Chapter 2

Issues and Findings

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Chapter 2
Issues and Findings

WHAT IS COGENERATION?

Cogeneration is the combined production of two forms of energy—electric or mechanical power plus useful thermal energy–in one technological process. The electric power produced by a cogenerator can be used onsite or distributed through the utility grid, or both. The thermal energy usually is used onsite for industrial process heat or steam, space conditioning, and/or hot water. But, if the cogeneration system produces more useful thermal energy than is needed onsite, distribution of the excess to nearby facilities can substantially improve the cogenerator's economics and energy efficiency.

The total amount of fuel needed to produce both electricity and thermal energy in a cogenerator is less than the total fuel needed to produce the same amount of electric and thermal energy in separate technologies (e.g., an electric utility generating plant and an industrial boiler). It is primarily this greater fuel use efficiency that has created a resurgence of interest in cogeneration systems. However, cogeneration also can be attractive as a means of adding electric generating capacity rapidly at sites where thermal energy already is produced.

Cogeneration technologies are termed "topping cycles" if the electric or mechanical power is produced first, and the thermal energy exhausted from power production is then captured and used (see fig. 3). "Bottoming cycle" cogeneration systems produce high-temperature thermal energy first (e.g., for steel reheating or aluminum remelting), and then recover the waste heat for use in generating electric or mechanical power plus additional, lower temperature thermal energy (see fig. 4). Topping cycle cogenerators would be used in residential, commercial, and most industrial applications, while bottoming cycle applications would most likely arise from high-temperature industrial processes.

WILL COGENERATION SAVE OIL?

Cogeneration is widely acclaimed as a conservation technology because it uses less fuel (measured in Btu equivalents) to generate a given amount of electricity and useful thermal energy than separate conventional energy systems (e.g., a powerplant and an industrial boiler; see fig. 2). However, just because cogeneration is more fuel efficient does not mean that it will automatically reduce oil consumption.

Whether cogeneration will save oil (or natural gas, or any other particular fuel) depends on the fuel burned by a cogenerator and the fuel used in the separate electric and thermal energy producing systems the cogenerator displaces. if both of these separate systems would burn oil, and continue to burn oil for most of the operating life of an oil-fired cogenerator that replaced them, then an oil burning cogenerator would reduce total oil consumption. This savings can range from a 15-percent reduction in oil use when a steam turbine cogenerator is substituted for a steam electric powerplant and a separate low-pressure steam boiler, to a 34 percent savings if a diesel cogenerator that converts 38 percent of the fuel energy to electricity (30 percent to useful thermal energy) replaces separate oil-fired powerplants and furnaces.

However, if a cogenerator that will burn oil during most of its useful life replaces either a powerplant or a conventional furnace or boiler that uses a different fuel (e.g., coal, wood), or that plans to convert to a different fuel during the useful life of the cogenerator, then oil burning cogeneration will actually increase total system oil use. Therefore, cogeneration will only save oil if it uses an alternate fuel itself (e.g., coal), or if it replaces separate electric and thermal energy systems that use (and will continue to use) oil.

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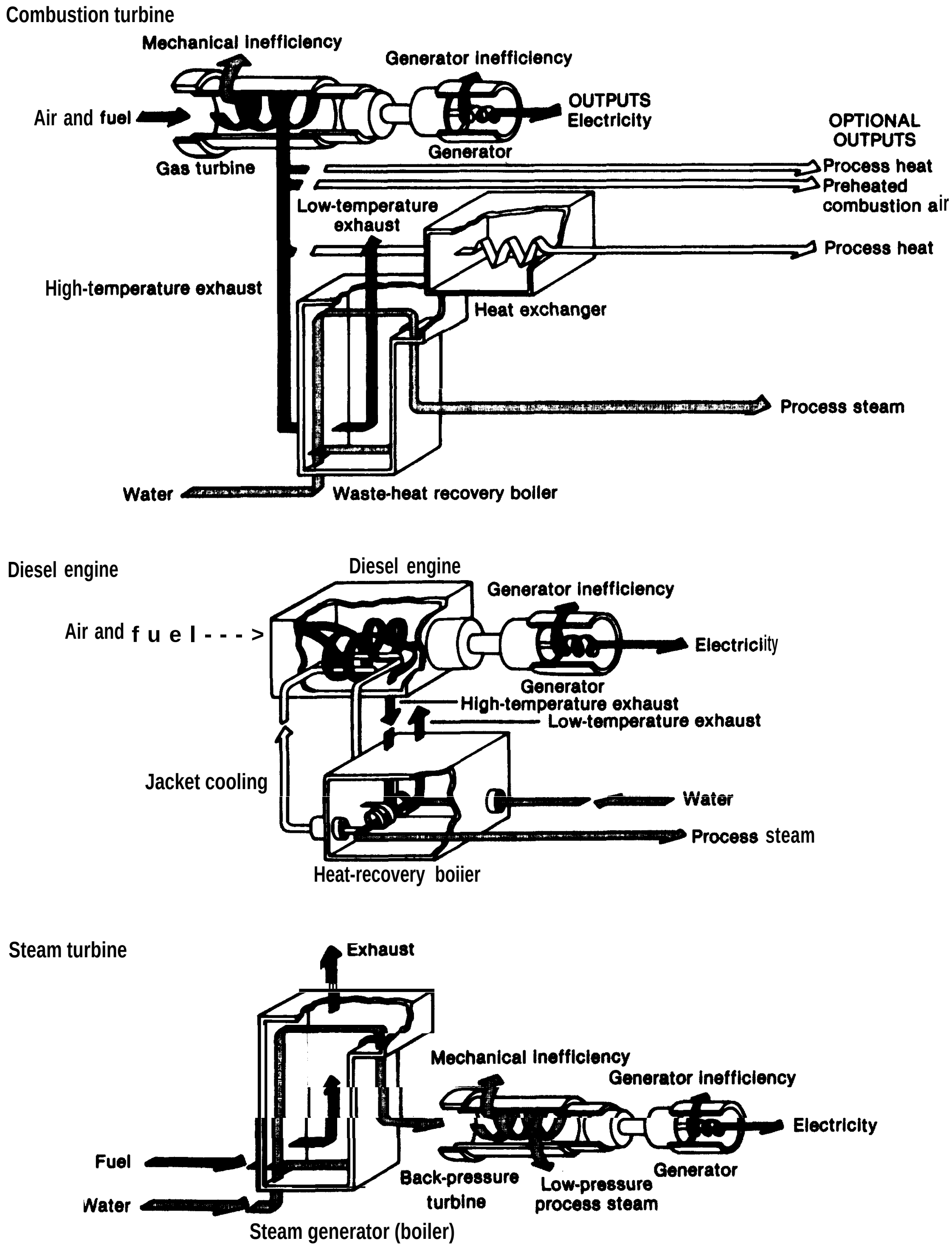
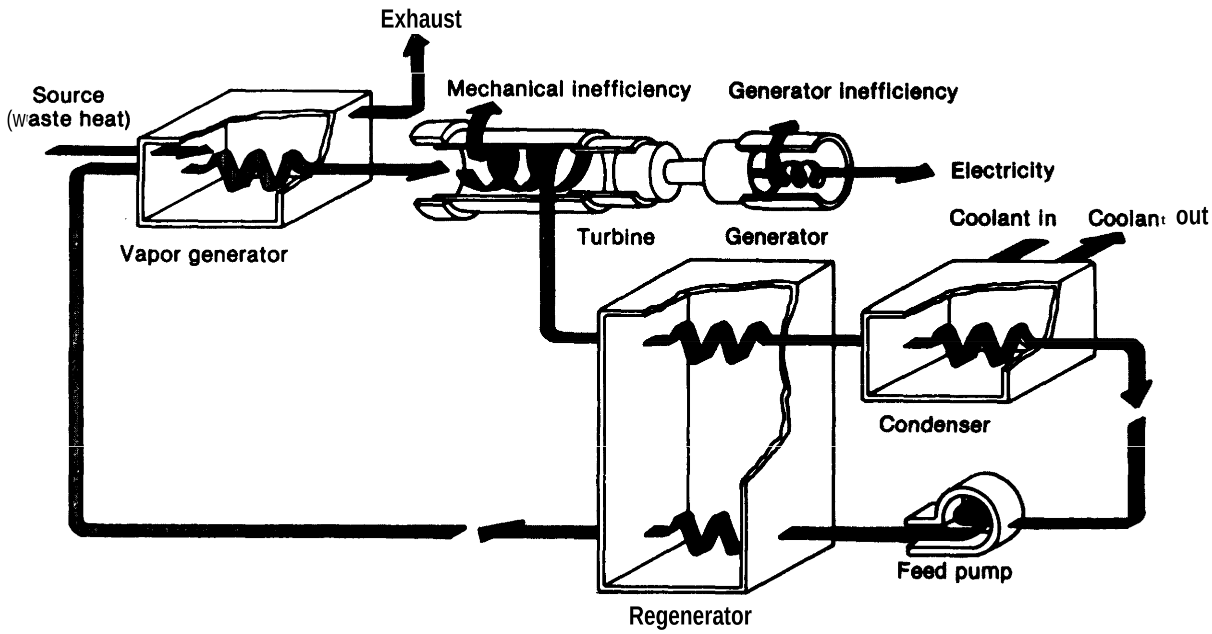
Figure 3.—illustrations of Topping Cycle Cogeneration Systems



