaluations of the technology. This is the 160 MWe demonstration unit which currently is being constructed at TVA's Shawnee Steam Plant in Kentucky; startup is scheduled for 1989. Investors, however, also by the early 1990s will benefit from the technical progress and *in*formation resulting from two large demonstration retrofit units, one of 100 MWe and the other of

Figure 4-26.– 160 MW AFBC Demonstration Plant in Paducah, KY



Authority

125 MWe, which also will have operated for several year-s by the early 1990s. **Also important** will be experience gained from the operation of a fully com mercia1, 125 MWe cogeneration u nit—also a~ retrotit—being installed by a private firm in Florida. And many hundreds of megawatts of \mall AFBs will have been installed by 1990.

The reference AFBC plant considered in the analysis has a generating capacity of approximately 150 MWe (net). The gross electrical power production of the plant actually would exceed net capacity, because power is required to oper- .~te the equipment which circulates the solids and forces air into the bed. Any commercial units considered in the early 1990s are not likely to exceed by very much the size of the demonstration units; AFBCs are subject to scale-up problems which probably will inhibit during the 1990s deployment of any commercial units much larger than the demonstration plants.

Many features of the AFBC installations deployed in the 1990s, regardless of type, are likely to be much the same. They will require access to coal and limestone supplies; this usually means railroad access. A rather sizable piece of land will be required, not only for the AFBC itself but for coal and limestone handling and processing facilities, storage areas for the limestone and coal, disposal areas for the solid waste generated by the plant, and ponds of various sorts. Disposal of spent limestone may be one of the most serious problems for the AFBC. Current estimates are that about 1,200 tons per MWe year need to be disposed of for 3.5 percent sulfur, Illinois coal.

For a 150 MWe plant, about 90 to 218 acres could be required; the exact amount depends on several conditions. Access to water also will be required; the 150 MWe reference plant is expected to require about 1.5 million gallons each day.

Like any large powerplant, the AFBC is expected to require a considerable amount of time to deploy. An AFBC in the 100 to 200 MWe range potentially has a lead-time of no more than 5 years because of its smaller size and environmental benefits. As with the IGCC, however, lead-times of the first plants are likely to be greater, and could be as long as 10 years. This includes up to 5 years for design, preconstruction, and licensing activities; and 2 to 5 years for construction. Favorable regulatory treatment, and rapid and quality construction could result in lead-times close to the potential.

If in fact large, grass-root AFBC plants take up to 10 years to build from initial commitment, orders for them must be made by 1990 for the AFBCs to contribute appreciably to generating capacity before the close of the century. Given the fact that the three large demonstration plants and numerous small cogeneration units will be operating by then, there is a possibility that considerable numbers of large plants indeed will be initiated by that time.

The operating availability of an AFBC powerplant may be around 85 to 87 percent. But considerable uncertainty surrounds this figure. Difficulties with the fuel feed system in bubbling-bed AFBCs could severely reduce operating availability. Or erosion or corrosion associated with both bubbling-bed and circulating-bed AFBCS could have similar effects.

AFBCs are expected to be used primarily as base load plants, though their demand-following capabilities will allow their use in intermediate applications. An AFBC plant is expected to last for approximately **30** years, **and to operate with an efficiency of approximately 35 percent—somewhat higher than a conventional pulverized coal plant equipped with scrubbers.**

The capital cost of a large AFBC probably will be pegged at a level roughly comparable to that of its main competitors, the conventional scrubber-equipped plants and the IGCC. The estimate in this analysis is $1,260 to $1,580/kWe. Fuel costs are expected to be approximately 17 mills/kWh assuming coal costs of $1.78/MMBtu. O&M costs are expected to fall between 7 and 8 mills/kWh, but high uncertainty is associated with this estimate. Should technical problems be experienced with the fuel feed system, or should serious erosion or corrosion problems arise, power production could suffer and expensive repairs and modifications could be required. Consequently, O&M costs could escalate.

The major opportunities for research which could yield technical improvements in the AFBC or reduce uncertainty about performance lie in the three large demonstration projects which currently are underway. These projects offer the chance to experiment with basically different designs and to compare technologies. Of particular importance will be research relating to the fuel feed systems and to designs and materials which can reduce erosion and corrosion of system components.

ENERGY STORAGE TECHNOLOGIES

Introduction

There are several tasks that electric energy storage equipment, employed by utilities, can perform. The most common is *load-leveling,* in which inexpensive base load electricity is stored during periods of low demand and released during periods when the marginal cost of electricity is high. In addition, storage equipment can be used as *spinning reserve,* the backup for generating systems which fail, or as *system regulation,* the moment-by-moment balancing of the utility's generation and load.

Energy storage technologies also may be used by utilities' customers in either remote or grid-connected applications. The latter typically involve the use of storage devices by utility customers wishing to avoid the high price of electricity during peak periods. Cheaper power is purchased during base periods and stored for use during higher cost, peak periods.

Modular storage technologies, such as batteries and flywheels, can be deployed in either a utility-owned or in a nonutility-owned dispersed fashion. However, economic considerations currently seem to favor large utility- or third-party-owned installations. While storage technologies may at some point be installed in conjunction with large deployments of intermittent generating plants, such as photovoltaics or wind, storage facilities in the 1990s will most likely be used to store the inexpensive output of large, conventional plants.[80]

There are two storage technologies which could, under some circumstances, see significant deployment in the 199os: advanced batteries and compressed air energy storage (CAES). Batteries are a well-established technology, familiar mostly in mobile applications, but only recently have advances in chemistry and materials made it possible to construct large-scale systems with sufficiently long lifetimes and low capital costs to attract utility interest.

A CAES plant is a central station storage technology in which off-peak power is used to pressurize an underground storage cavern with air, which is later released to drive a gas turbine. The technology has been demonstrated in Europe, but not in the United States.

Compared to batteries, CAES plants have several advantages. They are in a more advanced stage of technical development and are likely to be less expensive than batteries on a dollar per kilowatt-hour basis when long discharge times (roughly 5 hours or more) are required. However, compared to batteries, CAES plants are less modular, and thus carry more financial risk per project.

Among the storage technologies not likely to make a significant additional contribution in the 1990s are pumped hydro, flywheels, and superconducting magnet energy storage. While there are numerous pumped hydro plants in existence in the United States, it has become difficult to site these plants if they involve a large, above-ground reservoir. If all the water is stored underground, the plants are economic only in very large units.[81] Flywheels, while possibly competitive in small installations, e.g., cars or homes, cannot compete economically with batteries or CAES in larger installations.[82] Finally, superconducting magnetic energy storage is not likely to be commercial before the next century.

