AN INTRODUCTION TO THE GAS INDUSTRY

WITH SPECIAL REFERENCE TO THE PROPOSED ALASKA HIGHWAY GAS PIPELINE

(A PRELIMINARY REPORT TO THE ALASKA STATE LEGISLATURE)

AND

MARKETING AND FINANCING SUPPLEMENTAL GAS

THE OUTLOOK FOR, AND FEDERAL POLICY REGARDING, SYNTHETIC GAS, LNG AND ALASKA NATURAL GAS

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PREFACE

During the 1977 legislative session the legislature and administration in the State of Alaska were approached by the sponsors of the Alaska Highway Gas Transportation System with the request that the state participate in the equity financing of that project. It is expected this proposal will be an important issue before the legislature during the 1979 session.

In order to provide the legislature with information on the financial feasibility of the project and other pertinent factors, the Research Division of the Legislative Affairs Agency contracted with the University of Alaska's Institute of Social and Economic Research for the preparation of the first part of this report. Subsequent reports to be prepared by these authors under this contract will discuss: (1) the federal interest in the Alaska Natural Gas Transportation System, (2) a more detailed analysis of the recently passed federal natural gas legislation, (3) an analysis of alternative federal policies that may be available if the "private financing arrangements" now discussed for the system fail to materialize, and (4) a detailed list of the contractual, financial, regulatory, and other pre-conditions that must be satisfied before the project can be constructed and gas flow through it. A final report integrating these preliminary studies will be submitted to the Agency in March of 1979 and will be made available to the public shortly thereafter.

In addition, studies related to the management of the Prudhoe Bay Reservoir under conditions of gas withdrawal for sale are being prepared for the Agency by others.

The second part of this volume was not prepared under contract with the Agency, but it is included here because of its obvious relevance to the issue at hand.

Gregg K. Erickson
Director of Research & Analysis
Legislative Affairs Agency

Juneau, Alaska
November, 1978

PART ONE

AN INTRODUCTION TO THE NATURAL GAS INDUSTRY with special reference to the proposed Alaska Highway gas pipeline

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FOREWORD

This volume contains two closely related reports by Arlon R. Tussing and Connie C. Barlow. The first, *an introduction to the natural gas industry*, was supported by a contract between the Alaska Legislative Affairs Agency, the research and service arm of the State Legislature, and the University of Alaska Institute of Social and Economic Research (ISER). The second report, *marketing and financing natural gas supplements*, was supported through its first draft under a contract between the United States Department of Energy (DOE) and Arlon R. Tussing and Associates. Both reports depend in part on research Tussing conducted for the California State Energy Resources Conservation and Development Commission's Biennial Report.

At the end of July, 1978, the authors submitted the first draft of the supplemental gas marketing and financing report to the DOE, and began work on a final report. In August, they started research for a larger study of the proposed Alaska Highway gas pipeline for the Alaska State Legislature. A final report from this project, scheduled for March 1979, will examine the pipeline's economic viability and what is likely to happen if the State of Alaska does or does not invest in the venture. The contract between the Legislature and ISER provides that the authors submit an interim report containing an explanation in plain English of the structure, operation and regulation of the natural gas industry in the United States, to be used as background by legislators and state officials, plus an overview of gas marketing and financing issues, based upon the authors' work for DOE.

As the final version of the DOE report and the first interim report for the Alaska Legislature both neared completion, it became clear that the two papers neatly complemented each other: The primer on the natural gas industry is an ideal introduction for informed lay people anywhere in the United States to serious discussions of natural gas policy issues, while our observations on the marketing and financing of supplemental gas are directly relevant to the proposed Alaska gasline. For this reason, we have combined both reports into a single volume, and hereby submit them in fulfillment of our obligations both to DOE and to the Alaska Legislature.

Part One, *an introduction to the natural gas industry --- with special reference to the proposed Alaska Highway gas* *pipeline*, explains what natural gas and natural gas supplements are; where they come from; what determines the demand for gas; how gas transportation and sales in the field at wholesale and at retail are arranged, financed, priced and regulated.

Part Two, *marketing and financing natural gas supplements --- the outlook for, and federal policy regarding, synthetic gas, LNG and Alaska natural gas*, analyzes the "need" for supplemental gas, mainly synthetic natural gas (SNG) and liquefied natural gas (LNG), and Alaska gas; the role of government and regulated industry in determining gas supply and demand; project financing and the allocation of business risks in the gas industry; the ability of the "old gas subsidy cushion" and rolled-in pricing to assure the marketability of supplemental gas; the effect of gas tariff "profiles" -- their shape over time -- on marketability; and the effect on the gas industry and consumers of such regulatory innovations as "incremental pricing" and "commodity value pricing."

We began the two parts of this volume for different audiences, and they still differ somewhat in style and perspective. Part One is addressed first to Alaskans who want to understand the proposed pipeline and the debates surrounding it. Part Two speaks first to federal officials who have to decide how much, and what kind of, support the government should give to gas producing ventures that might be desirable from a broad national standpoint, but which would not meet a market test of benefits and costs. The careful reader may note that the interest of Alaska in these issues may conflict at points with the national interest, and certain differences between Part One and Part Two reflect this conflict. Nevertheless, the main lines of analysis and the general point of view of the authors are consistent throughout the volume, and we believe that the two parts make a logical whole.

Because of the time limits on production of the present work, none of Part I has been reviewed or even read by any person except the authors and Ms. Bonita Swanson, their secretary. The same is true of Part Two in its present form, which is substantially different from the draft delivered to DOE in July. Accordingly, this volume is in some respects not only an interim report but an unfinished draft, and we would not be surprised to find that we would want to change some of our formulations or conclusions after further research, review or reflection.

The present volume is only one of a continuing series of reports the authors have scheduled in the forthcoming months, and amendments or refinements of our concepts will reflect both the changing world and, we hope, a growing understanding of the issues. Other reports planned for 1978 or early 1979 include a description and analysis of project financing techniques, particularly as they apply to the Alaska gasline; an attempt to foresee what will really happen as a result of the Natural Gas Policy Act of 1978; a critical path analysis of the Alaska gasline; an assessment of Canadian gas industry developments and policies; and our final report to the Legislature on the economics and outlook for the Alaska Highway line.

Arlon R. Tussing
Connie C. Barlow

October 25, 1978

PART ONE

AN INTRODUCTION TO THE GAS INDUSTRY

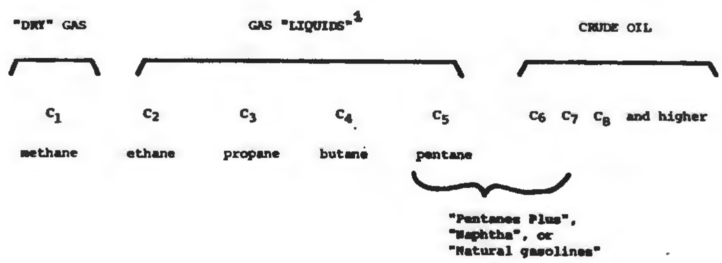
WITH SPECIAL REFERENCE TO THE PROPOSED ALASKA HIGHWAY GAS PIPELINE

CHAPTER I

COMPOSITION, CHARACTERISTICS, AND MEASUREMENTS OF NATURAL GAS

1.1 COMPOSITION

Natural gas, gas liquids or condensate, and crude oil are the terms used to identify different kinds of hydrocarbons found beneath the earth's surface. Natural gas represents the lightest of these hydrocarbons, and contains the least number of carbon atoms in each molecule. Unlike crude oil, it exists as an invisible vapor at atmospheric temperatures and pressures.



Associated and Non-Associated Gas. Natural gas is found either in conjunction with an oil reservoir ("dissolved and associated gas") or by itself ("non-associated gas"). Non-associated gas, as in some parts of Cook Inlet, is often "dry" -- meaning it is composed almost exclusively of methane.

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[1] Gas liquids are sometimes abbreviated "NGL's" for natural gas liquids. "LPG" or liquid petroleum gas is a chemically similar mixture, but is usually separated from crude oil at the refinery, rather than in the field.

Elsewhere (especially in reservoirs containing gas in association with oil) gas may be "wet", containing substantial amounts of "condensate", a mixture of "gas liquids" (C_2 - C_4) and "natural gasolines" or "naphtha" (C_5 - C_8) In these reservoirs, quantities of ethane, propane, and butane are mixed with the methane in a vapor state. In order for Prudhoe Bay gas to be transported to and burned by customers, much of these "liquids" (along with other impurities such as water and carbon dioxide) must eventually be removed and (if possible) sold separately. In 1977, about 20 percent of domestic gas sold was dissolved and associated gas and 80 percent was non-associated.

1.2. CHARACTERISTICS

Natural gas has two important characteristics which distinguish it from other types of fuels. One characteristic affects its value to consumers and the other affects its cost. The value of natural gas to consumers is enhanced by its clean-burning qualities. Gas essentially burns free of sulphur emissions and ash. This means that gas is often viewed as a "premium" fuel: it is worth paying a little more for gas than an equivalent amount of energy in the form of oil or coal. This is especially so in areas like Southern California, where air pollution standards are rigorous. However, the air quality premium is offset by transportation and storage problems. Oil and coal can be hauled almost anywhere by a variety of means and stored without much difficulty; but natural gas is moved by pipelines or in costly "cryogenic" vessels by ship, rail, or truck, for which it must be cooled and compressed into a liquid. Storage techniques are likewise sophisticated -- above ground in liquefied form, or pumped below ground into salt domes or exhausted gas fields. While small industry and even homeowners can afford to store their own caches of oil or coal, they depend completely upon the day-to-day functioning of pipelines and supply adequacy of often a single distributor.

1.3 MEASUREMENTS

1.3.1 Volume Measurements. In the United States and Canada, quantities of natural gas are usually denoted in cubic feet: A cubic foot of gas will fill a box measuring one foot on all sides.[1] The smallest volume usually dealt with is a thousand cubic feet, (abbreviated mcf) while the largest measurement is a trillion cubic feet (abbreviated Tcf).

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1 At some "standard" pressure base, usually about equal to atmospheric pressure at sea level.

Volumetric Measurements

mcf	=	thousand cubic feet	The average household used 123 mcf of gas in 1976
mmcf	=	million cubic feet	
bcf	=	billion cubic feet	The Alaska section of the Alaska Highway gasline will be designed to carry 2.4 bcf of gas each day.
Tcf	=	trillion cubic feet	Total recoverable gas reserves in the Sadlerochit reservoir at Prudhoe Bay are estimated at 26 Tcf. The U.S. produced and consumed about 20 Tcf of natural gas in 1977

1.3.2 Heating Value Measurements. Quantities of natural gas are sometimes referenced in "British Thermal Units", or BTU's, to denote heating values or energy potential. BTU's use somewhat similar prefixes to the volumetric measurements. Standard BTU measurements are as follows:

Heating Value Measurements

BTU	=	British Thermal Unit	It takes one BTU to raise the temperature of one pound of water one degree Farenheit.
mBTU	=	thousand BTU	(not often used)
Therm	=	100,000 BTU	A Therm is the unit used by gas utilities in billing residential customers.
mmBTU	=	million BTU	One barrel of No. 2 distillate fuel oil contains about 5.8 mmBTU's
Quad	=	quadrillion BTU	Total U.S. energy consumption from all commerical fuel types was estimated at 74 quads in 1976.

Since all fuels can be translated into BTU's -- electricity, coal, oil and natural gas -- BTU is a useful tool for making comparisons among these fuels, such as comparisons of price:

Comparative Prices of Fuels

\$ 2.38 per mmBTU	the average 1977 wholesale price of No. 2 FUEL OIL
\$ 10.11 per mmBTU	the 1977 price of ELECTRICITY to residential consumers
\$ 2.07 per mmBTU	the regulated ceiling price for NEW DOMESTIC GAS sales at the wellhead (under the Natural Gas Policy Act of 1978)
\$ 1.63 per mmBTU	the ceiling price for ALASKA GAS at the wellhead
\$ 3.00 to 5.00 per mmBTU	the ballpark range of price estimates for producing and transporting ALASKA GAS to domestic markets

Heating value measurements (BTU's) and volumetric measurements (MCF's) are used interchangeably to denote quantities of gas. Conversions between BTU's and MCF's are as follows:

Volumetric / Heating Value Conversions

Methane	(C_1)	1 cf = 950 BTU
Ethane	(C2)	1 cf = 1700 BTU
Propane	(C_4)	1 cf = 2300 BTU
Butane	(C_5)	1 cf = 2900 BTU
"Natural Gas"		1 cf = 1000 BTU (mostly methane)
"Town Gas"		1 cf = 350 to 500 BTU

The preceding table also shows that the same volume of ethane or propane has a higher heating value than methane. These liquids are "richer" than methane because each molecule has more carbon atoms to fuel the burning process through oxidation.

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1 "Town gas" or "coal gas" was widely manufactured from coal and steam for urban distribution before natural gas became available. It is a mixture of hydrogen, methane, carbon monoxide and carbon dioxide, with an energy content about half of what is found in natural gas.

CHAPTER II

SOURCES OF SUPPLY

2.1 "CONVENTIONAL" GAS SOURCES

For the next decade or more, the major source of natural gas consumed in the U. S. probably will continue to be "conventional" supplies -- relatively easy to produce gas from oil fields or nonassociated gas fields within this country. The amount of domestic conventional gas which remains is the subject of great speculation and controversy. While total volumes represented by "proved reserves" declined between 1970 and 1976 as U. S. consumption outstripped new discoveries, this trend did not necessarily mean that the U. S. had nearly run out of gas. Several factors historically have served to stifle interest in finding and producing gas. For one thing, a lack of long-distance pipelines and city distribution systems severely restricted gas markets prior to World War II. Until then, natural gas markets were pretty much limited to consumers who lived adjacent to oil fields where gas would otherwise be flared; and urban gas consumers elsewhere were supplied mostly with low-BTU "town gas" manuafactured from coal. Once pipeline systems became widespread, however, another factor arose that affected gas demand and that eventually led to the present gas "shortage". Federal price ceilings tended to lock gas prices at or near the low levels (relative to alternative fuels) that were established when gas was still an abundant by-product of oil exploration. Price controls then kept the cost of gas much lower than that of oil-based fuels. This situation resulted in a very rapid increase in gas consumption -- more than 5 percent per year between 1954 (when wellhead price ceilings were first imposed) and 1972 (which was the peak year) -- but at the same time, controls discouraged exploration, particularly for non-associated gas.

2.2 "UNCONVENTIONAL" GAS SOURCES

"Unconventional" gas denotes natural sources within the U. S. that cannot be produced economically with presently proved technology. These include methane dissolved in reservoirs of "geopressurized" brine in the U. S. Gulf states, Rocky Mountain "tight sands", "Devonian shales" in the Appalachians, and methane from coal seams. While these sources represent enormous potential volumes, federal policy-makers tend to view their prospects conservatively -- looking for other ways to ensure sufficient energy supplies, with no expectation that the necessary technological breakthroughs will occur in the near future.

2.3 "SUPPLEMENTAL" GAS SOURCES"

"Supplemental" gas refers to high-cost supplies which could readily supplement dwindling U. S. reserves of conventional gas. There are three major categories of supplemental gas sources; and each will be discussed separately.

(1) Synthetic methane from coal or gas liquids (synthetic natural gas or SNG)

(2) Liquefied natural gas from Alaska and abroad (LNG);

(3) Pipeline gas from Alaska.

While the feasibility and costs of producing "unconventional" gas will be known only as new technologies are tested, "supplemental" supplies can be produced by means of existing technology at costs that are high relative to historical prices of natural gas, but which are more or less predictable. In general, the expected costs of supplemental gas are somewhere within a range of one to two times the current price of alternative fuels (primarily fuel oil). Despite this predictability relative to the unconventional sources, supplemental projects are characterized by substantial risks with respect to costs, construction lead times, and changes in the regulatory environment. To reduce these risks to the point where private financing becomes possible, special governmental actions must be taken to transfer some of the risks from sponsors of supplemental gas projects and their lenders onto gas consumers or taxpayers at large. Current debate with respect to a variety of supplemental gas proposals center on these special governmental actions:

How much of the business risks usually borne by industry really must be transferred onto the public in order to make the projects go? And which public -- gas consumers or taxpayers at large? Finally, if the public has to bear large risks, is the gas still worth having?

2.3.1 Synthetic Natural Gas (SNG) - Synthetic gas refers to methane that is artificially produced from heavier fossil fuels. Long before natural gas came into widespread use, synthetic "town gas" was produced from coal. However, this coal gas was dangerous (because of its carbon monoxide content) and expensive, and had a relatively low heating value (about 400 BTU's per cubic foot compared to 1000 BTU's for natural gas). When natural gas became available, this low-BTU coal gas was quickly replaced. Instead, when the term "synthetic gas" is used today, it usually refers either to "high-BTU coal gas" or to SNG from liquids.

(a) High-BTU coal gas. For coal gas to be of use today, it needs to be of a quality virtually interchangeable with natural forms of methane. Coal gas of a sufficiently high heating value (about 1000 BTU's per cf) is produced by a more complicated and vastly more expensive process [1]

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[1] The process most commonly proposed for synthesizing SNG from coal is to gasify coal by the same "Lurgi" process used for town gas, and upgrade BTU content by "methanation".

than the coal gas of past years. While the raw material for making coal gas seems to be almost unlimited, land and water requirements and the capital for constructing these plants (not to mention willing buyers) are limited. While current federal policy is pushing the development of high BTU coal gas by means of federal guarantees subsidizing costs if the product proves too expensive to market at full cost, it is doing so only for 2 or 3 "demonstration" plants -- not for widespread production. Unless a major technological breakthrough occurs to reduce costs, high-BTU coal gas can be expected to play only a minor role in meeting domestic energy needs.

(b) <u>SNG from liquids</u>. SNG is also produced by "cracking" apart the heavier molecules of gas liquids or petroleum products (usually naphtha). About a dozen SNG plants are operating today. Owned by the largest gas distributors, these plants were constructed for "peak-shaving" purposes, and operate only during the winter months. Gas is produced (though at a very high unit cost) to take care of seasonal increases in demand. Since the "fixed" or "sunk" costs of building the plant are minor compared to the cost of purchasing naphtha as feedstock for operations, the owners can afford to run these facilities on a seasonal basis. Indeed, government regulators do not allow these plants to operate year-round, because natural gas is a much cheaper "base load" source. However, natural gas is generally available only on a continuous basis; thus, if a distributor is to meet the fluctuating needs of his customers, he must either store excess summer gas for use in the winter (which is also very expensive), produce SNG, or use some combination of these measures. (One other approach is to find "interruptible" customers, generally electric utilities or large industrial plants who are willing to have their supplies curtailed in the winter in return for a summer price lower than the cost of substitute fuels like oil or coal.)

Federal policy discourages construction of new petroleum-based SNG plants partly on the theory that gas liquids and naphtha represent scarce commodities which are essential for other uses such as petrochemical feedstocks and as "bottle-gas".

Another minor supply of gas today (again, used only for peakshaving) is very similar to SNG from liquids. "Propane-air" is a type of gas which is made by simply adding air to light "liquids", instead of cracking them into methane. These lighter liquids retain their vapor qualities at normal pipeline pressures, and when mixed with methane can be easily transported and burned. The air is added simply to dilute the caloric value of BTU-rich gases down to the level of methane, in order to stretch out supplies and make burning characteristics consistent.

Overall, SNG from petroleum liquids or propane is not expected to be a significant fraction of total supply, but this assessment may change as oil exporting nations expand recovery and marketing of crude oil-associated NGL's, which in many countries are now being flared.

2.3.2 <u>Liquified Natural Gas</u> (LNG). LNG is naturally occuring methane which is transported in liquid form by tanker (at a temperature around -160 degrees C) to reach its markets. With the exception of a proposal to liquefy and transport Cook Inlet gas to California, called the Pac-Alaska project, LNG would come predominantly from Eastern Hemisphere OPEC countries. West Coast LNG proposals rely on Indonesian supplies and East Coast projects are usually Algerian. Here again, the costs are substantial and federal policy is undecided as to whether and which of these projects should be encouraged. Unlike high BTU coal-gas, private industry is willing to enter into these projects without a government "guarantee" -- however, consumer guarantees seem to be a prerequisite. (These guarantees will be discussed shortly.) The important point here is that while coal gas and SNG from petroleum will probably be minor sources of supply for many years, LNG is potentially a substantial source of gas in the relatively short term. Figure 1 shows the LNG projects now being considered for certification by the federal government. Only one large-volume project is currently delivering gas to the U.S. ("El Paso I" delivers Algerian gas to Columbia Gas Company at Cove Point, Maryland).

FIGURE 1

APPROVED AND PENDING LNG PROJECTS

.S. Purchasing Companies	Receiving Terminal Location	Producing Country & Company	Contract Date & Length	Annual Volume Bcf / yr.	Status
ISTRIGAS	Everett, MD	Algeria "Sonatrach"	1976 (20 years)	42	operational
'El Paso I" COLUMBIA CONSOLIDATED SOUTHERN	Cove Point MD Elba Island GA	Algeria "Sonatrach"	1969 (25 years)	365	began phasing in in March 1978
'RUNKLINE	Lake Charles LA	Algeria "Sonatrach"	1975 (20 years)	168.4	approved by DOE/FERC
Pac-Indonesia" PAC. LIGHTING PAC. GAS & EL.	Point Conception CA	Indonesia "Pertamina"	1973, am. 1975 (20 years)	197	approved by FERC; approved by DOE autumn 1978; awaiting CA siting
El Paso II" EL PASO	Port O'Connor TX	Algeria "Sonatrach"	1975 (20 years)	365	awaiting DOE/FERC action
ENNECO	St. John, New Brunsw. CANADA	Algeria "Sonatrach"	1976 (20 years)	335 - 397	approved by Canada; awaiting DOE/FERC action
Pac-Alaska" PAC. LIGHTING PAC. GAS & EL.	Point Conception CA	Cook Inlet ---	-----	70 - Phase I 140 - Phase II	no contracts; difficulties with reserve life

Adaptation and update of American Gas Association LNG Fact Book, Dec. 1977

2.3.3 Alaska Pipeline Gas. Like LNG, Alaska pipeline gas must be considered "supplemental" because while production at the well is "conventional", transportation is difficult and costly.

2.4 CANADIAN AND MEXICAN GAS

In addition to conventional domestic gas, unconventional domestic gas, and supplemental supplies (of LNG, SNG and Alaska gas) Canadian and Mexican gas can be expected to play a role in U.S. energy needs -- perhaps even a major role. Like supplemental gas, Canadian and Mexican gas have comparatively high prices -- at least relative to the historical prices of federally controlled domestic gas -- but the high price is imposed by the respective governments seeking full value for their exported resources. The actual costs of production and transportation are not terribly high: if it were not for national boundaries making this gas special, reservoirs in Alberta and Mexico would be part of our so-called conventional supplies.

Canada's current policy allows limited gas exports to the U. S., (.9 Tcf in 1977) at a price of $2.16 at the Canadian/U. S. border. Mexico recently negotiated a big sale with six U. S. gas companies at $2.60 per mmBTU (purportedly equal to 100 percent of the price of imported fuel oil New York), but this sale was squelched by the U. S. Department of Energy, which feared both the domestic political consequences of paying a foreign government more than the Administration proposed to allow U. S. producers, and possible Canadian imitation in raising its gas export price to the Mexican standard.

Hence, one can expect Canadian and Mexican gas to be no "bargain" -- but, unlike at least some proposed supplemental gas sources -- these gas supplies will not greatly exceed the market value of gas as measured by the price of substitute fuels, either. Also in contrast to supplemental gas supplies which require 20 year governmental commitments to enable 20 year private financing, Canadian and Mexican sale offers have been and probably will continue to be short-term, reflecting the exporting countries' concern to adjust exports to meet changing perceptions of their own domestic needs. While such a practice may create problems for domestic purchasers and for governmental policy makers seeking long-term energy assurances, it nevertheless frees industry and regulators from long-term marketing risks which accompany proposals like LNG and Alaska gas.

Despite lingering disagreements between the U. S. and the Mexican governments, which have stalled entry of Mexican gas into U. S. markets, and despite the current reluctance of Canada to increase net exports to the U. S. ("swaps" for future Alaska gas are another matter), the prospects are good that Canadian and Mexican gas will play a large part in U. S. gas supplies over the next two decades.

Mexico's alternatives to U. S. exports are either (1) increasing conversion of Mexican oil consumption to gas -- a policy that Mexico is currently carrying out but with a limited potential for further substitution; (2) forcing the development of a large petrochemical industry in the face of persisting (and possibly growing) excess capacity in the world -- Alaskans are intimately familiar with this issue; (3) exporting gas to Europe, Japan or other markets in the form of LNG, severely reducing the "netback" at the wellhead, or (4) simply wasting large amounts of dissolved and associated gas by flaring it.

In Canada, Western Provinces and gas producers are urging increased exports to the U. S. Their case is enhanced by a growing oversupply of gas in Alberta -- the so-called "bubble". But current trade opportunities have to be balanced against national policies of (1) restricting exports in order to ensure long-term energy self-sufficiency for Canada; and (2) trying to develop a high-cost pipeline system to deliver western gas surpluses into the oil-dependent Eastern provinces. Alaskans recognize the similarity of these Canadian policies to United States policies which would shut-in potential Alaska or California oil production or build costly transcontinental pipelines in order to push the West Coast surplus of oil into Eastern markets, in preference to the more "economic" alternative of allowing the surplus to be exported.

2.5 INTRASTATE VERSUS INTERSTATE GAS SUPPLIES

While conventional, unconventional, supplemental, and Canadian and Mexican gas represent physical and geographic differences in supplies, the distinction between intra- and inter- state gas is strictly a governmental creation. The Natural Gas Act of 1938 was originally intended to regulate the service and rates of interstate natural gas transmission companies -- that is, gas pipeline companies transporting gas purchased in one state for resale in another. Production and sale of gas within the same state has (with certain notable exceptions) been regulated by state agencies or not at all.

In recent years, this uneven regulation of gas has been an incentive for sales to remain within the producing states and outside of federal jurisdiction. The most visible advantage is the difference in wellhead or field price regulation. Since 1954, prices of gas produced for interstate sales have been limited to levels determined to be fair and reasonable by the Federal Power Commission (predecessor of the present Federal Energy Regulatory Commission -- FERC). While the Commission's pricing methodology has changed several times since then, it has generally attempted to tie ceiling prices to the actual or estimated "costs" of producing gas. On the other hand, wellhead prices on most intrastate sales have been left to an unregulated market, which means a producer might sell gas at whatever price he can find a willing buyer.

As long as the "cost-based" price of interstate sales remained close to the unregulated price of intrastate sales, a sale into one market was just as attractive from a price standpoint to producers as a sale into the other. In the late 1960's, however, as the growth of gas consumption began to outstrip increases in production, industrial gas buyers in the producing states increasingly bid new gas supplies away from the interstate pipelines. The intrastate consumers were willing and able to pay any price for gas up to the price of the lowest acceptable substitute fuel -- home heating oil (No. 2 fuel oil), naphtha, propane, or residual oil (No. 6) -- while the interstate transmission companies were forbidden to pay more than a ceiling price set by the FPC on the basis of historical costs. The price gap between the two markets widened in the 1970's, as the price of oil increased -- why sell to Chicago at the regulated price of, say, one dollar if you can sell in Texas for two? This preference for selling Texas gas in Texas and Louisiana gas in Louisiana is part of the reason Louisiana and Texas users have generally been able to get all the gas they wanted, while in other states the utility commissions had to forbid their gas distributors from taking on new customers.

The Natural Gas Policy Act of 1978 subjects both inter- and intrastate gas sales to price ceilings specified in the Act. But even if prices were the same in both markets, producers probably would still prefer selling intrastate. Federal regulation of interstate sales is not limited to price controls, but extends to the term and other conditions of sale (including the purpose for which the gas is to be used). In particular is the problem that once gas from a field is sold into interstate commerce, the seller cannot later decide to sell gas from the field into intrastate markets without receiving from FERC a "certificate of abandonment," even if the original contract has legally expired. In effect, this FERC power (upheld by the courts in the "Southland Decision"), limits the producers' ability to execute short-term contracts, and makes each interstate sale an eternal commitment.

All sales of gas from the Outer Continental Shelf (OCS) are technically interstate sales as such gas crosses the adjacent state's territorial boundary as it comes ashore. Imports of natural gas and LNG from other countries are international transactions likewise subject to federal regulation as soon as they cross the border, and Alaska gas delivered to the Lower 48 states either by pipeline or by LNG tanker would also be interstate gas.

Under the Natural Gas Act, synthetic gas plants and SNG are not subject to federal regulation, but the Commission may regulate the sale and transportation of such gas as soon as it is mixed or "commingled" with conventional natural gas in an interstate pipeline. Thus, the federal regulators effectively have the power to veto major SNG projects if they regard their cost, financing arrangements or some other feature as unacceptable.

FIGURE 2

COMPARISON OF VOLUMES AND PRICES OF EXISTING AND POTENTIAL GAS SUPPLIES

CONVENTIONAL GAS	1977 U.S. production was about 20 TCF; Total remaining proved reserves (non-Alaskan) are estimated at 185 TCF; Intrastate delivered volumes in 1977 were about 8 Tcf at an average field price of $1.79 per mcf. Interstate delivered volumes in 1977 were about 11 Tcf at an average field price of $.69 per mcf.
UNCONVENTIONAL GAS	No significant quantity is yet being produced.
SYNTHETIC GAS (SNG) FROM COAL	2 or 3 plants may be on stream by 1985 for a total volume of maybe 200 bcf per year, at an average price of $4.00 to $5.00 per mcf.
SYNTHETIC GAS (SNG) FROM LIQUIDS	14 plants are operational, supplying about 300 bcf per year at prices around $4.00 to $6.00 per mcf. Present federal policy is adverse to construction of new plants.
LIQUEFIED NATURAL GAS (LNG)	1 major plant and 1 minor plant are on stream, designed to supply 400 bcf per year at a price of around $2.00 to $3.00 per mcf. If all pending applications are certified 1.8 Tcf per year would be contributed by 1985 at an average price estimated by sponsors at around $3.00 per mcf.
ALASKA PIPELINE GAS	If the Alaska Highway project is built and operated at capacity, 2.4 bcf per day (840 bcf / year) would be delivered. Total Sadlerochit reservoir recoverable volumes of gas are estimated at 26 Tcf. Estimated price of delivery is around $3.00 to $5.00 per mcf.
CANADIAN GAS	1977 exports limited to .9 Tcf at a $2.16 border price. Current gas "bubble" is estimated at a minimum of 10 Tcf.
MEXICAN GAS	U.S. certification withheld from an 8 year contract for purchase of 700 bcf / year at $2.60 / mcf. No reliable estimates exist of Mexican reserves.

Note: prices are at entry to existing transmission network

CHAPTER III

THE DEMAND FOR GAS

There is no inherent demand for natural gas -- only a demand for energy. Individual households, firms and industrial plants will take into consideration how reliable the supply of various fuels seems to be, the costs of installing and operating different types of burners, and local air quality requirements; but over the long run the main factor in their choice will be relative prices.

The benchmark price for gas is somewhere around the price of home heating oil (No. 2 or distillate fuel oil). While households and small commercial establishments might be willing to pay substantially more for gas than the price of oil if they view high-cost electricity [1] as the only realistic alternative for space heating (which is doubtful), about half of all U. S. gas is consumed by industrial plants and electric utilities. For these users, oil is unquestionably the preferred alternative fuel.

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[1] Electricity is usually high in energy cost because it is a relatively inefficient way to provide heat. Instead of using coal, oil, or gas for heating directly, electrical space heating starts with coal, oil or gas which is first turned into electricity (with much heat wasted in the process) at a central location and then turned back into heat at the point of consumption. This system bears not only the burden of direct energy losses, but the capital requirements for generating plants and transmission lines are substantially greater per unit of useful energy delivered to the end user than are the capital needs for conversion and transportation of energy in the form of oil or gas.

Further, many industrial and commercial gas burning installations already have the capability to burn oil -- an important consideration since some promoters of gas as a "premium fuel" charge that conversion costs will be a major factor in keeping industrial consumption high, despite rising gas prices. These dual-capacity customers were either forced to install oil-burning equipment when their contracted gas supplies were sharply "curtailed" in recent winters, or they freely chose to install both types of burners when they secured cut-rate "interruptible" gas contracts in the first place. These interruptible contracts are an important means by which gas companies adjust to fluctuating demand despite constant supply levels from producers. During the winter when "firm" residential use is up, gas companies unilaterally cutback on deliveries to interruptible customers. This allows them to function without installing costly facilities to store summertime deliveries for winter use, and to avoid building "peak-shaving" SNG facilities.

Overall, the demand for gas can best be predicted from a comparison of gas prices with the price of fuel oil. If gas is selling for substantially less than oil because of government imposed ceilings, demand will probably be high, as it is today; and if gas prices rose above the bulk price of No. 6 (residual) oil, to that of home heating oil and higher, demand could drop drastically --- in the long run, the use of gas would be confined to cooking, residential hot water heating, and a few "premium" industrial uses, which altogether account for not more than 5-10 percent of current U. S. gas consumption.

There is ample historical evidence for this view. While natural gas was used as a home heating fuel in about 84 percent of U. S. households in 1976, it has never penetrated those areas of the United States or Canada (New England, Eastern Quebec and the Maritime Provinces, for example) where transportation and distribution costs have kept the price of gas above the local price of oil. Experiences in Washington, Oregon, and Ontario over the last three years, where gas prices have risen rapidly to levels very close to the cost of home heating oil, present an even more striking confirmation. After many years in which the number of residential users increased at a rate of 5 to 7 percent annually, new residential connections ("hook ups") abruptly came to a halt, and the gas utilities actually began to <u>lose</u> industrial and commercial customers. (This development, it is worth noting, was a complete surprise to the local gas companies, who had believed their industry's own propaganda that gas is a "premium" fuel.)

Given that demand for gas is closely tied to the price of oil, high-cost supplemental gas projects, such as the Alaska Highway gas line, carry risks that their gas may ultimately prove unmarketable. For this reason, project sponsors have suggested creative means by which these high costs can be dispersed among lower cost gas supplies (through "rolled-in pricing") and by which remaining marketability problems would be borne by "downstream customers" (usually distribution companies or even the federal government, through federal debt guarantees). These regulatory approaches will be discussed later.

Ultimately, the real need for high-cost supplemental projects is not so much to meet any inherent consumer demand, but rather to meet the federally perceived "strategic" need to supplant OPEC oil with Algerian, Indonesian, Canadian, Mexican or preferably conventional Alaskan gas or SNG from coal -- for national security reasons, balance of payments problems, or whatever. This strategic need will be compatible with consumer preferences for as long and only for as long as supplemental gas projects actually deliver gas at prices equal to or less than the price of oil. Once this price is exceeded, some mechanism is necessary to force gas consumers (unknowingly perhaps) -- or the taxpayers -- to subsidize these strategic projects. The measure most commonly proposed to assure a market for high-cost supplemental gas -- and to provide a consumer subsidy whenever it may be required -- is to "roll-in" the cost of the supplemental gas with lower-priced conventional gas, so that the consumer faces a single average price, that is still lower than the price of substitute fuels.

The great unknown therefore is what the price of oil will be over the next twenty-odd years. Supplemental energy projects justified on the basis of steady or rising real[1] oil prices will prove to be misjudgments -- or even disasters --if the real price of oil were to fall. This is a growing concern, in that more and more respectable energy analysts are predicting that world oil prices may indeed decline. This prediction is based on the recognition that today's OPEC determined oil price does not reflect high actual costs of production and transportation, which would be difficult to undercut. Instead, the price is artificially created by the OPEC cartel, which may have difficulty increasing prices in step with the rate of general inflation as producing capacity grows both in OPEC member countries and outside (as in Mexico).

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[1] "Real" prices signify prices adjusted for inflation, as opposed to "nominal" prices. For example, if oil costs \$2.60 per mmBTU this year and \$2.60 per mmBTU a year from now, and if inflation proceeds at 5 percent per year, the nominal price of oil can be said to remain steady, while the real price is falling at about 5 percent per year.