SOURCE: Resource Planning Associates, *Cogeneration: Technical Concepts, Trends, Prospects* (Washington, D. C.: U.S. Department of Energy, DOE-FFU-1703, 1978).

Figure 4.—Schematic of a Bottoming Cycle Cogenerator



SOURCE: Resource Planning Associates, *Cogeneration: Technical Concepts, Trends, Prospects* (Washington, D. C.: U.S. Department of Energy, DOE-FFU-1703, 1978).

This finding is especially important for three reasons. First, most commercially available cogeneration technologies require clean premium fuels such as oil or natural gas (see ch. 4). Steam turbine cogenerators can burn coal or other alternate fuels such as biomass or solid waste, but may be prevented from doing so due to site or environmental considerations. Advanced cogenerators that can use alternate fuels may not be available for several years. Second, although industrial processes and, to a lesser extent, electric utilities, are heavily dependent on oil and natural gas, both groups already plan to reduce their use of these fuels either through conservation or conversion to alternate fuels or both. Third, although the Powerplant and Industrial Fuel Use Act of 1978 (FUA) prohibits the use of oil and natural gas in new powerplants and boilers, cogenerators are exempt from these prohibitions if less than half of their annual electric output is sold or exchanged for resale, *or* if they are relatively small (less than about 10 megawatts per unit (MW/unit) or 25 MW/site, assuming a 10,000 Btu per kilowatthour (Btu/kWh) heat rate), or if they can demonstrate a net savings of oil or gas.

When these three considerations are combined with economic conditions that favor cogeneration (e.g., high retail electricity rates), the combination could outweigh market considerations and result in oil-fired cogeneration that would lock industrial or commercial cogenerators into premium fuel use for 10 to 20 years or more. On the other hand, if oil cogeneration is used only where premium fuel savings are sure to result (i.e., where both the electric and thermal systems the cogenerator replaces would continue to burn oil for most of the operating life of the cogenerator), or where conversion to alternate fuels will be possible in the near term (e.g., a dual-fuel system that can convert from oil to synthetic gas when gasification technology is improved), then even oil-fired cogeneration can pose significant oil savings.

UNDER WHAT CIRCUMSTANCES ARE AVAILABLE COGENERATION TECHNOLOGIES ATTRACTIVE?

The commercially available cogeneration technologies described in this report include steam turbines, open-cycle combustion turbines, combined-cycle systems, diesels, and steam Rankine bottoming cycles. All of these technologies will provide energy savings because their fuel efficiency is greater than that of the separate electric and thermal energy systems they will replace, but their comparative technical, economic, and fuel use advantages vary (see table 1 and ch. 4; for a review of their relative environmental advantages, see, "What Are the Environmental Impacts of Cogeneration?").

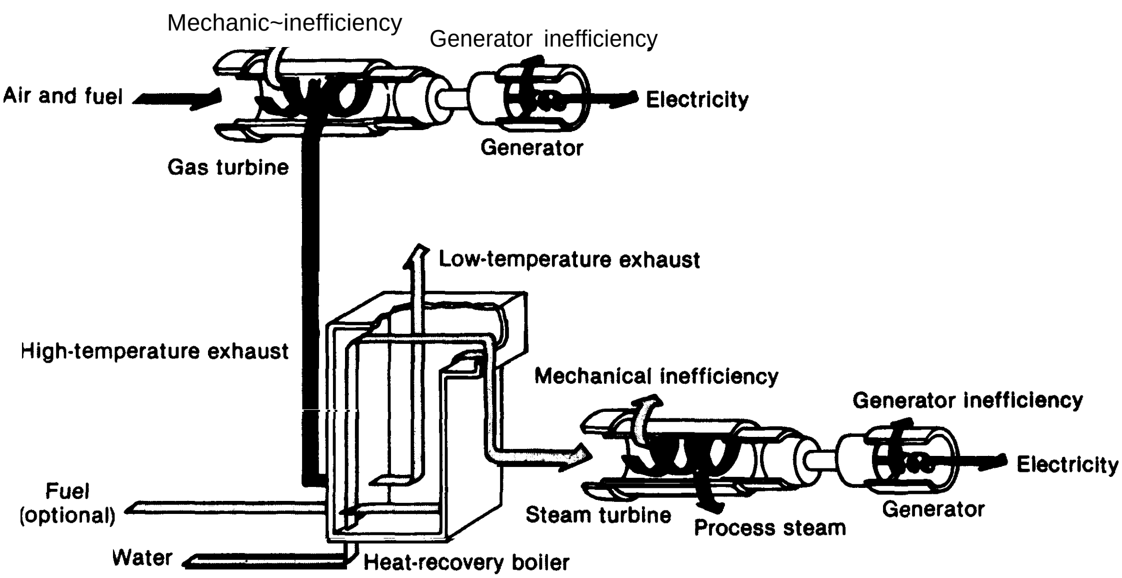
A steam turbine topping cycle cogenerator (see fig. 3) produces thermal energy at moderate temperatures and pressures that are suitable for many industrial applications that do not need high-temperature heat. Available steam turbines have a relatively high overall efficiency, but their ratio of electricity generated to thermal energy produced (electricity-to-steam (E/S) ratio) is relatively low. Therefore, steam turbine cogenerators are usually not appropriate where large electricity requirements are paramount, such as the need to provide power to the grid to improve economic feasibility. In addition, steam turbines can have relatively high unit costs, longer startup times and installation leadtimes than other available cogenerators, and more stringent personnel requirements specified by boiler codes. On the other hand, steam turbines are extremely reliable, and can use a wider range of fuels more easily than other cogeneration technologies, including coal, biomass, and solid wastes, as well as coal-derived liquids and gases when they become available.

Open-cycle combustion turbine topping cycles (see fig. 3) have a higher E/S ratio and produce higher temperature steam than steam turbines. Therefore, combustion turbines can meet the electric and thermal needs of more types of industries and are more likely to produce excess electricity that may be exported to the grid. Combustion turbines' unit cost and construction time are relatively low while their reliability is comparable to that of steam turbines. Combustion turbines are available in a wider range of unit sizes than steam turbines, and the lower capacity units (i.e., below 7 MW) may be attractive for commercial facilities (such as shopping centers, apartments, hotels) because they are small in size and can be operated remotely. Combustion turbines also are well suited to arid climates because they require no cooling water. Finally, although open-cycle combustion turbines cannot now use solid fuels such as coal or wood directly, they will be able to use synthetic gas or liquid fuels derived from coal or biomass, and units using pulverized wood directly are under development.

Combined-cycle cogenerators (combined steam turbine and combustion turbine systems; see fig. 5) increase electric power output at the expense of recoverable heat. They have a higher E/S ratio than either a steam or combustion turbine alone, and thus will be most attractive in situations where electricity requirements are relatively high, or where electric power can be distributed to the grid economically. Their unit capacity also tends to be greater than either of the separate turbine systems. Currently available combined-cycle systems require too much space for most commercial applications, but they should be well suited to larger industrial facilities. Their unit cost and installation leadtime are higher than combustion turbines', but comparable to medium- or large-size steam turbines. Furthermore, while combined cycles' availability is lower than either system alone, their overall fuel efficiency is higher. Finally, combined cycles can use the full range of fuels and will be readily adaptable to fluidized bed combustion systems.

