Chapter 5

Industrial, Commercial, and Rural Cogeneration Opportunities

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INDUSTRIAL COGENERATION

Large amounts of fuel are used to produce thermal energy for U.S. industries and this energy represents a potential for fuel savings through cogeneration. Industrial cogeneration is firmly established as an energy supply option in the United States, with a total installed capacity of about 9,000 to 15,000 megawatts (MW), or about 3 percent of the total U.S. electricity generating capacity (1 2). Industrial cogeneration currently saves at least 0.5 Quad of fuel each year.

The onsite production of electricity in industry (not necessarily cogeneration) has declined steadily throughout the 20th century. This decline was the result of a number of economic and institutional considerations that made it more advantageous for industries to buy electricity from utilities than to generate it themselves. At the same time, however, the technical potential for cogeneration (the number of industrial sites where the demand for thermal energy is sufficient to justify a cogeneration system) has been growing, and today may be as high as 200 gigawatts (GW) of capacity (equal to about 33 percent of total U.S. electricity generating capacity; see below). But, just as economic and institutional issues were responsible for the decline of onsite generation during the 20th century, these issues, rather than technical constraints, mean that the market potential (the number of sites at which investment in cogeneration will be sufficiently attractive) is much lower than the technical potential–perhaps 40 to 100 GW by 2000.

Industrial cogeneration systems may use any of the possible technology and fuel combinations described in chapter 4. These systems generally are smaller than baseload utility powerplants, but still vary considerably in size. Examples of proposed cogeneration units now under consideration illustrate this range: A 125-kW wood-fired unit being built in Pennsylvania to burn the scraps from a furniture company plant; a 5.8-MW combustion turbine system being built to serve a boxboard company on the west coast; a 60-MW biomass- and coal-fired system proposed for a pulp and paper mill in northern Mississippi; and a 140-MW coal-burning unit proposed by a major oil company to serve a complex of refineries and chemical plants on the gulf coast of Louisiana. This section will describe the industrial cogeneration technologies and applications, discuss the criteria for implementing an industrial cogeneration system, and review estimates of the market potential for industrial cogeneration.

Industrial Cogeneration Technologies and Applications

The cogeneration systems in place today primarily use steam turbine technology in a topping cycle. Steam is raised in a high-pressure boiler and then piped through a turbine to generate electricity before heat is extracted for the industrial process (see ch. 4). The thermal output of the turbine generally ranges from less than 50 to over 1,000 psig, which is appropriate for many types of industrial steam processes. The steam turbine topping cycle is extremely versatile, in that it can use any fuel that can be burned in a boiler; oil, gas, coal, and biomass are routinely used. But when the steam turbine technology is used for cogeneration, only 5 to 15 percent of the fuel is turned into electricity. Thus, these cogenerators usually are sized to fit an industry's steam load, and they produce less electricity than other cogeneration technologies.

The measure of the ability of cogeneration technologies to produce electricity is the ratio of electrical output (measured in kWh) to steam output (measured in million Btu), or the electricity-to-steam (E/S) ratio. A steam turbine cogenerator will produce 30 to 75 kWh/MMBtu, For some industries, this is only enough electricity to satisfy onsite needs, but, in others a modest amount may be available for export offsite as well. Higher E/S ratio technologies that have been proven in industrial uses are combustion turbines, diesels, and combined cycles. The combustion turbine can generate two to seven times as much electricity with a given quantity of fuel as the steam turbine, and the diesel five to twenty times as much. Combined-cycle systems perform in a range between combustion turbines and diesels. Typical E/S ratios for these technologies are given in table 31 (see also ch. 4). Shifts in future cogeneration projects to these higher E/S systems would increase the amount of electricity that could be provided to the grid, and would save more fuel than with the use of lower E/S technologies.

Fuel savings is one important advantage of cogeneration. All of the proven cogeneration technologies use about 50 to 60 percent as much fuel to generate a kilowatt-hour of electricity (beyond the fuel otherwise needed to produce process steam) as is required by a conventional steam generating station. Whereas a central station powerplant requires 10,000 to 11,000 Btu/kwh, the proven cogeneration systems require only about 4,500 to 7,500 Btu/kWh (see table 31). There is no particular fuel savings in the steam production part of the cogeneration process; raising steam by cogeneration usually is allocated the same amount of fuel as required by a conventional boiler. Therefore, overall fuel savings are roughly proportional to the total electricity production achievable with each technology.

However, while the higher E/S technologies produce more electricity and save more fuel than the standard steam turbines, their fuel versatility is more limited. Higher E/S systems can only

Table 31.—Fuel Utilization Characteristics of Cogeneration Systems

	Heat rate[a] (Btu/kWh)	Second law efflciencyb	E/S ratio (kWh/MhfBtu)
Steam turbine	4,500-6,0(N)	0.40 (0.32)	30-75
Combustion turbine	5,500-6,5fxl	0.47 (0.34)	140-225
Combined cycle	5,000-6,000	0.49 (0.35)	175-320
Diesel	6,000-7,500	0.46 (0.35)	350-700

The fuel required to generate elactrklty, In excess of that required for process steam production alone, assuming a boiler efficiency of 88 percent for process steam production.

%he second law efficiency for separate process steam and central station electricity generation Is shown In parentheses (see ch. 4).

SOURCE: Office of Technology Assessment from material in ch. 4.

use liquid or gaseous fuels of uniform composition and high purity, or turbine parts or engine parts may be corroded or eroded. Although there is some experimental work with coal and coal-derived fuels for use in high E/S cogeneration technologies, the only proven cogeneration technology using coal today is the steam turbine. Some of the technologies under development that could use coal in industrial applications are discussed below.

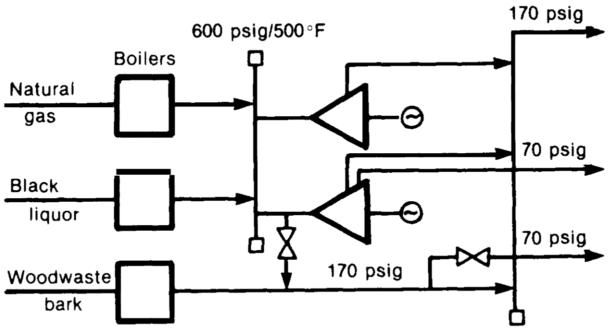
Systems Design

The characteristics of presently employed systems vary enormously. Rather than try to generalize the system configurations that might be used in different industries, six examples of successfully operating cogeneration plants are described briefly below.

A **pulp and paper industry** cogeneration system at the Potlatch Corp. plant in Lewiston, Idaho, burns various woodwastes and the “black liquor” from the first stage of the pulping operation, plus natural gas. This plant began to cogenerate in 1951, when the company installed a 10-MW steam turbine, which was supplemented by another 10 MW of capacity in 1971. The cogeneration system produces steam at both 170 and 70 psig, plus 23 percent of the plant’s electrical needs. The system generates less than’ the electric load needed onsite because of the extremely low retail electricity rates and purchase power rates in the region (see tables 19 and 34), but will be upgraded in the 1980’s with an additional 30 MW of capacity, at a cost of $89 million (1980 dollars), to supply almost all the onsite demand. The system is extremely reliable, operating 24 hours per day 360 days per year, giving a system availability of over 90 percent. Electrical efficiency (fraction of fuel Btu converted to electricity) is 64 percent, and the maintenance cost is 3 to 4 mills/kWh (29). A schematic of the cogeneration system is shown in figure 45.

An example of a chemicai industry cogeneration system, that is sized to export electricity to the grid, is the system installed by the Celanese Chemical Co. at its Pampa, Tex., plant in 1979. The system burns pulverized low-sulfur Wyoming coal in two large high-pressure boilers, each

Figure 45.—Potlatch Corp.—Schematic of the Cogeneration System



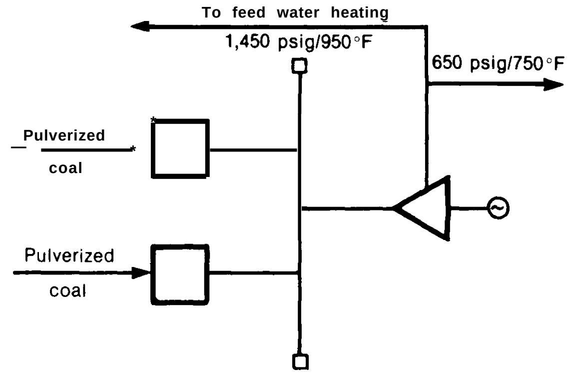
SOURCE: Synergic Resources Corp., *Industrial Cogeneration Case Studies* (Palo Alto, Calif.: Electric Power Research Institute, EPRI EM-1531, 1980).

producing 650,000 lb/hr of steam. After passing through a 30-MW steam turbine, the output steam is available (at 650 psig) for use in the plant. The boilers produce about 20 percent more steam than the plant needs, so the extra is used to heat the system's feedwater. The extra steam could be used for plant expansion in the future (29).

The Celanese Chemical Co. shares ownership of this system with a utility. The arrangement may be unique. The turbine and all the electricity produced are owned by the local utility, Southwestern Public Service Co., while the boiler and the steam it produces are owned by Celanese. The chemical company sells steam to the utility, which in turn sells electricity to Celanese at a favored rate—2.6¢/kWh including an 0.53¢/kWh standby charge. Without cogeneration, the company would have paid 3¢/kWh for retail electricity. (Rates quoted are for 1978.) The rate of return on this arrangement is expected to be over 20 percent for Celanese and over 15 percent for Southwestern Public Service. The cost of the system was $70 million (1979 dollars), the bulk of which was for coal conversion equipment (the plant previously used natural gas to raise steam). Operating and maintenance (O&M) costs are about 2.7 mills/kWh. The annual capacity factor for the system, including 2 to 4 weeks of planned downtime for maintenance, has been 72 percent (29). The system, for which a schematic is given in figure 46, operates to follow the electrical load.

One of the oldest ongoing cogeneration projects in the country serves a major **petroleum**

Figure 46.—Celanese Chemical Co./Southwestern Public Service Co.—Schematic of the Cogeneration System



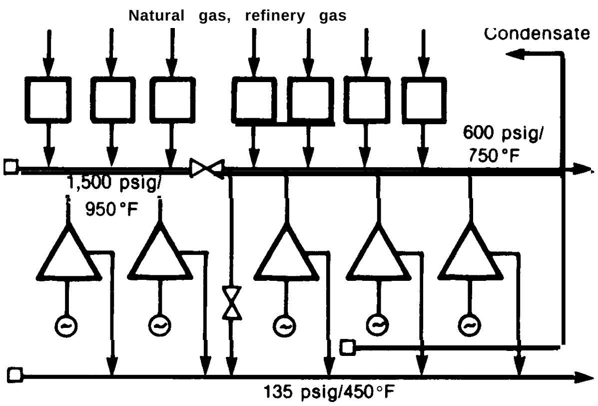
SOURCE: Synergic Resources Corp., */rrdustr/a/ Cogenerator* Case *Stud/es* (Palo Alto, Cahf : Electric Power Research Institute, EPRI EM.1531, 1980).

refinery, as well as a chemical manufacturer that produces ethyl lead for increasing gasoline octane. The system (Louisiana Station #l at Baton Rouge, La.) was built by the Gulf States Utility Co. in 193o and upgraded several times over the decades to a present capacity of 129 MW of electricity and 3.6 million lb/hr of steam. It has now been cogenerating successfully for almost half a century with only one unscheduled outage (during an electrical storm in 1960) (29).

This cogeneration plant uses natural gas and refinery waste gas as fuel for its boilers, which produce both 600 and 135 psig steam for sale by the company to its industrial customers. The overall efficiency of the system is 73 percent, and the industrial customers consider the system extremely reliable. Exxon, the refinery owner, has a 7-year contract for steam supply. The utility sells both the electricity and steam from the station (sale of the steam is unregulated), and the industrial users provide most of the fuel and pay the operating costs (29). Figure 47 presents a diagram of the Gulf States system.

Due to natural gas price increases, Louisiana Station #1 may be phased out soon. Until 1979, Gulf States had long-term gas contracts for $0.30/MMBtu, and when these contracts expired the price rose to $2.60/MMBtu. At the same time that their fuel prices were increasing, energy conservation by their industrial customers substantially reduced the demand for steam, which now

Figure 47.—Gulf States Utility Co.—Schematic of the Cogeneration System



SOURCE: Synergic Resources Corp., *Indusfrial Cogeneration Case Studies* (Palo Alto, Callf Electrlc Power Research Institute, EPRI EM-1531, 1980)

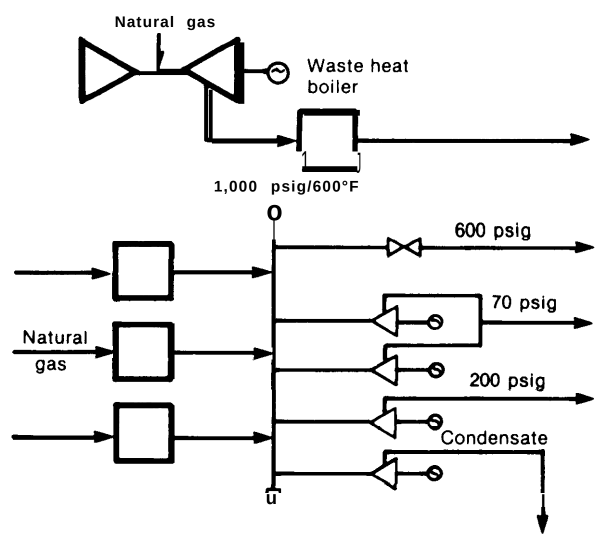
stands at one-half or two-thirds of the level that prevailed 2 to 3 years ago, according to Gulf States (29).

Gulf States reports that it is not in a position to raise the capital for a new system easily (the most recently added increment of capacity is now 27 years old), so the present system may be retired and a new one built by Exxon. Exxon is planning a 150- to 180-MW coal-fired cogenerator nearby. The proposed new cogeneration plant would produce 6 million to 8 million lb/hr of process steam and potentially could supply more industrial customers than the existing system.

Another cogeneration system associated with a chemical company in the southern part of the country is the Texas City, Tex., plant of the Union Carbide Corp. The Texas City cogeneration system is owned by the chemical company, which produces a wide variety of products from alcohols to plastics, and uses natural gas for fuel. The system is a complex network of both steam and combustion turbines that was started in 1941. It produces up to 70 MW of electricity, but historically has not sold any for use offsite due to regulatory restrictions, The peak demand for the plant is 40 MW. Union Carbide reports that it is satisfied with its return on investment, but that rising natural gas prices make future cogeneration questionable, especially with combustion turbines, Union Carbide is now concentrating on conservation through heat recovery applications and waste heat utilization, rather than cogeneration (29). This system is sketched in figure 48.

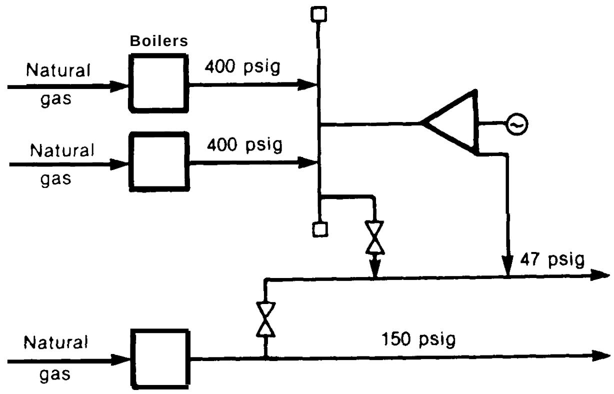
The operating patterns of food plants are considerably different from those of chemical or pulp plants. An example of a food plant that only operates 4 months per year is the Holly Sugar Corp. plant at Brawley, Cal if. The plant's 7.5-MW steam turbine system provides all the steam and electricity needed onsite. The company reports that it installed the cogeneration system for economics and reliability—there had been interruptions in power when it drew electricity from the local grid. Now the system is isolated from the grid and operates to provide the electrical load required for the plant. Holly Sugar reports that reliability is very high (99,9 percent) for the 120 days per year that the plant operates. The reported annual capacity factor is expectedly low for such a plant schedule—25 percent. This may be too low for economic cogeneration under most circumstances, but the alternative is charges for utility-generated power during the summer months, which would be seasonably high—a factor that improves cogeneration economics (29). A schematic for the system is shown in figure 49.

Figure 48.—Union Carbide Corp.—Schematic of the Cogeneration System



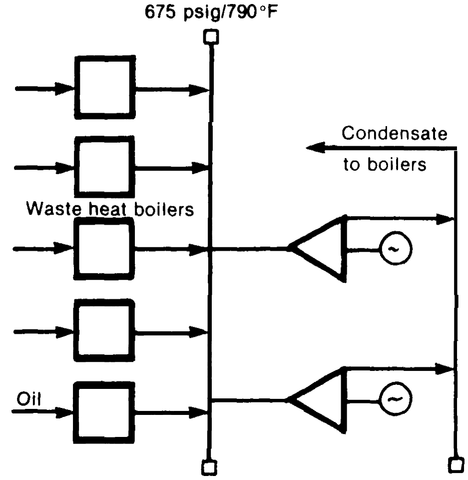
SOURCE: Synergic Resources Corp., *Industrial Cogeneration Case Studies* (Palo Alto, Calif,: Electric Power Research Institute, EPRI EM.1531, 1980)

Figure 49.—Holly Sugar Corp.—Schematic of the Cogeneration System



SOURCE: Synergic Resources Corp., *Industrial Cogeneration Case Studies* (Palo Alto, Calif.: Electric Power Research Institute, EPRI EM-1531, 1980).

Figure 50.—Riverside Cement Co.—Schematic of the Cogeneration System



SOURCE: Synergic Resources Corp., *Industrial Cogeneration Case Studies* (Palo Alto, Calif.: Electric Power Research Institute, EPRI EM-1531, 1980).

An example of a bottoming-cycle cogenerator is the system at the Riverside Cement Co. plant at Oro Grande, Calif. The plant has five waste heat boilers to recover energy from its cement kiln exhaust gases. These produce 100,000 lb/hr of steam for cogeneration via steam turbines. Because the production of steam in the waste heat boilers varies with the production rate of the cement kilns, the system also has two oil-fired boilers for use when the output of the waste heat boilers diminishes. At present, oil provides 21 percent of the energy for cogeneration. In order to reduce its oil consumption (the cement kilns operate on coal and natural gas), the company plans to add two additional waste heat boilers. The company reports that the system (see fig. 50) normally operates 24 hours per day, 365 days per year, and that there have been only two brief unscheduled outages since 1954. Because 80 percent of the energy that is used for cogeneration would otherwise be wasted, system efficiency calculations are not significant in this situation (see discussion of bottoming cycles in ch. 4). The cogeneration capacity available to the local utility is 15 MW (29).

Advanced Systems

Most of the existing cogeneration systems described above are limited to the use of clean premium fuels such as natural gas and distillate fuel oil, which are much more expensive than alternative solid fuels, and which may be in short supply in the coming decades. The only proven technology appropriate for a wide range of industrial sites that can use solid fuels (e.g., coal, biomass, urban refuse) is the steam turbine topping cycle, which has limited electrical production for a given amount of steam. However, a number of technologies now under development offer more fuel flexibility for cogeneration than the steam topping turbine with a conventional boiler.

The primary problem with these emerging technologies is the difficulty in handling and storing the solid fuel and disposing of its ash. Compared with the ease of handling traditional liquid and gaseous fuels, solid fuels—particularly coal—are cost intensive and complex to use. Small, medium-sized, and perhaps even large industrial plants would prefer to avoid the investment and operating costs associated with burning coal. These factors are likely to limit conventional coal cogeneration systems to units 30 to 40 MW or larger, according to sources surveyed by OTA.