CHAPTER IV

SALES AND PRICING OF GAS

4.1 INTRODUCTION

Particularly since the marketability of gas is closely linked to its price, understanding how buyers, sellers, and government regulators determine that price is essential. The main parties with whom we are concerned are:

(a) gas producers - mainly (but not exclusively) integrated oil companies;

(b) interstate gas pipelines (or transmission companies);

(c) local gas distribution companies;

(d) end users - households, businesses, institutions, industry, and electric utilities;

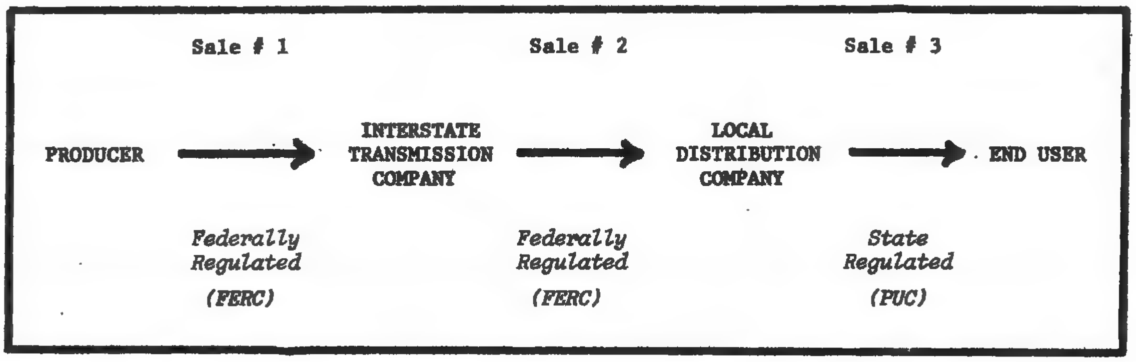
(f) Federal Energy Regulatory Commission (FERC) - formerly the Federal Power Commission (FPC);

(f) Economic Regulatory Administration (ERA) of the Department of Energy (DOE); and

(g) State public utility commissions (PUC's) - sometimes called public service commissions (PSC's).

Historically, interstate sales transactions from the wellhead to the end user "burner tip" have taken the following sequence:

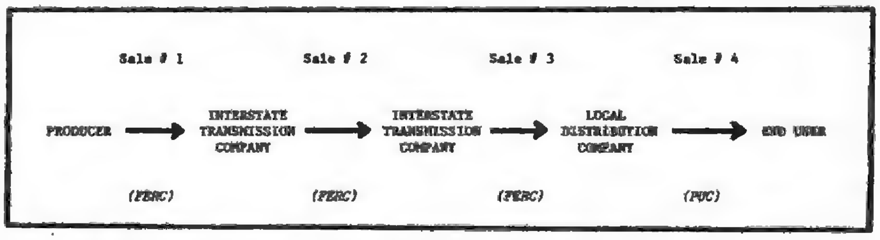
Typical Sequence of Sales



While this is the standard sequence of sale, it should be kept in mind that some significant (and some not so significant) variations can take place.

Interstate Sales Variation # 1

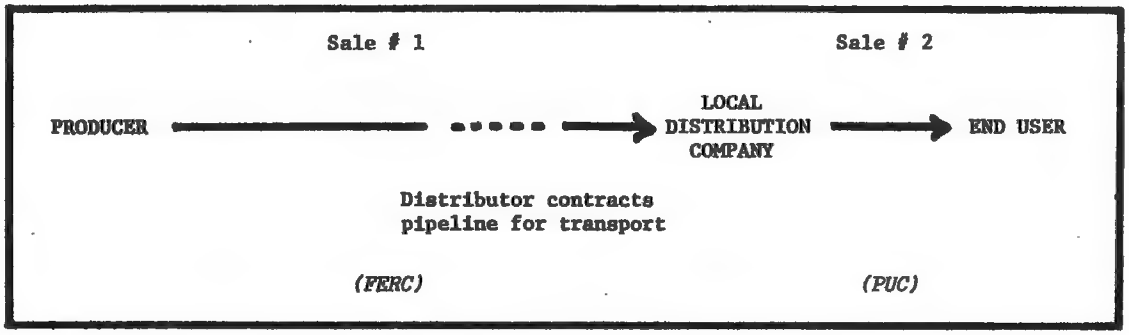
Multiple Interstate Transmission Companies



Here, it takes more than one interstate transmission company to carry the gas to the local distributor.

Interstate Sales Variation # 2

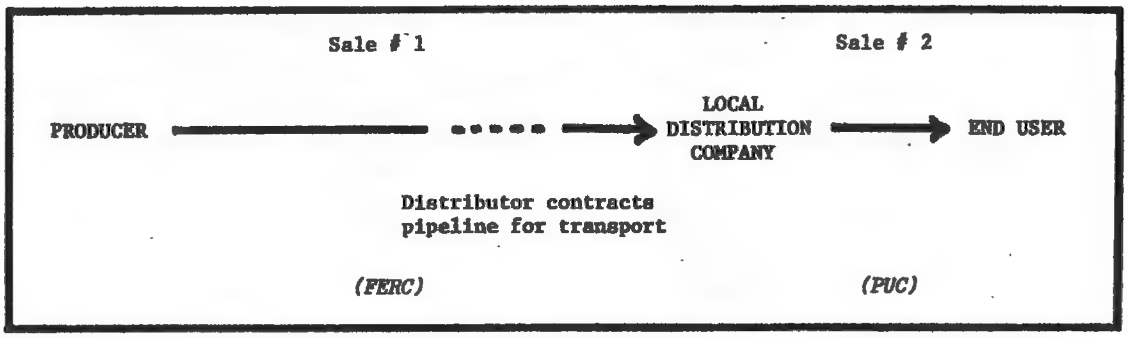
"Contract Carrier" Status



Here, the interstate pipeline company does not purchase gas and sell it at the pipeline tailgate. Instead it operates as a carrier of gas owned by other companies, contracting its transportation services on a first-come first-serve basis up to the pipeline's capacity. The actual sale, therefore, takes place between the producer and a downstream transmission company or even the local distributor. While Canadian gas pipelines generally operate as contract carriers, interstate pipelines in the U. S. operate as carriers only incidentally to their business as buyers and sellers of gas. The Alaska Highway Pipeline (U. S. segments) will be the first major interstate system to operate in the U. S. exclusively as a contract carrier, providing transportation services for downstream interstate pipelines which purchase gas at the wellhead.

Interstate Sales Variation # 3

"Common Carrier" Status



This sales variation is just like the "contract" carrier type of sale, except that here purchasers who wish to use an interstate pipeline for transporting their gas have broader rights. Unlike the limitations of contract carriers who transport gas on a first-come first-serve basis through long-term agreements, common carriers must serve all customers who tender gas for shipment. If this means that there is more gas for shipment than the pipeline can carry, then everybody's volume is reduced proportionally ("pro-rated") -- without respect to seniority or any other special preferences. No important gas lines in Canada or the United States function as common carriers. The closest comparison is with interstate oil pipelines, which are required to provide common carrier service. One can expect that common carrier arrangements will continue to be rare in the gas industry. The comparison is noted here simply to contrast with contract carrier status, because there has been some question raised as to whether the Alaska gas line will be a contract or common carrier.

Interstate Sales Variation # 4

"Direct" Industrial Sales

Sale # 1		Sale # 2	
PRODUCER →	INTERSTATE TRANSMISSION COMPANY	→	END USER
(FERC)		(PUC or unregulated)	

Here, the distributor is by-passed because the industrial customer is hooked up directly to the interstate pipeline. The Natural Gas Act specifically excluded direct sales from FPC jurisdiction, but the federal courts have nevertheless permitted the Commission a broad measure of authority over such sales.

Interstate Sales Variation # 5

"Self-help" Industrial Sales

Sale # 1

PRODUCER ———————— - - - - → END USER

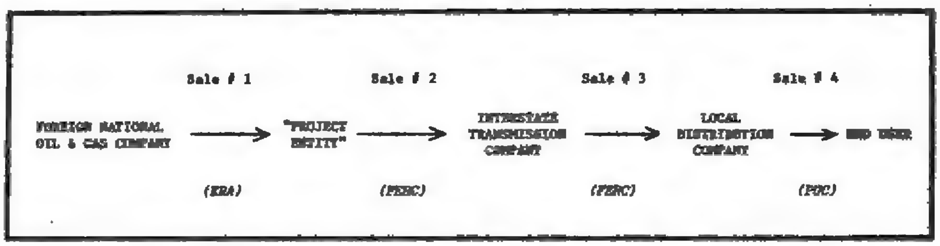
End User contracts pipeline for transport

(PUC or unregulated)

This variation combines the characteristics of Contract Carriers and Direct Industrial Sales. Here the end user purchases gas directly from producers and uses interstate transmission company pipelines under contract. The federal government has given limited support to "self-help" arrangements in order to entice more gas out of intrastate markets. Self-help industrial sales are allowed to circumvent federal price ceilings and are regulated instead by state public utility commissions (if at all).

Interstate Sales Variation # 6

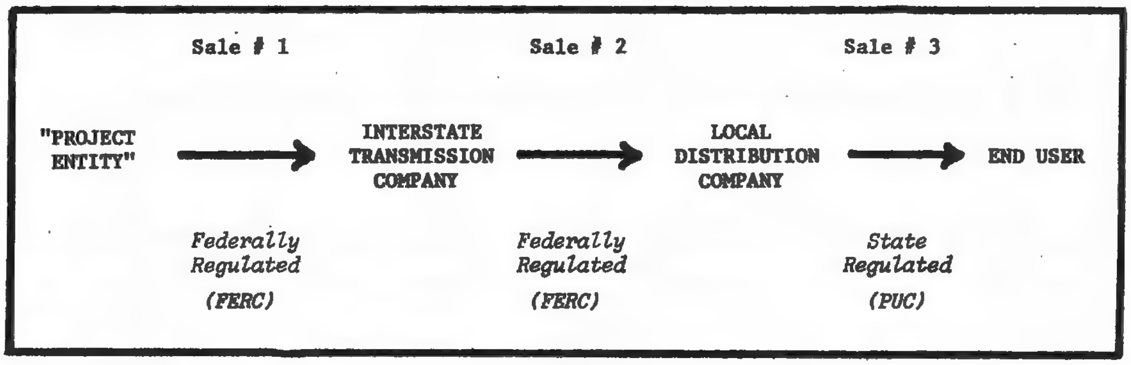
Liquefied Natural Gas Imports



Here, the producer is replaced by a national petroleum company in a foreign country, which sells gas already in liquid form to a "project entity". This "project entity" is usually a free-standing consortium (which exists by virtue of "project financing") composed of interstate transmission company subsidiaries (who later purchase the gas from the project entity). The project entity transports the LNG in its own or chartered tankers, regasifies the LNG on shore in the U.S., and then sells the gas to interstate transmission companies. The sale from the national oil company to the U.S. owned project entity is not, strictly speaking, under ERA or FERC jurisdiction, but the former can approve or deny permission for imports, and the latter can grant or deny a certificate for interstate gas sales; so each of them is in a position to act favorably or adversely on the basis of the terms and conditions of the original sale.

Interstate Sales Variation # 7

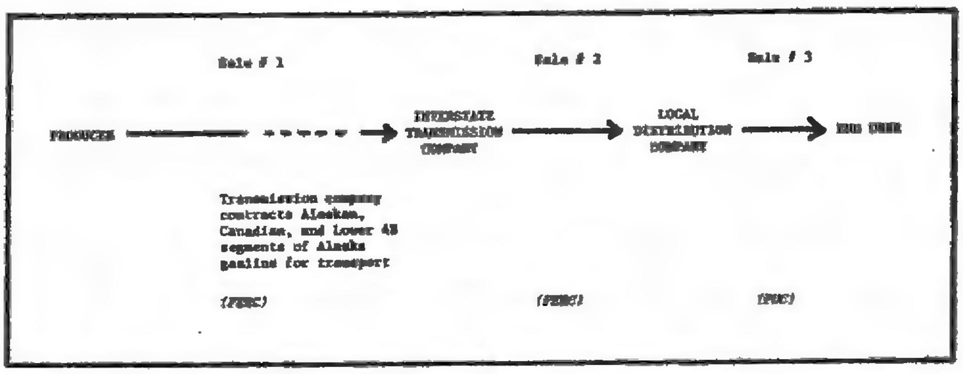
Synthetic Coal Gas



Here, the feedstock is coal, which is purchased by a special "project entity", converted into gas, and sold by the usual transactions. FERC's authority begins only when the synthetic gas is "commingled" (mixed) with natural gas in an interstate pipeline. Again, FERC has much wider effective authority than this jurisdiction would suggest because it can deny the transmission company authority to pass through synthetic gas costs of which it disapproves.

Interstate Sales Variation # 8

Alaska Pipeline Gas

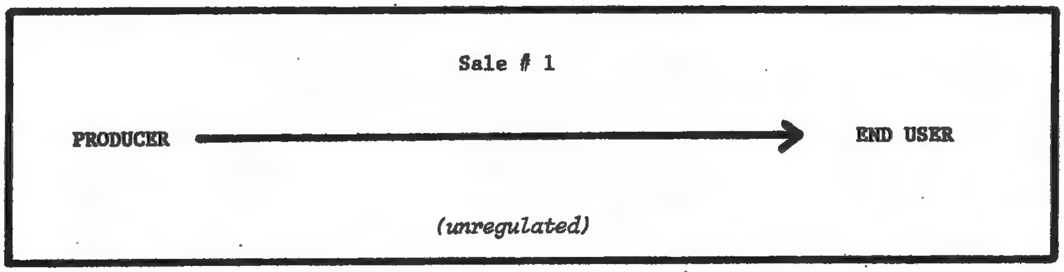


For Alaska gas, the most important variation in the probable sales sequence is what happens between Sales # 1 and # 2. The interstate transmission company(ies) that purchase gas from the producer will contract with (1) the "project entity" that owns the Alaskan pipeline segment, (2) the Canadian pipeline segments, and (3) the "project entities" that own the Northern Border or Western Leg segments within the U.S. for transport of its gas. Finally, it will carry the gas through its own line for sale to local distribution companies, and so on.

There are a varity of sales entirely within producing states, parallel to several of the interstate transactions just discussed. The most typical are direct sales by producers to end users and sales by producers to local distribution companies. Here, sales, if regulated at all, are under the jurisdiction of state utility commissions.

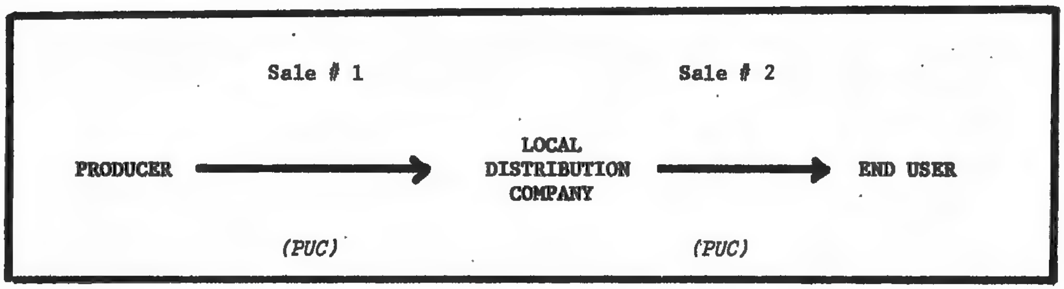
Intrastate Sales Variation # 1

"Direct" Unregulated Sales



Intrastate Sales Variation # 2

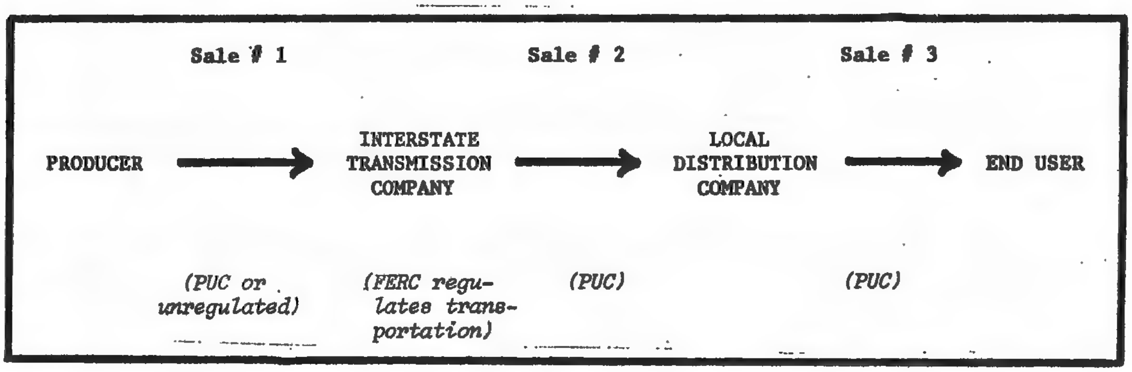
Regulated Sales



Where intrastate gas is moved by an interstate transmission company, either as a buyer and seller of gas, or as a carrier, the regulatory situation is more complicated.

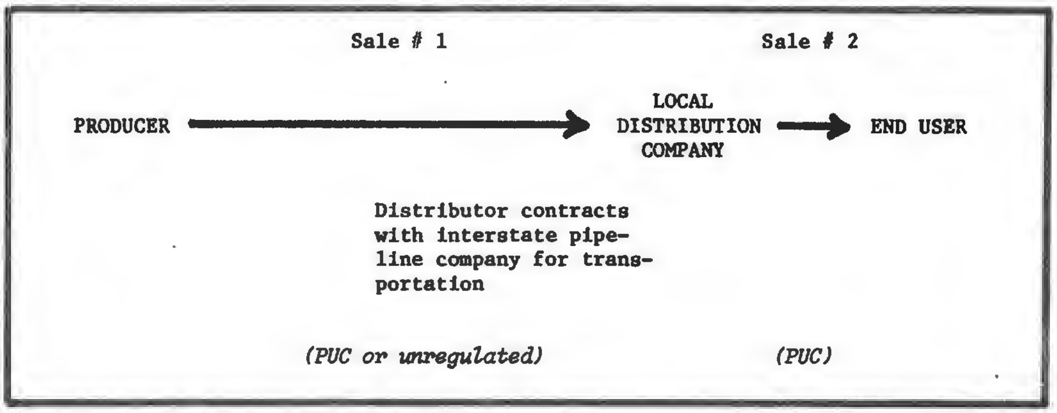
Intrastate Sales Variation # 3

Intermediate Purchase by Interstate Pipeline



Intrastate Sales Variation # 4

Interstate Pipeline as Contract Carrier



Thus, although a sale by a North Slope producer to a Fairbanks distribution company would technically be an intrastate sale, in practice the parties would have to get approval from FERC to ship any gas through the Northwest Alaskan pipeline.

* * * * *

This paper will treat in turn the details of each of the three major components of the sales process:

(1) Sale from Producer to Interstate Transmission Company

(2) Sale from Interstate Transmission Company to Local Distribution Company

(3) Sale from Local Distribution Company to End User

But first, we will review the characteristics of the four parties involved in the transactions: the producer, interstate transmission company, local distributor, and end user.

4.2 PRODUCERS

Producers of gas are often major oil companies who find and produce associated gas along with crude oil. In the case of Alaska pipeline gas, "producers" refers principally to Exxon, Arco, Sohio, and the State of Alaska (which, while not a producer, is an owner of oil and gas by virtue of royalty provisions in the leases).

PRUDHOE BAY OIL AND GAS OWNERS

Owner	Gas Ownership		Oil Ownership
	% of total	Daily volumes [1]	% of total
SOHIO	23.5 %	564 MMcf	46.5 %
EXXON	31.5 %	756 MMcf	17.5 %
ARCO	31.5 %	756 MMcf	17.5 %
STATE OF ALASKA	12.5 %	300 MMcf	12.5 %

[1] The daily volume of gas owned and sold assumes pipeline throughput of 2.4 bcf per day, as presently intended by the federal government and pipeline sponsors.

Nationwide, however, there are a substantial number of companies that are gas producers exclusively, and in recent years, interstate gas transmission companies have been getting more and more into the gas exploration business through two avenues:

(1) Formation of gas exploration subsidiary companies. Many of the large interstate transmission companies have recently created or expanded oil and gas exploration subsidiaries of the parent holding companies (these relationships will be discussed later). Such exploration companies are not regulated by the federal government. They often purchase "working interest shares" or join major oil and gas companies, such as Exxon, in "joint ventures," whereby several companies combine in bidding on lease sales -- primarily federal OCS sales. Since all gas produced on federal offshore lands automatically enters interstate commerce, these exploration subsidiaries are not confronted by the dilemma of whether to sell to sibling interstate transmission companies or whether to turn a higher profit by selling into intrastate markets.

(2) Advance payments. Many gas companies used to make interest-free loans to oil companies to assist in oil and gas exploration, in return for the right to match the highest bid for purchase of any gas found, which, with the existence of a price ceiling, was easy to do. This practice

was defended from a consumer standpoint in that it would bring in more gas to gas-deficient areas. However, after an adverse ruling in federal courts, FERC recently decided that advance payments could no longer be put into the transmission company's "rate base" (meaning gas customers pay for the loan and are reimbursed later through sale of gas at cheaper rates). Since this ruling, there has been little interest shown by transmission companies in making these loans. Prior to the ruling, Exxon, Arco and Sohio/BP had all made advance payment arrangements with interstate gas transmission companies regarding North Slope gas. It appears that only the agreement between Sohio/BP and Columbia is still in effect.

4.3 INTERSTATE TRANSMISSION COMPANIES

Interstate transmission companies purchase, sell, and transport gas across state lines. In the Natural Gas Act of 1938, Congress declared that such companies must function as public utilities, meaning that their sales transactions are strictly controlled and profits are limited to a "fair" return. The reason for taking interstate transportation of gas out of the free market was because the public interest was deemed to be better served by regulated monopolies. Because of "economies of scale" it is cheaper to transport a certain volume of gas in one large pipeline than for two competing companies to build two smaller pipelines for transporting that same volume. However, if a single company monopoly is allowed to exist, government regulation is essential in order to prevent the monopoly from exploiting customers who have no choice but to purchase gas from it. For these reasons, the Federal Power Commission (now FERC) was empowered (1) to certify the building of any new pipelines -- thus protecting monopoly status for existing pipelines; and (2) to approve all services and rates filed by these regulated gas companies -- thus protecting consumers.

Interstate transmission companies in the United States have generally owned the gas they transported; but have recently also served as "contract carriers" [1] for "self-help" industrial sales (described on page 31). The situation in Canada is quite different -- its gas pipelines within as well as between provinces, all operate as "contract carriers."

Some interstate pipeline companies are regulated subsidiaries of other regulated companies or of non-regulated parent holding companies. A good example of this is Northwest Alaskan Pipeline Company, which is one of the six partners proposing to build the Alaskan segment of the gasline:

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[1] Contract carriers are pipelines which contract to transport gas owned by other parties.

NORTHWEST ENERGY CO.

Northwest Alaskan Pipeline Co.	Northwest Pipeline Co.[1]	Prairie Pipelines Ltd.	Prairie Transmission Lines, Ltd.

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[1] Northwest Pipeline Company is an interstate transmission company which owns and operates pipelines in the Northern Rocky Mountain and Pacific Coast areas.

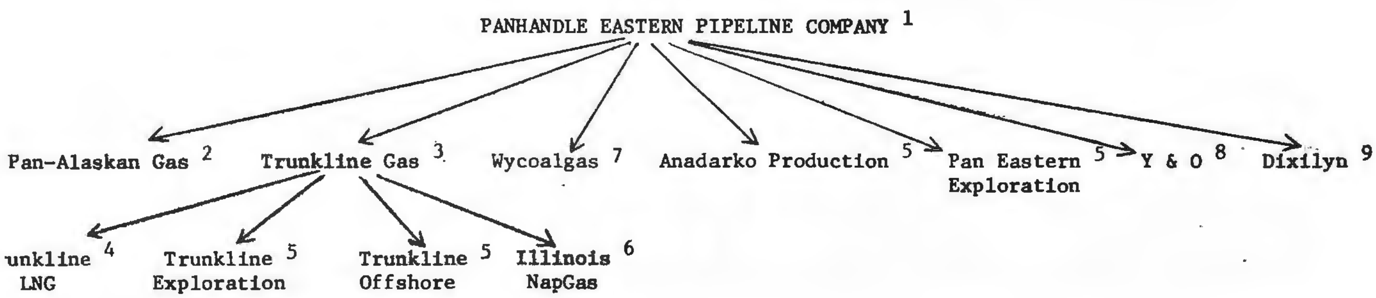
Since Northwest Energy Company is a "publicly held" corporation, its shares are bought and sold on the public market. (Note that a "publicly held" company is a privately owned enterprise, not a governmentally owned one.) No stock is issued separately for its subsidiaries. On the other hand, the "Alaskan Northwest" project entity that will own the Alaska segment of the proposed gasline will be a separate corporation; neither Northwest Alaskan Pipeline Company nor its parent, Northwest Energy, will be liable for project loss or failure.

A good example of just how complex the company affiliations can become is Panhandle Eastern, which is also a member of the "Alaskan Northwest" consortium. Its structure is shown in Figure 3. The parent transmission company has integrated both "vertically" by creating subsidiaries which explore for and produce gas, and "horizontally" by venturing into coal mining and marketing.

FIGURE 3

INTERNAL STRUCTURE OF INTERSTATE TRANSMISSION COMPANIES

(e.g. Panhandle Eastern Pipeline)



[1] Panhandle Eastern Pipeline Company operates interstate pipelines running from north Texas to Michigan.

[2] Pan-Alaskan Gas Company is one of the six partners which comprise Alaskan Northwest.

[3] Trunkline Gas Company operates interstate pipelines running from south Texas to Michigan.

[4] Trunkline LNG Company is involved in a project financed entity which is now gearing up for building facilities to import LNG from Algeria.

[5] These four companies are involved in oil and gas production and exploration.

[6] Illinois NapGas operates a peak-shaving SNG (from naphtha) plant in Illinois.

[7] Wycoalgas is an inactive company formed previously to study the feasibility of a coal gasification plant in Wyoming.

[8] Y & O Company mines and markets coal.

[9] Dixilyn provides contract well drilling for offshore areas owned by other companies.

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Currently, the six interstate pipeline companies who, through the use of the subsidiaries shown in parentheses, have signed the "Alaskan Northwest" partnership agreement are:

Northwest Energy Company
(Northwest Alaskan Pipeline Company)
Northern Natural Gas Company
(Northern Arctic Gas Company)
Panhandle Eastern Pipeline Company
(Pan-Alaskan Gas Company)
United Gas Pipeline Company
(United Fuels Corporation)
Pacific Gas & Electric
(Natural Gas Corporation of California)
Pacific Lighting Corporation
(Pacific Interstate Transmission Company)

It is generally believed that the final ownership of the U. S. segments of the Alaskan gasline will be determined by which pipeline companies are successful in purchasing gas from the Prudhoe producers and the state. However, two other factors might come into play:

(1) Some pipeline owners may not wish to own any gas. Northwest Pipeline Company is dependent upon expensive Canadian supplies already; and it is a matter of speculation whether Northwest has any ability or desire to purchase Alaskan gas for its own service area or whether it is seeking an equity position simply as a worthwhile investment, or some other reason.

(2) Some gas owners may not wish to join in pipeline ownership. Since the President's Decision selecting the Northwest project over the competing Alaskand Arctic Gas and El Paso Alaska proposals specified that the U. S. pipeline segments grant equal "access" to the facility to non-owners, a gas purchaser does not have to participate as a gas pipeline owner in order to transport its gas to market.

Whatever the final organization of the gasline consortium turns out to be, it is significant to keep in mind that there remain three hold-outs among the original Arctic Gas group who have to date resisted all pleas to join the Alaskan Northwest partnership. These are:

Columbia Gas Transmission Corporation

Texas Eastern Transmission Corporation

Michigan-Wisconsin Pipeline Company

Currently, the companies formed to build the Canadian sections of the Alaska gasline (the Foothills Pipeline group) are owned by two Canadian companies with existing gas lines. They are:

Westcoast Transmission Company,
(existing pipelines principally in British Columbia)

Alberta Gas Trunkline, Ltd.
(with existing gas pipelines in Alberta)

Each of these companies enjoys a special position in its home province. Westcoast is 10 percent owned by the British Columbia provincial government. AGTL was specially created by the province of Alberta, and 30 percent of the shares were reserved for individual residents of Alberta. While the provincial government does not own any of its stock, AGTL does enjoy monopoly privileges within the province -- in that any intraprovincial gasline within Alberta must be built by AGTL.[1]

TransCanada Pipelines, Ltd.[2] a proponent of the defunct Arctic Gas proposal, has so far resisted all efforts to bring it into the Foothills fold.

It is interesting to note that both TransCanada and Mighigan-Wisconsin (another Arctic hold-out refusing to join the Northwest project) are causing some problems for the Northwest consortium. TransCanada has urged that the Canadian National Energy Board not approve the short-term "swap" of Alberta gas to Northwest Pipeline, which would enable Foothills to "prebuild" the southern Canada portions of the Alaska Highway system. TransCanada maintains that any increases in exports to the U. S. should be carried through TransCanada's existing pipeline system, which is

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[1] This special status is one outgrowth of the longstanding rivalry between Eastern-controlled TransCanada and the Western provinces.

[2] TransCanada is Canada's largest interprovincial transmission company, carrying gas from the Alberta border to Eastern Canadian markets and Midwestern states.

now operating well under its design capacity and can deliver added gas to the desired U. S. markets with only minor expansions. Michigan-Wisconsin has filed suit against FERC, alleging that FERC's conditional approval of the gas swap violates certain principles of both the Natural Gas Act of 1938 and the Alaska Natural Gas Transportation Act of 1976.

4.4 LOCAL DISTRIBUTION COMPANIES

"Local" distribution company is somewhat of a misnomer: while some distributors operate in a single urban area, others serve virtually an entire state. A characteristic of all distribution companies, however, is that they operate transmission and distribution facilities within a single state, and are therefore regulated by state public utilities commissions. Some distribution companies are subsidiaries of holding companies that also operate interstate pipelines through other subsidiaries. Columbia is a good example:

Columbia Gas System, Inc.
(parent holding company)

Columbia Gas Transmission Corp.

Columbia Gas of Kentucky

Columbia Gas of Ohio

Columbia Gas of W. Virginia

Interstate Pipeline

Distributors

Unlike interstate pipeline companies, which generally sell set volumes of gas to distributors on a year-round basis, customers of distribution companies have demands which vary with the seasons. Residential customers use about five times more gas in the winter than in the summer. Thus, distribution companies are often involved in projects that use old gas fields or salt domes for storing excess summer gas for winter use, or in projects that synthesize gas out of naphtha during winter periods of peak demand.

With the exception of Pacific Lighting Company and Pacific Gas and Electric Company of California, (co-sponsors of the Pac-Alaska and Pac-Indonesia LNG projects), intrastate transmission and distribution companies are not involved in supplemental gas projects otherwise sponsored by interstate transmission companies. Distributors, instead, depend totally on the efforts of their interstate suppliers to offset declining gas reserves.

4.5 END USERS

4.5.1 Types of End Users. End users are usually grouped into four main categories:

* Residential - homeowners who use gas for heating or cooking;
* Commercial - business establishments that burn gas primarily for heating;
* Industrial - plants that use gas primarily for generating heat, and to a much lesser extent as feedstock for making fertilizer, methanol, or other chemicals by means of a direct flame; and
* Utilities - using boiler or turbine fuel for electricity.

4.5.2 Priorities of End Users. During recent gas shortages, FERC has categorized end users by "priority". The highest priority customers are those who cannot readily and economically switch to another fuel, like residential and small commercial customers. The lowest priority users are those who already have installed oil or coal burning equipment as back-up, or who use gas as boiler fuel in generating electricity. For those pipeline and distribution systems where winter demand surpassed supplies, customers were "curtailed" on the basis of their priority classification, with the lowest priority users cut off first.

4.5.3 "Firm" vs. "Interruptible Customers. High priority customers are usually "firm" meaning the distributor must service their needs year-round. However, large industrial users often purchase gas on an "interruptible" basis at cut-rate prices. When firm customers' needs increase in the winter, distributors have the unilateral right to stop serving interruptible customers, using this freed-up gas to meet increased gas demand for spaceheating. Interruptible customers, in turn, switch to their back-up facilities, burning oil or coal. The reason FERC instituted priorities among customers was that supplies had finally declined to the point where some pipelines and distributors had stopped serving all their interruptible customers and still did not have enough gas to meet their firm contracts.

Federally approved "curtailment schedules" filed by these companies help protect them from a rising number of damage suits filed by unsatisfied firm customers.

4.6 SALE FROM PRODUCER TO INTERSTATE TRANSMISSION COMPANY

The Natural Gas Act of 1938 specifically excluded federal regulation of gas production or gathering from FPC jurisdiction. It did, however, call for regulation of so-called "natural gas companies," defined as persons "engaged in the transportation of natural gas in interstate commerce, or the sale in interstate commerce of such gas for resale." For many years, the Federal Power Commission (FPC) interpreted the law to mean that the price negotiated between the producer and transmission company was not subject to its review and approval. At first, this interpretation posed no hardship for consumers because of the widespread "buyer's market" in which gas was plentiful and interested buyers scarce; transmission companies could easily obtain long-term (20 plus years) contracts for gas at a very low cost. Some of these old contracts are still in effect, often for less than 20 cents per mcf, in contrast to a "new" gas price ceiling of $1.45 today and supplemental gas costs estimated at $3.00 to $6.00 in 1978 dollars.

However, in 1954 the court ruled otherwise. In the Phillips case, the FPC (now FERC) was told that it can and must regulate producers of gas as "natural gas companies", to the extent that they sell gas in interstate commerce for resale.

In deciding whether to approve these wellhead prices, the FPC first turned to the straightforward pricing principles of utility regulation -- that price should reflect actual costs including a reasonable profit. But with thousands of producers participating in even greater numbers of individual sales, the conventional "cost of service" approach was clearly unworkable on a sale-by-sale basis. Beginning with the "Permian Basin" decision in 1965, the Commission attempted to set "area prices" on the basis of <u>average</u> exploration and development costs over a large producing area. The price reached in this decision was attacked in the courts by producers as unfairly low, and by distributors and consumer advocates as excessive. By the time the courts finally approved the Permian decision, however, it was obvious that even the "area rate" approach was too slow and cumbersome.

Finally, the FPC decided to put the problem to rest by establishing a single nationwide price ceiling (based on the average <u>projected</u> costs of producing non-associated gas), rather than judging actual costs on a sale-by-sale or area basis or even on a national average. This approach was set out in its Opinion 770, issued in 1975 (slightly revised in 770A), and has survived tests in court. Opinion 770 sets a price and establishes how it will escalate through the years.

Ironically, just after the federal courts have finally sanctified the methodology of Opinion 770, the rules are being changed again. Recent passage of amendments to the Natural Gas Act establishes 12, 17, or 26 different prices for different categories of gas (depending upon one's interpretation of the law).

Significantly, all these prices represent only "ceilings." Negotiated prices below this standard will be approved; negotiated prices above the ceiling will be rejected. However, in recent years this "ceiling" has in most cases become the firm price, since rising oil prices have created a gas demand at the regulated ceiling which far outstrips supplies. Hence, producers are almost always able to find a buyer at the ceiling price.

In fact, producers have preferred to sell to another class of buyers outside of FPC's jurisdiction: intrastate transmission and distribution companies who reside and make final sales in the same state in which gas is produced. These sales have been regulated (if at all) by state Public Utilities Commissions, since the commodity never enters interstate commerce. However, most state PUC's have not imposed price ceilings like the FPC. Hence, some Texas producers selling into the Texas intrastate market have been able to obtain prices well over $2.00/mmbtu.

This artificial marketing preference for intrastate purchasers and against interstate purchasers, due to lopsided regulation, has caused accumulations of unsold gas in some intrastate markets at the same time as shortages in those states in which gas must be imported across state lines. Either deregulation of interstate prices or imposition of ceiling prices on intrastate sales would resolve the contradiction; the Natural Gas Policy Act of 1978 takes the latter approach until 1985, when gas in both markets would be deregulated.

The Natural Gas Policy Act also explicitly sets a wellhead price for Prudhoe Bay gas, at $1.45 per mmBTU, escalating at the rate of general inflation in the United States. If this action had not been taken by Congress, a lengthy regulatory proceeding would have been undertaken by FERC to set a price; because Opinion 770 excluded exploration and production costs in Alaska from the data used to calculate the nationwide rate. (No gas from Alaska's Cook Inlet has yet been sold into domestic interstate markets, so the issue has not arisen.)

Both the earlier FPC national price and the Congressionally determined Alaska North Slope price represent ceilings; however, as previously discussed, domestic ceiling prices on gas have in practice turned out to be floors as well. There are signs that producers and the state might likewise view the Alaska ceiling as <u>the</u> price. Thus, purchasers may not be able to negotiate the price down, and the whole question of who is awarded contracts will turn on other criteria, such as how cleaning and conditioning responsibilities will be split between buyer and seller. This could cause an unusual problem: Unlike price-controlled lower 48 gas, Prudhoe Bay gas may not be worth the ceiling price. Once processing, transportation and distribution costs are added, the end price to consumers could make it unmarketable (unless the government takes certain steps to disperse the high costs, which will be discussed later).