Diesel cogenerators (see fig. 3) have a higher E/S ratio than the technologies described above, and thus will be very attractive for facilities with high electricity demand but low thermal energy needs (i.e., most commercial building applications and many smaller industries), or where electricity can be distributed to the grid economically. Diesels' relatively high efficiency, low cost, short installation leadtime, long service lifetime, and established service infrastructure all contribute to their attractiveness. However, diesels also can

Figure 5.—Schematic of a Combined-Cycle Cogenerator



SOURCE: Resource Planning Associates, Cogeneration: Technical Concepts, Trends, prospects (Washington, D. C.: U.S. Department of Energy, DOE-FFU-1703, 1978).

have high maintenance costs and may be less acceptable environmentally due to their potentially high nitrogen oxide and particulate emissions. In addition, currently available diesel technologies must burn oil or gas (some are dual-fueled), although they will be able to use synthetic fuels. Diesels capable of burning powdered coal or coal slurries are under development, but it is unclear whether they will be economically competitive with other types of cogenerators.

Rankine steam bottoming cycles (see fig. 4) are conceptually different from the technologies summarized above in that high-temperature process heat is produced first, then waste heat from the thermal process is used to produce electric or mechanical power plus additional lower temperature thermal energy. Because waste heat is used to generate electricity, Rankine bottoming cycles can present even greater fuel savings than topping cycle cogenerators. The cost, average annual availability, and construction leadtime of Rankine steam bottoming cycles are comparable to steam turbines, while their expected service life is approximately equal to combustion turbines, combined cycles, and diesels. Unit capacity, however, often is smaller than other cogeneration systems. Rankine steam bottoming cycles typically are considered for industrial applications with very high-temperature heat needs.

WHAT ARE SOME PROMISING FUTURE COGENERATION TECHNOLOGIES?

Current research and development efforts on cogeneration are directed toward both improvements in existing systems (see, "Under W/hat Circumstances Are Available Cogeneration Technologies Attractive?") and the development of new technologies. The primary concerns in these efforts include the ability to burn fuels other than oil and gas (e.g., coal, biomass, solid waste), improved fuel efficiency, increased electrical output, and lower capital and operating costs (see ch. 4).

Advanced steam turbine cogenerators with higher steam pressures and temperatures, and thus greater electric generating efficiency, should be available between 1985 and 1990. Much of the research on steam turbines is aimed at improving the efficiency of smaller systems (less than 7 MW), while reducing their cost. Similarly, research on open-cycle combustion turbines is directed toward increasing efficiency through higher inlet temperatures by improving turbine blade cooling or making materials changes in blade composition. Materials changes also would improve the anticorrosive properties of turbine blades and thus would allow combustion turbines to use solid fuels (municipal solid waste, pulverized coal, etc.). However, as with steam turbines, capital and operating costs for advanced combustion turbines are likely to be slightly higher than present costs. Improvements in combined-cycle systems include the advances in combustion turbines, as well as the development of smaller combined cycles with a wider range of potential applications. Finally, advanced diesel cogenerators are being developed that use coal-derived fuels, and have a much greater power output, as well as those for which all the recovered thermal energy could be high-quality steam. Each of these improvements in the diesel cogenerator should be commercially available by 1990, but not all in the same system.

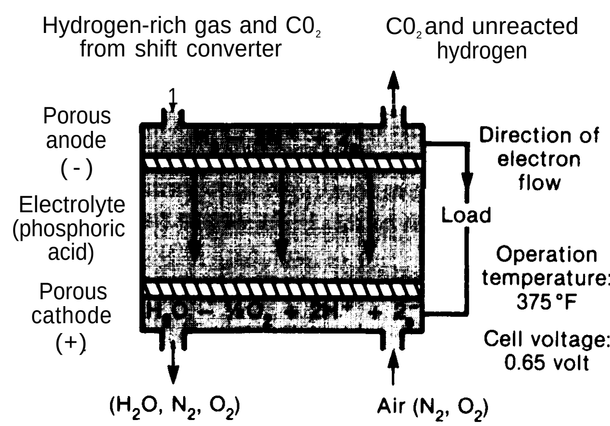
Advanced cogeneration technologies that are not now available commercially include closed-cycle combustion turbines, organic Rankine bottoming cycles, fuel cells, and Stirling engines (see table 1 and ch. 4). (Solar cogenerators, such as the therm ionic topping system, are not discussed in this report.)

Closed-cycle, externally fired combustion turbines are not available commercially in the United States but are well developed in Europe and Japan. These systems are potentially very attractive because they can use a wide variety of fuels (including coal), have a relatively high efficiency and E/S ratio, and should be priced competitively with other topping cycle cogenerators. They will be attractive primarily in larger industrial and utility applications.

Organic Rankine bottoming cycles evaporate organic working fluids (e.g., toluene) to produce shaft power, and can operate efficiently at lower temperatures and in smaller sizes (i.e., 2 kW to 2 MW) than steam bottoming cycles. Because they use lower temperature heat, they can be adapted to a wide variety of heat sources, including solar, geothermal, and industrial waste heat, or engine exhausts. However, they currently require more maintenance than most topping cycles, and further development and demonstration are necessary before the organic Rankine bottoming cycle can be considered a "mature" technology.

Fuel cells (electrochemical devices that convert the chemical energy of a fuel directly into electricity with no intermediate combustion cycle —see fig. 6) are potentially attractive cogenerators due to their modular construction, good electrical-load-following capabilities, automatic operation, ability to use coal-derived fuels, and low pollutant emissions. In addition, fuel cells could be adapted to a wide range of sizes and applications, from small (40 to 500 kW) residential and commercial systems to larger industrial and utility plants (5 to 25 MW). Although fuel cell demon-

Figure 6.—Fuei Cell Operation



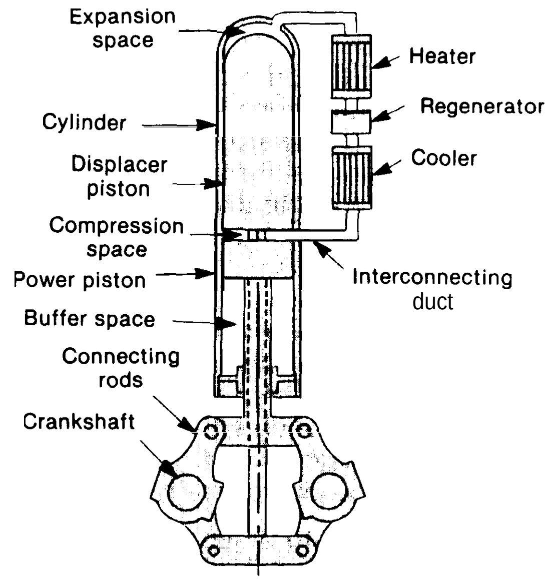
SOURCE: P. S. Khalsa and L. Stamets, *Commercial Status: Electrical Generation and Nongeneration Technologies* (Sacramento, Calif.: California Energy Commission, April 1980).

stration plants are under construction, commercial readiness is still at least 5 years away. The primary development concerns include somewhat high capital costs and short service life.

Finally, Stirling engines (see fig. 7) could offer an attractive alternative to available topping cycles because of their ability to use coal and other solid fuels, their high thermal and part-load efficiency, and their low emissions, noise, and vibrations. Stirling engines also could be used as components of solar energy systems or as adjuncts to fluidized bed combustors, nuclear reactors, or other conversion technologies. Current research efforts are directed toward improved efficiency and solid fuel combustion characteristics, as well as lower capital costs, before Stirling engines can be considered commercial. Because they produce relatively low-temperature recoverable heat, Stirling engines will be most attractive for water heating or in facilities with relatively small process heat requirements.