CENTRAL GASIFIER, REMOTE GENERATION SYSTEMS

An alternate system now under intensive development would eliminate the need for industrial firms to handle coal on their plant sites. Utilizing a central gasifier to serve a region, it would be possible to provide medium-Btu gaseous fuel to 50 to 100 industrial plants. Medium-Btu gas has an energy content between that of low-Btu power gas and synthetic natural gas (see ch. 4). It can be transported economically over a reasonable distance, and is cheaper than premium synthetic natural gas. Onsite, the industrial plants associated with such central gasifiers would only have relatively compact cogeneration systems that would entail no more accessory buildings and equipment than present oil or gas fueled cogeneration systems. A central

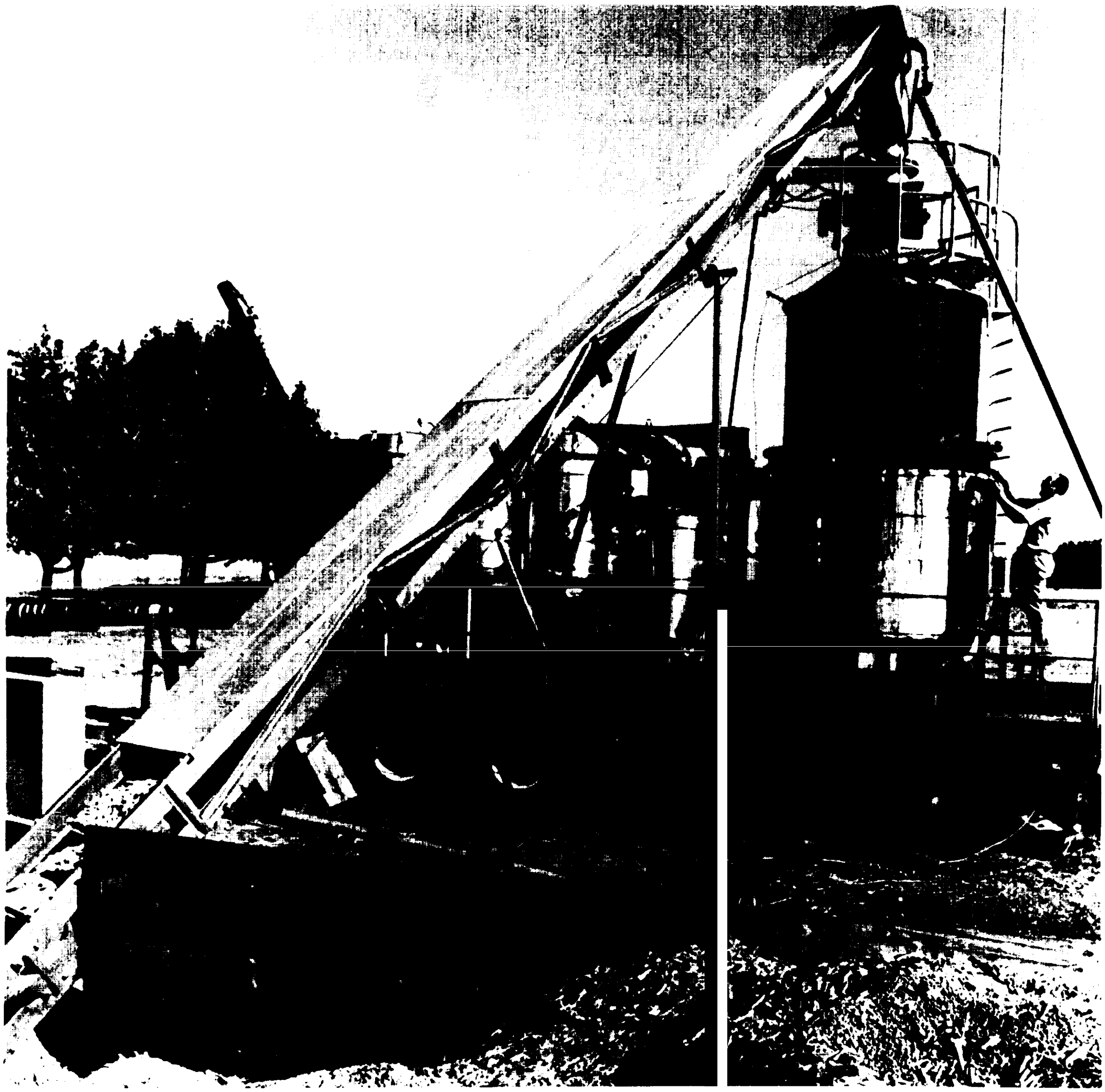


Photo credit: Department of Energy, Schneider

A prototype downdraft, airblown gasifier using wood chips as the fuel gasifier that produced medium-Btu gas (about 300 Btu per standard cubic foot) could serve a region up to about 100 miles in radius—the distance over which medium-Btu gas can be transported economically.

An example of the central gasifier/remote generation concept is the system proposed for central and southern Arkansas to serve as many as 35 industrial sites from a central coal gasification facility located at the Arkansas Power& Light Co. (AP&L) White Bluff coal-fired generating station. The initial central gasifier module would burn petroleum coke or Illinois #6 coal to produce approximately 120 billion Btu of gas per day. The as-spent cost of this module, for a design and construction time of 76 months, and with commercial operation beginning in mid-1988, is estimated at $1.8 billion. This initial module could supply fuel for combined-cycle cogenerators that would produce 400 to 475 MW of electricity and 1.6 million to 2 million lb/hr of steam, depending on the conditions at each industrial site. Four central gasifier modules of this size–producing 460 billion to 480 billion Btu per day of medium-Btu gas–would be required to supply the 35 industrial steam users identified by AP&L as the primary cogeneration candidates in its service area. With the central gasifier concept, these 35 cogenerators would use 6 million lb/hr of process steam and produce up to 1,700 MW of cogenerated electricity. The synthetic gas would be piped as far as 100 miles to user sites with combined-cycle cogeneration systems (14).

The medium-Btu gas for the system would be produced in a gasifier fed by streams of air or oxygen and coal/water slurry, both pumped into the system at controlled rates under pressure. Both streams enter a reactor vessel where partial oxidation of the fuel occurs, The product gas leaves the vessel at very high temperature, then passes through a series of heat exchangers that cool the gas to 400° F. Ash from the burning fuel is separated at the exit of the gasifier and directed into a water-quench that produces a glassy waste product that can be used as an asphalt filler. Because the gasifier operates above the melting temperature of the ash, the quenched ash is inert and the plant does not require scrubbers.

A 150-ton-per-day Texaco entrained-process gasifier (similar to that proposed by AP&L) has been operating for more than 2 years, producing synthesis gas for the Ruhr Chimie chemical plant near Oberhausen, Germany. In addition, the Tennessee Valley Authority is building a 200-ton-per-day Texaco gasifier at Muscle Shoals, Ala., and the Electric Power Research Institute–in conjunction with Southern California Edison Co.–is in the final stages of planning a 1,OOO-ton-per-day gasifier (the Coolwater project) that will be used to produce 100 MW of power. None of these projects is intended to cogenerate, but the technology could be used to do so (4).

FLUIDIZED BED SYSTEMS

Another advanced coal technology is the fluidized bed combustor, which can be used to burn coal or other solid fuels, including urban refuse, in a more compact system than a conventional coal boiler. The fluidized bed combustor can burn coal of any quality, including that with a high ash content, and it can operate at a temperature (1 ,500° F) only about half as high as a conventional pulverized coal boiler. At these lower temperatures, the sulfur dioxide formed during combustion can be removed easily by adding limestone to the bed, and the combustion gases may be suitable for driving a combustion turbine with minimal erosion damage, because the coal ash is softer at lower temperatures. Two types of fluidized beds currently are being developed–those that work at atmospheric pressure and those that work at considerably higher pressures (see ch. 4).

At present, fluidized bed systems are used to fire boilers, and thus can be readily used for cogeneration with conventional steam turbines. Fluidized bed systems incorporating combustion turbines, which have higher E/S ratios, are in an earlier stage of development and are just approaching commercial status. But, combustion turbines require a high-temperature gas at a pressure considerably above atmospheric pressure, so the output of an atmospheric fluidized bed combustor cannot be used as the input to the turbine. Instead, the fluidized bed output can be used in conjunction with air heater tubes for heat recovery in the fluidized bed, and the air, delivered from the turbine compressor to be heated in these tubes, can be used to indirectly fire a combustion turbine (either open or closed cycle).

The Curtiss-Wright Corp. in Woodbridge, N. J., is offering a prototype indirectly fired system on a semicommercial basis, sized to produce 2 to 10 MW of electricity and 25,000 to 150,000 lb/hr of steam. A spokesman for the company says that 20 MW is probably the maximum feasible size for such a system using an atmospheric bed combustor, the bed size being the limiting factor. Pressurized bed systems could be larger, however. The crucial factor in this technology, according to Curtiss-Wright, is the choice of alloy for the heater tubes. These tubes pass through the bed itself, operate at temperatures up to 2,000° F, and can be subject to corrosion, oxidation, and sulfurization. After "working the bugs out" of the first few demonstration units, Curtiss-Wright plans to offer the system on a commercial basis (4).

Pressurized fluidized bed combustors have output gases that exit at high enough pressures that these gases may be used directly to drive a turbine. These systems are also just approaching commercial status. The German Babcock Co. is planning a demonstration of a medium-sized system of this type in Great Britain. The major difficulty in the successful demonstration of such systems is perfecting the technology for cleaning the fluidized bed output gas so that it does not erode the turbine blades and shorten the lifetime of the system (4).

Shell Oil Co. recently decided to build a coal-fired fluidized bed cogeneration system near Rotterdam, Netherlands, a relatively small unit that will produce 110,000 lb/hr of steam. A considerably larger fluidized bed project is being undertaken by the American Electric Power Co. (AEP) at Brilliant, Ohio. The AEP system, being built in conjunction with Babcock& Wilcox, Ltd. of Great Britain and Stal-Laval Turbin AB of Sweden, uses a pressurized fluidized bed to operate a combustion turbine topping cycle in conjunction with an existing steam turbine. The capacity of the combined system (which will not cogenerate in this instance but which would be appropriate for cogeneration applications) will be 170 MW (4).

Other technologies also are receiving attention for use with coal. The Thermo Electron Corp. has tested the performance of a two-cycle marine diesel engine fired with a coal/water slurry. The engine, which is a low-speed tanker motor (see ch. 4), could achieve in principle 40 percent efficiency in generating electricity. Coal also can be used to fuel externally fired engines such as the Stirling-cycle engine. N.V. Philips, of Einhoven, Netherlands, has initiated work in applying fluidized bed coal systems to use with Stirling engines.

Potential for Industrial Cogeneration

Cogeneration's market potential depends on a wide range of technical, economic, and institutional considerations, including a plant's steam demand and electric needs, the relative cost of cogenerated power, the fuel used and its cost, tax treatment, rates for utility purchases of cogenerated electricity, and perceived risks such as regulatory uncertainty. The criteria for investment in an industrial cogeneration system is discussed below, including a description of the industrial sectors where cogeneration is likely to be attractive, and a brief review of the industrial cogeneration projections in the literature.

Appropriate Industries

A summary of cogeneration projects by region in the United States is given in table 32. The 371 projects in this table are those that are positively identified as cogeneration systems in a recent Department of Energy (DOE) survey (12). A breakdown by industry type is given in table 33. An additional 98 projects-representing at least 3,300 MW of capacity–have been proposed, are under construction, or are being added to existing cogeneration units.

The pulp and paper industry has, for some time, been a leader in cogeneration due to the large amounts of burnable process wastes that can supply energy needed for plant requirements. Integrated pulp and paper plants find cogenera-

Table 32—Cogeneration Projects by Region

Region[a]	Number of plants	Capacity[b] (MW)
New York , ...	27	913
New York/New Jersey	23	498
Mid-Atlantic	39	1,512
South Atlantic	62	2,200
Midwest	89	3,176
Southwest	57	4,812
Central	14	259
North Central.	14	413
West	25	629
Northwest	21	445
Total	371	14,858

aStandard EIA/DOE regions.
bTotal may not agree due to rounding.

SOURCE: General Energy Associates, *Industrial Cogeneration Potential.' Targeting of Opportunltles at the Plant Site* (Washington, DC.: U.S. Department of Energy, 1982).

tion particularly attractive. These plants dispose of woodwastes (e. g., bark, scraps, forestry residues unsuitable for pulp) and processing fluids ("black liquor"), and recover process chemicals in furnaces that can supply about half of a plant's energy needs. For at least two decades, the industry has considered power production an integral part of the manufacturing process, and new pulp and paper plants are likely candidates for cogeneration.

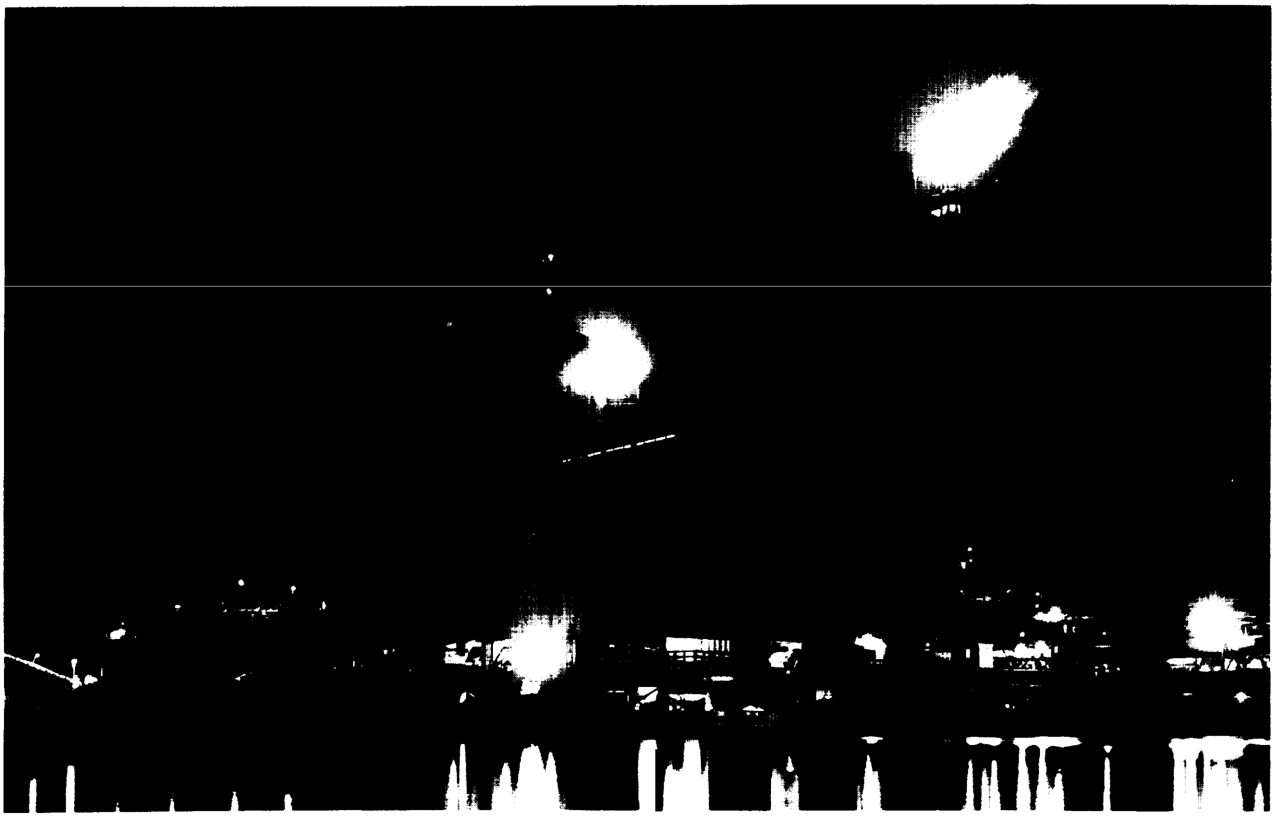
The chemical industry is another major steam-using industry that has great cogeneration potential. It uses about as much steam per year as the pulp and paper industry (1.4 Quads in 1976) and historically has ranked third in installed cogeneration capacity. The **steel industry** is also a major cogenerator, because the off-gases from the open-hearth steel making process provide a ready source of fuel, which is burned in boilers to make steam for blast furnace air compressors and for miscellaneous uses in the rest of the plant. Although the steel industry has been a major cogenerator in the past, most analysts project that it will not build more integrated stand-alone plants. Instead it is expected to build minimills that run with electric arcs and have little or no potential for cogeneration unless a market can be found for the thermal energy. Thus, new steel mills probably have considerably less cogeneration potential than the chemical industry. However, on the gulf coast substantial cogeneration capacity has been proposed for existing primary metals facilities (34).

petroleum refining also is an industry that is, in many ways, ideal for cogeneration. Existing refineries could be upgraded over the next

Table 33.—Existing Industrial Cogeneration by SIC Code

SIC code	Number	Percent of total	Capacity (MW)	Percent of total
20—Food	42	11.3%	398	2.7
21 —Tobacco products		<1.0	33	<1.0
22—Textile mill products.	9	2.4	224	1.5
23—Apparel	0			
24—Lumber and wood products.	19	5.1	479	3.2
25—Furniture and fixtures.	1	<1.0	2	<1 .0
26—Paper	136	36.7	4,246	28.6
27—Printing and publishing	1	<1.0		<1 .0
28—Chemicals.	62	16.7	3,438	23.1
29—Petroleum and coal products	24	6.5	1,244	8.4
30—Rubber, miscellaneous plastic products	3	<1.0	76	< 1 .0
31—Leather	—	—		—
32—Stone, clay, and glass products	6	1.6	115	< 1 . 0
33—Primary metals.	39	10.5	3,589	24.2
34-Fabricated metal products.	10	2.7	304	2.0
35—Machinery, except electrical	11	3.0	134	1.0
36—Electric and electronic equipment	3	< 1.0	83	1.0
37—Transportation equipment	1	< 1.0	345	<2.3
38—instruments and related products	3	< 1 .0	137	< 1 .0
39—Miscellaneous manufacturing	—			
Total.	371	100.0	14,858	100.0

SOURCE: General Energy Associates, *Industrial Cogeneration Potential: Targeting of Opportunities at the* Plant Site (Washington, DC,: U.S. Department of Energy, 1982).



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decade to increase gasoline and diesel fuel output and decrease residual oil production. A byproduct of this upgrading would be the production of low-Btu gas that might be used in cogeneration systems. One report estimates that such upgrading could produce 0.5 Quad/yr of gas, to meet about 40 percent of the refineries' 1976 process steam demand and provide 9 GW of electricity generating capacity (34). However, new refineries are not likely to be built in the near future except on the Pacific coast in conjunction with enhanced oil recovery in the Kern County heavy oilfields.

An industry in which cogeneration and conservation are in head-to-head competition is the cement industry. It has been identified as a candidate for bottoming-cycle cogeneration, an application in which the heat of the kiln exhaust gas is recovered and used to produce steam for electricity generation. But because the industry is highly energy intensive, it has improved its efficiency substantially in recent years, reducing the temperature of its exhaust gases from 9000 to 1,000° F to 300° to 400° F. One plant has reported exhaust temperatures as low as 180° F (28). In plants where conservation measures are that effective, it probably will not be economic to cogenerate.

Criteria for Implementation

A wide range of considerations must be taken into account in deciding whether to invest in an industrial cogeneration system. These include both internal and exogenous economic factors, fuel cost and availability, ownership and financing, tax incentives, utility capacity expansion

Photo credit: Department of Energy

Low-Btu gas suitable for fueling cogeneration systems is a byproduct at many petroleum refining facilities

plans and rates for purchases of cogenerated power, and a variety of perceived risks in such an investment.

ECONOMIC CONSIDERATIONS

For any potential cogenerator, the desirability of cogenerating depends on the price of power from the utility plus the cost of producing thermal energy, versus the cost of cogenerating. Historically, industrial and commercial users have paid different amounts for utility-produced power. Compared to the case for commercial cogeneration (see below), industrial facilities typically have lower electric rates, averaging up to about 1.5cents/kWh lower than commercial and residential users (see table 34) (9). Nevertheless, in some regions of the country, rates for utility purchases of cogenerated electricity have reached 8.3cents/kWh (see table 19), higher than the national average for either commercial or industrial retail electricity rates. These areas are prime targets for expanded industrial cogeneration (see discussions of purchase power rates and simultaneous purchase and sale, below).

The current costs of cogeneration for industrial users often are below the rates for utility purchases from industrial customers. A study for the Federal Energy Regulatory Commission (FERC) (28) found that the price of cogenerated electricity ranged from 4.4 to 5.6cents/kWh (1979 dollars) for various regions of the country, assuring the use of steam topping and gas turbine technologies. Diesel cogeneration was found to cost 7.2 to 7.6cents/kWh, assuming small, distillate-fired systems operating at a relatively low capacity factor. Larger systems using natural gas and operating at higher capacity factors should be able to compete at the busbar with new coal plants in many instances (34). While utility rates for purchases of cogenerated power vary widely by region (see table 19), the costs of cogeneration vary only 10 to 20 percent among the regions of the country, This is a strong indication that the rates for sales of cogenerated electricity will be important in determining the economic viability of industrial cogeneration over the next few years. More specifically, external economic factors, rather than technical breakthroughs that would reduce the intrinsic costs of cogeneration, are likely to be

Table 34.-Sample Industrial Electric Rates by State (costs per kWh for industries using 1.5 milllon kWh per year with a peak demand of 5 MW.

