Impediments to New Natural Gas Markets

Prepared for the INGAA Foundation, Inc., by:
RCG/Hagler, Bailly, Inc.
1530 Wilson Boulevard
Suite 900
Arlington, Va. 22209-2406

F-9201

IMPEDIMENTS TO NEW NATURAL GAS MARKETS

Prepared for:

INGAA FOUNDATION
555 13th Street, N.W., Suite 300 West
Washington, D.C. 20004

(202) 626-3200

HBI Reference No. 91-U303

Prepared by:

RCG/HAGLER, BAILLY, INC.
1530 Wilson Boulevard
Suite 900
Arlington, VA 22209-2406

(703) 351-0300

May 1992

CONTENTS

LIST OF EXHIBITS

PREFACE

Natural gas will play a major role in providing North America with clean-burning energy well into the 21st century. For gas to reach its full potential, however, additional pipeline capacity and other facilities must be constructed to serve new and expanded markets. Helping to identify and overcome barriers to pipeline construction and operation is the mission of the INGAA Foundation.

In the Spring of 1991, the INGAA Foundation engaged RCG/Hagler, Bailly, Inc. to conduct a study to identify generic impediments to new natural gas uses over the next decade, and to suggest ways for gas companies to overcome such impediments. This report presents the detailed findings of the study.

In order to analyze the factors shaping the market for potential uses of natural gas, the contractor collected a significant portion of the information from interviews with senior managers and project leaders from companies and organizations involved with natural gas. These included natural gas production, pipeline and local distribution companies, electric utilities, trade associations, federal agencies, equipment manufacturers and research centers. Those interviewed shared their opinions, concerns and outlook for natural gas, as well as their strategies for developing and introducing new gas uses into the marketplace.

The INGAA Foundation would like to express its gratitude to all those who participated in this project.

EXECUTIVE SUMMARY: IMPEDIMENTS TO NEW NATURAL GAS MARKETS

NEW MARKETS FOR GAS

Faced with natural gas consumption that fell 27% between 1972 and 1986 and has only recently begun to recover, the natural gas industry must expand to new or under-utilized markets that can fuel future growth. Three markets appear most attractive, offering the possibility of growth in demand for gas of between 1.6 trillion cubic feet and 4.2 Tcf. These three markets are:

- Electric power generation, where gas demand will grow between 1.5 trillion cubic feet and 3.6 Tcf by 2000 to fuel utility plants and plants built by non-utility generators. This market is by far the most attractive, accounting for 85% to 95% of the estimated growth in demand by 2000.

- Natural gas-fueled vehicles. Gas consumption by NGVs could increase by 60 billion cubic feet and perhaps as much as 200 Bcf during this decade.

- Gas cooling. The market for gas cooling, which virtually collapsed between 1970 and 1980, might see only negligible growth of 20 Bcf but could increase by as much as 400 Bcf by 2000.

New technologies will lead to increases in gas use in particular industrial applications, but the industrial sector does not appear to be a growth opportunity. The gas industry will likely focus on protecting industrial loads in the next decade, not in pursuing overall growth in this market.

IMPEDIMENTS TO NEW GAS MARKETS

But before gas can capture new markets in power generation, NGVs or gas cooling, the gas industry must overcome impediments in each market.

To make greater inroads into power generation, the gas industry must overcome customers' fears that it will be unable to deliver gas at stable prices over the long term. Electric utilities and non-utility generators, sophisticated customers, say they need greater cooperation with the gas industry, including detailed long-term assessments of the ability of the gas industry to deliver more gas reliably.

Gas industry restructuring, including regulatory changes under consideration at the Federal Energy Regulatory Commission, creates further uncertainty in the minds of many. Pipeline companies and power generators are not sure how the restructuring will impact on their dealings, providing further reason for better cooperation and dialogue.

In the gas vehicles market, technical issues are the key impediments as well as a perception by customers that gas may not be available at low prices in the future. Gas producers, pipelines and local distribution companies (LDCs) want improvements in fuel tanks, emission control and vehicle performance. Customers fear being at the mercy of a regulated monopoly -- the LDC -- for fuel.

For gas cooling, impediments include equipment reliability, the complexity of gas cooling technologies, and the need for greater attention to customer needs by LDCs, including integrated heating and cooling services. Many LDCs continue to regard themselves as selling a commodity rather than a service.

IMPLICATIONS FOR THE GAS INDUSTRY

To overcome these serious impediments to capturing new markets, the natural gas industry should consider two types of initiatives: first, generic -- or horizontal -- actions that the industry needs to take to assure removal of impediments to all three new markets; and second, a vertical initiative, aimed at the power generation sector, specifically.

Taking Generic Actions

- Developing collaborative market strategies.

  Current gas industry activities to capture a new market reflect how each industry segment views the potential of that market in light of its own interests and abilities. Gas companies from each industry segment support initiatives to develop gas use in markets where they see clear benefits. But producers, pipelines, and LDCs need to work together to address industry-wide market issues.

  The gas industry needs to coordinate the marketing efforts of the Natural Gas Vehicle Coalition, the American Gas Cooling Center, and the INGAA Power Generation Task Force with the technology advancements of equipment manufacturers, the Gas Research Institute and the Department of Energy. The industry should tap the resources of these groups and establish a program within an organization such as the newly established Natural Gas Council to develop strategies to overcome generic impediments to new market development in power generation, NGV and gas cooling markets.

This program should have a limited life and a capped budget, with specific goals to target the impediments described in this report. Among them:

- Demonstration and commercialization efforts to bring R&D products to market and disseminate information about new technologies.
- Public relations initiatives to overcome customer perception problems and deal with legislative and regulatory impediments.
- Workshops, conferences and forums to help the gas industry understand the impediments and to promote communications between the gas industry and its ultimate customers.

- Adjusting RD&D and Commercialization Priorities.

  The power generation market holds the largest opportunity for the gas industry and needs funding for commercialization. Also, NGV and gas cooling markets need substantial RD&D and commercialization funding, beyond current levels, to ensure that government and industry investments in these markets pay off. Long-term, high risk R&D, funded by the Department of Energy, is also necessary to give natural gas an opportunity to continue to offer consumers innovative solutions to their energy needs.

- Linking regulatory issues to customer needs.

  If the gas industry is truly entering a more competitive era, it will have to shift its attention from the concerns of regulators to the concerns of its customers. The gas industry should sponsor forums where federal and state regulators can discuss fundamental regulatory objectives with gas company representatives and their customers. This would provide regulators with the concerns of customer groups -- power generators, NGV owners and owners of gas cooling equipment -- outside the formal regulatory proceedings.

Capturing the Power Generation Market

To capture more power generation market opportunities, the industry should take four near-term actions:

- Address natural gas reliability. The different segments of the industry must work together to provide objective information on the gas industry's ability to meet projected loads, especially power generation swings, and recommend ways to reduce or eliminate curtailment risks.

- Study and understand emerging electric utility regulatory developments such as demand-side management, integrated resource planning and competitive bidding, to assure that the gas industry can take full advantage of the market opportunities these developments present.

- Offer technical assistance and institutional support for those marketing gas to electric utilities. In particular, the gas industry must understand how state regulators deal with gas price issues when comparing generating alternatives.

- Put greater resources into state-level programs to influence decisions by state regulatory agencies. Gas companies must coordinate their legislative and regulatory efforts more effectively, particularly before environmental agencies, so that the industry is well represented in state and local proceedings.

We found many companies in the gas industry that are pursuing the new and expanding gas markets of power generation, NGVs and gas cooling, as part of their own strategic plans. The analysis contained in this report is based on direct inputs from producers, interstate pipelines, local distribution companies, electric utilities and research organizations. Those interviewed shared their experience and concerns. The interviews formed the basis of our analysis and determined the extent to which a particular issue or problem was identified in this study as an impediment to new gas markets.

REPORT STRUCTURE

In Chapter 1 we describe the four new gas markets examined in this study, their current demand levels, and their projected level of demand growth through the year 2000. In Chapter 2 we present a conceptual framework for classifying and discussing the various impediments to uses of natural gas in these new markets, and provide a detailed comparison of the viewpoints of producers, pipelines, and local distribution companies concerning these impediments. In Chapter 3 we describe the actions that companies in the gas industry are taking to capture new markets and outline the activities of various gas industry organizations that are active in power generation, NGV and gas cooling markets. Finally, in Chapter 4, we analyze the implications of our assessment and present our recommendations to the INGAA Foundation.

Appendix A is the list of questions that we used as a guide during our interviews. Appendix B lists the organizations which we contacted for this study. Appendix C is a compilation of several statistical tables that detail the data used for the projections discussed in Chapter 1. Finally, Appendix D contains a discussion of the sensitivity of new gas markets to wellhead prices and price expectations in support of the findings summarized in Chapter 2.

This study relied on two types of information sources:

- Publications including topical periodicals and reports, market and R&D program descriptions, and legislative and regulatory documentation.

- Interviews with senior managers of producers, pipelines, local distribution companies, electric utilities, as well as experts at gas industry trade associations and RD&D centers, the Edison Electric Institute, and other trade associations. Most of these interviews were conducted in person.

CHAPTER 1: NEW MARKETS FOR NATURAL GAS

While U.S. gas consumption dropped by nearly 27% between 1972 and 1986, coal and electricity consumption has grown substantially. Natural gas consumption has, however, started to recover over the last five years, and the industry is placing its hopes on expanding "new" markets capable of fueling some demand growth. Power generation contributed to the recent rebound of gas consumption, while natural gas vehicles (NGVs), gas cooling, and selected industrial markets all offer growth opportunities.

In this chapter, we first review the attractiveness of these four new markets; next, we characterize their current level of gas consumption; and finally, we discuss how these new markets could grow by 2000.

Our analysis shows that the power generation sector is by far the largest opportunity. Annual gas demand in this sector will increase between 1.5 Tcf and 3.6 Tcf by 2000 in order to address the growing needs of both utilities and non-utility generators (NUGs). *Clearly such a potential increase in demand requires that the gas industry focus its attention onto the power generation market.* The next two markets -- NGVs and gas cooling -- are attractive to the gas industry but their combined demand is not expected to increase by more than 600 Bcf by 2000. Finally, we found that, in the industrial sector, the focus will remain on the prevention of any further erosion of gas market share. Although there may be promising market niches, the industrial sector as a whole does not appear to offer a new market for gas. We therefore do not deal much with that fourth sector in this study; further study would be needed to evaluate the potential of the best industrial market niches.

THE ATTRACTIVENESS OF NEW MARKETS

In the mid-1970s natural gas was regarded by many observers as a "premium fuel" that was so scarce that the federal government had an obligation to restrain gas demand.[1] In particular, the Powerplant and Industrial Fuel Use Act of 1978 imposed restraints on gas demand in the power generation market.

---

1 For a critique of the "premium fuel" concept, see Arlon R. Tussing and Connie C. Barlow, The Natural Gas Industry: Evolution, Structure, and Economics (Cambridge, MA: Ballinger, 1984), pp. 159-160.

As a result of this and other factors, natural gas consumption in the United States reached a peak of 22.1 Tcf in 1972, showed no growth in 1973, and then began to decline, reaching a low of 16.2 Tcf in 1986.[2] While annual consumption has recovered from the 1986 level, consumption in 1990 was only 18.7 Tcf and consumption for 1991 is expected to be slightly higher.[3] Over that same time period, U.S. coal consumption rose 58 percent (on a Btu basis) and electricity consumption rose 70 percent. In fact, electricity consumption has grown in every year in the last four decades except 1982. Even petroleum consumption is above its 1972 level, despite the sharp decline that occurred between 1978 and 1983.[4]

Not surprisingly, many companies in the gas industry would like to see gas demand grow. Natural gas producers consider demand growth desirable because it should result in higher wellhead prices. Natural gas pipelines and distribution companies also welcome demand growth because it creates attractive opportunities to invest in capacity expansion projects and/or improve the capacity utilization of their existing assets.

The growth of any one market is not, by itself, necessarily desirable. A large portion of the firm load of the U.S. gas industry is weather-sensitive and therefore exhibits a low load factor, meaning that the capacity in place is fully used a small portion of the year (e.g., 25% or 35%). If the gas business were simply a "cost-plus" business similar to local telephone or cable TV service, pipelines and LDCs (and even producers) could recover their costs by simply allocating fixed costs to peak load and allocating peak load to firm customers. The fact that gas consumption fell 15 percent from 1972 to 1990, while electricity consumption grew 70 percent is an indication that the gas industry cannot simply shift all its fixed costs to firm customers and expect load growth to be sustained. A low load factor on the gas system makes gas less competitive with oil, coal and electricity.

To enhance its competitive posture, the gas industry must therefore seek to build on its current demand by pursuing and investing in new markets that can be economically attractive because they offer three important characteristics:

1) *A high load factor* resulting from adding new firm customers. Such customer additions can raise the overall system load factor.

---

2 U.S. Department of Energy, Energy Information Administration, Annual Energy Review 1990, DOE/EIA-0384(90), p. 173.

3 Final statistics for 1991 were not yet released by the Energy Information Administration at the time this report was prepared.

4 Annual Energy Review 1990, pp. 11, 117, 185, 205.

2) *An off-peak seasonal load.* The new customers add off-peak seasonal load without adding to peak load and make some contribution to the fixed costs of the transmission and distribution system and the capital cost of the production system (i.e., gas wells and gathering lines).

3) *A high-margin service business.* As with many other industries, the commodity gas business can be combined with a customer service business that yields high margins and thereby covers the cost of adding low load factor customers to the system. This is analogous to what the U.S. Postal Service does when it offers express services in addition to the rural delivery of its first-class mail.

When these conditions are met, the expected "payback" of each new market then depends on the firmness and duration of customer commitment. If the market segment offers only interruptible load, it may offer a desirable contribution to load growth but it will not be worth heavy investments in research, development and demonstration (RD&D) or commercialization to obtain such a limited customer commitment. If, however, a new market segment offers the chance to acquire customers who will contribute to firm load for 20 years, it will be easier to commit corporate resources to this market. The stronger and the longer the customer commitment, the more incentive there is to justify not only new investments but also new RD&D and commercialization programs aimed at stimulating gas demand growth in these markets.

Gas suppliers must also consider how their markets fit together. For example, a new market can complement less attractive uses such as residual fuel oil displacement or peaking service:

1) <u>Residual fuel displacement</u>. At today's oil prices, gas that displaces high-sulfur No. 6 fuel oil (or low-sulfur No. 6 oil in markets that are far from gas supply areas) offers a low netback to the producer and a small contribution to the fixed costs of the transmission and distribution system. The dual-fuel market is a low-margin business with minimal customer service and no customer allegiance. Demand growth in this segment is not terribly attractive. However, many dual-fuel capable customers eventually develop requirements for firm service and look to gas to meet these needs. There is also the potential for natural gas to displace fuel oil due to environmental restrictions on the burning of fuel oil for power generation. Thus, the use of interruptible gas service can offer its own advantages, or complement firm load.

2) <u>Peaking service for electric utilities</u>. Where electric loads exhibit a "needle peak," or sharp increase in electricity usage, the least-cost resource may be some form of peak-shaving program or demand-side management that uses natural gas for cooling or cogeneration rather than gas-fired combustion

turbines. The use of combustion turbines to shift the needle peak from the electric system to the gas system is not necessarily an attractive business proposition for the producer, pipeline, or local distribution company (LDC). Gas demand growth in the combustion-turbine market is likely to be desirable when the gas system has underutilized peak day deliverability, e.g., when an LDC has large storage capacity and experiences a summer peak that is significantly lower than its winter peak.

FOUR NEW GAS MARKETS

In this study we focus on four market segments, which we will call "new markets" for gas even though they are not entirely new:

- *The power sector*
- *Natural Gas Vehicles* (NGVs)
- *Gas cooling*
- Selected *industrial end uses*

As shown on Exhibit 1.1, each new market can be further segmented between several market opportunities, each one involving its own competitors:

- The power sector includes opportunities for gas firing in power plants owned by both utilities and non-utility generators (NUGs):

  - Opportunities in utility power plants include the construction of new combustion turbines; new baseload gas-fired combined cycles (with or without No. 2 fuel oil back-up; designed for conversion to coal gasification or not); repowering projects; and select gas use and co-firing opportunities arising from the new Clean Air Act regulations.

    In utility power applications, the leading competitor is coal. Gas, however, has the potential to take advantage of environmental concerns about coal. In addition, gas-fired utility power plants compete with renewable energy in baseload applications and with No. 2 fuel oil, hydropower, and pumped storage in peaking applications.

  - Opportunities in non-utility generation plants result from the passage in 1978 of the Public Utility Regulatory Policies Act, which stipulated that non-utility organizations could, under certain conditions, build and own power plants without being regulated.[5] One type of unregulated "qualified

[5] PURPA also said that utilities could own up to 50% of any QF.

Exhibit 1.1
Energy Supplies That Compete With Gas in New Markets

	Competing Energy Supplies				
Type of New Market	Coal	Electricity	Petroleum products	Renewables & hydro	Energy conservation
Power sector					
Electric utility generation					
New baseload combined cycle					
Gas CC with No. 2 oil backup	X			X	
Gas CC without No. 2 oil backup	X			X	
CC designed for IGCC upgrade	X			X	
New combustion turbines			X	X	
Clean Air Act driven					
Repowering	X				
Select gas use	X				
Basic co–firing	X				
Co–firing with reburn	X				
Co–firing w/ sorbent injection	X				
Non–Utility Generation					
Large cogeneration QFs	X				
Small cogeneration QFs			X	X	
Independent Power Plants					
New baseload combined cycle	X				
New combustion turbines			X		

Source: RCG/Hagler, Bailly, Inc.

Note: CC= Combined Cycle; IGCC= Integrated Gasifier Combined Cycle; QF= Qualifying Facility.

Exhibit 1.1 (continued)
Energy Supplies That Compete With Gas in New Markets

	Competing Energy Supplies				
Type of New Market	Coal	Electricity	Petroleum products	Renewables & hydro	Energy conservation
Natural Gas Vehicles					
Automobiles and small trucks					
Commercial fleets		X	X		
Personal vehicles		X	X		
Buses and large trucks		X	X		
Gas cooling					
Gas–fired air conditioning					
Commercial/industrial		X			X
Residential		X			X
Gas–fired heat pumps		X			X
Industrial end uses					
Feedstock applications					
Industrial boiler applications	X		X		
Process heat applications	X	X	X		X

Source: RCG/Hagler, Bailly, Inc.

***Note:** CC= Combined Cycle; IGCC= Integrated Gasifier Combined Cycle; QF= Qualifying Facility.*

facility" (QF) involves gas-fired cogeneration projects of all sizes as long as they produce at least 5% of useful thermal energy (in the form of steam or process heat). These cogeneration projects can use either gas turbines equipped with waste heat recovery boilers to produce the necessary steam or combined cycles (i.e., the combination of a gas turbine and a steam turbine).

In addition, some gas-fired power-only plants can be unregulated if they have received special exemptions from the Public Utility Holding Company Act (PUHCA), which defines what type of power generation facilities are regulated. These exempted projects are called Independent Power Projects (IPPs). More of these IPPs can be expected to be built if PUHCA reform legislation, currently under consideration, is passed by Congress. One proposed amendment to PUHCA would allow exempt wholesale generators (EWGs) to own and operate generating facilities (all types, all sizes, all fuels) that are not rate-based. These EWGs would sell electric power to public utilities at wholesale without becoming subject to regulation as electric utilities or public utility holding companies. Such an amendment would open the door to large gas-fired power-only IPPs.

In non-utility applications, gas will compete with coal in large cogeneration QF projects and baseload IPPs; gas will compete with petroleum products in large peaking IPPs; and gas will compete with renewable projects in small cogeneration applications.

- NGVs include personal automobiles and small trucks, buses and large trucks, and commercial fleets. In the NGV market, gas competes with electricity and with reformulated gasoline (and methanol, which is produced from natural gas and butane).

- Gas cooling includes both gas-fired air conditioning for residential, commercial, institutional and industrial buildings and gas-fired heat pumps. In space conditioning applications, gas competes with electricity and with energy conservation alternatives. In some of the newer, well-insulated commercial buildings, the need for a furnace has been totally eliminated by energy conservation alternatives. The space conditioning load may be picked up by lights, computers, and machines that release heat as a byproduct of the use of electricity.

- Finally, industrial end uses include feedstock applications, industrial boiler applications, and process heat applications. Gas competes with oil and coal in industrial boiler plants. In process heat applications, gas competes with all energy sources (coal, oil, electricity) and, in some cases, with other energy conservation techniques which can strengthen the competitive position of electricity.

In most applications natural gas is merely a substitute for another energy source or energy conservation alternative. While there are applications in which the unique qualities of gas make it a premium fuel (e.g., in glass-blowing), these applications represent only a fraction of the total gas demand. Where gas is a petrochemical feedstock, the price that a U.S. industrial consumer can afford to pay is limited by the competitive nature of international petrochemical markets. In 1990, nonfuel consumption of gas was only 3 percent of total consumption. To maintain consumption at the 1990 level or at higher levels, therefore, natural gas will have to be economically competitive with other energy sources and with energy conservation alternatives.

Three of the four new markets meet our criteria for economically attractive new markets, as shown on Exhibit 1.2, where we evaluate each market (and its subsegments) in terms of both market attractiveness and customer commitment. High-volume opportunities exist in the power generation sector that can offer high load factors (baseload plants) or off-peak seasonal load (Clean-Air-Act driven applications), while NGVs and gas cooling customers generally offer firm commitments. For example, gas cooling can result in high-margin firm loads generating in some cases 25% to 50% more in revenues than it costs to provide.

One reason for the attractiveness of the NGV market and the gas cooling market is the fact that both market segments do not involve residual fuel displacement or peaking service.

The industrial sector is a collection of many different consuming applications involving different technologies where the competitive position of natural gas varies substantially. An assessment of the impediments for each end use application was beyond the scope of this study. However, the industrial market is a key to gas industry future stability and should definitely be included in future market studies.

CURRENT SIZE OF NEW GAS MARKETS

To put the market potential for natural gas in perspective, it is useful to measure the share of total primary energy already captured by natural gas in each of the sectors addressed in this analysis: power generation, transportation, cooling and industrial uses.

In the power generation sector -- which includes utilities and NUGs -- total gas consumption was 4.0 Tcf out of a total power generation energy consumption equivalent to 33 Tcf.[6]

---

[6] Calculated as the consumption needed to match the total generation capability of 666 GW of utility-owned capacity and 43 GW of NUG-owned capacity. Calculation based on an assumed average heat rate of 9,000 Btu/kWh.