Compressed Air Energy Storage

Introduction

A CAES plant uses a modified gas turbine cycle in which off-peak electricity—stored in the form of compressed air–substitutes for roughly two-thirds of the natural gas or oil fuel necessary to run an equivalent conventional plant (see figure 4-27). in a conventional plant, the turbine must power its own compressor to supply the compressed air necessary for operation. This makes only a third of the turbine's power available to produce electricity. In a CAES plant, however, off-peak electricity is used to drive the compressor (through the generator running in reverse as a motor) which charges an underground storage cavern with compressed air. Later the air is released and passes through a burner where a hydrocarbon fuel such as natural gas is burned.[83] The resulting hot gases then pass through a turbine which, freed from its compressor, can drive the electric generator with up to three times its normal fuel efficiency. The gases discharged from

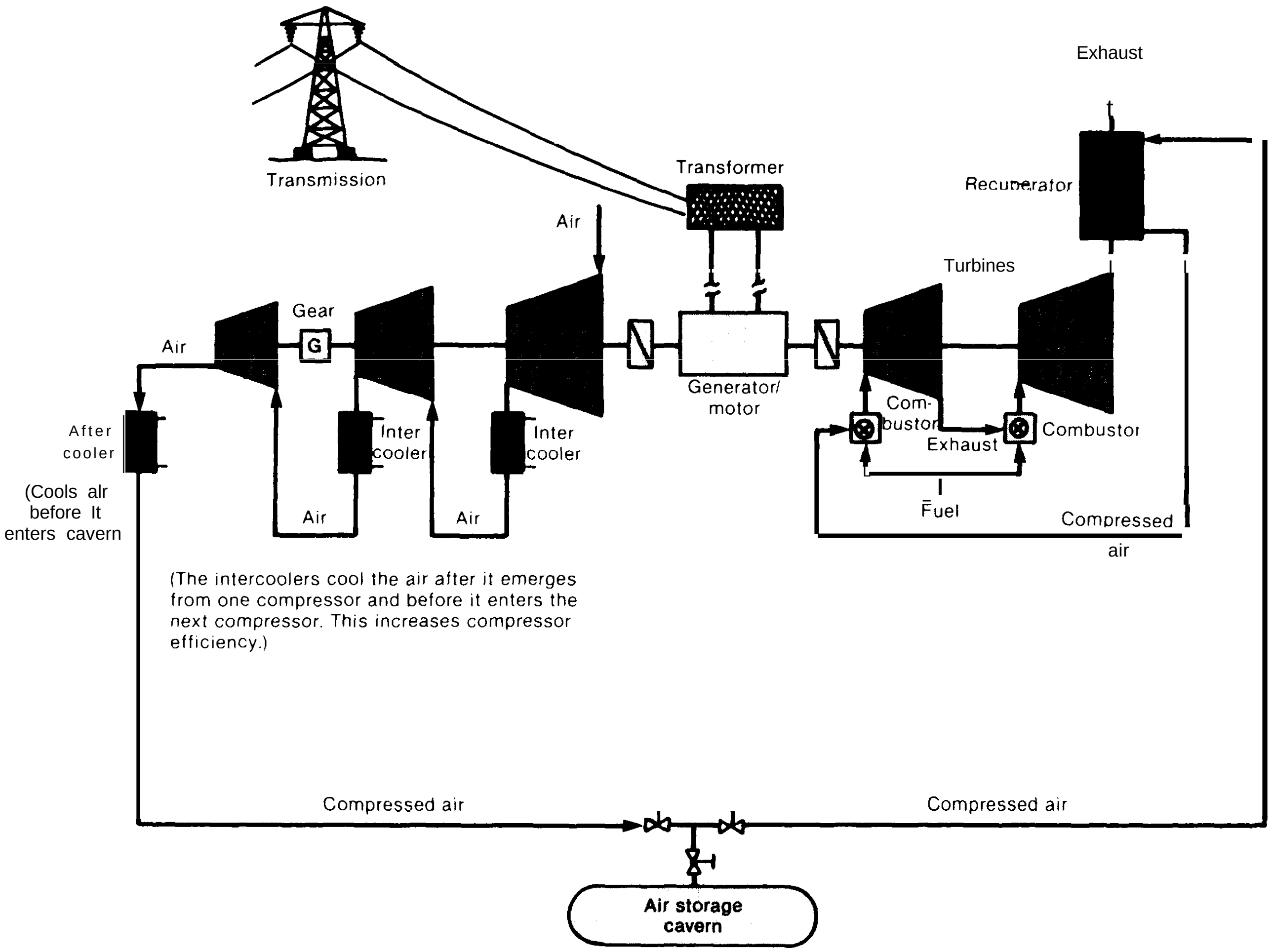
[80] As currently is the common practice with pumped hydroelectric facilities; there may be some exceptions, however, in certain isolated areas with large potential for renewable, such as Hawaii,

[81] Peter E. Schaub, Potomac Electric Power Co., comments on OTA electric power technologies November 1984 draft report, Jan. 29, 1985.

[82] James H. Swisher and Robert R. Reeves, "Energy Storage Technology," Energy Systems Handbook (New York: John Wiley & Sons, February 1983).

[83] In addition to the CAES technology described here, there are several, more advanced CAES systems which reduce or eliminate the need for natural gas or hydrocarbon fuel. These systems would be more expensive than the more conventional CAES systems, and while none have yet been demonstrated, they could be developed for the 1990s with sufficient utility interest.

Figure 4-27.– First Generation CAES Plant



A Compressed Air Energy Storage (CAES) plant is a modification of a conventional gas turbine cycle. Its principal components are combustion turbines, compressors, a generator/motor, and an underground storage cavern. The system stores energy by using electricity from the grid to run the compressor and charge the cavern with compressed air. This energy is discharged by releasing the compressed air to the combustion turbine where it is mixed with natural gas or oil and burned to produce the power which drives the generator. In a conventional gas turbine plant the turbine drives its own compressor simultaneously with the generator so that only a third of the turbine's total power is available to produce electricity. Thus, a CAES plant stores the energy in off-peak electricity to make a gas turbine three times as fuel efficient.

