Historical Impacts and Future Trends in Industrial Cogeneration

Joel Bluestein, Energy and Environmental Analysis, Inc.
Marie Lihn, Gas Research Institute

ABSTRACT

Cogeneration, also known as combined heat and power (CHP), is the combined sequential generation of electricity and thermal or electric energy. The technology has been known essentially since the first commercial generation of electricity as a high efficiency technology option. After a period of decline, its use increased significantly during the 1980s and it is receiving renewed interest lately as a means of increasing efficiency and reducing emissions of air pollutants including carbon emissions. New and developing technology options have added to this potential. Forecasts of future growth and efforts to stimulate cogeneration need to take into account the history of the technology, the factors that have driven it in the past, and factors which could stimulate or retard future growth. This paper reviews and analyzes these factors and looks toward the future potential for cogeneration.

Introduction

The benefits of cogeneration include more efficient generation of total energy and lower emissions per unit of useful energy delivered. The higher efficiency is largely due to the recovery of heat that is rejected from conventional electric generation systems, which ranges anywhere from 40 to 70 percent of heat input in conventional systems. Cogeneration recovers this thermal energy for useful applications, increasing the overall efficiency to 80 percent or higher. For this reason, cogeneration is often portrayed as electric generation with waste heat recovery. It may be better to think of it as a method of providing needed thermal energy with ultra-efficient electricity generation as a byproduct.

Another benefit of cogeneration is the replacement of older, less efficient, and higher emitting equipment with state-of-the-art technology that is more efficient and cleaner. Finally, cogeneration focuses on the appropriate and efficient matching of thermal and electric energy.

Cogeneration is commonly measured by electric capacity, but this is deceptive. The useful output of cogeneration is a combination of thermal and electric energy, and the shares can vary significantly depending on the technology and configuration. For example, the total energy provided by a 1 MW steam turbine system may be greater than that provided by a 10 MW combined cycle system. The ratio of electricity to thermal energy is typically portrayed as the power to heat ratio. This is one of the important technology parameters of cogeneration systems. The thermally optimum power to heat ratio ranges from about 0.2 for traditional boiler/steam turbine systems to 1.5 for gas turbine combined cycle systems. Higher power to heat ratios can be achieved at a sacrifice in overall system efficiency.

Users select cogeneration technologies based on the availability of fuels, the economic goals of developers, and utility and environmental regulations. All of these have determined the cogeneration inventory that exists today. Some of the same factors will determine the future growth, but some will change. A short review of the historical development of industrial cogeneration is a useful start in understanding some of these factors.

History

In the early days of electricity generation, on-site generation of electricity at industrial facilities was relatively common. Central utilities were just developing and were not significantly less expensive or more reliable than on-site generation. Many of these on-site generation facilities were retrofits of existing steam boilers, and cogeneration was a convenient and economical way of meeting both thermal and power needs.

However, as the reliability of central electric generation increased and price decreased through improved technology and economies of scale, industrial cogeneration remained effective and economical only in industries with high steam demands, high capacity utilization and "free" byproduct fuels that could be used in the cogeneration system. These factors led to the extensive use of cogeneration in the paper, chemicals, refining, and iron and steel industries, which remain some of the largest industrial users of cogeneration today.

This initial inventory of cogeneration facilities was based on the original cogeneration technology – boilers providing steam to turbine/generators with thermal energy provided by extraction from the turbine or the turbine exhaust. This was the primary technology available at the time for electricity generation and the use of boilers allowed the combustion of a wide variety of fuels, including the low quality byproduct fuels available in the core cogeneration industries.

As utilities became more sophisticated at generating electricity, they also became better at protecting their markets. By the 1970s, cogeneration was the target of a variety of anticompetitive practices that restricted its growth. Many utility companies refused to purchase power from cogenerators, limiting energy production to the generation they could use in-house. Utilities also demanded high payments for backup and standby power, and set prohibitive requirements for connection with cogenerators for backup.

The Public Utility Regulatory Act of 1978 (PURPA) was designed to address these issues in order to promote cogeneration for its efficiency benefits. The Act required utilities to purchase power from "qualifying facilities" (QFs) at the same rate the utilities would have had to pay to generate it themselves (their avoided cost). The rate which utilities must pay is typically called the buyback rate. Guaranteed payments at avoided cost improved the economics of many industrial cogeneration opportunities that were marginal or unattractive prior to the Act. PURPA also mandated that utilities provide standby and backup power at reasonable rates and exempted cogenerators from the Public Utility Holding Company Act, enabling industrial operators to pursue cogeneration opportunities that PUHCA regulations and discriminatory utility policies made impractical or uneconomical to develop prior to the Act.