Prudhoe Bay crude oil presents a good example of ceiling prices that do not in fact determine the market price. Prudhoe Bay crude, as "new oil" has a regulated wellhead price ceiling of over $11.00 per barrel, as does other "new" domestic crude oil. Crude oil from the Gulf Coast states, for example, competes with $14.00 foreign oil and requires (say) $.50 in transportation costs to the refinery, so actual sale prices are right at the new oil ceiling and would go even higher if price controls were removed. But in Alaska, with transportation costs of $7.00 or more, producers could not hope to get more than $8.00 for their oil -- far below the regulated ceiling. (The actual prices posted for Prudhoe Bay crude range from less than $1.00 per barrel to about $7.70, depending on the transportation cost to refiners in various parts of the United States.) The same may be true for Alaska gas; its market value, as adjusted by transportation costs, may be considerably less than the official ceiling. But while purchasers of Prudhoe Bay oil would not dream of offering more at the wellhead than the refinery cost of competing oil (less transportation charges), Prudhoe gas purchasers (interstate transmission companies) may be willing to offer more than the gas is worth to the final consumer (with comparable adjustment for transport costs). Why would these companies be willing to pay more than the gas is worth? Several factors contribute to this, including some rather perverse incentives which are a natural outgrowth of utility regulation, accompanied by unique regulatory actions which shift the burden of marketing risks away from the purchasing transmission companies.

Interstate transmission companies are regulated as utilities, which means their profits are limited to a fair rate of return. If a transmission company buys gas for a dollar and it costs the company another dollar to transport it, the gas must be sold for two dollars (including a fair profit on its investment). If a transmission company buys gas for two dollars and it still costs a dollar (including profit) to carry it, the company sells it for three dollars. Whether the company strikes a good bargain and buys gas at a dollar from the producer, or a bad bargain at two dollars, its profits remain the same! (This lack of a strong incentive to bargain down the price may be one of the reasons why wellhead price ceilings were required in the first place.) Yet, even if the foregoing distortion in normal profit incentives is accepted, one could reasonably expect transmission companies to bargain the price down at least low enough to make the end product saleable. However, in these high-cost supply projects like Alaskan gas and LNG, past ratemaking practice in the form of "rolled-in" pricing has offered the industry the means of selling gas priced at levels above its market value. While rolled-in pricing for supplemental gas projects is currently defended mainly as a means of making projects financible, this effect results from the fact that rolled-in pricing relieves the purchasing transmission companies from most (if not all) of the marketing risk. This issue will be discussed later.

In the days when actual gas producing costs were far below the "commodity value" that gas users would have been willing to pay, this "cost-based" pricing system for interstate sales in the U. S. could well be regarded as serving the interest of consumers. But for projects in which total costs may <u>exceed</u> the commodity value, cost-based pricing combined with protective regulation may, in effect, work against consumer interests.

In 1972, Canada changed its own cost-based pricing system to the "commodity value" approach. Now, unlike the U. S. where the wellhead price ceiling is set and costs are added on until the gas reaches the end-consumer, Canada does it backwards. The Canadian government sets the downstream price instead, and costs are subtracted back to the wellhead. Whatever is left after all costs (including royalties and taxes) are accounted for is left to the producers.

This system eliminates both the kind of gas "shortages" that have prevailed recently in the United States (consumer prices so low that demand exceeds supply) and the possibility of "marketability" problems (Will the delivered price of gas be low enough that consumers will buy it?). For these issues the Canadian system substitutes the possibility of "surpluses" (producer prices so high that supply exceeds demand in the field), or of a "producibility" problem (Will the field price of gas be sufficient to induce producers to find and develop additional gas?).

In addition to shifting the focus of pricing, the Canadian system of "netting back" price to the wellhead provides an efficiency bonus. Producers have a substantial incentive to be concerned about excessive and unnecessary transportation costs[1]; while in the United States, cost control depends largely upon the vigilance of federal and state regulators. The Federal Power Commission, in its 1977 recommendation to the President regarding the transportation of Alaska gas, recommended a commodity value net-back pricing scheme, but the Administration in its legislative program chose to continue the traditional cost-plus arrangement.

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[1] Witness the vocal support of the "Progas" group (comprised largely of Alberta producers) for the seemingly cheaper TransCanada pipeline export proposal versus the more expensive Foothills "swap" which entails the building of new line.

COMPARISON OF U.S. AND CANADIAN PRICING SYSTEMS

U.S. "COST-BASED" PRICING SYSTEM

Wellhead price	+	Interstate Transportation	+	Distribution	=	Consumer price
(at or below ceiling which is based on actual costs incl. profit)		*(actual costs incl. fair profit)*		*(actual cost incl. fair profit)*		

CANADIAN "COMMODITY VALUE" PRICING SYSTEM

Consumer price	-	Distribution	-	Interprovincial Transport.	=	Wellhead price
(85% of fuel oil price)		*(actual costs incl. fair profit)*		*(actual costs incl. fair profit)*		

In summary, the major points concerning producer to transmission company sales of Alaska gas are as follows:

(1) Congress has set a wellhead price ceiling for Alaska gas at \$ 1.45 per mmBTU (plus inflation);

(2) It is likely that this ceiling will prove to be higher than the true worth of the gas once conditioning, transportation, storage, and distribution costs are added;

(3) Nevertheless, the North Slope gas producers will probably hold out for the ceiling price;

(4) If sponsoring transmission companies and lenders perceive that the negotiated price may indeed push the gas over its commodity value to consumers, the project will still move forward <u>if</u> the federal government grants special regulatory treatment which protects transmission companies and lenders from these marketing risks. (These regulatory actions are discussed further on.)

(5) From a perspective of Alaska's own interests, the state as royalty owner would stand to gain more in revenues from the existing U.S. system of wellhead pricing than from a Canadian style of netback pricing, assuming of course that federal regulations are adequate to guarantee marketability of the gas and facilitate pipeline financing.

(6) While the existing pricing system may serve to bring to market Alaska gas that may have cheaper alternatives (oil) readily available, it may, nonetheless, be a "good thing" from a national perspective by reducing dependence on imports.

4.7 SALE FROM TRANSMISSION COMPANY TO DISTRIBUTOR

4.7.1 OVERVIEW

Since a sale from transmission company to distributor is a "sale for resale in interstate commerce," it is regulated by the federal government through the Federal Energy Regulatory Commission (FERC). State utility commissions exercise jurisdiction over these sales as well, though indirectly, as they must approve the costs distributors pass through to end users. This sale is sometimes referred to as the "wholesale" transaction, while the subsequent sale by the distributor to the final consumer is called the "retail" sale.

In selling gas at wholesale, the interstate transmission company and local distributor negotiate a sales contract, called a *service agreement*, which must be approved by FERC and the state commission. The *service agreement* combines both the sale of gas and its transportation to the distributor. It has three major components:

(1) Term - The term of a contract is the number of years the contract is in force, together with procedures for its renewal.

(2) Volume -- The contract establishes the rights and obligations of buyer and seller with respect to the amount of gas delivered and purchased.

(3) Price - The contract incorporates by reference the *tariff* of the seller as approved by FERC in a separate document that establishes different prices (or *rate schedules*) for various conditions of sale. The main function of the price term in the *service agreement* is to set forth which of these *rate schedules* applies to the purchaser in question. Again, while the distributor puchases gas through a *service agreement*, the price he pays is set forth in a separate *tariff* document.

As we mentioned on page 34, with respect to North Slope gas, there will be no "sale" of gas from the interstate pipeline consortium that owns the Alaska gasline to downstream transmission and distribution companies. Instead the Alaska gasline will operate as a *contract carrier*, contracting to transport gas purchased by downstream transmission companies and distributors directly from the producers. Nevertheless, a *service agreement* incorporating a filed *tariff* must still be negotiated for the transportation services. From the "tailgate" of each section of the Alaska gas transportation system, the interstate pipelines that purchased the gas from Prudhoe Bay producers will then ship the gas through their own lines for sale to distributors. This latter sale is the normal transaction between a transmission company acting as a *private carrier* and a distributor. Figure 4 illustrates the technical differences between *private* carriers and the Alaska gasline as a *contract carrier*.

FIGURE 4

SALES TRANSACTIONS, SERVICE AGREEMENTS, AND TARIFFS OF "CONTRACT CARRIERS"
(specifically showing the sale and transport of Alaska gas)

PRODUCER → *... sells gas at the wellhead (price is no greater than the $1.45 wellhead ceiling set by Congress) to ...* → INTERSTATE TRANSMISSION COMPANIES → *... which enter into service agreements (at prices according to tariffs filed with FERC and the NEB) with ...* → ALASKAN NORTHWEST PIPELINE COMPANY → *...for transport of gas through Alaska, ...* → FOOTHILLS PIPELINE COMPANY → *...for transport of gas through Canada, and ...* → NORTHERN BORDER PIPELINE COMPANY → *...for transport of gas through the northern U.S., to the facilities of ...* → INTERSTATE TRANSMISSION COMPANIES → *...who transport and sell gas under existing "service agreements" incorporating tariffs filed with FERC to ...* → LOCAL DISTRIBUTION COMPANIES

SALES TRANSACTIONS, SERVICE AGREEMENTS, AND TARIFFS OF "PRIVATE CARRIERS"

PRODUCER → *... sells gas at the wellhead (price is no greater than the ceiling price set by FERC or Congress) to ...* → INTERSTATE TRANSMISSION COMPANIES → *... who transport an sell gas under existing "service agreements" incorporating tariffs filed with FERC to ...* → LOCAL DISTRIBUTION COMPANIES

Whether the *service agreement* in question is held by a *private carrier* which is both selling the gas and providing its own transportation services, or whether it is held by a *contract carrier* (like the Alaska gasline) carrying the gas for others, all *service agreements* incorporate *tariffs* for their pricing provisions.

Tariffs posted by *private carriers* set forth *rate schedules* for various classes of purchasers. These schedules have two major cost components:

(1) Purchase price of gas. The purchase price is the actual price paid by the transmission company when it buys gas from the producer, including any severance taxes, conditioning charges, etc.

(2) Transportation costs.

(a) Depreciation of the original cost of construction;

(b) Interest on outstanding debt and return on outstanding equity;

(c) Operations and Maintenance ; and

(d) Taxes on income and property value.

Tariffs of *contract carriers* like the Alaska gasline, include only the transportation costs; they do not include the purchase price of gas. Nevertheless, this discussion will address both components.

4.7.2 DETERMINING COSTS: TARIFF COMPONENTS

When an interstate pipeline company files a tariff it does so with respect to gas carried through a particular pipeline system. In the case of supplemental supplies, tariffs will cover the following:

Alaska gas pipeline. At least three separate tariffs will be filed, each covering geographic segments of the gas line. "Alaskan Northwest Pipeline Company" will file the tariff for the Alaska segment, the "Foothills Pipeline" companies will file tariffs for the Canadian sections, and the "Northern Border Pipeline Company" will do so for portions of the line heading eastward in the lower states. For the "Western Leg" connecting California, Pacific Gas Transmission Company will file a tariff. Hence, an interstate pipeline company purchasing gas at Prudhoe Bay will have to enter into at least three separate *service agreements*, incorporating three separate *tariffs* in order to receive the gas into its own system.

Coal gas. One tariff will be filed for a particular coal gasification plant; and it will cover costs of purchasing coal, processing it into gas, and delivering it at the tailgate of the plant. A customer will sign a *service agreement* subject to that tariff, and may need to enter into an additional agreement a pay a second tariff to the interstate pipeline hooked up to the plant. This second tariff will be for moving the gas from the coal gas plant to the purchaser's own system.

<u>LNG</u> One tariff will be filed with respect to a particular regasification facility located in the United States. Gas will be delivered to the customer who signed a service agreement and the tariff will include costs of purchasing LNG at the tailgate of a liquefaction plant in Algeria or Indonesia, transporting the LNG in special tankers (either owned or chartered by the company), and turning the liquid back into gas onshore. Here again, a purchaser might need to enter into a second service agreement subject to a second tariff for downstream transportation.

An interstate pipeline that purchases Alaska gas, coal gas, or LNG will then move it through its own system for meeting the needs of its customers. In most cases these supplemental supplies will be mixed-in or "commingled" with gas from a variety of sources. This physical mixing of gas supplies lends itself to a system of pricing in which the purchase price of gas from all sources is, likewise, mixed together or "rolled-in".

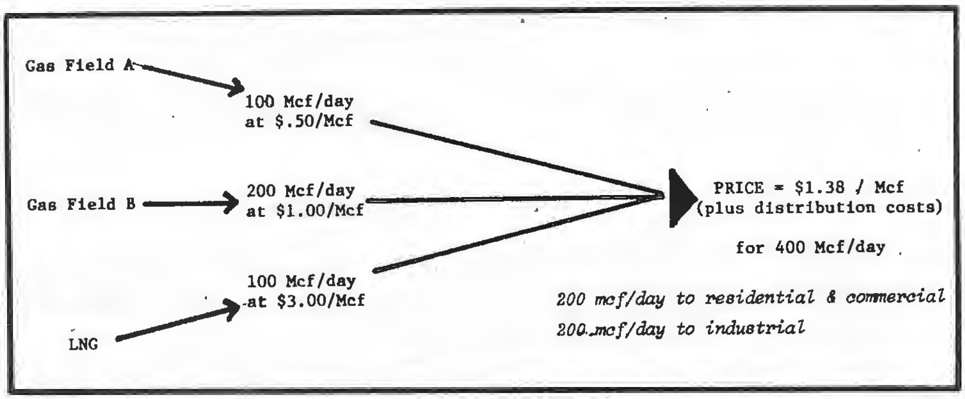
4.7.2 (a) <u>Purchase Price of Gas</u>

Traditionally, a pipeline system will "roll-in" the purchase price of gas from all its sources to yield a "weighted average" purchase price of gas.

In Figure 5 an interstate pipeline purchases gas from two Texas sources and an LNG plant, and has a tariff which reflects a weighted average purchase price of gas at $1.38 per mcf, even though the supplies range in price from $.50 to $3.00. Distribution companies, therefore, purchase gas from the pipeline under a single tariff that combines the costs of all these gas supplies.

FIGURE 5

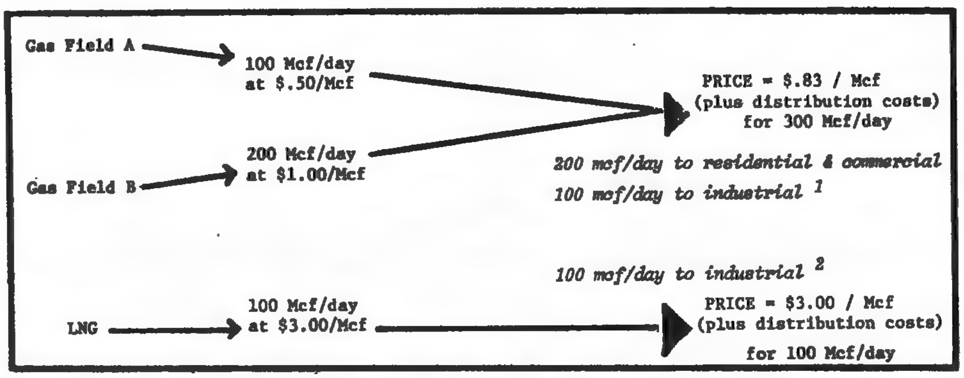
ROLLED-IN PRICING



Recently, national debate has turned to the merits of adopting "incremental", as opposed to "rolled-in", pricing. (See Figure 6.) In its initial decisions on the nation's first two large-scale LNG import projects, the Federal Power Commission mandated the use of "incremental" pricing--meaning the use of separate service agreements and separate rate schedules, even though the gas is physically mixed in with all other supplies during transport. However, in response to a court challenge of the Columbia LNG decision and an appeal by the sponsors of the Trunkline LNG project (who claimed that the pricing rule thwarted their best efforts to arrange financing), the Federal Power Commission reversed itself. Both projects were granted "rolled-in" pricing.[1]

FIGURE 6

INCREMENTAL PRICING (old style)



1 Industrial customers have been curtailed by 100 mcf/day

2 Industrial customers probably will not sign service agreements for incrementally priced gas at more than the price of No. 6 oil ($2.00); hence LNG facility cannot be financed.

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1 Columbia LNG: FPC Opinion No. 622; June 28, 1972
FPC Opinion No. 622-A; October 5, 1972
FPC Opinion No. 786; January 21, 1977
Trunkline LNG: FPC Opinion No. 796; April 29, 1977
FPC Opinion No. 796-A, June 30, 1977

To date, the only examples of "incremental" pricing have been sales of some "peakshaving" or "emergency" supplies during winter months by means of separate rate schedules. No "baseload" supplies (year-round, long term) have been subject to incremental pricing. However, the Congress, through passage of the Natural Gas Policy Act of 1978 mandated incremental pricing for supplemental gas supplies and a strange version of rolled-in pricing for Alaska gas; but this new definition of "incremental" pricing is not the same as the old. No one has yet explained how this new approach will actually work, but the following (much simplified) scheme is our best understanding at this time:

The law requires FERC and the state commissions to establish two tiers of rolled-in gas prices. The upper tier will apply to industrial boiler fuel users of gas (other than electric utilities) and to other industrial users as determined by FERC. The lower tier will apply to residential, commercial, institutional, agricultural, electric utility, and the balance of the industrial users of gas.

At the beginning (Phase I of Figure 7) all gas costs above a given "threshold level" (in most cases, $1.48 per mmBTU plus inflation) attributable to incrementally priced gas -- which includes "new" and "high cost" natural gas, LNG and other gas imports, and certain costs of Alaska gas -- are to be rolled into the upper tier price only.

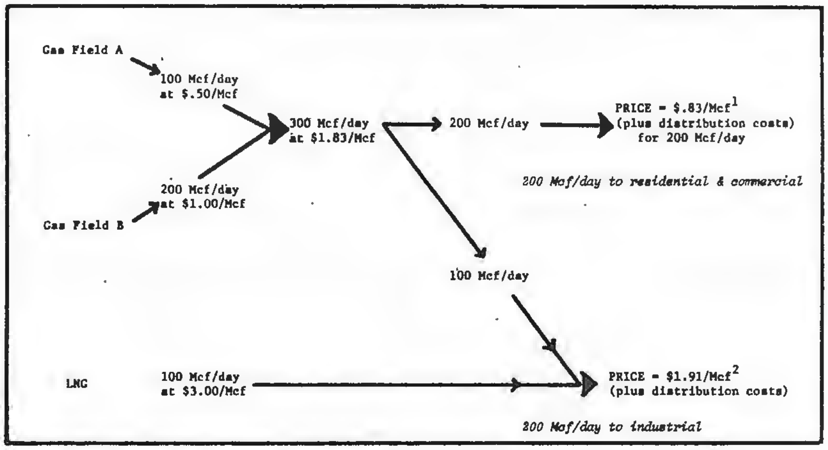
(The law is silent about the treatment of SNG from petroleum and coal.) Other gas costs would be rolled into both upper tier and lower tier prices. Initially, lower tier consumers would thus be protected from the brunt of natural gas price increases which would be directed mainly at cetain categories of industrial users.

Once this formula had increased the upper tier price to an equivalence (on a BTU basis) with the price of an alternate industrial fuel designated by FERC (the law allows FERC to designate any price between that of No. 6 oil and that of No. 2 oil), the upper tier price would be frozen at that level, and all additional cost increases attributable to the incrementally priced gas would now be rolled into the lower tier price. (Phase II of Figure 7.) Presumably, this process could continue until the lower tier price exceeded the price charged upper tier consumers; thus residential, commercial, institutional, etc. consumers would pay higher prices than industrial. (Phase III of Figure 7.)

FIGURE 7

INCREMENTAL PRICING

Phase I

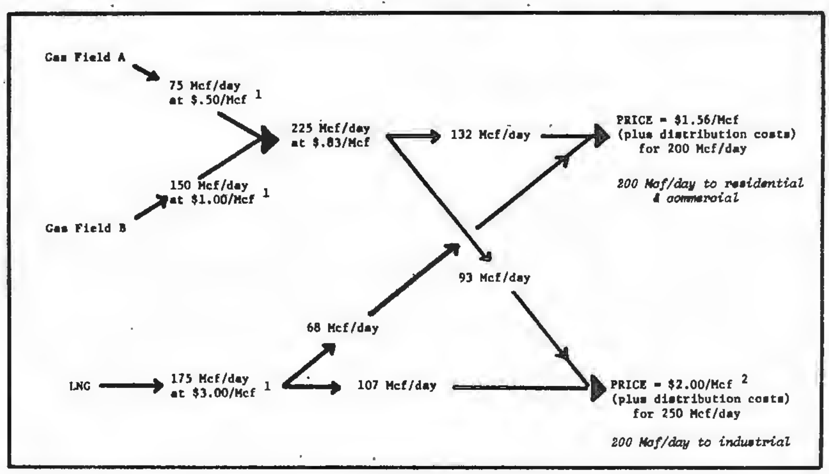


[1] *Residential-commercial rates are frozen.*

[2] *All "incremental" costs are rolled into industrial rates.*

INCREMENTAL PRICING

Phase II

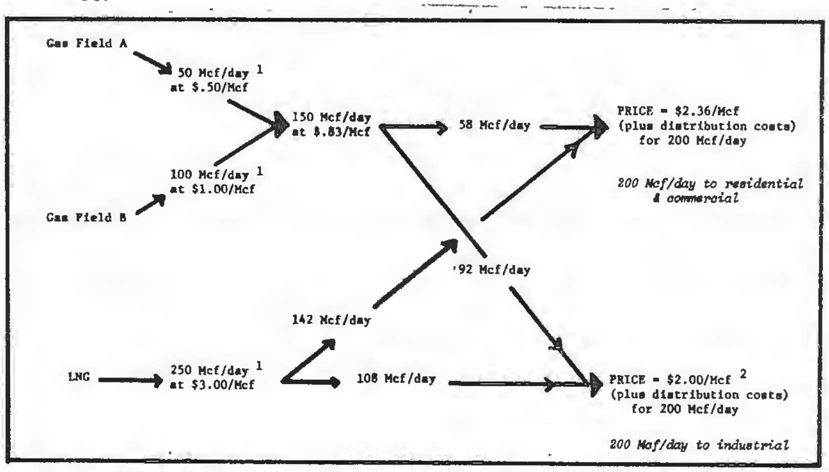


[1] *Old gas flowing under contract has declined 25% (75 Mcf/day), and has been replaced by another 75 Mcf/day of LNG.*

[2] *When the price to industrial consumers reaches the price of alternate fuel (No. 6 oil at $2.00) the industrial sale price is frozen and all incremental costs are rolled into residential and commercial prices.*

INCREMENTAL PRICING

Phase III



[1] *Old gas flowing under contract has declined another 33% (75 Mcf/day), and has been replaced by another 75 Mcf/day of LNG.*

[2] *After the price to industrial consumers reached the price of the alternate fuel (No. 6 oil at $2.00) the industrial sale price is frozen and all incremental costs are rolled into residential and commercial prices.*

4.7.2 (b) Transportation Costs

In addition to the purchase price of gas, tariffs specify the charge for transporting gas through the interstate pipeline. These transportation costs include:

depreciation

interest and return to equity

operations and maintenance

taxes

(1) Depreciation

When a pipeline is built a lot of money is "sunk" into the costs of construction. Naturally, the owners expect to recover this "sunk" capital in addition to turning a profit; so gas pipelines will charge customers a monthly or annual rate sufficient to pay back or "amortize" the original investment over a period of, say, twenty years. The pipeline "depreciates" in value during this time as sunk costs are amortized and the *rate base* shrinks correspondingly.[1]

Under this system, a pipeline which cost a billion dollars to build will have depreciated to a value of zero by the end of its twenty years, once all original costs have been amortized. Further on we will discuss how *depreciation schedules* are calculated.

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[1] *Depreciation* and *amortization* are often used interchangeably.

For purposes here, it is important to remember only that a *depreciation charge* is one component of a tariff's transportation costs; and that it represents a gradual reimbursement of the original costs incurred during construction.

(2) Interest on Debt and Return on Investment

Capital spent during construction is of two types: (1) *debt* furnished by lenders and (2) *equity* furnished directly by the project's sponsors. Both lenders and sponsors contribute money anticipating that the project will earn enough money both to pay back the original investment and to provide an additional return. *Depreciation charges* are the means by which the former is accomplished; and *interest* on debt and *return* on equity accomplishes the latter.

Lenders, such as banks and insurance companies, lend money for pipeline construction on the basis of contracts that specify how fast that money will be repaid or "amortized" and how much interest will be earned annually on the remaining undepreciated capital.

For example, if a pipeline is in its fifth year of operations and $800 million has yet to be repaid from an original debt contribution of $1 billion, the pipeline owners will owe the lenders $80 million in interest that year, based on a 10 percent annual rate. If $500 million is outstanding in the tenth year of operations, annual interest payments will have dropped to $50 million. Hence, interest on debt can be a large fraction of the costs in a tariff, particularly in its early years.

The equity component must also earn a *return*, or profit, on undepreciated equity capital. Interstate gas transmission companies are, however, regulated as utilities, meaning profits are controlled by federal regulators.[1] As explained on page 40, with the passage of the Natural Gas Act in 1938, Congress declared that all pipeline companies transporting gas across state lines must function as public utilities, with profits strictly controlled.

An interesting aspect of regulated profits within the gas transmission industry is that companies are not allowed to earn a profit on the buying and selling of gas as such. They earn a profit only on the transportion services provided, and even then only in proportion to their undepreciated fixed costs. The purchase price of gas at the wellhead is passed right through to the consumer. This means that the basis for calculating a return for a pipeline is exactly the same whether the pipeline operates as a *private carrier* (owning the gas it transports) or as a *contract carrier* (transporting gas owned by others.)

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[1] This discussion only deals with the regulation of interstate gas pipelines. Prior to the creation of FERC in 1977 interstate oil pipelines were regulated on a completely different basis by the Interstate Commerce Commission (ICC). (FERC is the successor to the ICC in oil pipeline regulation and the FPC with respect to gas.)

The Natural Gas Act directs the Federal Power Commission (now FERC) to regulate the profits of interstate gas transmission companies on the basis of a "just and reasonable" return, but left the details to FPC's discretion. The course chosen by the FPC (and continued by FERC) is somewhat more empirical than the vague direction posed by Congress, but it is still quite subjective. FERC takes a look at the profit levels of other companies involved in similar, but unregulated ventures; however, the principal criterion centers on the *opportunity cost of capital.*

Simply put, *cost of capital* means the amount of profit necessary to induce private investors to channel their money into building and operating gas pipelines. It is generally accepted that the *cost of capital* for utilities is less than for companies selling their goods in the free market. Unregulated companies need the prospects of higher profits to attract capital, since they face the unpredictable threats of competition. The riskier the venture, the higher the profit prospects need to be. But monopoly status conferred by FERC on interstate pipeline companies takes a lot of the risk out of selling and transporting gas.

Not all the risks are removed, of course. Federal regulation of tariffs does not guarantee a certain profit; it simply provides a reasonable opportunity to realize that profit. For example, if operations and maintenance costs prove higher than expected when the tariff was filed for a particular pipeline, profits go down until the company secures a tariff revision from FERC (which may take well over a year).

While the *cost of capital* for interstate gas transmission companies is generally viewed to be less than what is needed by unregulated counterpart industries, it is certainly more than the interest charged by lenders contributing debt capital to these companies. This is because debt contributors experience far less risk than the equity owners of interstate pipelines. A good way to see this is by examining the "seniority" of payments.

Revenues generated through tariffs from the sale and transportation of gas are used to make payments in the following order of "seniority":

(1) <u>Purchase price of gas, and operations and maintenance.</u> Producers must be paid for their gas; otherwise the producer may have a right to cancel the contract and sell its gas to some other party. Hence maintaining payments to the producer is essential. Likewise, unless workers are paid it will be difficult to convince them or anyone else to continue operating and maintaining the line; and gas flow will come to a halt.

(2) <u>Repayment of, and interest on, debt</u>. Whatever amount of capital was contributed as debt must be returned to the lenders over a set period of time with interest paid each year at a prescribed rate on the debt still outstanding. However, failure to pay back debt on schedule does not have

the disastrous consequences of a failure to pay producers or pipeline employees. Debt money is "sunk" and even if it can only be paid back over a longer period of time, lenders will find this more agreeable than shutting down the system which would make their debt contribution impossible to retrieve.

(3) Repayment of, and return on, equity. Following payments for the purchase price of gas, operations and maintenance, and debt payments with interest, the remaining revenues are used to amortize sunk equity capital (return of equity) and to provide a profit on the outstanding investment (return on equity). This component is, therefore, "junior" to all other payments.

In short, gas producers and pipeline workers must be paid first, lenders second, and whatever revenues remain are kept by the pipeline company -- presumably sufficient to pay back the equity money it sunk into the project during construction along with a reasonable profit. From this pool of profits annual dividends are paid to stockholders, and the rest is reinvested, presumably in a manner which increases a company's worth, thereby making its stock more valuable.

In the gas pipeline industry, debt presently can be secured at an interest rate of around 8 to 10 percent annually, while FERC will approve tariffs designed to return up to 11 to 15 percent annually in profits on outstanding equity capital.

This concept of *return* is complicated by a confusing array of technical jargon:

Return on equity, *return on common equity*, or *return on investment* are the phrases often used when talking about the company profits as described above. These profits, again, run about 11 to 15 percent after income taxes are paid (called, *aftertax return on equity*), and about 25 percent on a *pretax* basis.

Overall return, *return on total investment*, or *return on rate base* likewise can be on either a *pretax* or *aftertax* basis. They include a return on debt capital (in order to pay off the predetermined interest) as well as profits on the equity. This *overall return* can vary tremendously, depending on the ratio of debt to equity capital. For example, if regulators allow a 25 percent *pretax return on equity* and if debt is secured at 10 percent annual interest (interest is not taxed), *overall return* can vary dramatically relative to the ratio of debt and equity:

> If total capital for a particular project is composed of 50 percent debt (at 10 percent annual interest) and 50 percent equity (with annual profits of 25 percent), then the *overall pretax return* is 17.5 percent.
>
> However, if total capital is composed of 80 percent debt and 20 percent equity, the *overall pretax return* is only 13 percent.

Thus the debt/equity ratio (sometimes called the *capitalization* ratio or *capital structure*) can significantly affect the costs of a project which must then be passed on to purchasers through the tariff. As shown in the preceding example, the more highly "leveraged" the project (meaning a high proportion of debt), the smaller the tariff.

A couple other rather intriguing points must be kept in mind with respect to the regulation of gas pipeline profits. First, companies earn profits based on how much money they invest in their transmission facilities. For this reason, it has long been recognized that some incentive exists for regulated companies to "goldplate" their pipelines, spending more money during construction and subsequent improvements than is needed. This tendency must be checked by government oversight of construction costs.

The *goldplating* problem is exacerbated by the effects of a *vanishing rate base*. An interstate transmission company earns a return each year only on the portion of its original investment which has not yet been recovered. If the tariff is designed to amortize the equity over a twenty year period, by the time the fifteenth year rolls around there is very little investment outstanding upon which to earn a profit. Nevertheless, the company must continue to operate the pipeline[1]; and, in theory, after the twentieth year, the company can be required to continue operating the line and supplying gas to customers without making any profit whatever! As a result, profits of an interstate

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[1] A *certificate of abandonment* must be granted by FERC before a pipeline can shut down.

transmission company will automatically decline through the years if the company simply maintains its existing pipeline system. The only way for profits to stabilize (not to mention increase) is for the company to expand its *rate base* by building new pipelines, refurbishing old lines, or investing its money in non-regulated business ventures.

These dual incentives for *goldplating* and *rate base expansion* are two reasons why regulators must scrutinize high cost supplemental gas proposals. They must consider not only whether construction cost estimates are unduly inflated, but whether the consumers and nation even need the proposed facilities in the first place. The quirks of the regulatory process mean that private enterprise operating within the bounds prescribed by regulation no longer has natural incentives to keep costs low and to ensure that new facilities make marketing sense. Government regulation, thereby, breeds the need for even more government oversight.

With respect to Alaska gas, FERC has proposed an unprecedented scheme to counteract the *goldplating* tendency. While the details of its *variable* or *incentive rate of return* proposal are not yet worked out, its essence is to penalize the sponsors for cost overruns (by mandating a reduced return on equity), and to reward them with a correspondingly higher return if the project comes in under budget. FERC also appears to be looking closely at marketability questions to determine whether the consumers and the nation really do need this expensive gas.

(3) Operations and Maintenance ("O&M")

The tariff must also charge customers for the costs of operating and maintaining gas transmission facilities. These "O&M" costs are *expensed* -- meaning the tariff is designed to reimburse the transmission company during the same month or year in which they occur. However, some large expenditures for maintaining facilities are handled differently. For example, if a pump blows up and a replacement is installed its cost is *capitalized* rather than *expensed*; and it is added into the pool of remaining construction costs to be paid back gradually through an increased depreciation charge.

(4) Taxes

As mentioned earlier, severance taxes levied on the production of gas at the wellhead are included (if at all) in the price a producer charges for purchase of gas. However, other taxes -- primarily income and property taxes -- will appear as identifiable costs upon which a tariff is calculated.

4.7.3 APPORTIONING COSTS THROUGH TIME

As we discussed previously, two categories of costs go into building and operating a gas pipeline -- the purchase price of gas and the cost of transportation. The latter includes charges for depreciation, interest and return, operations and maintenance, and taxes.

All except depreciation are costs incurred throughout the time a pipeline is in service. These components, therefore, lend themselves to a straightforward apportionment of costs through time. On a month-by-month or year-by-year basis it is easy to determine how much money customers should pay for costs of purchasing gas, running the facilities, paying taxes, and interest.

But what about the original capital spent during construction? How much should customers pay each month, or each year, to ensure recovery of "sunk" debt and equity money? The answer, via design of a *depreciation schedule*, is almost arbitrary.

A *depreciation schedule* has two components -- the total time period over which costs are recovered *(operational life)* and the rate at which capital will be recovered during that time frame.

In determining the *operational life* of a pipeline, LNG facility, or coal gasification plant, there is no one correct method. However, regulators usually choose to view three guideposts: (1) What is the facility's *physical life*? (2) What is the *reserve life* of the fields supplying gas, and (to a lesser extent) (3) On what payback schedule have lenders contributed construction dollars?

Physical life - The *physical life* of a pipeline is based on a good guess of how long the pipeline can remain in service before it is ready to be junked, or at least in need of a major overhaul. This estimate will, of course, serve as the maximum time span over which fixed construction costs might be paid back. Since new pipelines can generally be expected to outlast their proved producing fields, and outlast the patience of creditors, *physical life* usually will not determine the limits of *operational life*.

Reserve life - The *reserve life* of a pipeline reflects how much gas is available for transport through the pipeline and for how long. This is based on the amount of "proved" reserves in the field or fields dedicated to the pipeline via sales contracts with producers. Historically, FERC has required pipelines to negotiate relatively long-term sales agreements and to show evidence of a field's capability to produce gas in sufficient volumes over the length of the contract before issuing a certificate authorizing line construction. With respect to Prudhoe Bay gas, the *reserve life* may pose problems. Northwest Alaskan Pipeline Company proposes to build a line capable of transporting 2.4 bcf per day of Alaska gas and .8 bcf per day of Canadian gas over a period of 20 to 25 years. In the initial years, a 2.4 bcf per day offtake of gas may reduce ultimate oil recovery, and it may take a decade or more before Canada approves a "lateral" line through its MacKenzie Valley to connect its Northwestern reserves, if there is enough gas there even to warrant the expense.

Period for repayment of debt - Naturally, a 20 year *operational life* based on *physical* and *reserve life* estimates makes little sense if the construction financing is arranged on a 30 year payback period, or *vice versa*. This is one reason why FERC will require evidence of long-term financing before giving final approval for construction of the Alaska gas line.

With respect to the proposed Alaska gas line, *pro-forma tariffs*[1] filed by the contenders during U.S. and Canadian certification hearings called for a 20 to 25 year *operational life*, upon which to design a *depreciation schedule* for

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1 Pipeline applicants are required to file *pro-forma* tariffs during the certification process and *final tariffs* (which ought to closly resemble the *pro-forma* submissions) about six months prior to pipeline startup. An important point here is that FERC does not design or mandate particular *depreciation schedules* or any other terms within tariffs; rather, FERC reacts to tariffs submitted by transmission companies, and if it disapproves a certain filing it will suggest changes which will make a new filing acceptable.

amortizing sunk costs.[2] Obviously, a 20 to 25 year period for capital recovery will only work if producer sales agreements and debt can be secured on terms at least that long.

Within that 20 to 25 year *operational life* a variety of ways exist to amortize sunk costs. Three basic types of *depreciation schedules* (corresponding to *tariff profiles*) will be discussed here: (1) *straight-line depreciation*, (2) *accelerated depreciation*, and (3) *levelized* tariff.