Exhibit 1.2
Characterization of New Markets for Gas

Type of New Market	Market Attractiveness: Increased volume only	High load factor	Off-peak seasonal load	High-margin service business	Customer commitment: Firm, >= 10y	Firm, < 10y	Seasonal or Interruptible
Power sector							
Electric utility generation							
New baseload combined cycle							
Gas CC with No. 2 oil backup		X			X		X
Gas CC without No. 2 oil backup		X			X		
CC designed for IGCC upgrade		X				X	
New combustion turbines	X *						X
Clean Air Act driven							
Repowering		X			X		
Select gas use			X				X
Basic co-firing			X				X
Co-firing with reburn			X				X
Co-firing w/ sorbent injection			X				X
Non-Utility Generation							
Large cogeneration QFs		X			X		
Small cogeneration QFs	X			X	X		
Independent Power Plants							
New baseload combined cycle		X			X		
New combustion turbines	X *						X

***Note:** CC= Combined Cycle; IGCC= Integrated Gasifier Combined Cycle; QF= Qualifying Facility.*

** Some potential customers could have such a low load factor that the gas industry would find the market opportunity unattractive.*

Source: RCG/Hagler, Bailly, Inc.

Exhibit 1.2 (continued)
Characterization of New Markets for Gas

Type of New Market	Market Attractiveness: Increased volume only	High load factor	Off-peak seasonal load	High-margin service business	Customer commitment: Firm, >= 10y	Firm, < 10y	Interruptible
Natural Gas Vehicles							
Automobiles and small trucks							
Commercial fleets		X				X	
Personal vehicles		X		X		X	
Buses and large trucks		X				X	
Gas cooling							
Gas-fired air conditioning							
Commercial/industrial			X	X	X		
Residential			X	X	X		
Gas-fired heat pumps		X		X	X		
Industrial end uses							
Feedstock applications		X				X	
Industrial boiler applications		X					X
Process heat applications		X				X	

Source: RCG/Hagler, Bailly, Inc.

However, the share of gas consumption was much lower in the electric utility sector than it was in the NUG sector.

In the electric utility sector, the size of the market was 28.7 Tcf equivalent in 1990 and the market share of natural gas was 9.7 percent.[7] If the total market grows only a few percentage points per year during the 1990s, but the growth is captured largely by natural gas, a high annual percentage increase in gas use in this sector becomes possible. Because the market for energy input to electric utilities is 90.3 percent dominated by competing sources of energy, however, the competitive position of gas is not easily assured.

Another way to measure the natural gas share of the electric utility market is in terms of generating capacity. Total U.S. utility-owned generating capacity in the summer of 1990 was 666,935 MW, of which 56,029 MW was gas-fired and 70,065 MW was dual fuel (oil/gas).[8] Gas has a market share of 8.4 percent when dual-fuel capacity is excluded and 18.9 percent when dual-fuel capacity is included. Combustion turbines represented 15 percent of the gas-fired capacity and 16 percent of the dual-fuel capacity.

In comparison, the gas industry's peak-day demand in December 1989 was 104 Bcf/d.[9] What these numbers suggest is that if the electric capacity additions in the 1990s were primarily gas-fired, a modest annual percentage growth in the electric utility system's peak day capacity could result in a large percentage annual growth in the gas industry's peak day deliverability. Although a high level of dependence on natural gas for capacity additions is unlikely to develop on a national basis, it could develop in a few states or regions.

---

[7] This calculation is based on total energy input of 29.6 quadrillion Btu, reported in U.S. Dept. of Energy, EIA, Monthly Energy Review: September 1991, DOE/EIA-0035(91/09), p. 33. At page 149 of this document the "electric utility sector" is defined as "privately and publicly owned establishments that generate electricity primarily for use by the public" and there is a comment that "An entity that solely operates qualifying facilities under the Public Utility Regulatory Policies Act of 1978 is not considered an electric utility." We assume that cogeneration is excluded from the 29.595 quad figure but independent power plants are included.

[8] These capacity figures are all taken from North American Electric Reliability Council, Electricity Supply & Demand 1991-2000 (July 1991), pp. 19, 32-39. In addition to the utility-owned 666,935 MW there is 18,156 MW of non-utility generation (NUG) capacity dedicated to meeting the electric utility system summer peak.

[9] U.S. Department of Energy, EIA, Natural Gas Productive Capacity for the Lower 48 States: 1980 through 1991, DOE/EIA-0542 (January 1991), p. 9. The coincident peak day capacity of the interstate natural gas pipelines is substantially below the peak capacity of the gas industry as a whole.

In the NUG sector -- which includes both cogeneration and IPP plants -- natural gas has captured a high market share, about 1.15 Tcf out of a total demand of 1.38 Tcf equivalent. GRI estimates that the total amount of coal, oil and natural gas consumed in industrial cogeneration in 1990 was 1.20 Tcf, of which gas represented 0.96 Tcf or 80 percent. To date, there are over 1,600 industrial cogeneration projects, with a combined capacity of 31,650 MW.[10] The market share of natural gas in commercial cogeneration in 1990 was estimated at over 90 percent, with a gas consumption of 0.19 Tcf.

In the transportation sector, gas is used as pipeline fuel and in natural gas vehicles. If we exclude natural gas used as pipeline compressor fuel, the market share of natural gas in the transportation sector in 1990 was minuscule - less than 4 trillion Btu out of a total of 21,570 trillion Btu.[11] The size of the transportation market, excluding gas used as pipeline fuel, was 20.9 Tcf equivalent in 1990.[12] If we exclude jet fuel, aviation gasoline, and electricity, the transportation market was 17.9 Tcf equivalent in 1990 and the market share of gas was only 3.5 Bcf, or 0.02 percent. Because natural gas begins with such a small market share, a very high annual percentage increase is conceivable in the future.

In the cooling market, gas has a small market share, with a total annual consumption currently estimated at less than 60 Bcf. In 1990, 26.5 trillion Btu of gas was used for cooling while 440 trillion Btu of electricity was used for space cooling. In the commercial sector in 1990, 34.2 trillion Btu of gas was used for cooling while 666 trillion Btu of electricity was used for space cooling.[13] These figures suggest cooling market shares of 5.7 percent and 4.9 percent, respectively, but a more meaningful measure would be the tonnage of cooling provided; the share of gas cooling tonnage is probably around 3 percent. If 2 Btus of gas is needed to displace a Btu of electricity, the size of the residential and commercial space cooling market is roughly 2.2 Tcf equivalent. The small size of this energy market relative to the electric utility sector is offset, to some degree, by the fact that the operating lifetime of an air conditioner is typically shorter

---

[10] Source: RCG/Hagler, Bailly, Inc. Independent Power Data Base.

[11] The level of gas use in methane vehicles is shown in Gas Research Institute, Baseline Projection Data Book: 1991 Edition of the GRI Baseline Projection of Energy Supply and Demand to 2010, p. 343. Total energy consumption in the transportation sector is shown in U.S. Department of Energy, EIA, Monthly Energy Review: September 1991, DOE/EIA-0035(91/09), p. 31.

[12] A conversion factor of 1034 Btu/cf may be assumed for electric utility consumption and 1030 Btu/cf may be assumed for other consumption. See U.S. Department of Energy, EIA, Annual Energy Review 1990, DOE/EIA-0384(90), p. 294.

[13] We exclude 4.3 trillion Btu of cooling obtained from gas-fired cogeneration. The gas cooling market includes gas-fired appliances but excludes electric appliances supplied with electricity from gas-fired cogeneration.

than that of a power plant. If new gas-fired appliances could capture both "new customer" markets and replacement markets, gas cooling could show a high annual percentage growth in the 1990s. Nevertheless it is clear that in terms of energy consumption the total cooling market is much smaller than either the electric generation or transportation market.

In the industrial sector, the total demand for gas was estimated at 6.97 Tcf in 1990: 17% for feedstock; 32% for industrial boiler use; and 51% for process heat.

PROJECTED NEW MARKET SIZES

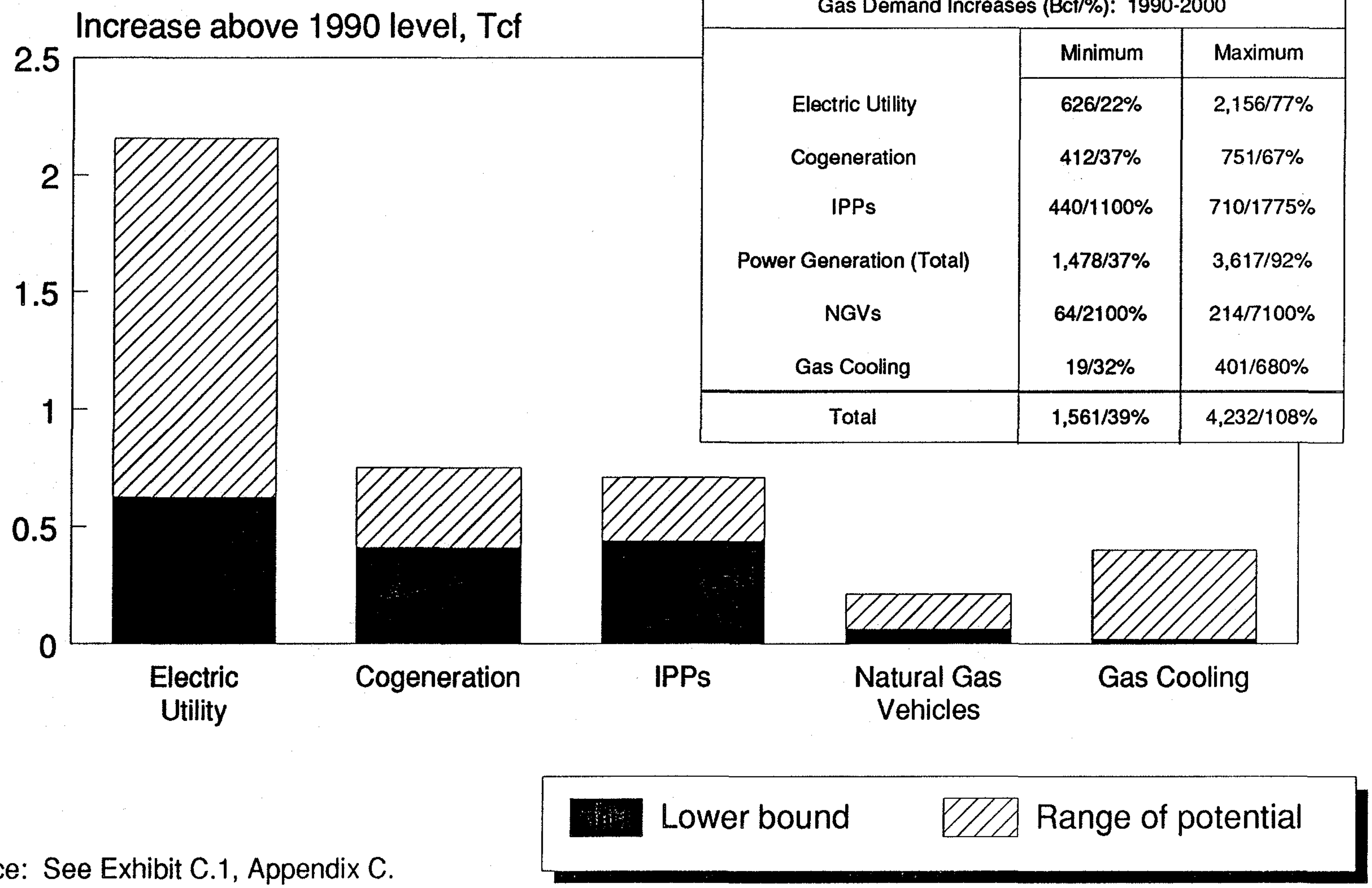
For this effort, we reviewed the range of gas volume projections issued for the 1990-2010 time frame by various organizations: the Energy Information Administration of the U.S. Department of Energy, the National Electric Reliability Council (NERC), the American Gas Association, the Gas Research Institute, Enron, and National Economic Research Associates (NERA). The development of independent estimates of deliverability and capacity requirements was beyond the scope of this study. Using data from various sources, we have estimated, for each new market, the lower and upper bounds of annual gas consumption increases between 1990 and 2000, without attaching specific probabilities to either one.

The results of our analysis -- summarized in Exhibit 1.3 -- show a potential increase between 1.6 Tcf and 4.2 Tcf, that is, between a 39% increase and a doubling of current demand in three of the four markets: power generation, NGVs, and gas cooling. On the basis of total annual volumes, it is also clear that between 85% and 95% of the growth in the 1990s in new markets is likely to be in the power sector.

The ranking of market opportunities - electric utility, cogeneration, independent power plant, NGVs, and gas cooling - is almost the same for upper bounds as for lower bounds. When lower bounds are used, gas cooling changes from a growth market that is roughly comparable to the NGV market to a small and insignificant growth market. Because gas has already demonstrated its ability to capture a large share (in fact, a dominant share) of the cogeneration market, the upper and lower bounds for gas cogeneration growth are relatively close. In contrast, IPPs appear to be the fastest growing market in either the lower or the upper case, since the expected amendment of PUHCA should create the demand for 5,000 MW to 9,000 MW of new gas-fired IPPs by 2000.

The largest divergence of opinion is found in the electric utility sector, where projections range widely, as shown in Exhibit 1.4. A striking aspect is that the federal government's projections (represented by DOE/EIA) are much higher than the utility industry's NERC projection. The range of opinion among other forecasters is illustrated by the difference between the Enron projection for power generation in 2005, excluding cogeneration

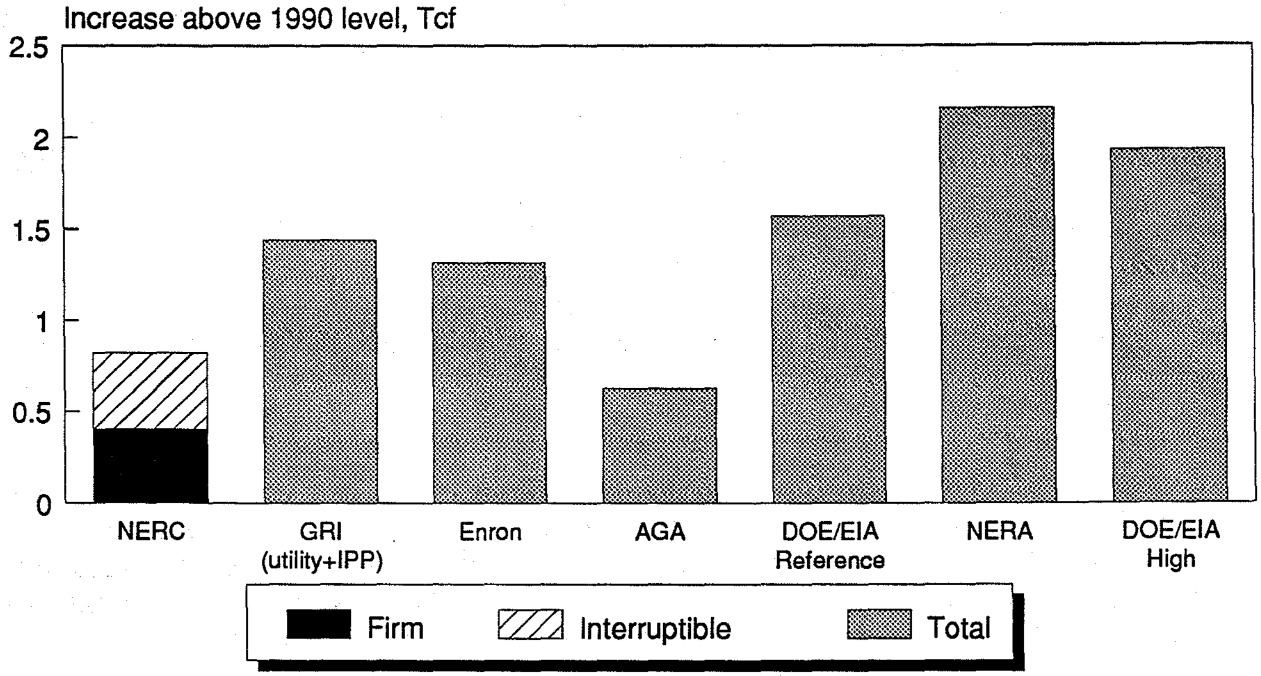
Exhibit 1.3
Potential Growth in Annual Volume of Natural Gas Used by New Markets (1990-2000)

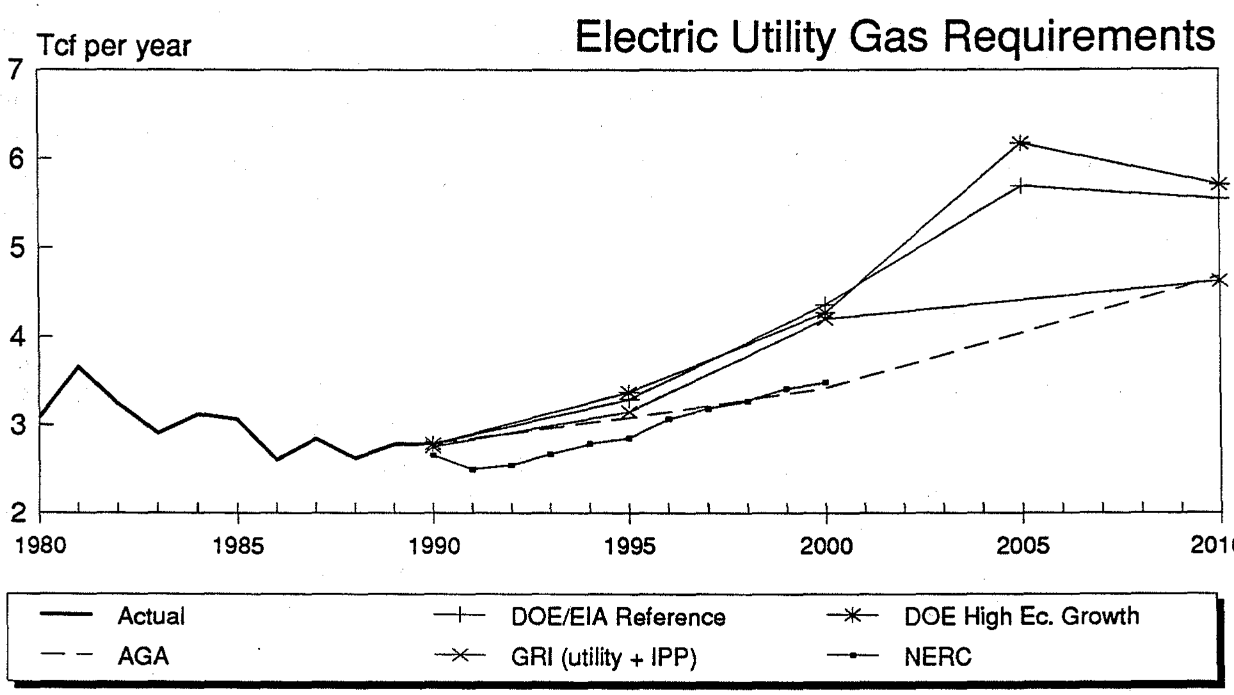


Gas Demand Increases (Bcf/%): 1990-2000		
	Minimum	Maximum
Electric Utility	626/22%	2,156/77%
Cogeneration	412/37%	751/67%
IPPs	440/1100%	710/1775%
Power Generation (Total)	1,478/37%	3,617/92%
NGVs	64/2100%	214/7100%
Gas Cooling	19/32%	401/680%
Total	1,561/39%	4,232/108%

Source: See Exhibit C.1, Appendix C.

Exhibit 1.4
Growth in Gas Use by Electric Utilities
1990-2000





Source: See Exhibit C.1 in Appendix C.

(about 3.8 Tcf), and the NERA projection for "electric utilities" in 2005 (7.4 Tcf). In fact, the NERA figure is substantially higher than Enron's projection of total powerplant demand including cogeneration (5.1 Tcf by 2005). There is also a difference of opinion regarding the trend between 2005 and 2010: the DOE/EIA projections show declining gas use while the AGA projection shows increasing gas use during that period.

From a pipeline perspective the NERC projections are particularly interesting because they distinguish firm and interruptible gas demand (see Exhibit 1.5). These projections of annual consumption do not suggest that there will be a significant shift away from interruptible service toward firm service. However, it is quite possible that a projection of peak day requirements would show a significant 10-year increase in requirements for firm gas deliverability. The extent to which electric utilities will rely on gas to meet the summer peak may be affected by environmental standards that constrain the utilities' ability to burn oil. The NERC projections show growth in dual-fuel capacity over the decade.[14]

In contrast, the issue of peak deliverability and capacity is far less critical for NGV and gas cooling markets than it can be for power generation. NGV use is a "baseload" demand, and NGVs will not exhibit seasonal peaks comparable to the peak associated with heating and cooling loads. Gas cooling is seasonal but it is unlikely to exhibit daily or hourly peaks comparable to combustion turbine loads in the power sector.

In the industrial sector, most projections show either a declining or a stable gas energy use. AGA predicts a 6% decrease while Enron forecasts no change between 1990 and 2000. Other projections by DOE/EIA and GRI -- once they are normalized to exclude cogeneration -- also suggest a stable demand level over the next 10 years. In the 2000-2010 period, the GRI and NERA projections appear to leave room for demand growth (other than in cogeneration), but the DOE projections show a decline in total industrial gas demand.[15]

From the perspective of the gas industry, therefore, the industrial sector (excluding cogeneration) may not be a growth sector over the next decade. While there are new gas technologies that may lead to increases in gas demand in particular industries, the role of new gas technologies in the sector as a whole is to prevent the erosion of gas demand. The strategies developed by the gas industry to maintain the volume of gas deliveries in the industrial sector will be largely motivated by a need to retain customers and retain load rather than opportunities to enter new markets. In this sense the industrial sector does not offer "new markets" for gas, although further study would required to assess the potential for gas use in specific new applications such as blast

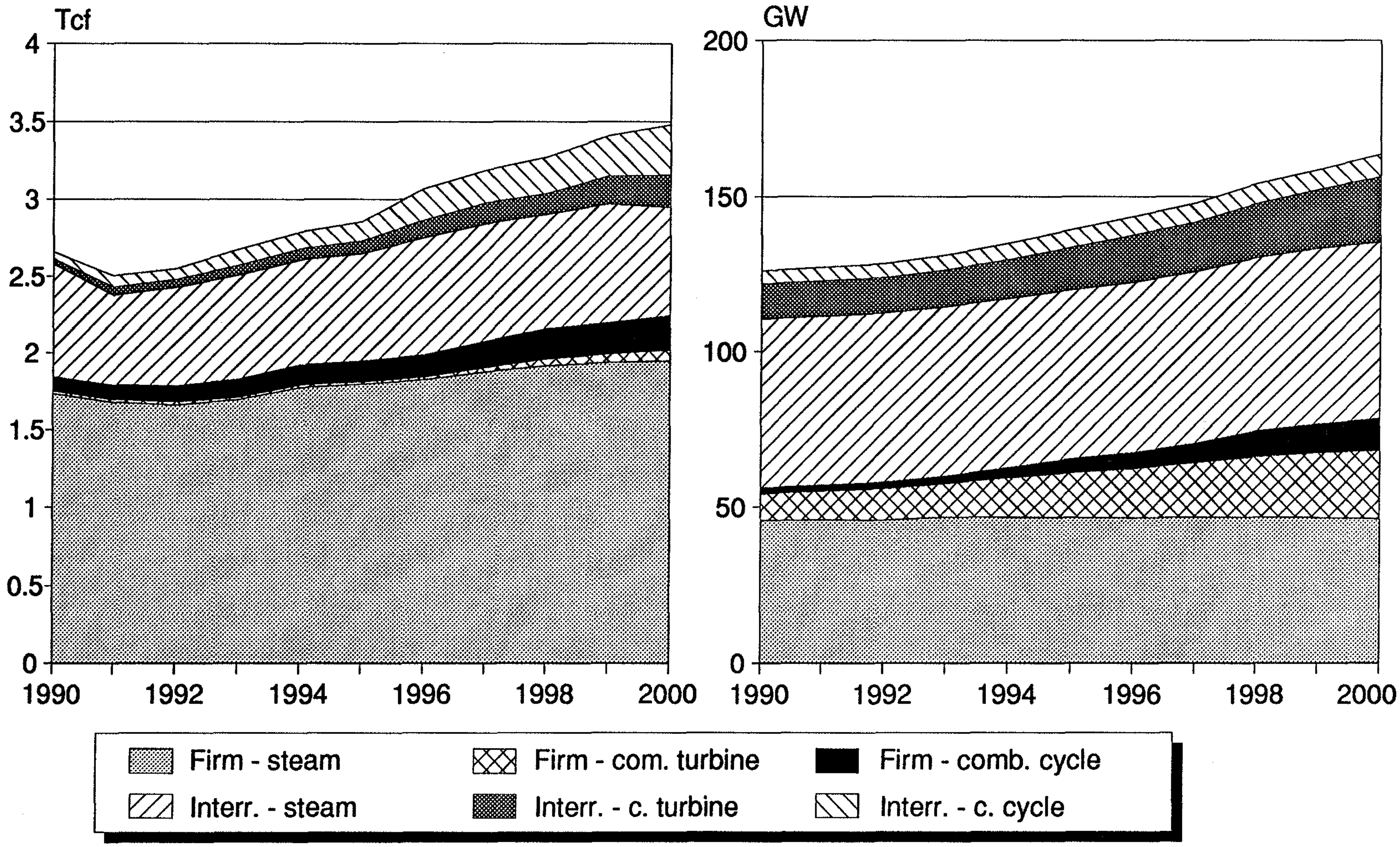
[14] See Exhibits C.3 and C.4 in Appendix C.