State	Rate	State	Rate
Alabama	3.60	Montana	1.70
Alaska	3.7	Nebraska	2.7
Arizona	4.4	Nevada	4.7
Arkansas	2.9	New Hampshire	4.8
California	5.0	New Jersey	4.4
Colorado	3.4	New Mexico	5.5
Connecticut	5.2	New York	7.6
Delaware	5.8	North Carolina	2.9
District of Columbia	3.9	North Dakota	3.5
Florida	3.1	Ohio	4.1
Georgia	3.7	Oklahoma	2.6
Hawaii	5.7	Oregon	1.7
Idaho	1.7	Pennsylvania	5.1
Illinois	4.0	Rhode Island	5.3
Indiana	3.6	South Carolina	3.6
Iowa	3.9	South Dakota	3.3
Kansas	3.9	Tennessee	3.2
Kentucky	3.0	Texas	3.7
Louisiana	2.9	Utah	3.1
Maine	3.6	Vermont	3.3
Maryland	2.7	Virginia	5.2
Massachusetts	5.2	Washington	1.1
Michigan	4.6	West Virginia	3.2
Minnesota	3.0	Wisconsin	3.5
Mississippi	3.9	Wyoming	1.5
Missouri	3.8		

[a]Rates shown are calculated from typical bills for 455 cities with a totai population of 76.9 million as of Jan. 1, 1980. The State averages are population-based averages. The range among regions in the country is from 1.1 to 7.6 cents/kWh, as of Jan. 1, 1960.

SOURCE: Energy Information Administration, *Typical Electric Bills, January 7, 1980* (Washington, D. C.: Government Printing Office, December 1960).

the dominant factors governing the rate of cogeneration implementation in the 1980's.

In most parts of the country, the rates for purchases of cogenerated electricity do not exceed the 4.5 to 5.5cents/kWh cogeneration cost quoted above. However, the avoided cost of many utilities may be higher than industrial electricity rates. The FERC study cited above found that in many (but not all) regions of the country this was the case. in regions with high avoided costs, it would be advantageous for industrial firms to sell all their cogenerated power to the utilities and buy back as much power as they need at the industrial wholesale price. The conditions for favorable election of this option, known as simultaneous purchase and sale (or arbitrage), are discussed further below.

FUEL VERSATILITY

The fuel used for cogeneration varies with the type of technology installed and with the size of the installation. The predominant fuels are coal, biomass, natural gas, and oil–usually residual (#6) and middle distillate (#2) oil. Oil and natural gas are the most versatile fuels because they can be used in all available cogeneration technologies from the lowest E/S systems (steam topping turbines) to the highest (combined cycles and diesels). However, due to the price and supply uncertainties of oil and natural gas, over the long term (10 years and beyond) the most attractive cogeneration investments will use solid fuels. As discussed previously, of the available technologies, only steam turbines presently can use such fuels, but these systems also have relatively low fuel savings for a given steam load, and a low E/S ratio. With the advanced technologies described previously, solid fuels could be used more widely than now possible. Both the medium-Btu gasifier and the fluidized bed systems could be used with combustion turbines or combined cycles, producing electric power with a high E/S ratio from coal or biomass.

OWNERSHIP AND FINANCING

ownership arrangements may be among the principal determinants of the rate of development of cogeneration. The issue is whether cogeneration systems will be owned by the industry that uses the thermal energy, whether they will be owned by the utilities that would distribute the cogenerated electricity, or whether a third party would invest in the cogeneration equipment. Joint ventures and multiparty ventures mingling these various players also are possible (see ch. 3).

Industrial ownership could be attractive if the surplus electricity were purchased by a utility at rates that reflect the utility's full avoided costs. Also ownership could assure the cogenerating industry of reliable power, which can be a strong incentive for particular industries in some regions. However, the capital requirements of a cogeneration system are large enough that many potential industrial cogenerators would like to have long-term (i.e., 20-year) contracts for power sales to the grid. Whether this can be reasonably expected under the presently applicable laws is an important question, one that is addressed in chapter 3 of this study.

Utility ownership has the advantage that utilities consider power production their primary line of business. Utility-owned cogeneration systems could be included in the rate base, thus allowing the utility to earn a return on the systems. Utility ownership also provides a straightforward means by which utilities could maintain dispatching control over the electric power entering the grid, providing them with assurance that this new form of generating capacity would preserve system stability (see the discussion of interconnection in ch. 4). Furthermore, cogeneration's relatively small unit size can decrease the cost of capital for capacity additions and can reduce the downside risk of unanticipated changes in demand growth (see ch. 6). However, as discussed in chapter 7, unregulated utility ownership raises concerns about possible anticompetitive effects.

Third-party ownership is most likely to occur in cases where new steam-producing equipment is badly needed to cut energy costs but the industry in question cannot raise capital for a new system. Novel cogeneration financing arrangements are emerging slowly and it is risky to make generalizations so early in the process. In some cases, the third party may be a separate entity set up by the utility. In other cases, it may be a large institutional investor wooed by the industry. There appear to be few instances on the industrial scene where—as happened in the development of hydro power under the Public Utility Regulatory Policies Act of 1978 (PURPA)—a small entrepreneur identified an attractive steam load, proposed building a new plant, served as capital matchmaker, and then ran the facility. Third parties will want to reduce the risks of ownership by negotiating long-term purchase power contracts with the utilities.

TAX INCENTIVES

Significant Federal tax incentives are available to cogeneration in recognition of its fuel saving value. These include the investment and energy tax credits, accelerated depreciation, and safe harbor leasing (see ch. 3). In some cases, cogeneration may also qualify for tax-exempt financing. An informal survey by OTA indicates that these tax incentives may promote some marginal cogeneration projects from "unattractive" to "attractive," but tax considerations are not, in most cases, the overriding economic issue. Industrial power cost and reliability, PURPA avoided cost prices, and restrictions on capital from traditional sources are still the dominant economic issues. On the other hand, tax considerations can have a very strong influence on ownership and financing decisions for a cogeneration project. A key issue in cogeneration tax treatment is whether or not facilities are categorized as "public utility property." Full utility ownership is generally the least attractive tax alternative for a cogeneration project under either the 1978 or 1980 tax bills.

FLEXIBILITY IN LOAD EXPANSION

One of the major reasons that cogeneration would be attractive to utilities in the short term is its suitability for adding new capacity in small increments that are deployable in a relatively short time. Cogeneration capacity sizes in industrial settings range from 100 kw, miniscule by utility standards, to over 150 MW, about half the size of the smallest unit of baseload capacity a large utility would consider installing. Many utilities favor 300-MW coal units as small incremental additions for central plant capacity. Adding leadtime for planning, the total time to put a cogeneration facility in place is 3 to 6 years–much less than the 5- to 12-year period required for utility baseload plants. As a result, cogeneration can represent an "insurance policy" against unanticipated changes in demand growth-a much less costly form of insurance than overbuilding central station capacity.

The planned cogeneration strategy of AP&L (described above) illustrates the flexibility in capacity growth that can be attained with cogeneration. AP&L's proposed 1,700-MW remote gasification system (described above) would be based on combined-cycle units at each plant site (up to 35 sites), which would allow the utility to decouple steam and electricity production. Thus, the utility could build a system to supply the industrial steam load of its customers, and then turn on electrical capacity as needed. In this way, AP&L could gradually augment its system capacity from zero to 1,700 MW over several years in a smoothly increasing trend (14).

PURCHASE POWER RATES

The critical economic considerations in a decision whether to invest in an industrial cogeneration system include the rates and terms for utility purchases of cogenerated power. As discussed below, the utility buyback rates are a primary determinant not only of the number of cogeneration systems installed, but also of the amount of electricity they will produce. However, Federal and State policies on this issue are in great flux just now, and the regional variability in purchase rates is quite high (see ch. 3). As a result, many potential cogenerators are caught in a "squeeze" between the regulatory uncertainty surrounding sales of electricity to the grid and the desire to invest during 1982 before the energy tax credit expires.

SIMULTANEOUS PURCHASE AND SALE

The regulations implementing PURPA section 210 allow industrial cogenerators to simultaneously buy all their needed power from the utilities (at rates that do not discriminate against them relative to other industrial customers), while selling all their cogenerated electricity at the utility's purchase power rate. In effect, this provision decouples a cogenerator's thermal and electric energy production (see ch. 3). Utilities, which are seeing their load growth diminish drastically as a result of price-induced conservation, may find this option attractive because it does not reduce their load base. Moreover, industries generally are less willing to project their steam or heat loads as far into the future as utilities. Systems that allow some decoupling of steam and electric production thus have potentially greater appeal to industry, under industry ownership. industries may also find simultaneous purchase and sale attractive because it does not require them to pay standby charges for electricity they would use when the cogeneration system was shut down for maintenance or unplanned outages.

REGULATORY UNCERTAINTY AND PERCEIVED RISKS

At present, probably the greatest deterrent to investment in cogeneration systems is regulatory uncertainty. Utility rates for purchases of cogenerated power under PURPA and the FERC regulations on interconnection of cogenerators with the grid are uncertain pending a final court ruling on the existing regulations (see ch. 3). Other regulatory or legislative items that may affect cogeneration implementation but are in a state of flux include: the Fuel Use Act regulations on exemptions for cogenerators; natural gas prices, the schedule for deregulation, and its effect on incremental pricing; and the expiration of the energy tax credit at the end of 1982.

Industrial companies also are concerned about limited capital resources and high interest rates, and may favor investments in process improvements that would contribute to plant efficiency over investments in new energy systems. Companies also are hesitant to invest until the payback periods are more firmly established, given uncertainties in fuel prices. Some companies also have expressed concern about a lack of technical expertise in the use of solid fuels, as well as about the possibility of using up air pollution increments that may be needed for future plant expansions.

Market Penetration Estimates

A number of recent studies have estimated the technical and/or market potential for cogeneration based either on the Quads of energy that might be saved by the substitution of cogenerators for separate conventional electric and thermal energy systems, or on the Quads of steam and megawatts of installed capacity that could be supplied by industrial cogeneration. The range of estimates given in these studies is large, extending from 6 to 10 Quads of energy saved annually by 1985, and from 20 to 200 GW of installed generating capacity by 2000. Differing assumptions about energy prices, ownership, and return on investment, whether the cogeneration facilities would export electricity to the utility grid, and the types of technologies employed account for the large range. The early projections of the potential for industrial cogeneration are summarized in table 35.

The general methodology in each of these studies was to estimate the industrial steam load and then quantify what portion of that load would be technically and economically exploitable for cogeneration. The choice of cogeneration tech-

Table 35.—Early Estimates of the Potential for Industrial Cogeneration

Study	Ownership	Cogenerator	Off site distribution	Installed capacity in 1985 (GW)	Expected annual steam load growth
DOW	Industry	Steam turbine	No	61	3.5 % (1968-80) 4.5% (after 1980)
RPA	Industry	Steam turbine	No	10-16	4.1% (1976-85)
Thermo Electron	Industry	Steam turbine	Yes	20-34[a]	4.1 % (1975-85)
		Combustion turbine		85-128	
		Diesel		107-209	
	Utility	Steam turbine		34-37[a]	
		Combustion turbine		131-137	
		Diesel		218-249	
Williams	Utility	Steam turbine	Yes	28 (in 2000)	20/0 (1974-2000)
		Combustion turbine or combined cycle:			
		Oil-fired		28	
		Coal w/FBC		95	
		Diesel		57	
		Total		208 (in 2000)	

aThe Thermo Electron estimates assume only one technology Is developed and are thus not additive.

SOURCE: OTA from Robert H. Willlams, "Industrlal Cogeneration," 3 *Annual Review of Energy 313-3S6* (Palo Alto, Callf.: Annual Reviews, Inc., 1978).

nologies, among other considerations, then would determine the electrical capacity achievable with such a steam load. In general, those studies that assumed the use of only steam turbine topping cycles (sized so there was no offsite export of electricity) arrived at much lower estimates of cogeneration electric capacity.

A DOW Chemical Co. study (6) projected 61 GW of electrical cogeneration capacity in 1985 (including existing capacity), corresponding to about 50 percent of the projected process steam demand for that year. The DOW study assumed industrial ownership (with a 20-percent rate of return) of steam turbine topping cycles installed in plants using over 400,000 lb/hr of steam. These cogenerators would produce the minimum amount of electricity for a given steam load (about 40 kWh/MMBtu) and would not export any electricity offsite. Even with this rather conservative choice of technologies, there were instances in which the study found that more electricity would be generated than could be used onsite, and so the estimated market potential for cogeneration was scaled down accordingly.

A 1977 study by Resource Planning Associates (RPA) for DOE (24) examined the potential for cogeneration development by 1985 in six major steam-using industries (pulp and paper, chemicals, steel, petroleum refining, food, and textiles). RPA only considered applications larger than 5-MW electrical capacity and assumed that all of the cogenerated electricity would be consumed onsite. Furthermore, approximately 70 percent of the total estimated process steam available for cogeneration development in 1985 was eliminated as unsuitable for cogeneration, due to technical or economic constraints, or to conservation and process improvements. As a result, RPA found the 1985 potential in the six industries to be 1.7 Quads of process steam output (10-GW capacity) without Government action, and 2 to 2.6 Quads of process steam (12- to 16-GW capacity) with Government programs such as the energy tax credits and the more rapid depreciation now in place, or PURPA-style regulatory and economic incentives.

A study by Thermo Electron (30) was based on three of the most steam-intensive industries—the chemical, pulp and paper, and petroleum refining industries—which were assumed to account for approximately 34 percent of the total estimated 1985 industrial steam loads. This study assumed that either industry or utilities might invest in high E/S technologies such as combustion turbines and diesels, and found that the maximum implementation for combustion turbines—137 GW of cogeneration capacity–occurred with utility ownership, an investment tax credit of 25 percent (rather than the 10 percent then available), and Government financing for half the project.

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A 1978 study by Williams (33) assumed utility ownership, and a mix of technologies in which steam turbine cogenerators met 42 percent of the steam load and higher E/S technologies the remainder. Williams assumed that fuel use for steam generation in existing industries would increase 2 percent annually through 2000, leading to a process steam demand of 16.1 Quads in those industries. Williams also assumed that about half of the total steam demand would be associated with cogeneration having an average E/S ratio of 140 kWh/MMBtu and producing electricity 90 percent of the time that steam is produced. Based on these assumptions, Williams estimated the total cogeneration potential in 2000 to be 208 GW, saving over 2 million barrels of oil per day.

As noted previously, each of these studies began by estimating the present demand for industrial process steam. These estimates include a 1974 steam load of 7.8 Quads (Williams, based on an Exxon analysis); a 1976 industrial steam demand of 9.7 Quads (RPA); and a 1980 estimate of about 14 Quads (DOW). In 1981, the Solar Energy Research Institute (SERI) attempted to reconcile the differences among these and other estimates of industrial steam load, and found that the data base (disaggregated by fuel use, boiler capacity, average and peak steam loads per site, steam quality, steam load by industry, steam load by State) is so inadequate that none of these published estimates could be considered accurate. However, SERI was able to reject the higher steam demand estimates in the literature because they did not account accurately for fuel use in smaller boilers in less energy-intensive industries. By reconciling differences in approach and accounting among the lower published numbers, SERI arrived at an estimate equivalent to approximately 5.5 Quads/yr during 1976-77 (27).

In addition to overestimating the base industrial demand for steam, the early studies of industrial cogeneration assumed robust steam growth-on the order of 4 percent annually. The steady progress that has been made in industrial energy conservation through the 1970's—amounting to a decrease in energy use per unit of industrial value-added of approximately 2 percent per year—makes these earlier predictions for steam load growth highly unlikely. More recent studies of cogeneration have projected steam growth rates that are either lower or constitute no growth. For instance, in 1980 SRI International projected 1.18 percent per year (28), while Williams now estimates zero growth in steam demand through 2000 (34), and SERI projected zero or negative growth (27).

More recent estimates of the potential for industrial cogeneration either have assumed a much smaller present steam base and lower thermal demand growth rates, or have devised a methodology that does not begin with an estimate of the current steam load. However, due to changes in the context for cogeneration since the earlier studies were completed, these recent studies have not necessarily projected a lower market potential for industrial cogeneration. These contextual changes include the PURPA economic and regulatory incentives for grid-connected cogeneration, substantial increases in oil and electricity prices, special energy tax credits, and shorter depreciation periods. As a result of these and other considerations, cogeneration is considered likely to be economically attractive at more industrial sites than in earlier studies (despite the lower thermal demand projections), and more likely to use technologies with higher E/S ratios that produce more electricity.

A 1981 study by RPA (23) examined the 1990 potential for cogeneration in five industries (those analyzed previously except for textiles), began with a 1990 steam demand of 682 million lb/hr (approximately 6 Quads/yr, assuming 1,000 Btu/lb and 24-hr operation). Of this base, RPA found an expected investment in the five industries of 155 million lb/hr (1 .36 Quads) steam production, or 20.8 GW of electric capacity, assuming "base case" utility buyback rates (see table 36). This would increase to 28.7 MW of installed cogeneration capacity if, as a result of utility ownership, 30 percent of the steam turbines were replaced by combustion turbines and combined cycles. The "high buyback rates" case would lead to an expected investment potential of as much as 37 GW of installed capacity, while the "low" case shows 14.2 GW (1.2 Quads steam). The amount of electric capacity declines more than the steam production with lower buy-

Table 38.-Range of Utility Buyback Rates Analyzed by RPA
(1980 dollars In cents/kWh)

DOE region	Marginal utility fuel	Low buyback rate	Base buyback rate	High buyback rate
1. New England	Oil	4.0	5.5	7.0
2. New York/New Jersey.	Oil	4.0	5.5	7.0
3. Mid-Atlantic	Oil	4.0	5.5	7.0
4. South Atlantic	Oil/coal	2.0	3.5	5.0
5. Midwest.	Coal	2.0	3.0	4.0
6. Southwest.	Natural gas	2.5	4.0	5.5
7. Central.	Coal	1.0	2.0	3.0
8. North Central	Coal	1.0	1.5	2.5
9. West.	Oil	4.5	6.0	7.5
10. Northwest	Coal	3.5	4.5	5.5

SOURCE: Resource Planning Associates, Inc., The *Potential for Industrial Cogeneratlon Development by 1990* (Cambrldge, Mass.: Resource Plannlng Associates, 1981).

back rates due to the sensitivity of technology E/S ratio to these rates (23).

In an informal update of his earlier work, Williams (34) begun with a much lower steam demand–4.l Quads in six industries in 1977–but assumed that cogeneration would achieve a higher degree of penetration of the steam base than he had assumed earlier. Of these 4.1 Quads, Williams assumed 1.25 Quads would be unsuitable for cogeneration (due to load fluctuations, low steam demand, low-pressure waste heat streams, declining demand, etc.), resulting in a six industry market potential of 93 to 142 GW in 2000, depending on the technology mix. Williams estimated an additional potential of up to 32 to 49 GW in other industrial sectors, if their steam loads are proportional to those in the six industries, but less if their steam loads are smaller or more variable. Finally, Williams estimates that new industries (e.g., thermally enhanced oil recovery) have a potential of 11 to 20 GW of installed capacity. Together, these sources have an "economic potential" of 136 to 211 GW of cogeneration capacity in 2000. Williams considers this economic potential to be the amount available for insuring against underdevelopment of central station generating capacity. The actual amount to be designated as a "prudent planning base" for such insurance could not be determined without better disaggregated data on the steam base, but Williams found 100 to 150 GW to be a "conservative estimate" (34).

Williams' approach to cogeneration as insurance against the uncertainty in future electricity demand growth was included in the 1981 SERI report on solar/conservation. SERI did not estimate the total potential for industrial cogeneration because the report's emphasis on conservation meant that projected electricity demand growth was so low (0.13 percent annually) that no cogeneration electrical capacity would be needed unless the conservation targets were not met. The study concluded that 93 GW of cogeneration in the six industries would be an adequate insurance measure, but made no attempt to ascertain how much capacity would be economically attractive (27).