Straight-line Depreciation - This is probably the most common *rate profile* used by the gas transmission industry. Every year, the same amount of debt and equity is repaid, so that a graph portraying depreciation charges yields a straight line. Figure 8 illustrates how *straight-line depreciation* works for a pipeline that cost ten billion dollars to build and is assumed to have a twenty year *operational life*. On a straight-line basis, 5 percent of the total fixed costs are recovered each year for twenty years. This is sometimes called a *five percent straight-line*

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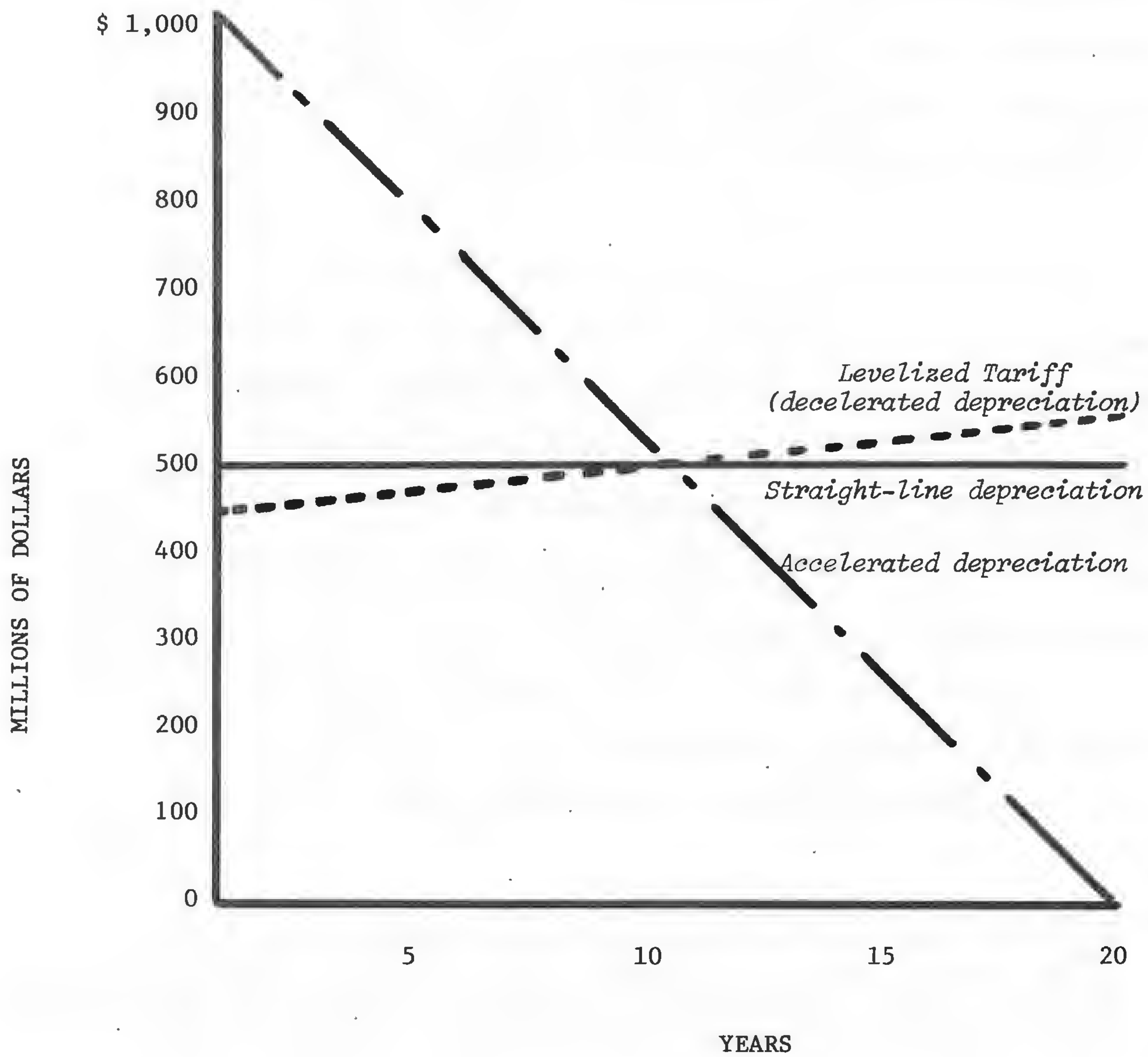
[2] A 20 to 25 year *depreciation schedule* means that a pipeline's major cost components will depreciate on a 20 to 25 year basis -- such as the pipe itself and pump stations. However, a small portion of construction costs will depreciate on a faster basis; for example, 10 years for communications and office furniture and 5 years for heavy equipment. The expectation is that these latter items will have to be replaced in about 5 or 10 years. Replacement equipment will then also be *capitalized* and depreciated during a subsequent 5 to 10 years.

FIGURE 8

REPAYMENT OF CONSTRUCTION COSTS

UNDER VARIOUS DEPRECIATION SCHEDULES



Note: Total repayment under each schedule is ten billion dollars over a twenty year operational life.

depreciation schedule. (A *4 percent straight-line depreciation schedule* is based on a 25 year *operational life.*)

Accelerated Depreciation - Sometimes it may make sense to depreciate sunk costs over the same amount of time (the same *operational life*) but at a faster, or "accelerated" pace. The depreciation charge is high in the early years and low towards the end of the *operational life. Accelerated depreciation* is a logical choice if debt financing was secured on the basis of accelerated payback, or maybe because a marketability risk looms in the future.

With respect to Alaska gas, one could argue that *accelerated depreciation* makes sense, since the cushion of low-cost "old" gas with which expensive Alaska gas can be "rolled-in" will decline as old gas fields in the lower 48 are depleted. In this view marketing risks, therefore, increase with time.

Levelized Tariff (Decelerated depreciation)- The President's report to Congress on the Alaska gasline instructed FERC to consider mandating a *levelized tariff*, in which sunk costs initially are paid back in small installments, that enlarge in later years. Figure 8 illustrates how a *levelized tariff* affects the repayment of construction costs.

Straight-line depreciation pays back original capital on an equal basis throughout the *operational life* but it does not result in equal total tariff charges. This is because as debt and equity are recovered, the interest and return components of the tariff become less and less. Under *straight-line depreciation* the first year tariff is somewhat higher than the twentieth year; and this "front-end loading" effect is even more noticible if depreciation is accelerated.

Hence, a *levelized tariff* contains a decelerated depreciation charge as a means to smooth out the tariff throughout a project's *operational life.*

The President suggested a *levelized tariff* for Alaska gas, in large part because he assumed that inflation and expected increases in OPEC oil prices would make alternative fuels more expensive through time. While consumers may be unwilling to pay more than $3.00 per mcf for gas today, they may view even $4.00 as a bargain several years from now. A *levelized tariff* also makes sense if one expects the pipeline to operate below its capacity initially, and at full capacity later. (A line operating below its design capacity has a smaller volume of gas over which to spread total costs than a line operating at full capacity.)

The one hitch to a *levelized tariff* is that lenders may not want to adopt the same approach in their debt agreements, since the risks that troubles may evolve are greater the further one looks into the future. Consider what might happen, for example, if the prices of alternative fuels actually went <u>down</u> over the life of the pipeline as large volumes of gas became available from fields in the lower states, Canada, and Mexico, and at prices significantly less than the cost of Alaska gas.

Hence, if FERC mandates a *levelized tariff*, but lenders still require *straight-line* (or worse yet, *accelerated*) repayment of their capital, this inevitably means that pipeline owners must bear the brunt of insufficient revenues. Their profits in early years fall below the norm deemed "just and reasonable" by FERC, with only a faint hope of recovering greater profits thereafter.

COMPARISON OF DEPRECIATION SCHEDULES

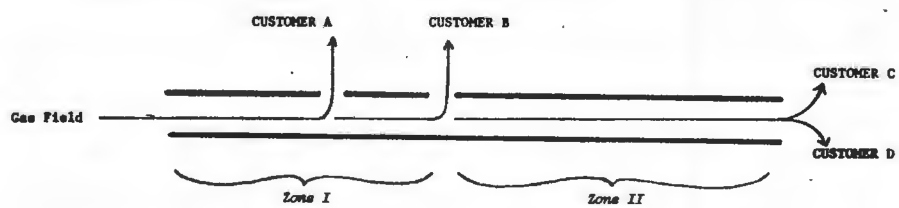
Depreciation type	Depreciation of sunk costs		Total tariff charges	
	1st year	20th year	1st year	20th year
Straight-line	$ 500 million	$ 500 million	$ 700 million	$ 600 million
Accelerated	$ 1000 million	$ 100 million	$ 1200 million	$ 200 million
Decelerated (levelized tariff)	$ 450 million	$ 550 million	$ 650 million	$ 650 million

Note: based on a 10 billion dollar project with a 20 year operational life.

4.7.4 APPORTIONING COSTS AMONG CUSTOMERS

(a) Transportation Distances

In addition to determining how costs will be apportioned through time, a tariff must delineate how costs will be divided up among customers. One of the first considerations is whether and how distinctions will be made among customers based upon where along the pipeline they receive their gas. There are three approaches to apportioning costs based on distance of transport: (1) *Mcf per mile*, (2) *Zone*, and (3) *Strict* or *Flat Volumetric*. Consider the following:



Under an *Mcf per mile* approach each customer is charged according to the actual distance gas is transported. In this example, Customer A would pay less than B and B would pay less than either C or D.

Under a *Strict volumetric* approach all customers pay the same rate.

A *Zone* tariff is a compromise -- in essence, it divides a pipeline into two or more segments and applies a *strict volumetric* tariff within each zone. Here, Customer A and B would pay the same rate, while Customer C and D would be billed a higher rate.

An *Mcf per mile* tariff appears, at first glance, to be the most equitable basis for cost calculation. Nevertheless, it can cause problems if, as a result of offtakes by Customers A and B, the remaining portion of line operates below capacity in moving gas to Customers C and D. These downstream users may be stuck with paying the full costs of a line too big to serve their needs. If the transmission company had designed a smaller line or had instead sold all its gas to customers near the pipeline's terminus, then C and D would have cheaper rates. But in this instance Customers C and D pay higher rates through no fault of their own.

A good example of this problem is the tariff charged North Pole Refinery for transporting oil through the TAPS line to Fairbanks. North Pole is billed the full tariff from Prudhoe Bay to Valdez, even though it uses the line for only half the distance. Alyeska charges all customers on a *strict volumetric* basis, and argues that to adopt either a *barrel per mile* or *zone* tariff would necessitate an increase in payments by everyone else; and that this outcome would be especially unfair as North Pole negotiated its purchase of oil long <u>after</u> Alyeska designed a line capable of moving all of the oil to Valdez.

(b) "Firm" vs. "Interruptible" Customers

Probably the simplest way to allocate costs among purchasers is to divide total costs by the total volume of gas carried, then charge each customer on the basis of how much gas he purchases. Naturally, the most cost-effective way for a pipeline to operate depends on finding purchasers willing to buy sufficient volumes year-round, thus enabling the pipeline to maintain full capacity. The problem is that gas purchasers may not want a constant supply of gas. For example, residential users typically consume five times more gas in winter than in summer. Distributors who service residential areas therefore have gas needs that strongly fluctuate with the seasons.

If a pipeline serves distributors with fluctuating needs, and is large enough to service peak demands in the winter, a lot of unfilled capacity remains in summer. This pattern yields a much smaller total volume of gas over which to spread costs than if the pipeline functioned at capacity year-round.

The *two-part tariff* was designed to counteract this problem. A *two-part tariff* encourages customers to find their own ways to even out peaks and valleys in residential demand (for example, by installing storage facilities); moreover, it encourages large industrial plants to purchase gas on an *interruptible* basis at a discount.

A *two-part tariff*, true to its name, has two parts:

(1) *Demand* Component - A *demand* charge (sometimes called *capacity* or *fixed* charge) reflects the maximum amount of gas a particular customer may purchase on any day during the year. Hence, the larger the *peak-day* use, the greater the *demand* charge. This can have rather striking consequences. For example, Distributor A is supplying residential customers an average daily volume of 100 Mcf; however, for several weeks in February they require 500 Mcf per day. On the other hand, Distributor B's customers are mostly petrochemical plants, purchasing an average of 250 Mcf per day during the year with *peak-day* use of only 300 Mcf. Distributor A is billed a much higher *demand* charge than Distributor B, even though A uses substantially less gas overall.

(2) *Commodity* Component - A *commodity* charge (sometimes called *volumetric* or *variable* charge) is based on how much gas is actually purchased. In the above example, Distributor A, averaging 100 Mcf per day will total up a lower *commodity* charge throughout the year than Distributor

B, who averages 250 Mcf per day -- even though A will pay a higher *demand* charge than B.

The *demand* charge of a *two-part tariff* is like a "take-or-pay" provision in a standard sales contract. Whether the customer actually purchases any gas at all, he still must pay the full *demand* charge, while the *commodity* charge applies only to gas volumes actually taken.

A customer whose *service agreement* calls for a *firm* gas supply will have the legal right to take up to a prescribed maximum volume (the same volume on which the *demand* charge is based); and he will therefore be subject to both a *demand* and a *commodity* charge. That customer pays the *demand* charge for the assurance that he is contractually entitled to take up to that certain volume. He pays the *commodity* charge for whatever he ends up taking. However, a customer who purchases gas on an *interruptible* basis (meaning the pipeline supplier can unilaterally cease shipments on short notice whenever its *firm* customers need the extra gas) will only have to pay the *commodity* charge. In theory, the *interruptible* customer (usually large industrial plants with back-up oil burning equipment) takes up no capacity of the pipeline -- only excess capacity which may exist temporarily -- and, therefore, should not be charged for *demand*.

In apportioning costs between *demand* and *commodity* components, pipelines (and professional economists) tend to argue that most (if not all) "fixed" costs should be allocated to the *demand* charge. "Fixed" costs include those costs that remain approximately the same regardless of the amount of gas transported, such as depreciation, interest and return, taxes, and (to some degree) operations and maintenance. Proponents of *interruptible* rates maintain that these "fixed" costs are incurred in building a specific capacity of line to serve the peak needs of *firm* customers, and that only variable costs should, therefore, be recovered through the *commodity* rate paid by all customers. Spokesmen for residential consumers, on the other hand, argue that *demand* charges should be deemphasized and most costs placed in the *commodity* portion of the tariff paid by everyone.

Federal regulators have been leaning more and more towards the residential consumer standpoint through the years. In 1952 the Federal Power Commission sanctioned the "Atlantic Seaboard" tariff structure which split "fixed" transportation costs equally (50/50) between demand and commodity components, the argument being that while interruptible customers certainly do assist firm customers by purchasing supplies in the off-season, these interruptible customers would not even have an opportunity to purchase gas were it not for the existence of firm customers for whom the pipeline was built. Hence, federal regulators split the benefits -- interruptible customers get cheaper rates, but they also pay for some of the "fixed" costs, thereby enabling firm customers to get cheaper rates too. In 1973 even more of the "fixed" costs were allocated to the commodity component which all customers must pay. Called the "United" method of rate design, now a full 75 percent of "fixed" costs are usually assigned to the commodity component, leaving a mere 25 percent of "fixed" costs as the demand factor. California has gone one step further. Intrastate pipelines within California no longer can sell gas under a two-part tariff. 100 percent of the "fixed" costs, as well as all other costs, go into a single commodity component, charged to all purchasers.

Not all distributors have supported this gradual phase out of the two-part tariff. Years ago, some distributors installed storage facilities or constructed naphtha-based SNG plants in order to reduce their peak-day demand -- thereby reducing their demand charge. But with the demise of the demand charge, distribution companies that did not provide their own storage are now paying about the same price for gas from a single interstate pipeline company as distribution companies that did install storage. The latter companies must pay storage costs anyway, so that these construction projects originally designed to save money have, to some extent, backfired.

4.7.5 ADJUSTING TARIFFS TO ACCOMODATE CHANGES IN COSTS

Of all the cost components that go into a tariff -- purchase price of gas, depreciation, interest and return, operations and maintenance, and taxes -- about the only thing that will not change during a pipeline's operational life is depreciation (and even depreciation will increase if old equipment is replaced and capitalized). The question of how to adjust tariffs to accomodate increases or decreases in costs is a major problem for pipeline owners and their regulators. Basically, there are two approaches, (1) *Fixed-rate tariffs* and (2) *Cost-of-service tariffs*.

(1) *Fixed-Rate Tariffs* - In the traditional form of tariff, pipeline owners estimate their costs, design either a two-part or a one-part tariff, and fix rates accordingly. If costs go up, then the company files a revised tariff with the appropriate regulatory body, but may have to wait a year or more for approval of that revision -- by which time costs may have risen even more. This causes problems for both pipeline owners and regulators. The owners' profits are eroded pending approval of the tariff revision; and regulators are swamped with work reviewing these filings. One way to counteract this is to include certain *automatic adjustment clauses* within the original *fixed-rate tariff*.

Probably the most common form of automatic adjustment which FERC sometimes finds acceptable is a *purchased gas adjustment clause*, or PGA. Through the PGA, increases in the cost of purchasing gas from producers automatically raise the tariff, and a revised tariff need not be filed. PGA's became an accepted approach when the FPC authorized purchase of "emergency" gas at prices not confined by the regulated interstate ceilings, in a desperate attempt to increase interstate gas supplies and thereby reduce the pains of curtailment on customers whose suppliers could not meet their needs.

Distribution companies that sign service agreements incorporating tariffs with PGA's have severely restricted their legal rights to protest acquisition of high-cost gas. Moreover, a distribution company might enter into a service agreement which, at the time, incorporates a purely fixed-rate tariff; however, the pipeline supplier has full powers to later seek approval from FERC for a tariff amendment incorporating a PGA clause -- and the distribution company is still obligated to purchase gas.[1]

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[1] It is interesting to note that this unilateral right to amend the tariff (which, in effect, is like changing a contract) would never hold water in the unregulated world of private enterprise. However, this is acceptable behavior within the regulated environment, because FERC ostensibly protects the distribution companies by retaining approval authority over all tariff changes.

Critics of rolled-in pricing of supplemental gas cite the prevalence of PGA's as one reason why incremental pricing (at least the original version of incremental pricing that preceded the Natural Gas Policy Act of 1978) with its separate rate schedule and separate service agreements is essential. Only under incremental pricing would distribution companies have a choice as to whether they wished to increase their gas supplies by the purchase of high-cost gas.

Pipeline companies have also argued that they should be allowed to include *volume variation adjustment clauses*, as well as PGA's in their tariffs. These clauses would further reduce the need for tariff revisions. In light of recent history in which many interstate pipelines have had difficulty purchasing new gas to replace dwindling supplies under old contracts (due in large part to the higher wellhead prices producers can achieve by selling intrastate), it is easy to understand why pipelines lobby for the inclusion of *automatic volumetric adjustments* in their tariffs. For example, if tariff charges are calculated on the basis of 2 bcf of gas flowing through the pipeline each year and that volume drops to 1 bcf per year, unless a tariff revision is secured the company's profits will falter.

The FPC recently adopted a strong stand against volumetric adjustments. In Opinion No. 802, dated June 1977, the FPC disapproved a tariff filed by United Gas Pipeline Company which included such an adjustment. The FPC felt, in part, that consequences of "regulatory lag" (in which profits suffer until a tariff revision is approved) create a crucial incentive for companies to do their best in finding new gas supplies and maintaining throughput.

(2) *Cost-of-service tariffs* - The approach chosen by the Alaska gasline partners is very different from the traditional *fixed-rate tariff*. Instead, a *cost-of-service* method is proposed. Essentially it accomodates all changes and provides for automatic adjustments whenever any cost or volume throughput fluctuates through time; and it does this without having to file a tariff revision with FERC. (FERC, of course, will audit the increases periodically to make sure all changes are, in fact, legitimate and "allowable".)

The Alaska gasline partners argue that a *cost-of-service* tariff is essential for financing -- and that the project will fail to secure debt and equity money if the standard *fixed-rate* approach is imposed. While a *fixed-rate* tariff if designed to recover all costs and provide the regulated return, it does not necessarily ensure adequate revenues. A *cost-of-service* tariff is much more secure.

4.7.6 APPORTIONING RISKS BETWEEN THE PIPELINE COMPANY AND ITS CUSTOMERS

Two documents, the *service agreement* and the *tariff* delineate the rights and obligations of seller and buyer. In so doing, these documents apportion a variety of risks between the transmission company and its distributors (or, in the case of the Alaska gasline, between the pipeline owners and the interstate transmission companies contracting for use of the line).

(a) Post-completion Risks - Once the pipeline begins operations, there are three primary risks which one party or the other must bear. These are risks of (1) a decrease in demand, (2) an increase in costs, and (3) deliverability problems.

(1) Decrease in Demand - For one reason or another (perhaps a marketability problem which arises when consumers begin switching to cheaper fuels), a distributor purchasing gas may not want to take the full volume of gas for which it has contracted. Under a two-part tariff he will, nonetheless, have to pay the full demand charge, and only his commodity charge will reflect the reduction. In this way, buyer and seller split the problems of a decrease in consumer demand. In the case of Alaska gas, however,

shippers will probably be asked to sign "take-or-pay" service agreements with the pipeline owners for transportation services. They are then obliged to receive and pay for a set volume of gas every month, and must also pay the transportation tariff. This places the full marketability risk squarely upon the purchaser (at least to the extent that the purchaser remains solvent).

(2) Increase in Costs - As we pointed out previously, a fixed-rate tariff places the burden of increasing costs on the seller until a tariff revision is secured. However, once that revision is approved by FERC, the purchaser is obliged to pay the increased rate. The service agreement most likely continues in force despite increases in the tariff which may occur from time to time. Hence, short-term risks of cost increases bear on the seller, but in the long run purchasers bear these costs. To eliminate even the short-term risks, the Alaska gasline sponsors propose a cost-of-service tariff, which automatically adjusts rates to meet cost increases whenever they occur.

(3) Deliverability Problems - Circumstances may arise in which the seller is unable to deliver the required gas volumes to its buyers. This could happen in Alaska, for example, if the State restricts the volume of gas produced in the field through use of its "oil and gas

conservation" powers, or if the pipeline simply blows up. In the event of a deliverability problem, the tariff and service agreement must identify who shoulders the burden. Do the purchasers still pay for their contracted volumes, even if a reduced amount (or none at all) is delivered? Under an *all events full cost-of-service tariff*, coupled with clauses to protect the pipeline owners in the event of "force majeure", purchasers pay the entire cost of service regardless of how much gas is delivered. This fully protects pipeline owners and their lenders by ensuring payments on equity and debt capital, along with interest and return. FERC probably will not approve an *all events tariff* for the Alaska gasline. Instead, FERC will require a tariff which strongly encourages pipeline owners to avoid deliverability problems. One such incentive is a *minimum-bill tariff* in which customers continue to pay all costs <u>except</u> the scheduled return of and return on equity. Since gasline sponsors argue that equity capital would be difficult to attract without a guaranteed return, FERC may authorize a compromise form of *minimum-bill tariff* in which a return <u>of</u> equity continues in the event of a deliverability problem, but the return <u>on</u> equity is reduced.

(b) <u>Non-completion Risks</u>

All the foregoing risks reflect problems which may arise during pipeline operations. But what if a pipeline is never completed? What if ten billion dollars are "sunk" into construction of the Alaska gasline, but five billion more are needed to complete it -- and nobody is willing to put up the money? Or what if an extremely high pressure line is laid and the owners discover that it cannot be operated safely? Remote as these problems may seem, they will have to be addressed before financing of the Alaska gasline can be completed.

In the contest for certification, El Paso Alaska Company argued for a variety of *all-events tariff* in which the interstate pipelines would be obliged to pay back sunk costs as scheduled under any and all circumstances -- including noncompletion. While called an *all-events tariff*, the key provisions probably attach to the service agreements (which are signed prior to construction) -- not the tariff, since tariffs traditionally become operative only after operations commence. The FPC frowned on the idea of an *all-events tariff* that would go into effect prior to completion of the facility, so the Alaska gasline sponsors must devise other ways to deal with pre-completion risks.

One approach is to secure enough capital at the beginning (say $15 billion instead of $10 billion) to ensure line completion even if overruns are substantial; or sponsors might try to convice some other creditworthy party to obligate itself to supply additional money in the event overruns occur. The producers and the State of Alaska are obvious candidates for this latter function.

Other technological and physical risks will just have to be borne by the pipeline owners and their lenders. While riskbearing is a normal condition of any capitalist endeavor, the scale of the Alaska project and the oddities of "project financing" proposed by its sponsors evoke special concerns on Wall Street.

(c) Downstream Tracking of Costs

If interstate transmission companies sign service agreements with *all-events* provisions (thereby bearing the burdens of non-completion), or sign service agreements with "take-or-pay" provisions (aimed at post-completion marketability risks), or if FERC approves a tariff incorporating some variety of *full* or *minimum-bill cost-of-service* rates, how do these transmission companies avoid getting stuck? One approach is to "track" costs through to subsequent customers, that is, the distribution companies.

During the Alaska gasline debate, arguments ranged widely with respect to downstream "tracking" of costs. The only safe conclusion is that no one can be sure whether costs can be "tracked" simply by unilateral amendments to the tariffs (especially those tariffs with PGA clauses) and under existing service agreements until someone tries and is tested in court. An even if risks <u>can</u> be passed off onto distribution companies, can these distributors, in turn, "perfectly track" these burdens all the way through to the end user? Since a multiplicity of state Public Utility Commissions take jurisdiction over final sales, the answer here is even more speculative.

Added to all this is the problem that even if FERC grants the pass-through of risks via tariff and service agreement mechanisms, can another set of Commissioners guiding FERC five years from now retract its previous actions? Here again, there are arguments on both sides. Some claim that FERC is effectively "estopped" from changing its mind unless the circumstances in question change radically. Some commentators believe that if FERC is indeed perceived to have the power to go back on its word, then nobody will be interested in putting money into this or any other high cost gas venture.

(d) Government Risk-bearing

In any discussion of who ought to bear the various post-completion and non-completion risks, the questions of government (i.e., taxpayer) risk-bearing comes up. For example, the New York Public Service Commission in its testimony during the Alaska gas hearings suggested that if private financing cannot be obtained without a substantial pass through of risks onto consumers, then the gasline should not be built at all: It is not in the consumer interest. And if the federal government views this outcome as unacceptable for national security, balance of payments, or whatever the reason, then the federal government as a whole should bear the risks through *guarantees* and *backstopping* mechanisms.

To date, Congress has sanctioned the use of government guarantees for a few coal gasification demonstration projects (after concluding the companies could not obtain private financing without them), but it has not yet taken the step of extending these assurance to other supplemental gas projects. For the Alaska gasline to obtain a federal guarantee, specific Congressional action is required. But the report of the Congressional Conference Committee that approved rolled-in pricing for Alaska gas in the Natural Gas Policy Act of 1978 was quite specific about this prospect: "The conferees agreed to provide rolled-in pricing . . . because they believed that private financing of the pipeline would not be available otherwise. *Rolled-in pricing is the only Federal subsidy, of any type, direct or indirect, to be provided for the [Alaska Highway] pipeline."* (emphasis added).

4.7.7 SUMMARY

This section on the sale of gas from transmission companies to local distributors was, necessarily, complicated and permeated with technical language. To assist the reader in keeping track of how all the concepts fit together, the following list incorporates most of the major ideas just discussed.

I. *SERVICE AGREEMENT*

   A. Term (in years)

   B. Volume (minimum and maximum)

   C. Price (incorporates *tariff* by reference)

      -- *take-or-pay*

      -- *firm* vs. *interruptible*

II. *TARIFF* (*pro-forma* vs. *final*)

   A. Cost components

      1. purchase price of gas

         -- *rolled-in* vs. *incremental*

      2. Transportation costs

         a. *depreciation* of construction costs

            -- *rate base*

            -- *depreciation schedule/charge*

            -- *amortization*

b. *Interest on debt; and Return on investment*

-- *pre-tax* vs. *after-tax return*

-- *return on common equity* vs. *overall return*

-- *cost-of-capital*

-- *capitalization* (debt/equity ratio)

-- *incentive* or *variable rate of return*

-- *goldplating*

-- *vanishing rate base*

c. *Operations and Maintenance ("O&M")*

-- *capitalize* vs. *expense*

d. Taxes

-- property taxes

-- corporate income taxes

B. Apportioning Costs through Time

1. *Operational life* of transmission facilities

a. *Physical life* of transmission facilities

b. *Reserve life* of transmission facilities

c. period for repayment of debt

2. *Depreciation schedules* or *Rate profiles*

a. *Straight-line depreciation*

b. *Accelerated depreciation*

c. *Levelized tariff (decelerated depreciation)*

C. Apportioning Costs among Customers

1. transportation distances

   a. *Mcf per mile*

   b. *strict (flat) volumetric*

   c. *zone*

2. *Firm* vs. *Interruptible* customers

   -- *two-part tariffs*

   a. *demand charge (fixed* or *capacity charge)*

   b. *commodity charge (variable* or *volumetric charge)*

D. Adjusting tariffs to Accomodate changes in costs

1. *fixed-rate tariffs*

   a. *purchased gas adjustments (PGA's)*

   b. *volume variation adjustments*

2. *Cost-of-service tariffs*

E. Apportioning Risks between Transmission Company and its Customers

1. *Post-completion risks*

   a. decrease in demand

   b. increase in costs

   c. *deliverability* problems

      -- *full cost-of-service* vs. *minimum bill tariff*

2. *Non-completion* risks -- *all-events tariff*

3. Downstream *tracking* of risks; *perfect tracking*

4. Government risk bearing through *guarantees* or *backstopping*

4.8 SALE FROM LOCAL DISTRIBUTION COMPANY TO END USER

The sale from distributor to end user incorporates many of the concepts we discussed in the previous section. Rates are regulated by state public utility commissions on the same general basis (cost including a fair profit) as FERC regulates the rates charged by interstate transmission companies. In addition, the state commissions hold powers which, in effect, reach upstream to the sales transaction between interstate pipeline and distributor: A state commission has jurisdiction over which costs claimed by a distributor are, in fact, "allowable". If a commission finds a particular gas purchase by a distributor to be imprudent, it can block the pass-through of costs related to that sale.

All the points previously discussed with respect to tariffs, depreciation schedules, the apportionment of risks, etc., apply in general to this transaction as well. The only point we will discuss here is *end use pricing* -- the price the final consumer must pay.

The question of "firm" versus "interruptible" service also applies to the end use sale. However, within the "firm" category, there are a variety of acceptable approaches to structuring rates.

U.S. commercial law is firmly rooted on the concept of *non-discrimination* -- the notion that all customers must be charged the same price for the same service, and that no customer or class of customers may be treated in a discriminatory fashion. The key words open to wide interpretation are, of course, "the same service".

A good example of how this concept works is the following:

> A train hauls coal for Customer A at $1.00 per ton, meaning that another customer seeking transportation service for coal over the same distance must also be charged $1.00. However, a railroad is not prohibited from charging lower rates per ton for hauling a load of coal weighing a million tons than for hauling a load of only ten tons.

This form of price discrimination arguably is valid because hauling a million tons of coal is a different kind of service than hauling ten tons, and it recognizes the advantages of economies of scale. It has been widely accepted in the gas utility business. Under *declining block rates*, large volume users (such as major commercial establishments or industrial plants) have traditionally paid less per mcf of gas than residential customers.

Overall, industrial energy users are encouraged to burn gas through two forms of discounts: (1) purchase of gas on an "interruptible" basis, and (2) purchase of gas in large volumes or "blocks".

Just as discounts for interruptible service have come under attack in recent years, manifested by restriction of the amount of fixed transportation costs allocated to the *demand* component of a *two-part tariff*, state public utility commissions are also moving away from the use of *declining block rates.* The rationale turns on the recent emphasis upon energy conservation: If one can achieve lower rates by purchasing more gas, where is the incentive to conserve? And if gas is (or will soon become) scarce, why should discounts be allowed which encourage gas consumption by "low priority" industrial customers?

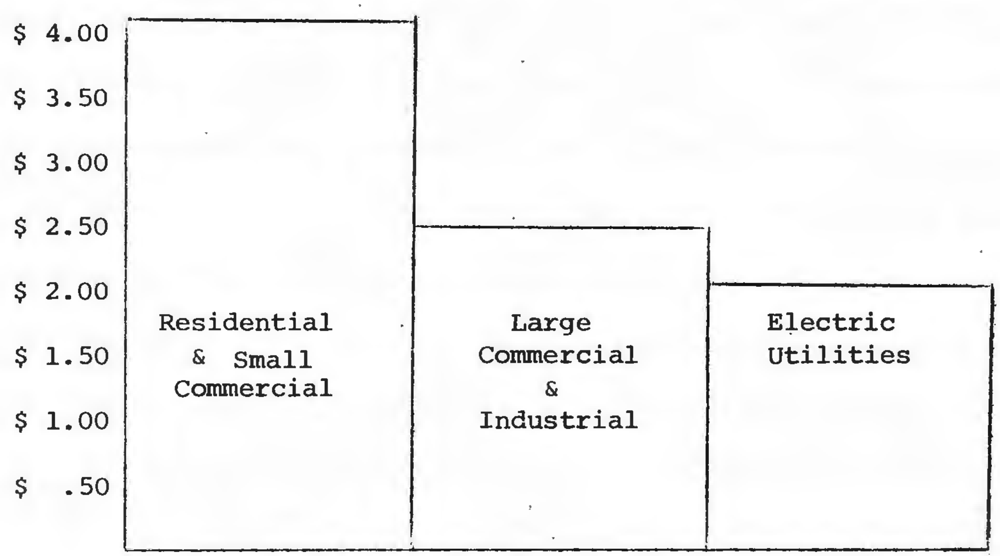
One other generally acceptable form of discrimination, or rather difference, in end use pricing relates to surcharges for new hook-ups. Here again, arguments pro and con are wide-ranging. Consider the following:

Distributor ⟶ Town A ⟶ Town B

> Town A was among the first customers served by the distribution company that came into being many years ago. The costs of providing trunklines and spurs to A have long been paid off by the users in Town A. The distributor now plans to extend services to Town B. Should the costs of building new trunkline go into the rate base paid by everyone, or should customers in Town B pay higher rates?

Another form of price discrimination is *value of service pricing*, or charging everything "the traffic will bear" -- a practice condemned in unregulated industries. Consider the following example:

VALUE OF GAS TO DIFFERENT CLASSES OF CUSTOMERS



Residential consumers of gas are willing to pay up to around $4.00 per mcf before they will choose to switch to oil or electricity. Large commercial or industrial users view alternate fuels more favorably -- they are willing to make the switch at a lower threshold price. Finally, electric utilities using gas to raise steam would probably switch to another fuel (No. 6 oil or coal) at a much lower threshold price. There is plenty of evidence that choice of fuel is linked to relative prices in areas which have experienced gas prices which rose high enough to "clear the market"; Texas is one good example.

One interesting feature of *value of service pricing* is its potential for subsidizing the burning of high cost gas. For example, if the average price of gas were $2.50 utilities would probably choose not to purchase gas if all classes of customers were charged the same *nondiscriminatory* rate of $2.50. But if enough residential customers were charged $3.50, the distributor could afford to sell gas to utilities at $2.00. A *value of service* form of *end use pricing*, along with *rolled-in pricing* at the transmission level, can therefore have a powerful influence on the economics and marketability of high cost gas, such as Alaska gas. It is important to note that the mechanism called *"incremental pricing"* in the Natural Gas Policy Act of 1978 appears to be a blend of *rolled-in* and *value of service pricing*. (See page 69 for more detail.)

PART TWO

MARKETING AND FINANCING SUPPLEMENTAL GAS

THE OUTLOOK FOR, AND FEDERAL POLICY REGARDING, SYNTHETIC GAS, LNG AND ALASKA NATURAL GAS

INTRODUCTION AND SUMMARY

The following report by Arlon R. Tussing and Connie C. Barlow originated in a study for the U. S. Department of Energy on the marketability and financibility of large-scale supplemental gas ventures like LNG import projects, the Alaska Highway pipeline and coal conversion plants.

The authors proposed such a paper to the Department because they were skeptical about the financial viability of certain base load gas projects which were certain to produce energy at a cost considerably higher than the present world prices of substitute fuels. Thus, they would not have been surprised to find that marketability risks would make private financing of these projects difficult or impossible without some kind of direct federal aid. While there is indeed a substantial market risk, it falls on different shoulders, with different economic and financial consequences, from those originally anticipated by the authors.

The marketing and financing strategy of the gas transmission companies who are proposing supplemental gas projects seems to be workable provided the projects receive the necessary federal approvals under existing law. Under this strategy, new gas production and transportation facilities would take the form of independent "project-financed" entities owned by the transmission companies. Highly leveraged financial structures would be possible because debt service (and perhaps return to equity as well) would be secured by full-cost or minimim-bill contracts between the projects and their transmission company owners. Payments for gas or for transportation under these contracts would take precedence as operating expenses over principal and interest on the transmission companies' own bonds. Thus, there would be practically no marketability risk to the projects themselves or to their lenders, regardless of how much the cost of the gas might exceed its value to consumers.

The transmission companies sponsoring supplemental gas projects, however, generally have no intention of taking on themselves any risk that they might be caught between fixed contractual obligations to their project-financed ventures and an uncertain future gas market. In all but a few cases, they are quite unwilling to make such commitments if the new high-cost gas must be sold on a separate rate schedule subject to approval by state utility commissions. What the sponsors want and require is action from the Federal Energy Regulatory Commission permitting or requiring them to add the cost of this gas to that of the conventional gas their customers are receiving under existing contracts. With this arrangement, neither the gas distributors nor the state utility commissions would have an opportunity to decide whether or not they wanted the additional gas with its high costs and attendant market risks.