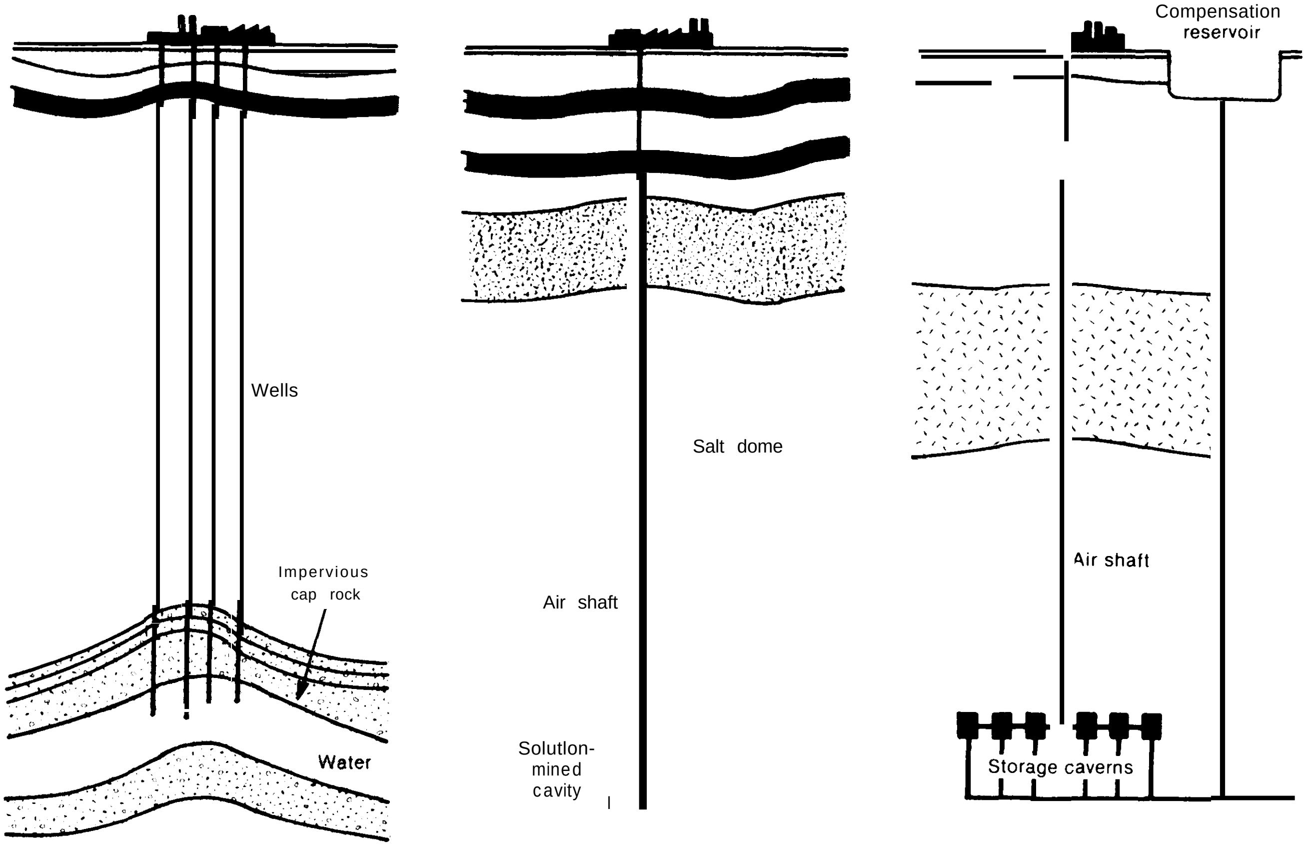
SOURCE: Robert B. Schainker, *Executive Overview: Compressed Air Energy Storage (CAES) Power Plants* (Palo Alto, CA: Electric Power Research Institute, 1983)

the turbine pass through a "recuperator" where they discharge some of their heat to the incoming air from the cavern; this, too, increases the overall efficiency of the plant.

Three types of caverns may be used to store the air: salt reservoirs, hard rock reservoirs, or aquifers (see figure 4-28). Each has its advantages and disadvantages. About three-fourths of the United States rests on geology more or less suitable for such reservoirs (see figure 7- I 2 in chapter 7). The salt domes are concentrated mostly in Louisiana and eastern Texas. Salt caverns are "solution-mined" by pumping water into the deposit and having it "dissolve" a cavern. The resulting reservoir is virtually air-tight. These salt caverns are pressurized to up to 80 atmospheres, have a depth of 200 to 1,000 meters, and a volume of 1,000 cubic meters/MWe.

Rock caverns are located throughout the United States. They must be excavated with underground mining equipment. A typical CAES plant using a rock cavern would be coupled to

Figure 4-28.—Geological Formations for CAES Caverns



In an aquifer system, numerous wells are sunk through an impervious caprock into porous material such as sand, sandstone, or gravel. The force of the surrounding water confines the compressed air and maintains it at a constant pressure as it is injected and withdrawn from the system.

Salt caverns are mined by a technique called solution-mining. A narrow well is drilled into a salt dome and fresh water is continuously pumped in to dissolve the salt while the resultant brine is pumped out. The process is continued until the desired storage volume is reached, The necessary volume is larger than that needed in a hard rock or aquifer system because without water present, the pressure of the compressed alr drops as it is withdrawn from the cavern,

Hard rock caverns are mined with standard excavation techniques. A compensation reservoir on the surface maintains a constant pressure in the cavern as the compressed air is injected and withdrawn. This minimizes the volume of rock it is necessary to excavate.

SOURCE “Eighty Atmospheres In Reserve” .E/W *Journa/,* April 1979

an above-ground compensating reservoir which would maintain a constant pressure in the cavern as it discharges. The maintenance of constant pressure offers several important operational advantages. In addition to maintaining the desired pressure, the reservoir also allows for a much smaller cavern than is the case with salt reservoirs. Thus, only about 600 cubic meters/MWe are needed underground, though a pool of about 700 cubic meters/MWe of water is required on the surface.[84]

84 Use of a compensating reservoir is less suitable for salt reservoirs because the salt dissolves in the water. This can only be prevented by the use of water saturated with salt, an approach which could result in major environmental problems.

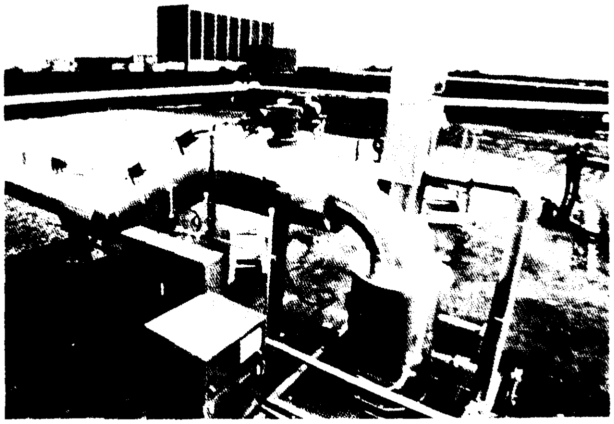
The aquifer reservoirs are naturally occurring geological formations found in much of the Midwest, the Four Corners region, eastern Pennsylvania and New York. An advantage of this kind of reservoir is that it does not require any excavation. It consists of a porous, permeable rock with a dome-shaped, nonporous, impermeable cap rock overlying it. Compressed air is pumped into the reservoir, forcing the water downward from the top of the dome. Later, as air is drawn from the reservoir, the water returns to its original place beneath the dome. An important advantage of this kind of reservoir lies in the fact that the volume of the reservoir is quite flexible, allowing for a variety of plant capacities and operating schedules.

With the exception of the recuperator, the technologies required for CAES plants—the turbomachinery and the reservoir-related technologies such as mining equipment—are well-established technologies. The turbomachinery is only a slight modification of currently used equipment and there are several manufacturers, American and foreign, that offer CAES machinery with full commercial guarantees, While there are some questions as to the dynamic properties of the air as it enters and leaves a cavern, there is little doubt that the technology exists to build and maintain underground storage facilities. These caverns have been used for years to store natural gas and other hydrocarbons, and the same firms that supply the oil and gas industry have offered to provide utilities with CAES caverns that can be warranted and insured.[85]

Despite the relative maturity most of the components which make up the CAES plant, there has been no experience in the United States with CAES itself–though a CAES plant using a salt cavern has been in operation since 1978 at Huntorf, West Germany (see figure 4-29) and has performed well. This lack of domestic experience with the technology constitutes the largest hurdle facing CAES. There is a general reluctance among utilities in this country to be the first to make a commitment to build a plant. While several utilities have made preliminary planning

[85] Personal correspondence between Arnold Fickett (Electric Power Research Institute) and OTA staff, July 2, 1984

Figure 4-29.—The Huntorf Compressed Air Energy Storage Plant in West Germany



[n the foreground is the wellhead, where compressed air is Injected and released The rest of the plant is in the background

SOURCE BBC Brown Boven, Inc

studies, the Soyland Electric Cooperative in Illinois is the only American utility that has ordered a plant. This plant, however, was for various reasons canceled and no project has been initiated since then.