In addition to the cogeneration technologies reviewed above, two types of advanced combustion systems may be attractive for increasing cogenerators' fuel flexibility: gasifiers and fluidized bed combustors. Gasifiers would convert coal, pet coke, or other solid fuels to medium-Btu gas (about 300 Btu/standard cubic foot) for distribution to cogenerators (or other facilities) within about a 100-mile radius. Gasification could centralize the use of solid fuels, and thus eliminate cogenerators' need for coal storage and handling facilities. However, gasification is not yet a proven technology, although both small- and large-scale systems are being demonstrated. Whether such a scheme will be successful is heavily dependent on the capital costs, which are still highly uncertain. Fluidized bed combustors can accommodate a wide range of solid fuels, and operate at a lower temperature and pose fewer environmental and operating problems than conventional boilers. Fluidized beds can be adapted to fire several different types of cogeneration technologies. Atmospheric fluidized bed systems could be used with steam or combustion turbines or combined cycles, while pressurized systems could drive combustion turbines or combined cycles. Fluidized bed combustors are now being demonstrated and could become commercial within a few years.

Figure 7.—Schematic of a Stirling Engine



SOURCE: *Application of Solar Technology to Today's Energy Needs* (Washington, D. C.: U.S. Congress, Office of Technology Assessment, OTA-E-66, June 1978).

WILL COGENERATION BE COMPETITIVE WITH CONVENTIONAL THERMAL AND ELECTRIC ENERGY SYSTEMS?

Cogeneration is most likely to be competitive with conventional separate electric and thermal energy technologies when it can use relatively inexpensive, plentiful fuels, and where there are large thermal energy needs or it can meet onsite energy needs while supplying significant amounts of electricity to the utility grid.

oil-fired cogeneration will only save oil in a few circumstances (see, "Will Cogeneration Save oil?"). Moreover, the price gap between oil/gas and other fuels is likely to become wider over time. Therefore, cogenerators will have to use relatively inexpensive and plentiful fuels (such as coal, biomass, or solid wastes) in order to be economically competitive with utility generating capacity over the long run (10 to 20 years and beyond). Alternatively, if the utility's avoided cost is determined by the price of oil, or if the utility is primarily dependent on oil-fired capacity, then natural gas may remain economically attractive as a cogeneration fuel for several years. In the short term, it is possible that cogenerators may be able to rely on natural gas as a transition measure until synthetic gas from coal or biomass becomes widely available at a competitive price. However, if gasifier technology or planned advances in the fuel flexibility of cogeneration technologies are not available as soon as expected, or synthetic gas is not competitive in price with natural gas, this strategy could lock cogenerators into premium fuel use for many years.

For cogeneration to be economically attractive, there usually must also be substantial thermal loads. Sites with low loads (e.g., less than 50,000 lb/hr of steam) due to conservation measures or limited process needs, or with fluctuating loads, generally would not be economically competitive with conventional steam boilers and utility-supplied electricity. Thus, commercial buildings are likely to have a low potential for cogeneration because of their very low thermal load factors. In some cases, however, cogenerators can be "undersized" and operated at a high capacity factor to meet the base thermal load, with conventional boilers or furnaces used when necessary to meet the remaining thermal demand (see, "What Are the Opportunities for Cogeneration in Commercial Buildings?").

Finally, cogeneration's ability to meet onsite thermal and electrical needs, or to meet the thermal needs and supply significant amounts of power to the utility grid, will be a major determinant of its economic competitiveness. In the regions where electric utilities have substantial amounts of generating capacity fueled by oil or natural gas, or where demand growth is significant (primarily the Northeastern States and California, and to a lesser extent the South Atlantic and West South-Central States), cogeneration will be more attractive when it can supply significant amounts of electricity to the grid (see, "What Are the Potential Effects of the PURPA Incentives?"). Alternatively, if the utility has substantial excess capacity or primarily uses coal or other nonpremium fuels, and avoided costs are low or retail electricity rates are high, a cogenerator's economic competitiveness will depend primarily on its ability to reduce onsite energy costs.

These determinants of cogeneration's economic competitiveness will affect the choice of cogeneration technologies. Of the technologies that are commercially available, only the steam turbine topping and Rankine cycle bottoming systems can use fuels other than oil/gas. However, bottoming cycles usually are limited to specialized applications that require high-temperature heat, while steam turbines have low E/S ratios (see, "Under What Circumstances Are Available Cogeneration Technologies Attractive?"). Systems with higher E/S ratios that will be able to use alternate fuels are under development or demonstration, as are advanced combustion technologies such as fluidized beds and gasifiers, and should be available commercially by the mid to late 1980's (see, "What Are Some Promising Future Cogeneration Technologies?").

WHAT ARE THE INDUSTRIAL COGENERATION OPPORTUNITIES?

Cogeneration of electricity and thermal energy for industrial processes is a proven concept, with approximately 9,000 to 15,000 MW of cogeneration capacity in operation at industrial sites throughout the United States (see table 2), and at least 3,300 MW in the planning stage or under construction. The technical potential for industrial cogeneration (the number of sites at which the thermal load is sufficient to justify an investment in a cogeneration system) is high—perhaps as much as 200 gigawatts (GW), or about 32 percent of current U.S. generating capacity. However, the market potential (the amount for which an investment is likely to be made) is much lower due to economic and institutional considerations.

The industries in which cogeneration has a significant market potential are those that use large amounts of thermal energy, especially the pulp and paper, chemical, steel and other metals, petroleum extraction and refining, cement, food processing, and textiles industries. In these and other industrial sectors, cogeneration's market potential will be determined by:

- **The availability of, and economics of using, alternate fuels:** The pulp and paper industry, for example, produces large amounts of burnable wastes and has long considered cogeneration to be an integral part of its industrial process. Where wastes (including waste heat) or other solid fuels are unavailable or infeasible (due to economic, site, or other limitations), cogeneration may not be able to compete economically with conventional thermal energy production plus utility-supplied electricity.
- **Whether conservation measures will reduce the economics of cogeneration:** Industry has reduced its thermal energy use substantially through conservation in the last few years, and conservation may be cogeneration's primary "competitor." For instance, the cement industry once was considered a prime candidate for bottoming cycle cogeneration due to the high temperature (900° to 1,000°F) of the kiln exhaust gases. But conservation measures have reduced that temperature so much (now 300° to 400° F, and still declining) that it is no longer feasible to use in bottoming cycle systems.
- **The availability of new process technology that uses less (or no) thermal energy:** For example, the thermal energy requirements of the open-hearth steelmaking process made the steel industry a major cogenerator. But large open-hearth mills are expected to be replaced gradually by small mills run with electric arcs that have little or no thermal demand and thus a low potential for cogeneration. However, if new electric arc mills were sited close to another thermal energy user, the output from a cogenerator could be shared between the two facilities.
- **The availability of advanced process technologies:** New technologies and improved versions of existing process technologies now under development will have greater fuel flexibility, higher fuel efficiency, and higher electricity output.
- Whether cogeneration retrofits are feasible or new plants will be built: For instance, petroleum refineries are well suited to cogeneration, and some existing refineries could be upgraded, resulting in the production of low-Btu gas suitable for onsite cogeneration. But, few new refineries are likely to be built except in areas such as California, which has special requirements related to enhanced oil recovery.
- Whether a plant's operating pattern makes cogeneration economic: Many food processing plants operate only during harvest season, and the resulting low capacity factor may make cogeneration economically infeasible. However, the food processing season often overlaps the hottest months when irrigation and air-conditioning loads contribute to peak demands on electric systems in rural areas, the seasonal price for utility generated power is often very high and/or its reliability is low. As a result, this industry's seasonal operating pattern can be outweighed by its potential for lower energy costs.
- The availability of capital for investments in cogeneration: Industrial firms typically require shorter payback periods for their investments than cogeneration may be able to provide, although current accelerated depreciation measures and investment and energy tax credits can improve the payback significantly. Cogeneration also must compete for available capital with process equipment or other investments that improve an industry's competitive position (as well as with conservation measures, as mentioned above). Third-party or utility ownership can improve capital availability (see, "Who Will Own Cogenerators?"), as can low interest loans and other financing measures that alleviate the effects of high interest rates and capital shortages.
- Whether there is a match between a plant's needs and the cogenerator's output: An industry may need more or less thermal or

electric energy than a cogenerator provides. usually the technology will be chosen to optimize the match between load and output, but this will not always be possible. The Pub lic Utility Regulatory Policies Act (PURPA) requirements that electric utilities offer to buy power from and sell power to cogenerators can mitigate an electricity supply and demand mismatch, but the economics may not always be favorable to the cogenerator (see, "What Are the Potential Effects of the PURPA Incentives?"). In some cases, industrial parks with central cogenerators and shared energy products through dedicated distribution systems may be an attractive solution to thermal and electric supply/demand mismatches.