This report concludes that there are real marketability issues with respect to the large-scale supplemental gas projects, but that the strategy described above can shift the risk entirely from the project sponsors and investors to the gas distribution companies. We can imagine circumstances under which some distributors could be bankrupted by decisions of the transmission companies and federal authorities over which neither the local companies nor the state commissions have any control.

The crux of the problem is that none of the large-scale base-load supplemental gas projects can deliver gas to final consumers at an energy cost lower than the present world price of oil. The usefulness of such projects to consumers and the nation depends upon the assumption that the next twenty years will see very substantial increases in the price of oil. The National Administration and most energy experts expect that this will be the case, but forecasts of a prolonged period of stable or declining energy prices are becoming more frequent and more respectable. In the next two or three years' climate of increasing energy abundance and stable oil prices, legislative initiatives such as new federal loan guarantee programs are almost out of the question.

Whatever the future holds, the gas utility industry *now* has a large cushion of "old gas" flowing under regulation and long-term contracts at very low prices relative to those of substitute fuels. Substantial volumes of high-cost gas could be marketed now in most regions of the United States, if that gas could be rolled together with the currently "underpriced" supply of old gas and sold at a price reflecting the weighted average of the two. The ability of the old gas cushion to subsidize the sale of otherwise uneconomic gas is not unlimited, however. Gas markets have already "cleared" in the Pacific Northwest and Texas; supply and demand may soon come into balance *without gas supplements* in some other regions of the United States. And the size of the old gas cushion will diminish year by year; by the late 1980's it may have little ability to shelter new sources of gas energy that costs more than oil.

This report briefly considers the "incremental pricing" rule in Title II of the Natural Gas Policy Act of 1978. There is yet no clear consensus on the meaning, impact, or even the intent of this legislation, but the authors have tentatively concluded that this brand of "incremental pricing" will neither foster economic efficiency nor protect consumers. In the short term, the law will delay the impact of higher gas prices on households and other politically reactive consumer classes, but at the expense of greater oil imports to serve industry. Later, "incremental pricing" may cause gas prices for these "high priority" consumers to increase more rapidly and further than they otherwise would; eventually, it will transform itself in a "value-of-service" pricing system in which high-priority consumers pay higher prices in order to subsidize gas consumption by low priority industrial users.

The authors have not attempted to judge whether the pending large-scale gas projects will in fact be needed or cost-effective from a national standpoint. The report does point out, however, that FERC and the state commissions can manipulate effective demand for gas over a very broad range of values by means of their control over transmission and distribution company rate design. The commissions could probably bail out almost any plausible volume of surplus gas producing capacity if they were willing to approve the most drastic imaginable "value-of-service" tariff schemes --- ones that charged high-priority consumers the last cent that they would be willing to pay, and used the surplus revenue extracted from those customers to subsidize gas sales to industry and electric utilities at prices below even marginal costs. The authors do not regard such a policy as desirable or politically acceptable, however, and suggest another way of assuring that gas from large-scale supplemental gas projects could be marketed, and of facilitating the financing of such projects.

For those projects that the regulatory authorities determine -- on the basis of current projections -- would be cost-effective over the long run, the report proposes using the greatest "front-end load" in financial plans and tariff profiles that would meet the legal test of reasonableness. This strategy would involve rate-base treatment of CWIP (construction work in progress) and double declining balance depreciation schedules. Thus, the present large cushion of old gas could be used to help finance construction in order to reduce project tariffs in the late 1980's and the 1990's to levels barely above variable costs, and thereby to assure the marketability of the new gas supply whatever happened to the prices of substitute fuels.

The authors finish with a discussion of the merits of relying more on market incentives and less upon regulation to decide which supplemental gas projects should be approved, to control their costs, and to establish prices for gas and transportation services. They conclude that a rigorous application of "incremental pricing," in its earlier meaning of a separate rate schedule for each supplemental gas source, is not a workable compromise. A modified form of "commodity value pricing" is suggested as a method of screening projects and imposing greater cost discipline on their sponsors, without subjecting them to intolerable business risks.

CHAPTER I

THE "NEED" FOR SUPPLEMENTAL GAS

1.1 The consumer need for supplemental gas. It is not very meaningful to speak of the demand or need for gas as such. There are few uses of natural gas that could not be served just as well by electricity or oil. Thus, there is no compelling reason why any particular proportion of the Nation's total energy requirements has to be met by gas, either natural or synthetic, domestic or imported. For the purpose of serving almost all *new* demand, potential gas consumers can now choose between gas and some other energy form, usually electricity, oil or coal. Many present commercial and industrial consumers of gas already have the ability to switch fuels, and almost all other current consumers of gas could more or less readily substitute other sources of energy, depending upon the type, age, and efficiency of their present burners. In any case, there is a broad latitude for substitution between gas and other energy forms in the U. S. economy; over a span of ten to twenty years, which is the normal economic life of gas-burning appliances, this flexibility is almost total.

Individual households, firms and institutions will take into consideration how reliable the supply of various fuels seems to be, the costs of installing and operating different types of burners, and local air quality requirements, but the main factor in their choice will be relative prices.

In some residential and commercial uses of energy, particularly cooking and water heating, and in some specialized industrial uses, the only practical substitute for gas is electricity. All together, however, these uses account for only a very small portion of total gas consumption. For most current uses in all user categories, natural gas is interchangeable with some refined petroleum product such as distillate fuel oil, naphtha, kerosene or propane. These uses include space heating, medium- and large-scale water heating, food processing, crop drying, turbine fuel and chemical feedstocks. A substantial portion of the U. S. gas supply, moreover, is still being used to raise steam for electric utility or industrial boilers, where less costly primary fuels like residual oil or coal may be feasible substitutes.

At bottom, both the growth of U. S. natural gas consumption since World War II and the present shortage have resulted from a combination of market and regulatory influences that have consistently set the price of gas cheaper than any of its practical substitutes. If it were not for the prevalance of regulation and long-term contracts at low prices, there would be no natural gas shortage in the United States today; many consumers never would have chosen gas as a fuel in the first place and others would have quit using it as soon as its price rose above the price of some potential substitute. If natural gas prices were now to be totally deregulated or retail prices set at marginal or "replacement" costs, the discovered gas reserves of the United States might last for several decades serving those uses that are not readily convertible to oil. Thus, there would be no present "need" to produce natural or synthetic gases which would cost the final consumer more than fuel oil, naphtha or propane.

For this reason, the maximum prices *consumers of all types* are willing to pay for gaseous fuels are closely related to prevailing and expected prices of oil. However, prices for petroleum products vary greatly: In May 1978, for example, high-sulfur residual oil sold at an average wholesale price of $1.76 per million btu, while the retail price of home heating oil averaged $3.50.[1] There are, in addition, significant differences in fuel prices among different regions of the United States. About half of the natural gas currently used is consumed by the "low priority" sectors -- industry and electric utilities.[2] It is these sectors that would benefit from any additions to gas supply; they would also pay the cost of switching to other fuels if gas supplies diminish. For this reason, it is currently *the lower end* of the petroleum price spectrum that determines the value of new gas supplies and the cost of not having them.

Even if we supposed that gas shortages (or government policy) would eliminate electric utility and low-priority industrial uses of gas in the near future, the great bulk of industry and government deliberation over gas policy today would still be based on utterly unrealistic assumptions about the demand for gas, particularly by households and small commercial consumers. The literature of the American Gas Association and the Institute of Gas Technology is filled with rhetoric and analysis that compares the relative

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1. No. 6 oil exceeding 1.0 percent sulfur had a wholesale price of $10.86 per barrel; the home heating oil average selling price was 48.3 cents per gallon. (Converted at 6.3 and 5.8 million btu per barrel respectively). Monthly Energy Review, August 1978.

2. Ibid.

costs and efficiencies of gas and electricity, on the assumption that electricity is the principal competitor of natural gas, both in the marketplace and for the favors of governmental energy planners. More specifically, among the gas marketing studies and demand projections we have seen, the few which take price into consideration at all assume that the value of gas to residential and commercial consumers is several dollars per million btu higher than the price of fuel oil. Such an assumption is correct only for cooking and for household water heating, and these uses are a tiny fraction of total gas demand.

No previous analysis of gas demand has, to our knowledge, made the crucial distinction between (1) the price at which consumers would *switch from gas to oil* (or electricity) for space heating; (2) the price that would induce builders or consumers to *choose gas heat for new installations;* and (3) the price that would lead consumers to *switch from oil (or electric) heat to gas.* It is reasonable to believe that households *currently* using gas for space heating would not change to another fuel in large numbers until the gas price exceeded the price of that fuel by a substantial margin. These considerations would be dominant if curtailment of service to existing residential and small commercial gas consumers were an immediate issue. But they are *not* relevant to the present situation in which the gas industry, Congress and the federal and state regulatory authorities are considering "load upgrading" measures -- that is, the use of pricing, taxation, allocation, and curtailment policies to discourage "low priority" (industrial and electric utility) consumption of gas, thereby freeing supplies for new "high priority" (residential and small commercial) customers.

Residential and commercial customers generally will not install *new* gas burning equipment if the price of gas is expected to be higher than that of fuel oil. In some jurisdictions, real estate developers or homeowners have to pay the extra cost of extending gas mains or making new hookups in addition to that of their new appliances; under these circumstances, they would choose gas heat only if its price is expected to be considerably *below* that of oil. An even larger differential would be necessary to convince present users of oil heat to switch to gas.

There is ample historical evidence for this view: While natural gas was used as a home heating fuel in about 84 percent of U. S. households in 1976, it accounted for less than half of the total energy used for residential and commercial space heating. Further, gas heating has never penetrated those areas of the United States or Canada where transportation and distribution costs push the price of gas above the local price of fuel oil -- for example, New England, Eastern Quebec and the Maritime Provinces, and small communities anywhere far removed from gas trunklines.

Experience in Washington, Oregon, Texas, and Ontario, where gas prices have risen rapidly in the last three years to a level very close to the cost of fuel oil, presents an even more striking confirmation of the way price limits the demand for gas in even the "high priority" sectors. After many years of 5- to 7-percent growth in the number of gas hookups, new residential connections abruptly came to a halt, and the gas utilities actually began to *lose* industrial and commercial customers. This development, it is worth noting, was a complete surprise to the local gas companies, who had believed their industry's own propaganda that gas is a "premium" fuel. Thus, there is little justification for the common assumption in the gas industry and government that, as higher prices and regulatory actions combine to force low priority consumers out of the gas market, load upgrading will automatically create a market for natural gas supplements which are more costly than petroleum fuels.

There is one further reason why the value of incremental gas supplies should not be calculated on the basis of their highest premium uses, and why even the cost of other fuels for residential space heating may exaggerate the marketability of new supplies. The high premium uses (and particularly home heating) are highly seasonal, while the supplemental gas projects under consideration here are capital-intensive "base load" facilities which depend upon steady year-round sales. If the justification of LNG, Alaska gas or synthetic gas from coal is protection or expansion of the high priority residential space heating market, their off-peak supply must either be sold to the lowest-priority industrial customers on interruptible contracts in competition with residual oil or coal, or it must bear the added costs of storage. It costs somewhere on the order of $1.00 per million btu to put gas into a new storage facility and take it out again --- a figure which would devour most if not all of the premium that high priority consumers might pay over the price of oil. In our view, the "long-term equilibrium value" of gas to homeowners and small businesses is very close to the retail price of distillate fuel oil and will remain so in the forseeable future.

1.2 The strategic need for supplemental gas

1.2.1 The prevailing energy outlook.

The official position of the United States government is that the whole world faces an imminent shortage of petroleum, and that higher real costs for energy are inevitable. In this view, which is probably the majority opinion among energy specialists in the United States, there is a growing demand in economic terms (and an urgent "need" in strategic terms) to develop substitutes for conventional oil and natural gas. This outlook has its roots in three interrelated experiences of the late 1960's and early 1970's: (1) the failure of domestic oil and gas production to keep pace with the growth of consumption, resulting in a rapid increase in Eastern Hemisphere oil imports; (2) the politically motivated Arab oil embargo of 1973; and (3) the OPEC price upheaval that accompanied and followed the embargo.

The investment plans of gas transmission and distribution companies and the energy policies implemented or advocated by Congress and the executive branch reflect to different degrees the belief that these three experiences accurately foretell national and world energy conditions over the next several decades. There seems to be a broad agreement, specifically, (1) that the domestic production of conventional oil and gas has peaked and that higher wellhead prices or accelerated leasing of public lands and the Outer Continental Shelf (OCS) can only moderate their decline; (2) that the alternative energy source which is most readily accessible in the short run--foreign oil--is unacceptably insecure, and unacceptably costly in terms of foreign exchange, and (3) that world energy demand will in any case soon outstrip either the physical ability or the political desire of the major oil exporting countries to increase production.

The interest of national policymakers in promoting the development of supplemental gas supplies stems mainly from their concern that the supply of domestic energy and imports from elsewhere in North America be sufficient to meet the long-term needs of the U. S. economy. Thus, supplemental gas would serve energy demands that would otherwise have to be supplied by increasingly costly and insecure foreign oil.

1.2.2 <u>Controversy and uncertainty over the energy outlook</u>. Neither the Arab embargo nor the abrupt rise in world oil prices in 1973-1974 in themselves made world energy resources any more scarce or less secure. They did, however, profoundly affect people's consciousness of energy issues and focused their attention on those facts which supported the thesis of imminent shortage and rapidly rising real energy costs.

Since the end of 1975, however, the price of OPEC oil has fallen by almost 20 percent in constant U. S. dollars,[3] and the purchasing power of the OPEC oil barrel has fallen by more than 30 percent in terms of the weighted average of OECD currencies. Today, there are oil "gluts" worldwide including the one on the West Coast of the United States. There are also an oil and gas bonanza in Mexico, an oil *and* gas surplus in Alberta, a gas surplus in Texas, and so on . . . *Whatever the price and supply outlook for the mid and late 1980's* may be, it is almost certain that the *real* price of OPEC oil will be stable or will continue to fall over at least the next two years as world oil producing capacity continues to grow, and that the gas supply situation will keep improving in most of North America.

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3. According to Department of Energy reports, the average refiner acquisition cost of imported crude oil was $14.48 per barrel in the last six months of 1975, and $14.49 per barrel in the first six months of 1978. Over the same period, the implicit deflator for the gross national product --- the most general indicator of U. S. inflation, rose 17 percent.

Once again, nothing has happened that really changes the objective long-term outlook, but industry, government and public perceptions of the future are sure to be powerfully affected by the current situation. In our opinion, a few years of fuel abundance will go a long way toward erasing or reversing the "lessons" learned in 1973-1974. At the very least, the basic assumptions of the Administration's energy policies will become more rather than less controversial: Consumers, lenders, state utility commissions, and Congress will become increasingly skeptical about the need for large capital-intensive and costly supplemental gas projects.

While a majority of energy experts regard scarcity and rising real costs for energy as the most likely prospect, and while the National Administration has made this outlook a major premise of its energy policy, such views are not held unanimously. A significant and growing number of respectable analysts believe that a relatively long period of abundant world oil supplies together with stable or declining real prices are more probable developments. Most advocates of the majority view, moreover, admit that there are plausible if unlikely scenarios in which conventional oil and gas might continue to be available at reasonable prices through the end of this century.

1.2.3 <u>The effect of uncertainty on the wisdom, economic viability, and financibility of supplemental gas projects</u>. Our intention in this paper is not to join the debate over the world energy outlook. One of our main themes, however, is the effect that such disagreement and uncertainty may have on the wisdom, economic viability, or financibility of large supplemental gas projects.

If constant-dollar world oil prices were truly to stabilize for a decade or more, or if higher prices brought forth large new volumes of conventional natural gas in the United States (or in Canada and Mexico), then large-scale LNG projects, synthetic gas plants and pipelines from the Arctic could turn out to be a huge waste of capital and labor, and under certain circumstances become financial disasters for the investors who backed them, or for distribution companies caught between fixed contractual obligations and a declining market.

Even if the federal government and the majority of energy experts today are correct that the long-term outlook is one of scarcity and rising costs, and that LNG, Arctic gas and synthetic gas will be good energy bargains in the 1980's at prices of four to seven (1978) dollars per million btu, controversy and uncertainty about the future cannot but affect the attitudes of lenders toward billion- and multi-billion dollar ventures that have very high proportions of borrowed money in their capital structure.

Uncertainty about the need for and marketability of supplemental gas may not only affect the attitudes of private lenders, but the same caution is likely to infect state regulatory commissions if they are asked to approve long-term gas purchase contracts at high or uncertain prices. Such uncertainty would also have its effect on the U. S. Congress in the event that it were asked to approve federal loan guarantees or other "backstopping" for projects that private lenders would otherwise turn down.

Doubts about the basic premises and wisdom of the Administration's energy policy will be powerfully amplified during the 1979-1981 period if those are years of recession -- and sluggish demand growth for energy -- as many economic forecasters now expect. Yet these are just the years in which the Alaska Highway gas pipeline, the second generation of LNG facilities, and the first generation of high btu coal gasification plants must put together their private financing, get whatever federal support is necessary to back that financing, and obtain the approval of federal and state regulatory commissions for any consumer guarantees or subsidies that are needed to assure their viability.

The situation described here could, of course, be changed drastically and suddenly, for example, because of war or political upheaval in the Middle East. But over the next few years, surprises in the opposite direction are just as plausible. Verification of recent claims about the potential of Western Canada's Deep Basin, a growing realization that Mexico's oil and gas resources rival those of Saudi Arabia, or the announcement of a cheap in situ process for extracting tar sands or oil shales could well be a death sentence for most of the supplemental gas projects now under consideration.

If, however, the prevailing view is correct that the mid and late 1980's may be a period of high energy costs and shortages, it is important that the "breathing spell" the United States has been granted for the next few years be used for investment in substitute energy sources. Yet, in our judgment, the very factors that created this breathing spell may make it difficult or impossible to put together the necessary financing for such investments. This is the central policy dilemma toward which this paper is addressed.

CHAPTER II

GAS SUPPLY AND DEMAND: THE ROLE OF GOVERNMENT AND REGULATED INDUSTRY

2.1 Introduction. While the demand for natural gas by each class of consumer is predictably related to the prices of substitute fuels, the total *amount* of gas demanded by *all* consumers is not a given market "fact" that the industry seeks to satisfy. In this respect the market for gas, like those in other regulated industries, differs profoundly from the elementary textbook model in which prices coordinate the adjustment of supplies to consumer demand.

The amount of gas that consumers as a group want to buy at "prevailing" prices is powerfully influenced by the way in which gas companies and regulatory commissions classify consumers and structure those prices. For this reason, the demand for gas is essentially a *political* fact. Once society brands the gas industry as a "business affected with a public interest" or a "natural monopoly" that must be regulated as a public utility, there are no natural or normal rules for allocating costs among different consumers or end uses --- only traditional and novel rules, discriminatory and non-discriminatory rules, pro-consumption and pro-conservation rules, etc.

Likewise, the *cost* cost of gas is not a market "fact" in the conventional sense, reflecting the cheapest mix of supplies necessary to meet a given demand volume. Rather, it is a figure twice chosen by the gas companies and their regulators --- first when they determine demand volumes by means of company-filed rates and regulatory actions on those rates, and again when companies determine and regulators certify what kind of gas supply facilities to build.

In this context, there is no way the role of Congress, the executive branch, FERC, and the state utility commissions can ever be limited to simply accommodating the plans of industry to meet consumer demand, or to monitoring those plans only to the extent necessary to protect the public from "unreasonable" prices and from unsafe or environmentally unacceptable conditions.

The challenge for governmental policymakers today is not only to make the "right" guesses about the course of external events (such as the price of foreign crude and the physical extent of conventional domestic supplies) and to act accordingly. They must also recognize where government actions inherently dictate both supply and demand, make these actions responsive to sensible and consistent goals, and ensure their effectiveness within the context of world conditions and industry incentives.

Meeting this challenge becomes crucial in the face of a supply and demand system *which cannot balance on its own.* Government control of price and supply will dictate whether a "balance" is reached, a "shortage" continues (with attendant need for government allocation), or an "oversupply" develops (with consequent injury to those who have borne the risks of supplying unmarketable gas). This need for the federal and state governments to chart their own course in influencing supply and demand is coupled with a need for officials to be equally aware of how the regulatory system and national policies affect industry incentives and the allocation of business risks.

2.2 <u>Governmental influence upon gas demand</u>. The most traceable governmental activities influencing gas demand are those related to prices -- since price is, after all, the main consideration of energy users in choosing among alternative fuels. Although the level of regulated wellhead prices (or price deregulation) for new domestic gas has received primary attention in recent years, there are two other crucial areas of federal action that impinge on prices and hence demand.

Governmental decisions which determine whether high-cost supplemental gas projects come into being are one such factor since the addition of high-cost supplies means a higher cost of service to be borne by consumers. These decisions include not only standard certification powers of "public convenience and necessity," but direct governmental assistance in financing that would otherwise be unattainable on the project's own assets or those of its sponsors. Potential forms of assistance include regulatory commitment to favorable end-use pricing; authorization to pass on to consumers capital charges for projects which are not yet in service; approval of tariffs that charge downstream transmission and distribution companies for scheduled debt (and possibly equity) repayment regardless of whether contracted volumes are actually delivered; rate base treatment of sunk costs in the event of plant non-completion; and government guarantees to ensure the return of and return to debt capital.

Another avenue by which the regulators influence gas demand is the power they wield over end-use rate structures in the gas industry. This power will determine how the costs of gas supplies are spread through time and among consumer classes --- whether the costs are borne equally or whether one consumer class subsidizes another. Chapter III shows how gas demand is powerfully influenced by variations in rate structures, and by variations in supply strategies, wellhead price controls, while Chapter V is devoted to the implications of various rate "profiles" --- different rules for allocating fixed costs over time.

2.3. <u>Governmental influence upon gas supply</u>. Federal policy makers in particular have dramatic and inescapable powers over the volume of natural gas supplies. The supply from *conventional domestic sources* is directly influenced by federal leasing on public lands and the outer continental shelf and by federal regulation of wellhead prices, which affects producer incentives to find and develop gas fields. Conventional domestic supplies are also indirectly influenced by a host of other policies and programs --- with respect to taxation and environmental protection, for example. In addition, the imposition of federal price ceilings only on "interstate" gas sold across state lines has created an artificial preference for selling into unregulated intrastate markets, thereby affecting the volume of gas which reaches customers in importing states.

The supply of gas from *non-conventional* domestic and foreign sources is directly controlled by the federal government. On the one hand, federal certification powers can be used to inhibit the development of supplies that would otherwise take place (for example, the failure to approve Mexican pipeline imports for which the negotiated buyer/seller price was rejected for reasons of Administration policy).

On the other hand, governmental entities hold the key to bringing some facilities on stream which for one reason or another cannot deliver gas without some form of unusual federal assistance. This category includes "second generation" Southern Alaska and foreign LNG projects, Alaska North Slope pipeline gas, and high btu coal gasification. All of these require some form of consumer or distributor guarantee (such as "minimum-bill" tariffs or rate-base treatment of sunk costs) or taxpayer guarantees (such as federal backstopping of debt).

With respect to this latter category of high-cost gas supplies, federal policy makers must consider not only whether these projects would further a host of national policies, but whether the benefits of these added supplies outweigh the risks borne by consumers and/or taxpayers. This is one point where "marketability" arises as a federal policy issue, because if gas is delivered at a price which would make it unmarketable, any consumer or taxpayer "guarantees" carried by the project turn into subsidies.

2.4 Industry incentives and risk-bearing: Effects on private sector supply decisions. The question of whether a gas project will deliver a marketable product cannot prudently be left either to the judgment of industry sponsors or their lenders. Utility regulation results in substantially different profit incentives and distributions of business risks from those that characterize most industry.

2.4.1 Effects of utility regulation on industry incentives. One reason why government must give serious weight to marketability questions is related to industry incentives for seeking supplemental gas supplies in the first place. If gas companies were conventional profit maximizers responding to consumer demand, one could expect them to seek the lowest cost strategy for obtaining gas and to avoid contracting for gas whose cost might well exceed its value to the lowest priority consumers. Gas transmission and distribution companies, however, are not permitted to maximize profits; their earnings are held to a governmentally determined "fair" rate of return on investment. For this reason, regulated gas companies do not always have a powerful drive to minimize costs.

In place of an incentive to maximize return on investments --- by reducing costs, for example --- the principal way in which a regulated gas company increases its earnings is by expanding the investments upon which it is allowed to earn the regulated return. This incentive to create new rate base facilities is amplified by the fact that the existing rate base "vanishes" through time as revenues are collected and the investment is amortized; as with most public utilities, a return is allowed only on the outstanding capital which has not yet been paid off.

Added to this is another regulatory feature that reduces what would seem to be a normal incentive to keep existing facilities operating at full capacity. Prices can usually be increased (perhaps with some time lag) when supplies go down or costs go up, so that company earnings are maintained over a wide range of conditions, and are largely independent of the volume or price of gas transmitted.

Together, these regulatory features create the following "perverse" incentives:

1. *A regulated gas company has a strong incentive to purchase additional supplies if those supplies enable expansion of rate base, but*

2. *Under many circimstances, a regulated gas company will have a less than compelling incentive to offset dwindling supplies in order to maintain existing earnings;*

3. *A regulated gas company would prefer to purchase higher cost gas that requires rate base expansion (new construction) than to purchase lower cost gas that can be transported through existing facilities; and*

4. *A loss of industrial customers, due to rising gas prices and/or delivery uncertainties, can be turned into an earnings increase if rate base is expanded as a result.*

Loss of *interruptible* industrial customers worsens the already strong seasonal variations in gas demand, and may justify investment in additional storage facilities and synthetic gas plants designed for winter operations. The loss of firm industrial demand also may make additional investment possible in distribution facilities, so long as new residential hook-ups are permitted by the state utility commission and prices have not yet risen so high as to discourage such new connections.

2.4.2. Effects of governmental allocation of gas on industry incentives. In response to the gas "shortage" that first became apparent around 1971, the Federal Power Commission (FPC), predecessor of the present Federal Energy Regulatory Commission (FERC), sanctioned curtailment schedules which served to protect gas companies from the liabilities of failing to supply purchasers with volumes contracted on a firm basis. Likewise, the Emergency Natural Gas Act of 1977, and similar provisions in the Natural Gas Policy Act of 1978, authorize federal allocation of supplies between pipeline systems for "essential human needs." The presence of these programs tells gas companies and their customers that they can expect their own supply situations to be influenced as much by national supply conditions as by their own individual efforts (or lack thereof) to secure new sources. Together, governmental involvement in the allocation of scarce supplies both *within* pipeline systems (through "curtailment") and *between* pipeline systems further reduces incentives of regulated gas companies to be particularly concerned about obtaining supplies primarily to meet their own customers' needs. Instead, these programs reinforce rate-base expansion as the chief driving force in the industry's supply strategy. Significantly, curtailment and allocation also tend to make state regulatory commissions less concerned than they otherwise might be to assure that distribution systems under their jurisdiction have adequate supplies under contract, particularly if they clearly involve higher prices to the consumers whose interests the commissioners are enjoined to protect.

2.4.3 Effects of Industry assessment of national energy policies. Since the 1973-74 oil embargo and price upheavals, supplemental energy projects, particularly domestic projects such as Alaska and coal gas, have exuded a mystique of national interest. Many companies seem to believe that regulators can and will adopt whatever policies are necessary (if not now, then certainly later) to guarantee the marketability of new gas supplies brought on stream. After all, there is a national "need" to reduce dependence on foreign oil; and it is therefore inconceivable that a gas pipeline from Alaska would be built and then be allowed to operate at a loss simply because there is no market for the gas on a cost-of-service basis. The notion that the federal government can be counted on to "do something" may not be sufficient to recruit large blocks of debt capital, but it does assure that there will be sponsors for supplemental gas projects however much their projected costs seem to exceed present day oil prices.

This blind faith in government may not be a particularly prudent approach in light of the unpredictability of perceived national needs, together with the closeness --- and vehemence --- of recent Congressional divisions on major energy issues. Even today, the desire of the Administration, Congress, and utility regulators to protect residential consumers against rising gas costs seems to outstrip their enthusiasm for reducing dependence on foreign oil, and that preference may well intensify between now and the early 1980's.

CHAPTER III

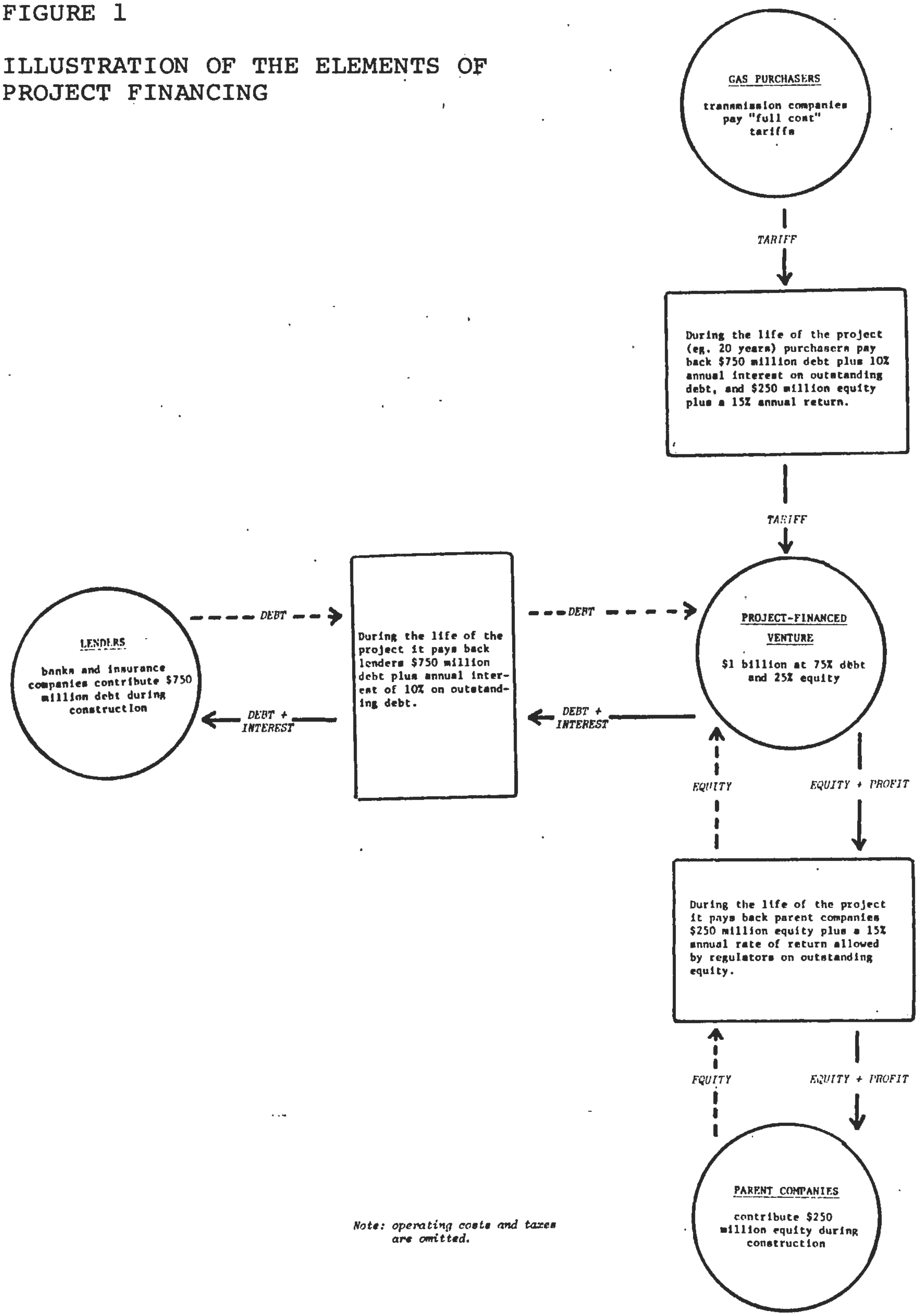
PROJECT FINANCING AND THE ALLOCATION OF RISK

3.1 General. The supplemental gas supply projects with which we are concerned here --- LNG import facilities, the Alaska Highway gas pipeline, and synthetic coal gasification plants --- are generally planned as "project-financed" ventures. Figure 1 shows the principal elements of project financing; its essence is the creation of a new corporate entity in charge of a project for which the sponsoring transmission companies bear no liability, at least after it goes into service. This corporate entity has virtually no assets outside the project itself, hence prospective lenders must be assured that some other credit-worthy party will pick up the tab for debt and interest payments in the event that revenues generated by the sale of gas are insufficient to meet these payments.

The transmission companies sponsoring high-cost ventures rightfully argue that project financing is about the only means by which sufficient private capital can be raised for projects whose size far outstrips the total assets of the sponsoring companies, or at least the assets which could prudently be dedicated to any single market venture. But

FIGURE 1

ILLUSTRATION OF THE ELEMENTS OF PROJECT FINANCING



this form of financing carries two added bonuses for them: (1) the debt equity ratio can be comparatively high (70-100 percent debt compared to a norm of 40-55 percent); and (2) the debt is secured by means other than placing the assets of parent companies on the line. It virtually absolves the sponsoring gas companies from carrying any business risks beyond contributed equity capital --- and under some tariff proposals, even this risk would be eliminated.

3.2 Transfer of risks. The potential methods for transferring risks in project-financed gas ventures to some other creditworthy entity are of two general types. The first is a rather straight-forward and uncomplicated approach --- relying on governmental backstopping to cover any operating costs, scheduled debt payments, and interest charges beyond what can be handled by project revenues. (Sponsoring companies sometimes argue that backstopping must also cover the scheduled return of sunk equity capital --- and maybe even a return *on* that capital --- in order to attract equity interest.) While Congress recently sanctioned this approach as a means for getting coal gasification *demonstration* projects off the ground, it is clear that the Alaska gas pipeline sponsors would be fighting an uphill battle in order to get the same treatment, and such assistance would be quite out of the question for sponsors of foreign LNG projects (apart from the shipbuilding loan guarantees for which they are eligible under an existing program designed to help the maritime industry).

Instead, debate centers around the methods for adequately and legally transferring risks "downstream" to purchasers of supplemental gas supplies. These methods can take a variety of forms and occupy a spectrum from partial to total placement of risk on downstream purchasers. Federal approval of tariff rules will largely determine *who* bears *how much* of *what* risks. But, perhaps more importantly, federal action on pricing methods will determine whether downstream purchasers and state public utility commissions have any say at all (beyond the right to testify in federal proceedings) on what risks they must bear for the sake of securing additional gas.

With respect to project financing, there are three other bonuses, apart from the transfer of risk away from sponsoring transmission companies previously discussed, that make this form of capital raising particularly attractive.

3.3 <u>Avoidance of bond indenture limitations</u>. One bonus is the way in which sponsoring transmission companies can use project financing to sidestep prohibitions in their existing debt obligations that otherwise limit their ability to incur further debt --- no matter how sound the venture. In many cases "indentures" on present debt (that is, the company's contracts with existing bondholders) effectively prohibit a gas company from borrowing additional funds on its own account for the purpose of financing supplemental or any other gas projects. Where a company owns less than 50 percent of a project-financed entity, however, that company does not have to list the project debt on its own balance sheet; thus, the bond indentures restricting its further borrowing are not invoked.