Typical CAES Plant for the 1990s

CAES plants in the 1990s are likely to be available in two modular unit sizes, 220 MWe, commonly called *maxi-CAES,* and 50 MWe, *mini-CAES.* These sizes are determined by the sizes of existing models of turbomachinery—the turbines, compressors, generator/motor, and a gearbox which connects them.

A CAES plant must be sited in an area with access to water and fuel. The turbomachinery requires about 2,000 ga[lons/MWe of water per day, and a plant with a rock cavern needs additional water for the compensation reservoir. Both mini- and maxi-CAES plants burn about 4,000 Btu/kWh of fuel and emit the standard combustion byproducts, such as nitrogen oxide, but at only a third of the level of a similar size conventional gas turbine. CAES plants also have noise levels similar to those of more conventional plants. There are several waste disposal problems involved with building the caverns. If a rock cavern is used, it is necessary to dispose of a large volume of waste rock,[86] and when a salt cavern is used, the brine pumped out of the cavern must be disposed of. Land requirements would range from around 15 acres for a maxi-CAES plant to 3 acres for a mini-CAES plant.

The lead-times expected for CAES plants will probably range from 4 to 8 years. The large plants would occupy the higher end of the range, while the smaller units would fall at the lower end. The primary source of uncertainty in lead-time estimates concerns licensing and permitting, which is expected to take 2 to 4 years. Regulatory hurdles will vary depending on the type of reservoir used. Among the regulatory impediments are those relating to the disposal of the hard rock or brine from the mining operation, and relating to water usage and impacts. Also problematic may be the requirements of the Powerplant and industrial Fuel Use Act of 1978. Even though a CAES plant is an oil and gas saving device, the fact that it uses these fuels means a utility must receive an exemption from the act to operate one. A precedent was established when such an exemption was granted to the Soyland Electric Cooperative, but under the current regulations, exemptions would be required for every CAES plant.[87]

The properties of the two sizes are similar (see table A-8, appendix A); the mini-CAES turbomachinery costs somewhat less—$392/kWe vs. $51 5/kWe for the maxi-CAES. The storage caverns can be formed out of three types of geological formations: aquifers, salt deposits, and hard rock. In general, aquifers are the least expensive, followed closely by salt. Rock caverns, which must be excavated, are by far the most expensive. on a total dollars per kilowatt basis, caverns for maxi-CAES plants are less expensive than those for mini-CAES.

[86] This problem is greatly alleviated by the fact that the excavated material can be used in constructing the compensating reservoir or other facilities (Peter E. Schaub, comments on OTA electric power technologies November 1984 draft report, op. cit., 1985).

[87] P. L, Hendrickson, *Legal and Regulatory Issues Affecting Compressed Air Energy Storage* (Richland, WA: Pacific Northwest Laboratory, July 1981), PNL-3862, UC-94b.

Advanced Batteries

Introduction

Batteries are more efficient than mechanical energy storage systems, but their principal advantage is flexibility. Batteries are modular so that plant construction lead-times can be very short and capacity can be added as needed. Batteries have almost no emissions, produce little noise (though because of pumps and ventilation systems, they are not silent), and they can be sited near an intended load, even in urban areas. A battery's ability to rapidly begin charging or discharging (reaching full power in a matter of seconds, as opposed to minutes for a CAES system) makes it valuable for optimizing utility operations. However, battery-storage installations do not benefit very much from economies of scale either in capital costs or in maintenance costs, so that if large blocks of storage are required, CAES may be less expensive. Also, though cost effective and reliable in numerous remote applications, battery technology has not yet achieved the combination of low cost, good performance, and low risk necessary to stimulate investment in grid-connected applications.

There are two types of utility-scale batteries which under some circumstances could be particularly important in the 1990s: *advanced lead-acid batteries,* and *zinc-chloride batteries.* Lead-acid batteries are in wide use today mostly in automobiles and other mobile applications; advanced lead batteries constitute an incremental improvement over the existing technology. Zinc-chloride batteries are a newer technology, and constitute a fundamental departure from the conventional lead-acid battery. In both cases, individual modules similar to commercial modules which might be deployed in the 1990s, have been tested at the Battery Energy Test Facility in New Jersey.[88] Though neither type of battery has been deployed yet in a multi megawatt commercial installation, plans to do so during the late 1980s are being developed and implemented.

Other battery technologies meanwhile are being pursued. Among these, the most promising appear to be zinc-bromide batteries and sodium-

[88] See ch. 9 for further details on this facility.

sulfur batteries. But the development of both lags considerably behind that of the lead-acid and zinc-chloride batteries. Neither has been tested at the BEST facility; such tests are not likely to begin until 1989-90. Given the subsequent need for full-scale commercial demonstration installations and other time-consuming steps, it is very unlikely that either the zinc-bromide or sodium-sulfur batteries could be extensively deployed commercially in the 1990s. Several other advanced battery technologies, such as Iron/Chromium, Zinc/Ferricyanide, Nickel/Hydrogen, and Lithium/Iron Sulfide cells, are all considered even less developed and are not considered here either.

Typical Battery Installation for the 1990s

If battery technology is deployed in the 1990s by utilities, the general requirements of a typical plant, regardless of the battery technology employed, are expected to be a peak power output of 20 MWe and a storage capacity of about 100 MWh. Such a plant could consist of about 10 to 50 factory built modules, along with control and power conditioning equipment, housed in a protective building (see figures 4-30 and q-31). Battery installations outside the utility-industry might be considerably smaller.

The total land necessary will depend on both the so-called "energy footprint" (energy density i n kilowatt-hour per square meter) of the particular battery technology as well as the amount of space necessary for easy maintenance. Each of the reference battery installations discussed here will require about 0.02 to 0.03 acres. There are no fuel and only minimal water requirements.

The lead-time required to deploy battery installations is expected to be very short. Because of the comparatively low environmental impacts of the installation, licensing could proceed quite rapidly. And since the battery modules are factory built, construction can be very rapid too. The lead-time of the plant should be less than 2 years. There is, however, uncertainty regarding the time required for licensing and permitting. Concern over possible accidents and disposal of hazardous materials, discussed in greater detail below, could be a source of regulatory delays particularly when the installations are dispersed in urban areas.[89]

Though the battery installations will share many characteristics, other features of the battery plants will differ significantly, depending on the type of battery used. These individual characteristics therefore are treated separately below for each of the two battery types emphasized in this analysis.

Advanced Lead-Acid Batteries.—When fully charged, a lead-acid battery consists of a negative lead electrode and a positive lead dioxide electrode immersed in an electrolyte of sulfuric acid (see figure 4-32). As the battery discharges, the electrodes are dissolved by the acid and replaced by lead sulfate, while the electrolyte becomes water. When the battery is recharged, lead is deposited back on the negative electrode, lead peroxide is deposited back on the positive electrode, and the concentration of acid in the electrolyte increases.