- Regulatory uncertainty and perceived risks: Doubt about the continued availability of the economic and regulatory incentives offered by PURPA, the fuel use and pricing provisions of FUA and the Natural Gas Policy Act, and the various tax incentives for investment in cogeneration (e.g., investment and energy tax credits, accelerated cost recovery, safe harbor leasing) can be a significant deterrent to investment in cogenerators. Similarly, uncertainty about interest costs and capital availability, fuel costs, investment payback periods, the use of solid fuels, and environmental regulation can be disincentives to the implementation of cogeneration projects.

All of the above factors could lead industrial managers to adopt a "wait-and-see" attitude toward cogeneration. As a result, widespread deployment of industrial cogeneration capacity could be delayed a decade or more. But the resolution of legal and regulatory uncertainties, the rapid development and demonstration of advanced technologies that can burn solid fuels cleanly, and lower interest rates or innovative financing and ownership arrangements could substantially improve industrial cogeneration's market potential. In addition, if natural gas prices are seen to be lower than distillate for an extended period—lo to 20 years—an industry might decide it is worth the investment risk if their purchase power rates are based on oil.

WHAT ARE THE OPPORTUNITIES FOR COGENERATION IN COMMERCIAL BUILDINGS?

Although the opportunities for cogeneration in commercial buildings depend on the same general factors as industrial cogeneration—thermal energy demand, availability of capital, competition with conservation, capability of using nonpremium fuels, etc. —there are characteristics about buildings that constrain cogeneration more than in industry.

In the near term–the next 10 to 15 years–commercial cogeneration will be fueled predominantly by natural gas. Coal-fired units can be used but these will be limited because of the difficulties of handling and storing coal in and around commercial buildings. Therefore, the principal determinants for commercial cogeneration for the near term will be the price and availability of natural gas, and either the price of electricity from central station units or the price that utilities will pay for electricity from cogenerators as set by their public utility commissions. For those regions where the latter is set at or near the price of oil-fired electricity and the utilities have oil or natural gas fueled capacity, commercial cogeneration fueled by natural gas has a promising market even if natural gas prices should approach those of distillate fuel oil. The primary advantage of commercial cogeneration in these cases is that it allows rapid development of new capacity to meet new demand and/or to replace the utility's oil-fired capacity.

Under least cost conditions, cogenerated electricity will be produced and sold when it is less expensive than central station electricity (see, "Will Cogeneration Be Competitive With Conventional Thermal and Electric Energy Systems?"). Net fuel savings by cogeneration compared to separate production of electricity and heat, however, may be less than that indicated by the amount of electricity sold because of the very low thermal load factors of commercial buildings. The most promising arrangement for commercial buildings probably would be to undersize the cogenerator and operate it at a high capacity factor to meet the base thermal load, and use conventional thermal energy systems when necessary to meet the remaining load. This allows a high degree of heat recovery and efficient capital utilization. Alternatively, the diversity added by using several buildings for heating loads could greatly increase net fuel savings. This also means that buildings located in regions with high thermal loads (about 6,000 degree days or higher per year) will be the most attractive candidates for cogeneration.

However, in both the near and long term, commercial cogeneration will compete with conservation-especially in new buildings. Conservation will very likely be more economic than cogeneration for most of the Nation's buildings. Further, the more efficient a building is, the lower its thermal demands and the less attractive cogeneration becomes. This is particularly significant when capital is scarce. Utility ownership may be one way of reducing the severity of the latter concern (see, "Who Will Own Cogenerators?").

For the longer term, beyond 10 years, commercial cogeneration ultimately must compete with new coal-fired or, possibly, nuclear capacity. It is unlikely that natural gas-fired cogeneration will be able to compete economically with new coal-fired central station capacity—even with byproduct credit for displacing natural gas for space heating—unless natural gas prices stay well below distillate oil. This is not likely to be the case toward the end of the century as supplies of conventional natural gas diminish. Where electricity growth rates are high (greater than 2 percent per year) and thermal demands are high (6,000 degree days or higher per year), however, natural gas-fired commercial cogeneration, even at high gas prices, could be competitive for new intermediate and peaking electric loads or for cases in which coal use is limited.

Cogeneration directly fired by coal with new technologies, such as fluidized bed combustion, or indirectly through low-Btu gasification and combined-cycle systems, could compete with new central station coal capacity (see, "What Are Some Promising Future Cogeneration Technologies?"). Some current analyses indicate that this will be so, but the OTA analysis of synthetic fuels for transportation shows that there is considerable uncertainty with respect to cost of synfuels production (6). Other promising possibilities are combined-cycle systems fired by biomass or solid waste gasifiers. These new technologies do not eliminate the coal or biomass handling problem, however, which will still act to inhibit cogeneration.

Finally, environmental considerations are likely to be more important for commercial buildings than for other cogeneration applications. This is due in part to the potential for increased emissions with the technologies that are most suited to commercial building applications, and in part to the inherent characteristics of the urban environment (e.g., proximity of buildings to each other, urban meteorology; see, "What Are the Environmental Impacts of Cogeneration?").

WHAT ARE THE INTERCONNECTION REQUIREMENTS FOR COGENERATION?

In the past, electric utilities and the agencies that regulate them have only been concerned with power flows from the central grid to customers, or from one utility to another. However, the economic and other incentives offered to cogeneration under Federal (and some States') law assume that cogenerators may feed power back into the grid. These "two-way" power flows have raised concerns about the technical and safety aspects of interconnection and integration with the grid, about liability for any damage that may result from improper interconnection, and about the costs of the equipment needed for proper interconnection and integration. OTA found that most of the technical aspects of interconnection and integration with the grid are relatively well understood, although some electric utilities still have reservations. Rather, the primary issues re lated to interconnection are the costs of the equipment and the utilities' legal obligation to interconnect.

The technical aspects of interconnection about which utilities are concerned include maintaining power quality, metering cogenerators' power production and consumption, and controlling utility system operations. Power supplied by cogenerators to the grid must be within certain tolerances so that the overall utility system power quality remains satisfactory and utilities' and customers' equipment will function properly and not be damaged. In order to maintain power quality, grid-connected cogenerators may need capacitors to keep voltage and current in phase, over/ under relays to disconnect the generator if its voltage goes outside a certain range, and a dedicated distribution transformer to isolate voltage flicker problems. However, the power quality effects of interconnected cogenerators often are technology- and site-specific, and not all systems will need all of this equipment. in particular, smaller systems (under 20 kW) may have few or no adverse effects on power quality and may require only limited interconnection equipment. Larger systems probably will already have dedicated transformers, and would only need capacitors to correct power factor if they use induction (as opposed to synchronous) generators.

Cogenerators' power production and consumption must be metered accurately in order to collect data for better understanding their contribution to electric system loads, and thus for determining how to price buyback and backup power. Two standard watthour meters can be used, with one operating normally to measure electricity consumption and the other running backwards to indicate production. Alternatively, more advanced meters are available that indicate not only kilowatthours used/produced, but also power factor correction and time-of-use. Although an advanced meter provides more useful data, it also costs about five times more than two standard watthour meters. Whether cogenerators are given a choice between standard and advanced meters and, if not, whether the utility or the cogenerator pays for the advanced meter, varies among utilities.

Utilities also are concerned about cogenerators' effects on their ability to control utility systems operations, including the possibility that large numbers of cogenerators (or small power producers) would overload system dispatch capabilities, and would contribute to unstable power systems. Although very large cogenerators might be dispatched by a central utility control center (and thus require connection via expensive telemetry equipment), most utilities will treat cogenerators as "negative loads" by subtracting the power produced by the dispersed generators from total system demand, and then dispatching the utility's capacity to meet the reduced demand. Studies of such negative load treatment indicate that it should work well where the total capacity of the cogenerators is limited compared to the overall system capacity. However, additional research is needed on the effects of large numbers of cogenerators on system stability. The primary concern with a significant system penetration of cogenerators is their ability to remain synchronized with the system following a disturbance.

Without proper interconnection measures, large numbers of cogenerators also might pose hazards to worker safety during repairs to transmission and distribution lines. First, dispersed generators will need to locate their disconnect switches in specified areas in order to simplify line workers' disconnect procedures. Second, induction (and, very occasionally, synchronous) generators must guard against self-excitation either by using voltage and frequency relays and automatic disconnect circuit breakers, or by locating their power-factor correcting capacitors where they will be disconnected with the cogenerator or where they can be isolated easily by line workers. Therefore, while proper interconnection must be ensured in order to protect utility workers' safety, none of the necessary precautions is difficult to implement.