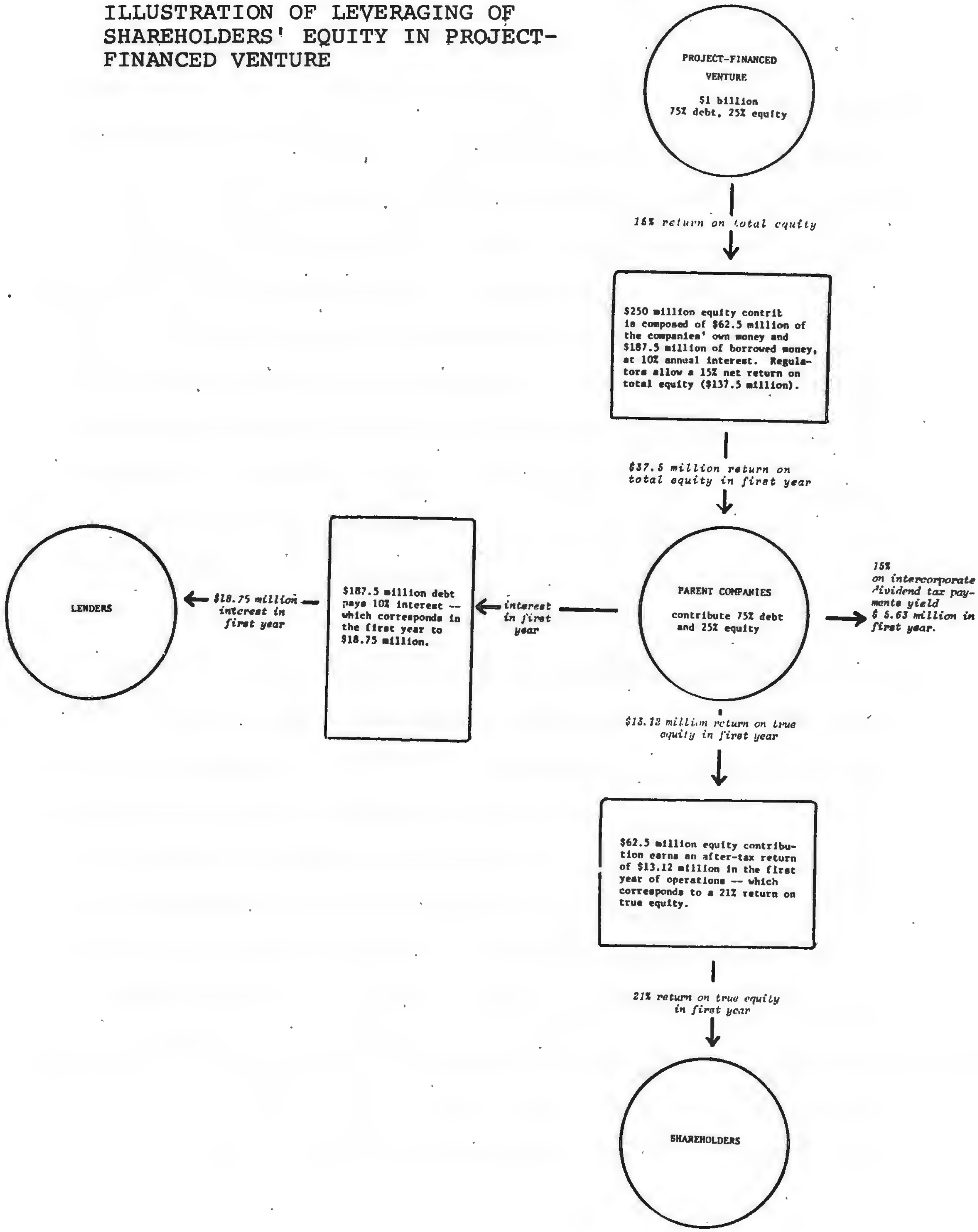
3.4 <u>Reduction of cost of capital</u>. In addition, use of project financing can actually reduce the overall cost-of-service compared to conventional financing, because of differences in debt/equity ratios and the return required on each. These potential savings are significant because a project sufficiently backstopped with full-cost or minimum-bill contracts can be financed with a capital structure of 70 to 100 percent debt, in contrast to the 40 to 55 percent which is typical in the gas utility industry as a whole. If the interest rate on long-term debt were 10 percent and the necessary pretax return to equity were 25 percent, a facility project-financed with 75 percent debt and 25 percent equity would require a composite return to capital of 13.25 percent, while a conventional project with a 50-50 capital structure would require a 17.5 percent return to total capital.

3.5 The ability to borrow equity contributions. Finally, equity shares in a project-financed venture whose income is adequately secured by cost-of-service contracts are themselves "bankable" assets. By *borrowing* part or all of the funds they put up as equity in such a venture, the parent companies can earn truly impressive rates of return on their own equity. In Figure 2, a project-financed venture is permitted a 15 percent after-tax return on its contributed equity; if 75 percent of that contribution were borrowed at 10 percent interest, the owners' net return on their own investment would be 21 percent (after payment of the 15 percent tax on intercorporate dividends).

3.6 Tariff conditions on project financed ventures. Sponsoring companies have proposed that "minimum bill" tariffs be imposed by FERC on downstream purchasers of supplemental gas to cover operating costs, scheduled debt

FIGURE 2

ILLUSTRATION OF LEVERAGING OF SHAREHOLDERS' EQUITY IN PROJECT-FINANCED VENTURE



repayment, and interest, so as to satisfy lenders that debt will be paid back --- and paid back on time. Some companies have further argued that sufficient equity capital will likewise be impossible to come by unless scheduled equity amortization and even a return on outstanding equity capital are also guaranteed by downstream purchasers through a "full cost-of-service" tariff. Minimum-bill and full-cost tariffs both rely on an approach in which gas purchasers continue to pay part or all of the price whether or not gas is actually delivered. However, since final tariffs are not filed for new facilities until operations are about to begin, these tariffs can transfer risk to purchasers only *after* a facility is constructed and begins operations; pre-completion risks are not covered. Therefore, some sponsors have suggested that these guaranteed charges be imposed on buyers "in all events" --- to ensure repayment of sunk debt and/or equity capital no matter how far the project is from completion. This purpose could not be achieved through the *tariff*, which would specifically attach to the new facilities only when they were completed; instead, it would require insertion of special clauses into existing service agreements between transmission companies and local distributors or automatic "rate-base treatment" of sunk costs.

It is somewhat ironic that sponsoring companies, which got rid of the risks in the first place by creating a new corporate entity, are the first in line to bear the burdens of a minimum-bill or full cost-of-service tariff. This is because the sponsoring companies generally intend to buy a large share of the project's gas, thereby becoming the first purchasers subject to the tariff. Naturally, these companies anticipate "tracking" these charges through to their downstream purchasers in turn. But here again, this mechanism carries an unusual bonus for the sponsors. Gas purchase or shipping tariffs incurred by a gas company are regarded as part of its operating costs and, as such, must be paid prior to paying off any of the company's debt. This, in effect, makes the debt (and maybe equity) component of the tariff senior to all other company debts, and hence makes the bonds issued for the supplemental project more attractive to potential lenders than they would be if they were co-equal or junior to the sponsor's existing indebtedness --- which would be the case if conventional financing were used in the first place.

3.7 <u>Rate schedules and the distribution of risks</u>. Selection by the federal government of a pricing method will, to a large extent, determine whether downstream distribution companies and consumers (through their state public utility commissions) have a distinct opportunity to decide whether they are willing to accept the costs and risks of supplemental gas in order to get the benefits of additional supplies.

If purchasing transmission companies are allowed to "roll-in" the costs of supplemental gas with their other supplies, then local gas distributors would be required to accept the cost of this gas as an indivisible part of the costs that their existing service agreements already obligate them to pay. Not only would this strategy shift the market risk to the local gas distributor, but the latter would have no choice even at the outset to accept or reject that risk. The state commissions which regulate the local companies, moreover, would also be deprived of any opportunity to decide on behalf of their consumer constituents whether the additional gas is a necessary, cost-effective, or prudent purchase.

The strategy described here would not work if the transmission company had to sell supplemental gas under a separate service agreement and a separate rate schedule. Each local distributor or direct industrial customer would then have an individual opportunity to assess the benefits and risks of entering into a long-term contract for added gas supply, while each state regulatory commission would have a chance to weigh the impact of the price of this gas on consumers they are supposed to protect or the distribution companies they regulate.[4]

It is not difficult, therefore, to understand why the transmission companies sponsoring high-cost supplemental gas projects argue vigorously for "rolled-in" pricing. Under the proposed arrangements, both the transmission companies and their project-financed subsidiaries are guaranteed whatever revenues the project requires from ultimate consumers, without the possibility that distributors will reject the gas or state utility commissions will veto its purchase. Rolled-in pricing would enable the project to move forward without first having to secure new downstream purchase contracts and consequent state PUC approval of those contracts, which an "incremental price" approach would require. Not only would rolled-in pricing therefore eliminate these potential delays, but it would also serve to

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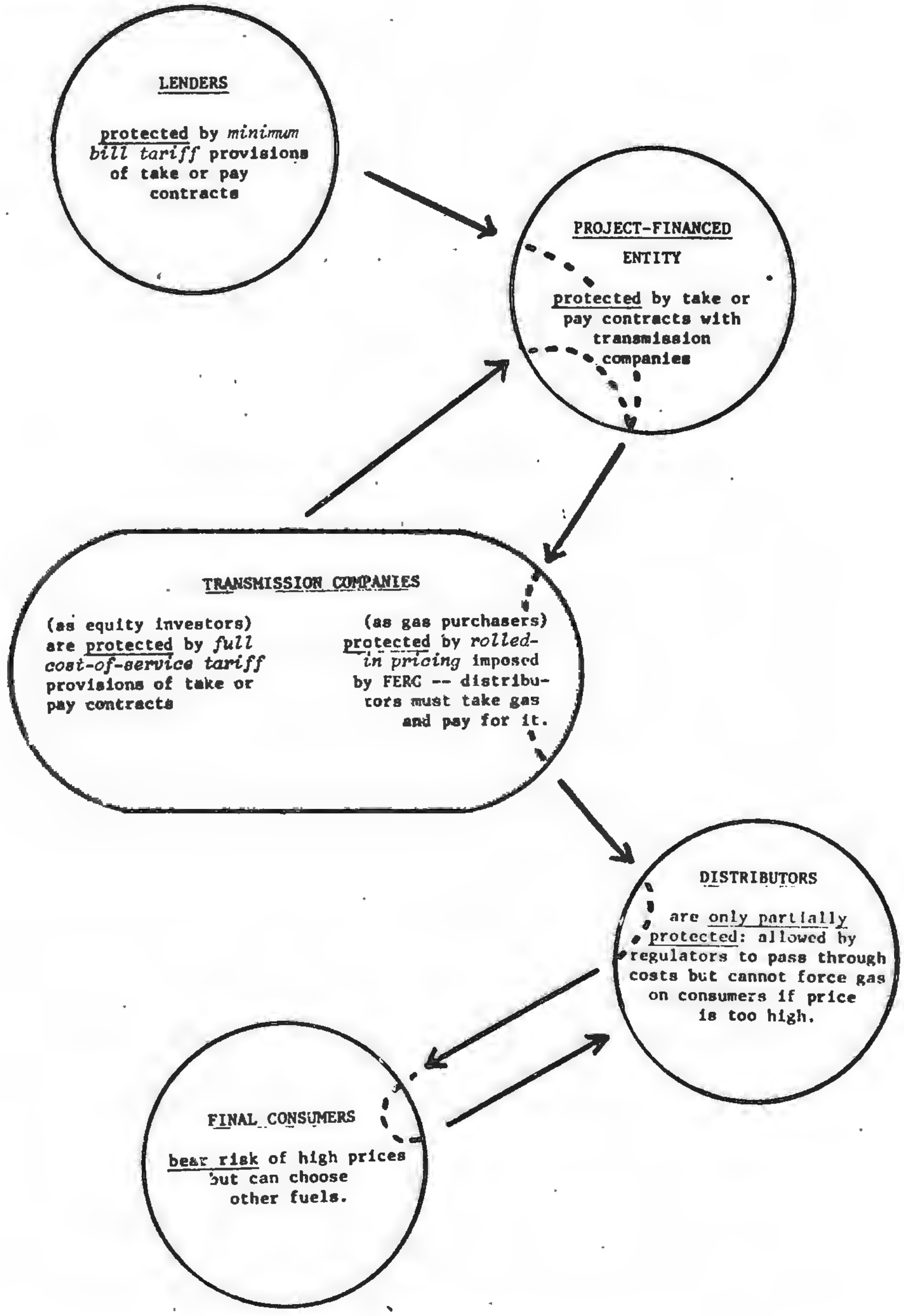
4. Distribution companies, consumer representatives and state commissions do have a right to "intervene" in FERC proceedings and to state their views on certification of projects, transmission company purchase contracts, and other interstate transactions.

FIGURE 3

TRANSFER OF MARKET RISK



confine the go/no go decisions to the federal government, sponsoring companies and their lenders --- excluding those purchasers who ultimately bear the risks.

3.8 <u>The crunch on the distribution companies</u>. Transfer of these costs and risks from sponsoring transmission companies downstream would suggest that the final purchasers of gas might ultimately be left holding the bag. However, this is not strictly the case, as local distributors could very well be the real risk bearers. If charges to consumers become too great because project failure triggers a minimum-bill tariff that adds these costs on to other gas supplies, or because of higher than expected project costs, consumers have a clear choice. They can choose to bear these additional costs, cut down on their total gas use, or switch to other fuels. However, reduced gas consumption would *not* diminish the distributors' fixed costs nor relieve them of "take or pay" or minimum-bill gas purchase obligations passed on to them by the transmission companies. Figure 3 traces the transfer of market risk "downstream" from the project-financed entity and its investors to the point at which gas distributors meet the final consumer.

If conservation and fuel-switching are highly responsive to gas price increases -- as we believe -- they can result in an oversupply of gas at the distribution level. In some foreseeable situations, even a temporary oversupply might trigger a spiralling collapse in gas demand: fixed costs are borne by smaller volumes of gas sold, prompting higher prices and further cutbacks in consumption, thus necessitating increased charges on remaining sales, and so on. Even if the loss of rate-sensitive industrial and commercial loads could be offset by new residential hookups, these too would add to the upward price pressures as they required higher rates to finance new distribution lines and new storage facilities.

We will not try to estimate the likelihood of such a contingency, but it is conceivable that what happened to urban transit in the United States could be repeated in the gas distribution industry. Caught between diminishing patronage and a combination of heavy fixed indebtedness and rapidly rising operating costs, the subway, streetcar and motorbus companies repeatedly raised fares and cut back on service quality and frequency.

Each fare increase boosted revenues in the short run, and each service curtailment cut total costs, but revenues remained higher and average costs less than before only for as long as it took previously captive riders to buy automobiles or otherwise change their travel habits. Ultimately, most big city transit companies in the United States stopped paying dividends and defaulted on their bonds. Because they still provide an indispensable public service, they have been taken over by municipal governments or metropolitan transit authorities, which operate them at a loss made good by the general taxpayer.

Perhaps there was no policy that utility commissions or municipal franchise boards could have adopted to avert the collapse of the transit companies, given the public's growing preference for the automobile and suburban single-family housing. If local gas distributors meet a similar fate, however, it will be a direct result of self-interested investment decisions by the interstate transmission companies, endorsed by federal regulators. And with rolled-in pricing at the wholesale level, the state utility commissions that have the primary responsibility for protecting consumers and assuring the viability of the gas distributors, may have little direct control over the process.

It is important to emphasize at this point that the submissions of distribution companies and state commissions before FERC (and its predecessor the FPC) have overwhelmingly favored approval of the supplemental gas projects proposed by the transmission companies that supply them, and the distributors and state regulation have generally supported rolled-in prices and minimum bill tariffs as necessary means to obtain financing for such projects. As the first chapter noted, however, the gas industry has tended to underestimate the sensitivity of gas consumption to prices. In those cases where marketability problems have indeed developed in recent years (Oregon, Washington, Texas, and Ontario), they appeared suddenly and caught the distribution companies and state regulators by surprise. In our judgment, most companies and state commissions are still unaware of the marketability issue -- but that condition will not last long.

3.9 Conclusion. Overall, gas industry investment incentives vary profoundly from that of most other businesses, because of (1) utility-type regulation, (2) governmental allocation of gas, and (3) the perceptions of national policy. These pecularities along with the proposed transfer of all marketing risks associated with large supplemental gas projects downstream provide ample reason for federal and state officials to use their own judgment in considering marketability questions and the "need" for supplemental gas supplies. While it may be unfair to assign less than respectable motives to regulated gas companies, it is equally unfair to expect company management to act in accordance with the "public interest" at the expense of growth and stockholder earnings. Assessment of the consumer and national economic benefits, and the ultimate marketability risk for supplemental gas projects should not be left to the gas industry and its lenders alone.

CHAPTER IV

RATE DESIGN AND THE MARKETABILITY OF SUPPLEMENTAL GAS

4.1 Introduction. A market economy normally counts on the willingness of private investors to supply capital as the ultimate and most sensitive measure of a venture's expected economic usefulness. Chapter I of this report concluded, however, that market uncertainty could preclude the private financing of even the most desirable supplemental gas sources if the gas they supplied had to be sold at its full cost in direct competition with other fuels. Chapter II described the organizational innovations and regulatory measures -- project financing, full-cost tariffs and rolled-in pricing at the wholesale level -- with which gas project sponsors and their advocates in government hope to overcome market risk.

We have concluded that these devices would indeed make financing possible for most of the supplemental gas ventures under active consideration today (provided non-market risk factors, chiefly non-completion and regulatory instability, are satisfactorily dealt with). But the strategy described here would, at the same time, be capable of sheltering and subsidizing projects that are clearly not cost-effective on a consumer benefit or national interest standard. Moreover, the business risks which investors in supplemental gas projects avoid by these means may not be eliminated but simply shifted downstream to other parties.

The balance of this report is devoted to a further assessment of the size and ultimate resting place of market risk; the standards regulators should use (given the inadequacy of conventional market tests) to determine which supplemental gas supply projects desire to be insured against market uncertainty; and the ways in which government may provide this insurance to investors without creating incentives for inefficiency and without imposing unacceptable risks on gas distributors or consumers.

4.2 Rate structures and the allocation of costs among consumers and end uses. A crucial premise of this report is that in the long run, there is little inherent demand for natural gas because gas has acceptable substitutes at some price for practically all its uses. For this reason, government regulators can manipulate gas demand over a side range of values through their control over total gas costs and the way in which those costs are allocated among residential, commercial and industrial gas users. Federal and state regulators influence the cost of gas to the regulated gas companies, along with its supply, by wellhead price controls on conventional natural gas and by their approval or disapproval of higher-cost supplemental gas supply projects. Even more effectively, perhaps, government can influence the amount of gas that consumers want to buy by choosing among various rate *structures*, all of which are consistent with the principle that regulated utilities should earn only a "fair and reasonable" rate of return.

Federal policy is currently undecided about the purpose for which this power over gas demand is to be used, particularly between the desire to minimize long-term U. S. reliance on imported oil and the desire to protect households and other favored classes of consumers from high prices in the short term. The choice of a policy that balances these objectives is further complicated by the fact that neither of them is always consistent with one of the dominant motivations of the regulated gas companies, which is to enlarge their rate base facilities.

4.3 <u>A simple model of the gas industry</u>. This section presents a simple model of a regional gas transmission and distribution system designed to illustrate these principles and to show general orders of magnitude for the effects of two crucial aspects of regulatory policy - rate structure and supply strategy. It also demonstrates the relative sensitivity of gas demand to rate structure as compared to wellhead price controls.

The model arbitrarily classifies consumers into three sectors and gas supplies into five. For the sake of simplicity, each consumer sector attributes a single specific "value" to each btu of gas energy and each source of supply entails a single specific "cost" for delivering a btu of gas to the consumer. The model also combines the transmission and distribution sectors and thus federal and state price regulation. The firms in the gas industry are assumed to buy conventional natural gas at set prices from producers (domestic oil companies, Canada and Mexico) outside the industry.

No explicit allowance is made for seasonal or regional differences in demand or costs, or for differing regulatory situations (interstate versus intrastate gas transactions, for example). The model operates on the assumption that the companies and the regulators adopt a set of policies that make gas supply equal to demand and (except in one case) make revenues equal to costs. It makes no difference to the model whether the companies and the regulators choose a pricing regime and then provide the amount of investment in supplemental gas facilities necessary to meet the demand created by the price structure, or whether the companies and the regulators decide how much and what kind of gas is to be supplied and adjust their rate structures to make that gas marketable. The results of each "scenario" describe only the necessary end point of either process after it has brought supply and demand into balance. The model does not deal with any non-price measures (such as curtailment, end-use controls or prorationing) the companies and the regulators might adopt if price and supply strategy were not successful in equating supply and demand.

The model does not pretend to predict the real world volumes of gas that would be produced or consumed or the prices various types of consumers would pay. It is not inherently sophisticated enough to serve this purpose, and the prices and volumes the authors have assigned to the various supply and demand sectors are almost arbitrary. "Almost," because the assigned values are intended to be plausible or realistic enough to make it easy for the reader to follow the analysis, but neither the names of the supply and demand categories nor the specific numbers should be taken too seriously.

Again, the chief purpose of this exercise is to *illustrate* the ways in which manipulation of rate structures and supply strategies affect total consumer demand for gas, and *the direction and general order of magnitude* of that influence.

4.3.1 Demand. The demand for gas in some unspecified year is assumed to have three parts, all of which are keyed to price:

Priority 1 demand is composed of present residential and small commercial consumers, who would use up to 4 units of gas energy (equal to 400 trillion btu or 400 billion cubic feet) per year, and who would be willing to pay a price of $4.50 per million btu (mmbtu) for that energy. In other words, we assume that is would cost Priority 1 users $4.50 per mmbtu to replace gas with another fuel, taking into account the retail cost of No. 2 distillate oil (assumed to be $3.50 per mmbtu) plus the costs of replacing appliances or burners, or to refrain from using any fuel at all.

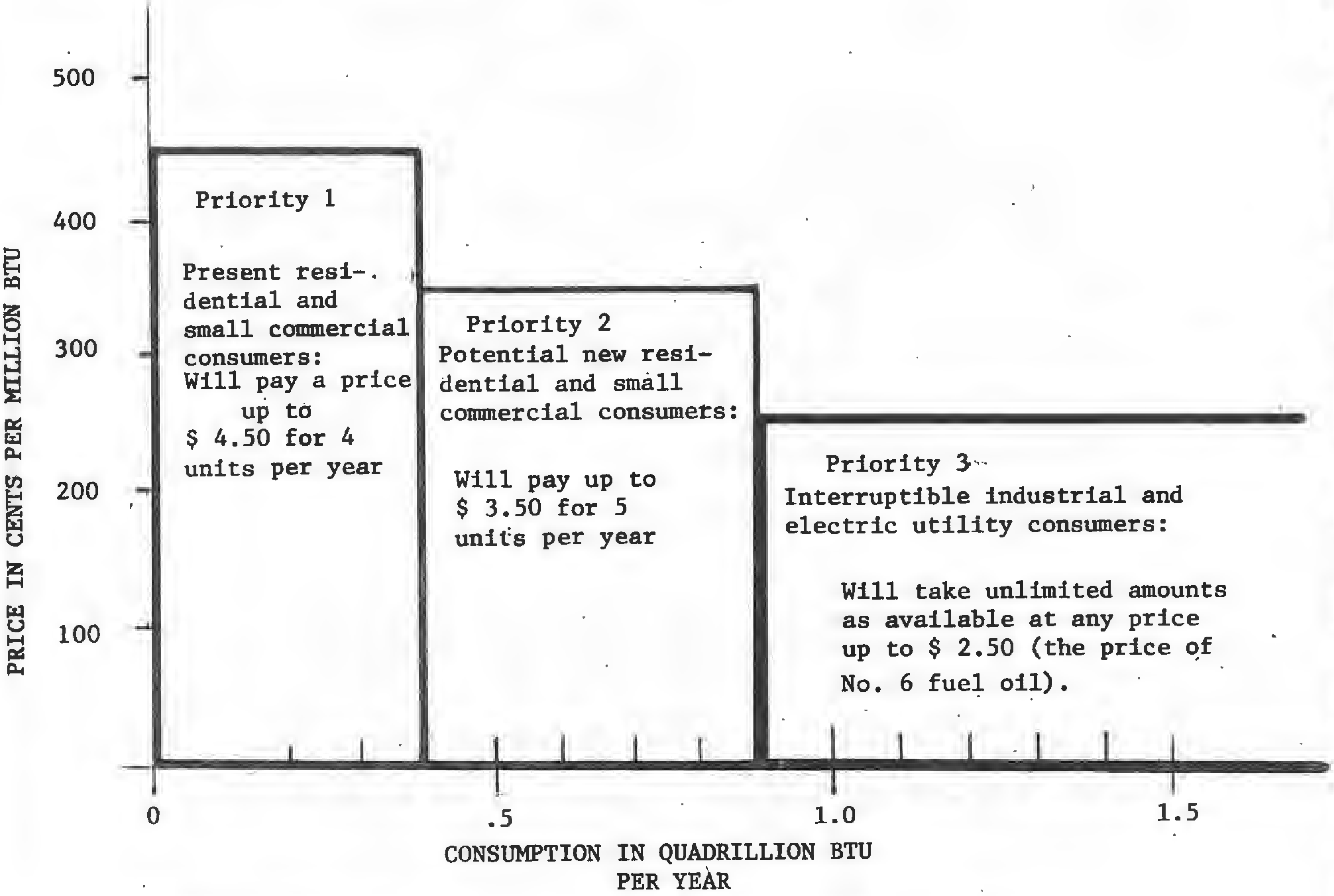
Priority 2 demand includes potential *new* residential and small commercial customers, plus existing "firm" industrial and large commercial users, who would be willing to pay up to $3.50 per mmbtu for a combined volume of 5 units per year. For the first group, this price reflects the retail price of No. 2 fuel oil ($3.50); for the latter, the wholesale price of No. 6 oil ($2.50) plus the capital cost of converting from gas to oil.

Priority 3 demand represents interruptible industrial users and electric utilities who are willing to take virtually unlimited quantities of gas at a price not exceeding the wholesale price of No. 6 fuel oil, in this case $2.50 per mmbtu.

Figure 4 shows these three demand components in descending order from left to right, reflecting the assumption that either market incentives or curtailment and allocation rules give a priority to those customers who place the highest value on a unit of gas.

4.3.2 <u>Supply</u>. Potential gas supplies are classified into five categories, each with a different cost to the gas industry:

FIGURE 4 DEMAND ASSUMPTIONS



A UNIT IS EQUAL TO 100 TRILLION BTU OR 100 BILLION CUBIC FEET.

(1) Six units (or .6 quads) of conventional "old gas" available at a cost of $1.00 per mmbtu;

(2) Two units of conventional "new gas" at $2.00;

(3) Three units of Canadian and Mexican imports at $3.00;

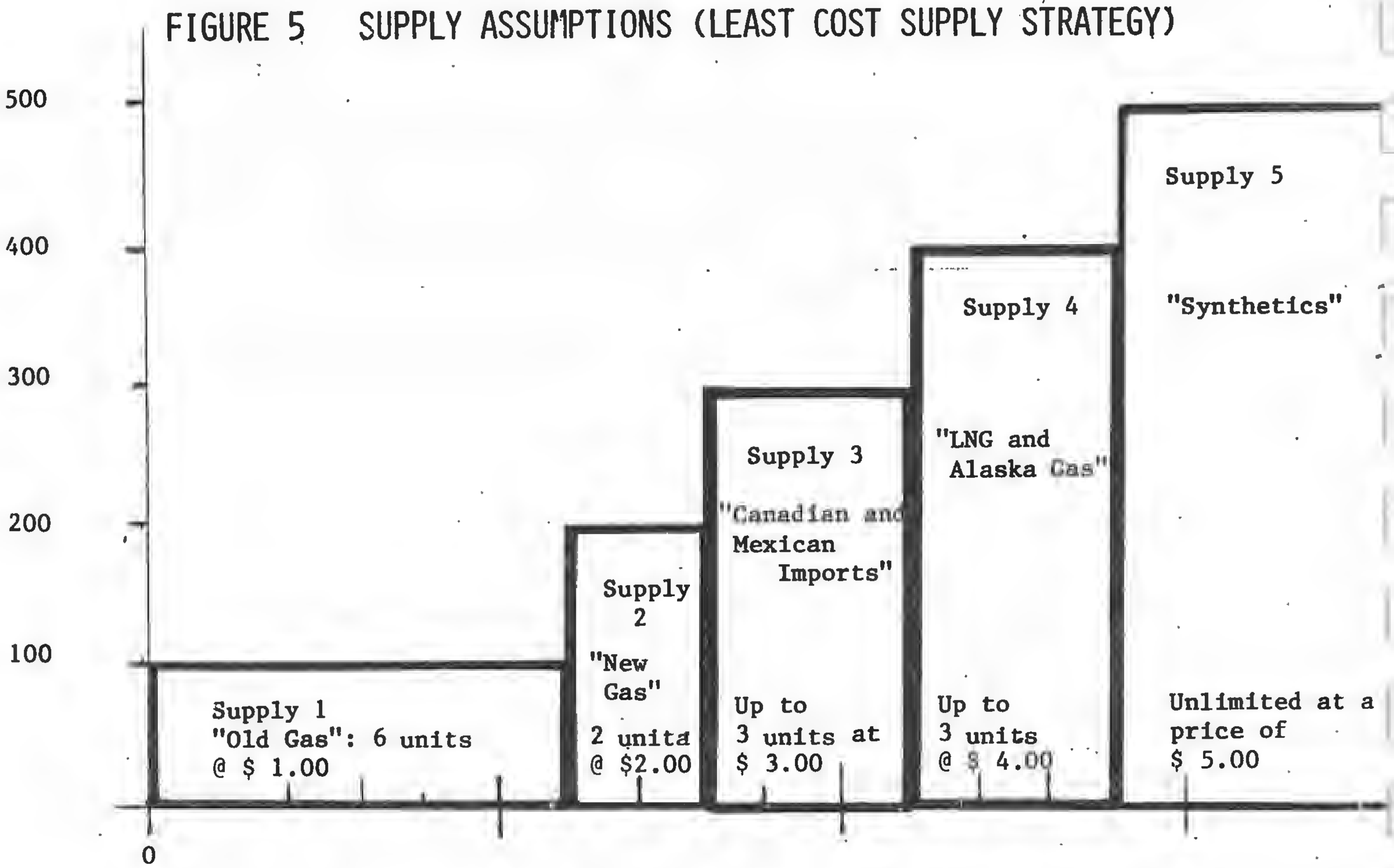
(4) Three units of LNG and Alaskan gas at $4.00; and

(5) An unlimited quantity of "synthetics" at $5.00.

These values represent total costs to the regulated companies of purchasing or producing the gas and delivering it to final consumers, including a "fair and reasonable" return to company investment in production and distribution (but without any excess profits or "company surplus", as defined below).

Figure 5 shows these supply categories arranged from left to right in order of ascending costs. This is the order that would minimize the industry's cost of providing any given volume of gas, and it corresponds to the supply strategy that would normally be chosen by an unregulated firm. But it is not necessarily the supply strategy that would be preferred by a regulated gas company or its governmental regulators; further on we shall consider the implications of choosing a higher than minimum cost supply strategy.

FIGURE 5 SUPPLY ASSUMPTIONS (LEAST COST SUPPLY STRATEGY)

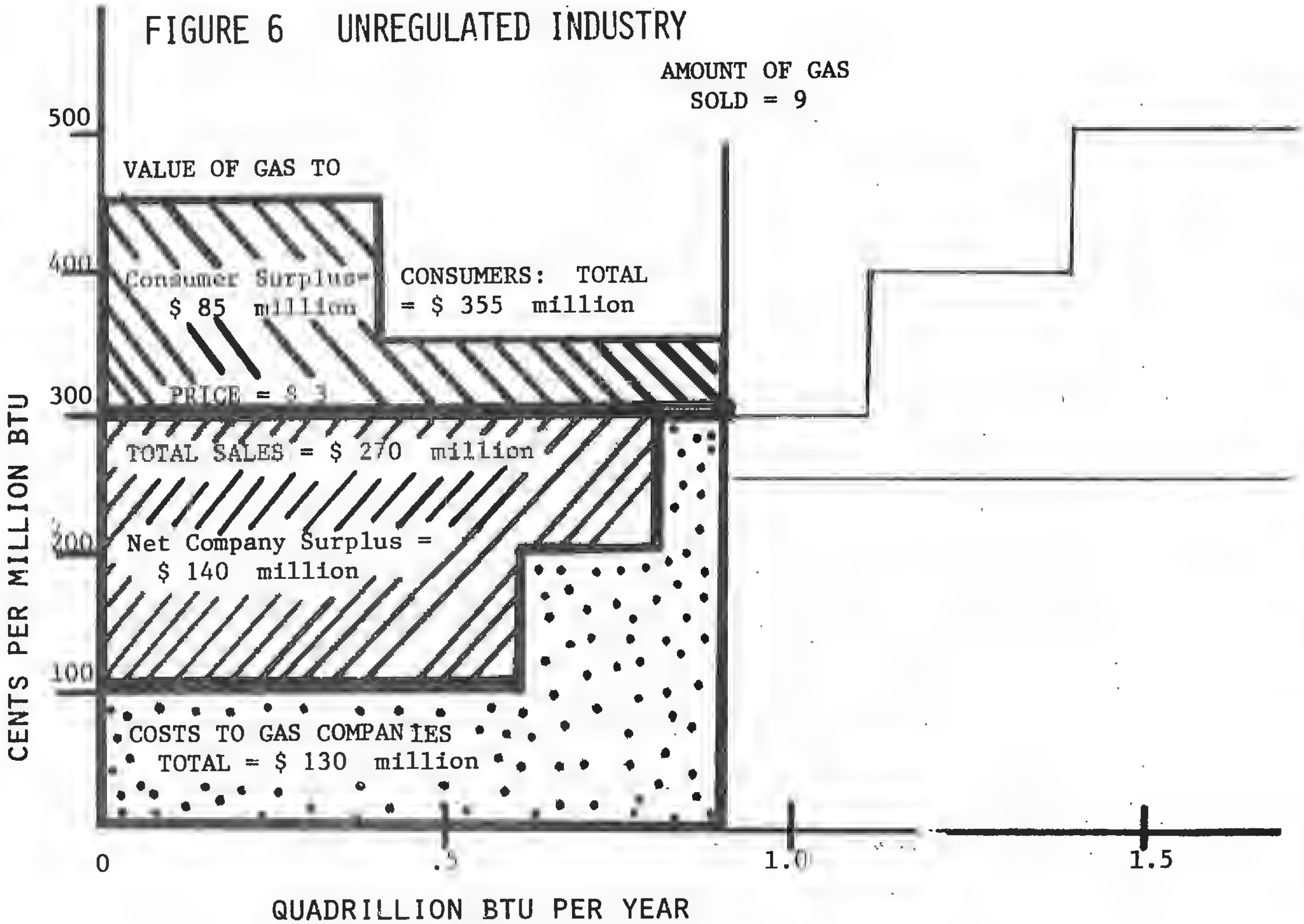


QUADRILLION BTU PER YEAR

A unit is equal to 100 trillion btu or 100 billion cubic feet.

4.4 <u>An unregulated base case</u>. Figure 6 shows the interaction of supply, demand and price in an imaginary unregulated gas industry. The lack of regulation here refers to costs that the transmission and distribution industry charges for its services -- not to producer prices, which may be regulated or not but in any case are assumed to be determined outside the model. This case is not a realistic one as a policy alternative, but because it most closely resembles the conventional supply-demand equilibrium of textbook economics, it is the simplest case with which to demonstrate the working of the model, and provides a basis for understanding the effects of various pricing rules imposed by regulation.

In an unregulated industry without price discrimination -- that is, one in which all gas must be sold at the same price -- gas companies would direct their marketing efforts at those consumers willing to pay the highest prices for any given volume. They would in turn seek to supply as large a quantity as they could so long as additional units of gas did not cost them any more than consumers would be willing to pay for these additional units. (In technical terms, the companies would try to buy and resell more gas until their "marginal costs" rose to equal "marginal revenue.")



<u>In this instance,</u>

The amount of gas sold is -	9 units
At an average price of -	$ 3.00
For total sales of -	$ 270 million
The value of gas to consumers is -	$ 355 million
The consumer surplus (value less price) -	$ 85 million
The cost of the gas to the company is -	$ 130 million
The company surplus (sales less cost) -	$ 140 million
The net national benefit (value less cost= consumer surplus plus company suprlus) is -	$ 225 million
Priority 1 consumers pay a price of -	$ 3.00
And have a surplus of -	$ 60 million

In doing so, the companies would maximize their profits, that is, the difference between their total sales revenues and their total costs.

The price and volume at which the consumer value and the cost to the company of the last unit are equal is shown in Figure 6 by the large dot where the supply and demand lines intersect. In this illustration, consumers pay $3.00 per mmbtu for a total of 9 units of gas per year; thus, total sales are $270 million. Only Priority 1 and 2 customers are served at that price, however, because Priority 3 customers would not pay $3.00 for gas as long as they could get residual fuel oil at $2.50 per mmbtu.

The upper (red) line graphs the value of gas to consumers, who, if they had to do so, would have been willing to pay up to $355 million (4 units at $4.50 per mmbtu plus 5 units at $3.50) for the amount they consume. Thus, the gas is worth $355 million to consumers, but they pay only $270 million for it. The $85 million difference is the *consumer surplus*, which is the measure of the sale's net economic benefits to all consumers -- in other words, the additional amount consumers would have been willing to pay, but do not in fact have to pay.

On the other hand, the same 9 units of gas cost the companies only \$130 million (6 units at \$1.00, plus 2 units at \$2.00, plus 1 unit at \$3.00). As the companies' sales revenue is \$270 million, the difference creates an excess profit or a *company* surplus of \$140 million.

The net contribution of the transaction to the real national income is the difference between the *value* of the gas to consumers (\$355 million) and its *cost* to the companies (\$130 million), which difference is also equal to the sum of the consumer surplus and the company surplus. This *net national benefit* is the measure of the economic efficiency of the arrangement -- its contribution to the real national income.

4.5 <u>Public utility regulation</u>. The central principle of public utility regulation is that the earnings of regulated companies should be held to a "fair and reasonable" rate of return on investment. In contrast to the unregulated case, utilities are not supposed to reap any excess profit or company surplus. Simply stated, revenues may not exceed costs --- this is the so-called "revenue constraint" in utility ratemaking. The revenue constraint, however, does not in itself dictate how costs are to be allocated among the various consumer sectors. Rate structures can be designed to maximize the consumer surplus and to allocate it among consumers according to some notion of equity or efficiency or, alternatively, to use up the potential surplus in subsidizing additional consumers who would not be willing to purchase gas if they had to pay its full costs.