[15] See Exhibit C.5, Appendix C, for detailed statistics.

Exhibit 1.5
NERC Projections for the U.S. Utility Sector

Gas Needed by Electric Utilities

Electric Utility Gas-Fired Capacity



Source: NERC, "Electric Utility Supply & Demand 1991-2000" (July 1991), pp 32-39, p 80.

furnace injection, waste processing, and other environmentally-driven opportunities to displace coal or oil.

Consequently, we will focus on only three markets -- power generation, NGVs, and gas cooling -- in the following chapter, where we analyze the various types of impediments to each new market.

CHAPTER 2: IMPEDIMENTS TO NEW GAS MARKETS

In this chapter we first present a framework to help classify the different impediments to gas demand growth, and then describe how these impediments can be expected to affect the future growth of natural gas demand in the three new markets that we have focused on: power sector, NGVs, and gas cooling.

Our analysis of these impediments is based on direct inputs from representatives of gas production, interstate pipeline, local distribution companies and electric utilities who were interviewed for this effort. The companies that we contacted are listed in Appendix B. We also present, in each case, our own assessment of the various impediments to gas demand growth that were identified.

A CONCEPTUAL FRAMEWORK FOR CLASSIFYING IMPEDIMENTS

For this effort, we grouped the impediments to the development of new uses for natural gas in the United States into seven categories:

- Economic
- Technical
- Logistical, due to delivery system constraints
- Legislative/regulatory
- Institutional
- Customer perception
- Tax policy related.

Each impediment category is briefly defined and reviewed in a systematic framework outlined in Exhibit 2.1.[1]

For the purpose of this study, we focused on **economic impediments** affecting the competitiveness of gas use under economically-efficient market conditions. We therefore did not consider the impacts caused by market distortions such as economically inefficient regulatory restrictions or misinformation. Generally speaking, economic impediments make natural gas use more expensive than oil, electricity, or other energy sources in specific applications. Some economic impediments, such as oil and coal

[1] That framework was designed to provide an effective and objective method to systematically compare interview responses while being flexible enough to cover a variety of topics and not be strictly limited to a questionnaire compilation.

Exhibit 2.1
Classification of Impediments to Natural Gas Use in New Markets

The following paragraphs define a system for classifying impediments and are not intended to address the question whether these impediments actually exist.

Economic Impediments

Production costs: The projected price of gas supply needed to serve the new market segment is so uncertain or so high that gas is not economically competitive at the point of end use. The cost of supply is measured at the point of delivery to the pipeline. Supplies include conventional domestic supplies, non-conventional sources, pipeline imports and LNG imports. Supply reliability must be sufficient to meet the customer's requirements.

Gas facilities costs: The projected cost of the transmission, storage, and distribution facilities needed to serve the new market segment is so uncertain or so high that gas is not economically competitive. Supply reliability must be sufficient to meet the customer's requirements.

End use equipment costs: Either the projected cost of the customer-owned equipment needed to use gas in the new market segment is so uncertain or so high that gas is not economically competitive, or the reliability of existing technology fails to meet the customer's requirements. Relevant costs include operation and maintenance costs as well as installation costs.

Technical Impediments

Gas resources: New technology is needed to lower the cost of gas supplies (e.g., deepwater OCS supplies). Under existing technology, resources are insufficient to meet the incremental needs associated with the new market segment.

Distribution technology: New technology is needed to extend or modify the distribution system to meet the needs of the new market segment.

Equipment reliability: New technology is needed to meet reliability standards or performance standards set by the customer. (If new technology is needed to meet legislative or regulatory requirements, the impediment is classified as legislative/regulatory.)

Delivery System Impediments

Reliability: For technical and operational reasons, the transmission, storage, and distribution system is either unable to meet peak demands in the new market segment or unable to grow rapidly enough to meet demand growth. These impediments are related to technical limits to gas system operations, not regulatory delays.

Legislative/Regulatory Impediments

Supply: Supply is constrained by legislative or regulatory measures (e.g., environmental standards, permits needed to construct gathering lines or pipelines, state conservation regulation, or price controls). Supply constraints are an impediment to the development of the new market segment.

Source: RCG/Hagler, Bailly, Inc.

Exhibit 2.1 (continued)
Classification of Impediments to Natural Gas Use in New Markets

Legislative/Regulatory Impediments (continued)

Gas operations: The ability of the transmission, storage, and distribution system to meet the needs of the new market segment is constrained by legislative or regulatory measures. For example, pipeline capacity additions are impeded by regulatory delay.

End use: The ability of a customer to purchase or install gas technology in the new market standard is constrained by legislative or regulatory action (e.g., emission standards). For example, existing technology does not meet the regulatory standards.

Institutional Impediments

Long-term contracts: Producers are unable or unwilling to sign long-term contracts under the terms and conditions required by customers in the new market segment. There is a fundamental difference between producer and end user perceptions that creates an impediment to long-term contract negotiation. The problem is not simply the projected cost of supply additions.

Focus on customer needs: The companies in the gas industry perceive gas as a commodity and lose sight of the customer's ultimate objective related to gas use (e.g., space conditioning) and the competitiveness of the customer's alternatives to gas. For example, through marketing programs, companies in the industry try to persuade customers to purchase the type of service that the gas industry wants to sell rather than the type of service the customer wants to buy.

Funding for R&D and commercialization: Federal and state agencies have an institutional bias against gas and in favor of coal, electricity, reformulated gasoline or other competitors to gas.

Industry cooperation: The various segments of the gas industry (producers, intrastate pipelines, interstate pipelines, distribution companies) do not cooperate to serve the needs of the end user. The lack of cooperation cannot be explained simply by the business interests of the parties involved.

Customer Perception Impediments

Long-term supply problems: However the economics of gas supply may be characterized by impartial analysts, the customer perceives a problem. The customer considers long-term supplies to be either inadequate or unavailable under the terms and conditions he requires in the new market segment.

Gas industry reliability: However the capacity and reliability of the transmission, storage, and distribution system may be characterized by impartial analysts, the customer perceives a problem. The customer considers the transmission, storage, and distribution system to be unable or unlikely to meet the customer's reliability standards, particularly during peak periods.

Equipment reliability: However the cost and reliability of gas-fired equipment may be characterized by impartial analysts, the customer perceives a problem. The customer considers gas technology to be uneconomic or unreliable in the new market segment.

Source: RCG/Hagler, Bailly, Inc.

prices, are beyond the control of the gas industry. Other economic impediments might be overcome through new production technologies that lower finding costs or through research and development on gas appliances. Specifically, economic impediments can result from high or uncertain gas production costs, gas facilities costs or end-use gas equipment costs.

Technical impediments also make natural gas less desirable than oil, electricity, or other energy sources in specific applications. At the extreme, some technical impediments are unavoidable and so severe that they make the use of natural gas in a particular application prohibitively expensive or impractical. Often, however, technical impediments may be overcome through RD&D and technology improvements in three areas: gas resources, gas distribution technology and equipment performance and reliability. An example of a technical impediment in gas distribution would be a very low population density (typical of rural areas). At low population densities the cost of natural gas distribution to residential customers will be too high unless the cost of pipeline expansion can be dramatically reduced by a technological breakthrough.

Delivery system impediments are present when the infrastructure for delivery of gas supply and/or gas appliances cannot grow fast enough to keep up with consumer demand. Impediments associated with limits to the rate of increase of gas use can occur, for example, when a sudden change in technology or in fuel prices makes a whole new market open up.

Delivery system impediments are associated with limits to the gas industry's ability to expand capacity. Several categories of capacity expansion could be involved:

- Expansion of wellhead production capacity and gathering systems
- Expansion of interstate pipeline capacity and elimination of capacity bottlenecks
- Upgrading of gas distribution systems to provide the ability to serve power generation equipment and large industrial customers at high delivery pressure
- Expansion of natural gas delivery systems for CNG vehicles
- Expansion of manufacturing capacity for gas appliances or other end use equipment.

Legislative/regulatory impediments create obstacles to natural gas use in situations where natural gas is otherwise competitive with energy sources such as oil and electricity (under market conditions associated with economic efficiency). There are several types of regulatory impediments that can affect gas supply, operations, and end use:

- <u>Environmental regulations</u> can favor coal or oil by not giving a full credit to natural gas for being a cleaner fuel. Regulations may also directly penalize gas and restrict access to gas acreage, limit LNG imports, require reductions in gas compressor station emissions, or divert pipeline cash flow to PCB cleanup and other cleanup operations.

- Federal and state regulatory obstacles to the award of a construction permit and other permits required for new pipeline construction or reopening of an LNG terminal.

- Mechanisms for transition cost recovery that can cause new customers to pay for costs unrelated to their gas use decision. For example, cost pass-through provisions can cause price distortions and ineffective pipeline cost recovery provisions can lead to slow acceptance of market changes. Important cost transition issues will arise from the major restructuring effort contemplated by the recent FERC Order 636 (The Restructuring Rule).[2] That rule calls for the mandatory unbundling of pipeline sales services, equality of transportation services, open storage services, straight fixed-variable rate designs, and new pregranted abandonment rules.

- Increases in business risks associated with constantly changing regulations, changes in rate structure and changes in the allocation of costs to different classes of customers.

- Possible changes to gas laws that can pose higher risks to the returns of pipeline companies (i.e., provisions for increasing pipeline refund exposure when pipelines file new rates, incremental rates, more stringent environmental or pipeline safety laws).

Institutional impediments are obstacles to natural gas use that are associated with the institutional structure of the gas industry and the agencies that regulate the industry. Institutional impediments create real delays as well as biases and perceptions among key decision-makers that make it difficult for industry groups (or industry and government) to work together effectively to serve the needs of the gas industry's ultimate customers. The impact of institutional impediments cannot be quantified as easily as the impact of economic or technical impediments.

Institutional impediments do not tend to fall into general categories. For the purpose of this study, four problem areas are explored: long-term contracts, focus on customer needs, funding for R&D and commercialization, and industry cooperation.

Customer perceptions can be impediments to natural gas use and arise when the ultimate customer perceives a problem but there is no clear-cut evidence that the

---

[2] Order 636, *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations*, 57 Fed. Reg. at 13267 (April 16, 1992).

impediment falls in one of the categories above. For example, consumers may have negative impressions regarding future gas prices, gas supply reliability, gas equipment reliability, or the cost of operating and maintaining gas equipment. If the customer is misinformed, or if there is some question about the accuracy of the customer's understanding, the problem may be classified as a customer perception impediment rather than an economic, technical, legislative/regulatory, or institutional impediment. For the purpose of our analysis, we analyzed three types of customer perception impediments related to long-term supply problems, gas service reliability, and gas equipment reliability.

Tax policy can make natural gas less competitive with oil and other energy sources. Changes in tax policy can create impediments as well as incentives for gas use. Thus a distinction must be made between tax changes that actually penalize gas supply or consumption, and create impediments to gas use, and tax policy changes that remove an artificial stimulus to gas production or consumption. For example, some gas producers argue that certain provisions of the Alternative Minimum Tax (AMT) disadvantage the domestic oil and gas industry in competition with other U.S. industries and industries abroad for capital investment. On the other hand, the elimination of special IRS provisions for coal seam methane would simply remove a stimulus to gas production.

The results of our initial interviews for this study indicated that tax policy impediments are not likely to be a significant factor affecting gas use in the next decade. We therefore did not elaborate on that last category of impediment in the ensuing discussion.

OVERALL IMPEDIMENT ASSESSMENT

We summarize in Exhibit 2.2 the impediments that affect each of the three new gas markets analyzed in this part of our effort: power generation, NGVs and gas cooling.

In this exhibit, an X indicates a perception that the impediment is serious; a blank indicates either a lack of recognition of a problem or a belief that the impediment can be overcome through "business as usual" R&D, marketing, and public relation activities.

Natural gas economics, the lack of focus on customer needs and end-use regulatory impediments are the three major impediments that affect all three new gas markets. Next, the issue of industry cooperation plays an important role in both the power generation and NGV markets.

While gas deliverability and long-term contracts issues are very important in the power generation market, they have limited impact in the NGV market. Specific impediments to that latter market tend to be related to technical end-use issues and customers' perceptions about the supply of NGV fuel. In the gas cooling markets, specific issues involve technical end-use impediments and RD&D funding impediments.

Exhibit 2.2
Impediments to Increased Gas Use in New Markets

Type of impediment	Power Sector	Natural Gas Vehicles	Gas Cooling
Economic			
Production costs	X		
Gas facilities costs	X	X	
End use equipment costs			X
Technical			
Gas resources			
Distribution technology			
Equipment reliability		X	X
Delivery system/reliability	X		
Legislative/regulatory			
Supply			
Gas operations	X		X
End use	X	X	
Institutional			
Long–term contracts	X		
Focus on customer needs	X	X	X
Funding for R&D and commercialization			X
Industry cooperation	X	X	
Customer Perception			
Long–term supply problems		X	
Gas service reliability	X		
Equipment reliability	X		X

Exhibits 2.3 and 2.4 provide additional information on the perceptions of producers, interstate pipelines, local distribution companies, and electric utilities in each of the three new markets.

Source: RCG/Hagler, Bailly, Inc.

In the following, we discuss each new market more specifically, using the framework presented at the beginning of this chapter.

IMPEDIMENTS TO INCREASED USE OF GAS IN THE POWER SECTOR

In Exhibit 2.3, we summarize how we characterize the impediments to the increased use of gas in the power sector in terms of the perceptions of gas producers, interstate pipeline companies, local distribution companies (LDCs) and electric utilities.

The power sector is characterized by market opportunities in which site-specific evaluation of the economics of natural gas use are made by electric utilities and NUGs rather than by gas producers, pipelines or LDCs. As a result, companies in the gas industry are less familiar with impediments to gas use in power generation than the electric utilities.

In the following pages, we discuss our findings for each impediment category, based on the results of our interviews, supplemented, when deemed appropriate, by our own research.[3]

Economic impediments

Production Costs. Electric utilities are concerned about the potential for large increases in the cost of delivered-to-pipeline supplies over the next 20 to 30 years. For this reason, the price of gas supply is perceived to be an impediment to increased gas use in the power sector. Because spot gas prices are at a relatively low level today, this impediment is much more important for firm long-term commitments than for interruptible requirements. Electric utilities do not seem to want to make a major commitment to rely on a fuel that they perceive is going to command a premium price in the future. The reluctance of gas producers to sign long-term contracts with escalators similar to coal contract escalators only increases this concern.

Expectations about the price of gas at the wellhead is an impediment where a long-term customer commitment is required. The market segments in the power sector may be grouped into three categories, with regard to length of customer commitment:

- A firm, long-term commitment to gas is required for new gas-fired baseload utility or NUG combined cycle plants, with or without No. 2 oil backup. Utilities that desire to own such plants are concerned about the long-term (20-year) availability

[3] This section emphasizes new markets for gas in the power sector and does not discuss the current underutilization of existing gas-fired generation capacity. However, this is an application where increased gas use could be significant.

Exhibit 2.3
Impediments to Increased Gas Use in the Power Sector: Differences Among Perceptions

Type of impediment	Producers	Interstate Pipelines	Local Distribution Companies	Electric Utilities	RCG/Hagler, Bailly
Economic					
Production costs				X	X
Gas facilities costs				X	X
End use equipment costs					
Technical					
Gas Resources					
Distribution technology					
Equipment reliability					
Delivery system/reliability			X	X	X
Legislative/regulatory					
Supply					
Gas operations	X	X		X	X
End use	X	X	X	X	X
Institutional					
Long–term contracts	X	X	X	X	X
Focus on customer needs				X	X
Funding for R&D and commercialization		X		X	
Industry cooperation				X	X
Customer Perception					
Long–term supply problems	X	X			
Gas service reliability		X			
Equipment reliability	X	X			X

Source: RCG/Hagler, Bailly, Inc.; based on selected industry interviews.

of gas to supply facilities with startup dates as late as 4-8 years in the future. NUGs are concerned about 15-year availability of gas to supply facilities with startup dates 1 to 3 years in the future. Similar concerns affect utilities that want to repower existing peaking gas turbines by converting them into combined cycles.

- A firm, medium-term commitment to gas is required for new baseload combined cycle plants designed to switch to integrated coal gasification after 5 to 15 years of operation on pipeline-quality gas. Electric utilities are concerned about the availability of gas for the interim period before coal gasification becomes economic.

- Seasonal or interruptible gas use is possible in select gas use and co-firing applications, and in combustion turbines with No. 2 oil backup; seasonal gas use (with emphasis on a summer peak) is characteristic of combustion turbines.

With varying degrees of success and varying degrees of commitment, electric utilities have addressed environmental concerns and have tried to reduce their vulnerability to oil price shocks by investing in energy conservation, renewables and nuclear energy. Many electric utilities still view natural gas as just another fossil fuel, the price of which could, in their opinion, be strongly affected by oil prices. To them, natural gas looks like a "bridge" fuel rather than a long-term solution to the challenges facing the electric utilities. Although it is not exactly clear what is on the other end of the bridge — a focus on conservation and renewables (the "soft energy path") or a focus on coal and nuclear energy — the electric utilities are concerned that gas will eventually price itself out of the power sector.

From a U.S. gas producer's perspective, there is no incentive to increase gas demand in the power sector unless the power sector customer is willing to pay a "market" price, i.e., a price tied to spot prices of natural gas, No. 6 oil, and/or No. 2 oil. Although a producer may regard an increase in U.S. gas consumption as a favorable indicator, a producer's primary interest is in realizing higher prices per Mcf and (if possible) lower costs per Mcf. There is rarely a reason for a producer to think of an electric utility as some sort of preferred customer. Price uncertainty has been a problem since the mid-1970s for long-term contracts signed with electric utilities in Texas, Oklahoma and Louisiana. The gas producer wants to deal with spot customers and with customers who can absorb price risk.

In general, a gas producer does not want to project the competitiveness of gas-fired electric generation with other generating options in the year 2000, or 2010, or beyond. From a producer perspective, such projections are too speculative. Furthermore, the issue is not critical to a producer's success and profitability. For both reasons, many producers did not want to express any opinion to us on whether long-term gas supplies will support a substantial increase in power sector use.

Interstate pipelines tend to look at the recent growth of gas-fired cogeneration, the successful development of independent power plants such as Ocean States Power, and the willingness of California utilities to sign long-term transportation agreements as indications that gas supply economics are no longer a major impediment to natural gas use in the power sector. Some of the recent projections of large growth in electric utility demand, such as NERA's projection of 7.4 Tcf by 2005 or the DOE base case of 4.4 Tcf by 2000, tend to support an optimistic view of the economics of gas use in the power sector.

Our assessment is that electric utilities are correct when they continue to be concerned about the number of years that they will be able to economically justify their fixed costs — their investments in generating capacity, their supply contract commitments, and their contracts for firm transportation. Gas may be very competitive in the startup years of a new combined cycle plant, but it is not clear how it will look in the later years of the plant's life. If gas prices are high in the later years, baseload dispatch will not be possible. Under a worst-case scenario, an electric utility facing high gas prices and an unfriendly regulatory climate could face a take-or-pay problem comparable to the interstate pipeline's take-or-pay problem in the 1980s.

Despite the 1973-1986 decline in gas demand, and despite the long-term trend toward declining use per residential customer and per square foot of commercial space, the gas industry is not accustomed to having a firm customer, such as a combined cycle plant, whose annual throughput requirement may drop dramatically in response to gas price increases. Pipelines are accustomed to dealing with customers whose requirements for firm transportation capacity are rolled over indefinitely rather than reduced or eliminated. If gas is a "bridge" fuel for the power sector, the demands on the gas system will be temporary (e.g., peaking in 2005) and it will be necessary for the gas industry to figure out how to cope with the decline period as well as the growth period.

In some respects, the electric utilities and the gas pipelines face the same problems since they are both regulated energy companies. Being regulated, they are forced to depreciate assets over long time periods (20 to 30 years), and use straight-line depreciation for ratemaking purposes. As companies involved in the energy market, they both are threatened with market erosion from conservation and renewables while regulatory bodies increasingly turn to competition rather than regulation as a method of protecting consumer interests. An unfavorable shift in the competitive position of gas could lead to excess capacity, and it is not clear that regulators will permit the cost of excess capacity to be shifted to the consumer. In this environment it can be risky to make the investments needed to increase gas consumption in the power sector.

The gas industry's success in fueling cogeneration projects should not be taken as an indication that gas will take the lead in electric utility capacity expansion projects. The economics of gas-fired cogeneration are quite different from the economics of utility-owned combined cycle plants. Because they are so fuel-efficient, cogeneration plants are in a better position to pay a premium for firm gas supply and transportation. A cogeneration plant's annual gas load is stable because the operating schedule is usually based on steam requirements, and is not subject to economic dispatch. In the more profitable cogeneration facilities the owner may recover his investment in less than 10 years — long before an electric utility would recover its investment in a combined cycle plant. A proposed cogeneration plant typically has a 12-15-year financing period and 2 or 3-year lead time, and the owner is typically unregulated, so there is less concern about gas prices beyond 2005.