The main advantage of lead-acid batteries is that the technology has been used for decades. It is likely that utility-sized batteries can be produced with sufficient performance characteristics for utility use. At present, it is possible to buy a load-leveling lead-acid battery with a guaranteed lifetime of 1,500 cycles.[90] Accelerated testing results indicate that refinements of the current design can probably bring the lifetime up to 3,000 to 4,000 cycles.[91] While such tests must always be regarded with caution, the many years of experience with accelerated testing of this technology lends confidence to these estimates. However, 4,000 cycles probably represents a limit on the lifetime attainable with current lead-acid battery technology.[92]

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[89]See:

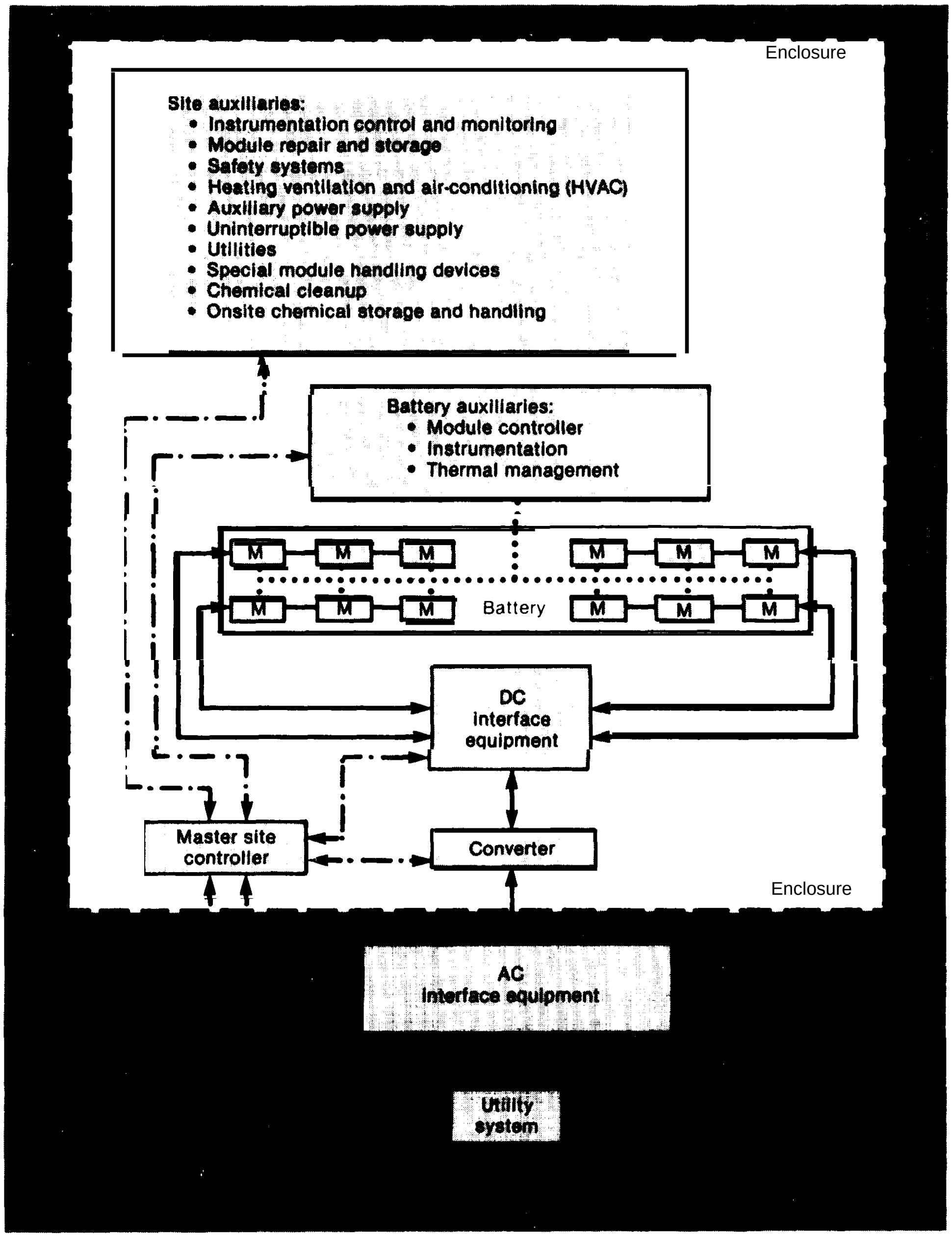
1. Bechtel National, Inc., *Generic Environmental and Safety Assessment of Five Battery Energy Storage Systems* (San Francisco, CA: Bechtel National, Inc., December 1981), DE82-902212.
2. J. Abraham, et al., Public Service Electric & Gas Co., *Balance of Plant Considerations for Load-Leveling Batteries (draft report)*(Newark, NJ: Public Service Electric & Gas Co., 1984).

[90]OTA staff interview with Arnold Fickett, Electric Power Research Institute, Aug. 30, 1984.

[91]Exide Management and Technology Company, *Research, Development, and Demonstration of Advanced Lead-Acid Batteries for Utility Load Leveling* (Argonne, IL: Argonne National Laboratory, August 1983), ANL/OEPM-83-6.

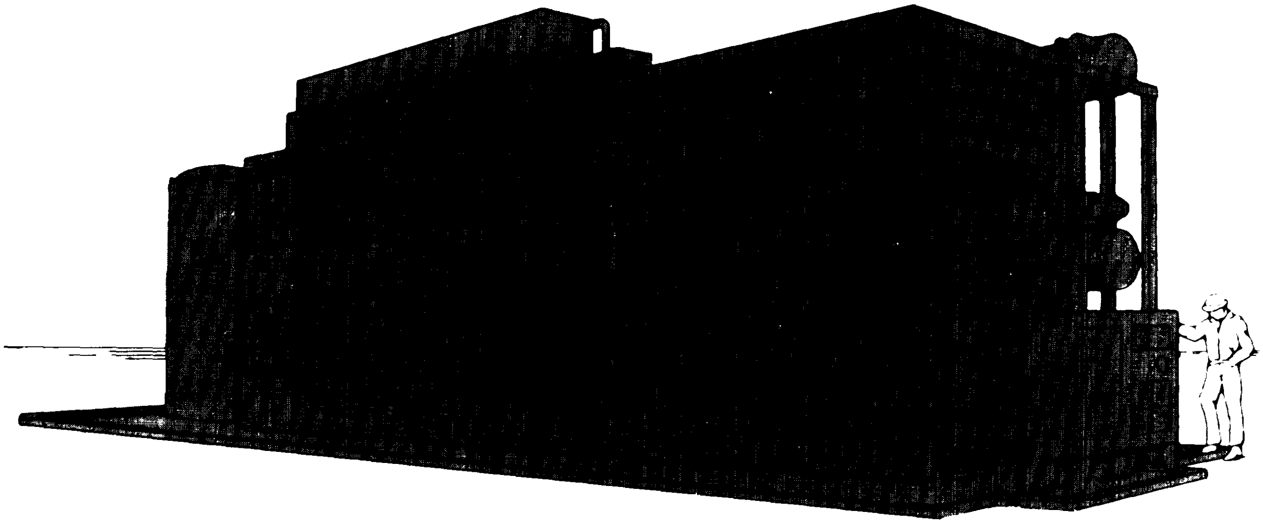
[92]OTA staff interview with Arnold Fickett, op. cit., 1984.