A different methodology was adopted in a 1982 analysis for DOE (12). Rather than using a gross estimate of steam demand as the primary measure of potential, this study began by individually analyzing the 10,000 largest U.S. industrial sites for their cogeneration potential based on buyback rates, accelerated depreciation, heat match, and other considerations. This analysis identified 3,131 plants in the 19 manufacturing sectors that would have a return on investment greater than 7 percent and represent the maximum potential of 42.8 GW of cogeneration capacity (producing 3.3 Quads of steam). Ninety-two percent of the electric capacity and 95 percent of the steam generated are in the five top steam-using industries. The "best" mix of technologies for these sites was found to be 70 percent combustion turbines and 30 percent steam turbines, resulting in the offsite export of 49 percent of the electricity generated. If the return on investment increased to 20 percent, the maximum potential decreases to 20 GW. The study also estimated that an additional 48.5 GW of capacity could be installed at new industrial sites based on U.S. Department of Commerce industrial growth figures and assuming that plant expansions and new plants would have characteristics similar to those in existing plants (12).

The studies reviewed above illustrate two main points:

1. The technical potential for cogeneration is very large; even the lowest of these estimates corresponds to the equivalent of 20 new baseload central generating plants, while the highest estimate corresponds to a generating capacity capable of producing more than one-sixth of the electrical power presently used in the country.
2. Economic and institutional considerations are paramount in determining how much cogeneration will actually be installed, as illustrated by the wide sensitivity of these estimates to variations in utility purchase rates, tax incentives, ownership, fuel prices, etc. The underlying consensus among these studies on all matters except the likely steam load is in fact remarkable.

While the market for cogeneration is potentially large, the actual rate of cogeneration equipment installation is much lower than expected a few years ago. This trend is occurring in spite of higher electricity prices because of the weakened financial posture of utilities, industries' difficulty in raising capital for expansion due to unprecedentedly high interest rates, and the unexpectedly rapid rate of energy use reductions in industry. Long-term fuel supply uncertainties also may work against cogeneration, or against the more attractive cogeneration options.

The effect of energy conservation in industry is one of the key influences on future cogeneration. Whereas substantial steam load growth was assumed in most cases, the rate of energy use **per unit of production** has in fact dropped substantially in major industries. The industry that has traditionally been most committed to cogeneration as an integral part of its business, the pulp and paper industry, has reduced its energy consumption per ton of production by 26 percent between 1972 and 1980. The chemical industry has reduced its energy use by 22 percent over the same period, and the petroleum refining industry, 15 percent. Steam production at the largest operating industrial cogeneration system–the Gulf States 130-MW complex supplying steam to oil refineries and related industries near Baton Rouge, La.—has decreased ***by* 30 to** 50 percent over the past several years, according to a spokesman for the utility.

The weakened financial position of some industries is also likely to be a factor in cogeneration. Whereas the steel industry is a very heavy energy user, it has been a declining industry over the past decade and one unlikely to have the capital for new cogeneration facilities. In most industries, cogeneration faces competition for capital with expansion of production capacity, and in such a face-off cogeneration investments are likely to have a low priority. However, this situation would be averted under utility ownership, or under the leasing provisions of the Economic Recovery Tax Act of 1981. Although utilities face more financial problems than at any time in decades, smaller investments in cogeneration systems can be financed more easily than 1,000-MW central powerplants.

If cogeneration is implemented, the amount **of** electrical capacity resulting from a system sized to fit a given heat or steam load could vary by as much as a factor of 4 depending on the type of cogeneration equipment that is used. For example, a large industrial installation that uses 0.5 million lb/hr of steam would cogenerate 30 to 40 MW of electricity with steam turbines, and 120 to 150 MW with gas or oil burning combustion turbines. A major question for industrial usage, therefore, is the extent to which alternate fuels such as coal or biomass can be adapted to turbine technology, because the traditional fuels (oil and gas) are now the most expensive available on the U.S. market.

COMMERCIAL COGENERATION

Although the opportunities for cogeneration in industry are numerous and diverse, cogeneration in commercial buildings is likely to have a smaller market potential. Commercial enterprises typically use thermal energy only for space conditioning and water heating, and have thermal load factors that are usually much lower than those of industrial concerns. As a result, the economics of cogeneration systems for commercial buildings traditionally have been much less favorable than those of industrial systems. Recently, however, market incentives resulting from PURPA and/or from high electricity and fuel prices have changed the economics of commercial cogeneration. Several technical and economic factors in particular determine the relative attractiveness of commercial building cogeneration and purchasing utility-generated electricity, such as the suitability of electrical and thermal load profiles, the potential for fuel savings, and the change in relative fuel prices.

This section discusses the results of OTA analyses of cogeneration in commercial buildings v. centralized electric utility systems. The section begins with a review of the literature on commercial cogeneration, followed by a general introduction to OTA's analytical methods, a discussion of the major assumptions used in the analyses, and a summary of the results.

Previous Studies of Commercial Cogeneration

Several existing studies have examined the potential for commercial cogeneration in particular areas or under certain conditions. These include a FERC study that estimated the amount of cogeneration that would be stimulated by PURPA (28); a study by the American Gas Association (AGA) that compared gas-fired cogeneration with two conventional heating systems in a hospital in different climate regions (l); and regional studies by Consolidated Edison (Con Ed) for their service area (1 3,25) and by the State of California for State-owned buildings (s).

The FERC study calculates the national and regional penetration of cogeneration and small power production induced by PURPA through 1995, and concludes that only in the Mid-Atlantic region (New York, New Jersey, and Pennsylvania) is commercial building cogeneration likely to be economically attractive. FERC projects that 2,500 MW of commercial sector capacity could or might be installed in this region by 1995, producing 10,000 GWh/yr of electricity. In these calculations FERC assumed: first, that the PURPA regulations would be the sole incentive for cogeneration; second, that cogeneration would only occur in large new buildings (e.g., new apartment buildings with more than sO units, new hospitals having more than So beds); third, that all commercial investment would earn a fixed rate of return of 20 percent; and fourth, that all equipment would have a fixed capacity factor of 45 percent and a fixed size of 500 kw. Some of these assumptions may be both too kind and too cruel to commercial cogeneration. That is, FERC'S analysis ignores incentives other than PURPA (e.g., tax benefits, high electricity rates), the possibility of retrofits or eventual use in smaller buildings, and the achievement of higher capacity factors, and thus may understate cogeneration's potential. At the same time, the analysis uses a very favorable rate of return and thus may overstate the market potential for cogeneration under current high interest rates.

The AGA study is based on a prototype design for a 300,000 square foot hospital located in four different climate regions. AGA assumed two different rates for utility purchases of cogenerated power to compare the annualized capital, fuel, O&M, and net electricity costs for three different types of heating and cooling systems for the hospital: 1) a conventional combination system, using a gas boiler to provide steam for space heating plus an electric air-conditioner for space cooling, and relying on the grid for electricity; 2) an all-electric system, using baseboard resistance heaters and air-conditioners run with utility-generated electricity; and 3) an all-gas system, using a gas-fired cogenerator to provide electricity and space heating and a waste heat recovery system to run an absorptive air-conditioner. AGA assumed the cogenerator was sized to match the thermal load, with any excess electricity being sold to the electric utility.

The AGA study concluded that the "economic attractiveness (of cogeneration) is heavily dependent on the buyback rate for cogenerated electricity." The study found that, for all four climate regions, the cogeneration system had a lower annual cost than the other options when the buyback rates were set at 8cents/kWh. However, when the rate was lowered to 2cents/kWh, cogeneration was found to be economical only in the Mid-Atlantic region. This is because the higher buyback rates offset cogeneration's high capital cost compared to the capital costs of the combination and all-electric systems. But when the buyback rates were lowered, cogeneration's capital cost became prohibitive in all but the Mid-Atlantic region, where high fuel costs and electric utilities' dependence on foreign oil give fuel-efficient cogenerators an economic advantage.

Although the AGA study analyzes the sensitivity of cogeneration economics to factors such as buyback rate and climate, it is limited to hospitals, a type of commercial building with a relatively constant energy demand.

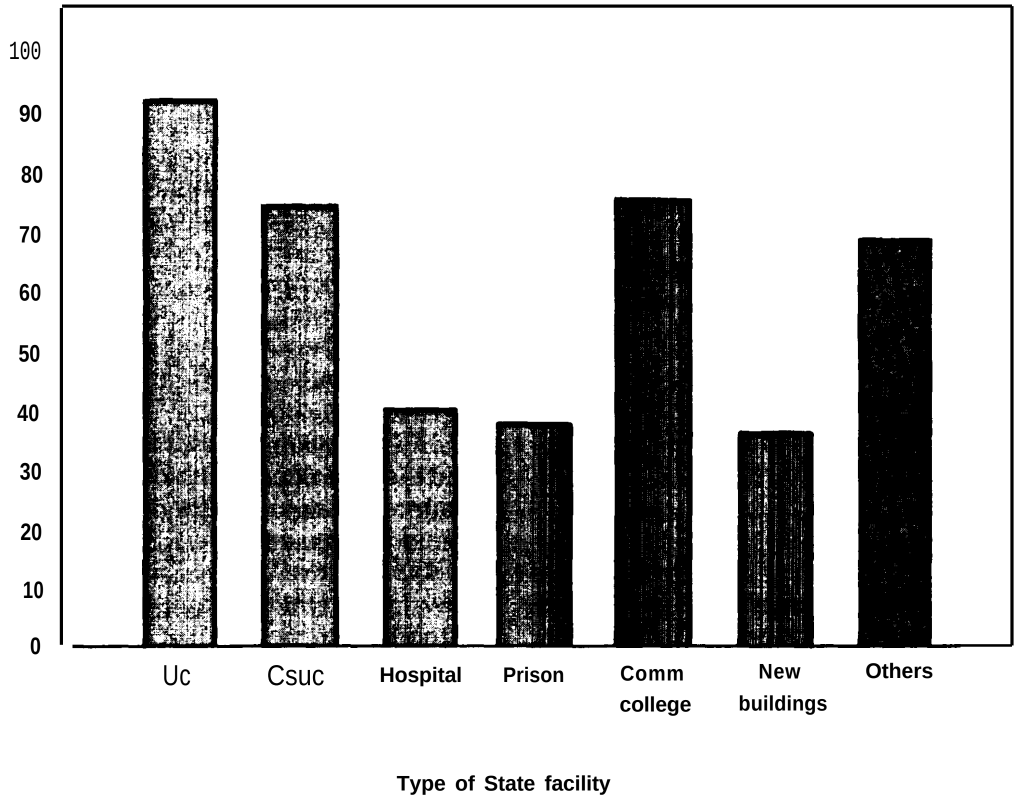
ConEd developed a model of the costs and benefits of investment in cogeneration based on the internal rate of return from such investment, and applied the model to load data for their 4,500 largest customers, assuming that the investment would be made if the rate of return would be at least 15 percent over 10 years. Depending on customers' loads and other variables, ConEd found an "expected" cogeneration penetration of 395 customers with a combined peakload of 1,086 MW, with a high range of up to 750 cogenerators totaling 1,483 MW peakload. The analysis was then repeated using a slightly higher cost cogenerator (and thus a lower rate of return), and the market potential dropped substantially—to 27 customers with a combined peakload of 130 MW.

These market penetration estimates for cogeneration depend heavily on how the cogenerators will operate. Con Ed assumed that cogenerators would only operate when there is sufficient electrical demand on the system. Thus, the assumed thermal efficiency is low (52 percent for commercial building systems and 62 percent for residential systems), and the cogenerators are unable to provide either substantial fuel or cost savings. However, if cogenerators are undersized (relative to the electrical demand) so that they operate as "baseload" heaters and only supply some of the electrical needs, they may have lower total costs, and thus, higher penetration rates than the ones calculated by ConEd (3). Therefore, even in the Mid-Atlantic region, cogeneration's market penetration may be very sensitive to operating and cost assumptions.

In the fourth study of cogeneration in commercial buildings three State agencies in California calculated the cogeneration potential in State-owned buildings, including hospitals, universities, and State offices. The State identified 188 State-owned facilities that have significant potential for cogeneration, and initiated engineering studies for the cost effectiveness of cogeneration. "The evaluation showed that 150 MW at 24 sites could be designed, under construction, or in operation in fiscal year 1981. An additional 97 MW at 31 sites could be developed in fiscal year 1982, totaling 247 MW at 55 sites. It should be clearly understood that these are preliminary estimates of cost-effective cogeneration capacity. Further engineering analyses may result in increased or decreased capacity." The study concludes that the total potential for cogeneration in State-owned buildings is over 400 MW. The distribution of this capacity among State facilities is shown in figure 51.

Because the literature on commercial cogeneration is sparse, OTA undertook its own analysis of cogeneration opportunities in the commercial sector. This analysis is concerned with illustrating those parameters that significantly affect the use of cogeneration in commercial buildings. To do this, in part, we make use of a computer-based model—the Dispersed Electricity Technology Assessment (DELTA) model–that simulates decisionmaking by electric utilities in choosing new capacity. The model can accommodate ranges of values for the technical, operating, and financial characteristics of utilities and cogenerators. There are limitations to its use, however, due to the number of assumptions that have to be made and to the gaps in the available data. Consequent-

Figure 51.—Cogeneration Potential at California State Facilities



SOURCE: California Energy Commission, *Commercial Status: Electrical Generation and Nongeneration Technologies* (Sacramento, Calif.: California Energy Commission, P102-8O4O4, April 1980).

ly, the DELTA model cannot be used to accurately project levels of cogeneration use in commercial buildings over the next several years. in particular, we have not used the model to analyze the case where natural gas and distillate oil prices are significantly different from one another, nor the case where retrofits of existing buildings are included in the demand for thermal energy. A qualitative discussion of these cases is presented, however. The model does give us, though, insight into how cogeneration might compete with new central station capacity to supply commercial electricity demand, and the effect of such factors as thermal load profiles on that competition. Therefore, despite its limitations it is believed that the DELTA model–properly clarified–will substantially assist in understanding the conditions that affect cogeneration's future in the commercial sector.

Critical Assumptions and Limits of the DELTA Model

The DELTA model uses a linear program (similar to those used by utility planners) that minimizes the total cost of producing electricity and thermal power during the years 1981 to 2000 (see app. A for model description). The model simulates the addition of grid-connected cogeneration in three kinds of large new commercial buildings, with different types of daily load cycles, to supply electricity, space heating, and space cooling demands. Several scenarios were constructed to explore the sensitivity of cogeneration in these buildings to regional utility and climate characteristics, future fuel price changes, and different technological specifications. The structure of the model, the assumptions about thermal and electricity supply and demand, and the features of the scenarios constructed are described below.

Model Structure

Electric and Thermal Cost Minimization.—The DELTA model differs from many existing utility planning models in that its objective is the minimization of total annualized fixed plus operating costs for **both utilities and their commercial building customers (e.g.,** for heating and cooling). Thus, DELTA goes beyond traditional utility planning, which usually analyzes only those costs borne by the power system. The strategy selected through this hybrid cost minimization may not exactly match either the strategy chosen by the utility or by the customer acting alone, but will tend to produce an "average" between both parties.

Demand Assumptions

Grid-Connected Cogeneration.–The DELTA model only examines grid-connected cogeneration because the PURPA provisions on purchases of cogenerated power are intended to benefit cogeneration systems that provide energy and/or capacity as well as diversity to utilities. Therefore, OTA did not analyze the effects of stand-alone systems on utility operations.

Three Types **of Energy Demands.–The DELTA model specifies hourly demands for three types of energy: space heating, space cooling, and electricity. The analysis begins in 1980 with a specified thermal baseline** of zero load and zero capacity, and an electrical baseline of 1,000-MW load and the existing generating capacity mix (normalized to the 1,000-MW load) in each sample region. The model then determines what capacity additions will minimize utility and customer costs for all three types of energy, assuming a range of growth rates for energy and peak demands in each sample region (see table 40, below, for a description of existing electrical capacity and growth rates). New capacity is added at the end of each decade—in 1989 and 1999—and then system costs are evaluated in 1990 and 2000.

The 1980 electric generating capacity in each sample region was normalized to 1,000 MW to facilitate comparisons of capacity additions and future utility operations among the different regions. However, in order to compare thermal demands among the building types and regions a different approach was necessary. A large amount of data would be needed for a precise specification of existing thermal capacity and demands–unlike electrical demands, there is no accurate and centralized source of information on thermal demand and capacity. Thus, in order to ensure consistent and accurate treatment of thermal demands, OTA would have had to collect individual commercial customer profiles–a time-consuming and expensive process. Therefore, OTA chose another method for the DELTA model: to set existing thermal demands and capacity equal to zero. In effect, this is equivalent to only allowing cogeneration in new buildings, and then comparing the cost of installing cogeneration with the costs for new centralized capacity and new steam boilers, but not considering the replacement of any existing steam boilers with new cogeneration equipment. As was stated, without inclusion of such boiler retrofits, the model cannot be used to project the cogeneration potential in the entire commercial sector. Although we have not attempted to project the retrofit potential in any other way, the factors that will influence this potential will be discussed later in this section.

Eight Typical Days. –OTA chose to specify each type of energy demand with a yearly pattern of eight different "typical days" in order to observe more clearly the range and frequency of utility operating characteristics (see table 37).

Table 37.—Typical Days Used in the DELTA Model

Day type	Frequency Per Year
Winter:	
Peak[a]	6
Weekday	59
Weekend	26
Summer:	
Peak[a]	8
Weekday	80
Weekend	34
Fall/spring:	
Weekday[a]	108
Weekend	44
Total	365

aThe 1990 electrlc bad patterns for region 1 for these 3 days are shown in fig. 52.

SOURCE: Off Ice of Technology Assessment.

Each typical day has a specific load cycle pattern for each region and year. For example, the load cycle patterns during 1990 for three different typical days and for one region (New England) are shown in figure 52. The differences among these cycles are caused by the different assumptions for energy use and demand growth used in each region.

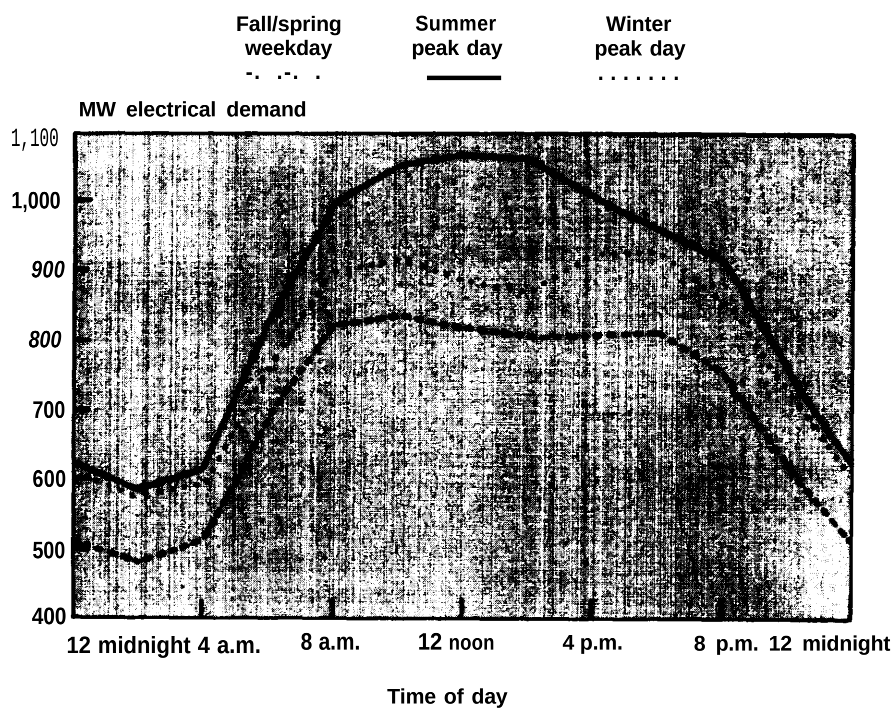
Three Commercial subsectors.-In addition to specifying the annual load patterns for electricity, OTA chose to disaggregate the commercial sector's thermal heating and cooling demands into three parts: hospitals and hotels, multifamily buildings, and 9-to-5 office buildings. This was done to explore the effects of load diversity on cogeneration operation, and thus to provide more precise information on the opportunities for commercial cogeneration. Other commercial sector building types (such as universities and retail stores) have energy demand profiles that are combinations of these basic three categories. (The electric demands were not disaggregated in the DELTA model because the load profiles for the entire commercial sector were sufficient to capture the interaction of the cogenerators with the centralized utility system.)