Facilities Costs. Electric utilities are concerned about the ability of gas pipelines to meet projected future combustion turbine loads during electric system peaks which occur in the summer in most cases. Because weather-related peaks are impossible to predict, it is very difficult to meet such loads through advance reservation of firm pipeline and storage capacity. Most producers and pipelines are not very concerned, however, about their ability to make future contractual commitments to provide peaking capacity to the electric utility industry. Pipeline facilities built to handle peakloads would operate at low load factors, however, and could be costly to build and operate. Our impression is that the gas industry is waiting for the electric industry to make specific requests for firm service.

In our view, the cost of peaking supplies could be an economic impediment to the ability of the gas industry to meet all of the combustion turbine loads currently envisioned by the electric utility industry unless there are other actions taken to reduce these peaks. Although it is technically possible to add peaking capacity such as liquefied natural gas (LNG) facilities, storage and propane/air injection, it is not clear that electric utilities can afford to pay for this peaking service. Part of the solution to the problem may be to have electric utilities consider gas cooling as part of their programs to manage electricity demand (often called demand side management). An increase in gas cooling load would be easier for some gas systems to accommodate than an increase in combustion turbine load.

Furthermore, in our view, uncertainty regarding the number of years over which new combined cycle plants will be operated as base load plants creates an economic impediment associated with the installation of gas pipeline capacity to meet power sector needs for base load capacity. The problem is simply the difficulty of guaranteeing that the customer will continue to need firm capacity on a twelve-month basis for a period longer than 10 years. The cost of pipeline capacity becomes very steep when amortization periods as short as 10 years are considered. The trend toward decreasing use per residential customer and per square foot of commercial space make it difficult to rely on load growth in other customer classes to absorb the firm capacity that may eventually be released by the power sector.

Equipment costs. There is no industry group that is very concerned about the projected costs of power generation gas turbines or combined cycles — either in terms of first costs, operation and maintenance costs, or reliability-induced costs. Most electric utilities or NUGs feel that the increased demand for gas turbines can translate into better pricing through economies of scale and that there is enough competition among equipment suppliers to keep prices in check and stimulate enough pressure for product improvements to happen.

Technical impediments

Our interviews did not reveal any significant technical impediments to power sector gas demand. Although there were several mentions about the need for sustained R&D in the areas of gas production, gas facilities and equipment cost, nobody expressed the concern that the growth of gas use in the U.S. power sector could be held up because the combined cycle technology is not "ready" for commercial use. In fact, equipment manufacturers have been able to achieve substantial progress in the past 5-7 years. As a result, they can announce very attractive efficiencies (up to 53-54%) for advanced combined cycles that will be available before the end of this decade.

Delivery system impediments

The electric utility industry is concerned about the ability of the gas industry to meet the peaking requirements associated with a substantial increase in combustion turbine capacity in the southeastern United States and in other selected regions. This concern has been documented in a recent study conducted for the Electric Power Research Institute by Charles River Associates, Jensen Associates, and Energy Ventures Analysis.[4]

It is not clear exactly what type of and how many gas facilities would be required to meet combustion turbine loads and what lead times would be needed to contract for and build these facilities.

Along the East Coast and in the Mid-Atlantic region, NUGs have proposed to build gas-fired generation facilities that would require large volumes at high pressures that could not be supplied by the existing distribution grid. LDCs are aware of the difficulty of meeting these large loads and obviously want to ensure that delivery pressures on their systems are not adversely affected by deliveries to cogeneration projects and IPPs. There are, however, limits to the rate at which cogen/IPP loads can be introduced without disrupting delivery pressures to existing pipeline customers.

In our view, these limits create a potential impediment to increases in power sector gas use associated with combustion turbine loads. The lead times needed to add storage

---

[4] Charles River Associates, Jensen Associates, Inc., and Energy Ventures Analysis, Inc., Gas Consumption in Electric Generation, Draft Report, 1991.

and/or peaking capacity to LDC gas systems and meet peaks lasting only a few hours per day could be longer than the lead times for pipeline construction projects. A technical analysis of this issue is needed to define potential impediments more clearly.

Legislative/regulatory impediments

Supply. During our interviews, we found no evidence that legislative or regulatory issues that directly affect gas supply are creating impediments to increased gas use in the power sector. Because the Natural Gas Wellhead Decontrol Act of 1989 will eliminate all wellhead price controls by January 1, 1993, these controls are no longer regarded as an impediment to new supply. Although producers continue to press FERC for changes in the way pipelines are regulated, and perceive certain aspects of pipeline regulation (e.g., traditional pipeline sales, construction certificates) as an impediment to competition, these allegations are not directly related to regulation of gas production. Although oil and gas producers have objected to limitations on access to offshore California and the ANWR coastal plain, these concerns are focused on oil production rather than natural gas production. In our interviews with producers, state regulation of wellhead production was not cited as an obstacle to gas production.

Gas operations. The producers, pipelines, and electric utilities that we interviewed all expressed concerns about pricing, risks and regulatory delays associated with the implementation of the industry restructuring of sales and transportation services and new pipeline construction rules.

Pipelines are particularly concerned with the way the rules of the game are likely to change with unbundled sales and equality of transportation services.[5] They are not sure that they will be able to recover the costs that they will incur as they restructure their contract portfolios to match the demand for unbundled services and how such costs may affect their ability to be competitive in the power generation sector. Pipeline companies are also concerned that unbundling could allow further "cream-skimming" by increasingly sophisticated customers such as NUGS and utilities.

A common perception is that the construction and rate provisions for new pipelines and facilities under Order 555[6] create uncertainties and could cause delays. Order 555 offers a variety of alternative procedures for establishing tariffs associated with new pipeline construction. Although the FERC is presently reviewing the rule, and some of the

[5] Op cit., Order 636.

[6] The construction rule issued in 1991. Order No. 555, Final Rule, *In Re Revisions to Regulations Governing Authorizations for Construction of Natural Gas Pipeline Facilities*, 56 Fed. Reg. at 52330, October 18, 1991. Order Granting Rehearing for Further Consideration and Postponing Effective Date of Order No. 555, 57 FERC, November 13, 1991.

ambiguities may be removed by Order 555-A, the Commission appears to leave unanswered the fundamental question whether the consumer will be protected most effectively by regulation or by competition. As a result, pipelines may still be unable to assure potential customers that the facilities will be completed in time and at an economic cost. The complexity of Order 555 illustrates the difficulties that the gas industry faces in trying to anticipate the regulatory climate of the next few years.

End use. Decisions by electric utilities to increase reliance on natural gas are influenced strongly by two categories of regulation: electric rate regulations by state public service commissions, and air and water emission regulations passed by the EPA and by state environmental agencies. In addition, the future growth and availability of capital for investment in IPPs (in particular, the availability of utility company capital) is limited by the Public Utility Holding Act (PUHCA) until that legislation is modified. Producers, pipelines, LDCs, and electric utilities all perceive impediments associated with at least one of these legislative/regulatory categories.

The gas industry is very interested by the opportunities that could be offered by a PUHCA amendment. Most market analyses show that such an amendment would trigger the development of large gas-fired combined-cycle IPPs with good load characteristics. However, there are concerns about how quickly this amendment will be enacted and then regulated, not only at the Federal level by FERC, but also by state public utility commissions. There are also concerns that lack of open contractual access to transmission lines could limit the real potential for new gas-fired IPPs, as new units (located where sites are available and environmentally acceptable) may not find their ways to customers to buy. Open transmission access is a very serious issue to the electric utility industry, somewhat akin to the take or pay issue in the gas industry, and it will take most of the 1990s to find a solution. In the meantime, case-by-case decisions will be made by FERC, with all the resulting uncertainties that can be expected.

The gas industry would also benefit if public service commissions issued rules or policy statements that substantially diminish the electric utilities' risk of disallowance of costs associated with gas combined cycle plants, gas pipeline interconnects and other investments required to increase gas use. Because future gas prices are uncertain and could be high enough to make gas technologies more expensive than coal for baseload use, an electric utility must try to avoid the risk that it will someday be told during a prudence review that its investments in gas firing or its gas purchase contracts were imprudent. Under cost-of-service regulation a utility has an incentive to avoid surprises, i.e., to select the generating alternative in which actual costs are likely to be close to the projections that are used to support an application for regulatory approval of new facilities and rates. Thus, regulatory pressures at the state and federal (EPA) level may create a bias in favor of coal. Pipelines are aware of these issues and regard the ambiguity of existing regulatory policy as an impediment to gas demand growth.

In our view these concerns are entirely valid. In making choices between gas-fired and coal-fired generating alternatives, an electric utility faces a tradeoff between fuel price risk and initial capital cost. The coal-fired option will have a higher capital cost but will "insure" the utility against the risk of fuel price spikes and substantial increases in the cost of fuel. In making the tradeoff the utility will want to make decisions that are consistent with the regulators' views regarding the kind of capital cost premium that is worth paying for coal facilities. Because electricity consumers do not make choices among generation companies, the selection of the best option is not going to be made on the basis of competitive market forces.

Some state PUCs, however, have started to recognize this problem. For example, one pipeline company mentioned that the Texas Public Utility Commission (PUC) was looking into the possibility of issuing a proposed rulemaking in favor of precertifying electric utility gas contracts to lessen the risk exposure to Texas utilities. In one other case, an electric utility explained to us how it wanted its PUC to be part of the process of acquiring natural gas resources through regular consultations. However, that electric utility found that gas companies were then becoming reluctant to enter into contract negotiations with "real-time scrutiny" from the PUC.

On the environmental side, the interstate pipelines serving the region in which Appalachian coal is used in utility boilers are particularly concerned about regulatory obstacles to select gas use and co-firing. The coal mining industry in Ohio, Indiana, Illinois and West Virginia has been able to obtain favorable legislative and regulatory treatment in the context of Clean Air Act compliance. For example, scrubbers will be installed at Monongahela Power's Harrison County plant despite the opposition of the West Virginia Natural Gas Coalition, which favored co-firing as an alternative to scrubbers.[7] Some pipelines feel that select gas use and co-firing would be much more widespread if state and federal environmental authorities issued policy statements identifying the situations in which these options will be accepted as compliance measures under the Clean Air Act.

Finally, one of the impediments to co-firing is the scarcity of data on the precise effects of co-firing on stack gas emissions in particular boilers using particular coals. The optimal placement of sorbent injection burners may have to be determined for each boiler, and the optimal mix of gas and coal may have to be fine-tuned under different levels of capacity utilization. Furthermore, the Clean Air Act imposes tight statutory deadlines that do not leave electric utilities with much time to experiment with co-firing and find out whether it will achieve the new emissions targets. Here again, the competition between gas and coal is influenced by the way regulations are written and

[7] This coalition includes Hope Gas Co. (a subsidiary of Consolidated Natural Gas), Equitable Gas Co., the West Virginia Oil and Gas Association, and the Independent Oil and Gas Association. See "West Virginia Gas Coalition Gives Up on Anti-Scrubber Plan," Natural Gas Week, September 30, 1991, pp. 1,14.

implemented. State implementation plans required under the Clean Air Act will also greatly affect the use of gas in utility boilers. However, the Gas Research Institute (GRI), the U.S. Department of Energy (DOE), and the Electric Power Research Institute (EPRI) (in different combinations) are sponsoring a total of four co-firing demonstration projects and individual GRI members have already conducted co-firing tests in Pennsylvania and Oklahoma.

Institutional impediments

Long-term contracts. Producers, electric utilities and NUGs have not been able to reach an understanding regarding the appropriate allocation of gas price risk over the long term. Producers would like to shift most price risk to their customers, especially in the NUG market.

To date, there has been a strong inclination among U.S. suppliers to prefer fixed-price deals, involving a fixed price generally set 2 to 2.5 years ahead of first delivery with a fixed escalator, that could range between 3% and 10%. U.S. suppliers have been reluctant to use long-term price indexes which could offer more flexibility to NUGs who have to match the specifics of their power sale agreement (PSA). Such indexes could be tied not only to the producer price index, but also to the price dynamics of the utility's sources of gas or any other fuel that the utility would avoid consuming by buying power from NUGs. There are some indications, however, that the situation is progressively improving.

Focus on customer needs. From the viewpoint of electric utilities or NUGs, the gas industry does not make enough of an effort to tailor its services to the needs of its customers.[8] Unlike many service-oriented industries (e.g., telecommunications, credit cards and food service), the gas industry does not try to develop new services to make it easier and more convenient for the customer to do business. Instead the gas industry offers a menu of services that meets the convenience of the industry and its regulators.

We find this criticism legitimate. The gas industry has gone through a period of regulatory changes and financial strains that have adversely affected the industry's ability to focus its attention on the customer. Companies have expended considerable efforts trying to establish the allocation of the total revenue "pie," and have not always devoted a comparable effort to meeting the needs of customers.

This is particularly true for NUGs who have a special need for negotiating complex long-term agreements that have to be tied to the energy and capacity (variable and fixed) terms of their PSA. To do so, the gas supply contract package must be able to match

[8] Some representatives of oil and gas producers have the same view. We did not find that the majority of producers have accepted this self-criticism, however.

very closely (1) the escalation rates of the energy credits in the PSA and (2) the split between fixed and variable revenues over the entire range of dispatchability conditions required by the electric utility. This is complicated by the fact that at least two-thirds of the PSAs now require NUG plant dispatchability by the electric utility. In final analysis, the "trick" is to be able to tie the variations in PSA fixed and variable charges with the mix of demand and commodity charges sought by the gas producer(s), pipeline company(ies) and the LDC that are involved. In particular, NUG owners complain that pipeline companies do not take enough time to understand the intricacies of their PSAs.

There is a consensus, however, that this situation is improving somewhat as more producers get involved with NUGs.

Funding for R&D and commercialization. Interstate pipelines perceive a bias in federal funding of R&D that gives coal and nuclear and renewable technologies an unreasonably large share of total R&D outlays.

Industry cooperation. The electric utility industry is vertically integrated and represented by the Edison Electric Institute; reliability issues are overseen by the North American Electric Reliability Council, which is composed of nine regional power pools; and RD&D efforts are coordinated by the Electric Power Research Institute (EPRI). In the gas industry production, transmission, and distribution are primarily the responsibility of different groups of companies, and each group has historically been represented by at least one trade organization (the Natural Gas Supply Association and the Independent Petroleum Association of America; INGAA; and AGA and regional associations). There is no reliability council and there are no regional organizations responsible for ensuring reliability.

Gas consumption in the electric utility sector has historically been concentrated in Texas, California, Louisiana, New York, Florida and Oklahoma. In 1990 these 6 states accounted for 83 percent of electric utility gas consumption. In the rest of the country, the competition between gas companies and electric companies in end-use markets has led to a competitive relationship rather than a cooperative one. For many of the gas LDCs that are not affiliated with electric companies, it is still difficult to accept the idea that a gas company should help an electric company meet its peak load or lower its cost of service. The fear is that the electric company will try to make gas customers switch to electricity (e.g., to electric heat pumps) and thereby hurt the profitability of gas companies.

However, the electric utility industry now perceives a need for greater cooperation with the gas industry to address the problems associated with increased gas consumption in the power sector. In particular, electric utilities interviewed often mentioned the need to develop detailed long-term assessments of the ability of the gas industry to deliver increased gas volumes for both baseload and peaking applications and the necessity of a better coordination with the gas sector to address reliability issues. All the electric utilities interviewed insisted on their need for more sophisticated information systems and better data bases to track the situation almost in a real-time mode. One suggestion often made was to create regional reliability councils.

We agree with this characterization of the gas industry. If a potential customer must deal with several companies (producers, pipelines, and LDCs) with disparate interests, the task of securing firm gas supply and transportation is complicated by the need to negotiate several contracts and understand the regulatory framework. Securing long-term supplies can be difficult and time-consuming for the customer, and the lack of cooperation is an impediment to gas demand growth. This can be particularly true with NUGs that often rely for their projects on a combination of two to five contracts including contracts with one to three suppliers, contracts with one to two transporters and the contract with the LDC. Under these circumstances, it is not surprising to find that it might take up to 6 to 8 months to negotiate a complete gas procurement package for a 150-MW combined-cycle cogeneration project in the mid-Atlantic area, for example.

Customer perception impediments

Long-term supply problems. From a producer's perspective, the desire of electric utilities to negotiate gas price escalators tied to average generation costs, bulk power rates (e.g., the interconnect rate for the Pennsylvania-Jersey-Maryland — PJM — power pool in the Mid-Atlantic area or the NEPOOL fossil fuel index) or coal costs is unreasonable and reflects a bias against gas. To a gas producer, a gas contract tied to coal prices makes no more sense than a coal contract tied to gas prices. Some pipelines feel that the electric utilities' concern about a future gas shortage is unwarranted, given the recent trend in average wellhead prices and the evidence of continuing technological improvements that will lower finding and development costs. Given the demonstrated ability of cogeneration projects to secure gas supplies, it sometimes appears that electric utilities are making the supply issue more of an impediment than it needs to be.

Our assessment is that electric utilities are operating rationally under the regulatory system to which they must adapt. Unlike residential and commercial customers, who have applications in which gas competes with electricity or distillate oil, electric utilities dispatch gas-fired generating units in competition with coal, nuclear, hydro and renewables. Furthermore, the prices of fuels delivered to electric utilities are typically more volatile than the prices of fuels delivered to residential and commercial customers, because the latter include distribution costs. Finally, electric utilities face the risk that gas purchase costs will be disallowed by regulators — a risk that gives the electric utility an extra incentive to be price-sensitive. The utilities' concerns about long-term trends in gas prices and long-term availability therefore reflect economic and regulatory impediments rather than customer perception impediments.

Gas service reliability. There appears to be some misunderstanding between the electric industry and the gas pipeline industry regarding the methods used by the gas industry to assure a firm supply of gas to firm customers. Electric utilities see gas as unreliable in the winter. For example, gas pipelines would most likely object to the following EPRI report characterization:

> Gas supply reliability under severe weather conditions is a serious concern for utilities in the Southwest (ERCOT and SPP[9]). The problem, which is akin to forced outages in the electric industry, occurs when gas wells freeze during cold spells. Since the gas industry typically sheds load in such situations rather than maintaining extra capacity margins, fuel supply in the region may prove unreliable.[10]

In fact, pipelines and LDCs use various components — underground storage, LNG storage, line pack, extra compressor station capacity, LNG terminal supplies, and propane/air injection — to assure peaking capacity. This statement about capacity margins could be perceived as an example of a customer perception that creates an impediment to gas use in the power sector.

In our view, the operations-related customer perception problems in the power sector are attributable primarily to a lack of communication between the electric utility industry and the gas industry and to the absence of gas industry analyses on gas supply and service reliability. If more complete information on gas system reliability were readily available to the public, the customer's perception of reliability would be less influenced by subjective perceptions. The more serious impediments are therefore economic and institutional, rather than a matter of customer perception.

Equipment reliability. Some producers and interstate pipelines have the impression that electric utilities are biased in favor of coal technologies. Obviously the use of combined cycle plants for baseload generation is new, and utilities are much more familiar with coal-fired steam plants. From the perspective of producers and pipelines, the tendency of electric utilities to favor coal technologies for Clean Air Act compliance reveals a bias in favor of coal. One hypothesis is that electric utilities favor coal technologies because they are capital-intensive, creating opportunities to expand the utility rate base. However, rate-base expansion can cause price increases and make electric utilities less competitive. Our impression is that most electric utilities have a bias against oil and

---

9 Two regions defined by the National Electric Reliability Council (NERC): ERCOT covers the state of Texas while the SPP region includes Arkansas, Kansas, Louisiana, parts of Missouri, and Oklahoma.

10 Electric Power Research Institute, Natural Gas for Power Generation: Strategic Issues, Risks, and Opportunities (Palo Alto, CA: EPRI, 1990), p. 8.

natural gas because of the price volatility of these fuels, not because utilities prefer to make large capital investments.

Even though the cost of electric generation in the next 20 years will be affected by many factors that are difficult to predict — e.g., the market price of an SO_2 allowance and the cost per kW of photovoltaic capacity — electric utilities tend to regard average delivered prices of utility coal as a reasonable standard against which fuel price volatility may be measured.

IMPEDIMENTS TO INCREASED USE OF NATURAL GAS VEHICLES

In Exhibit 2.4, we summarize how we characterize the impediments to increased use of gas in the emerging NGV market as they are perceived by gas producers; interstate pipeline companies; and local distribution companies. The size and scope of the NGV market is very different from power generation. The annual fuel consumption of a natural gas vehicle is roughly equivalent to the heating load of a single-family home.[11] Many thousands of NGVs will be required to make a noticeable impact on gas demand. Clearly, all three types of organizations agree on the tremendous operational and economic impediment of having to develop a whole new infrastructure, and they also agree on the importance of technical and legislative/regulatory end-use impediments.

In the following, we discuss our findings for each impediment category.

Economic impediments

Production costs. Today the natural gas vehicle market represents a very small portion of total U.S. gas supply. GRI's estimate of 1990 gas use in methane vehicles is 3.6 trillion Btu, or about 3.6 Bcf per year.[12] For vehicle fleets owned by pipelines and LDCs, system supplies can be used to provide the gas. For other vehicle fleets, supplies are usually provided by the LDC using its system supply, or by a gas producer using its own production. In either case there is no need to have supply contracts tailored to the NGV market. We do not know of an instance in which NGV customer purchases gas supply and gas transportation on an unbundled basis.[13] It appears that because gasoline

---

[11] Paul McArdle, "An Analysis of the Economic and Environmental Effects of Natural Gas as an Alternative Fuel," Gas Energy Review (American Gas Association), March 1990, p. 13.

[12] GRI, Baseline Projection Data Book: 1991 Edition of the GRI Baseline Projection of U.S. Energy Supply and Demand to 2010, p. 343.

[13] The possibility that fleet owners would want to have unbundled supply and transportation was cited in a study published by API. See Russell O. Jones, The Economics of Alternative Fuel Use: Compressed Natural Gas as a Vehicle Fuel, API Research Study #056 (December 1990), p. 21.

Exhibit 2.4
Impediments to Increased Use of Natural Gas Vehicles: Differences Among Perceptions

Type of impediment	Producers	Interstate Pipelines	Local Distribution Companies	RCG/Hagler, Bailly
Economic				
Production costs				
Gas facilities costs	X	X	X	X
End use equipment costs			X	
Technical				
Gas resources				
Distribution technology				
Equipment reliability	X	X	X	X
Delivery system/reliability				
Legislative/regulatory				
Supply				
Gas operations				
End use	X	X	X	X
Institutional				
Long–term contracts				
Industry cooperation			X	X
Focus on customer needs			X	X
Funding for R&D and commercialization	X	X		
Customer Perception				
Long–term supply problems			X	X
Gas service reliability				
Equipment reliability				

Source: RCG/Hagler, Bailly, Inc.; based on selected industry interviews.

is purchased on a "spot" basis by the end user, it is generally assumed that the NGV user (other than a pipeline or LDC) will purchase gas without a long-term contract.