Figure 4-30.—Generic Battery System



SOURCE: Peter Lewis, Public Service Electric & Gas Co. (Newark, NJ), "Elements of Load-Leveling Battery Design for System Planning," presented at the International Symposium and Workshop on Dynamic Benefits of Energy Storage Plan Operation.

Figure 4-31.—A Commercial Load-Leveling Zinc-Chloride Battery System



This system is known as the FLEXPOWER System, developed by Energy Development Associates. This particular system is rated at 2 MWe, and can operate from 3 to 4 hours.

SOURCE: B.D. Brummet, et al., "Zinc-Chloride Battery Systems for Electric Utility Energy Storage," presented at the 19th Annual Intersociety Energy Conversion Engineering Conference San Francisco CA, Aug 19-24, 1984

The main problem with lead-acid batteries is the capital cost. (See appendix A, table A-9.) The price of lead has recently dropped, primarily because its use in paint and gasoline is legally prohibited in many instances. At this low price, the lead alloy and other active materials contribute about one-fourth of the battery's projected selling price of $600/kWe.[93]

This is close to the $500/kWe cost at which batteries are generally considered to be economic. The battery costs are so dependent on materials cost, however, and it is not clear if the prices of lead-acid batteries can be reduced much further. If the price of lead rises to its previous level, then the projected price would rise to over $800/kWe. These figures are based on a production level of 200 MWe/year, but since similar lead-acid batteries are already in production for mostly transportation applications, the utility price may not be a strong function of demand in stationary applications.

In general, the O&M costs of batteries will depend strongly on the extent to which various battery components survive in a highly corrosive environment. These costs are also likely to depend strongly on how the battery is used, e.g., one deep discharge a day versus many shallow discharges. Current estimates indicate that the largest component of the O&M costs for lead-acid batteries will most likely be due to the periodic replacement of the battery stacks every 2,000 to 4,000 cycles (roughly equivalent to 8 to 16 years). Since many parts of the used stacks, such as the lead, are reusable or recyclable, a replacement stack only costs about 50 percent of the original. Assuming the plant operates for 250 five-hour cycles per year, these costs, levelized over a 30-year-plant life, are 6 to 20 mills/kWh.

The costs of the daily maintenance can be greatly reduced by the addition of systems such as an automatic water system to add water to the batteries, and monitors to track chemical concentrations. However, battery housings will have to be cleaned periodically to prevent deposits from developing which could short circuit battery terminal connections. These annual O&M costs are estimated to be about 1 to 4 mills/kWh.

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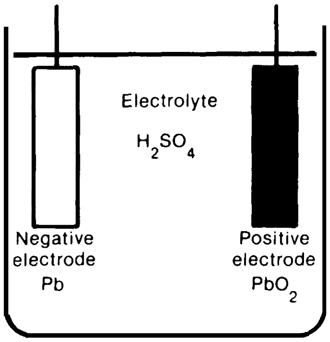
[93] Battery capital costs are best represented in units of kilowatt-hour not kilowatt-electric. However, to be consistent with the other technologies considered here, we will use this latter measure. To convert kilowatt-electric to kilowatt-hour, divide the former by 5 (assuming a five hour discharge period).

Figure 4-32.— Lead-Acid Batteries

The illustrations below show how a lead-acid battery stores electrlc energy. Advanced lead-acid batteries differ (n the construction of the electrodes, etc., but the basic operation is the same as the more traditional designs.

In its fully *charged* state, the negative electrode consists of spongy lead with a small mixture of antimony (around 10 percent), while the positive electrode is lead dioxide. The electrolyte is sulfuric acid.

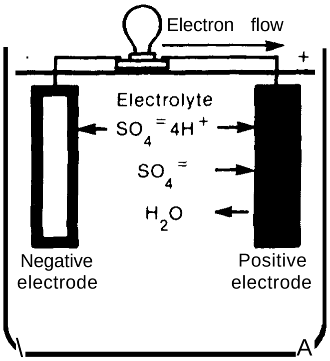


Fully charged

As the battery *discharges*, the lead in the negative electrode reacts with sulfate ions in the electrolyte to form lead sulfate and release two electrons. At the positive electrode, these electrons combine with the lead dioxide in the electrode, and four hydrogen ions and a sulfate ion from the electrolyte to form lead sulfate and water.

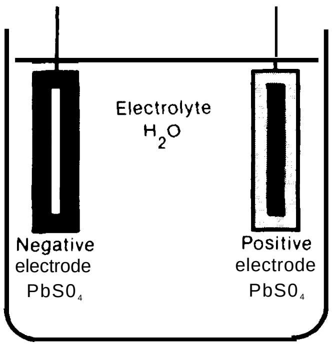
Negative electrode: $pb + SO_4^{=} \rightarrow PbSO_4 + 2e^-$

Positive electrode: $PbO_2 + 4H^+ + SO_4^{=} + 2e^- \rightarrow PbSO_4 + 2H_2O$



Discharging

When fully *discharged,* the battery's electrodes are almost entirely lead sulfate and the electrolyte is largely water.

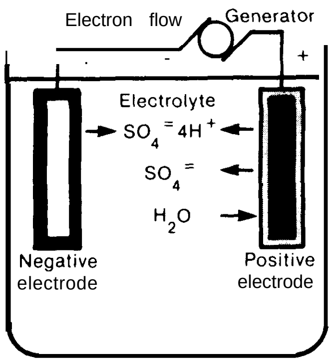


– Discharged

To *charge* the battery, electrons are driven back into the negative electrode, where they combine with the lead sulfate to form lead, which remains on the electrode, and sulfate ions, which are released into the electrolyte. At the positive electrode, the lead sulfate combines with water molecules to form lead dioxide, which stays on the electrode, hydrogen and sulfate ions which are released into the electrolyte, and two electrons, which are driven by the charging generator to the negative electrode.

Negative electrode: $PbSO_4 + 2e^- \rightarrow Pb + SO_4^{=}$

Positive electrode: $PbSO_4 + 2H_4O \rightarrow PbO_2 + 4H^+ + SO_4^{=} + 2e^-$



Charging

SOURCE: *The Encyclopedia Americana*, International Edition (Danbury, CT: Encyclopedia Americana Corp., 1980), vol. 3. p. 360

The safety hazards of advanced lead-acid batteries occur primarily if the battery is overcharged. In this instance, it will generate potentially explosive mixtures of hydrogen and oxygen which must be ventilated. Stibine and arsine can also be formed from the materials used in the electrodes. Finally, there are also dangers from acid spills and fire. When the battery is decommissioned, the lead must be recycled, and the acid disposed of. However, there is much experience with lead-acid batteries, and few safety problems are anticipated if well-established maintenance and safety procedures are followed.

Zinc-Chloride Batteries.–The zinc-chloride battery has been under development since the early 1970s. It is a flowing electrolyte battery (see figure 4-33). During charging, zinc is removed from the zinc-chloride electrolyte and deposited onto the negative graphite electrode in the battery stack, while chlorine gas is formed at the positive electrode. The gas is pumped into the battery sump, where it reacts with water at 10° C to form chlorine hydrate, an easily managable slush. During discharge, the chlorine hydrate is heated to extract the chlorine gas, which is pumped back into the stack, where it absorbs the zinc and releases the stored electrical energy.