4.6 <u>"Incremental" vs. "rolled-in pricing</u>. One crucial element in rate design, which affects the total volume of demand as well as the size and distribution of the consumer surplus, is the choice between "rolled-in" and "incremental" pricing rules. Generally, a rolled-in price means an average price incorporating different costs for a good or service from more than one source. A gas company, for example, may acquire gas from several sources at prices from 20 cents to $5 per million btu, and resell all of it at a single rolled-in price of $1.50. While this kind of pricing scheme is probably the easiest for a utility to administer and for regulators to comprehend and supervise, it is increasingly regarded as wasteful: If the last ("incremental") unit of gas supply costs $5.00 per mmbtu, rolled-in pricing would encourage consumers to use $5.00 gas as if it were worth only $1.50; in other words, it would also encourage gas companies to use real resources (labor, capital and materials) that cost society $5.00 in order to produce gas that society values at only $1.50.

"Incremental pricing" in general means a system in which the price for one unit of a good is equal to the cost of producing one more unit or, what is the same thing, the savings from producing one less unit. If this condition is met, prices will give each consumer the "right signal" regarding the cost to society of his own consumption, and consumers can be expected to use (or conserve) just the "right" amount of the good because it would cost them just the same amount as it cost society at large. In recent years, there has been a shift in sentiment among energy experts, regulators, and legislators away from the traditional rolled-in utility pricing rules, and toward some form of incremental pricing.

4.6.1 <u>Incremental pricing before the Federal Power Commission</u>. The debate over rolled-in versus incremental pricing has recently acquired some very confusing semantics, as each of the two terms has come to denote more than one kind of ratemaking method. In procedings before the former Federal Power Commission (FPC), incremental pricing referred to the sale of gas from a given high-cost source under a *separate service agreement* and a *separate rate schedule* from natural gas flowing under existing agreements, thereby allowing purchasers to decide whether or not they wanted to buy the supplemental gas after comparing its cost with that of alternatives. Under this proposal, consumers would face the actual costs of the "incremental" gas supply, in contrast to the more common arrangement in which these costs would be averaged or "rolled" into a single rate schedule with lower-cost conventional gas. An incremental pricing rule of *this* sort would have effectively blocked development of any supplemental gas supply whose future cost was expected to be greater than that of alternate fuels for the "incremental," or lowest-priority customer.

4.6.2 Incremental pricing vs. "Incremental Pricing": The Natural Gas Policy Act of 1978. In deliberations over the proposed Natural Gas Policy Act of 1978, "incremental pricing" has come to have a much different meaning. In this context, the term refers to a formula for allocating the *average* price of gas among certain categories of end uses or users. Strictly speaking, all gas purchasers would continue to face a "rolled-in" price in the sense that final prices would reflect the average of several different prices for gas from different sources. What would be new about this scheme would be the establishment of *two tiers* of such rolled-in prices. The higher cost of certain "incremental" supplies would be rolled-into only those prices faced by certain industrial users (up to a prescribed point), while households and other favored consumers would face a lower rolled-in price which did not reflect these higher costs. Once the higher of the two price tiers reached equivalence with the price of fuel oil, however, further cost increases resulting from higher prices for "incremental" supplies would be rolled into the prices faced by both classes of customers.

This "incremental pricing" scheme initially requires certain industrial gas users to pay higher prices than other consumers; later, these industrial gas users will pay lower prices than households and other high-priority consumers. It is impossible to forecast with any confidence just what the effect of this rule will be --- the result will depend on the whole array of expected volumes and prices for gas from various sources, the relative volumes of gas demanded by consumers in the two end-use classes, and above all, the way in which FERC interprets the law.

If the reader views all this as confusing and overly ingenious, so do the authors. Accordingly, we shall use the term incremental pricing cautiously, making it clear whether we are referring, for example, to the pricing of supplemental gas under a separate rate schedule or to a single rate schedule in which lower priority gas users pay higher rolled-in prices than other consumers. *The latter type of rate structure we will call an "inverted" or "ascending block" rate structure.* The first phase of the so-called incremental pricing rule of the pending Natural Gas Policy Act is only one of a number of conceivable inverted rate schemes; others that we shall consider briefly in this chapter are "lifeline" rates and "marginal cost" pricing.

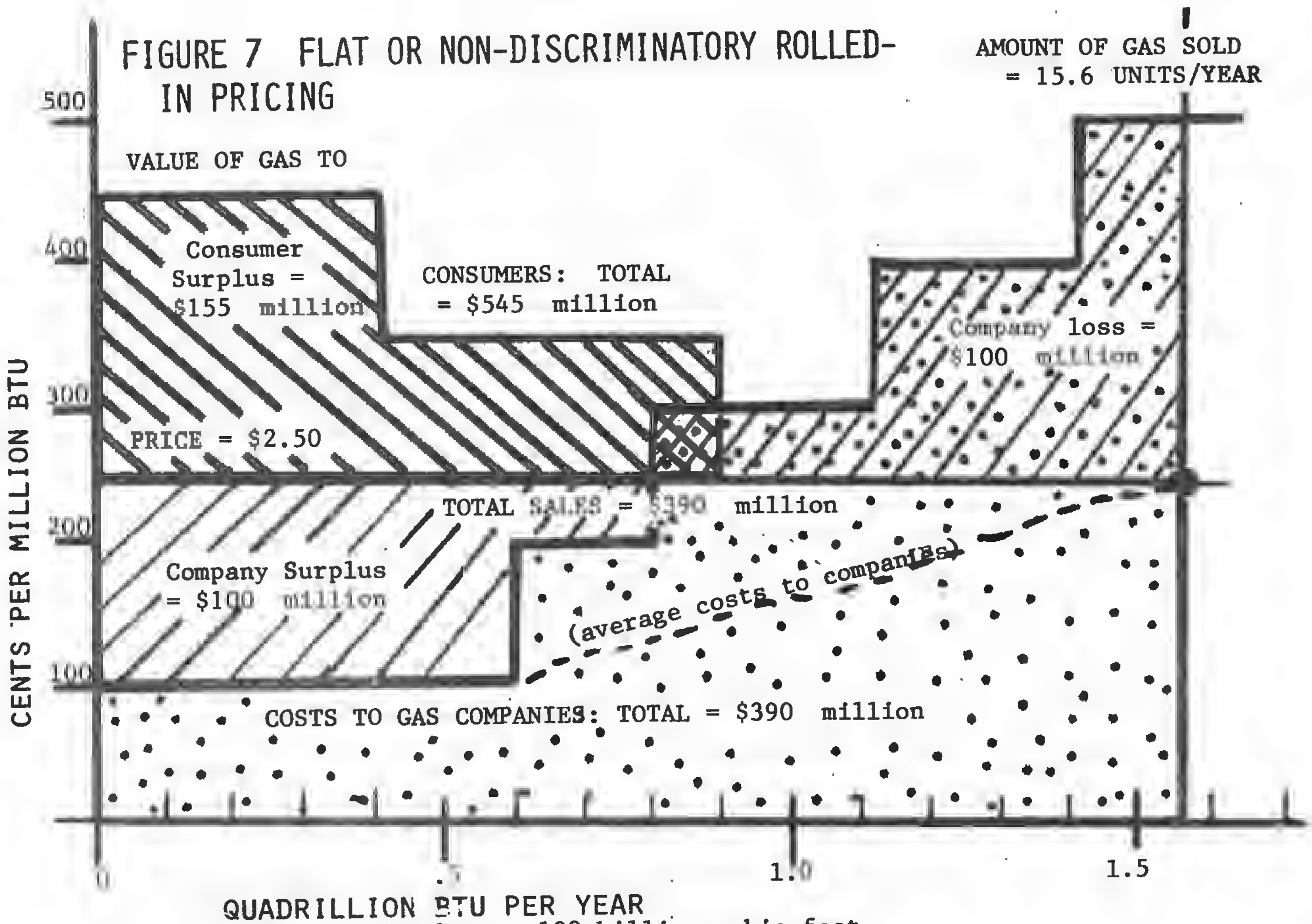
The following pages compare three ideal types of rate design for a regulated gas industry with one another and with the unregulated base case, namely (1) flat "non-discriminatory rolled-in" rates, (2) "value of service" rates, and (3) "inverted" rates.

4.7 Alternative rate structures

4.7.1 Flat or non-discriminatory rolled-in rates.

Figure 7 shows the case that most people have in mind when they speak of "rolled-in" pricing. There are a vast number of rules for allocating rolled-in costs among different

FIGURE 7 FLAT OR NON-DISCRIMINATORY ROLLED-IN PRICING



A unit is 100 trillion btu or 100 billion cubic feet

In this instance,		Compared to unregulated case...
The amount of gas sold is	15.6 units	6.6 units MORE
At an average price of	$2.50 / MM btu	$.50 / MM btu LESS
For total sales of	$390 million	$120 million MORE
The value of gas to consumers is	$545 million	$150 million MORE
The consumer surplus (value less price) is	$155 million	$45 million MORE
The cost of gas to the company is	$390 million	$260 million MORE
The net company surplus (sales less cost) is	-0-	$140 million MORE
The net national benefit (value less cost = consumer surplus plus company surplus) is	$155 million	$95 million LESS
Priority 1 consumers pay a price of	$2.50 / MM btu	$.50 / MM btu LESS
And have a surplus of	$60 million	$20 million MORE

Oil consumption is 330 mbd LESS

consumers or end users; we shall be more specific, however, using the term *non-discriminatory* rolled-in pricing. This is a system in which all consumers are charged a *flat rate* equal to the average cost of the gas needed to serve them. The supply line on the graph shows the cost of obtaining *additional supplies* for each supply category, and the upward sloping dotted line below it shows the *average cost* of total supply for any given level of sales. Regulated companies will seek to sell the largest volume of gas at which the *average* cost of all gas supplies is just equal to the price consumers are willing to pay for an additional unit. In Figure 7, this condition is fulfilled at a sales volume of 15.6 units per year. Total sales at this volume are $390 million (15.6 units at $2.50) and total costs are also $390 million (6 units at $1.00, plus 2 units at $2.00, 3 units at $4.00, and 1.6 units at $5.00).

All consumers pay an average price of $2.50 per mmbtu, which is $.50 less than in the unregulated case, and gain a surplus of $135 million (compared to $85 million). There is no company surplus because the central principle of utility regulation requires that revenues be no more than costs (including a specified return to investment). The net national benefit --- the contribution of this transaction to the real national income --- ($155 million) is less than it would have been without regulation ($225 million), because the additional gas demand created by rolled-in pricing costs the companies (and thus the national economy) more than the additional gas is worth to Priority 3 consumers, and more than those consumers would have been willing to pay for it had they been offered the gas in a separate transaction.

While a purely flat, non-discriminatory rate structure is very rare in the gas industry, a comparison of these two scenarios illustrates five crucial implications of rolled-in pricing generally:

(1) *In a competitive market, no commodity is normally sold whose cost is more than its value to the lowest priority consumer. This would also be the case even under regulation if the high-cost gas were offered to consumers under a separate rate schedule. With regulation and rolled-in pricing, however, the demand for gas can be "artifically" enlarged.*

In the example here, non-discriminatory rolled-in pricing would increase gas consumption by 6.6 units, or 73 percent over the unregulated case, all of which would be in the form of relatively high-cost supplements.

(2) *Rolled-in pricing "wastes" gas (which is presumably bad) but it "saves" oil (which is presumably good).*

If oil were the alternative fuel for all gas uses in the present example, rolled-in pricing would reduce oil consumption and oil imports by about 330 thousand barrels per day compared with the situation that would exist without regulation.

(3) *Consumers pay lower prices under non-discriminatory rolled-in pricing than they would in the absence of any regulation.*

In this example, the average price to consumers was reduced from $3.00 to $2.50 per mmbtu.

(4) *Rolled-in price regulation is less economically efficient than the hypothetical unregulated situation, because it encourages gas companies to acquire and sell some gas that costs more than consumers would pay for it if they had the choice.*

The loss of the company surplus more than offsets the increase in the consumer surplus.

(5) *To the extent that the greater consumer demand created by rolled-in pricing requires a larger rate base to serve it, regulated gas companies will have an interest in defending rolled-in pricing for high-cost gas supplements.*

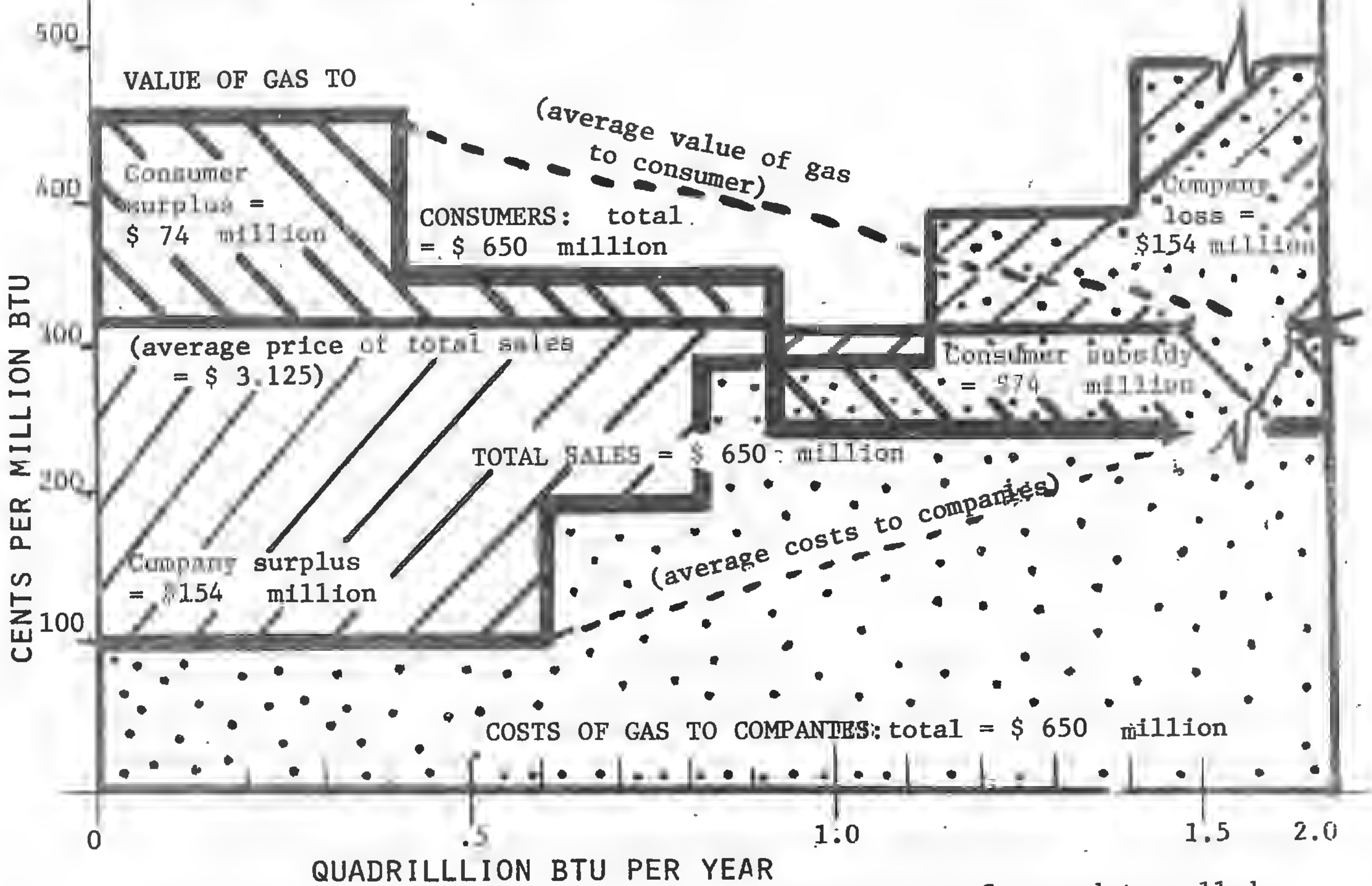
4.7.2 Value-of-service rates. Very few regulated industries operate in a completely non-discriminatory fashion, charging all categories of consumers the same price. Instead, a common principle in the design of utility rate structures is "value of service." This is the rule under which consumers who place a higher value on the goods or service are charged more than those who value it less. In unregulated industries, value-of-service pricing has uncomplimentary names such as price discrimination or "charging all the traffic will bear." Value of service, however, is a quite respectable rule in the design of transportation tariffs, and is also represented in the gas and electric industries by the conventional descending block rate structure whereby residential consumers pay the highest rates and interruptible industrial consumers the lowest.

Different rates for different consumer groups and end uses do not always harm those who are required to pay the higher rates; in some cases these consumers may actually benefit. For example, regulatory commissions have approved tariffs in which low prices are used to induce industrial customers who are able to burn other fuels to sign contracts under which their gas supply might be interrupted at any time. These "interruptible" contracts enable the gas company to divert gas to "firm" customers when demand is high, as in winter when space heating consumption is at its peak. As a result, the company can reduce its need to install costly storage facilities or purchase very high cost "peak shaving" gas like synthetic gas manufactured from naphtha. Nevertheless, high priority consumers (and all consumers as a group) will benefit from such discriminatory rate structures only where the savings from a higher "load factor" (the ratio of average to peak consumption) are actually used to lower rates across the board and *not* to subsidize the production or purchase of high-cost gas supplements which would have been unmarketable under a separate price schedule.

For purposes of comparison, we have used the term "value of service" here only to refer to the case in which the rate structure provides low priority consumers with gas at prices below its actual marginal cost. Figure 8 shows the operation of a value-of-service tariff taken to its extreme, in which each class of consumer is charged the highest price it is willing to pay. The value-of-service tariff must submit to the "revenue constraint," exactly as non-discriminatory rolled-in tariffs. That is, total sales revenues of the companies may not exceed their total costs, (Thus, average revenues may not exceed average costs). In contrast to non-discriminatory pricing, where each group of consumers is charged the single price at which average cost equals the value of the gas to the *lowest* priority consumers (Priority 3), the value-of-service principle charges Priority 1 customers the entire $4.50 they would be willing to pay for gas, and Priority 2 customers are charged the entire $3.50 they would be willing to pay, and so on.

Value-of-service pricing uses the additional revenue generated by "exploiting" the highest priority groups to "cross-subsidize" sales of supplemental gas (which costs $3.00, $4.00 and $5.00 per mmbtu) to Priority 3 consumers who are not willing to pay more than $2.50. Total revenue to the companies is greatest in this case, as cross-subsidization enables purchasers to pay for 20.8 units of

FIGURE 8 VALUE OF SERVICE RATES



A unit is 100 trillion btu or 100 billion cubic feet.

In this instance,		Compared to rolled-in pricing ...
The amount of gas sold is	20.8 units	5.2 units MORE
At an average price of	$ 3.125 / MM btu	$ .725 / MM btu MORE
For total sales of	$ 650 million	$ 260 million MORE
The value of gas to consumers is	$ 650 million	$ 105 million MORE
The net consumer surplus (value less price) is	-0-	$ 130 million LESS
The cost of gas to the companies is:	$ 650 million	$ 260 million MORE
The net company surplus (sales less cost) is	-0-	SAME
The net national benefit (value less cost = consumer surplus plus company surplus) is	-0-	$ 130 million LESS
Priority 1 consumers pay a price of	$ 4.50 / MM btu	$ 2.00 / MM but MORE
And have a surplus of	-0-	$ 80 million LESS

Oil consumption is 260 mb/d LESS

supply per year.

The average price to consumers as a whole would be 72.5 cents per mmbtu higher with value-of-service pricing than with non-discriminatory rolled-in pricing, and 12.5 cents per mmbtu higher than in the unregulated case. Priority 1 consumers would pay $2.00 per mmbtu more than with non-discriminatory rolled-in pricing and $1.50 more than they would pay in an unregulated industry. With value-of-service rates, there is no consumer surplus at all, because the surplus Priority 1 and 2 customers might have gained under a non-discriminatory pricing rule is used up subsidizing the delivery of high-cost gas supplements to Priority 3 consumers. An industry totally committed to value-of-service pricing thus would make no contribution at all to the real national income because the total cost of gas would be just equal to its total value.

The example here is an extreme case but it does validly illustrate several important implications of the traditional declining block rate structure for natural gas:

(6) *Value-of-service pricing rules, such as those in conventional declining block tariffs, create the*

largest possible "artificial" market for gas.

The 20.8 units per year of gas demanded in Figure 8 are one-third more than would be demanded with a non-discriminatory rolled-in price structure, and more than twice the amount in the unregulated base case.

(7) *Value-of-service pricing is the pricing mechanism most "wasteful" of gas but it "saves" the most oil.*

If oil were the only alternative fuel, value-of-service pricing would reduce oil consumption by 260 thousand barrels per day relative to non-discriminatory rolled-in pricing and by 590 thousand barrels per day compared to the unregulated base case.

(8) *Consumers as a group pay much higher prices under value-of-service pricing then with non-discriminatory rolled-in pricing, higher even than in an unregulated industry. This is particularly the case for high priority consumers.*

(9) *Value-of-service pricing is <u>totally</u> inefficient from a national economic standpoint as defined pre-*

viously, using up all of the potential net economic benefits in order to pay people to consume gas that they would not buy if they were charged its actual cost.

(10) *Regulated gas companies have historically used modified value-of-service pricing rules, and can be expected to defend them vigorously, because a larger consumption volume requires a larger rate base.*

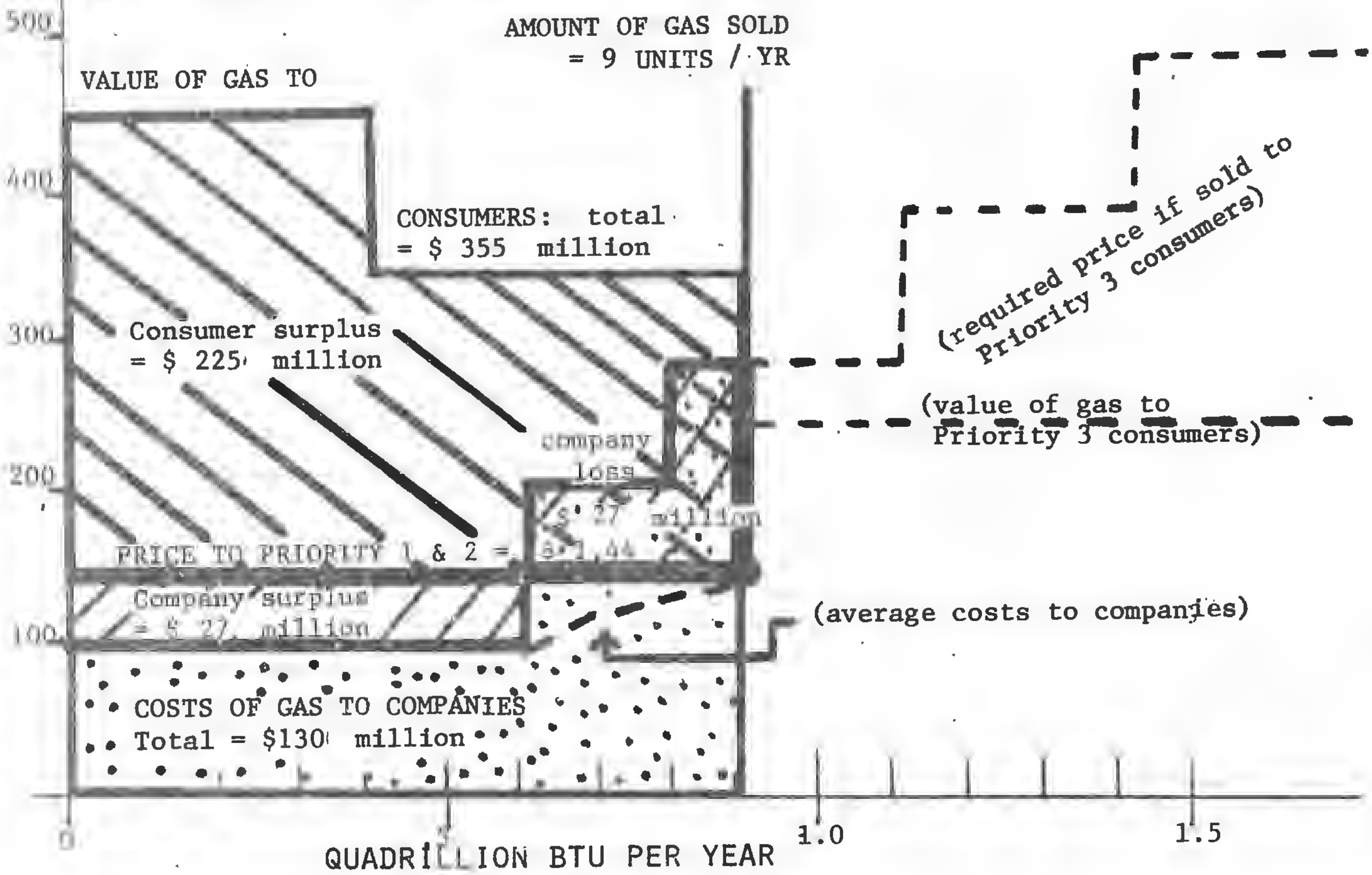
This motive is intensified by the fact that the high-cost gas supplements which could not be marketed under other arrangements tend to be relatively capital-intensive, meaning a larger rate base and thus greater company earnings per btu.

4.7.3 Inverted or ascending block rates. It is possible for a regulated industry to operate under pricing rules designed to simulate the incentives for conservation and efficiency that would exist in a competitive market, yet which transfer the potential company surplus to consumers in the form of lower rates. The term "incremental pricing" has been applied to certain of these schemes; what they have in common is that the lowest priority consumer groups (the "incremental" consumers) are required to pay higher rates than other gas users. Essentially, this approach "inverts" the order of price discrimination among consumers that would exist under a value-of-service rule.

Figure 9 shows the operation of one such rule. In this example, the demands of Priority 1 and 2 consumers are met first, and the costs of all the gas needed to serve them are rolled-in. The high priority consumers thus are charged a price that is equal to the lowest attainable average cost for the quantity of gas that they consume. Priority 3 consumers, however, are required to pay the full price for any additional high-cost gas that is required to meet their needs. The effects of this rate schedule are about the same as under one in which the higher cost components of supply are offered under a separate schedule.

In the present model, the inverted pricing rule results in consumption of the same gas volumes (.9 units) having the same total costs ($130 million) as in an unregulated market. Here again, Priority 3 consumers would not consume gas at all, because they could obtain oil at a lower price than the cost of the additional gas necessary to serve them. Thus, the demand for high-cost gas supplements would be minimal.

FIGURE 9 INVERTED OR ASCENDING BLOCK RATES



A unit is equal to 100 trillion btu or 100 billion cubic feet.

<u>In this instance,</u>		<u>Compared to value-of-service ...</u>
The amount of gas sold is	9 units	11.8 units LESS
At an average price of	$ 1.444 / MM btu	$ 1.68 / MM btu LESS
for total sales of	$ 130 million	$ 520 million LESS
The value of gas to consumers is	$ 355 million	$ 300 million LESS
The consumer surplus (value less price) is	$ 225 million	$ 225 million MORE
The cost of gas to the compan	$ 130 million	$ 520 million MORE
The net company surplus (sales less cost) is	-0-	SAME
The net national benefit (value less cost= consumer surplus plus company surplus) is	$ 225 million	$ 225 million MORE
Priority 1 consumers pay a price of	$ 1.44 / MM btu	$ 3.06 MM btu LESS
And have a surplus of	$ 183 million	$ 183 million LESS

Oil consumption is 59 mb/d MORE

Average consumer prices are lower with these ascending block rates than with the other rate structures. In this example, the average price is $1.44 per mmbtu, $1.06 less than with non-discriminatory rolled-in pricing. The net national benefit is the same as in the unregulated industry, but the inverted rate structure eliminates the company surplus. The potential surplus is instead passed on to high-priority consumers in the form of lower prices.

Again, we have chosen to illustrate an extreme form of inverted rate structure, but its general implications are clear:

> (11) *A strict ascending block pricing rule would limit demand to about the same level as would be expected from an unregulated market; in other words, no gas would be sold that costs more than it is worth to low-priority consumers.*

In the Figure 9 example, the inverted pricing rule makes all supplemental gas unmarketable except about .1 unit of Canadian or Mexican imports. Consumption is only 58 percent of what it would be under non-discriminatory rolled-in pricing and 43 percent of what could have been sold with a value-of-service tariff.

(12) *Inverted rate structures are exceptionally effective in conserving gas; conversely, they encourage the consumption of more oil than the other regulated cases.*

In the present instance, ascending block rates could result in oil imports of 260 thousand barrels per day more than non-discriminatory rolled-in pricing and 590 thousand barrels more than with value-of-service pricing.

(13) *Consumers as a group and high-priority consumers in particular pay the lowest prices under inverted rate structures.*

An ascending block rate structure could theoretically be designed to preserve the entire potential contribution of gas sales to the real national income, while transferring this benefit to high-priority consumers in the form of lower rates, rather than to the gas industry as company surplus.

(14) *Ascending block prices are economically the most efficient rate design for a regulated gas industry*

because they do not create a market for gas that costs society more than it is worth to consumers.

(15) *Regulated gas companies can be expected to oppose a shift to any kind of inverted rate structure, because it would limit demand and particularly the demand for those high-cost, capital-intensive investments which make the greatest relative contribution to their rate base.*

As we noted earlier, the "incremental pricing" concept in the Natural Gas Policy Act of 1978 is only one approach to the design of inverted or ascending block rate structures. Other approaches are "lifeline" rates and "marginal cost" pricing.

4.7.4 <u>"Lifeline" rates</u>. The "lifeline" concept of gas or electric rate design flows from the notion that low-income or other "needy" households consume less energy than other consumers and that they are less willing or able to conserve energy as a response to higher prices. The utility allocates to each customer in these preferred classes a quota of gas or electricity representing the quantity required to maintain some minimum standard of living, at a "lifeline" rate lower than the average rate to all consumers.

Recent studies of lifeline rates cast considerable doubt on the premise that such rates result in a progressive redistribution of income; nevertheless, they do impart some upward tilt to the rate structure. By making all categories of consumers -- including low income households -- pay higher rates for each unit of consumption in excess of their "lifeline" quotas, lifeline rate schemes are a partial offset to the "value of service" elements which may exist elsewhere in the rate structure, and would be likely to encourage *some* conservation and fuel substitution.

Accordingly, we can expect gas companies to oppose such innovations, and their position is probably explained better by the demand-limiting influence of lifeline rates than by any fallacies they have discovered in the welfare theories behind such rates.

4.7.5 Marginal cost rates. Like "incremental pricing" and "lifeline" rates, the term "marginal cost pricing" denotes a number of different ratemaking proposals. The words "marginal" and "incremental" are just about interchangeable -- they both refer to the *change* in some variable such as cost, product, or revenue, caused by (resulting from, or associated with), *a one-unit change* in some other variable like output, input, or sales. Thus, marginal cost is the change in cost associated with a one-unit change in product; marginal product is the change in product associated with a one unit change in some input, marginal revenue is the change in revenue associated with a one unit change in sales, etc.

"Marginal" is the term preferred by economists; "incremental" seems to be preferred by almost everybody else. It would be a reasonable guess that a "marginal cost pricing" scheme was proposed by an economist, while an "incremental pricing" proposal is one invented by a lawyer or an engineer.[5] In general, marginal cost pricing proposals are ones in which all consumers pay a price per incremental or "marginal" unit equal to the cost of adding another unit of supply. Conversely, these proposals would reward each

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5. One more concept is "replacement cost" --- this term may be the favorite in the petroleum producing industry. It is argued, for example, that <u>old</u> oil should be priced not on the basis of "historical cost" but at its <u>replacement</u> cost, that is, the cost of <u>new</u> domestic supply or the price of imports (whichever is higher). It is the latter (not the "sunk costs" of past investment) which represents the real resource burden that the consumption of old oil imposes on society. The reader can see that this concept and its policy rationale are almost identical with their "incremental" and "marginal" counterparts.

consumer for conserving gas or electricity by a reduction in his bill equal to the full cost of the energy.

This marginal cost pricing condition could be fully satisfied only if all categories of consumers faced a flat rate equal to the unit cost of the most expensive element of supply -- a situation which is closely approached in our hypothetical unregulated case. But a flat marginal cost rate would be inconsistent with a major principle of public utility regulation -- the revenue constraint -- as it would allow industry to capture large company surpluses.

In practice, any marginal cost pricing scheme that meets the revenue constraint must allocate rights to any old, low-cost supplies among different consumers or classes of consumers in a more-or-less arbitrary way; such an allocation will inevitably involve some compromises that depart from strict marginal cost pricing. In any event, marginal cost pricing is the goal of a number of proposed rate designs, each of which involves an ascending block rate structure, and each of which would substantially restrict demand relative to a flat or descending block (value-of-service rate) structure.

4.7.6 <u>Incremental pricing" once again</u>. No consensus yet exists about the meaning, implications, or even the intent of the "incremental pricing" provisions of the Natural Gas Policy Act of 1978. It is safe to speculate that not more than a handful of members of the Congress -- if that many -- understood how Title II of the Act was expected to work. The following, much simplified, is our understanding of the legislation:

The law requires FERC and the state commissions to establish two tiers of rolled-in gas prices. The upper tier will apply to industrial boiler fuel uses of gas (other than by electric utilities) and to other industrial uses determined by FERC. The lower tier will apply to residential, commercial, institutional, agricultural, electric utility, and the balance of the industrial uses of gas.

At the beginning, all gas costs above a given "threshold level" (in most cases, \$1.48 per mmbtu plus inflation) attributable to "incrementally priced" gas --- which includes "new" and "high cost" natural gas, LNG and other natural gas imports, and certain costs of Alaska natural gas --- are to be rolled into the upper tier price only. (The legislation is silent on the treatment of synthetic gas and domestic

LNG.) Other gas costs would be rolled into both upper and lower tier prices. Initially, lower tier consumers would thus be protected from the brunt of natural gas price increases, which would be directed mainly against certain categories of industrial uses.

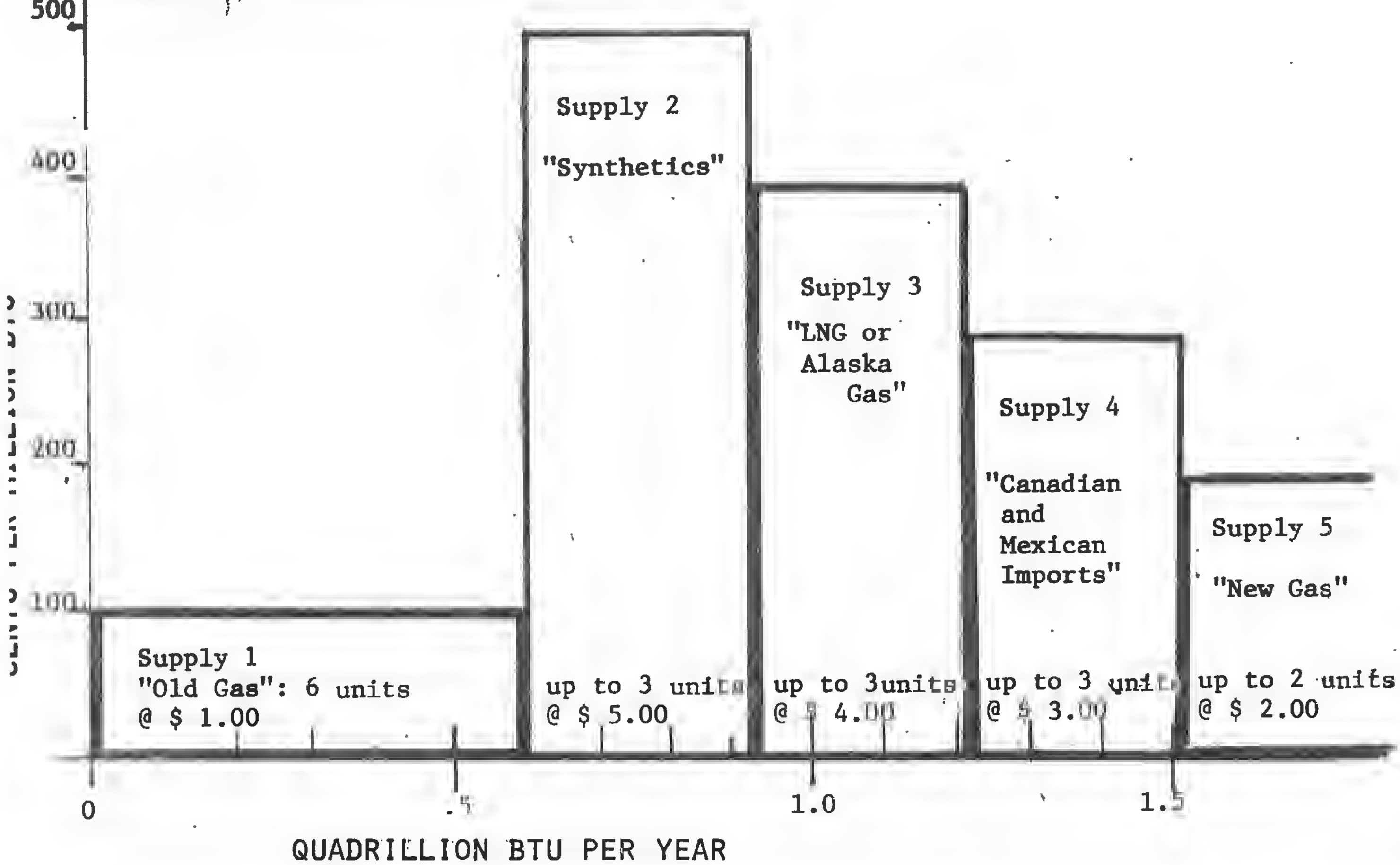
Once this formula had increased the upper tier price to an equivalence (on a btu basis) with the price of an alternate industrial fuel designated by FERC (the law allows FERC to designate any price between that of No. 6 oil and that of No. 2 oil), the upper tier price would be frozen at that level, and all additional cost increases attributable to the "incrementally priced" gas would now be rolled-into the lower tier price. Presumably, this process will continue until the lower tier price exceeds the price charged upper tier consumers; thus residential, commercial, institutional, etc., consumers would pay higher prices than industrial. In other words, the upper tier would become the lower, and *vice versa*.