Moreover, it is commonly assumed that where NGV sales are subject to utility regulation, the price of gas will be established in a rate schedule for which the cost of service is computed from the load profile of the NGV filling station rather than the NGV user. Such an approach would yield an average cost per Mcf comparable to the average for firm industrial customers.[14]

Economic analyses of the competitiveness of NGVs with gasoline or diesel vehicles show either a net cost or a modest savings to the user. For example, a study published by API in December 1990 shows a net user cost in 2005 in the range of 1 cent per gallon to 56 cents per gallon for private vehicles; 1 to 48 cents per gallon for fleet vehicles; and 4 to 50 cents per gallon for transit buses.[15]

In contrast, a study published by AGA in June 1991 shows a total capital and operating cost of 16.96 cents per mile for an NGV, versus 17.69 cents per mile for a gasoline vehicle produced in the mid-1990s. The AGA study assumes a gas price of roughly $5.62 per MMBtu at the filling station, of which $3.15 per MMBtu is the price excluding tax. The NGV achieves a savings in fuel cost (excluding the cost of compression) of 2.04 cents per mile, or the equivalent of 50 cents per gallon of gasoline.[16] Both studies show that NGVs offer significant environmental benefits which are not reflected in the net cost to the user. The API study shows a net cost to the user in 1996, 2000, and 2005, while the AGA study shows a net savings for a vehicle produced in the mid-1990s.

In the course of our interviews the cost of delivered-to-pipeline supply was never cited as an impediment to increased gas use in NGVs. What is important is the differential between the natural gas price (measured in dollars per equivalent gallon) and the gasoline price, not simply the risk that natural gas prices will increase. The fuel cost savings will decline under a scenario with low crude oil prices and high wellhead gas

---

[14] Op cit., Paul McArdle, p. 13.

[15] These results were based on projected 2005 gas prices (in 1990 dollars) of $4.47 per Mcf, $4.82 per Mcf, and $5.61 per Mcf, respectively, excluding motor fuel tax. For the year 2005 the savings in fuel cost (including motor fuel tax but excluding the cost of CNG fueling equipment and operating expense) is equivalent to 43 cents per gallon of gasoline for private vehicles, 39 cents per gallon of gasoline for fleet vehicles, and 4 cents per gallon of diesel fuel for transit buses. Source: Russell O. Jones, The Economics of Alternative Fuel Use: Compressed Natural Gas as a Vehicle Fuel, Research Study #056 (Washington, DC: API, 1990), p.ix, 38.

[16] Paul Wilkinson, ""Natural Gas and Electric Vehicles - An Economic and Environmental Comparison with Gasoline Vehicles," Gas Energy Review 19,6 (June 1991) p. 22. We estimated the $5.62 figure by multiplying the pre-tax cost per MMBtu by the ratio of after-tax cost per mile to pre-tax cost per mile.

prices. On the other hand, the savings will grow under a scenario in which imported oil is expensive while natural gas is plentiful and cheap.

Facilities costs. NGVs require gas supply to be delivered in small quantities at high pressure at filling stations conveniently located for the user, not the LDC or the pipeline company. A standard delivery pressure of 3000 psi is often assumed for NGVs, much higher than the 1000 psi or the 125 psi operating pressures of transmission or distribution lines.[17] This higher pressure creates the need for a whole new infrastructure of NGV filling stations equipped with compressors. Home compressors may be too expensive for a large segment of consumers.

Everyone in the gas industry - producers, pipelines, and LDCs - recognizes that the cost of this infrastructure is significant and poses an impediment to NGV use. We support this consensus of opinion.

The best way to provide convenient refueling service for the consumer, and at the same time achieve low costs per Mcf, is to have a large number of NGVs and a large number of NGV filling stations. If there are only a few NGVs on the road, the infrastructure becomes prohibitively expensive. Creating such infrastructure poses what is called a "chicken and egg" problem because it is hard to say which comes first, the filling stations or the NGVs.

Furthermore, an LDC can perceive its investment in a new NGV distribution infrastructure as risky under current utility regulations. Although such investment is a natural candidate for "rate base" investment because it is linked with its existing gas distribution system, it is also riskier than a traditional rate base investment. For example, the LDC would run a risk of underrecovery if its projections of throughput and capacity utilization used to establish its rates for compression services turn out to be too optimistic. As a result, public utility commissions may have to allow a higher rate of return on NGV infrastructure investments to attract the necessary capital.

Equipment costs. The near-term growth in the NGV market is likely to come primarily from users served by an LDC. Non-utility companies — primarily oil companies — do not wish to become regulated utilities and, to date, only three states — Colorado, Minnesota, and Texas — have permitted non-utility companies to sell NGV fuel without being subject to utility regulation.[18]

Our interviews showed that LDCs are particularly sensitive to the customer's concern that his NGV will be reliable; that proper maintenance will be available (through the

---

[17] Jones, The Economics of Alternative Fuel Use: Compressed Natural Gas as a Vehicle Fuel, pp. 7, 23.

[18] Todd Bernhardt, "Fill 'Er Up?," American Gas, September 1991, p. 17.

LDC or other channels); and that maintenance costs will not be prohibitive or vehicles will not be as reliable as they should be. Moreover, an LDC that is actively marketing NGVs must deal with the customer's reluctance to pay a higher initial cost (relative to gasoline vehicles) in order to achieve a lower fuel cost. Gas producers and pipelines are not as close to the customer service aspect of the NGV market and do not appear to share the same concern.

For the end user, one of the impediments to NGV use is the capital cost premium of either converting his vehicle to natural gas or buying a NGV instead of a gasoline vehicle. For that user, the NGV can achieve a lower cost per mile only if this first cost premium is offset by later, lower operating costs. Thus, economic impediments in the areas of supply, gas operations and end use are all closely related. In that respect, however, the first cost premium associated with a converted or new NGV can be an impediment, but it is far much less critical than the major uncertainties that will determine the economics of NGV gas distribution.

Technical impediments

Gas resources. A technical impediment to supply would exist whenever a technological breakthrough is needed to make gas resources accessible to NGVs. No such impediment is likely, even in regions where technical impediments may restrain supply, since, in the final analysis, the availability of gas for the NGV market will be determined by gas supply and demand in North America as a whole. Producers, pipelines and LDCs agree that economic impediments are a far more serious constraint on gas supply than technical impediments.

Distribution technology. Although the cost of compression is clearly an impediment to greater NGV use, there is no evidence that a technological breakthrough is needed for the gas industry to supply the NGV market. The technology for refueling NGVs and building filling station fuel tanks is fully commercialized. The producers, pipelines, and LDCs that we interviewed all agreed on this point.

Equipment reliability. Gas industry companies perceive the need for technological improvements in NGV design to achieve better compliance with strict NO_x standards and smaller and lighter fuel tank construction.

There is a divergence of expectations regarding the NOx performance of future NGVs. Ford Motor Company, for example, expressed some concerns about NGV NOx emissions when it described in a 1991 conference the following results of emission tests from a natural gas prototype truck:

> Nitric oxide emissions resulted in 1.96 grams per mile. This was back in 1984 when the standard from this truck was 2.3 grams per mile. That standard today is

> 1.2 grams per mile, and we had a very tough time getting it to 1.96. So we are very concerned — even though natural gas has many attributes that make it a clean fuel — whether or not we are going to be able to meet the future nitrous oxide emission standards with this fuel.[19]

And in a report published in January 1990, AGA questioned the validity of EPA assumptions:

> EPA estimates of a 40 percent increase in NOx emissions for NGVs compared with gasoline vehicles is not echoed by recent studies. Some of the studies project decreases in NOx emissions for NGVs relative to gasoline vehicles. This is particularly true for advanced technology NGVs.[20]

To compare emissions from electric vehicles and NGVs, a recent AGA study used the assumption that NGVs "would do no better that the Phase I standard of 0.4 gpm, the same as gasoline vehicles."[21]

Ironically, the tightening of NOx emission standards in the 1990s may be most severe in California, which is one of the leaders in NGV use. The California Air Resources Board certified the Tecogen engine for natural gas buses, and NGV fueling stations are being built.[22] However, the California Air Resources Board is now considering a requirement to introduce a specified number of Low Emitting Vehicles in the late 1990s and Ultra Low Emitting Vehicles after the year 2000. Alternative fueled vehicles will most likely have to be introduced to meet these regulatory requirements; unfortunately, strict emission standards favor electric vehicles over NGVs.[23] It is therefore likely that the ability of NGV technology to meet strict emission standards will initially be determined in California.

---

[19] Roberta J. Nichols, conference presentation, published in U.S. General Accounting Office, Meeting the Energy Challenges of the 1990s, GAO/RCED-91-66 (March 1991),p. 76.

[20] Paul McArdle, "A Side-by-Side Comparison of Studies Concerning Alternative Vehicle Fuels," Gas Energy Review 18,1 (January 1990), p. 12.

[21] Paul Wilkinson, "Natural Gas and Electric Vehicles - An Economic and Environmental Comparison with Gasoline Vehicles," Gas Energy Review 19,6 (June 1991), p. 24.

[22] Stations are being built by SoCal Gas, by a joint venture between Unocal and San Diego Gas & Electric, and by a joint venture between Shell and Pacific Gas & Electric.

[23] Atkinson, D., A. Cristofaro, and J. Kolb, "Role of the Automobile in Urban Air Pollution," paper presented at an MIT conference on Energy and Environment in the 21st Century, Cambridge, Mass., March 26-28, 1990, p. L-11.

While NGVs may be able to meet the NOx standards, our assessment is that NOx emissions standards could pose an impediment to NGV use in the late 1990s in selected regions of the country, including southern California. Consequently, the gas industry will need to continue funding R&D on methods of reducing NGV emissions.

In addition, producers, pipelines, and LDCs perceive a need for technological improvement in NGV fuel tank construction. The essence of the engineering problem is that NGV fuel tanks need to be large and (under present technology) need to be cylindrical. Because natural gas at 3000 psi has about 25 percent of the energy content of gasoline, on a volume basis, NGV fuel tanks need to be about 4 times as large as gasoline tanks to provide the same mileage range.[24] The cylindrical design is needed to store gas safely at 3000 psi and minimize the likelihood of damage to the fuel tank. In a sedan with modest requirements for trunk space it is easy to accommodate these requirements, but in some vehicles the bulkiness of the fuel tank is perceived to be a problem. The perception among gas industry companies is that many customers will not be willing to pay a premium for a natural gas vehicle that sacrifices trunk space and cargo capacity. We agree that this impediment must be recognized.

In addition, the extra weight associated with NGV fuel tanks may be considered an impediment to higher fuel economy. More broadly, any technology that reduces the weight of NGVs and improves their fuel economy would be desirable. For example, a scenario in which NGVs have a 25 percent energy efficiency advantage over gasoline vehicles shows a significant improvement in the competitiveness of NGVs.[25] R&D efforts in this area would therefore be beneficial.

Delivery system impediments

Although there are economic impediments to putting a delivery system in place, there is no reason to believe that the gas industry is either unable to meet peak demands from NGV stations or unable to grow rapidly enough to meet NGV demand growth. Peaking capability should not be a problem because NGVs use has a relatively flat load profile. Demand growth should not be a problem because NGV stations can be supplied through minor modifications to the existing distribution network. The increase in NGV demand between 1990 and 2000 is projected to be in the range of 60 to 210 Bcf/y (see Exhibit 1.3) - an amount that the gas industry should be able to accommodate easily.

---

[24] Jones, The Economic of Alternative Fuel Use: Compressed Natural Gas as a Vehicle Fuel, p. 7.

[25] Op cit., Paul McArdle, p. 12.

Legislative and regulatory impediments

Supply. As in the power sector market, the supply of gas is no longer perceived to be constrained by legislative and regulatory measures.

Gas operations. There is some disagreement within the industry regarding the desirability of decontrol of the sale of fuel to NGVs. This category of gas sales has been decontrolled in Colorado, Minnesota, and Texas. If decontrol is not enacted in other states, LDCs will have to take the lead role in the creation of filling stations and the establishment of prices for NGV fuel. Joint ventures between LDCs and gasoline station owners or major oil companies may be needed to give the LDCs access to the best sites for filling stations, but under utility regulation the prices of compressed natural gas are established through regulated rates. Some pipelines are concerned that LDCs will not market NGVs aggressively and will charge rates that are excessive, thereby impeding the development of the market. Other companies, including other pipelines, believe that the involvement of LDCs is essential to the development of the NGV market and that customer confidence in NGVs is more easily developed by building on the customer's existing relationships with the LDC.

Our assessment is that utility regulation enhances NGV use in an urban area with very few NGV stations, but it could create an impediment to NGV use in an urban area with many NGV stations. In the early development of the industry, the customer does not want to be captive of a single filling station that can charge whatever the market will bear. The monopolistic character of the first filling station in an area will tend to deter customer investment in NGVs unless the customer is assured that he is protected through utility regulation. When the number of NGVs is large enough to support several filling stations and thereby support a competitive marketplace, there will be no further need for utility regulation. A reasonable compromise between regulation and competition may be provided through "price cap" regulation, under which price ceilings are established on the basis of the regulated firm's cost of service but both regulated and unregulated firms are permitted to charge prices below the ceiling. From the perspective of the LDC, NGV fuel rates would be comparable to interstate pipeline transportation rates, which are subject to discounting, but the LDC (unlike the pipeline offering transportation service) would face competition from non-utility suppliers.

One of the potential difficulties with utility regulation of NGV fuel is the possibility that gasoline and diesel fuel prices will be unstable. Gasoline and diesel prices are deregulated and there is a possibility that these prices will be volatile due to local "price wars" or due to global events such as the crude oil price crash of 1986 or the invasion of Kuwait in 1990. If the price of gasoline falls sharply, an NGV station subject to a price cap will be able to discount NGV fuel to compete with gasoline, but if the price of gasoline rises sharply the NGV station will be prevented from charging higher prices to recover the fixed costs that could not be recovered in a period of low gasoline prices. It may be possible to design flexible rates tied to gasoline prices to provide parity to NGV customers. Our impression — based in part on our interviews — is that LDCs have only begun to address how rates can be designed for NGV to be competitive with gasoline and diesel fuel.

If fuel-switching were likely, NGV rates would have to be automatically adjusted relative to competing fuel prices, and the NGV market would become a dual-fuel market. Fortunately, NGV fuel prices should be low enough (and NGV mileage high enough) to ensure that the effect of low gasoline prices is merely to discourage conversions and new purchases of NGVs, not to make the customer switch from natural gas to gasoline.

End use. State NOx and CO2 environmental standards and excise taxes can create impediments to future NGV use.

Producers, pipelines, and LDCs agree that environmental regulations will affect the competitive position of NGVs, reformulated gasoline, methanol vehicles and electric vehicles. State governments can set vehicle emission standards that are more stringent than federal standards, and it is possible that the net effect of more stringent standards in a particular state could be a decline in the market share of NGVs in favor of electric vehicle use.[26] Because NGVs may have difficulty meeting future NOx emission standards (or other emission limits), these standards create a potential impediment to NGV use.

On the other hand, the competitiveness of NGVs would be improved if CO2 emissions are taxed or regulated to address global warming concerns. Under such measures, NGVs are likely to fare better than gasoline vehicles or electric vehicles supplied with power from fossil fuel generating stations. NGVs would be affected only to the limited extent that NGVs would compete with electric vehicles supplied with power from renewable energy technologies.

In addition, each state can establish an excise tax on NGV fuel, just as it establishes a tax on gasoline, and there is no guarantee that state tax policies on NGV fuel will be consistent.[27] As a result, variations in state excise taxes on NGV fuel would lead to

[26] When the vehicle alone is examined, the cleanest technology is clearly the electric vehicle. On an integrated basis, however, the electric vehicle clearly minimizes air pollution only if the electricity is provided by solar energy or other renewables; if that electricity is provided by fossil fueled plants, the comparison is less clear. When the national average power generation mix is used to estimate the total emission impact of electric vehicles, their emissions of nonmethane hydrocarbons and carbon monoxide are lower than NGV levels, but NOx, SO2, and CO2 emissions and solid waste are above NGV levels. See Paul Wilkinson, "Natural Gas and Electric Vehicles - An Economic and Environmental Comparison with gasoline Vehicles," p. 24.

[27] Although analyses of the economics of NGVs use sometimes assume a level of taxation that is "equivalent" to that of gasoline taxes, the calculation of an "equivalent" tax is typically based on the simplistic assumption that all gasoline vehicles have a certain fuel efficiency and all NGVs have a

variations in the economic attractiveness of NGVs relative to gasoline vehicles. At present the federal road tax is not applicable to NGV fuel and some states do not have a road tax applicable to NGV fuel.[28] A state that wishes to promote NGV use for environmental reasons could adopt a policy of not taxing NGV fuel. Therefore the road tax in states with relatively high taxes on NGV fuel may be considered an impediment to NGV use in those states.

Finally, it should be noted that state governments can create incentives for NGV use, as well as impediments. California, Colorado, Texas, West Virginia and Louisiana have clean fuel programs that encourage investment in NGVs.[29]

Institutional impediments

Long-term contracts. Because gasoline and diesel fuel are sold to end users on the basis of spot prices, and because vehicle and compressor lifetimes are shorter than power plant lifetimes, owners of NGVs and NGV filling stations are unlikely to insist on long-term contracts for gas supply.[30] This was confirmed in our interviews with gas industry representatives who did not perceive in the NGV market any institutional impediment related to long-term contracts.

Focus on customer needs. We found the perception among some LDCs that many companies in the gas industry merely offer a commodity or standardized service rather than a mix of services focused on the customer's needs. Perhaps the best illustration is the historical link between gasoline sales, automobile repair services, and the sale of tires, batteries and accessories. In the early development of the automobile it was convenient to find all of these services at a service station. Similarly, in the early development of the natural gas vehicle it may be convenient for the customer to be able to deal with a single company for his NGV needs, including fuel, parts and maintenance.

---

certain fuel efficiency. Clearly it would not make sense to tax natural gas on a per gallon basis unless a particular pressure is specified, and it may be simpler to tax NGV fuel on a Btu basis rather than volume.

28 Op cit., Paul McArdle, p. 14.

29 Jeffrey Seisler, "NGV Update for the U.S.: Politics, Technology & Marketing," paper originally presented to the International Association of Natural Gas Vehicles, Oct. 21-24, 1990, Buenos Aires, Argentina, p. 4.

30 Although compressor lifetimes as long as 40 years may be possible, a standard assumption is about 20 years. See Russell O. Jones, The Economics of Alternative Fuel Use: Compressed Natural Gas as a Vehicle Fuel, p. 41.

Many gas industry companies (especially producers) have tended to perceive their role as simply a provider of fuel. The comparable role in the NGV market would be to provide nothing more than compressed natural gas. Some LDCs expressed concerns that such a marketing approach would be too passive, and would not provide an effective means of increasing gas sales in the transportation sector.

We agree with the assessment of these LDCs. Because the original equipment manufacturers in the automobile industry have not made a strong commitment to NGVs or demonstrated leadership in the NGV market, potential customers are more likely to look to the gas industry for such leadership. To enhance the growth of the NGV market, the gas industry needs to make a commitment to ensure that the technology is reliable, that emission standards will be met, that parts and service will be available, and that LDC rates for NGV fuel will not be subject to radical changes in ratemaking methodology. This commitment will require that the industry focus on customer needs beyond fuel supply.

Funding for R&D and commercialization. In our discussions, producers and pipelines were quite aware of the very low level of U.S. Department of Energy funding of natural gas technology, including NGV technology. Their perception was that the imbalance in R&D funding creates an impediment to NGV development. The existence of a bias in Department of Energy funding is undeniable. For example, DOE's FY 1992 request did not include any funds for NGVs. This situation has been somewhat rectified since DOE's FY 1993 request proposes a new collaboration with industry to develop hybrid vehicle propulsion technologies combining batteries with fuel cells or gas turbines.

In addition, several pipeline companies expressed concerns about GRI funding for NGV R&D. However, the gas industry has presently a mechanism for funding R&D on NGVs through GRI. Following a court challenge by the Process Gas Consumer Group, which claimed that GRI-funded NGV research does not benefit ratepayers, an amendment to the 1992 DOE appropriations bill approved the research on the basis of environmental benefits to existing and future ratepayers.[31] Should this funding be withdrawn, the resulting absence of R&D support would be an impediment to the development of the NGV market.

Some pipeline companies were also concerned that GRI's funding for NGV R&D tends to focus on long-term R&D and that GRI cannot fund initiatives to commercialize new technologies. In their opinion, this lack of GRI funding is a serious impediment. In fact, GRI has been able to help develop NGV technologies with short-term impacts. For example, technologies resulting from GRI's research in storage cylinders, the Chrysler van, and the bus engine of the Cummins Company are already in the commercial market.

31 "FERC Proposal Would Allow GRI Research on Gas Vehicles," Natural Gas Week, September 30, 1991, p. 7.

Industry cooperation. Some LDCs perceive a need for greater cooperation among all segments of the gas industry to better support future NGV market development.

Because the NGV market has a high load factor, it offers benefits to producers and pipelines as well as LDCs. It may be argued, therefore, that it is in the interest of the entire gas industry to disseminate information on NGVs, sponsor studies that characterize the competitive position of NGVs, ensure that facts in support of favorable regulatory decisions are presented to state regulatory bodies, and fund the necessary R&D and infrastructure development. Because NGV users include small commercial (and eventually, residential) customers who do not purchase gas directly from producers or pipelines, LDCs are generally more familiar with the customers' concerns and the obstacles to increased sales of compressed natural gas. This marketing situation explains why producers and pipelines may not be doing enough to promote NGV use.

Producers and LDCs have started to cooperate, however, in the NGV market. For example, several producers — including Unocal, Phillips, Amoco, Shell and FINA — have taken an active role in NGV market development.[32]

Still, there is a concern among some LDCs and pipelines that major oil companies do not want NGVs to threaten gasoline sales. In September 1991, the American Petroleum Institute (API) released a report criticizing government mandates that increase the number of vehicles using alternative fuels (natural gas, propane, methanol, ethanol, or electricity) regardless of the emissions performance of gasoline vehicles.[33] Although this report may be perceived as evidence that the oil industry opposes alternative fuel vehicles, we believe that the report can be better characterized as a statement of opposition to government mandates. The major oil companies do not want the federal government or state governments to restrict competition between gasoline vehicle technology and alternative-fuel vehicle technology, given a set of emission standards.

In our view, there is a need for industry cooperation in connection with state regulatory proceedings. States must determine the taxes to be applied to NGV fuel; the rates under which LDCs may provide NGV service; the emission standards for vehicles, where there is a desire to exceed federal standards; and the certification of clean fuel engines

---

[32] More specifically: Unocal helped SoCal Gas to sell compressed natural gas at one of its Los Angeles service stations, and formed a joint venture with San Diego Gas & Electric; Phillips opened the first NGV outlet on an interstate turnpike (I-40 near Oklahoma City); Amoco opened four stations in the Denver area and formed a joint venture with Washington Gas Light to open a Washington, DC station; Shell formed a joint venture with Pacific Gas & Electric; FINA formed a joint venture with Lone Star Energy Co; and the current chairman of the Natural Gas Vehicle Coalition is T. Boone Pickens, Jr. of Mesa Limited Partnership.