Within the economic and regulatory structure of the electricity markets at that time, these provisions went a long way toward addressing barriers to industrial cogeneration. PURPA changes resulted in a major growth spurt in cogeneration, with the installed electric capacity going from about 10 GW in 1981 to nearly 46 GW in 1996 – 300 percent growth in 15 years. Several factors prompted rapid growth in industrial cogeneration during this period:

- Most of the growth was simply due to PURPA having the predicted, desirable effects of removing regulatory and competitive barriers. The flexibility afforded by known and reasonable buyback and standby rates improved the economics and feasibility of cogeneration for operators of industrial facilities, including industries that traditionally used a lot of cogeneration. Much of the post-PURPA growth was in the chemicals and refining industries in the southwestern U.S., for example.

- In some places, public utility commissions set standard offer buyback rates that were high relative to retail electricity prices and the marginal cost of cogenerated electricity. These favorable rates resulted in high cogeneration growth in states such as New York and California. While some of these contracts seem anachronistic and possibly counterproductive in today's restructuring electric industry, they were a reasonable response to policy issues of the time when they were introduced.

- Finally, the opportunity to sell electricity to utilities for a high price, whether determined by market conditions or regulatory policy, stimulated the development of a new class of non-utility, merchant electric generators.

The last factor was the precursor to many changes in the market leading to today's electric industry restructuring. PURPA created the first institutional opening for non-utility generators of electricity. High PURPA-driven prices prompted the arrival of non-utility power developers who built facilities which were physically and economically driven by the market for electricity rather than a thermal requirement. An unforeseen result of PURPA, therefore, was the development of two distinct markets within industrial cogeneration: traditional and non-traditional. Traditional cogeneration facilities provide steam to industrial users as their primary function, with electricity generated as a by-product. Non-traditional facilities are designed to provide electricity for sale to utilities with steam as a secondary product. The original non-traditional facilities used cogeneration to overcome regulatory barriers to participation in electricity markets . They were developed primarily to maximize profits through the sale of electricity to utilities rather than by minimizing operational costs for an industrial application.

From the cogeneration perspective, this meant that the non-traditional facilities were leveraged to produce the maximum possible electric output within the constraints of the PURPA power-to-heat heat requirement of about 18. Although the plants provided a useful source of steam to an end user, the plants often received only minor income from the steam sales and their efficiency was lower than that of a more thermally optimized cogeneration plant. Cogeneration capability was the price these plants paid to get into the power sales market.