The three subsectors were chosen for their different thermal load patterns; examples of these patterns for two typical day types are given in figures 53 and 54 for 1990 New England heating and cooling demands respectively. For heating demands, hospitals and hotels have the lowest energy demands of all the subsectors, with small peaks at 8 a.m. and 9 p.m. Multifamily buildings use somewhat more energy and have similarly occurring peaks, while 9-to-5 offices use the most energy and have the most pronounced peak during the winter days at 6 a.m. The cooling demands of hospitals and hotels and multifamily buildings are small when compared to office buildings, the latter having a peak during summer days at 2 p.m.

Supply Assumptions

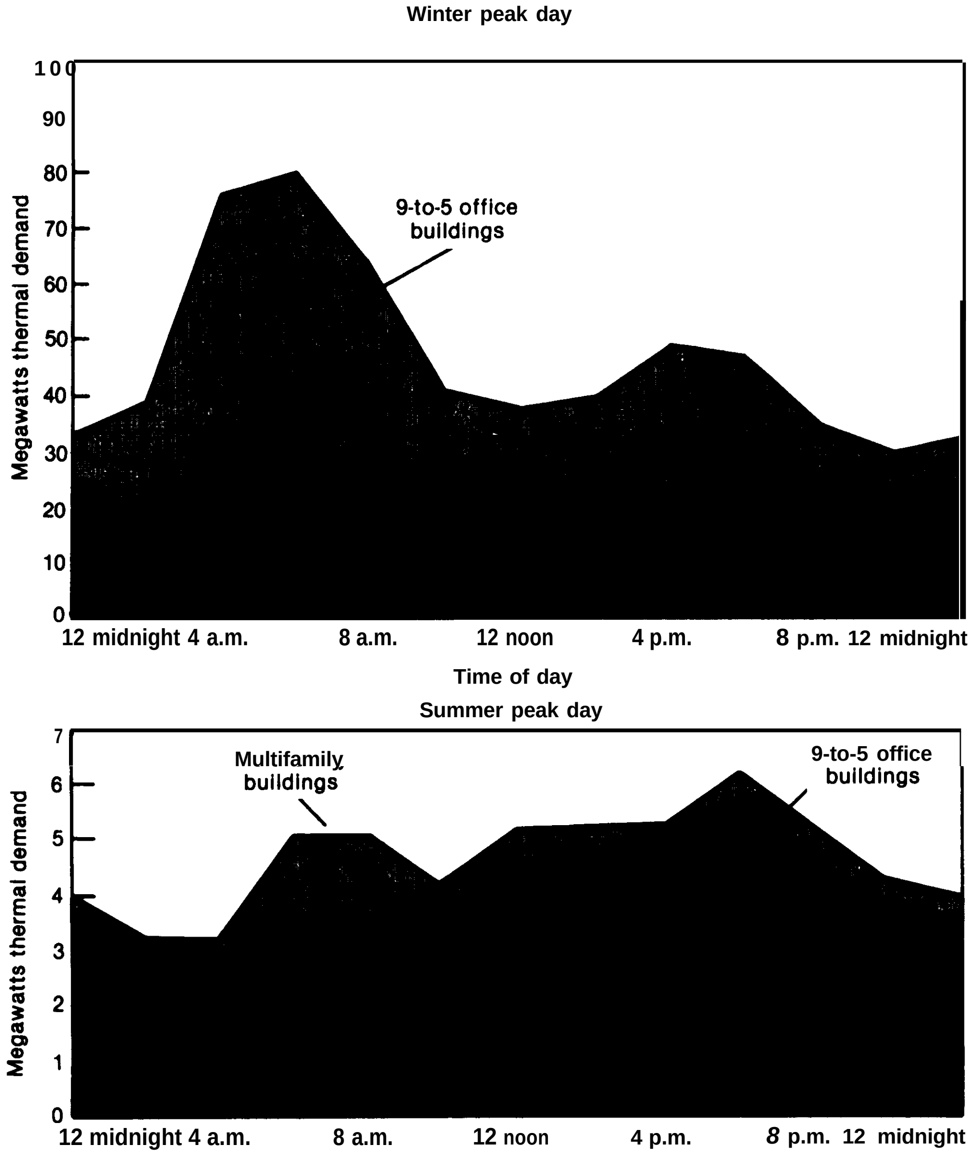
The energy supply assumptions in the DELTA model specify different sets of fuel prices and of

Figure 52.—Comparison of Eiectric Demand for Three Types of Days (for region 1 during 1990)



SOURCE: Office of Technology Assessment.

Figure 53.—1990 Heating Demands for Scenario 1[a] (for Region 1 during 1990)



aScale on two graphs is different.

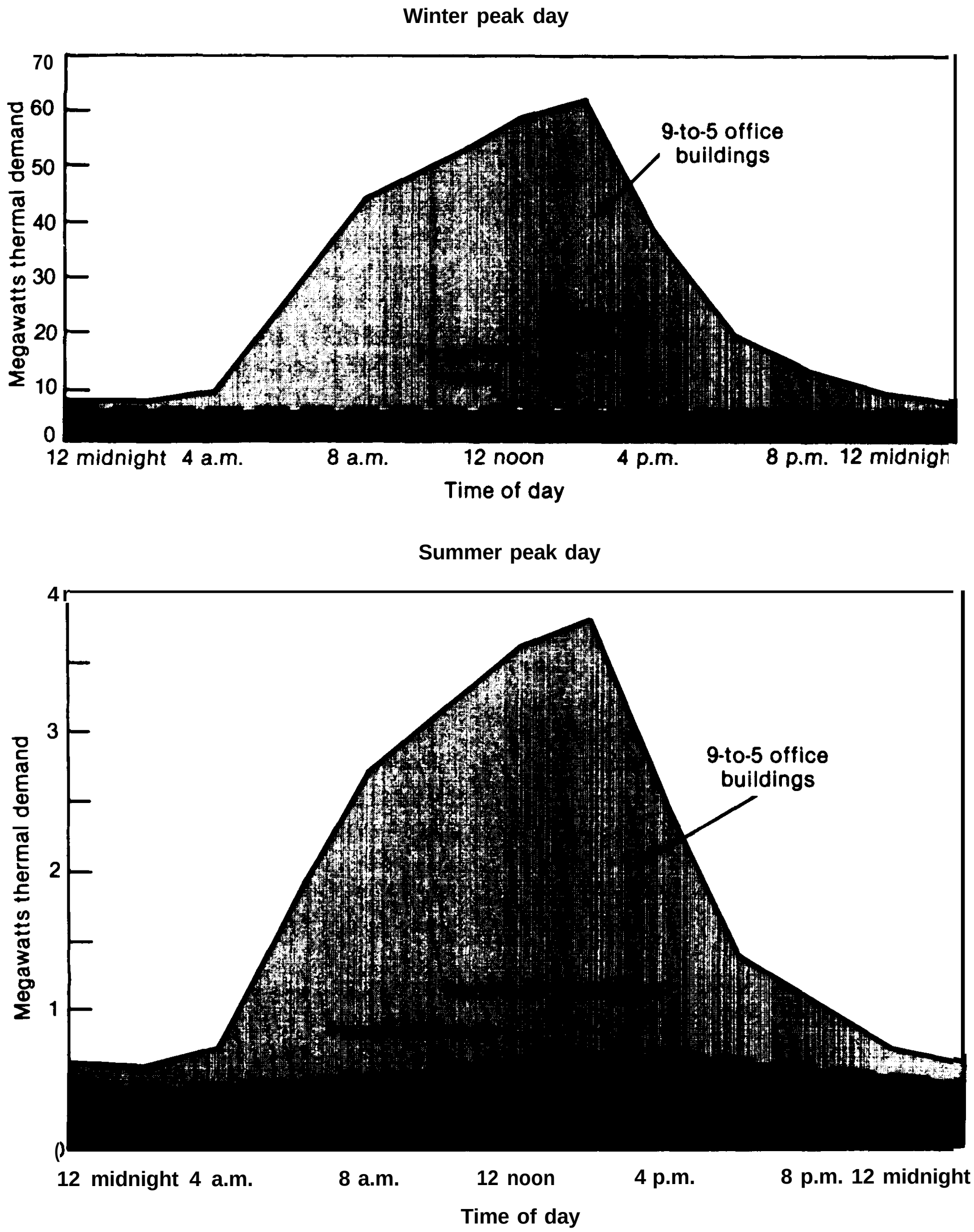
SOURCE: Office of Technology Assessment.

technological and operational characteristics in order to describe the three different sample utility regions.

Fuel Prices.–OTA specified two different fuel price trajectories, based on the 1980 average prices in the commercial sector (31) and the range of real growth rates (not accounting for inflation) assumed in two previous OTA studies (17,20). These growth rates are: 1.0 percent annually for coal (and electricity) and 1.7 percent per year for fuel oil and natural gas for the low price trajectory, and 4.7 percent annually for coal (and electricity) and 4.8 percent per year for fuel oil and natural gas for the high price trajectory. * For this analysis of commercial cogeneration, these as-

*These growth rates are explained in the OTA report, *Application of Solar Technology to Today's Energy Needs,* vol. 11, September 1978.

Figure 54.-1990 Cooling Demands[a] (for Region 1 during 1990)



a Scale on two graphs Is different.

SOURCE: Office of Technology Assessment.

sumptions were modified slightly by setting the price of natural gas equal to fuel oil after 1985.

Using two different fuel price trajectories allowed us to test the sensitivity of our results. However, the results varied by less than 2 percent between the two different price paths. Therefore, only the lower price path results were reported. These prices are shown in table 38.

our assumption about natural gas prices requires elaboration. Currently, most natural gas is used for purposes that require a higher quality fuel than coal or residual fuel oil. About 25 to

Table 38.-Fuel Prices
(all prices In 1980 dollars per MMBtu)

	1980	1990	2000
Coal	1.34	1.95	2.38
Residual	4.05	5.86	7.13
Distillate	5.67	8.20	9.98
Natural gas	2.09	8.20	9.98

SOURCE: Office of Technology Assessment.

30 percent of current natural gas use is for raising steam, while the remainder goes for space heating in buildings, industrial process heat, peakload electricity generation (primarily combustion turbines), and chemical feedstocks (7). The future price of natural gas will be determined by the relative strengths of these demands combined with the availability and cost of new domestic natural gas.

The conversion of all natural gas-fired boilers to coal would free about 4 trillion to 5 trillion cubic feet (TCF) of natural gas per year at current consumption rates. If there were no other change in natural gas supply and demand, this new "supply" would be more than enough to replace all current distillate fuel oil used for stationary purposes (1.9 MMB/D) (8). If price increases resulting from decontrol bring about more conservation, additional natural gas would be freed, which, when combined with the displaced boiler fuel, would result in a substantial surplus of natural gas. The most logical use for this surplus gas would be to displace residual fuel oil used to fire boilers. (Of course, in reality, the gas would only leave the boiler market until it just displaced all stationary fuel oil). This competition with residual fuel oil would keep the marginal cost of natural gas about the same as that of residual oil.

This scenario, however, assumes that domestic natural gas supplies do not decline significantly over the same period, and that the marginal cost of the new supplies that offset the decline in production from existing reserves will be below the price of distillate fuel oil. It is quite possible–indeed both Exxon and the Energy Information Administration have projected as much–that there will be a net decline in domestic natural gas supplies by as much as 3 TCF by 1990 (10). On the other hand, AGA estimates that supplies could increase substantially over this same period (2). In all cases, however, a significant fraction of new domestic supplies in these projections is made up of high cost supplemental supplies—unconventional gas, Alaskan gas, and synthetic gas from coal. In fact, the three organizations project about the same amount of conventional domestic natural gas production—about 14 TCF in 1990 and 12 TCF in 2000. This is close to the quantity now being consumed by the so-called high priority uses for which only distillate fuel oil or electricity are feasible substitutes (19). Therefore, if the cost of new marginal natural gas supplies were equivalent to distillate fuel oil, the price of all natural gas would approach that of distillate or electricity (whichever is cheaper) as decontrol takes effect and the quantity of old, flowing natural gas under contract vanishes. It is partly the somewhat optimistic supply assumptions about new, "lower cost" gas that has caused most recent price projections to show natural gas prices below those for distillate fuel oil for the remainder of the century (8).

Our price scenarios rest on the assumption that "lower cost" gas supplies will decline as fast or faster than the rate at which coal displaces natural gas in boilers. Even in this case, however, natural gas prices could be lower than distillate oil if electricity prices stay below distillate (on an energy-service basis)—as they currently are in many regions of the country. in this case, natural gas prices will likely approach those of electricity (again on an energy service basis). Similar speculation has been offered by others (26). Because OTA did not run the model with natural gas prices below distillate, the model results presented are confined to what would happen under the plausible situation that the prices of the two fuels are the same. To partially expand the analysis, some calculations of target gas prices are presented for the condition that cogeneration produces power at the cost of electricity determined by the model. There is evidence, as will be seen, that some cogenerators are proceeding based on the assumption that natural gas prices will remain below distillate prices for the economic life of their projects.

Technology Characteristics.–The major technologies used in the DELTA model include three types of central electricity generating plants, several space heating and cooling technologies, and the cogenerators. Table 39 summarizes the characteristics for each type.

OTA specified three different types of generic utility generating plants to serve base, intermediate, and peak loads. The baseload type is represented by coal-fired steam powerplants, the intermediate-load type by either residual oil-fired or distillate or gas-fired steam turbines, and the peaking technologies by distillate or gas-fired combustion turbines.

Space **heating and** cooling technologies in the model include ordinary steam boilers used for heating, electric air-conditioners, absorptive air-conditioners using distillate or gas fuel, and thermal storage equipment with a capacity of up to 24 hours storage. Because of the linear programing formulation, the model cannot change the type of fuel used in either electric generating or thermal equipment from their original specification in table 39.

Two sets of capital costs for cogeneration capacity were included in the analysis. The higher cost cogenerator has a capital cost of $750/kW, while the lower cost system has a capital cost of $575/kW (both in 1980 dollars). These capital costs are typical of the range of cogeneration costs described in chapter 4 (see table 23). We did not include, explicitly, cogeneration technologies that could use coal by means of synthetic fuel production or advanced combustion technologies (e.g., fluidized beds). If the capital costs of these technologies are similar to those used in the model, the results would remain unchanged. The only exception would be a reported increase in coal use if these technologies are employed, because the model allowed cogeneration technologies to use only oil or natural gas.

Operational Assumptions.–OTA made three operational assumptions that would allow the DELTA model to follow more closely the way actual grid-connected cogeneration systems would operate. First, OTA specified the utility planned reserve margin to be 20 percent of annual peak demand. This includes scheduled maintenance for 10 percent of the year for the base and intermediate types of plants, and is typical of reserve margins used in power systems planning, although actual reserve margins may be much higher than 20 percent. For the sample utility regions used in this analysis (see below), all 1980 reserve margins were above 20 percent. In addition, the actual 1981 national average reserve capacity was around 33 percent (16).

Second, the model assumes that all cogeneration equipment has an E/S ratio of 227 kWh/

Table 39.—Technology Characteristics (all costs are for 1980 In 1980 dollars)

Technology type	Cap cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/kWh)	Availability[a] (percent)	Heat rate[b] (Btu/kWh)
Base	1,014	14.0	0,001	68	10,300
Intermediate	200		0,0015	88	10,500
Peak	200	0.3	0.003	93	14,000
Cogeneration—high	750	0.0	0.008	95	9,751
Cogeneration—low	575	0.0	0.008	95	9,751
Thermal boiler	100	0.0	0.0	95	4,266
Thermal storage	2'	0.0	0.0	—	—
Electric air-conditioners	700	0.0	0.0	95	1,138
Absorption air-conditioners	110	0.0	0.0	95	5,251

aAvailability is the maximum percent of time that capacity can serve demand—thus 88 percent means the baseload equipment is out of service a total of 12 Percent of the year.
bThe cogeneration heat rate shown is the heat rata for electrical service only: the net heat rate (Including the energy In Steam produced by the cogenerator) is 5,333 Btu/kWh. Both of the heat rates shown for air-conditioners are calculated in Btu/kWh of heat removed from commercial buildings.
cCapital cost of thermal storage is expressed in dollars/kWh.

SOURCES: Electric Power Research Institute, The Technical Assessment *Guide,* Special Report PS 1201 SR, July 1979, specifies capital cost, variable and fixed O&M costs, heat rates, and availabilities for coal steam plants with flue-gas desulfurization, for distillate oil-fired steam plants, and for oil- and gas-fired combustion turbine plants. OTA multiplied the costs for these plants by the Consumer Price index inflator to bring 1978 costs to 1980 costs, and used the Gross National Product inflator to bring 1978 dollars to 1980 dollars. Characteristics for the thermal technologies were obtained by averaging the data collected in ch. 4 for cogeneration equipment, thermal boilers, and storage (see table 23 for these figures). Zero fixed and variable O&M costs are assumed for the conventional space heating and cooling technologies, because these costs are very small when compared to the 8 mills/kWh variable O&M costs of the cogenerators.

MMBtu, with 35 percent of the output used for electricity, 45 percent to satisfy the thermal load, * and 20 percent exhausted to the outside environment—an overall efficiency of 80 percent. Third, thermal storage is assumed to have an efficiency of 90 percent (i.e., 1.0 MWh (thermal) into storage can supply 0.9 MWh (thermal) out of storage). No electrical storage is considered. These values are within the range of actual values described in chapter 4 for E/S ratios and efficiencies for gas turbine or combined-cycle cogeneration systems, which are or will be applicable in the commercial sector (see table 23).

Sample Regions.–OTA chose three sample utility regions based on the technological and operational assumptions mentioned above and on data from the regional electric reliability councils. **Region 1** is typical of areas with utilities that have a large percentage of oil-fired steam generation, high reserve margins (over 40 percent), and a relatively moderate annual growth in electricity demand of 1 percent (such as the Northeast Power Coordinating Council). The summer and winter peaks for Region 1 are about equal. **Region 2** is typical of summer-peaking regions with mostly nuclear or coal baseload capacity, a higher annual load growth than in Region 1 (2 percent), but lower reserve margins (26 percent) (e.g., the Mid-America Interpool Network). **Region 3 is typical of areas with** large reserve margins (over 40 percent), relatively high load growth (3 percent), and large amounts of gas-fired steam generation (such as the Electric Reliability Council of Texas). Region 3 is also summer-peaking. (See fig. 8 for the location of each of these regions of the North American Electric Reliability Council.)

● Measured in megawatts, i.e., 1 MW (thermal) = 3.412 MMBtu/hr.

Table 40 summarizes the electrical demand and supply characteristics of each region, normalized to 1,000 MW.

Scenario Description

Based on the above demand and supply assumptions, OTA used nine "standard scenarios" to investigate the effects of cogeneration on the sample utility regions for different cogeneration costs (see table 41). These standard scenarios were grouped into three sets to represent the three utility regions. Each set has three different scenarios: a base case in which no cogeneration is allowed and only utility powerplants are used, and two cogeneration cases using higher and lower capital costs of the cogenerators. As mentioned previously, the scenarios also originally included two sets of fuel prices. However, the results of the analysis varied by less than 2 percent between the higher and lower prices, and only the results for the lower prices are reported here.

In addition, five **special scenarios were formulated to investigate the effects of limiting the addition of baseload capacity and of using a zero capital cost cogenerator. Not all possible combinations of regions and cogeneration capital costs were made** for these five special scenarios because OTA was primarily interested in observing the sensitivity of the standard set of scenario assumptions to particular situations, rather than making complete inter-regional comparisons. Table 41 identifies these special scenarios and their distinguishing assumptions.

Commercial Cogeneration Opportunities

The DELTA model described above chooses among the varying technological, financial, and other assumptions to find the minimum total cost

Table 40.-Sample Utility Configurations

Region	1960 capacity installed (MW) Base	Intermediate	Peak	Total	Electrical demand growth[a]	Annual peak in	1960 reserve margin
	500	740	150	1,390	1%	Summer, winter	39%
2	1,020	0	237	1,257	2%	Summer	26°A
3	265	1,107	50	1,442	3%0	Summer	44%

aAnnual growth in both electrical peak demand and total energy demand.

SOURCE: Office of Technology Assessment.