The cogenerator usually is liable for accidents or damage to equipment resulting from improper interconnection or operation. The utility may include the cost of insurance against such mishaps in the cogenerator's regular billing, or liability (and adequate insurance to cover it) may be a condition of the contract between the utility and cogenerator. However, in some cases, requirements for both insurance and protective equipment may be redundant and place an excessive cost burden on the cogenerator.

The cost of interconnection varies widely depending on the size and type of cogenerator, the equipment already in place, and the utility's or State regulatory commission's requirements. Few guidelines have been published (although several are being prepared) and some utilities or commissions may require more equipment than described above in order to provide extra protection for their system and their other customers. In addition, the quality of equipment required (industrial or utility grade) can affect the cost substantially. Most utility engineers agree that the less expensive industrial grade should be adequate for smaller cogenerators, but specifications of the cutoff range from 200 to 1,000 kW. Finally, costs will depend on the amount of equipment that is already in place (e.g., dedicated transformers) and on the adequacy of existing distribution lines.

Based on published studies, OTA estimated two sets of interconnection costs for three sizes of cogeneration systems: a "base case" that assumes that much of the equipment is already in place or not required (e.g., capacitors, dedicated transformers, protective relays), and a "worst case" that assumes this equipment must be purchased (see table 3). Most of the cost difference between the two cases results from the addition of a dedicated transformer, and from the use of more expensive relays and other protective devices. Moreover, these estimates indicate that there are significant economies of scale in interconnection costs.

The Federal Energy Regulatory Commission's (FERC) rules implementing section 210 of PURPA originally specified that "any electric utility shall make such interconnections as may be necessary to accomplish purchases or sales" of cogenerated power. However, this rule recently was overturned by the U.S. Court of Appeals on the grounds that it is inconsistent with other parts of PURPA that provide for individual FERC orders requiring interconnection after the opportunity for a full evidentiary hearing in accordance with the Federal Power Act. Thus, if cogenerators cannot get a utility to agree to interconnect with them, they will have to meet the multiple stringent legislative tests of the Federal Power Act, which will be very difficult, expensive, and time-consuming for the cogenerator.

Table 3.—interconnection Costs for Three Typical Systems

Equipment	50 kW Best	50 kW Worst	500 kW Best	500 kW Worst	5MW Averaae
Capacitors for power factor		$1,000	-------	$5,000	
Voltage/frequency relays	$1,000	1,000	,	1,000	$1,:00
Dedicated transformer	—	3,900		12,500	40,000
Meter	80	1,000	80	1,000	1,000
Ground fault overvoltage relay	600	600	600	600	600
Manual disconnect switch	300	300	1,400	1,400	3,000
Circuit breakers	620	620	4,200	4,200	5,000
Automatic synchronizers	—	—	2,600	2,600	2,600
Equipment transformers	600	1,100	600	1,100	1,100
Other protective relays	—	3,500	–	3,500	3,500
Total costs ($)	$2,600	$13,020	$11,080	$32,900	$57,800
Total costs ($/kW)	52	260	22	66	12

NOTE: "-" means an optional piece of interconnection equipment that was not included in the requirements and cost calculations.

SOURCE: Office of Technology Assessment calculations based on data derived from Howard S. Geller, *The /interconnection of Cogenerators and Small Power Producers to a Utility System* (Washington, D. C.: Office of the People's Counsel, February 1982).

WHO WILL OWN COGENERATORS?

Cogenerators might be owned by industrial, commercial, or other users, by utilities, by third parties, or by some combination of these (joint ventures). Each of these forms of ownership has relative advantages and disadvantages for financing, taxation, operating characteristics, and regulatory considerations.

The energy and investment tax credits, coupled with the economic and regulatory incentives instituted by PURPA, encourage private firms (e.g., industrial facility and commercial building owners) to cogenerate. The PURPA requirement that utilities purchase electricity from, and sell it to, cogenerators, and the provision that exempts cogenerators from regulation as electric utilities, removed the primary institutional and economic obstacles to private ownership of cogeneration capacity. PURPA also encourages the development of contractual relationships between private owners and electric utilities—often a prerequisite for obtaining attractive financing. Long-term contracts can establish a purchase rate based on the utility's avoided costs either at the time of the contract or at the time power is delivered to the utility, or the cogenerator and utility can negotiate a price independent of avoided cost considerations. PURPA incentives are augmented by private owners' ability to earn up to 20 percent tax credits for investment in cogenerators through the end of 1982, and 10 percent thereafter, which offers a boost to cash flow early in a project's life. Finally, user ownership generally would provide the greatest control over the cogenerator's energy output. However, industrial and commercial firms' willingness to invest in cogeneration will be influenced heavily by the cost of capital (often higher than the cost to utilities or many third-party investors), the need to invest in process equipment or other items that will contribute to a firm's competitive position, and the availability of less costly conservation measures.

Investor-owned electric utilities and their subsidiaries are logical potential owners of cogeneration capacity because electricity generation is their primary business. Ownership of cogenerators would enable the electric utility industry to provide a wide range of energy supply options and not just to facilitate their development by other parties. Moreover, utility ownership would reduce the potential for revenue losses from the development of generating capacity by nonutilities, while providing an additional revenue stream from thermal energy sales. Direct utility ownership (i.e., not utility subsidiaries) also could result in lower generation costs to be passed on to consumers because the avoided cost would become the lower of the cost of cogenerating or of providing electricity from alternate sources (see, "What Are the Potential Effects of the PURPA Incentives?"). In addition, utilities are more likely to choose technologies that have high E/S ratios and that can accommodate coal or other alternate fuels (e.g., with gasifies). As a result of all these considerations, cogeneration's market potential in general, and its ability to supply large amounts of electricity to the grid in particular, are likely to be enhanced substantially under utility ownership.

However, current Federal policy toward cogeneration discourages full utility ownership. First, PURPA incentives are not available to cogenerators in which utilities own more than a 50-percent interest. Allowing 100-percent ownership would mean that utilities could earn a higher rate of return on unregulated cogeneration capacity than on their regulated central station capacity, and would compensate utilities more fully for accepting the business risks of investment in generating equipment over which they have little control (e.g., strikes, plant closings, or fuel interruptions at the cogeneration facility). Second, utility property is not eligible for the energy tax credit, and thus utilities would not gain the same cash flow advantages as private investors. Removing these disincentives would allow electric utilities to compete on at least an equal basis with other potential owners, and may give utilities a competitive advantage, and thus could substantially increase cogeneration's market potential.

However, full utility ownership raises concerns about competition and potential economic distortions. Utilities could favor their own (or their subsidiaries') projects through the duration or other terms of the purchase power contract, the interconnection requirements, or the priority for contracting. There is also a potential for utilities to cross-subsidize cogenerators through their other operations, making it difficult for private owners to compete, or for utilities to favor particular models and thus stifle competition among vendors. Each of these concerns can be dealt with either through carefully drafted legislation and regulations, or through careful review of utility ownership schemes by State regulatory commissions.

Publicly owned utilities also are logical candidates for investment in cogeneration capacity. Most publicly owned electric utilities purchase all or some of their power from the grid. investment in cogeneration capacity would enable them to add a new source of municipal revenue while increasing the reliability of their power supply. Moreover, many existing small municipal powerplants are sitting idle due to their high operating costs relative to the cost of grid-supplied power. These small plants could be retrofitted for cogeneration and the thermal energy used to meet local needs for such processes as grain drying or ethanol production. Municipal utilities also have advantages in financing because they are tax-exempt and so is the interest paid on their obligations.

Finally, joint ventures among any of the types of owners listed above or with third-party investors will be attractive, primarily due to the tax advantages. If the primary investor cannot take advantage of tax benefits such as credits or accelerated depreciation (e.g., because the investor is tax-exempt or has a low tax liability), the *cogeneration* equipment can be sold to another party for tax purposes only and leased back to the cogenerator or other owner.

WHAT ARE THE POTENTIAL EFFECTS OF THE PURPA INCENTIVES?