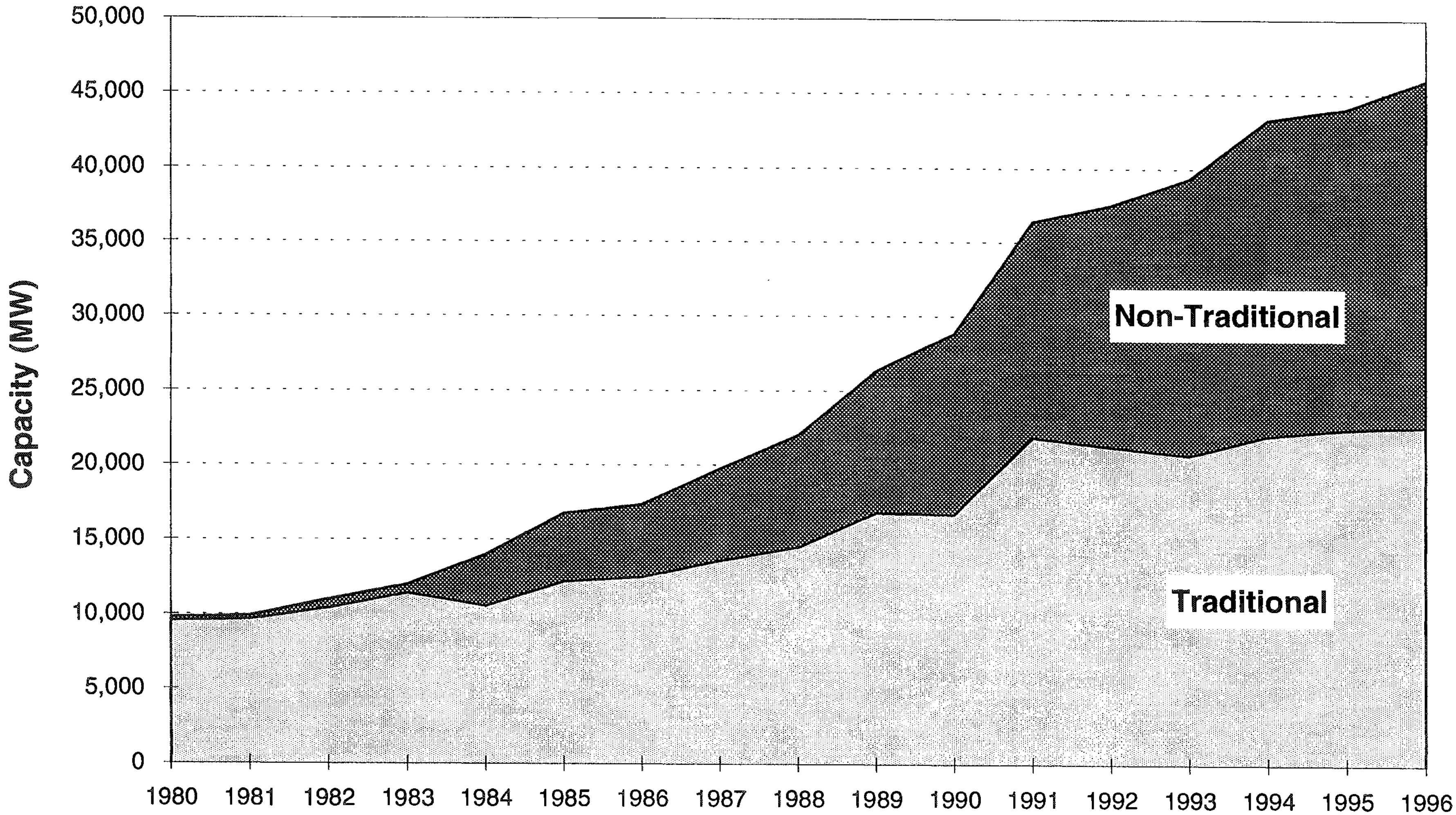
The development of the non-traditional market changed the mix of technologies in the cogeneration industry. Some of the early non-traditional projects used the well known boiler/steam turbine technology, but configured the systems to achieve a higher power to heat ratio to maximize electricity production. Even boiler steam/turbine facilities have been built with power to heat ratios greater than 10. However, the development of the new market coincided with the increasing availability of lower cost, higher efficiency combustion turbines. Either in simple cycle or combined cycle mode, combustion turbines provide more electricity per unit of steam at peak efficiency than do boiler/steam turbine facilities (P/H=1 to 1.5 vs 0.2). The increased generation capability and interest in selling excess electricity spurred the application of more and more combustion turbine-based projects. These turbines are limited to burning either natural gas or more expensive distillate, so the growth in turbine use also triggered growth in the consumption of natural gas as a cogeneration fuel. In terms of electric capacity, the new projects were larger than many historical cogeneration projects which had lower power to heat ratios. Figure 1 shows the growth of industrial cogeneration from 1980 to 1996. Non-traditional projects account for two thirds of the rapid growth that occurred during this period.

The developers of non-traditional projects quickly began to look beyond the traditional steam hosts in siting projects. Since the electricity market was the primary driver, the traditional host parameters of high steam load were not as important. PURPA set a minimum steam use requirement of 5 percent to ensure that the projects were really cogenerators. However, questions over the ultimate usefulness of the thermal output of a few projects gave rise to the myth of the "PURPA" machine, in which thermal energy was supposedly generated for no purpose other than to qualify for PURPA benefits. While there may have been isolated examples of questionable projects, there is no documentation of their widespread existence and the vast majority of projects developed during this time provide thermal energy to bona fide industrial and commercial thermal energy-using processes. In fact, most of the non-traditional capacity is in traditional cogenerating industries such as chemicals and refining.