Table 41.—Description of Scenarios Used

Standard scenarios:	
I-NO COGEN	Region 1, base case/no cogeneratlon allowed
1-HIGH COST COGEN	Region 1, high capital cost cogeneration
I-LOW COST COG EN	Region 1, low capital cost cogeneration
2-NO COGEN	Region 2, base case/no cogeneration allowed
2-HIGH COST COGEN	Region 2, high capital cost cogeneration
2-LOW COST COG EN	Region 2, low capital cost cogeneration
3-NO COGEN	Region *3,* base case/no cogeneration allowed
3-HIGH COST COGEN	Region 3, high capital cost cogeneration
3-LOW COST COG EN	Region 3, low capital cost cogeneration
Special scenarios	
I-NO COGEN/COAL-LIMITED	Region 1, coal-fired baseload capacity limit, no cogeneration
I-LOW COST COGEN/COAL-LIMITED	Region 1, coal-fired baseload capacity limit, low capital cost cogeneration
2-ZERO COST COGEN	Region 2, zero capital cost cogeneration
3-NO COGENI/OAL-LIMITED	Region 3, coal-fired baseload capacity limit, no cogeneration
3-LOW COST COGEN/COAL-LIMITED	Region 3, coal-fired baseload capacity limit, low capital cost cogeneration

SOURCE: Office of Technology Assessment.

of providing electric and thermal energy in each scenario. The model results are not predictions about future utility behavior—rather, they represent what might happen under the conditions and assumptions used to specify the scenario. By answering these "what-if" types of questions, the model can provide valuable insights about the interaction of cogeneration with the existing centralized utility systems.

Capacity Additions and Operating Characteristics

In order to analyze the addition of cogeneration capacity and its effects on utility system operations, OTA determined, first, whether a minimum-cost capacity expansion plan would include significant amounts of cogeneration, and second, how the cogeneration equipment that is added is used to supply electric and thermal energy.

COGENERATION CAPACITY

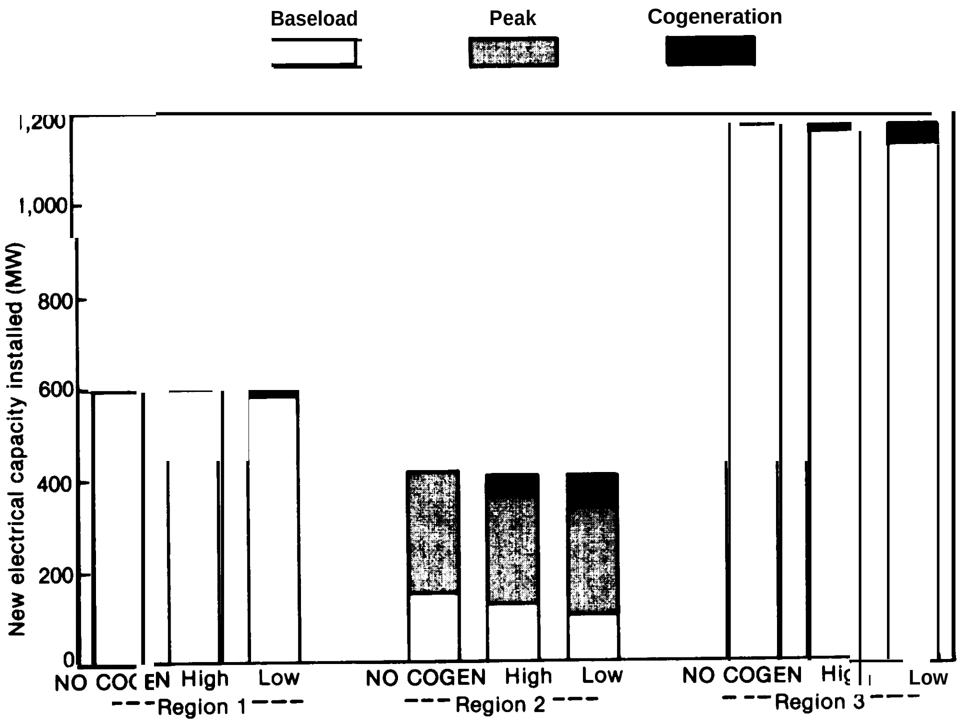
To see if cogeneration capacity would be economically attractive compared to central station generation for our set of assumptions, OTA compared the electric generating capacity additions for the base-case scenarios–in which no cogeneration is allowed—with the scenarios in which cogeneration can be added. Figure 55 summarizes these capacity addition comparisons for the nine standard scenarios.

The results show that the greatest opportunity for cogeneration occurs when the match between thermal space heating and electrical demands is the closest. Thus, the largest proportion of cogeneration capacity is added in Region 2, which has the highest thermal demand of the three regions. Region 3, on the other hand, adds more total capacity (cogeneration and central station) because it has the largest growth in electricity demand, and because it has a large proportion of existing gas-fired capacity that can be replaced by less expensive coal-fired units. With our assumptions, therefore, commercial cogeneration in new buildings is competitive with central station technologies only when there is a significant need for space heating and at least a moderate growth in electricity demand. Coal-fired capacity is cheaper than new cogeneration capacity when electricity is needed but very little or no heating is required. Coal is cheaper because of the difference in fuel prices, and that difference dominates any other cost of installing or operating the technology under our assumptions.

One way to test this result is to vary the capital cost of the cogenerator. By going to the extreme case of zero capital cost, the limit of cogeneration penetration can be shown under our fuel cost assumptions. * We ran this case for Region

*This analysis also provides a rough approximation of what might happen by keeping the capital cost unchanged but lowering natural gas fuel prices.

Figure 55.–Electrical Capacity Additions 1990-200@



aFor 1990, scenario l–LOW-COST COGEN/COAL-LIMITED.

SOURCE: Office of Technology Assessment.

2 (abbreviated as 2-ZERO COST COGEN), and found that the cogeneration technology was more competitive with the coal baseload capacity and more cogeneration was installed than in the other cogeneration scenarios for Region 2. However, the amount of electricity produced from the cogeneration did not increase significantly (see the discussion on costs below).

In another set of special cases, the amount of coal that could be used for central station capacity was restricted. This constraint had two purposes. First, it simulated conditions where coal burning may be prohibited or severely restricted for environmental, availability, or other reasons. (This assumption also simulates the case where nuclear would serve as the baseload and it, too, would be restricted.) The second purpose was to examine the effect of much higher coal prices relative to natural gas and oil. This method (restricting coal use) is not as satisfactory as carrying out model runs with different fuel price trajectories and ratios, but will serve qualitatively to show how higher coal prices would benefit oil- or natural gas-fired cogeneration.

In Region 1, no baseload plants were allowed to be added through 2000, while in Region 3, baseload capacity additions through 1990 were limited to a small percentage of the total existing baseload capacity, while no limits were placed on additions from 1990 to 2000. Two scenarios were run for each region: a **new base-case** in which only central station equipment was added (abbreviated l-NO COGEN/COAL-LIMITED and 3-NO COGEN/COAL-LIMITED, for Regions 1 and 3 respectively) and a **cogeneration case** (abbreviated l-LOW COST COGEN/COAL-LIMITED and 3-LOW COST COGEN/COAL-LIMITED). Table 42 summarizes the capacity additions for these four scenarios.

Table 42 shows that the limits on baseload capacity additions increase the economic attractiveness of cogeneration in both regions. For ex-

Table 42.—New Capacity Installed for Coal-Limited Scenarios

Scenario	Total electrical capacity installed (MW)	Proportion of new electrical capacity installed (o/o)		
		Base	Peak	Cogeneration
I-NO COGEN/COAL-LIMITED	15	—	100	—
I-LOW COST COGEN/COAL-LIMITED	62	—	0	100
3-NO COGEN/COAL-LIMITED	1,192	100	0	
3-LOW COST COGEN/COAL-LIMITED	1,363	63	0	17

NOTE: "-" means assumed zero input for this scenario.

SOURCE: Office of Technology Assessment.

ample, 3-LOW COST COGEN/COAL-LIMITED installs 77 percent of its total capacity as cogeneration while the standard Region 3 scenarios (3-HIGH COST COGEN, and 3-LOW COST COGEN) install at most 4 percent.

These results demonstrate the competition between cogeneration and central station coal-fired capacity to meet new electricity demand. Both capital and operating costs of the system and the thermal demand determine this choice. If new coal-fired capacity is sufficiently inexpensive, even in the face of the efficiency advantage of cogeneration, coal will provide electricity and conventional oil- or gas-fired space heaters will provide thermal energy for these new buildings. Further, if excess electric generating capacity exists, the ability of cogeneration to penetrate the commercial market may also be limited, even if cogeneration is less costly than new, coal-fired central station generation. Electricity from the existing capacity, because of its sunk capital cost, is usually cheaper than that produced by new, more efficient cogeneration if the latter is confined to premium fuels. In some cases, however, economics may still favor cogeneration, particularly if the existing central station capacity is oil fired and near retirement. In some markets where retirement would be desirable in the next few years, cogeneration from natural gas-fired units could be the only means of replacement capacity, whether coal-fired generation is permitted or not. We will discuss this further below.

COGENERATION OPERATION

The above results on cogeneration capacity are explained by the details of how the electrical and thermal loads are met. OTA calculated the electrical capacity factor (the ratio of time a generator actually supplies power to the time the plant is available for service) for both the cogeneration and the baseload capacity in each of the scenarios. Table 43 shows the electrical capacity factors calculated by the model for both the standard and coal-limited scenarios. Most of the baseload capacity operates 66 to 70 percent of the time, while the cogenerators operate less than 30 percent of the time. * The low load factor for cogeneration results from its inability to generate electricity that is competitive with central station electricity even though cogeneration is more energy efficient. This is a result of our assumed fuel prices. As we shall see, the DELTA model only operates cogenerators when the electricity is needed to meet intermediate or peaking demands that otherwise would be supplied by oil-fired utility units. The higher fuel prices of these utility units, combined with the high overall efficiency of the cogenerator, allows the latter to compete economically in the market for intermediate and peaking power. When coal is prohibited, the thermal and electrical capacity factor of the cogenerators increases from 30 percent or less to over 50 percent. In this case, the cogenerators are also supplying a small amount of baseload electricity. This is because the cogenerators can supply power less expensively than other types of central station generation when coal-fired additions are limited.

However, these capacity factors only indicate the most general performance of each type of equipment. in order to provide a more complete description, we need to observe, for each scenario, the hour-by-hour dispatching schedule (for

*For the cogenerator, this is also the thermal capacity factor since the unit is producing both electricity and thermal energy while it operates.

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Table 43.-Capacity Factors for Baseload and Cogeneration Plants

	Baseload plants		Cogeneration plants	
	1990	2000	1990	2000
Standard scenarios				
I-NO COGEN	69	68	—	
1-HIGH COST COGEN	69	68	—	27
1-LOW COST COGEN	70	69	31	29
2-NO COGEN	66	67	—	—
2-HIGH COST COGEN		70		10
2-LOW COST COGEN	66	68	7	13
3-NO COGEN	69	68		
3-HIGH COST COGEN	70	68	21	20
3-LOW COST COGEN	70	69	21	21
Baseload-limlted-scenarlos				
I-NO COGEN/COAL LIMITED	80	80	—	
I-LOW COST COGEN/COAL-LIMITED	80	80	58	53
3-NO COGEN/COAL-LIMITED.	80	67		
3-L0W C0ST COGEN/COAL-LIMITED	80	69	95	7

Note:"—" means no cogeneratlon was Installed by the model, elther due to economics of the model or because of input es zero for the base-case scenarlos. Capacity factors are calculated for each plant type as follows:

$$\frac{\text{MWh Supplied}}{\text{(MW installed + existing MW)} \times 8{,}760 \text{ hours}} \times 100$$

SOURCE: Off Ice of Technology Assessment.

both cogenerators and central station generators) for each of the eight different types of "typical" days used in the analysis. Figures 56 and 57 present the space heating and electric demands, respectively, and show how each technology is dispatched to meet these demands for 1 day (winter peak which occurs six times a year) in 1990 for scenario 1-LOW COST COG EN/COAL-LIMITED.

Figure 56 shows that, during the 1990 peak winter day, the cogenerators provide about 37 MW of heat to meet thermal demands that vary between 30 and 78 MW. During this peak day, the cogenerators operate 95 percent of the time. Thus, seen from the perspective of a commercial building owner, cogenerators operate as a "baseload" heating system during winter peak days.

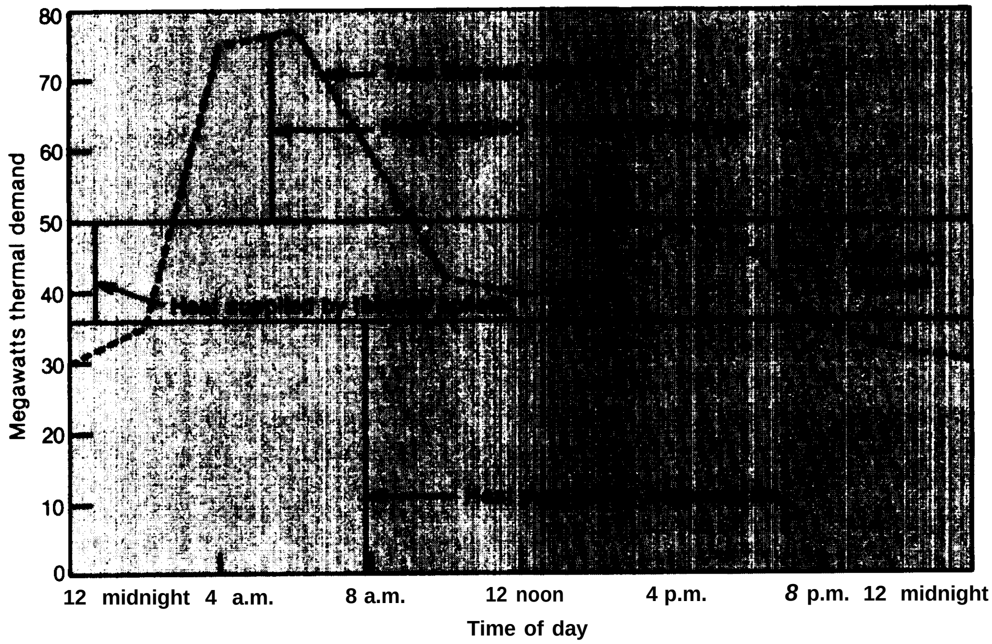
Figure 57 shows the electrical demands for the same 1990 winter peak day. Note that the cogenerators only contribute to the peak and intermediate load. The small numerical value of these contributions is partly due to our assumptions of zero thermal demand and 1,000 MW of electrical demand for 1980. If a larger thermal demand had been assumed and retrofits considered, the electricity contribution of the cogenerators would have increased substantially, although it would still be confined to the peak and intermediate load. What is important here, however, is not the absolute value of the electrical contribution by cogeneration, but rather what portion of the electrical demand it can supply economically compared with other options.

RETROFIT OPPORTUNITIES

As discussed above, existing buildings (hence existing thermal demands) were not included in this analysis. This rules out cogeneration retrofits and thus the analysis understates cogeneration's contribution to the total electric load. It is therefore important to discuss the factors that will influence the choice of whether to install a cogeneration system in an existing building. In addition to the considerations about economic competition with new central station electric generating capacity, the major constraints to retrofitting are excess central station capacity, the uncertainty about natural gas prices and availability, and the difficult financial conditions brought about by high interest rates and short loan terms.

The first constraint, excess capacity, has the effect of keeping the price of electricity well below its marginal cost in most regions of the country

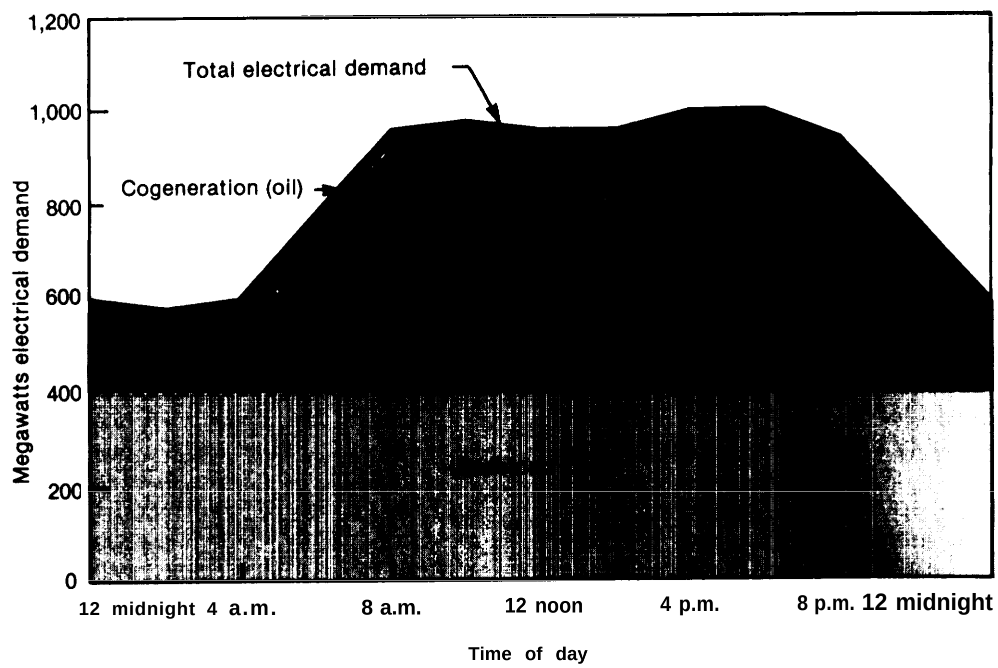
Figure 56.—Thermal Supply and Demand for Winter Peak Day[a]



aFor 1990, scenario 1- LOW-COST COGEN/COAL-LIMITED.

SOURCE: Office of Technology Assessment.

Figure 57.–Electricity Supply for Winter Peak Day



aFor 1990, scenario 1 - LOW-COST COGEN/COAL-LIMITED.

SOURCE: Off Ice of Technology Assessment.

and thus to force payments for cogenerated power under PURPA to be determined by fuel savings alone (i.e., no capacity credit). Both act as an incentive for building owners to continue purchasing all their electricity from the utility. New buildings have a similar incentive–as the model results have demonstrated. In the case of existing buildings the incentive is even greater, however, because of the sunk costs of existing heating equipment and interconnection with the utility. Where current prices exceed marginal cost, as would likely be the case if oil is the dominant fuel used to generate electricity and the future capacity would be coal-fired, shortrun PURPA payments based solely on fuel savings could be high, stimulating cogeneration investment. More will be discussed on this below.

The second constraint, uncertainty about fuel prices and availability, is important because natural gas is the most likely fuel for commercial cogeneration retrofits for the next several years. As discussed earlier, the price of natural gas will increase, but it could still be low enough to make cogenerated electricity and thermal energy (using a combustion turbine, diesel, or combined-cycle system) cost less than a combination of electricity produced from central station generators and an individual heating plant. Gas prices also could be much higher, perhaps as high as distillate fuel oil, which would make potential retrofits too costly in most cases. In the latter case, the results would be similar to those obtained for new construction as given by the model. The price at which natural gas-fired cogeneration is competitive with electricity depends primarily on the size of the facility, the credit obtained for displacing natural gas or oil used for space heating, the financial conditions available to the prospective owner, and the thermal load factor of the building. Capital and O&M costs per unit output increase as the facility size decreases, lowering the natural gas prices required for breakeven with electricity. The displacement credit depends on the amount of fuel saved from the displaced space heating unit, and the cost of hooking up the cogeneration unit. The thermal load factor will determine the amount of electricity that can be produced assuming the cogeneration unit operates to supply baseload thermal demand. The

Photo credit: OTA staff

Some older commercial buildings could be retrofitted for cogeneration, but the economics of such retrofit will depend on the price of electricity and the price and availability of cogeneration fuels—primarily natural gas

analysis of this point is similar to that described above for the new buildings.

As an example of these considerations, we examine a combined-cycle cogeneration unit of about 10 MW (a size typical for a very large building), operating to supply 50 percent of a building's heat load. Further, if this unit can operate at a high electric load factor of 85 percent or more, this unit could produce electricity that would compete with central station electricity priced at 5cents/kWh if natural gas cost $4.50/MMBtu or less (all in 1980 dollars) (34). * The na-

***This calculation assumed a value for the capacity factor in order to determine a breakeven natural gas price. In actual operation it is the other way around. Under the conditions that the building owner's goal is minimum cost and that the cogeneration unit is sized**

tional average price of natural gas in the commercial sector commercial sector for the third-quarter of 1981 was about $3.50/MMBtu. Therefore the combined-cycle system described above appears to have a definite economic advantage for regions where electricity is selling for 5cents/kWh or greater.