PURPA extends several important incentives to qualifying cogenerators (and small power producers). These include exemptions from electric utility or utility holding company regulation under Federal and State law and from some Federal fuel use and pricing regulations; incentive rates for sales of cogenerated electricity to the grid, and nondiscriminatory rates for purchases of backup or supplementary power from the grid; and special provisions on interconnection, and on wheeling of cogenerated power. All of these incentives are important because they could remove longstanding regulatory and economic barriers to onsite electricity generation. However, the rate provisions of PURPA are likely to have the most important impacts.

PURPA requires electric utilities to purchase power from cogenerators at a rate that does not exceed “the incremental cost to the electric utility of alternative electric energy.” This is termed the utility’s avoided cost, and is measured by the savings to the utility in not generating the power itself or purchasing it from the grid. Avoided cost rates are based on a cogenerators’ contribution to power supply or peak load during daily or seasonal peak demands (including the reliability of that contribution from the utility’s perspective); a credit for capacity and/or energy if the cogenerator enables the utility to defer new construction and decrease oil/gas use; and any costs or savings to the utility in transmission and distribution.

The level at which avoided cost rates will be set is uncertain at this time. The original FERC rules implementing PURPA provided for purchases of cogenerated power at 100 percent of the utility’s avoided cost. This provision was challenged successfully on the grounds that PURPA established the full incremental cost as a rate ceiling, and that FERC had not adequately justified their choice of the highest permissible rate when a lower rate would share the economic benefits of cogeneration with the utility’s ratepayers. FERC is appealing this ruling, but it may be months before a final decision is available and the regulations are rewritten, if necessary.

Regardless of whether the rates for purchases of cogenerated power are set at 100 percent of avoided costs or less than 100 percent, these rates will vary widely regionally. In most cases, only those utilities that are heavily dependent on oil or gas, have a declining reserve margin, or are anticipating relatively high peak demand growth (e.g., 3 percent per year or greater) will have sufficiently high avoided costs to make grid-connected cogeneration an attractive investment (see table 4). Therefore, PURPA rate provisions are most likely to be an incentive to cogeneration in the New England States (especially Massachusetts, Rhode Island, New Hampshire, and Connecticut); the Mid-Atlantic States (particularly New York, New Jersey, and Delaware); the Southern and South-Central States of Florida, Mississippi, Arkansas, Louisiana, and Texas; and the State of California and the Pacific Northwest.

However, in each area, PURPA avoided cost incentives may be reduced by such factors as utility plans to convert to less costly generating capacity, or by conservation measures that reduce the rate of peak demand growth. Thus, if peak demand growth rates are not so high as those presented in table 4, then reserve margins would be higher than shown and avoided costs would be lower. Where avoided costs are low, a cogenerator may deliver its electricity to a more distant utility that would have higher avoided costs, if the local utility agrees to transmit the power.

PURPA economic incentives also can have important impacts on electric utilities and their customers—especially if cogenerated power is priced at 100 percent of the utility's avoided cost. Because the avoided cost rate is based on the cost to the utility of alternative electric power, the price of electricity for non-cogenerating customers should not be any higher than it would be if the utility did not make avoided cost payments to cogenerators (unless the State has established rates higher than the full avoided cost). However, neither will the price to those customers be any lower under 100-percent" avoided cost rates (except in those cases where utilities negotiate a contract price for cogenerated power that is less than the full avoided cost).

Moreover, even though utilities should treat cogenerated power as part of their overall capacity, they will not earn a rate of return on cogeneration equipment unless they own it. Under PURPA, cogenerators that are more than 50 percent utility-owned are not eligible for PURPA economic and regulatory incentives. If utilities could own cogeneration capacity outright and still benefit from those incentives, the avoided cost could become equivalent to the cost of cogenerated electricity or the cost of alternative power—whichever is lower. If the cost of cogenerated power were lower, utilities could pass this savings on to their non-cogenerating customers, while still earning a higher rate of return on unregulated cogenerators than the regulated return on their conventional capacity. Therefore, removing the ownership limits in PURPA could act as an incentive to utility investment in cogeneration, and thus increase the technology's market potential. However, utility ownership also raises concerns about possible anti-competitive effects (see, "Who Will Own Cogenerators?").

WHAT ARE THE POTENTIAL ECONOMIC IMPACTS OF COGENERATION ON ELECTRIC UTILITIES?

Cogeneration could have either beneficial or adverse economic impacts on electric utilities and their customers, depending on the choice of cogeneration technologies, their fuel use, and the type of utility capacity they might displace; on who owns the cogenerators; on the systems' operating characteristics; and on the price paid by utilities for cogenerated power. These potential impacts include decreased (or increased) costs of constructing and operating electric generating capacity, increased (or decreased) employment associated with electricity supply, and a decreased (or unchanged) rate of growth in electricity rates.

In order to gauge the potential magnitude of these economic impacts if cogeneration achieved a very large market penetration, OTA developed

Table 4.–Considerations in Determining Avoided Costs Under PURPA

Region[a]	Fuel used (percent)[b]		Reserve margin (percent)			Peak demand growth (percent)	
	Oil	Gas	1981	1990	2000	1981-1990	1991-2000
Northeast	45.4	52.9	43.8	43.7	24.2	1.9	2.1
Maine	16.0	—					
New Hampshire	38,3	—					
Vermont	—	—					
Massachusetts	80.0	—					
Rhode Island	75.4	24.1					
Connecticut	44.8	—					
New York	38.0	—					
Mid-Atlantic	17.4	2.1	31.6	29.1	25.6	2,4	1.9
Pennsylvania	—	—					
New Jersey	44.5	10.5					
Delaware	59.4	—					
Southeast	15.5	4.9	33.5	28.5	18.6	3.7	3.0
Virginia	39.5	—					
North Carolina	—	—					
South Carolina	—	—					
Georgia	—	—					
Florida	47.9	16.0					
Tennessee		—					
Alabama	—	—					
Mississippi	37.7	30.6					
East-Central	4.9	—	38.8	33.5	29.0	3.5	2.9
Maryland	23.8	—					
District of Columbia	100.0	—					
West Virginia	—	—					
Ohio	—	—					
Kentucky	—	—					
Indiana		—					
Michigan	10.7	—					
Midwest	4.8	2.9	19.4	18.4	14.7	2.9	3.2
Wisconsin	—	—					
Illinois	—	—					
Missouri	—	—					
North-Central	1.6	2.4	41.4	20.4	14.8	3.8	3.3
Minnesota	—	—					
North Dakota	—	—					
South Dakota	—	—					
Nebraska	—	—					
Iowa	—	—					
South-Central	5.3	70.4	25.4	19.7	17.6	4.0	**3.6**
Kansas	—	41.1					
Oklahoma		82.9					
Arkansas	27.0	15.5					
Louisiana	17.7	82.3					
Texas		73.2					
Western	15.7	14.4	30.1	34.3	25.6	3.5	2.8
Montana	—	—					
Colorado	—	12.5					
Wyoming		—					
New Mexico	—	26.3}	32.8	40.2	16.5	4.7	3.6
Arizona	—	13.5}					
Utah	—	—					
Idaho	—	—					
Oregon		—					
Washington	—	—					
California	40.6	28.8}	21.2	18.0	11.4	2.6	2.2
Nevada	—	26.0}					

aRegions correspond roughly to North American Electric Reliability Council regions.
bElectric utility fuel use of less than about IO percent is not included for individual States.

SOURCE: Office of Technology Assessment, from Edison Electric institute, Statlsflcal Yearbook *off the Electric Utility Industry:* **1980(Washington, D.C; Edison Electric Instltute,1981~ and North Amerlcan Electrlc Rellabillty council,** *Electrlc Power Supply and Demand,* **1981-1990 (Princeton, N.J; North American Electric Reliablllty Council, July 198l)**

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six scenarios of cogeneration use that postulate penetrations of 50,000, 100,000, and 150,000 MW of cogeneration capacity by 2000 with two different technology mixes. We then compared the capital requirements, operation and maintenance (O&M) costs, and construction and O&M labor needs for these scenarios to those for installing an equivalent amount of central station baseload and peaking capacity (using two mixes for baseload capacity–loo percent coal and so/so coal and nuclear). In this comparison, OTA found that:

- capital requirements for cogeneration varied from around 95 percent less to about 25 percent more than the capital requirements for an equivalent amount of central station capacity;
- O&M costs for cogeneration ranged from approximately 75 percent less to about 95 percent more than the O&M costs for central station generation;
- construction labor requirements for cogeneration varied from around 45 percent less to approximately 70 percent more than those for constructing an equivalent amount of utility capacity; and
- O&M labor requirements, measured in work-hours per megawatthour, varied much more widely (e.g., 10 to several hundred times greater labor needs for cogeneration than for central station capacity).