The development of the non-traditional market attracted more capacity offers from third-party developers than utilities expected or needed. Utilities faced increasing demands to buy electricity from non-utility generators at high PURPA prices, as well as regulatory requirements to justify their own construction programs relative to demand side management and other alternatives. Beginning in the mid-1980s, many utilities began receiving capacity offers in excess of their incremental requirements. Paying a standard offer rate including capacity costs to all cogenerators became a financial liability and, according to utilities, a disbenefit to rate payers. Some utilities solved this by including only energy costs in the avoided cost/buyback rate. Competitive bidding programs were then instituted to select those projects which would be credited for incremental capacity. Gradually, under state rules and the Federal Energy Policy Act of 1992 (EPACT), non-cogenerating, non-PURPA generators gained the right to operate in these competitive power generation markets.

The EPACT defined a new class of non-utility power producer, called Electric Wholesale Generators (EWGs), which are exempt from many federal regulations governing wholesale sales of electricity (including PUHCA), and it clarified the regulatory treatment of these facilities. While the EPACT did not create a mandatory purchase obligation for EWGs comparable to that created for cogeneration facilities qualifying under PURPA, many states

Figure 1
Historical and Current Industrial Cogeneration Capacity - Traditional and Non-Traditional



Source: Edison Electric Institute and Energy and Environmental Analysis, Inc.

implemented "all-source" bidding programs for making decisions on solicitations of incremental capacity. These programs place EWGs theoretically on a level playing field with PURPA-qualified cogeneration facilities, other utilities, and other non-utility generators. These changing regulations have reduced the incentives for independent power developers to design their power plants as non-traditional cogeneration facilities in the future.

With the highest value electric contracts being awarded through bidding programs, standard offer PURPA buyback rates fell to unattractive levels. Power purchase contracts became interruptible rather than must-pay arrangements, and standby and backup rates increased. These factors further reduced the attractiveness of a merchant electric/ cogeneration plant. The value of cogeneration/PURPA-qualification as a ticket into the market had disappeared and serving a steam host in addition to the electric utility has become an unnecessary burden for merchant electric power plants.

A growing number of independent developers are therefore pursuing the EWG route to new project development, rather than trying to meet the stringent efficiency standards of a qualified facility as defined by PURPA. With changing incentives during the late 1980s and early 1990s, cogeneration growth tapered off and the growth of simple merchant electric plants increased.

Many factors have converged to create a slower market for cogeneration, including many related to the onset of electric industry restructuring. In a restructured market, retail electric prices are expected to be lower and all generators will have to compete in the same market for sales. For cogenerators this means reduced economic value at both ends of the value equation. Utilities have also started to offer preferential pricing to customers to discourage them from cogenerating. In a competitive electricity market, old high-cost cogeneration contracts are a liability and utilities have began to buy out existing and even planned cogeneration projects to reduce their costs as they prepare for competition. Ultimately, cogeneration developers today may find themselves in a situation similar to the pre-PURPA situation – one of reduced access to the market, low buyback rates, high standby charges, and increasing anti-competitive behavior by utilities.

Current Status

In 1996, electric capacity in industrial cogeneration facilities constituted nearly 46 GW or 6 percent of the total 755 GW of electric capacity on-line in the U.S.[1] In terms of generation, industrial cogeneration accounted for around 280,000 GWh, or over 9 percent, of the total U.S. power generation of around 3,000,000 GWh in 1996, indicating a higher than average utilization.

In addition to the regulatory factors described above, cogeneration has been shaped by a variety of factors related to the needs and characteristics of U.S. industry and the capabilities and characteristics of available fuels and technologies. Understanding these factors provides significant insight into the current cogeneration market.

[1] Estimates of the existing cogeneration population were developed using data from the Edison Electric Institute and the Utility Data Institute (see reference list) and from published reports of new projects.

The industrial sector is generally highly concentrated. Many energy-intensive industries tend to concentrate in certain locations for reasons related to raw material and energy supplies, creating a linkage between industry, location, and fuel. The needs and characteristics of specific industries have historically been a primary driver for the development of industrial cogeneration. As noted above, industries with high steam demand, high capacity utilization and "free" byproduct fuels have been good applications for cogeneration. More recently, non-traditional cogeneration has developed in some areas in response to regulatory developments or actions taken by state public utility commissions.

The result has been concentration by both region and industry. For example, 67 percent of industrial cogeneration capacity is found in the chemicals, refining, and paper industries. The chemicals industry alone accounts for nearly one third of total industrial cogeneration capacity. Similarly, over 27 percent of U.S. industrial cogeneration is concentrated in the West South Central region (Texas, Lousiana and Oklahoma) due to its high concentration of chemicals, refining and paper industries. When the Pacific 2 (California and Hawaii), South Atlantic and Middle Atlantic regions are added (most of the east coast), nearly 75 percent of industrial cogeneration capacity is accounted for. Figure 2 shows the dominance of relatively few regions and industries in the cogeneration inventory.