A principal advantage of the zinc-chloride battery is that it promises to be ultimately less expensive than the lead-acid battery, due primarily to the inexpensive materials that go into its construction. However, the technology, which requires pumps and refrigeration equipment, is more complex—it is sometimes described as being more like a chemical plant than a battery.[94] Since no commercial design zinc-chloride battery has yet been operated, any cost projections must be taken with some caution. (See appendix A, table A-9.)

Estimates indicate that at a production level of about 700 MWe/year, zinc-chloride batteries could be sold at a price less that-t $500/kWe, Because zinc-chloride batteries will most likely make their first appearance in grid-connected use (unlike lead-acid batteries which are already sold in other markets), this price is likely to depend strongly on the volume produced. If only 50 MWe/year were made, the price could be about $860/kWe; and early commercial units could cost as much as $3,000 /kWe.

The zinc-chlorine battery may have a longer lifetime than the lead-acid battery. The best cells have run for 2,500 cycles, and while there have been numerous problems with pumps and plumbing, no basic mechanisms have been identified which would limit the lifetime to less than 5,000 cycles.[95] However, the 500 kWh test module at the BEST facility has only run for less than 60 cycles, and several tough engineering problems have yet to be overcome before the battery can have a guaranteed lifetime long enough for commercialization. In addition, the AC to AC round-trip efficiency, which is currently in the low 60 to 65 percent range for the large battery systems, must be increased to 67 to 70 percent; values in this range have been attained by smaller prototypes.

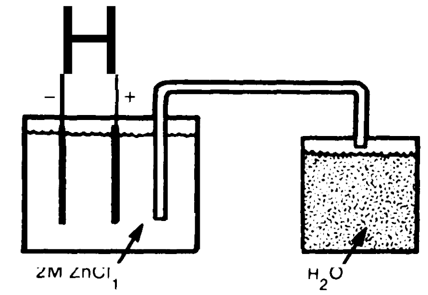
The O&M requirements of zinc-chloride systems are even more uncertain than for lead-acid systems. However, the expected longer lifetimes, and the less expensive replacement costs for the stacks and sumps (estimated to be about one-third the initial capital cost of the battery) should lead to levelized replacement O&M *costs in the 3* to 9 mills/kWh range. For lack of better data on operating experience, the annual O&M costs are estimated to be the same as for lead-acid, 1 to 4 mills/kWh, though because of the increased complexity of the system, they probably will be higher.

Another major advantage of the zinc-chloride battery over the lead-acid battery is that their reaction rates are controllable. This is due to the fact that, in a charged zinc-chloride battery, the zinc and the chlorine are separated in the stacks and sumps. The rate at which the battery discharges is controlled by the speed at which the pumps allow the reactants to recombine. This not only makes the battery more flexible in its operation, but provides a major safety advantage in that if a zinc-chloride cell malfunctions, its discharge can be stopped by shutting off the chlorine pumps. In contrast, the reactants in a

[94]OTA staff interviews with (1) Arnold Fickett, op. cit., 1984 and (2) J.J. Kelley, EXIDE Corp., Aug. 29, 1984,

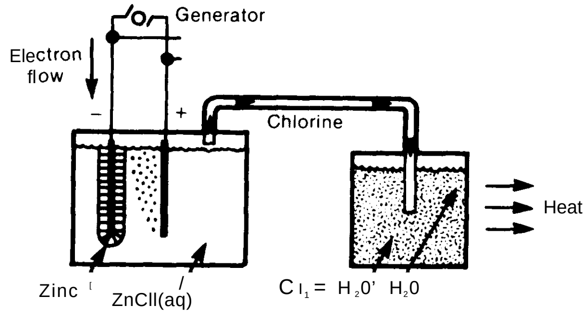
[95]OTA staff interview with Arnold Fickett, op. cit., 1984.

Figure 4-33.—Zinc-Chloride Flowing Electrolyte Batteries



Fully discharged

n its fully *discharged* state, the electrolyte in the battery stack consists of a concentrated solution of zinc chloride. The graphite negative electrode and the graphite or ruthenia-catalyzed porous titanium positive electrode are inert. The battery sump contains water.



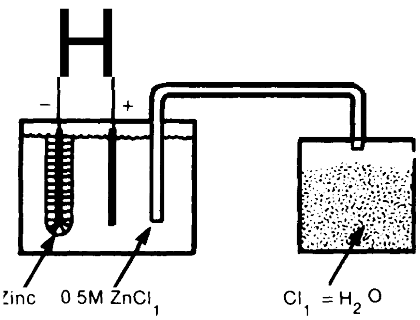
Charging

As the battery is *charged,* chlorine ions from the electrolyte combine at the positive electrode to form chlorine gas and release two electrons. These electrons are driven to the negative electrode by the charging generator There they combine with zinc being plated onto the negative electrode, The chlorine gas is pumped to the sump which has been chilled to below 10 "C, The gas reacts with the cold water and forms an easily storable solid, chlorine hydrate.

Negative electrode: $Zn^{+} + e^{-} \rightarrow Zn$

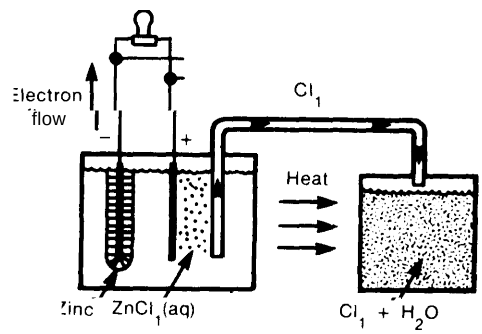
Positive electrode: $2\ Cl' \cdots Cl_2 + 2e^{-}$

Sump: $Cl_2(\text{aqueous}) + xH_2O \rightarrow Cl_2 = xH_2O\ (\text{solid})$



Fully charged

When the battery is fully *charged,* the negative electrode is plated with zinc and the electrolyte has only a weak concentration of zinc chloride. The battery sump is filled with chilled chlorine hydrate.



Discharge

The battery is *discharged* by heating he chloride hydrate in the sump, which then releases the chlorine gas. This gas is pumped to the stack, where it combines with electrons from the positive electrodes and breaks into chlorine ions. At the negative electrode the zinc atoms release electrons and enter the electrolyte as zinc lons.

Negative electrode: $Zn - Zn^{+} + e^{-}$

Positive electrode: $Cl_2 + 2e^{-} \rightarrow 2\ Cl^{-}$

Sump: $Cl_2 + xH_2O\ (\text{solid}) \cdots Cl_2(\text{gas}) + xH_2O$

SOURCE: Energy Development Associates, *Development of the Zinc-Chloride Battery for Utility Applications* (Palo Alto, CA: Electric Power Research Institute, June 1983), EPRI EM-3136.

charged lead-acid battery cell remain in the same battery case, so that short-circuited terminals could lead to a sudden release of the stored energy.

A major concern of regulatory officials considering zinc-chloride plants is likely to be the safety problems associated with the accidental release of chlorine. Since the chlorine is stored in a solid form, there is no danger of a sudden release of large quantities of the gas. However, the same procedures used in industrial plants manufacturing or using this gas must be followed. In addition, the sum ps must be sufficiently insulated so that in the event of a malfunction of the refrigeration system, the chlorine will stay frozen in the chloride hydrate phase long enough for repairs to be made.