[33] W. David Montgomery and James L. Sweeney, Mandates for Alternative Fuels: A Policy Analysis, submitted to the American Petroleum Institute (August 1991).

and vehicle types. The natural gas industry has created organizations for effective representation at the federal level, but is less effective at the state level.

As the number of NGVs increases, an increasing number of NGV owners will want to use these vehicles to travel several hundred miles, from city to city, rather than restrict their travel to a single urban area. The provision of services over a broad geographic area, such as the Boston to Washington corridor, will require gas industry coordination on a regional level. In our view, the need for this regional coordination will underscore the need for gas industry cooperation on NGV issues.

Customer perception impediments

Long-term supply problems. One of the comments heard from LDCs during our interviews is that customers are concerned about switching from reliance on a competitive retail distribution industry (for gasoline and diesel fuel) to reliance on a monopolistic retail system (for compressed natural gas). Some potential customers are accustomed to price-shopping for gasoline or diesel and do not want to be at the mercy of a monopoly, even if it is a regulated monopoly. This customer concern was perceived to be an impediment to the growth of the NGV market, and we agree with this assessment.

Gas service reliability. We found no evidence in our interviews that customer perception of the gas transmission, storage and distribution system creates an impediment to NGV demand growth. In fact, our research indicates that NGV customers may have a good deal of faith in the gas industry's ability to offer reliable service to NGVs. Fleet owners generally have a realistic assessment of the cost and reliability of compressors and related equipment.

Equipment reliability. We have found no evidence that customer perceptions of the cost and reliability of end-use equipment create impediments to NGV use, beyond the impediments associated with a realistic assessment of the economic and technical factors affecting the choice of vehicle fuels. Where the customer sees a problem, there is likely to be a real problem rather than an error in customers' perception.

IMPEDIMENTS TO INCREASED USE OF GAS COOLING

Our assessment of impediments to increased use of gas cooling is summarized in Exhibit 2.5. For the purposes of this summary, the interview at the American Gas Cooling Center is reflected in the viewpoints of "local distribution companies." Most of the comments we received from individual companies were from interstate pipelines and local distribution companies, not producers. Most gas producers have very little

Exhibit 2.5
Impediments to Increased Use of Gas Cooling:
Differences Among Perceptions

Type of impediment	Producers	Interstate Pipelines	Local Distribution Companies	RCG/Hagler, Bailly
Economic				
Production costs				
Gas facilities costs				
End use equipment costs	X	X	X	X
Technical				
Gas resources				
Distribution technology				
Equipment reliability			X	X
Delivery system/reliability				
Legislative/regulatory				
Supply				
Gas operations			X	X
End use				
Institutional				
Long–term contracts				
Focus on customer needs			X	X
Funding for R&D and commercialization	X	X	X	X
Industry cooperation				
Customer Perception				
Long–term supply problems				
Gas service reliability				
Equipment reliability		X	X	X

Source: RCG/Hagler, Bailly, Inc.; based on selected industry interviews.

understanding of the gas cooling market but are attracted by the idea of a market segment that offers the potential to increase gas demand during the summer months.

Economic impediments

Between 1970 and 1980 the gas cooling market nearly collapsed, and there are only the beginnings of a recovery under way. In 1970, annual sales of residential gas air conditioners reached 62,000 while sales of large commercial units reached 5,000.[34] From 1970 to 1975 sales of gas air conditioners fell sharply and by 1980 the figures fell to 11,000 and less than 100, respectively. Whirlpool stopped manufacturing gas air conditioners in 1971 and Bryant exited the market in 1975. The dramatic decline during the 1970-1975 period was caused primarily by gas supply shortages, which led to moratoria on new gas hookups and expectations of gas price increases. The decline was exacerbated by equipment maintenance problems associated with residential air conditioners. In an era of declining sales it became difficult for manufacturers and service companies to provide reliable maintenance service, and gas distribution companies were unable to make up for this deficiency. By contrast, the increasing sales of electric air conditioners facilitated the training of technicians in electric system maintenance and installation, and facilitated improvements in efficiency and other design characteristics of electric air conditioners. Gas cooling has never recovered from the 1970-1975 decline, and is now finding it difficult to catch up with electric cooling. Most if not all of the manufacturers of gas cooling equipment are also manufacturers of electric cooling equipment.

A comparison between 1989 and 1990 statistics in the AGA's "1990 Commercial Gas Cooling Survey" shows an upward trend in cooling installations: a 14 percent increase in installations and a 64 percent increase in average tonnage per installation, resulting in an 86 percent increase in total tonnage.[35] However, the number of commercial installations in 1990 was very small (155 installations) compared with sales of large commercial units in 1970 (around 5,000 units sold).

If gas cooling can recover from the depressed level of sales in the 1975-1990 period, it will have to take advantage of (1) improvements in the thermal efficiency of state-of-the-art gas cooling systems and (2) the fact that electric cooling installations raise the electric system peak for many electric utilities, while the gas consumption associated with gas cooling occurs in the off-peak months for gas pipelines and distribution companies. At present it is much easier for a gas distribution company representative to explain these technical and economic benefits to commercial customers than to residential customers.

---

[34] American Gas Cooling Center, "Memorandum to NARUC Staff Gas Subcommittee's Task Force on Gas Cooling" (1991), Appendix C, "The History of Natural Gas Cooling."

[35] American Gas Association, "1990 Commercial Gas Cooling Survey," Issue Brief 1991-16, October 28, 1991, Table II.

Production costs. When producers, pipelines, and local distribution companies discuss impediments to increased gas cooling, they focus upon the competitive position of electric cooling systems and the cost-effectiveness and reliability of end use equipment. The question of gas supply is not raised and typically not considered to be a problem.

Gas facilities costs. Because gas cooling represents such a small share of gas system load and is concentrated in the summer months, there is a consensus that there are no impediments associated with gas operations, even if the higher range of the demand projections shown in Chapter 1 were reached.

End use equipment costs. All of the organizations interviewed regarding gas cooling expressed concern about the economics of gas versus electric cooling, based on end use equipment. The initial cost of a gas cooling system is higher than the initial cost of an electric cooling system, mostly because gas-engine-systems are inherently more complex technically than electric cooling systems. Consequently, this first-cost differential is not expected to go away in the next decade or even in the following decade. This first-cost premium for gas cooling products is probably the single most important impediment. In addition, it was mentioned that major equipment vendors of electric cooling products had not yet committed enough resources to produce, advertise and sell gas cooling products that, in their mind, would tend to replace their normal product lines rather than add sales volume. Furthermore, until the installed base of gas cooling equipment becomes large enough to employ an ample supply of trained technicians, the costs of maintaining a gas cooling system are likely to be higher than the costs of maintaining an electric system. To overcome these impediments, a gas cooling system must offer lower operating costs through equipment purchase rebates (provided as part of demand-side management programs) combined with possible tariff incentives and performance improvements.

In our view, the economics of end use equipment creates the major impediment to gas cooling, and further commercialization efforts are required.

Technical impediments

Gas resources. Since gas cooling represents such a small share of the total gas demand, none of the organizations interviewed perceived a technical impediment regarding the availability of gas resources or the need to access higher-cost resources.

Distribution technology. Similarly, none of the organizations interviewed perceived a technical impediment in distribution technology against gas cooling, which can easily be served by existing infrastructure only after minor modifications.

Equipment reliability. In contrast, LDCs perceive a serious problem with the reliability of gas cooling equipment. In the ideal situation, the customer would be offered equipment that is highly reliable and needs practically no maintenance. The experience of several distribution companies, however, has been the opposite: unless gas cooling equipment is regularly serviced by skilled technicians, there is a notable risk that the equipment will break down and the customer will completely lose interest in gas cooling. Thus, a common perception is that the technology of gas cooling should be improved, if possible, to make it more reliable and more foolproof. This can be achieved, for example, through the development or use of better equipment diagnostic controls.

We share this concern about gas cooling equipment reliability. Furthermore, this situation is accentuated, since gas cooling has a very small share — probably less than 3% — of the total cooling installed tonnage capacity. With a small market share, an equipment manufacturer must generally achieve a high level of equipment reliability in order to overcome the competitive disadvantage associated with the absence of a network of service and maintenance centers. This technical impediment must be addressed not only through increased R&D efforts but also through the cooperative funding of well-targeted demonstration projects and commercialization initiatives.

Delivery system impediments

Because gas cooling loads can easily be served by existing infrastructure with minor modifications, there are no delivery system impediments. This point is widely recognized. The simplest example is the delivery of gas to residential sites where gas is already used for heating; in this situation the existing infrastructure can be used to serve cooling loads.

Legislative and regulatory impediments

Supply. None of the organizations interviewed perceived a supply constraint associated with legislative or regulatory measures.

Gas operations. Some local distribution companies expressed the viewpoint that current rate structures for electricity and for natural gas are biased in favor of electricity on very hot summer days (i.e., the periods when electric systems are at their summer peak). The various state public service commissions (PUCs) have not established a consistent approach to the demand-side management (DSM) benefits of gas cooling. The availability of financial incentives for gas cooling varies notably on a utility-by-utility basis.[36] Similar wide-ranging variations exist in the levels of LDCs' promotion and funding of gas cooling demonstration and commercialization efforts.

[36] See the AGA's "1990 Commercial Gas Cooling Survey" for a summary table describing financial incentives encouraging gas or electric cooling installations.

End use. There is a consensus that today, gas cooling appliances do not face a competitive disadvantage associated with legislative or regulatory restrictions on end use equipment. The moratoria on new gas hookups that existed in the 1970s were a very serious impediment, but there is no parallel in today's regulatory climate. On the contrary, gas cooling technologies offer the environmental benefit of using refrigerants with minimal or no ozone-depleting potential.

Institutional impediments

Long-term contracts. There is a consensus that the long-term contract issue is not relevant to the growth of gas cooling. The majority of cooling customers either rely on system supply from the local distribution company or rely on short-term contracts. For the customer, payback periods for cooling equipment are much shorter than for power generation facilities.

Focus on customer needs. One theme that came out in our interviews is that the development of gas cooling will require greater attention to customer needs. If LDCs have been quite successful in marketing heating services, they have met far less fortune with cooling services. Furthermore, the customer would like its distribution company to provide a total service that integrates heating and cooling services. This is not, however, a familiar concept to all LDCs, many of which continue to regard themselves as primarily suppliers of a commodity rather than a service. We consider this institutional impediment to be important.

Funding for R&D and commercialization. There is a consensus that there is lack of funding to help commercialize gas cooling and that this is an important impediment. In terms of R&D funding, however, it was not necessarily as clear that more R&D monies could contribute significant near-term impacts on reducing the first costs and improving the reliability of gas cooling equipment.

Industry cooperation. There is a consensus that the issue of industry cooperation is not relevant to the growth of gas cooling. The typical cooling customer deals with the local distribution company on issues related to gas cooling, and does not want to bypass the distribution company.

Customer perception impediments

Long-term problems. There is a consensus that gas supply concerns are not a major factor affecting the customer's perception of gas cooling.

Service reliability. Similarly, the customer's perception of gas operations does not create an impediment to the growth of gas cooling. Customers recognize that the addition of summer season loads is easily managed by pipelines and distribution companies.

Equipment reliability. Several organizations expressed concern about the image of the reliability of gas cooling equipment in the customer's mind. This is an important impediment which must be addressed by the gas industry.

*** *** ***

This assessment of the impediments for each new market shows that the gas industry must focus more on the needs of the customers. Electric utilities are primarily concerned about their long term investments. Thus, institutional and legislative/ regulatory impediments dominate in the power generation sector. In the NGV and cooling markets, shorter term concerns about equipment first cost and reliability are critical.

In the following chapter, we review the activities already conducted by the gas industry, its trade associations and RD&D organizations to promote gas demand growth in the three new markets analyzed in this study. In Chapter 4, we discuss various policy options to help further promote gas growth.

CHAPTER 3: GAS INDUSTRY ACTIVITIES

In this chapter, we review the types of activities undertaken by the natural gas industry to capitalize on the market opportunities offered by the power generation, NGV and gas cooling markets. This will provide a baseline against which new possible activities can be evaluated.

First, we describe the types of activities already under way by producers, pipelines and distribution companies to develop the three new markets analyzed in this study. Next, we review the range of promotion activities pursued by industry trade associations (AGA and INGAA) as well as six other organizations:

- The U.S. Department of Energy (DOE)
- The Electric Power Research Institute (EPRI)
- The Gas Research Institute (GRI)
- The Natural Gas Vehicle (NGV) Coalition
- The American Gas Cooling (AGC) Center
- The New York Gas Group (NYGAS).

Finally, we focus our discussion on the research, development and demonstration (RD&D) activities that these organizations are sponsoring.

The purpose of this discussion is to provide a summary review of the kinds of things that are already being done to overcome impediments to new natural gas markets. In the following chapter, we discuss the implications of our assessment of impediments in terms of the types of policies and actions that the gas industry should pursue to increase its chances of capitalizing on new gas markets.

ACTIVITIES CONDUCTED TO DEVELOP NEW MARKETS

Considering all the activities which producers, pipelines and distribution companies are pursuing individually as well as through gas industry organizations, the gas industry is pursuing the development of new natural gas markets in several ways (see Exhibit 3.1):

1) *Operational support*. These activities include gas marketing, capacity assignment, capacity brokering, and all other activities that are conducted by pipelines and LDCs to acquire supplies and move gas but do not require investment in new facilities. These activities require a commitment of staff time but not a commitment of capital. In general, LDCs can be expected to take the lead role in providing service to customers that are or will be firm customers of the LDCs. Pipelines serve direct sale and firm

Exhibit 3.1
Gas Industry Activities Being Conducted to Develop New Markets

	Operational support	Firm gas supply aggregation by PLs or LDCs	Gas utility investment	RD&D by individual PLs or LDCs	GRI funding	Commercial–ization centers
Power sector						
Electric utility generation						
New baseload combined cycle						
Gas CC with No. 2 oil backup	PL	some PL **	Yes			
Gas CC without No. 2 oil backup	PL	some PL **	Yes			
CC designed for IGCC upgrade	PL	some PL **	Yes			
New combustion turbines	PL (summer)*					
Clean Air Act driven						
Repowering	PL	some PL **	Yes			
Select gas use	PL					
Basic co–firing	PL				Yes	
Co–firing with reburn	PL				Yes	
Co–firing w/ sorbent injection	PL				Yes	
Non–utility generation						
Large cogeneration QFs	PL	some PL **	Yes			
Small cogeneration QFs	LDC	LDC	Yes		Yes	
Independent Power Plants						
New baseload combined cycle	PL	some PL **	Yes			
New combustion turbines	PL (summer)*					

PL = pipelines   *LDC = Local Distribution Companies*

* *Due to the low load factor for combustion turbines, pipelines are unlikely to commit firm winter capacity to meet winter peaks on the electric system. On some pipelines (particularly those with large storage capacity) capacity may be made available (through brokering, reassignment, or seasonal assignment) to meet summer peaks.*

** *Enron is an industry leader in the area of gas supply aggregation for the power generation market*

Source: RCG/Hagler, Bailly, Inc.

Exhibit 3.1 (continued)
Gas Industry Activities Being Conducted to Develop New Markets

	Operational support	Firm gas supply aggregation by PLs or LDCs	Gas utility investment	RD&D by individual PLs or LDCs	GRI funding	Commercial–ization centers
Natural Gas Vehicles						
Automobiles and small trucks						
Commercial fleets	PL, LDC	LDC	Yes	Yes	Yes	Yes
Personal vehicles	LDC	LDC		Yes	Yes	Yes
Buses and large trucks	LDC	LDC		Yes	Yes	Yes
Gas cooling						
Gas–fired air conditioning						
Commercial/industrial	LDC	LDC	***	Yes	Yes	Yes
Residential	LDC	LDC	***		Yes	Yes
Gas–fired heat pumps	LDC	LDC	***		Yes	Yes

PL = pipelines LDC = Local Distribution Companies

*** *New utility investment may not be needed to serve these applications, which fall under traditional customer classes. On some PL and LDC systems, new uses of gas may simply ensure long–term utilization of existing capacity.*

Source: RCG/Hagler, Bailly, Inc.

transportation customers on their own lines and both pipelines and LDCs serve firm and interruptible transportation customers who do not bypass LDCs.

2) *Firm gas supply aggregation by pipelines or LDCs*. To serve new markets, pipelines or LDCs may aggregate supplies by signing contracts with gas producers. Long-term contracting may expose the pipeline to underrecovery of its gas purchase costs. If a company in the gas industry has assumed this supply aggregation role, that company has demonstrated a willingness to take risks to support the development of new market segments. At present the leading example of such a company is Enron.

3) *Gas utility investments.* Combination electric and gas utilities are building gas-fired power generation facilities for new or repowered facilities. Gas utilities are also investing in pipelines to serve new utility and NUG plants. In addition, some LDCs have set up subsidiaries to help develop and participate in gas-fired NUG projects. To date, nearly a dozen of such subsidiaries have been created. Finally, LDCs are investing in NGV commercial fleets.

4) *RD&D by individual pipelines or LDCs*. A portion of the commercialization activity supported by the gas industry is performed by individual companies acting independently of the industry-wide commercialization centers. Marketing efforts are typically tailored to the local regulatory environment and the competitive position of gas versus electricity and/or reformulated gasoline.

In addition, we should note the existence of the New York Gas Group (NYGAS) which regroups the gas distribution companies that are operating in the state of New York. NYGAS' objective is to provide New York State gas customers with security in gas energy supply, safety in gas distribution operations, and economy in gas consumption. As such, NYGAS engages in R&D activities and funds demonstration projects to show benefits to New York state customers. Annual contributions to NYGAS are expected of all New York gas distribution companies. The New York State PSC reviews NYGAS' R&D activities and controls the way in which member companies' contributions are recovered.

5) *GRI funding*. The gas industry provides R&D support through GRI. GRI's funding is ensured through a surcharge determined by the Federal Energy Regulatory Commission (FERC) and incorporated into the sales and transportation tariffs of the interstate pipeline systems that are members of GRI. The surcharge, which is adjusted annually, was 1.46 cents per Mcf in

1991. While pipelines currently voluntarily collect the surcharge on behalf of GRI, that funding mechanism is undergoing review.

FERC is empowered to exercise broad control over the allocation of GRI funds (decided by GRI's Board of Directors) as well as the total amount of funding. Because one of the principal criteria considered by FERC is the extent to which GRI programs offer net benefits to the ultimate customers who bear the cost of the GRI surcharge, such regulatory review can constrain the scope of GRI's activities.

GRI's activities are primarily guided by the FERC definition of RD&D, which includes the following guidance regarding appropriate RD&D expenditures: "... expenditures for the implementation and development of new and/or existing concepts until technically feasible and commercially feasible operations are verified." Consequently, this definition gives GRI the authority to seek FERC approval to engage in major field testing and demonstration activities to support the technology deployment of new products. However, that definition also excludes product commercialization activities such as advertising, product promotions and consumer surveys. This creates the risk that the gas industry's commercialization and marketing efforts could lag the industry's R&D funding. As a result, it is possible that the potential benefits from successful R&D efforts on gas technologies for power generation, the NGV markets, and gas cooling could be only partially realized, due to a shortage of funds to support commercialization.

6) *Commercialization centers.* The gas industry has established at AGA facilities two commercialization centers dealing with NGVs and gas cooling. These centers focus on the operational and company-specific problems associated with transferring new technology from the R&D environment to the marketplace. They do not duplicate the work of GRI. GRI coordinates its R&D efforts with other organizations.

- The NGV Coalition is actively involved in commercialization activities, but its funding is limited to about $1 million per year. The coalition is funded by annual dues from both regulated and unregulated companies; these dues range from $500 to $20,000, according to a standard schedule set by the coalition by categories of companies. For example, the coalition's annual membership dues for all gas transmission companies are $15,000. The coalition is not subject to regulatory oversight, but the ability of regulated companies to recover these contributions through rates is dependent on regulatory approval.

- The American Gas Cooling (AGC) Center is also funded by annual membership dues. Membership is voluntary and available to regulated and unregulated firms, and the AGC Center itself is not regulated. In 1991, there were two categories of members: corporate members with first-year dues set at $20,000 and affiliate members whose annual dues were only $500. The level of dues is adjusted annually by the AGC Center's Managing Committee, which includes one representative from each corporate member. In 1991, the AGC Center had a budget of $700,000.

ACTIVITIES OF GAS INDUSTRY ORGANIZATIONS

In this section, we review the different roles of gas industry trade associations (AGA and INGAA) and the six RD&D and commercialization organizations described above in promoting new uses of natural gas.

As summarized in Exhibit 3.2, there are at least two organizations involved in each of the ten following activities:

- Economic evaluation of technology alternatives
- Forecasting of market potential
- Strategic planning to support industry-wide programs
- Management of R&D
- Fund-raising to support commercialization projects
- Industrial and commercial marketing
- Surveys of gas industry activity
- Advertising
- Programs to influence federal legislation
- Programs to influence regulatory decisions at the state level.

By far, most of these activities are conducted at the national level rather than the state level. Only two organizations have programs at the state level: the American Gas Cooling Center is strongly committed to programs (other than advertising and lobbying) to influence regulatory decisions of public service commissions while the American Gas Association is the only other organization to have programs to influence the regulatory decisions of state environmental agencies. If we compare the gas industry with the coal and electric utility industries, the cooperative organizations in the gas industry tend to devote much less effort to legislative and regulatory issues at the state level. Of course, individual gas pipeline companies and distribution companies are active at the state level, and a few gas producers are active in NGV markets.

Exhibit 3.2
Activities of Selected Gas Industry Organizations

	American Gas Association	Interstate Natural Gas Association of America	U.S. Department of Energy	Electric Power Research Institute	Gas Research Institute	Natural Gas Vehicle Coalition	American Gas Cooling Center	New York Gas Group
Economic evaluation of technology alternatives	X	X		X	X		X	
Forecasting of market potential	X		X	X	X	X	X	
Strategic planning for industry-wide programs	X	X				X	X	
Management of R&D			X	X	X	X		X
Fund-raising to support commercialization projects	X			X		X	X	X
Industrial and commercial marketing	X						X	
Surveys of gas industry activities	X	X	X					X
Public relations and advertising	X					X		
Programs to influence federal legislation	X	X	X			X		
Programs to influence regulatory decisions at state level	X						X	

Source: RCG/Hagler, Bailly, Inc.

The pattern of activity shown in Exhibit 3.2 reveals another gap in current gas industry activities: the absence of strategic planning efforts to support industry-wide programs in new markets, especially the power generation market. Although there exist organizations that develop strategic plans for increasing the market penetration of gas technologies over the next decade in the NGV and gas cooling markets, there is no locus of strategic planning functions aimed at the power generation sector, despite the significant effort that gas producers and pipelines devote to strategic business planning on a company-specific basis.