In 1996, the West South Central region had 12,499 MW or 27 percent of the total U.S. industrial cogeneration capacity. The vast majority of this capacity (8,102 MW) was related to the chemicals industry, followed by paper and refining. About 5,225 MW of cogeneration in the chemical industry was non-traditional. Combustion turbine technology accounted for 67 percent of the West South Central region's cogeneration capacity. Much of this was non-traditional capacity which values the high power-to-heat ratios of combustion turbines. The extensive use of natural gas and gaseous byproduct fuels in the region also facilitates the use of combustion turbine technology.

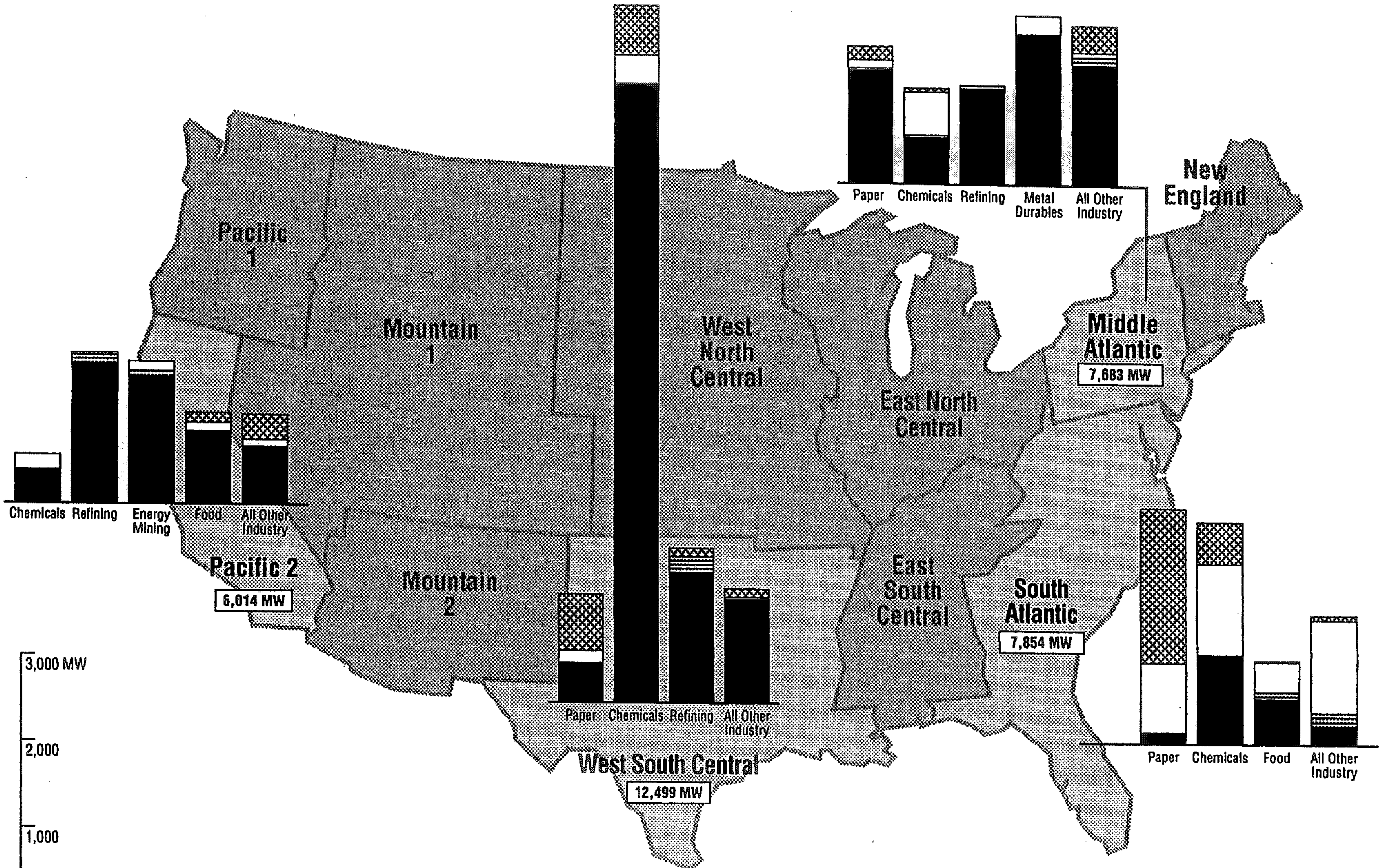
The South Atlantic region also has a large concentration of paper and chemical industries which have made it a fertile area for cogeneration. In 1996, the South Atlantic had 7,927 MW of capacity or nearly 17 percent of the total cogeneration capacity. The paper and chemicals industries each comprised over 33 percent of the capacity in the region. Of this, 76 percent was based on the conventional boiler/steam turbine system design. This is most likely due to its proximity to and use of coal (used in the paper and chemicals industries) and also the availability of biomass and byproduct fuels in paper mills. Coal fueled 42 percent of the South Atlantic region's capacity while gas supplied 24 percent and "other fuels" provided 30 percent of capacity.