There is another set of conditions that would allow natural gas-fired cogeneration to be economically competitive even if the price relationships just calculated do not hold. If the price that utilities must pay to cogenerators for power is set high enough by the State public utility commission, then cogeneration would be installed even if its electricity production costs were greater than the retail price for electricity. Further, depending on the purchase power price under PURPA, cogenerated electricity from a natural gas unit could cost more than new, central station coal-fired generation and still be economically preferable to the latter. In California, for example, the purchase price is based on the cost of oil-fired generation. Many industrial and commercial establishments see this as a very attractive opportunity because their natural gas prices are below the fuel oil prices paid by the utility. Therefore, these cogenerators are willing to enter into agreements with utilities in California to sell them electricity for the next 5 to 10 years.

Even though natural gas prices will increase and probably surpass those of residual oil during that period, the cogenerators will still receive a high return because of their higher overall efficiencies. Further, the utilities will be able to replace current oil-fired capacity more quickly than by more conventional means—i.e., coal or nuclear central station. For the period beyond 1990, however, coal-fired, central station capacity is planned and probably will be cheaper than natural gas-fired cogenerated electricity as the ultimate replacement for the existing oil-fired capacity. However, successful coal gasification with combined-cycle generation could alter the economics back to favoring cogeneration. More is discussed about this last point below.

The California case is not typical of fuel oil dependent utilities, primarily because such utilities located in other States usually can purchase power from neighboring utilities with an excess of coal or nuclear power. In California, power purchases generally are not an option because of limited transmission interties with other systems. The California case does, however, point out the potential for natural gas-fired cogeneration in the next 10 years. We have also not calculated that potential for new buildings since that analysis determines longrun generation needs only (hence longrun avoided costs).

The final point about cogeneration's potential in existing buildings concerns the financing conditions currently available to prospective cogeneration owners. Financial factors will help determine the cost of electricity and thermal energy from a cogenerator. The current high interest rates and short loan terms available to non utility investors for investments in building energy systems are acting to severely limit cost effective investments of any type—conservation or cogeneration.

In a study released by OTA, Energy Efficiency of Buildings in Cities (18), these current financial conditions are partially responsible for keeping about 60 percent of the otherwise cost-effective conservation retrofits identified in that study from being installed. Although OTA did not examine cogeneration in this same way, it is likely that cogeneration retrofits will be affected similarly, perhaps even more so because of the much higher initial investment levels per building needed for cogeneration than conservation. This is one place where utility or third-party ownership would be potentially very helpful. In the former case, utilities would be able to secure longer term loans at lower interest rates than commercial investors. In addition, utilities possess the engineering skills needed to install and hook up the units. Utilities currently are prohibited from owning

to supply baseload thermal energy, cogeneration would be operated whenever it can produce electricity at a cost less than or equal to the combined cost of central station electricity and separate thermal energy production (e.g., a conventional building heating system). The former cost depends on the price of the fuel for cogeneration (natural gas in this case), various financial parameters (interest, taxes, debt/equity ratio, etc.), and O&M costs. The cogeneration unit must be sized to provide baseload thermal energy because the cost of electricity alone from the cogenerator will nearly always be greater than the cost of electricity from a central station plant due to economic and efficiency reasons. It is therefore necessary for the cogenerator to be able to displace building heating fuel and obtain a cost credit in order to meet the minimum cost criteria.

more than so percent of a cogeneration unit and still qualifying for PURPA benefits.

Aside from this legal barrier, however, a potentially more important one exists as a result of the low thermal load factors in individual buildings. Because of this, cogeneration that supplies baseload thermal demand to these buildings may not produce excess electricity for sale to the grid. Unless such electricity is produced, utilities cannot be expected to invest in commercial cogeneration. Raising the load factor, for example, by supplying clusters of buildings (each with different load patterns), would be one way to eliminate this problem. Finally, third-party ownership with lease arrangements may also be promising because of the provisions of the new tax laws.

Although we have not attempted to project the retrofit potential for cogeneration, it is probable that movement in that direction will be tentative for the next few years, primarily due to unfavorable financial conditions. Even should interest rates and loan terms ease in the near future, however, there still will be competition with conservation investments, which will reduce the technical potential for cogeneration in a given building. Further the uncertainty over natural gas is likely to remain until resolution of pricing policy and elimination of end-use restrictions (the Fuel Use Act, see ch. 3). Once these conditions are cleared, however, and if natural gas prices are low enough, or purchase power rates are high enough, there could be considerable interest and activity in cogeneration retrofits in the last half of the 1980's. If new technologies that can use solid fuels—through gasification-are successfully developed by then, further stimulus would exist.

Fuel Use

In addition to investigating the changes in utility capacity additions and operating characteristics that might result from cogeneration, OTA also analyzed the change in proportion of fuels used in the sample utility regions to determine if cogeneration would displace any oil or gas. As mentioned earlier, the analysis assumes that all cogeneration equipment uses distillate fuels in Regions 1 and 2 and natural gas in Region 3. The results of the calculations of fuel consumption in 1990 and 2000 for the "no-cogeneration" standard scenarios are shown in table 44.

Not all scenarios are shown in table 44 because the total fuel used and the proportion used by each fuel type are similar between the base-case ("NO COG EN") and the cogeneration scenarios for each region. Cogeneration accounts for less than 1 percent of the total fuel used in all cogeneration scenarios, and the total fuel and proportionate fuel use change less than 1 percent between the two types of scenarios. As expected for our fuel price and use assumptions, because cogeneration cannot compete with baseload coal-fired electricity, cogenerators operate only a small fraction of the time (when they can supply intermediate and peak demand electricity) and therefore use only a small fraction of the total fuel. A further caveat is the exclusion of existing buildings' thermal demand, as explained earlier.

Because the model was restricted to the case where natural gas and distillate prices were equal, no results were obtained for the case when natural gas prices fall low enough so that cogenerated power could compete with central station electricity. OTA calculated this gas price, given

Table 44.-Base-Case Standard Scenario Fuel Use, By Generation Type and Year

	Percentage of total fuel used					
Scenario	Base	Intermediate	Peak	Cogeneration	Steam boiler	Total annual fuel use (10^{12} Btu)
1990						
I-NO COGEN	98	1	0			64.2
2-NO COGEN	97	0		0	2	62.5
3-NO COGEN	95	2	0	o	3	74.0
2000						
I-NO COGEN	97		0	0	2	69.3
2-NO COGEN	95	0		o	4	74.4
3-NO COGEN	94	1	0	o	5	95.1

SOURCE: Office of Technology Assessment.

the set of costs and technical assumptions as well as the average price of electricity determined in our analysis (ranging from 3.3cents/kWh to 7.0cents/kwh). Using our assumptions of $575/kW capital cost for the cogenerator, 0.8cents/kWh O&M cost, and an overall heat rate of 9,750 Btu/kWh with an 80-percent combined heat and electric power efficiency, we can calculate the breakeven price range of natural gas. For a cogenerator capacity factor of 0.85 this price ranges between $2.55/MMBtu to $8.40/MMBtu, which brackets the current commercial natural gas price of $3.50/MMBtu (in 1980 dollars). Again, the capacity factor will be determined by the cost of electricity produced by the cogenerator and, therefore, the cost of natural gas. This is a complex interaction because lower capacity factors reduce the fuel displacement credit, thus increasing the net cost of cogenerated electricity.

Similar arguments can be applied for the new technologies not considered in the model. The ability of these newer technologies to enter the market depends ultimately on the cost of steam and power they produce. Currently a few systems are being developed that will allow these costs to be estimated. One such system is the Coolwater combined-cycle, coal gasification system recently announced (1 1). Although that system is being designed to supply electric power to the Southern California Edison system, successful demonstration of the technology could lead the way to cogeneration applications. An unpublished analysis of the economics of the Coolwater facility as a cogeneration plant estimates an electricity cost of about 3.6cents/kWh, including a credit for heat recovery (fuel displaced by byproduct steam from the cogenerator) of about 4.6cents/kWh (34). This price for electricity is lower than the marginal cost of electricity from a new central station coal plant, although higher than the average cost calculated in some of the cases of our analysis. The calculation, however, assumes a return on equity that may be less than will be required of new plants such as the Coolwater facility. * In addition, using such facilities for commercial buildings entails the development of coal handing, delivery, and storage facilities plus the need for air quality control equipment. All will add expenses to these systems (which were not included in the calculation cited above), and the question of the economic attractiveness of these advanced cogeneration systems is still open. Biomass and urban solid waste have been proposed as fuels for gasification-cogeneration systems, and, in some cases, are under development. The economic analysis of these systems is similar to that given for the Coolwater facility. One exception is that for proposed solid waste units, a credit is available in the form of the tipping fees usually charged to dispose of these wastes.

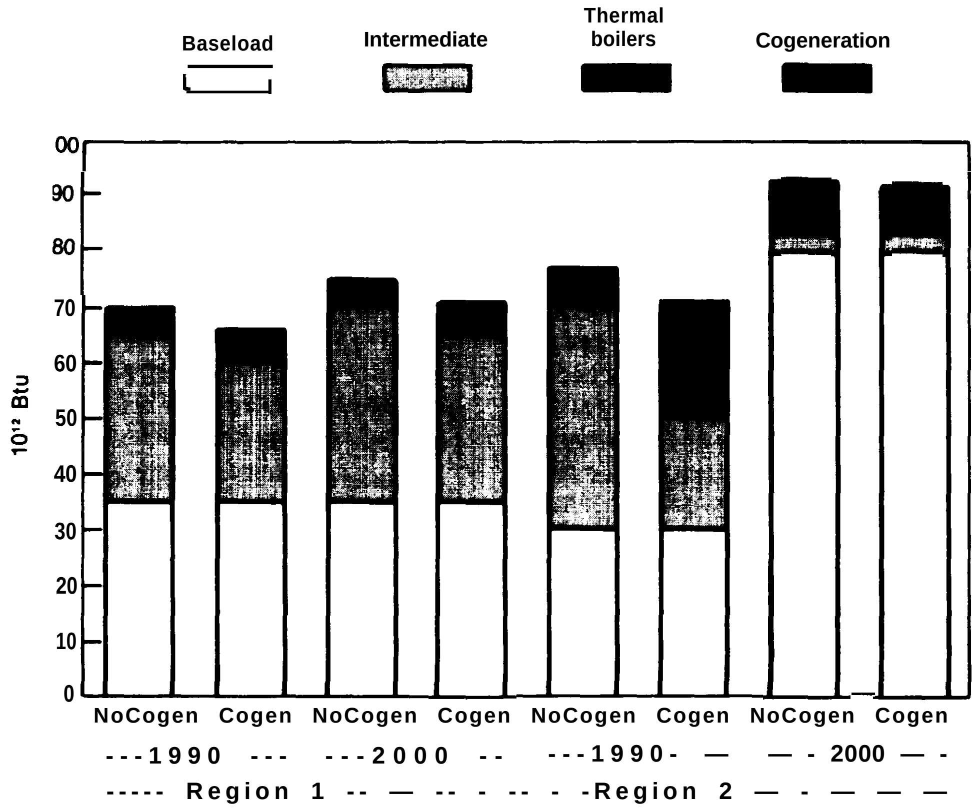
A recent development concerning biomass cogeneration is a combined-cycle system using a direct-fired combustion turbine fueled by pulverized wood. Using hot gas cleanup technology developed in the British pressurized fluidized bed combustion program, turbine blade damage is reduced to an acceptable level. A 3-MW test unit is currently being designed and built by the Aerospace Research Corp. of Roanoke, Va. Economic analysis of this technology in a cogeneration system looks very promising and may be competitive with coal-fired central station electric power (35). As with other systems described in this chapter, the economics are highly dependent on the electric load factor. Consequently, they are more promising for industrial sites then for buildings.

COAL-LIMITED SCENARIOS

While few changes in fuel use are observed in 1990 and 2000 between the cogeneration and the base-case standard scenarios, some changes do occur in the special scenarios that limit coal-fired capacity additions (thus allowing other types to operate more frequently than they would without these limitations). As mentioned earlier, four special scenarios that limit baseload additions were constructed: two allowing cogeneration and two restricting cogeneration. Figure 58 shows that the addition of cogeneration to the sample sys-

•In the particular example cited, the return on equity assumed was 10 percent along with a 50/50 debt-equity ratio and a real interest rate on debt of 3 percent. If we repeat the calculation with a 15 percent return on equity and a 5 percent real interest rate on debt, values which we have found to be operative in favor of synfuels projects (21), the cost of electricity increases to 5.9cents/kWh. Utility financing, however, would allow a lower return even for a first-of-a-kind plant, perhaps close to that assumed in the original calculation. This argues in favor of utility ownership of such cogeneration facilities.

Figure 58.—Fuel Used in 1990 and 2000 or Coal= Limited Scenarios



SOURCE: Off Ice of Technology Assessment.

terns decreases total fuel use when the cogeneration scenarios (I-LOW COST COGEN/COAL-LIMITED and 3-LOW COST COGEN/COAL-LIMITED) are compared to their respective base-case scenarios (I-NO COGEN/COAL-LIMITED and 3-NO COGEN/COAL-LIMITED). This is a result of two factors. First, there is considerably more cogeneration that operates at higher capacity factors, as shown above. Second, this greater penetration allows the higher overall fuel efficiency of cogeneration to significantly affect total fuel use.

Most of the decrease in overall fuel use in the coal-limited scenarios (when 1- and 3-LOW COST COGEN/COAL-LIMITED are compared to 1- and 3-NO COG EN/COAL-LIMITED, respectively) results from the decrease in fuels used by the intermediate electric generating capacity. While the baseload coal consumption remains identical between the base-case and the cogeneration scenarios, the efficiency of the cogenerators, combined with the reduction of intermediate capacity generation, reduces overall fuel used for the two special coal-limited cogeneration scenarios. Table 45 compares the use of oil and gas for the four coal-limited scenarios.

In summary, cogeneration has only a small effect on utility fuel use as long as electricity can be produced more cheaply with other types of technologies. However, in the special coal-limited scenarios, cogeneration may cause less total oil to be used and may displace fuel used by the intermediate capacity.

Sensitivities to Changes in Assumptions

In addition to analyzing fuel use and operating characteristics with and without cogeneration, we must also determine the sensitivity of this analysis to changes in some of the assumptions used in

Table 45.-Comparison of Fuel Use for Coal-Limited Scenarios

	Region 1 coal-limited scenarios (net change in percent[a])		Region 3 coal-limited scenarios (net change in Percent[a])	
	1990	2000	1990	2000
Total fuel	–1	– 2	–7	–1
Total residual	– 6	– l o		—
Total distillate/natural gas	+155	+ 121	–13	+3
Total oil	– 3	– 5	–13	+3

aA negative change means that the coal-limited cogeneratlon scenarios use less fuel than the no Cogeneration coal-limited scenarios; a positive change means that the cogeneratlon scenarios use more fuel. All fuel is measured In Btu-equivalents.

SOURCE: Off Ice of Technology Assessment.

the scenarios. One important assumption is the cost for installing and operating cogenerators. As mentioned above in the discussion of capacity additions, OTA formulated a scenario, 2-ZERO COST COG EN, that uses zero capital cost cogenerators for Region 2.

The sensitivity of our results to the costs of cogeneration is determined by comparing the types of capacity that are installed and how the utility system uses cogeneration for two scenarios: the 2-ZERO COST COGEN scenario with the 2-LOW COST COG EN scenario. While the ZERO COST scenario installs 81 percent of its capacity as cogeneration, the LOW COST scenario installs 20 percent. Despite the difference in cogeneration capacity between the two scenarios, the fuels consumed by cogeneration are only 2 percent of the total fuels used in each scenario. In other words, for our fuel price assumptions, baseload electricity from coal is still cheaper so it is used to meet the baseload demand. In the zero capital cost case, however, cogenerators can supply thermal energy much more cheaply than boilers, so cogeneration is being used primarily to meet space heating demands plus as much intermediate and peak electricity demand as possible. Zero-capital cost cogeneration therefore is used as an inexpensive heater, without displacing any coal-fired generation. Thus, the cogeneration in this scenario displaces some of the peakload equipment, and does not use its steam during peak summer days.

Summary

By using the DELTA model and our set of technical and economic assumptions, OTA was able to determine the interaction of cogeneration with several sample centralized utility systems. Under most circumstances, cogeneration additions in new buildings were very limited because they could not compete economically with central station coal-fired generation. As a result, fuel usage did not change greatly from an all-centralized system. When coal-fired expansion was limited, however, cogenerators penetrated the utility system significantly and provided much of the heating demands and peak and intermediate electricity for the system.

Three specific conclusions can be made from this analysis. First, given the assumptions, cogenerated electricity cannot compete with central station, coal-fired capacity. Therefore, in commercial buildings, cogeneration will only contrib ute to peak and intermediate demands and will only operate when it can supply such electricity. This holds for even a zero capital-cost cogenerator. Lower natural gas prices, however, could greatly increase the opportunity for cogeneration. in fact, natural gas prices somewhat above current gas prices would allow cogeneration to compete with new, baseload, coal-fired central station capacity. Alternatively, successful development of gasification technologies that can produce moderately priced (about $5/MMBtu) medium-Btu gas from coal, biomass, or solid waste could expand the competitive position of cogeneration. Finally, cost relationships could be determined by high utility purchase rates for cogenerated power that would also make natural or synthetic gas-fired cogeneration preferable regardless of the actual longrun marginal costs of new COA fired capacity.

Second, existing electric generating plants usually can provide power more cheaply than new cogenerators. Even if oil is used for these plants, the cogenerator capital costs dominate any gains from more efficient fuel use; and this domination results in little significant penetration of cogeneration. However, lower cost natural gas could change these economics. In some regions this is the case now where natural gas-fired cogeneration is the preferable choice to existing oil-fired central stations that are near retirement. Third, if oil- and natural gas-fired equipment is used, the best opportunity for cogenerators is in regions with high heating loads (about 6,000 heating degree-days) and moderate electrical growth (at least 2 percent annual growth in peak and total energy).

RURAL COGENERATION

Although industrial and commercial sector cogeneration opportunities are recognized widely, little attention has been paid to cogeneration applications in rural areas, particularly in agriculture. The rural cogeneration potential is not so large as in the industrial sectors, but could present fuel and cost savings on farms or in rural communities. The principal rural cogeneration opportunities arise where there are existing small powerplants or where agricultural wastes can be used as fuel. Promising cogeneration applications for rural communities include producing ethanol, drying crops or wood, and heating livestock shelters.

Small, rural municipal powerplants can gain significant economic and fuel conservation advantages with cogeneration if a market for the thermal energy is available. Many of these powerplants use reciprocating internal combustion engines or combustion turbines as their prime movers. Dual fuel engines predominate (generally burning natural gas, with small amounts of fuel oil to facilitate ignition), but diesel engines and natural gas fueled spark ignition engines also are common. Generally, these small rural powerplants have a peak electric power rating of 10 MW or less, and they operate at around 33 percent efficiency in producing electricity (i.e., 33 percent of the fuel input energy is converted to electricity and 67 percent is exhausted as waste heat). If only half of the waste heat from these plants were used, the energy output would double (IS).

Table 46 shows the distribution and maximum temperature of waste heat sources in a supercharged diesel engine. As shown in this table,

Table 4&—Distribution of Waste Heat From a Supercharged Diesel Engine

Heat source	Percent of total waste heat	Maximum temperature (F°)
Engine cooling jacket	20	165-171
Aftercoolers [a].	15	104-111
Lubrication system	10	140-150
Exhaust gas[b].	55	797-696

aAftercoolers generally are used In temperate cllmates, with maximum use occurring In the summer.
bIn engines that are not supercharged, exhaust gas temperatures maybe cooler, approximately 572° to 662° F.
SOURCE: Randall Noon and Thomas Hochstetler, "Rural Cegeneratlon: An Untapped Energy Source," Public Power January-February 1981.

most of the waste heat is in the exhaust gases. The engine cooling jacket and lubrication system together produce almost as much waste heat as the exhaust gases, but at a much lower temperature (15).

The hot exhaust gas from an existing powerplant fueled with natural gas can be used directly in a waste heat boiler. Alternatively, water can be preheated via heat exchange with the aftercoolers, lubrication system, and cooling jacket, then flashed into dry steam through heat exchange with the exhaust gas. Steam temperatures as high as 850° F can be obtained in this manner (15).