In that area, one endeavor is worth noting, however. INGAA has established a Power Generation Task Force to create forums for all sectors of the industry to stimulate the use of natural gas by utilities and NUGs. The forums include meetings between CEOs from all sectors of the gas industry and electric industry CEOs to begin a dialogue to foster the use of gas in power generation. INGAA's Power Generation Task Force also expects to sponsor meetings between operations experts in the gas and electric industries to help all sectors understand the operational and policy concerns that prevent increased gas demand by NUGs and to develop solutions to the identified problems. The Power Generation Task Force does not fund demonstration projects, however; it is therefore not classified as an R&D organization. Like another industry forum, the Natural Gas Council, the Power Generation Task Force does not have its own staff or funding.

GAS RD&D ACTIVITIES AIMED AT NEW MARKETS

Gas RD&D activities in support of the three new markets are undertaken largely through six organizations: DOE, EPRI, GRI, the NGV Coalition, the American Gas Cooling Center, and NYGAS.[1] As shown on Exhibit 3.3, these organizations have different responsibilities regarding the three new markets that are the focus of this report: power generation, NGV and gas cooling markets. Clearly, DOE, GRI and EPRI are (in that order) the three most active organizations with the broadest scope of activities and resources.

Altogether, however, the total funding by these six organizations for natural gas RD&D was estimated at $309 million for 1991, about 16 percent of the total R&D monies spent by the seven organizations that we listed. In turn, we estimate, as displayed in Exhibit 3.4, that $132 million was spent on the three new markets, or 6.5% of the total RD&D funds spent. These funds can be divided as follows between all three new markets: $91.9 million (69 percent) for gas power generation; $13.5 million (11 percent) for NGVs; and $26.8 million (20 percent) for gas cooling. Further analysis shows that less than $33 million is spent on RD&D aimed at mid-term baseload power generation technologies with the best market payoffs; most of the balance involves work on fuel cells, a technology that will take another 8 years to scale up for baseload power use.

[1] Individual gas companies also participate in GRI projects.

Exhibit 3.3
New Market Segments Addressed by Selected Gas Industry Organizations Involved in Research, Development, and Demonstration

	U.S. Department of Energy	Electric Power Research Institute	Gas Research Institute	Natural Gas Vehicle Coalition	American Gas Cooling Center	New York Gas Group
Power sector						
Electric utility generation						
New baseload combined cycles	X	X				
New combustion turbines	X	X				
Clean Air Act driven	X	X	X			
Non-Utility Generation						
Large cogeneration QFs	X		X			
Small cogeneration QFs	X		X			X
Independent Power Plants	X	X	X			
Natural Gas Vehicles	X		X	X		X
Gas cooling	X		X		X	X

Source: RCG/Hagler, Bailly, Inc.

Exhibit 3.4
Summary of 1991 Funding by Selected RD&D Organizations

Organization	R&D Spending ($ million) in				Natural Gas RD&D ($ million)	Non–Gas RD&D ($ million)	% RD&D in New Markets
	Gas Power Generation	NGVs	Gas Cooling	Three New Markets			
U.S. DOE	58.5 (*)	5.5	6.0	70.0	117	1,340	4.8%
EPRI	18.0	0.0	0.0	18.0	18	278	6.1%
GRI	15.2	6.4	19.6 (**)	41.2	169	0	24.4%
NGV Coalition	0.0	1.0	0.0	1.0	1	0	100.0%
AGC Center	0.0	0.0	1.0	1.0	1	0	100.0%
NY Gas Group	0.2	0.6	0.2	1.0	3	0	37.0%
Total	91.9	13.5	26.8	132.2	309	1,618	6.9%

(*) Including $40 million for fuel cell RD&D.

(**) Estimated fraction out of a total budget of $22.3 million for residential/commercial space conditioning/gas heat pump programs.

Source: RCG/Hagler, Bailly, Inc. estimates; based on various organization R&D budgets available.

Overall, the level of gas industry funding for the commercialization of gas-fired power generation technology could be increased to reflect the current size and projected growth of the power generation market, which can represent up to 95% of the total expected increase in gas demand. This is accentuated by the fact that there are commercialization centers for NGVs and for gas cooling but no such center exists to promote gas-fired power generation technology advancements. In addition, EPRI's RD&D efforts are much more oriented on coal-fired fossil power plants.

Power sector. Three organizations are conducting or managing RD&D on gas technologies for power generation: DOE, EPRI, and GRI.

DOE's RD&D activities aimed at the power generation sector include fuel cells R&D (with $36 million obligated in 1991, the largest fraction by far, about 61 percent), work on gas co-firing ($7 million, or 12 percent) and industrial cogeneration ($15.5 million or 27 percent). In the co-firing area, DOE is involved in a field test project at the Ohio Edison Niles project to which EPRI and GRI also contribute. DOE has also awarded two demonstration projects under its Clean Coal program to which it is contributing a total of $22 million. One project sponsored by Energy and Environmental Research (EER) Corporation involves the evaluation of gas reburning and low-Nox burners on a wall-fired boiler of Public Service Company of Colorado. This project is supported by GRI and EPRI as well. Another project -- also sponsored by EER -- deals with gas reburning on tangentially- and cyclone-fired boilers at two Illinois sites and involves the cooperation of three Illinois utilities. Because these projects tend to last between 3 and 4 years, DOE's funding averages about $7 million per year. Other projects may be funded under the new rounds of the Clean Coal program. In addition, DOE is very interested in the development of a high-temperature steam generator that could improve the performance of future combined cycles. DOE's analysis indicates that up to 21,000 MW of such combined cycles could develop between 1996 and 2015.

EPRI is pursuing gas-fired power generation RD&D in five key areas: fossil steam plant availability, fossil steam systems and performance, combustion turbines and combined cycles, gasification power plants, and fuel cells. For example, EPRI is interested in increasing the availability of peaking combustion turbines (by 3 percent for installed units, 10 percent for new units) and developing a next-generation combined cycle with a 46 percent efficiency. In EPRI's analysis, combined-cycle gasifier units could capture more than 25 percent of the new baseload capacity between 1993 and 2010.[2] In addition, EPRI is participating in two gas co-firing projects, as mentioned previously.

GRI naturally tends to focus its attention only on the market segments in which there appears to be the greatest need for cooperatively funded R&D. These segments concentrate on gas-fired industrial, commercial, and residential cogeneration facilities

---

[2] EPRI, Research and Development Program: 1989-1991.

and small power "packaged" plants. To date, the bulk (i.e., over 65%) of that research is spent on small- to medium-size gas turbines, reciprocating engines and fuel cells. To promote gas use in large baseload power generation alternatives, GRI is involved in two programs for a total of $3.1 million/year (in CY 1992 funds) aimed at natural gas use (e.g., co-firing) for boiler emission controls. As noted before, GRI is involved in the Ohio Edison Niles project and two gas co-firing demonstration projects launched under the DOE Clean Coal Program. One of these projects involves EER's gas reburn/sorbent injection (GR/SI) technology. GRI also co-funded with individual members co-firing tests in Oklahoma and Pennsylvania.

NYGAS focuses on the needs of customers served by gas distribution companies, not the needs of end users who are served directly by interstate pipelines. Thus, electric utilities and large NUGs are outside the scope of its R&D efforts. NYGAS, however, supports the development of small-size cogeneration technology by funding projects such as a field test of an integrated gas engine-vapor compression cogeneration system and an evaluation of the energy performance, economics and environmental impact of cogeneration equipment at multi-family residential sites.

Natural gas vehicles. Along with individual gas companies, four organizations are supporting the introduction of natural gas vehicles: the NGV Coalition, GRI, the New York Gas Group and the DOE.

The NGV Coalition is spending about $1 million/year, mostly in NGV commercialization efforts. A joint effort between AGA and the NGV Coalition in 1992 is designed to bring forward the NGV market through a combination of federal and state lobbying and national television advertising. The NGV Coalition raised additional funding for the lobbying effort.

However, the overall level of gas industry funding for NGVs is largely determined by the allocation of GRI funds which average $7 million per year. GRI controls the bulk of the R&D funds spent in that area and, although there is some overlap between the activities of GRI and NYGAS, it is clear that the gas industry has well-established programs to support the introduction of NGVs. GRI is actively involved in programs with the Big Three automakers -- Chrysler, Ford, and General Motors -- to develop natural gas engines and systems for light- and medium-duty truck and cargo/passenger vans. In addition, GRI is funding the development of gas engines for transit buses, trucks and vans in sizes ranging from 3.7 to 12 liters; these activities involve companies like Cummins, Detroit Diesel, and Stewart & Stevenson. GRI has also funded the development of a commercially-available lightweight onboard storage cylinder. Finally, GRI has several projects aimed at addressing the public's concerns about NGV safety.

One of these projects, for example, called for the development of new test criteria for qualifying pressure-relief devices to equip on-board NGV fuel cylinders.[3]

The DOE is now becoming a player in the NGV market, since it is seeking in its proposed FY93 budget to fund R&D on hybrid vehicles which combine batteries with fuel cells, gas turbines or other systems. Although such R&D is not in the mainstream of conventional NGV R&D, it can have some spin-off benefits. The potential contribution of such DOE's R&D to the promotion of the use of gas in vehicles should therefore not be ignored.

Gas cooling. The organization of gas cooling promotional efforts is similar to that of NGVs, since four organizations are supporting the continued development of gas cooling: The American Gas Cooling Center, GRI, DOE, and the New York Gas Group. Here again, GRI controls the bulk of the R&D funds, with about $17-20 million spent in that area (or related areas) each year. Next comes DOE which spends some $6 million on R&D on or related to gas cooling. The American Gas Cooling Center is the third most active player in this area.

GRI's gas cooling activities involve about 20 initiatives sponsored as part of its activities in four different project areas: residential space conditioning; commercial space conditioning; residential gas heat pumps; and commercial gas heat pumps. Some of the larger projects call for the development of absorption cooling systems, gas-fired residential and commercial heat pumps based on internal-combustion engine technology, and adsorption heat pumps. For 1992, GRI's funding for these 20 projects amounts to $17 million (out of a total of $19 million allocated to the four project areas).

DOE's gas cooling activities are part of two projects: one on absorption heat pump technology (calling for the development of three advanced cycle systems for both residential and commercial applications) and one on engine-driven heat pump technology (using either internal combustion engines or Sterling engines).

Overall, given the dominant market share of electric cooling and the difficulty of installing and servicing gas cooling equipment, the breadth of gas industry support for new initiatives in gas cooling is unclear. The organizations needed to address impediments to increased gas use in this market segment are well established, however.

[3] This project was co-sponsored by NYGAS and the Canadian Gas Association.

CHAPTER 4:
IMPLICATIONS FOR THE GAS INDUSTRY

In this chapter we recommend various policy options and courses of actions that the natural gas industry should pursue to overcome impediments to gas demand growth. Based on our analysis and our interviews, we find that the gas industry needs to consider two types of initiatives:

- Generic -- or horizontal -- actions designed to assure removal of impediments to all three new markets; and,
- A vertical initiative aimed at capturing the power generation sector.

THE NEED FOR GENERIC ACTIONS

The industry needs to undertake three types of generic actions:

- To develop collaborative market strategies
- To adjust research, development and demonstration (RD&D) and commercialization priorities
- To link regulatory issues to customer needs.

The need to develop collaborative market strategies

Although it is useful to maintain different organizations to tackle different markets - the Natural Gas Vehicle Coalition, the American Gas Cooling Center, and the Industrial Gas Technology Commercialization Center and the ad hoc organizations such as INGAA's Power Generation Task Force and the Natural Gas Council -- the gas industry needs to coordinate the marketing efforts of the different organizations addressing the three major segments discussed in this study — power generation, NGVs, and gas cooling. Each of the existing organizations has a different membership as well as a different set of priorities.

To address these concerns the gas industry should establish a process for developing collaborative market strategies. Collaboration among producers, pipelines and LDCs is needed to resolve industry-wide market issues relevant to new and expanded uses of natural gas. Companies in the gas industry could pursue this collaboration through an existing organization such as the newly established Natural Gas Council. The industry should consider establishing a program with a limited life, a capped budget and specific goals to target the impediments identified in this report:

- Demonstration and commercialization efforts to bring R&D products to market and disseminate information about new technologies.

- Collaborative gas industry representation and public relations initiatives to overcome customer perception problems and deal with legislative and regulatory impediments.

- Workshops, conferences, and forums may help overcome institutional impediments by fostering a better understanding of issues. A workshop or conference could have one of three orientations:

  - Industry orientation: a forum designed to help the gas industry increase its market share and identify marketing opportunities

  - Customer orientation: a forum designed to provide existing and potential customers with information on the benefits of natural gas use in relation to electricity or other energy sources

  - Customer/industry orientation: a forum designed to promote communication between the gas industry and its ultimate customers.

To some extent these initiatives are already fostered by the activities of AGA, GRI, INGAA, and other gas industry organizations. The role of collaborative market strategies would be to tie all these activities together on a coordinated industry-wide basis. Most importantly, to become effective, these strategies would have to be recognized, endorsed, and even better accepted by the leading companies in the gas industry.

The need to adjust RD&D and commercialization priorities

One serious deficiency in present funding patterns is the relatively modest level of monies allocated to demonstration and other commercialization projects for gas-fired power generation technologies. The power sector is clearly the largest market opportunity for the gas industry, yet the commercialization of R&D concepts receives relatively modest funding. Demonstrations of the effectiveness of advanced co-firing in meeting Clean Air Act requirements, for example, could receive more industry-wide funding. Since power generation is the biggest market opportunity, it should receive more commercialization funding.

Because gas producers and power generation customers have not yet been able to reach an understanding regarding the appropriate allocation of gas price risk over the long term, and LDCs may not be directly involved in gas sales to the power sector, pipeline companies may be in the best position to exercise leadership in the development of gas demand in the power sector.

A possible approach to funding commercialization projects in the power generation sector is to organize a center[1] with funding based on commitments to specific projects in a specific time frame rather than annual dues with an open-ended time frame. Each project would have a limited number of sponsors with an identifiable interest in the success of the project.

Another finding of our study is that the NGV and gas cooling markets still need substantial RD&D and commercialization funding -- beyond their current levels -- to overcome technical impediments and ensure that the products are successfully introduced to the market. It is necessary to continue RD&D funding on NGV emissions, safety-related issues and NGV fuel storage tank designs. It is also necessary to improve the reliability and ease of maintenance of high-efficiency gas cooling systems.

Long-term, high-risk R&D must also be funded to give natural gas an opportunity to offer innovative solutions to consumer needs. Research on innovative methods of gas storage, and research that could yield a technological breakthrough in liquefaction technology to sharply reduce the cost of liquefaction and regasification, should be pursued by the U.S. Department of Energy. Although the impact of long-term R&D on gas technology may not be concentrated in the power generation, NGV and cooling markets, the need for long-term options must be recognized in the development of an overall R&D funding strategy.

The need to link regulatory issues to customer needs

One impediment to the expansion of new gas markets is the fact that producers, pipelines and LDCs have separate legislative and regulatory objectives which make it difficult to develop a collaborative approach to serve the ultimate customer. The regulated companies must closely watch regulatory developments that can fundamentally alter the profitability of different categories of gas services or capital investments. During a period of major regulatory change, there is a need for senior management to respond to regulatory initiatives introduced by FERC or state commissions. The unregulated companies find their business interests vitally affected by regulatory issues which they would rather not have to deal with. From a customer standpoint, the complexity of gas industry regulations and the level of effort devoted to regulatory compliance and representation is at best uninteresting and at worst an indication that the industry is unable to focus its attention on serving the customer.

1 This type of center could be similar to the Industrial Gas Technology Commercialization Center.

If the ultimate objective of regulations is to protect the interests of consumers of natural gas, it should be possible to involve the regulators in a dialogue with consumers. In the markets we address in this study, the consumers are power generation customers, NGV owners and owners of gas cooling equipment. Among these groups only the power generation customers can afford to play an active role in regulatory proceedings, but their regulatory staffs are already obligated to devote time to electric utility regulatory proceedings. The natural gas regulatory process appears to have its own momentum, independent of the viewpoints of the ultimate customers who are supposedly protected by regulation.

As the gas industry enters a more competitive era, it will have to shift its attention from the concerns of the regulators to the concerns of the customers. To involve the regulators in a dialogue with consumers, the gas industry should sponsor forums where representatives of federal and state regulatory bodies are invited to discuss fundamental regulatory objectives with representatives of gas companies and ultimate customers. Regulators would then be made aware of the concerns of these customer groups outside of formal, and often adversarial, regulatory proceedings.

THE NEED TO CAPTURE POWER GENERATION MARKETS

As the data presented in Chapter 1 make clear, the growth in gas use for power generation is likely to exceed the growth in gas use for natural gas vehicles, gas cooling, and industrial applications through the year 2000. The power generation market, which includes utility and non-utility plants is by far the largest market opportunity facing the natural gas industry, representing the greatest potential with the highest expected growth through the year 2000.

Yet that biggest market is not aggressively pursued in a way that can be effective and focused enough:

- The activities of INGAA's Power Generation Task Force are ad hoc in nature, without permanent staff or funding.

- Because of the composition of its membership, which includes electric and gas combination utilities as well as gas utilities that are competing with electric utilities, AGA members may have difficulty reaching a consensus on gas industry marketing objectives in the power generation sector.

- GRI is not permitted to develop comprehensive marketing strategies that address legislative, regulatory, institutional and customer perception impediments.

In contrast, each of the smaller market opportunities is being addressed by an organization with a specific focus: the Natural Gas Vehicle Coalition and the American Gas Cooling Center.

For the gas industry as a whole, therefore, there appears to be a need for better coordination of efforts to serve the power generation market, particularly the electric utilities. There are four near-term actions that the gas industry can take to serve electric utilities more effectively:

- *Address natural gas reliability.* The different segments of the industry must work together to (1) provide quantitative, objective information regarding the nature of projected winter and summer peak loads and the gas industry resources available to meet these peak loads, (2) identify situations in which the gas industry may be forced to curtail firm transportation customers or firm supply customers, and (3) recommend measures needed to reduce or eliminate the risk of curtailment. For example, a joint effort by producers and pipelines could result in a white paper that outlines one or more of these issues.

- *Study and understand emerging electric utility regulatory developments.* Provide funding for market strategy studies and forums to ensure that market opportunities created by new regulations affecting electric utilities are actively pursued, including opportunities that may stem from new regulations in demand-side management, integrated resource planning, and NUG competitive bidding. These electric utility regulations are sufficiently complex that many gas companies may find it difficult to assess their potential impact on gas demand.

- *Offer technical assistance and institutional support to companies marketing gas to electric utilities.* In particular, there is a clear need for a program to fund research on procedures to be used by Public Utility Commissions (PUCs) to compare generation planning alternatives with different degrees of exposure to gas price risk. Another example would be a study comparing the coal and natural gas industries and explaining the effect of production economics on the producer's ability to commit to price escalators other than spot prices in long-term contracts.

- *Put greater resources into state-level programs to influence the regulatory and environmental decisions of PUCs and state siting agencies.* Gas companies must coordinate their legislative and regulatory efforts more effectively to ensure that the gas industry is as well represented as the coal industry in state proceedings in front of local agencies and public utility commissions. It would be useful to know, for example, which states have programs that provide a "model" for other states with regard to removing impediments to increased gas consumption, and how state environmental plans evaluate natural gas.

Both the electric utilities and gas companies interviewed for this study affirmed a need to promote communication between these two industry groups. First, electric utilities have some difficulty understanding the reluctance of gas producers to enter into long-term contracts, while producers have difficulty understanding why a gas price escalator should be tied to anything but spot prices of gas. Second, electric utilities have difficulty applying the concept of loss of load probability to firm gas service, and are sometimes surprised that gas utilities do not routinely calculate such probabilities for planning purposes. On the other hand, gas utilities may look at their record of service to firm customers over the last ten years and wonder why the electric utilities are concerned about gas reliability. These two points best highlight the need for better communication between the electric and gas industries in a time when the electric utility share of gas system load is likely to increase.

*** *** ***

In this report we have attempted to identify impediments to new uses of natural gas in selected markets, so that the members of the INGAA Foundation can develop marketing strategies on the basis of an objective look at the impediments facing the industry. The collaborative thrust needed to be successful in these markets can only come from the gas industry itself.

APPENDIX A: INTERVIEW GUIDE

To suggest a framework for discussion of new gas markets and impediments to increased gas use in these markets, RCG/Hagler, Bailly developed the interview guide shown on the following pages. However, none of the interviews exactly followed the sequence of questions in the interview guide.

Impediments to New Natural Gas Markets and Expanded Natural Gas Use

INTERVIEW GUIDE
for interviews conducted by RCG/Hagler, Bailly, Inc.
on behalf of the INGAA Foundation

Part I. New Natural Gas Uses Being Promoted by Your Organization

1. In which market segments is your organization promoting new uses of natural gas?

    - Gas-fired cogeneration
    - Gas-fired independent power plants
    - Utility baseload power generation (e.g. co-firing and repowering)
    - NG vehicles
    - Commercial gas cooling and air conditioning
    - Feedstock applications
    - Industrial boiler applications where gas can displace oil or coal
    - Process heat applications with growth opportunities

2. What are the key factors shaping these market segments and determining the growth of gas use?

    - Economic factors; prices and costs
    - Development of new technology
    - Gas transmission and distribution capacity
    - Tax laws
    - Legislation and regulation
    - Institutional factors; cooperation among industry groups
    - Customer perceptions

3. What is your strategy for promoting new uses of natural gas?

    - Marketing strategy
    - R&D strategy
    - Legislative and regulatory strategy
    - Public relations strategy

4. What are your goals in terms of market penetration and timing?

    - Market development goals
    - R&D objectives
    - Legislative and regulatory goals
    - Public relations goals

5. What are the impediments to the achievement of these goals?

6. What can your organization do to overcome these impediments?

Part II. The Competitive Position of the Natural Gas Industry

7. What can other private sector organizations do to overcome the impediments to development of new uses of natural gas?

8. In markets where gas competes with other fuels, what are the sources of competitive advantage for the natural gas industry?