Since the implementation of PURPA in 1979, and the advent of high buyback rates, several regions have experienced significant growth in industrial cogeneration. Most notable were the Middle Atlantic and Pacific-2 regions. Before PURPA, industrial cogeneration in the Middle Atlantic region was about 6 percent of the total U.S. on-line capacity. By 1996, cogeneration had grown to 7,683 MW, or 17 percent of U.S. capacity. Much of this capacity was provided by relatively large cogenerating plants such as the Sithe plant, with 1,038 MW of capacity, and Linden, with 600 MW of capacity. The Middle Atlantic region's high cogeneration growth was spurred by regional shortages of electric capacity, the resulting high electricity prices and the active role taken by the region's public utility commission to promote non-utility generation.

FIGURE 2

1996 Cogeneration Capacity By Industry In Four Major Regions

— Total 45,924 MW —



Oil data include residual fuel oil, distillate, still gas, and petroleum coke. Other data include biomass, waste heat, coke oven gas, blast furnace gas, and other gas.

Source: Edison Electric Institute and Energy & Environmental Analysis, Inc.

For example, in the mid-1980s, New York State's Public Utility Commission promoted a 6 cents per kWh minimum buyback rate as an incentive for independent power production. This helped promote much of the growth in the Middle Atlantic region, which has been non-traditional cogeneration. Much of this non-traditional growth is powered by gas, which accounted for 85 percent of non-traditional capacity in this region in 1996. This history has become problematic in recent years as utilities have been anxious to buy out or otherwise divest the older, high cost contracts.

The Pacific-2 region's cogeneration capacity has also increased substantially. Since the early 1980s, the region's industrial cogeneration grew at an annual rate of 25 percent to 6,014 MW or 13 percent of the total on-line capacity in 1996. This was also due to an active role taken by the region's public utility commission and shortages of electric capacity. Much of the growth has been cogeneration associated with enhanced oil recovery operations in Kern County, California equal to 1,715 MW of capacity. By 1996, 83 percent of the region's cogeneration capacity was gas-fired, due in part to California's stringent environmental standards as well as the desire to maximize electric output in non-traditional projects.

Though not shown, the East North Central region, with 4,203 MW of cogenerating capacity, was the fifth largest cogenerating region in 1996. There was more than twice as much traditional cogenerating capacity (2,810 MW) as non-traditional capacity (1,393 MW) in 1996, with traditional cogeneration concentrated in the paper and primary metals industries. The chemicals industry was the largest cogenerating industry in the region with 1,478 MW of capacity, 1,274 MW of which was non-traditional and 1,439 MW of which was fired by gas. Both the paper and primary metals industries, with the second and third largest cogenerating capacity in the region respectively, were fired primarily by coal in 1996. One very large non-traditional facility accounts for almost all of the non-traditional capacity in the region.

The remaining regions account for less than one fifth of industrial cogeneration capacity.

Although the primary metals (iron and steel) industry was once a significant cogenerator, this is no longer the case due to changes in the structure and organization of the industry. Cogeneration in the iron and steel industry was strongly linked to integrated steel-making operations. By-product fuels from coke ovens and blast furnaces were available as fuel and there was a need for steam to run large mechanical drives related to blast furnace operations. As the iron and steel industry has moved away from integrated steel-making to increased use of electric arc furnaces, the opportunities for cogeneration have decreased and the iron and steel industry is no longer a major cogenerator.