In general, the wide variations in these results can be attributed to the economies of scale in the costs and labor needs for constructing and operating cogeneration capacity. Thus, total estimated cogeneration capital requirements are, on the average, lower than those for central station capacity, but may be slightly higher if all the cogenerators were very small systems with a high initial cost per kilowatt (e.g., 500-kW steam turbines, 75-kW diesels, 100-kW combustion turbines). Similarly, average estimated construction labor requirements for cogeneration range from about the same as those for installing conventional utility capacity to around so percent higher, and could be even greater when the smallest cogenerators (that require more work-hours per kilowatt of capacity) are installed. On the other hand, construction labor requirements for cogeneration may be lower than those for central station utility capacity if the largest cogenerators are used (e.g., 100-MW steam or combustion turbines, 30-MW diesels). For O&M costs, cogeneration tends to be more expensive for small systems and those with a higher capacity factor, and less expensive for large systems or those with a lower capacity factor. Finally, the O&M labor requirements for cogeneration are the most uncertain, primarily due to the lack of data in this area and because the economies of scale are even more pronounced.

Because the mean cost of cogenerated electricity tends to be lower than the marginal cost of electricity from new central station capacity, cogeneration may have the potential to reduce the rate of growth in retail electricity rates. That is, if utilities installed cogeneration capacity, lower costs would be passed on to their customers than if they installed conventional capacity. However, if utilities purchase cogenerated power at a rate based on their marginal, or full avoided costs, then the cost passed onto other customers would be equivalent to the cost of alternative electricity (i.e., either central station capacity or power supplied by the grid), and cogeneration would not reduce retail electricity rates, (see, "What Are the Potential Effects of the PURPA Incentives?"). Furthermore, where State regulatory actions provide for purchases of cogenerated power at rates that are even higher than full avoided costs (e.g., either because the State commission sets purchase power rates equivalent to the cost of oil and the utility uses a mix of fuels, or when the commission establishes an explicit subsidy rate), non-cogenerating ratepayers will be subsidizing cogeneration.

WHAT ARE THE ENVIRONMENTAL IMPACTS OF COGENERATION?

The primary environmental concern about cogeneration is the air quality impacts. In general, cogeneration does not appear to offer automatic air quality improvement or degradation compared to the separate production of electricity and thermal energy (see table s). Rather, each cogeneration application must be evaluated separately. Thus, cogeneration's greater fuel efficiency—when considered by itself—appears to offer a decrease in the total emissions associated with electric and thermal energy production, but, when evaluated in combination with the other changes associated with substituting cogeneration for conventional energy systems (including changes in the type of combustion equipment, its scale, and the type of fuel), may actually lead to an increase in total emissions.

Similarly, the location and technological characteristics of a cogenerator will affect ambient pollution concentrations and pollution dispersion. Cogeneration usually involves shifting emissions away from a few central powerplants with tall stacks to many dispersed facilities with lower stacks. In many situations, this shift will lead to local increases in annual average pollutant concentrations near the cogenerators. For urban cogenerators, total population exposure may increase because the emissions sources have been moved closer to densely populated areas. Also, air quality under certain meteorological conditions (such as low-level inversions) may be worse with cogeneration than with conventional separate electricity and thermal energy production. On the other hand, in some situations the "worst case" short-term pollutant concentrations caused by cogenerators will not be so high as the worst case concentrations associated with the facilities they displace. Moreover, if a cogenerator replaces several small furnaces or boilers then its air quality impacts can be positive.

Industrial and large-scale commercial cogeneration systems using steam or combustion turbines do not appear to present significant air quality problems in most situations. However, if the substitution of these cogeneration technologies for separate electric and thermal energy production also involves a switch from "clean" to "dirty" fuels (e.g., from distillate oil to high sulfur coal) then emissions could increase. Similarly, where a new steam or gas turbine cogenerator that primarily produces electricity is substituted for a new boiler or furnace, then the cogenerator could add significantly to local emissions.

Table 5.—Effect of Cogeneration Characteristics on Air Quaiity

Technological characteristic	Direct physical effect	Effect on air quality (positive or negative)
Increased efficiency	Reduction in fuel burned	Positive
Change in scale (usually smaller for electric generation, at times larger for heat/steam production)	Change in pollution control requirements (stringency increases with scale)	Negative for electric[a] Positive for heat
	Change in stack height and plume rise (increases with scale)	Negative for electric Positive for heat
	Changes in design, combustion control	Mixed
Changes in fuel combustion technology	Changes in emissions production, required controls, types of pollutants, physical exhaust parameters	Mixed
Change of fuels	Change in emissions production, type of pollutants	Mixed
Change of location (most often for electric generation)	Change in emissions density and distribution—electric power more distributed, heat/steam may become more centralized	Mixed

[a]The air quality effect of replacing the electric power component of the conventional system with the electric component of the cogeneration system is negative.

SOURCE: Office of Technology Assessment from material in ch. 6.

The use of diesel cogenerators (and gas-fired spark-ignition engines), however, generally will lead to increased levels of nitrogen oxide (NO_x) emissions at the cogenerator site, even after accounting for the displaced emissions from the separate electric and thermal energy sources. Available controls can reduce diesel NO_x emissions by nearly one-half, which mitigates but does not eliminate this problem. Diesels also emit potentially toxic particulate, but conclusive medical evidence of harm is lacking at this time, and the evidence that is available suggests that this hazard may not be critical.

Cogenerators' greater fuel efficiency can lead to an important environmental benefit through reduced exploration, extraction, refining/processing, and transportation of the fuel saved. However, this benefit is difficult to quantify and compare to the various air quality effects noted above. Furthermore, this benefit usually will occur only when the cogenerator uses the same fuel as the conventional energy systems it displaces. That is, if a fuel that is difficult to extract, process, and transport (e.g., coal) is substituted for a "cleaner" fuel (such as natural gas) the overall impacts may be adverse rather than beneficial.

The air quality concerns reviewed above mean that cogenerators—especially those in urban areas—must be designed and sited carefully. Most urban cogenerators are likely to be diesels or gas-fired spark-ignition engines, both of which have higher NO_x emissions than the systems they would replace. In urban areas with high NO_x concentrations, deployment of large numbers of cogenerators without pollution controls and careful siting could lead to violations of ambient air quality standards and increased risks of adverse health effects. There is considerable potential to mitigate these problems through proper site selection and engine design, and the use of available NO_x controls. For example, uncontrolled diesel NO_x emissions may vary by as much as a factor of 8 depending on the engine model and manufacturer, so appropriate engine choice alone might improve environmental acceptability significantly. However, there are no Federal emission standards for stationary diesel engines and the degree of risk from their deployment will depend on the effectiveness of State and local air quality permitting and management.

Proper siting and design also are important in avoiding the problems of "urban meteorology, " or the effect of tall buildings on air currents and, thus, on pollutant dispersion. Urban meteorology can cause plumes to downwash or to be trapped and recirculated in the artificial canyons created by urban buildings, and can therefore result in very high local pollution levels during certain wind conditions. Proper design and siting—especially ensuring that exhaust stacks are taller than surrounding buildings—can avoid air quality problems caused by urban meteorology. But the solutions may be costly in certain circumstances (e.g., when adjacent structures are much taller than the cogenerator's building), and may be ignored by developers unless there is a strong State or local permit review process.

Although potential air quality impacts are the primary environmental concern for cogeneration, water quality, solid waste, noise, and cooling tower drift also may be important. Water pollution can result from blowdown from boilers and wet cooling systems, and runoff from coal piles and from scrubber sludge and ash disposal. In urban areas, these effluents may have to be pretreated before discharge into the municipal treatment system. in addition, sludge and ash disposal may be a problem in urban areas due to the lack of secure disposal sites. Noise is also primarily an urban problem, but control measures are readily available. Finally, cooling tower drift can be a nuisance for those in the immediate area.

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