For on-farm systems, a small powerplant (with direct heat recovery or steam production, as described above) could be connected with an anaerobic digester (using animal wastes as the feedstock) producing biogas, or with a small gasifier that converts biomass (e.g., crop residues) to low- or medium-Btu gas. However, as described in chapter 4, further development of combustion turbine or internal combustion engine technology may be necessary if these systems are to operate efficiently for long periods of time with low- or medium-Btu gas derived from lower quality feedstocks.

Potential Applications

Ethanol production is one promising application for rural cogeneration. Ethanol has been shown to be a useful fuel for spark ignition engines, and it can be produced readily from renewable biomass feedstocks (e.g., grains and sugar crops). If ethanol is used as an octane-boosting additive in gasoline, and if the ethanol is distilled without the use of premium fuels, then each gallon of ethanol can displace up to about 0.9 gallon of gasoline. However, if ethanol distilleries are fueled with oil, then ethanol production for gasohol could actually mean a net increase in oil use. * Moreover, the premium fuels usually considered for ethanol distilleries–diesel fuel and natural gas–already are used widely in the agricultural sector but often are in short supply. Using these fuels in distilleries could aggravate any shortages.

One way to improve ethanol production's premium fuels balance is to cogenerate with existing small rural powerplants. The waste heat would be flashed into dry steam (as described above), and the steam distributed into the distillation columns of the ethanol recovery system. To facilitate cooking (the process stage where starch grains are ruptured for effective enzymatic action), steam above atmospheric pressure and at about 300° F can be bled from the exhaust gas heat exchanger. In addition, warm water can be bled from ***the*** aftercooler heat exhanger to soak the milled corn and speed up water absorption. Finally, heat for drying wet stillage into distillers dried grain (which can be used as a livestock feed supplement) can be obtained either directly from the exhaust gas in a natural gas-fired plant, or by placing an air-to-exhaust gas heat exchanger downstream from the steam-producing heat exchanger (15). Figure 59 shows a schematic of ethanol cogeneration with diesel engine heat recovery.

The waste heat from a 1 -MW powerplant operating at full load (33o full-time operating days) is sufficient to produce around 600,000 gallons of anhydrous ethanol per year with wet byproduct, or 300,000 to 400,000 gallons annually with dried distillers grain byproduct (15).

*See ***Energy From Biological Processes (OTA-E-124;*** **July 1980) for an in-depth analysis of ethanol production.**

Cogeneration also can be used for **grain drying,** which requires relatively low-temperature heat. Seed drying requires a temperature of approximately 110° F, while milling drying requires 130° to 1400 F depending on the crop, and animal feed drying needs around 180° F. These temperatures are well below those of exhaust gases, and thus, for grain drying, the exhaust gas of natural gas-fired powerplants can be mixed with flush air and used directly (i.e., without heat exchangers). For plants that use fuels other than natural gas, a heat exchanger may be required in order to recover the energy without contaminating the grain with the exhaust gas. Due to the low temperatures needed, waste heat from the cooling water or lubrication oil also can be recovered and used to dry grain (15).

The waste heat from a 1-MW powerplant could dry grain at a rate of approximately 370 bushels per hour. In the case of field-shelled corn, this would reduce the moisture content from around 25 to about 15 percent—a safe level for storage. That grain-drying rate is comparable to that of many commercial dryers, and is sufficient for the grain-drying needs of small communities (1 5). However, grain drying is a seasonal activity and other uses for the waste heat would have to be

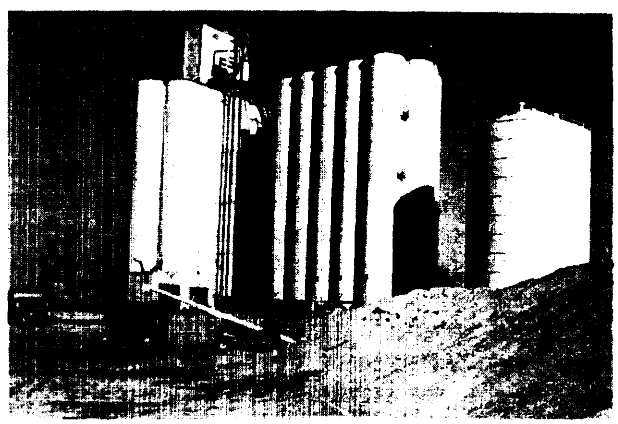
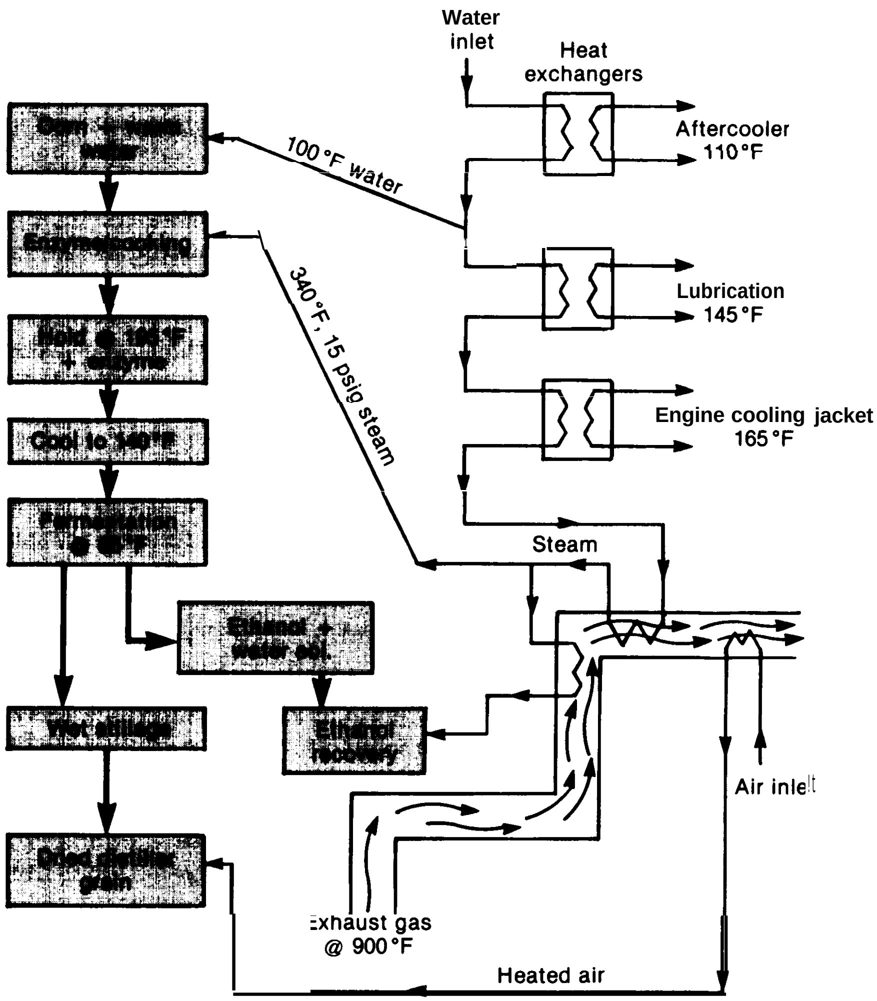


Photo credit: Department of Agrlculture

Small existing powerplants can be retrofitted for cogeneration with the thermal output used for applications such as drying grain

Figure 59.—Ethanol Cogeneration With Diesei Engine Waste Heat Recovery



SOURCE: Randall Noon and Thomas Hochstetler, "Rural Cogeneration: An Untapped Energy Source," *Public Power* January-February 1981).

found in the off-seasons in order to optimize the efficiency of the system.

In most cases, applying cogeneration to grain drying using existing powerplants will cost only slightly more than a conventional grain drying facility. A relatively small additional investment would be required for the engineering design needed to interface the exhaust stacks (or heat exchanger) with the drier. The grain drying would need flexible scheduling in order to coordinate with the powerplant's operation, especially when expected electricity demands do not materialize, but this is a relatively minor inconvenience. A more important concern is that rural grain elevators usually have low priority or interruptible service from natural gas suppliers (unless they use propane). Any resulting shutdowns can be a serious problem during a harvest season that is wet and cold, because the grain could spoil before it can be dried.

Drying crops with cogeneration can have significant dollar and fuel savings advantages. If the cost of waste heat is set at so percent of the cost per Btu for natural gas, then a facility drying 500 bushels of grain per hour would save $11.25 per hour compared to the cost of using a separate natural gas-fired dryer using $2.50/MCF gas for continuous operation, and the fuel cost savings would amount to $7,000 per month (1 5).

Wood drying is similar in many respects to grain drying. Both commodities are dried prior to shipping to minimize moisture weight. Historically, both drying processes have relied on relatively cheap and plentiful natural gas supplies, but can do so no longer. Furthermore, most wood drying kilns, like grain drying facilities, require relatively low-temperature heat–104° to **117°** F–although a few kilns may need temperatures above 212° F (1 5).

Because most modern wood drying kilns use natural gas combustion units, the exhaust gas from a small powerplant can be substituted easily for the natural gas burner. A 1-MW powerplant will produce approximately 8,000 MWh of usable drying heat annually (based on 24 hours per day, 330 days per year operation). This is sufficient to dry as much as 11 million board feet of air dried hardwood or 6.5 million board feet of green softwood per year.

As with grain drying, substantial savings can be gained through cogeneration/wood drying. Because the basic design would not change in a cogeneration retrofit, the capital and installation costs of a cogenerating unit would not be substantially more than those of a new conventional gas-fired kiln. It is estimated that 2 to 5 MCF of natural gas would be saved for each 1,000 board feet of lumber that is dried with cogeneration. For the 1-MW powerplant drying 11 million board feet, this would mean a savings of 22000 MCF/yr. If the cogenerated heat were sold at 50 percent of the value of $2.50/MCF natural gas, $27,000 per year could be saved in fuel costs (1 5). Additional savings would accrue from the electricity generation.

Fuel Savings

The three rural cogeneration applications described above—producing ethanol and drying grain or wood–rely on existing small powerplants fueled with oil or natural gas. In each case, fuel savings is assumed to result when the plant's waste heat is recovered and substituted for a second oil- or gas-fired facility. However, as discussed earlier in this chapter, the fuel saved may not always be oil. For example, recovering the waste heat from a diesel oil fueled engine and substituting it for heat previously provided by a natural gas combustion unit will save gas but increase oil consumption. Similarly, if the waste heat from a spark-ignition engine burning oil is substituted for a boiler using coal or biomass, no oil would be saved.

As a result of these fuel use considerations, rural cogeneration opportunities that use fuels other than oil (i.e., that do not rely on waste from an existing powerplant) merit a good deal of attention. These opportunities are based on the direct firing of cogenerators with fuels derived from plentiful rural resources.

Wood wastes have long been the traditional fuel in the forest products industry, which historically has been the largest industrial—and rural—cogenerator. The cogeneration potential in the forest products industry was discussed earlier in this chapter. At this point it will be sufficient to mention that, in the wood drying example cited above, a steam turbine and boiler can be substituted for the powerplant and natural gas-fired kiln. Although the capital costs of the boiler system would be higher (about one boiler horsepower is needed to dry 1,000 board feet of hardwood), and it would not produce as much electricity, this system can burn wood wastes or coal and thus save oil or natural gas. Similarly, fuel savings in ethanol distilleries will be greater if coal or biomass is used as the primary fuel for the cogenerator. Savings also can be achieved in grain drying but the potential for contaminating the grain would be greater unless heat exchangers were used.

Alternatively, internal combustion engines or gas turbines can be adapted to **alternate fuels.** These technologies, if successful, would require a smaller investment for equipment than steam turbines, an important consideration for small dispersed cogenerators. In some cases, fuel flexibility can be achieved through advanced engine design, advanced combustion systems such as fluidized beds, or fuel conversion (synthetic gas or oil). The technical and economic aspects of using fuels other than oil or natural gas in conjunction with combustion turbines or internal combustion engines are discussed in detail in chapter 4. Two applications that are especially promising for rural areas include gasification of crop residues and anaerobic digestion of animal wastes. However, small powerplants also can be modified to accommodate alternate liquid fuels such as ethanol and methanol, which can be made from relatively plentiful rural biomass resources; these liquid fuel options are discussed in more detail in OTA's report on ***Energy From Biological Processes.***

Gasification of crop residues has been suggested as a means of providing relatively cheap nonpremium fuels for rural cogenerators. One demonstration project being developed in Iowa uses downdraft gasifiers to produce low-Btu gas from corn stover for use in retrofitted diesel engines. Some of the probable end uses for the thermal energy include grain drying, **green houses,, dairies, food processing, space heating, or drying** the corn cob feedstock (22).

Downdraft gasifiers were selected for this project because they can generate producer gas that has relatively low amounts of tars and other hydrocarbons and is suitable for use in steam generators, directly fired dry kilns, or internal combustion engines. Field tests with downdraft gasifiers in California have produced diesel quality producer gas successfully from corn cobs, walnut shells, and other crop residues (32).

The demonstration project focuses on stationary diesel engines for several reasons. First, the wide number of domestic diesel models in place allows a range of retrofit considerations to be evaluated. Second, a number of tests are underway around the country using dual-fuel diesels fired with 80 percent producer gas and 20 percent diesel oil. European firms have offered efficient commercial producer gas/diesel packages capable of continuous operation on 90 percent gas/10 percent diesel oil since World War 1. Third, a large number of functional diesel powerplants are standing idle because of high oil prices. A recent survey showed that more than 70 Iowa communities have diesel generators with a total capacity of over 300 MW that operate at an average capacity factor of less than 2 percent (22).

Finally, the projects will use corn cobs as the feedstock because this is a relatively plentiful, clean fuel with a low ash and sulphur content. Moreover, they require no special handling (e.g., baling, chopping) and they are easy to gather and store. * Other possible biomass gasification combinations for cogeneration include other types of organic wastes (e.g., crop residues, wood waste) and wood from excess commercial forest production or intensively managed tree farms.

Cost estimates for this project are shown in table 47. Two rural test sites designed to demon-

*For an in-depth analysis of the technical, economic, and environmental considerations related to the use of crop residues as a fuel or feedstock, see *Energy From Biological Processes (OTA-E-124, July 1980).*

Table 47.—Model Community Gasification/Diesei Eiectric Generation Energy Cost Estimate

Operating data from the fuel rate calculations:		
Energy output: Maximum, 1,000 kW; average, 750 kW		
Gas input for electrical powec 10.18 MMBtulhr		
Solid fuel input for electrical power: 1,810 lb/hr		
Fuel oil input for electrical power: ***0.825*** MMBtulhr at 7.5 percent of total energy input (5.9 gal/hr)		
Costs-gasiWr plant:		
Equipment:		
Gasifier system	$259,610	
Installation	64,800	
Capital cost total	324,410	
Annualized at 5°/0 for 20 years . . .		$33,670
Diesel retrofit @ $150/kW	150,000	
Annualized at 8.25% for 20 yrs. . .		15,564
Insurance at 2.5°/0 of plant cost		6,490
Total fixed costly r.		$55,724
@ 6,570,000 kWh/yr, fixed cost = $0.0085/kWh		
Operational cost		
6,570 hr/yr, operating at 75°/0 capacity:		
Fuel handler, 1 person, 40 hr/wk, w/fringes		31,200
Maintenance charge @ 5°/0 of plant cost		16,200
Fuel costs:		
Diesel oil @ $1.15/gal x 38,716 gal		44,523
Corn cobs at 18.80/T x 5,979 T/yr		112,400
Total operational costs		$204,323
6.57 MMkWh/yr, operational costs/kWh = $0.0311		
Total cost $O.0396/kWh		
Cost ***of hot producer gas from gasifier***		
Operating at 90°/0 capacity; with gas conversion efficiency of 850/o		
1,810 lb cobs/hr x 8,760 hr x 0.90 = 7,135 T/yr @ $18.80~ = (fuel)		$134,138
Labor, maintenance, amortization, Insurance. .		87,560
Total cost. .$221,698(7,135 T cobs x 15 MMBtu x 0.85 efficiency) = $2.441 MMBtu		

SOURCE: J. J. O'Toole, et al., "Corn Cob Gasification and Diesel Electric Generation," in ***Energy Technology VIII: New Fuels Era*** Richard F. Hill (cd.) (Rockville, Md.: Government Institutes, Inc., 1981).

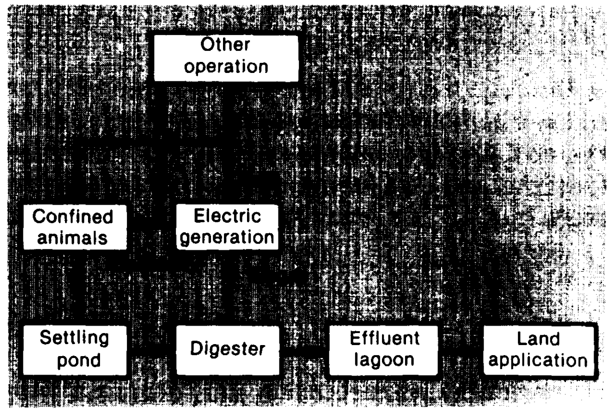
strate the technical and economic feasibility of downdraft gasifiers using corn cobs to produce low-Btu gas for diesels have been identified. The sites (in Iowa) have different diesel models and usage patterns as well as different biomass resource concentrations (one town has a local source of excess corn cobs, one must set up a collection and transportation system on neighboring farms). Thus, the sites will allow a sensitivity analysis on a wide range of variables, including energy prices, Btu value, moisture content, farmer participation rate, and cob processing costs. Economic modeling for the project will yield data on agricultural production for the site, the quantity of cobs used, the system kWh costs, emissions, and energy balance. If these and other tests yield positive results, then gasification of crop residues could become an important source of energy for diesel cogeneration in rural communities—one that enables those communities to use existing local resources and equipment at a cost competitive with energy from central station powerplants.

A second rural cogeneration option is the **anaerobic digestion of animal wastes** to produce biogas (a mixture of 40 percent carbon dioxide and 60 percent methane). The national energy potential of wastes from confined animal operations is relatively low—about 0.2 to 0.3 Quad/yr–but other important benefits are that anaerobic digestion also serves as a waste treatment process and the digester effluent can be used as a soil conditioner, or dried and used as animal bedding, or possibly treated and used as livestock feed. Digesters for use in cattle, hog, dairy, and poultry operations are now available commercially and are being demonstrated at several sites in the United States. * Wastes from rural-based industries (e.g., whey from cheese plants) also are being used as a feedstock for farm-based digesters.

In a typical digester system (see fig. 60), a settling pond is used to store the manure prior to digestion. The digester consists of a long tank into which the manure is fed from one end. After several weeks, the digested manure is released at the other end and stored in an effluent lagoon.

*For a detailed analysis of anaerobic digestion of animal waste, see *Energy From Biologica/ Processes* (OTA-E-1 24, July 1980).

Figure 60.-Anaerobic Digester System



SOURCE: Office of Technology Assessment.

Gas exits from the top of the digester tank, the small hydrogen sulfide content is removed if necessary, and the biogas is used to fuel an internal combustion engine that drives an electric generator. The system supplies electricity for onsite use (or for **export Off-Sit@. The heat from the engine can be used onsite for a variety of purposes, including heating the animal shelter or a green**house (that could also use the soil conditioning effluent), or for crop drying, or even residential space heating.

Finally, it should be noted that the above applications can be combined in **farm energy complexes** that integrate methane and alcohol systems so that waste heat and byproducts are utilized more fully. For example, the waste heat from generating electricity with biogas can be used in alcohol production, while spent beer from the distilling process can be used as a digester feedstock. Moreover, the waste heat from a generator often is used to help maintain an optimum digester temperature.

Summary

Significant energy and economic savings can be achieved with cogeneration in rural areas. Communities can improve the economics of operating small powerplants by recovering **waste** heat for use in distilling ethanol, **drying grain or** wood; heating homes, greenhouses, or animal shelters, and other applications; or by retrofitting existing powerplants to accommodate alternate fuels. In addition, significant oil savings can be achieved if the cogenerator uses alternate fuels or replaces two separate oil-fired systems.

Although the rural cogeneration potential is not so large as that in industry and urban applications, the cost and fuel savings can be very important for farms and rural communities. in rural economies, much of the gross income escapes the local economy rather than being recirculated to produce a second round of local income. Developing cogeneration opportunities could double the productive energy output of rural powerplants, creating significant local economic expansion in both public revenues (from electric and thermal energy sales) and private income (from new jobs) without increasing the base demand of energy.

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