Broader Industry Impacts

The rapid growth of cogeneration has had broader implications for the industrial sector. Although it increases the efficiency of the total economy, cogeneration creates the appearance of increasing industrial energy consumption by shifting primary energy use from the utility sector to the industrial sector. For a conventional system, energy consumption for steam generation is shown in the industrial sector, while the energy consumption for electric generation is reflected in power generation statistics. For a cogeneration system, the energy for both thermal and electric generation is allocated to the industrial sector, creating an apparent increase in energy use. This is particularly true for non-traditional projects, which burn fuel and export electricity which may not be used in the industrial sector. This effect may be one reason that the industrial sector has shown increasing energy intensity during the last 10 years at a time when other factors would have indicated efficiency gains.

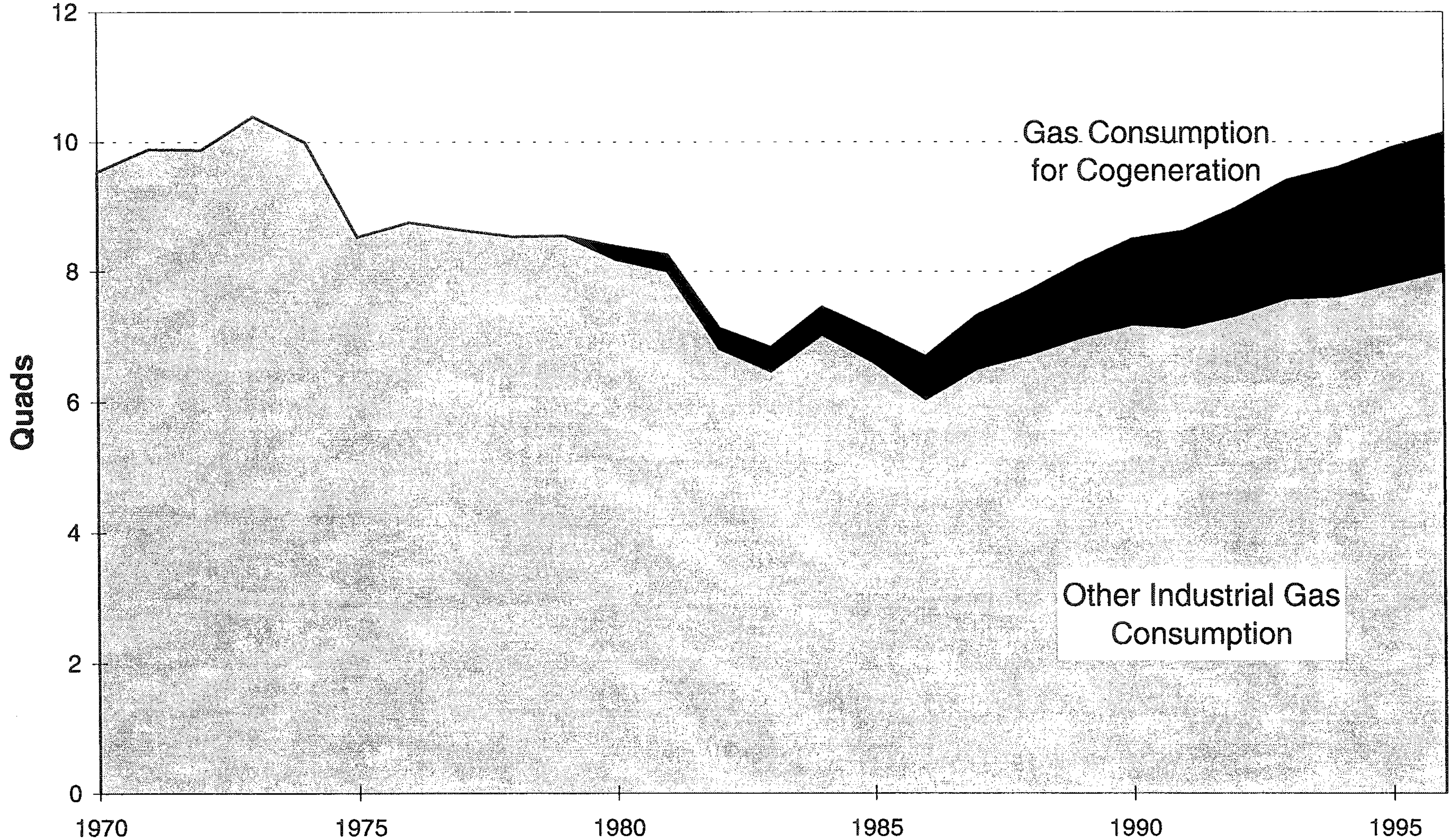
Cogeneration growth may have had a related effect on industrial use of natural gas, as shown in Figure 3. Industrial gas use peaked at 10.4 Q in 1973. Gas use declined along with consumption of other fuels during the mid 1970's due to increased energy prices and again in the mid 1980's due to economic factors. By about 1985, however, gas use for cogeneration was starting to account for significant growth, driven largely by the rapid growth in gas-fired non-traditional projects. By 1996, other industrial gas consumption had recovered to about 1980 levels, but gas consumption related to cogeneration added another 2 Quads, bringing the total to greater than 1970 levels. Thus cogeneration is a primary factor in the recovery of industrial gas load.