9. What are the principal regulatory and policy changes affecting the competitive position of the natural gas industry?

10. Are the current strategies of gas industry participants going to be effective in promoting new uses of natural gas?

    - Marketing strategies
    - R&D strategies
    - Legislative and regulatory strategies
    - Public relations strategies

11. Should natural gas industry participants adopt new strategies, to promote new uses of natural gas?

    - Marketing strategies
    - R&D strategies
    - Legislative and regulatory strategies
    - Public relations strategies

APPENDIX B:
LIST OF ORGANIZATIONS INTERVIEWED

- **Trade Associations**
  - American Gas Association
  - American Gas Cooling Center
  - American Petroleum Institute
  - American Refrigeration Institute
  - Edison Electric Institute
  - Gas Appliance Manufacturers Association
  - Independent Petroleum Association of America
  - Industrial Gas Technology Commercialization Center
  - Interstate Natural Gas Association of America
  - Natural Gas Supply Association
  - Natural Gas Vehicle Coalition

- **Research Institutes**
  - Gas Research Institute
  - Institute of Gas Technology
  - New York Gas Group

- **Producers**
  - Conoco Inc.
  - Phillips Petroleum Company
  - Shell Oil Company

- **Pipelines**
  - CNG Transmission Corporation
  - The Coastal Corporation
  - Columbia Gas Transmission Corporation
  - El Paso Natural Gas Company
  - Enron Pipeline Operations International
  - Pacific Gas Transmission Company
  - Panhandle Eastern Corporation
  - Southern Natural Gas Company
  - Tenneco Gas
  - Transco Gas Company

- **Local Distribution Companies**

  - Atlanta Gas Light Company
  - The Brooklyn Union Gas Company
  - Southern California Gas
  - Wisconsin Energy Corporation

- **Electric Utilities**

  - Consumers Power Company
  - Houston Lighting & Power
  - Northern Indiana Public Service Company
  - Southern California Edison
  - Southern Company Services, Inc.
  - Texas Utilities
  - Virginia Power Company

U.S. Department of Energy

- Office of Fossil Energy
- Office of Industrial Technologies
- Office of Policy
- Office of Transportation Technologies

Equipment Manufacturers

- Solar Turbines, Inc.

APPENDIX C: DETAILED MARKET PROJECTIONS

This Appendix provides the details of the various projections presented in Chapter 1. Five statistical exhibits are included:

- Exhibit C.1 Potential Growth in Gas Demand in New Markets: 1990-2000
- Exhibit C.2 Projected Gas Demand in the Electric Utility Sector
- Exhibit C.3 NERC Projections of Gas Requirements in the U.S. Electric Utility Sector
- Exhibit C.4 NERC Projections of Gas-Fired and Dual Fuel-Fired Generating Capacity Owned by U.S. Electric Utilities
- Exhibit C.5 Projected Gas Demand in the Industrial Sector

Exhibit C.1
Potential Growth in Gas Demand in New Markets, 1990–2000

	Market Size in 1990, Bcf	Lower Bound in 2000, Bcf	Upper Bound in 2000, Bcf	Minimum Increase, 1990–2000 Bcf	Maximum Increase, 1990–2000 Bcf	Excess of Upper B. over Lower B. Bcf
Electric Utility	2,794 (a)	3,420 (b)	4,950 (c)	626	2,156	1,530
Cogeneration	1,115 (d)	1,527 (e)	1,866 (f)	412	751	339
Indep. Power Plant	40 (g)	480 (h)	750 (h)	440	710	270
Natural Gas Vehicles	3 (i)	68 (j)	217 (k)	64	214	149
Gas Cooling	59 (l)	79 (l)	460 (m)	19	401	381

Data Sources:

(a) U.S. Dept. of Energy, EIA, "Monthly Energy Review: January 1992," DOE/EIA-0035(91/12), p. 31.

(b) American Gas Association, "1992 A.G.A.-TERA Base Case," Appendix A.4, Table A.7.

(c) National Economic Research Associates, Inc., "Energy Outlook," Sept. 23, 1991, p. 6.

(d) Gas Research Institute, "Baseline Projection Data Book: 1992 Edition of the GRI Baseline Projection of U.S. Energy Supply and Demand to 2010", p. 125 (commercial cogen), 195 (industrial cogen).

(e) This is the 1991 GRI projection cited in source (d), less 10 percent.

(f) This is the 1991 GRI projection cited in source (d), plus 10 percent.

(g) RCG/Hagler, Bailly, Inc. estimate based on operating IPP capacity.

(h) RCG/Hagler, Bailly projection.

(i) Gas Research Institute, "Baseline Projection Data Book: 1992 Edition," p. 453.

(j) This is 50 percent of the difference between the projected total transportation sector consumption (including pipeline fuel) shown in the 1992 GRI Baseline forecast (Ref.d) the 1992 projection of pipeline consumption shown. All data from p. 453.

(k) American Gas Association, "1992 A.G.A.-TERA Base Case," Appendix A.4, Table A.6.

(l) Gas Research Institute, "Baseline Projection Data Book: 1992 Edition," p. 39 (residential), p. 125 (commercial).

(m) Unpublished figure based upon a conversation with Anthony Occionero of the American Gas Cooling Center, October 3, 1991.

Note: Where required, consumption data is converted from Btu to cf using a heat content of 1,031 Btu/cf.

Exhibit C.2
Projected Gas Demand in the Electric Utility Sector

Year	Actual Bcf (a)	NERC 1991 Forecast Bcf (b)	GRI 1992 Baseline (Utility +IPP) Bcf (c)	Enron 1991 (utility + IPP) Bcf (d)	AGA 1992 Base Case Bcf (e)	DOE/EIA 1992 Reference Case Bcf (f)	NERA September 1991 Baseline Bcf (g)	DOE/EIA 1992 High Economic Growth Bcf (f)
1980	3,084							
1981	3,655							
1982	3,242							
1983	2,908							
1984	3,123							
1985	3,065							
1986	2,610							
1987	2,847							
1988	2,628							
1989	2,785							
1990	2,794	2,660	2,758	2,786	2,794	2,790	2,790	2,793
1991	2,869	2,503	2,846				2,830	
1992		2,550					2,950	
1993		2,676					3,150	
1994		2,788					3,400	
1995		2,855	3,151	3,400	3,084	3,290	3,630	3,375
1996		3,070						
1997		3,189						
1998		3,274						
1999		3,410						
2000		3,480	4,198	4,100	3,420	4,360	4,950	4,724

Exhibit C.2
Projected Gas Demand in the Electric Utility Sector

Year	Actual Bcf (a)	NERC 1991 Forecast Bcf (b)	GRI 1992 Baseline (Utility +IPP) Bcf (c)	Enron 1991 (utility + IPP) Bcf (d)	AGA 1992 Base Case Bcf (e)	DOE/EIA 1992 Reference Case Bcf (f)	NERA September 1991 Baseline Bcf (g)	DOE/EIA 1992 High Economic Growth Bcf (f)
2001								
2002								
2003								
2004								
2005				3,800	4,045	5,690	7,400	6,169
2006								
2007								
2008								
2009								
2010			4,622		4,677	5,540		5,703
1990–2000 increase:								
Firm		402						
Interruptible		418						
Total		820	1,439	1,314	626	1,570	2,160	1,930

Sources:
(a) U.S. Dept. of Energy, EIA, "Monthly Energy Review: January 1992," DOE/EIA–0035(91/12), p. 31; energy consumption figures report in Btu, converted at 1,031 Btu/cubic foot per Ref. (g), p. 148. 1991 demand is 1991 year-to-date (October), plus average of 1989/1990 Nov./Dec. consumption.
(b) NERC, "Electric Utility Supply & Demand 1991–2000" (July 1991), p. 80.
(c) Gas Research Institute, "Baseline Projection Data Book: 1992 Edition of the GRI Baseline Projection of U.S. Energy Supply and Demand to 2010", Volume 1, p. 305. Btu converted at 1,031 Btu/cf per Ref. (g).
(d) Enron Corp., "Enron Corp's Outlook For Natural Gas," 1991, pp. 4–5.
(e) American Gas Association, "1992 A.G.A.–TERA Base Case," Appendix A.4, Table A.7.
(f) U.S. Dept. of Energy, EIA, "1992 Annual Energy Outlook with Projections to 2010," DOE/EIA–0383(92), Table A.9, p. 73 for reference case, Table B.2, p. 80 for high economic growth case.
(g) National Economic Research Associates, Inc., "Energy Outlook," Sept. 23, 1991, p. 6.

Exhibit C.3

NERC Projection of Gas Requirements in the U.S. Electricity Utility Industry Sector

Year	Firm				Interruptible				Total Firm and Interruptible
	Steam	Combustion Turbine	Combined Cycle	Total	Steam	Combustion Turbine	Combined Cycle	Total	
U.S. electric utility needs, MMcf									
1990	1,733,515	16,036	95,714	1,845,265	735,081	34,737	44,493	814,311	2,659,576
1991	1,675,292	19,845	96,929	1,792,066	584,825	53,822	72,712	711,359	2,503,425
1992	1,658,881	21,290	107,763	1,787,934	640,110	52,588	69,818	762,516	2,550,450
1993	1,693,681	15,810	121,614	1,831,105	675,849	65,531	103,700	845,080	2,676,185
1994	1,773,377	17,981	133,737	1,925,095	682,098	73,390	107,610	863,098	2,788,193
1995	1,795,739	16,161	139,146	1,951,046	697,416	83,693	122,983	904,092	2,855,138
1996	1,824,556	18,463	147,456	1,990,475	760,942	113,117	205,275	1,079,334	3,069,809
1997	1,876,512	28,522	175,261	2,080,295	761,349	136,152	211,172	1,108,673	3,188,968
1998	1,917,150	42,733	203,134	2,163,017	739,879	136,333	234,507	1,110,719	3,273,736
1999	1,939,111	55,119	207,955	2,202,185	768,968	180,059	259,241	1,208,268	3,410,453
2000	1,949,672	70,495	227,390	2,247,557	701,788	208,972	321,725	1,232,485	3,480,042
1990–2000 increase	216,157	54,459	131,676	402,292	(33,293)	174,235	277,232	418,174	820,466

Source: North American Electric Reliability Council, "Electricity Supply & Demand 1991–2000" (July 1991), p. 80.

Exhibit C.4

NERC Projection of Gas-Fired and Dual Fuel-Fired Generating Capacity Owned by U.S. Electric Utilities

Year	Gas-fired				Dual Fuel-Fired				Total Gas-fired & Dual-Fired
	Steam	Combustion Turbine	Combined Cycle	Total	Steam	Combustion Turbine	Combined Cycle	Total	
U.S. electric utility capacity, summer MW									
1990	45,586	8,524	1,919	56,029	54,499	11,374	4,192	70,065	126,094
1991	45,802	9,219	2,048	57,069	54,380	11,501	4,305	70,186	127,255
1992	45,747	10,009	2,186	57,942	54,495	11,501	4,510	70,506	128,448
1993	46,735	10,696	2,485	59,916	54,573	11,972	4,764	71,309	131,225
1994	46,658	12,579	3,377	62,614	54,558	12,620	5,258	72,436	135,050
1995	46,639	14,277	4,567	65,483	54,527	13,794	5,670	73,991	139,474
1996	46,477	15,762	5,200	67,439	55,001	15,304	5,900	76,205	143,644
1997	46,780	17,287	6,284	70,351	55,467	16,024	6,106	77,597	147,948
1998	46,811	19,186	8,443	74,440	55,891	17,513	6,330	79,734	154,174
1999	46,665	20,666	9,341	76,672	56,727	18,966	6,382	82,075	158,747
2000	46,287	21,731	10,465	78,483	56,900	21,085	7,186	85,171	163,654
1990–2000 increase	701	13,207	8,546	22,454	2,401	9,711	2,994	15,106	37,560

Source: NERC, "Electric Utility Supply & Demand 1991–2000" (July 1991), pp. 32–39.

Exhibit C.5
Projected Gas Demand in the Industrial Sector

Year	Actual Bcf (a)	AGA 1992 Base Case Bcf (b)	WEFA Winter 1991/90 Bcf (c)	Enron 1991 Bcf (d)	DOE/EIA 1992 Reference Case Bcf (e)	DOE/EIA 1992 High Oil Price Case Bcf (e)	GRI 1992 Baseline Projection Bcf (f)	NERA September 1991 Baseline Bcf (g)
1980	7,172							
1981	7,128							
1982	5,831							
1983	5,643							
1984	6,154							
1985	5,901							
1986	5,579							
1987	5,953							
1988	6,383							
1989	6,816							
1990	6,970	7,225	6,972	6,000	7,240	7,240	6,587	7,240
1991	7,184						6,695	7,540
1992								7,750
1993								7,750
1994								7,800
1995		7,402		6,200	7,660	7,750	6,980	7,800
1996								
1997								
1998								
1999								
2000		6,777		6,000	7,810	8,010	6,950	7,500

Exhibit C.5

Projected Gas Demand in the Industrial Sector

Year	Actual Bcf (a)	AGA 1992 Base Case Bcf (b)	WEFA Winter 1991/90 Bcf (c)	Enron 1991 Bcf (d)	DOE/EIA 1992 Reference Case Bcf (e)	DOE/EIA 1992 High Oil Price Case Bcf (e)	GRI 1992 Baseline Projection Bcf (f)	NERA September 1991 Baseline Bcf (g)
2001								
2002								
2003								
2004								
2005		8,137		5,700	7,600	7,890		8,250
2006								
2007								
2008								
2009								
2010		8,536	6,290		7,400	7,610	8,073	
1990–2000 increase		(448)		0	570	770	363	260
1990–2010 increase		1,311	(682)		160	370	1,486	

Sources:

(a) U.S. Dept. of Energy, EIA, "Natural Gas Monthly: November 1991," DOE/EIA-0130(91/11), p. 7 and "Historical Monthly Energy Review: 1973-1988," DOE/EIA-0035(73-88), pp. 142-144. 1991 data is 1991 year-to-date (August) plus average of 1989/1990 Sept.-Dec. consumption.

(b) American Gas Association, "1992 A.G.A.-TERA Base Case," Appendix A.3, Table A.5, includes total consumption for heat, light, and power, excludes lease and plant fuel.

(c) WEFA Group, Energy Analysis Quarterly, Winter 1991 and Winter 1990.

(d) Enron Corp., "Enron Corp's Outlook For Natural Gas," 1991, p. 4. These figures exclude cogeneration and EOR.

(e) U.S. Dept. of Energy, EIA, "1992 Annual Energy Outlook with Projections to 2010," DOE/EIA-0383(92), Table A.9, p. 73 for reference case, Table D.9, p. 121 for high oil price case. These figures include cogeneration.

(f) Gas Research Institute, "Baseline Projection Data Book: 1992 Edition of the GRI Baseline Projection of U.S. Energy Supply and Demand to 2010", Vol. 1, p. 193. These figures include industrial cogeneration and exclude lease and plant fuel.

(g) National Economic Research Associates, Inc., "Energy Outlook," Sept. 23, 1991, p. 6.

Note: Where needed, consumption figures where converted from Btu to cubic feet on the basis of 1,031 Btu/cf from Ref. (e), P. 148.

APPENDIX D: SENSITIVITY OF NEW MARKETS TO WELLHEAD PRICES AND PRICE EXPECTATIONS

The gas supply outlook will have an important effect on the development of new markets for natural gas. To remain competitive with other producers, and to survive periods of low spot prices, a gas producer must try to minimize the cost of finding and producing natural gas. If new technology and efficiency improvements enable the producing segment of the gas industry to reduce the long run marginal cost of new gas supplies, the reduction in cost should be reflected in a reduction in wellhead gas prices. If we assume that transmission and distribution companies are not allowed to increase their margins when wellhead prices decline, lower wellhead prices will result in lower prices to end users. Lower prices to end users will provide an important stimulus to the growth of new natural gas markets, as well as existing natural gas markets.

If producers can develop new technology or new production methods that achieve a reduction in the real (inflation-adjusted) cost of producing gas from existing resources, they will shift the natural gas supply curve downward and thereby increase the volume of gas sold while reducing wellhead prices. While producers may claim that they would prefer to see the demand curve shifted upward, yielding an increase in annual gas consumption and an increase in prices, their actions may result in a downward shift in the supply curve. There may be a discrepancy between what producers forecast for the market as a whole and what they do as individual companies. In negotiating a long-term contract a producer will find it to his advantage to persuade the buyer (and, perhaps, the producer's banker) that gas prices will rise over the long term. However, an individual producer has every incentive to minimize costs, even if he wishes that his competitors' costs will increase and thereby raise wellhead prices.

If the gas industry's price expectations were based simply upon recent trends in gas prices, the real decline in average wellhead prices since 1983 would represent a significant contribution to the development of these new markets. Measured in constant 1982 dollars, the average U.S. wellhead price fell from $2.49 in 1983 to $1.31 in 1990.[1] The decline in average wellhead prices appears to be associated with real reductions in the cost of finding and developing gas reserves along with the surplus deliverability. According to a recent study, finding costs for natural gas in the United States "were more than halved in real terms from 94 cents/Mcf in 1983 to 44 cents in 1989."[2] It appears that the long-run marginal cost of gas has been reduced, and therefore customers' long-term price expectations may also have been reduced.

---

1 U.S. Department of Energy, Energy Information Administration, Annual Energy Review 1990, p. 177.

2 Phillip A. Ellis, "New technology for gas finding: How important has it been?" Oil & Gas Journal, Sept. 30, 1991, pp. 42-44.

Unfortunately, price expectations are not based simply on recent trends in gas prices. Price expectations are also based upon producers' actions in gas contract negotiations, as well as their price forecasts and statements about future price trends. In this context producers have taken actions that appear to have the effect of limiting the growth of gas demand in the power sector. The following anecdote is illustrative:

> Early this year, Southern California Edison Company (SCE) solicited 120 Rocky Mountain producers for long-term natural gas on terms similar to those received in Canada, including an annual price renegotiation. Only 16 organizations responded to the bid request and but four met SCE's terms. Other utilities and non-utilities have indicated the difficulties in signing long-term contracts especially with domestic producers.[3]

Because several electric utilities have made plans to increase gas-fired generation with or without long-term contracts from gas producers, it is difficult to estimate the effect on gas demand of producers' lack of interest in long-term contracts.

Our assessment is that both producers and pipelines have a poor track record as gas price forecasters over the 1975-1990 period. Therefore, the tendency of producers to anticipate a surge or a spike in gas prices in the mid 1990s or late 1990s is not necessarily a good indication of long-term price trends. The past system of rolled-in pricing subject to NGPA price ceilings resulted in gas price fluctuations that sent "incorrect" signals to producers, i.e., prices well above the levels an end user would pay if gas transportation and sales were unbundled. During the 1978-1982 period, prices of section 109 gas under new contracts were often far above the prices end users would be willing to pay. Pipelines then stopped signing new supply contracts, and spot prices fell sharply from 1983 to 1986. Today's institutional impediments to long-term contracting arise largely from the pipelines' inability to comply with the terms of contracts signed in the 1978-1982 period. The take-or-pay problem cannot be explained simply by discrepancies between actual and projected gas prices, however. To meet pipeline service obligations and obtain sufficient volumes of gas in a marketplace subject to regulated price ceilings, interstate pipelines were forced to sign contracts with non-price concessions. The regulatory environment constrained the pipelines' supply contracting behavior.

In theory an electric utility could develop its own forecast of spot gas prices and accept spot price risk if it felt that the long-term trend will be favorable. Because electric transmission and distribution is a natural monopoly, it is difficult to objectively determine the socially optimal degree of fuel price risk that should be absorbed by electric utilities or their customers. The electric customer does not have the opportunity to choose

[3] Charles W. Linderman, "Do We Have the Supply for the New Markets? Power Generators View of Supply and Other Factors in the Gas Market," 14th Annual Meeting, Natural Gas Transportation Association, September 6, 1991, pp. 7-8.

between generating options with high capital cost and low fuel price risk (i.e., coal) and generating options with low capital cost and high price risk (i.e. gas). Before 1973, electric utilities accepted a significant amount of fuel price risk; they built oil-fired capacity (and in California, oil- and gas-fired capacity) without a guarantee of long-term stability of fuel prices.

In practice, however, many electric utilities are reluctant to accept long-term spot price risk for natural gas. In the current regulatory environment, and in the context of competition between gas and coal, electric utilities would like to evaluate gas-fired generation options on the basis of long-term gas supply contracts with escalators that are roughly comparable to coal price escalators.

To some degree the disparity between producers' views and electric utilities' views creates a business opportunity for third-party companies to act as supply aggregators. However, supply aggregation is to a large extent a mechanism by which the smaller independent producers can gain access to large-volume customers.

Thus, producers are at the same time (1) stimulating the development of new markets, by lowering finding costs and lowering real (inflation-adjusted) spot prices, and (2) hindering the development of new markets by objecting to long-term contracts with escalators other than spot price escalators. The impact on new gas markets is mixed, as shown in Exhibit D.1. A negative impact on demand growth occurs in those segments for which it is essential to assure long-term supply at low prices. A positive impact on demand growth occurs in segments for which low spot prices promote gas use.

Institutional impediments associated with long-term contracts have a negative impact on gas demand growth in power generation. However, gas demand growth in NGVs and gas cooling are not so seriously affected because these markets are served by LDCs. Because gasoline prices are in effect spot prices based on world oil supply and demand and on federal and state tax policies, NGV owners have no reason to object to spot pricing of compressed natural gas. By contributing to the commercialization of the NGV market and investing in NGV service stations, producers are demonstrating an acceptance of NGV market development on the basis of spot prices.

New combustion turbines in the power sector are suited to peaking use only. In Exhibit D.1 the word "impractical" is used to describe the requirement for long-term firm supplies for new combustion turbines because the economics of peaking use favor spot pricing (or even propane/air injection) rather than long-term contracting. There is no reason for a producer to sign a long-term contract for less than ten days per year of gas delivery. The key component of peak supply is the firm capacity or on-site storage used to guarantee peak day deliverability, not the guarantee of wellhead supply.

Exhibit D.1
Sensitivity of New Markets to Gas Supply Outlook

Type of New Market	Are long-term firm supplies needed?	Is coal a competitor?	Is it essential to assure long-term supply at low prices?	Do low spot prices promote gas use?	Do producers fund RD&D?
Power sector					
Electric utility generation					
New baseload combined cycle					
Gas CC with No. 2 oil backup	Usually	Yes	Usually		
Gas CC without No. 2 oil backup	Yes	Yes	Yes		
CC designed for IGCC upgrade	Yes	Yes	Yes		
New combustion turbines	Impractical				
Clean Air Act driven					
Repowering	Yes	Yes	Yes		
Select gas use	Seasonal	Yes		Yes	
Basic co-firing	Seasonal	Yes		Yes	
Co-firing with reburn	Seasonal	Yes		Yes	
Co-firing w/ sorbent injection	Seasonal	Yes		Yes	
Non-Utility Generation					
Large cogeneration QFs	Yes	Yes	Yes		
Small cogeneration QFs	Yes			Yes	
Independent Power Plants					
New baseload combined cycle	Yes	Yes	Yes		
New combustion turbines	Impractical				

Source: RCG/Hagler, Bailly, Inc.

Exhibit D.1 (continued)
Sensitivity of New Markets to Gas Supply Outlook

Type of New Market	Are long–term firm supplies needed?	Is coal a competitor?	Is it essential to assure long–term supply at low prices?	Do low spot prices promote gas use?	Do producers fund RD&D?
Natural Gas Vehicles					
Automobiles and small trucks					
Commercial fleets	Yes			Yes	Yes
Personal vehicles	Yes			Yes	Yes
Buses and large trucks	Yes			Yes	
Gas cooling					
Gas–fired air conditioning					
Commercial/industrial	Yes				
Residential	Yes				
Gas–fired heat pumps	Yes				

Source: RCG/Hagler, Bailly, Inc.