SUMMARY OF CURRENT ACTIVITY

The tables in appendix A at the end of this report summarize the cost and performance characteristics discussed in this chapter. Table *4-2* summarizes the information detailed in the appendix. Table 4-4 provides an overview of the plants which currently are installed or operating in the United States. The extent to which capacity already has been deployed or is being constructed provides an additional indication of the cost, performance and risk associated with the technologies.

Table 4.4.—Developing Technologies: Major Electric Plants Installed or Under Construction by May 1, 1985

Technology	Capacity	Location	Primary sources of funds	Status
Wind turbines[a]	550+ MWe (gross)[b]	California wind farms	Nonutility	Installed
	100+ MWe (gross)[c]	U.S. wind farms outside of California	Nonutility	Installed
	? MWe[d]	All U.S. wind farms	Nonutility	Under construction (1986)
Solar thermal electric:				
Centrai receiver	10 MWe (net)[e]	Daggett, CA	Utility, nonutility, and Government	installed
	0.75 MWe	Albuquerque, NM	Utility, nonutiiity, and Government	Installed
Paraboiic trough	14 MWe (net)	Daggett, CA	Nonutility	Installed
	30 MWe (net)	Daggett, CA	Nonutiiity	Under construction (1986)
Parabolic dish	0.025 MWe (net)[f]	Palm Springs, CA	Government	Installed
	2 x 0,025 MWe (net)[f]	Various iocations	Nonutility	Installed
	2 x 0.025 MWe (net)[f]	Various locations,	Non utility	Under construction
	3.6 MWe	Warner Springs, CA	Nonutility	Installed
Solar pond	None			
Photovoltaics:				
Fiat piate	1 MWe (de, gross)	Sacramento	Utility and Government	Installed
	1 MWe (de, gross)	Sacramento, CA	Utility and Government	Under construction (1985)
	1 MWe (de, gross)	Hesperia, CA	Nonutility	installed
	6.5 MWe (de, gross)	Carrisa Plains, CA	Nonutility	Installed
	0.75 MWe (de, gross)	Carrisa Plains, CA	Nonutility	Under construction
Concentrator	4.5 MWe (de, gross)	Borrego Springs, CA	Nonutility	Instaiiedg
	1.5 MWe (de, gross)	Davis, CA	Nonutility	Installed
	3.5 MWe (de, gross)	Barstow, CA	Nonutiiity	Instaiiedg
Geothermal:				
Dual flash	10 M'We	Brawley, CA	Utility lnonutiiity	Installed
	10 MWe	Salton Sea, CA	Utilitylnonutility	Installed
	47 MWe (net)	Heber, CA	Nonutility	Under construction (1985)
	32 MWe (net)	Salton Sea, CA	Nonutility	Under construction (1985)
Binary:				
Smail	2 x 3.5 MWe	Mammoth, CA	Nonutility	Installed
	3 x 0.3 MWe	Hammersly Canyon, OR	Nonutility	Installed
	3 x 0.4 MWe	Hammersly Canyon, OR	Nonutility	Instalied[h]
	10 MWe	East Mesa, CA	Nonutility	installed
	1 x 0.75 MWe (gross)	Wabuska, NV	Nonutiiity	Instalied
	3 x 0.35 MWe (gross)	Lakeview, OR	Nonutiiity	Instaiied[h]
	3 x 0.45 MWe (gross)	Lakeview, OR	Nonutiiity	Instailed[h]
	4 x 1.25 MWe (gross)	Suifurviiie, UT	Nonutiiity	Under construction (1985)!
	3 x 0.85 MWe (gross)	Sulfurville, UT	Nonutility	Under construction (1985)[i]
Large	45 MWe (net)	Heber, CA	Utility, nonutility, and Government	Installed

Table 4-4.—Developing Technologies: Major Electric Plants Installed or Under Construction by May 1, 1985-Continued

Technology	Capacity	Location	Primary sources of funds	Status
Fuel cells:				
Large	None			
Small[j]	38 × 0.04 MWe (net)	Various locations	Utility, nonutility, and Government	Installed
Small[j]	5 × 0.04 MWe (net)	Various locations	Utility, nonutility, and Government	Under construction
Fluidized-bed combustors:				
Large grass roots	160 MWe	Paducah, KY	Utility[k] and Government	Under construction (1989)
Large retrofit	100 MWe	Nucla, CO	Utility[k]	Under construction (1987)
	125 MWe	Burnsville, MN	Utility[k]	Under construction (1986)
	125 MWe	Brookesville, FL	Nonutility	Under construction (1986)
Small cogeneration	30 MWe	Colton, CA	Nonutility	Under construction (1985)
	25 MWe	Fort Wayne, IN	Nonutility	Under construction (1986)
	15 MWe	Ione, CA	Nonutility	Under construction (1987)
	67 MWe	Chester, PA	Nonutility	Under construction (1986)
	90 MWe[l]	Decatur, IL	Nonutility	Under construction (1986)
	50 MWe[m]	Cedar Rapids, IA	Nonutility	Under construction (1987)
	3.5 MWe	Pekin, IL	Nonutility and Government	Installed
	28 MWe	Pontiac, MI	Nonutility	Under construction (1986)
	2.8 MWe	Washington, DC	Nonutility and Government	Installed
	24 MWe	Enfield, ME	Nonutility	Under construction (1986)
	20 MWe	Chinese Station, CA	Nonutility	Under construction (1986)
IGCC[n]	100 MWe	Daggett, CA	Utility, nonutility, and Government	Installed
Batteries:				
Lead acid[o]	0.5 MWe	Newark, NJ	Utility and Government	Installed
Zinc chloride	None[p]			
CAES:				
Mini	None			
Maxi	None			

[a]Includes small- and medium-sized wind turbines.
[b]Approximately 550 MWe were operating in California at the end of 1984. It is not known how much additional capacity was installed by May 1985
[c]Approximately 100 MWe were operating outside of California at the end of 1984. It is not known how much additional capacity had been installed outside California by May 1985.
[d]It is not known how much capacity was under construction on May 1, 1985.
[e]This facility, the Solar One Pilot plant, is not a commercial scale plant and differs in other important ways from the type of system which might be deployed commercially in the 1990s.
[f]This installation consists of only one electricity producing module; a commercial installation probably would consist of hundreds of modules.
[g]Only 10 percent of the modules were operating at the time because of problems with the power conversion systems.
[h]Installed but not operating, pending contractual negotiations with utilities.
[i]The equipment modules have been delivered to the site; site preparation, however, has not started.
[j]These units are not commercial-scale units.
[k]Including the Electric Power Research Institute.
[l]This is the total capacity which may be generated from the four AFBC boilers which will be installed,
[m]This is the total capacity which may be generated from the two AFBC boilers which will be installed.
[n]While this installation, the Cool Water unit, uses commercial scale components, the installation itself is not a commercial-scale installation,
[o]While this installation at the Battery Energy Storage Test Facility uses a commercial-scale battery module, the installation itself is not a commercial-scale installation
[p]A 0.5-MWe zinc chloride commercial-scale battery module was, however, operating at the Battery Energy storage Test facility until early 1985.

SOURCE: Office of Technology Assessment.