The Future of Industrial Cogeneration

As noted above, the current climate for industrial cogeneration is in some ways similar to that prior to PURPA. The arrival of electric restructuring is creating a negative environment in a variety of ways. Cogenerators are caught in an unfortunate state of limbo while restructuring develops. In the interim, they are stuck with the worst of both worlds. They are unable to sell power except to the local utility and they are still forced to rely on the local utility for backup and standby power. The price at which they can sell power, however, is determined by the broader market, which is relatively low. At the same time, utilities are offering very low retail prices to industrial users as well as using a variety of tactics to actively discourage cogeneration, which erodes their customer base. Finally, as new sources, new cogeneration projects are subject to the most stringent environmental requirements. While these are understandable outcomes in the context of today's developing market and regulatory structure, they do not help the development of cogeneration as a means of addressing national energy or environmental goals.

There are some reasons to be optimistic however. If electric restructuring does become a widespread reality and depending on its implementation, the value of cogeneration will be easier to realize and in a way that sends the proper signals to encourage efficiency. Among the important regulatory factors required to support growth of cogeneration are: open access to both customers and sources of back-up power, reasonable interconnect standards, and avoidance of anticompetitive exit fees or stranded cost changes. With such a regulatory environment, a thermally matched cogeneration facility can provide steam to an industrial facility at cost-effective but profitable prices, and generate electricity at extremely market-competitive costs. The efficiency of the system is, in effect, manifested as a below-market cost of electric generation. The more efficient the system, the more competitive it will be in the electric market. This should be even more effective than the mandates of PURPA at driving developers towards establishing efficient systems, rather than gaming a regulatory program.

Figure 3
Contribution of Gas Consumption for Cogeneration to Overall Industrial Gas Consumption



Source: Energy and Environmental Analysis, Inc. and Annual Energy Outlook

At the same time, cogeneration system developers will have new technologies available. The combustion turbine technologies have continued to get smaller and more efficient. New technologies, such as fuel cells, may be available in the near future. These technologies are important because many of the larger industrial thermal users have already applied cogeneration. Nevertheless, other studies have shown significant remaining thermal load to be served (Davidson 1997a,b). Continued expansion of cogeneration will depend on the availability of technologies that are amenable to these smaller applications and can produce electricity at a price competitive with central plants. There may also be opportunities related to replacement of some of the older technologies. For example, there is currently much interest in replacing recovery boilers in the paper industry with gasification combined-cycle systems that would be cleaner and have a higher power-to-heat ratio.

Industrial cogeneration achieved explosive growth during the 1980s which has resulted in significant reductions in energy use and emissions. That growth is stalled today due largely to the regulatory environment. Resolution of the regulatory issues and the availability of new technologies have the potential trigger another wave of cogeneration growth with attendant national benefits.

Acknowledgements

This paper is based on work funded by and performed for the Gas Research Institute. The authors gratefully acknowledge GRI's support for this activity.

References

Bluestein, Joel. 1998. *Summary of the 1998 Industrial Cogeneration Projection*, Gas Research Institute

_________. 1997. *Capacity & Generation of Non-Utility sources of Energy*, Edison Electric Institute

_________. 1995. *Directory of Selected U.S. Cogeneration, Small Power & Industrial Plants, 11th Edition*, Utility Data Institute

Davidson, Keith. 1997 *Chemical Industry On-Site Power Market Assessment,* Gas Research Institute

Davidson, Keith. 1997. *Food Industry On-Site Power Market Assessment,* Gas Research Institute