Hence, at the outset, "incremental pricing" is an *inverted rate scheme* that can be expected to induce gas conservation and fuel switching *away from gas* in the industrial sector, while it delays the impact of higher gas prices on households and other politically reactive consumers. Low prices will encourage these consumers *to switch to gas* and to *use more gas*, thereby "upgrading" loads and enlarging the captive market for gas before the second phase of the incremental pricing rule takes effect, in which industrial gas prices stabilize and residential and commercial gas prices bear the entire burden of further increases in costs.

In this later phase, "incremental pricing" would rapidly transform itself into a *value-of-service* rule, whereby high prices to the less rate-sensitive classes of consumers (including the new markets captured while prices to these consumers were kept artificially low) could be used to subsidize --- and thus to create an artificial market for --- industrial consumption of gas.

If FERC (which has a broad range of discretion in implementing the new law) acts according to this interpretation, "incremental pricing" may reduce gas demand (and thus increase oil imports) in the short term, but over a longer period, it may be the means by which federal authority is used to *enforce value-of-service pricing nationwide*, and thus to expand greatly the market for natural gas supplements. If this is indeed the case, many members of Congress and the

FIGURE 10 HIGH COST SUPPLY STRATEGY



A unit is 100 trillion btu or 100 billion cubic feet.

public who believed that "incremental pricing" was a consumer protection measure --- and economists or engineers who believed that it would promote economic efficiency --- will be unpleasantly surprised. In any event, this view may explain why the regulated gas industry, which consistently opposed "incremental pricing" when it meant a separate rate schedule for supplemental gas, has generally supported the present legislation.

4.8 <u>Variations in supply strategies</u>. The three idealized rate designs in the preceding section were illustrated on the assumption that a regulated company would choose the same least-cost supply strategy that an unregulated gas company would select in order to maximize its profits. Actually, the incentive in regulated industries to minimize costs is often weak because companies have the most to gain by looking for the supply mix that maximizes their rate base, subject only to the condition that the goods or services produced by that rate base are marketable. The resulting supply mix is likely to be the least-cost case. Regulators, moreover, may take factors other than cost into consideration in deciding which supply projects to license.

Figure 10 presents an alternative supply scenario in which the order of preference is just the opposite of the least-cost assumption the authors have used in the previous sections. Except for "old gas," (to which we assume the companies are already committed in "take or pay" contracts), we have assumed that gas companies obtain the *most costly* supplies first, proceeding successively to less and less costly sources. The volumes and costs are the same as in Figure 5, except that synthetics, the supply category immediately after Number 1 ("old gas"), is limited to 3 units of at $5.00 per mmbtu, followed by 3 units of "LNG and Alaska gas" at $4.00, 3 units of "Canadian and Mexican imports" at $3.00, and 2 units of "new gas" at $2.00.

A strategy which is tantamount to seeking *maximum* costs may seem ludicrously unrealistic, but the reader might consider a world in which:

(a) Lawmakers and regulators would prefer consumers to pay cost-of-service prices for supplemental gas then to pay prices for domestic new gas which (although less than the cost of supplements) might create producer surpluses or "windfall profits" for oil companies;

(b) Regulated gas companies tend to prefer capital-intensive supplemental gas projects like coal gasification and Arctic pipelines over purchases of natural gas from oil companies or from Canada and Mexico, which require little new rate base;

(c) Regulators prefer synthetic gas to other gas supplements because they believe that synthetic gas technology should be developed for future use regardless of its short-term cost, as it is a potentially unlimited source of domestic energy; and

(d) Regulators prefer synthetic gas to Arctic pipelines and LNG, Arctic pipelines and LNG to Canadian or Mexican imports, and North American gas imports to Eastern Hemisphere oil imports, because they are concerned about the foreign exchange outlay per unit of energy.

The foregoing combination of motives and policies is entirely plausible and it could lead in the direction of a strategy like that of Figure 10, in which supply costs were maximized rather than minimized.

Thus, an analysis which assumes that companies and regulators choose something other than a least-cost gas supply strategy clearly has *some* relevance to today's decisions about investments in *new* supplies. A high-cost assumption corresponds *even more closely* to the decisions a company would make in *shedding or shutting-in excess supplies* in the event it overestimates demand volumes. Whether the higher-cost supplies are purchased from other firms on full cost-of-service or minimum-bill contracts, or incorporated into the company's own rate base, these costs would be wholly or mostly unavoidable. Instead of shutting in these supplies, therefore, the company would tend to postpone contracted deliveries of lower-priced conventional domestic or imported gas bought under "take or pay" contracts, which require current payments on a minimum-bill schedule, but allow the purchaser to take the same gas at a later date without any other penalty. This predictable behavior on the part of the companies could well contribute to the spiral collapse of demand described in Chapter III.

We have not presented the results of using a high-cost supply strategy graphically as we did for the low-cost strategy; but Table 1 summarizes the differences between the two strategies. for the three types of retail rate structures: non-discriminatory rolled-in, value-of-service and inverted rates.

TABLE 1 COMPARISON OF ECONOMIC IMPACTS OF ALTERNATIVE SUPPLY STRATEGIES AND PRICING RULES

	UNREGULATED BASE CASE	LEAST COST SUPPLY STRATEGY			HIGH COST SUPPLY STRATEGY			NEW GAS DEREGULATION (LEAST COST SUPPLY STRATEGY)					
								NO PRICE RESPONSE			HIGH PRICE RESPONSE		
		rolled-in pricing	value of service pricing	inverted pricing	rolled-in pricing	value of service pricing	inverted pricing	rolled-in pricing	value of service pricing	inverted pricing	rolled-in pricing	value of service pricing	inverted pricing
Gas demand (quads)	9.0	15.6	20.8	9.0	10.0	20.8	9.0	14.0	18.4	9.0	17.4	21.1	9.0
Sectors demanding gas	*P1,2*	*P1-3*	*P1-3*	*P1,2*	*P1-3*	*P1-3*	*P1,2*	*P1-3*	*P1-3*	*P1,2*	*P1-3*	*P1-3*	*P1,2*
New gas price per million btu	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$4.00	$5.00	$3.00	$3.84	$4.27	$3.00
Consumer price per million btu:													
Average	$3.00	$2.50	$3.125	$1.44	$2.50	$3.125	$2.33	$2.50	$3.20	$1.67	$2.50	$3.11	$2.00
Priority 1	$3.00	$2.50	$4.50	$1.44	$2.50	$4.50	$2.33	$2.50	$4.50	$1.67	$2.50	$4.50	$2.00
Priority 3	$3.00	$2.50	$2.50	na	$2.50	$2.50	na	$2.50	$2.50		$2.50	$2.50	na
Net consumer surplus	$85 million	$155 million	none	$225 million	$110 million	none	$145 million	$130 million	none	$205 million	$130 million	none	$175 million
Net company surplus	$140 million	none	none	none	none	none	none	none	none	none	none	none	none
Net national economic gain	$225 million	$155 million	none	$225 million	$110 million	none	$145 million	$130 million	none	$205 million	$130 million	none	$175 million
Oil savings: thousands of barrels per day	base case	330	590	none	280	590	none	250	470	none	500	600	none

The principal implications of this exercise are that:

(16) *A supply strategy other than the least-cost approach degrades efficiencies, and consumer and national benefits, in almost every direction.*

For non-discriminatory and inverted rate structures, a high-cost supply strategy results in a smaller consumer surplus and a reduced net national economic benefit. (There is no consumer surplus or net national benefit under a pure value-of-service rate in either case.)

(17) *Gas consumption and oil savings are lower in the high-cost strategy than in the least-cost strategy except with an inverted rate structure that makes all of the higher-cost supply components unmarketable under either supply strategy.*

4.9 Deregulation of wellhead prices for domestic new gas. For all the previous scenarios, the volume and cost assumptions for new domestic natural gas remained constant at 2 units and $2.00 per mmbtu respectively. However, there is a further variable to consider, deregulation of new conventional gas, which results in higher wellhead costs to the gas companies. Uncertainty regarding the responsiveness of new gas production to increases in wellhead prices complicates the analysis of the effects of deregulation.

For the purpose of projecting the order of magnitude effects of deregulation, this section compares the implications of two extreme assumptions; a zero supply response and a high supply response. If deregulation actually occurred, its effects would most likely fall somewhere between these two hypothetical cases.

With the first assumption of non-responsive supply, we have assumed that the volume of new domestic gas holds steady at 2 units regardless of the prices that result from deregulation. As ceilings are removed, prices become subject to market forces; they would adjust differently depending on the type of rate structure. In the instance of highly responsive supply, we have assumed a price elasticity of +2.0. This means that a 1 percent increase in wellhead prices would induce a 2 percent increase in production; a doubling of the price would increase supplies fourfold. Unlike the case of non-responsive supply, the volume of new domestic gas would respond to market forces along with its price.

In both cases, we have assumed a least-cost supply strategy in which gas companies purchase deregulated new gas only when and to the extent that a lower-cost supplemental supply is not available. The total volume of gas from all sources that would be sold if new conventional gas were deregulated is determined in the same way as with a fixed price for new gas. The volumes sold would be the volume at which the *average* price of gas equals:

(a) The *lowest value* of a unit of gas to any consumer who actually receives gas, under non-discriminatory rolled-in rates;

(b) The *average value* of a unit of gas to all consumers who receive gas, under value-of-service rates; and

(c) The *value of gas to the lowest priority* of consumer (Priority 2) who is not required to buy gas at an "incremental cost price" under inverted rates.

The implication of these rate structures under the two extreme responses to deregulation are compared in

Table 1. We can see from the table that the *relative* consequences of the three pricing rules remain the same whether or not new gas is deregulated. That is, value-of-service pricing still results in the greatest gas consumption and oil savings, the highest consumer prices, and the lowest economic efficiency. An inverted rate structure restricts gas consumption and maximizes oil consumption, but results in the lowest consumer prices and the greatest economic efficiency. Non-discriminatory rolled-in pricing falls between the two extremes with respect to all of its economic effects. Furthermore,

(18) *Deregulation of new gas prices reduces the ability of industry to market high-cost gas supplements through manipulation of price structures, but deregulation does not necessarily make all high-cost supplements unmarketable unless the supply response to deregulation is very strong.*

(19) *Deregulation, coupled with rolled-in pricing or value-of-service rates (but not inverted rates), result in a bidding of new gas prices up to levels substantially higher than the price of oil.*

However, in view of the regulated gas companies' preferences for building their rate base, it is unlikely that they would bid up prices for conventional natural gas to levels above what they would expect to pay for supplemental sources which carry added opportunities for rate-base expansion.

(20) *An inverted rate structure (for example, "incremental pricing") coupled with deregulation can be nearly as effective in protecting consumers as continued wellhead price controls.*

4.10 Summary and conclusions. The most important implication of the previous analysis is that rate design occupies the most crucial place in determining the amount of gas that can be sold. While the supply preferences of gas companies and regulators, and the regulation or non-regulation of domestic wellhead prices, also have substantial impacts on gas marketability, the key factor in every case seems to be where the authorized rate structure falls within the spectrum of possible utility pricing rules --- where, that is, between pure value-of-service pricing and pure marginal cost pricing.

In the previous illustrations, the choice of ratemaking principles alone varied the size of a hypothetical market for gas by a factor of two or more regardless of the assumptions we made about supply costs. This is a crucial point despite the improbability that the charges for gas transmission and distribution experienced by final consumers will ever reflect any one of the three idealized pricing systems in its pure form.

In addition to its effect on marketability, rate design wields a powerful influence over the net national benefit (as defined in strictly economic terms) and on the demand for imported oil. Yet it is clear that the use of rate design to achieve more than one national goal may be futile. For example, the use of value-of-service rates for gas would reduce U. S. consumption of imported oil. However, from the standpoint of consumer interest narrowly defined, or from a strict national economic benefit standard, value of service is a disaster. The opposite holds true for inverted rate design, and non-discriminatory rolled-in pricing falls somewhere in between.

CHAPTER V

THE OLD GAS SUBSIDY CUSHION

5.1 Introduction. Previous chapters of this report have shown that three crucial factors determine the marketability of a supplemental gas supply at any point in time: (1) the cost of alternative fuels to various consumer groups and for various end uses, (2) the volumes and costs of gas supplies to which the companies are already committed, and (3) the rate structures designed by the companies and approved by the regulatory authorities. Thus, as the costs of substitute fuels and the mix of existing supplies change over time, the amounts of additional gas that consumers would be willing to buy under a given rate structure also change.

Specifically, the amount of supplemental gas the market will accept at a given cost will tend to grow as (and if) the prices of oil-based fuels increase. At the same time, however, the ability of the gas industry to use rolled-in or value-of-service pricing to subsidize the sale of higher-cost gas diminishes as the reserves of lower-priced old gas are depleted. Thus, the uncertainty about the market for supplemental gas rests on three main issues:

(1) Will the prices of oil-based fuels be high enough that consumers would voluntarily buy the supplemental gas rather than some other fuel? In order words, would the project be viable if its gas had to be sold under a separate rate schedule or at an "incremental cost" price?

(2) If the cost of gas from such a project did in fact exceed the price of oil, would there be a big enough cushion of low-priced old gas left in the system to accommodate whatever subsidy the supplemental gas project needed to cover its costs?

(3) Assuming that an adequate cushion of low-price gas existed, would the prevailing laws and the policies of federal and state regulators permit sufficient rolling-in or value-of-service pricing to make good any potential revenue shortfall?

The answer to the first question regarding the prices of gas substitutes is reasonably clear. Base load supplies of Alaska natural gas, imported LNG and synthetics will *not* be marketable on a separate or inverted rate schedule unless the real prices of oil in world markets do rise substantially between now and the mid-life of the necessary investments.

The second question -- how large a potential subsidy will exist for high-cost gas supplements in the form of the old gas cushion -- does not lend itself to such a categorical answer. The size of the old gas cushion will vary among regions and companies, but it will generally reflect the remaining volume of old gas and its average price.

This chapter attempts a rough estimate of how much supplemental gas the old gas cushion could support in 1985 and 1990 under three assumptions about oil prices. Chapter VI considers the relation between the size of the old gas cushion, and the allocation of the capital costs of supplemental gas over time. The final chapter is devoted to the third issue -- what policies and regulatory measures might be adopted to assure the marketability of supplemental gas without imposing unacceptable risks on either industry or the public?

5.2 <u>The influence of shrinking or expanding total gas supply on the marketability of high-cost gas</u>. The potential subsidy cushion is and will continue to be made up almost entirely of old gas already flowing in interstate commerce.

On the other hand, the more capital-intensive portions of the supplemental gas supplies (such as LNG, Alaskan gas and the synthetics) will need support from this cushion. As the authors explained in the introduction to this report, the volumes and prices of gas sold within the major producing states, new interstate gas, and imports from Canada and Mexico are not likely to have much direct impact on either the size of the subsidy cushion or the need for it because, as a rule, their delivered prices will probably be close to the prices of petroleum fuels.

The total volume of conventional natural gas available from new sources (including the intrastate market and pipeline imports from Canada and Mexico) will, nevertheless, have a significant effect on the amount of higher cost supplemental gas for which a given volume of old gas can assure its marketability. If, on the one hand, the supply of new gas from conventional sources falls short of the amount necessary to offset the decline of old gas production, the role of high-cost gas supplements will simply be to replace established supplies. This circumstance has two important implications for the marketability of supplemental gas:

(21) *If total gas sales should continue to decline, the alternative fuel to gas for the marginal consumer is likely to be light (No. 2) fuel oil, and the value of gas to final consumers would be related to the retail price of fuel oil. Moreover, purely replacement supplies of gas would require no or little investment in new transmission and distribution facilities. As a result, the cost of supplemental gas to final consumers would be only slightly higher than cost of delivering it into the existing transmission network.*

(22) *If, on the other hand, new supplies of conventional continental natural gas are in themselves sufficient to offset the decline of production from established sources, high-cost supplements will have to compete with residual fuel oil at bulk rates in electric utility or industrial markets.*[9] *New supplies would, in addition, require new investments for transmission, storage and distribution, as well as for production facilities.*

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9. Abundant natural gas, able to displace residual fuel oil from utility and industrial markets, would tend to reduce the demand for residual oil (already in excess supply on the West Coast of the U. S. and in Eastern Canada) and thus widen the spread between distillate and residual fuel oil prices.

5.2.1 Demand price. As we pointed out in Chapter I, the average retail price of No. 2 fuel oil is currently almost twice the wholesale price of No. 6 oil -- a spread of $1.74 per mmbtu in May 1978. Part of this differential results from the operation of the crude oil entitlements system, and that factor can be expected to shrink somewhat in the future, but *the value of gas to the marginal consumer is nevertheless likely to vary by about $1.00 per mmbtu in 1978 dollars depending upon whether total gas supplies shrink or expand.*

5.2.2 Supply cost. If natural gas supplements are merely a replacement supply for existing gas users, they will have to bear little additional cost for investment in new transmission and distribution facilities. If these supplements are put on stream to serve new customers, however, new investment will be necessary and there is no reason to expect additional transportation, storage and distribution charges to be less than the current average ($1.02 per mmbtu in 1976). It is reasonable to suppose that *the cost of delivering supplemental gas to consumers will also very about $1.00 per mmbtu depending upon whether total supplies shrink or expand.*

(23) *Thus, with differences on the order of $1.00 per million btu in both the consumer value and the supply cost of supplemental gas, the consumer subsidy required to make Alaska gas, LNG or synthetics marketable can vary by as much as two 1978 dollars per mmbtu depending solely upon the availability of other gas supplies.*

5.3 <u>The size of the old gas cushion in 1985 and 1990</u>. The potential subsidy cushion for high-cost gas supplements will clearly shrink over time as the volume of "old gas" under low price contracts declines. In any given year, the cushion that regulated gas companies have for subsidizing gas that costs more than consumers would willingly pay is roughly equal to the volume of price-controlled old gas times the price spread between the average delivered cost of that gas and the delivered price of petroleum fuels.

5.3.1 <u>Shrinking total supply</u>. Table 2 illustrates how the size of the old gas subsidy cushion might be projected for 1985 and 1990 under conditions of shrinking total gas supplies and under three assumptions about future oil prices. On the supposition that industrial and utility consumption of gas will have been largely eliminated, we have assumed that No. 2 fuel oil at retail is the relevant

TABLE 2 EFFECT OF OIL PRICES ON THE OLD GAS SUBSIDY CUSHION
LOW TOTAL SUPPLY

	(1)	(2)	(3)	(4)	(5)	(6)
		Old Interstate Gas				
	Substitute fuel price (bulk -- low S No. 6 oil)	Volume produced (AGA)[h]	Wellhead price per mcf or mmbtu (AGA)[i]	Transport and distribution cost per mcf or mmbtu[j]	Final price per mcf or mmbtu (3) + (4)	Old gas subsidy cushion[k]
Case I: RISING REAL OIL PRICE[a]						
1976	$1.99[d]	11.1 tcf	$.44	$1.02	$1.46	$ 5.9 billion
1985	$6.54[f]	4.8 tcf	.53	1.25	1.78	22.8 billion
1990	$11.17[f]	2.9 tcf	.64	1.45	2.09	26.3 billion
Case II: STABLE REAL OIL PRICE[b]						
1976	$1.99[d]	11.1 tcf	$.44	$1.02	$1.46	$ 5.9 billion
1985	$4.93[e]	4.8 tcf	.53	1.25	1.78	15.1 billion
1990	$6.59[e]	2.9 tcf	.64	1.45	2.09	13.0 billion
Case III: FALLING REAL OIL PRICE[c]						
1976	$1.99[d]	11.1 tcf	$.44	$1.02	$1.46	$ 5.9 billion
1985	$3.28[g]	4.8 tcf	.53	1.25	1.78	15.1 billion
1990	$3.28[g]	2.9 tcf	.64	1.45	2.09	13.0 billion

Prices are in current nominal dollars.

Footnotes are at the end of this chapter.

substitute fuel. In each of the three cases, U. S. prices for petroleum are expected to reflect world market prices, either because oil price controls have ended or because Congress has imposed a differential excise tax on domestic oil among the lines of the crude oil equalization tax (COET) proposed by the President. In each case, we have assumed that the general price level increases at 5 percent per year.

In the *high-price case, real* oil prices increase at 2 percent annually through 1985 and then increase at 5 percent per year. (Thus, *nominal* oil prices would increase at 8.12 percent per year from 1978 to 1985, and 11.3 percent per year between 1985 and 1990.

In the *intermediate case, nominal* oil prices just keep pace with U. S. inflation at 6 percent per year; and in the *low price case,* the nominal or current dollar price of fuel oil is assumed to remain at the 1978 level, effecting a 6 percent annual decline in its real price.

Each year's volumes and average prices for old gas are the wellhead prices reported in productions of the American Gas Association (AGA), plus a flat $1.02 per mmbtu for transmission and distribution charges, which is the average figure reported by the AGA in the 1976 volume of <u>Gas Facts</u>. (We have assumed that this latter part of the consumer price of gas remains level in nominal dollars on the premise that shrinkage of the existing transmission and distribution company rate base offsets about half of the increases in costs resulting from (1) rises in variable costs and (2) from the fixed costs of investment in new storage facilities, new customer connections, etc.) The 1976 actual and 1985-1990 projected prices of oil that we used in each case are shown in column 1, and the volumes and delivered prices of old gas are those in columns 2 and 5 respectively.

The old gas cushion which could be used to cover the excess costs of gas supplements by means of non-discriminatory rolled-in pricing is equal to the volume of old gas multiplied by the difference between the delivered prices of old gas and the price of distillate fuel oil. This cushion, shown in column 6, is the additional revenue residential and small commercial consumers would "willingly" pay in order to keep getting gas rather than switch to another fuel. What happens to the size of this cushion depends powerfully on the course of oil prices. *In the high oil price case, the potential subsidy more than doubles between 1976 and 1990,* *while in the low oil price case, the cushion shrinks by more than two-thirds during the same period. (The intermediate case reflects an inconclusive trend.)*

5.3.2 Stable or increasing total supply. Table 3 repeats the calculations of Table 2 but on the assumption -- a more likely one, we believe -- that total gas supply will be great enough between now and 1990 that the marginal consumer is still an electric utility or an industrial user of gas who would be able to burn low sulfur residual oil if gas were too expensive or unavailable. Accordingly, in this table, we have assumed that the substitute fuel price remains $1.00 per mmbtu (in 1978 prices) lower that the retail price of No. 2 fuel oil. With stable constant-dollar prices for oil, these assumption yield an old gas cushion that is much smaller than in the low supply case illustrated in Table 2. Here, the 1990 cushion is trimmed by more than half compared to Table 3, and if the increase in oil prices lags behind inflation and hence declines in real terms, the cushion would virtually disappear by 1990.

5.4 Estimating the market for supplemental gas. The subsidy (i.e. old gas cushion) needed to market a million btu of supplemental gas is approximately equal to the

TABLE 3 EFFECT OF OIL PRICES ON THE OLD GAS SUBSIDY CUSHION
HIGH TOTAL SUPPLY

	(1)	(2)	(3)	(4)	(5)	(6)
	Substitute fuel price (Retail No. 2 oil)	Old Interstate Gas: Volume produced (AGA)[h]	Old Interstate Gas: Wellhead price per mcf or mmbtu (AGA)[i]	Transport and distribution cost per mcf or mmbtu[j]	Final price per mcf or mmbtu (3) + (4)	Old gas subsidy cushion
Case I: RISING REAL OIL PRICE[a]						
1976	$1.99[d]	11.1 tcf	$.44	$1.02	$1.46	$ 5.9 billion
1985	$5.04[f]	4.8 tcf	.53	1.25	1.78	15.6 billion
1990	$9.16[f]	2.9 tcf	.64	1.45	2.09	20.5 billion
Case II: STABLE REAL OIL PRICE[b]						
1976	$1.99[d]	11.1 tcf	$.44	$1.02	$1.46	$ 5.9 billion
1985	$3.43[e]	4.8 tcf	.53	1.25	1.78	7.9 billion
1990	$4.58[e]	2.9 tcf	.64	1.45	2.09	7.2 billion
Case III: FALLING REAL OIL PRICE[c]						
1976	$1.99[d]	11.1 tcf	$.44	$1.02	$1.46	$ 5.9 billion
1985	$2.21[g]	4.8 tcf	.53	1.25	1.78	2.1 billion
1990	$2.21[g]	2.9 tcf	.64	1.45	2.09	.3 billion

Prices are in current nominal dollars.

Footnotes are at the end of this chapter.

difference between its delivered price and the delivered price of the type of fuel oil that the marginal consumer could substitute for it, No. 2 or No. 6 oil as the case may be. The maximum volume of gas that could be subsidized by means of rolled-in pricing can therefore be estimated by dividing the necessary subsidy per unit into the total old gas subsidy gas cushion. Tables 4 and 5 show how much supplemental gas would be from a mix of sources which would have had an average cost of $4.00 per mmbtu in 1978.

The assumptions of Table 4 are the same as those of Table 2 -- (1) that supplemental gas enters the distribution system as a replacement for declining supplies of conventional gas, (2) that the substitute fuel for the marginal consumer is home heating oil at retail prices, and (3) that little or no new investment in transmission, storage or distribution facilities is required to deliver the added gas.

The assumptions of Table 5 are the same as those of Table 3 -- (1) that conventional domestic gas and pipeline imports are available in such abundance that supplemental gas can serve new markets, (2) that the substitute fuel for the marginal consumer is therefore low sulfur residual oil

TABLE 4 EFFECT OF OIL PRICES ON MARKET FOR $4.00 (1978) SUPPLEMENTAL GAS LOW TOTAL SUPPLY

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Old gas Subsidy Cushion[d]	Substitute fuel price (retail price of No.2 fuel oil)[d]	Cost of supplemental gas: Variable cost per mmbtu[e]	Fixed cost per mmbtu[e]	Transport & distribution cost per mmbtu[e]	Total gas price per mmbtu	Market for supplemental gas[f] (1-6)+(2)
CASE I : RISING REAL OIL PRICES[a]							
1976	$13.2 bil	$ 2.92	$1.78	$1.78	$.26	$3.82	14.6 tcf
1985	22.8 bil	6.54	3.45	2.46	.46	6.37	unlimited
1990	26.3 bil	11.17	5.80	2.82	.61	9.23	unlimited
CASE II: STABLE REAL OIL PRICES[b]							
1976	$13.2 bil	$ 2.92	$1.78	$1.02	$.26	$3.82	14.6 tcf
1985	15.1 bil	4.93	3.01	2.46	.46	6.37	10.4 tcf
1990	13.0 bil	6.54	4.02	2.82	.21	9.23	6.6 tcf
CASE III: FALLING REAL OIL PRICES[c]							
1976	$13.2 bil	$ 2.92	$1.34	$1.78	$.26	$3.82	14.6 tcf
1985	7.2 bil	3.21	3.01	2.46	.46	6.37	2.3 tcf
1990	3.5 bil	3.21	4.02	2.82	.61	9.26	.8 tcf

Footnotes to this table are at the end of the chapter.

TABLE 5 EFFECT OF OIL PRICES ON MARKET FOR $4.00 (1978) SUPPLEMENTAL GAS HIGH TOTAL SUPPLY

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Old gas Subsidy Cushion[d]	Substitute fuel price (price of No.2 fuel oil)[d]	Cost of supplemental gas: Variable cost per mmbtu[e]	Fixed cost per mmbtu[e]	Transport & distribution cost per mmbtu[e]	Total gas price per mmbtu	Market for supplemental gas[f] (1-6)+(2)
CASE I : RISING REAL OIL PRICES[a]							
1976	$ 5.9 bil	$1.99	$1.78	$1.78	$1.02	$ 4.58	2.3 tcf
1985	15.6 bil	5.04	3.45	2.46	1.49	7.40	6.6 tcf
1990	20.5 bil	9.16	5.80	2.82	1.83	10.45	15.9 tcf
CASE II: STABLE REAL OIL PRICES[b]							
1976	$ 5.9 bil	$1.99	$1.78	$1.02	$1.02	$ 4.58	2.3 tcf
1985	7.9 bil	3.43	3.01	2.46	1.49	6.96	2.2 tcf
1990	7.2 bil	4.58	4.02	2.82	1.83	8.67	1.8 tcf
CASE III: FALLING REAL OIL PRICES[c]							
1976	$ 5.9 bil	$1.99	$1.34	$1.78	$1.02	$ 4.58	2.3 tcf
1985	2.1 bil	2.21	3.01	2.46	1.49	6.96	.4 tcf
1990	.3 bil	2.21	4.02	2.82	1.83	8.67	.0 tcf

Footnotes to this table are at the end of the chapter.

at bulk prices, and (3) that delivery of supplemental gas requires new investments in transmission, storage and distribution facilities.

Under the highest of the three assumptions about oil prices, (Case I) rolled-in pricing could easily create a market for great volumes of supplemental gas if total gas supplies declined so rapidly as to phase out industrial and electrical utility consumption of gas. It appears, indeed, that just about any volume of supplemental gas produced at $4.00 per mmbtu in 1978 dollars would be marketable under these circumstances even on the separate rate schedule variety of incremental pricing. Moreover, if new domestic natural gas and pipeline imports only replaced part of the declining supply of old gas (in other words, if its demand does not depend on electric utility or industrial boiler fuel markets), it appears that rolled-in pricing would enable the old gas subsidy cushion to support as much as 6.6 trillion cubic feet of $4.00 supplemental gas in 1985 and 15.9 trillion cubic feet in 1990 -- considerably greater volumes than are presently projected by the most optimistic advocates of supplemental gas projects!

If petroleum prices were to remain stable in constant dollars (Case II), however, the picture changes drastically. In the low total supply case, $4.00 supplemental gas could not be marketed on a separate rate schedule, but rolling in its costs with the price of old gas would still provide plenty of market backstopping. The market for supplemental gas could be 10.4 tcf in 1985 and 6.6 tcf in 1990. If gas supplies from conventional sources were to increase, however, the old gas cushion could provide an effective market guarantee for only 3.3 tcf of high-cost supplements in 1985 and 1.8 tcf in 1990.

If the prices of petroleum did not keep pace with general inflation, the tables suggest that supplemental gas sources with a cost of $4.00 in 1978 dollars would be in trouble *whatever the supply of conventional gas*. In our low supply case, rolling in the costs of $4.00 supplemental gas could shelter 2.3 tcf of $4.00 gas in 1985 and only 800 billion cubic feet in 1990 -- just about the projected production from the main reservoir at Prudhoe Bay! In the high supply case, it appears that the old gas cushion would be virtually ineffective in either year as a marketing aid for supplemental gas!

5.5 <u>Summary</u>. This chapter has suggested that the future volume of conventional natural gas supplies (including continental imports) and the cost of substitute fuels are both highly uncertain. At one plausible extreme, a virtually unlimited quantity of $4.00 gas (in 1978 dollars) could be sold in 1985 or 1990 even on a strictly incremental price basis. At the other extreme -- which in our judgment is equally plausible -- such gas would be virtually unmarketable even with the help of rolled-in pricing. This possibility obviously creates a painful level of uncertainty for industry and government decision makers contemplating the "need" and wisdom of taking action now which will determine the volumes of high cost gas in 1985 and 1990.

Granted, some of the assumptions that went into these calculations were both simplistic and arbitrary. We might have made more sophisticated projections of the volumes and prices of old gas, the range of actual costs for different kinds of supplemental gas, the mix and prices of supplemental fuels, and transportation and distribution costs. A complex computer model of the gas industry might have replaced the simple arithmetic by which we projected the size of the old gas cushion and the amount of high-cost gas sales it could subsidize. These "improvements" surely would have produced somewhat different numbers, *but we do not* *believe that they would have changed the following conclusions in any way:*

(24) *It is very unlikely that gas from Alaska, synthetics or new LNG import projects will be saleable in the 1980's at an "incremental cost" price, and there is some risk that such gas could not be sold even under a "rolled-in" pricing rule --- at least under the non-discriminatory rule people usually have in mind when they refer to rolled-in pricing.*

Nevertheless, if the sponsors of supplemental gas projects can obtain their planned project financing if the gas is sold under tariffs with "cost of service" and the other protections, and if Congress and the FERC were to permit or require the interstate transmission companies to roll-in the costs of supplemental gas with the cost of all other gas, these projects might well come to fruition even *if their net benefits to consumers and the nation were negative.* Marketing problems, nevertheless, could cause financial distress or disaster later, *somewhere* in the gas industry if even not for the project sponsors themselves or for their lenders.

These conclusions return us to the policy dilemma we identified in Chapter II. Uncertainty about the future availability and price of conventional fuels -- particularly imported oil -- is the main reason for going ahead with large gas supply investments whose products will have a real cost greater than today's prices for substitute fuels. Yet because of the same uncertainty, it is likely that none of the concerned private parties -- transmission companies, lenders, distribution companies or consumers (to the extent they are represented by an educated Congress and state utility commissions which likewise have thought through the implications) -- will voluntarily accept the financial risks of these investments.

In the calculations that led to these judgments, we made one crucial assumption about ratemaking in the gas industry -- an assumption whose relaxation might help resolve the dilemma. We assumed that the capital cost of the new facilities would be amortized or depreciated in the conventional way -- at a more-or-less even rate over the life of those facilities.

The following chapter considers other less conventional rules for allocating fixed capital costs over time and concludes that FERC probably could -- if it had the will -- guarantee the marketability of gas from all the supplemental gas projects now under active consideration *without resorting to value-of-service rate design, without federal loan guarantees, and without imposing unacceptable financial risks on the distribution companies.*

NOTES FOR TABLE 2

a) Constant dollar annual oil price increases 2 percent between 1978 and 1985; 5 percent between 1985 and 1990; general inflation is 6 percent per year. (Nominal prices increase at 8.12 and 11.3 percent respectively.)

b) Constant dollar oil price remains stable between 1978 and 1990; general inflation is 6 percent per year.

c) Nominal oil price remains stable between 1978 and 1990; general inflation is 6 percent per year.

d) Average retail price of No. 6 oil, 0.0 to 0.3 percent sulfur, $12.55 per barrel; source: Monthly Energy Review.

e) Case II 1985 and 1990 prices are AGA "substitute fuel" price, assuming 6 percent annual increase in the nominal price; source: American Gas Association, Energy Analysis, (April 8, 1977).

f) Case II 1985 and 1990 price figures adjusted to reflect case I assumptions --- see note (a).

g) Case II 1985 and 1990 price figures adjusted to reflect case III assumptions --- see note (c).

h) Source: AGA, loc. cit.

i) Ibid.

j) 1976 difference between average U.S. wellhead price ($0.58) and gas utility average sales price ($1.60), increased at 3 percent per year.

NOTES FOR TABLE 3

a) through (d) Same as for table 2.

e) through (g) Substitute fuel prices from table 2, less $1.00 (in 1978 dollars)

e) through (j) Same as for table 2.

NOTES FOR TABLE 4

a) through (c) Ame as for table 2.

d) Average seller price of residential heating oil, 40.3 cents per gallon; source: Monthly Energy Review.

e) The cost of supplemental gas delivered into the existing distribution system is assumed to be $4.00 per mmbtu in 1978 dollars, composed in equal parts of (1) raw materials (such as Alaska natural gas at the wellhead; LNG, FAS the exporting country; and coal or oil delivered to synthetic gas plants), plus operating and maintenance costs (column 3), and (2) fixed costs (column 4). The former are deemed to increase in the same proportions as the price of substitute fuels, or at the 6 percent rate of gerneral inflation, whichever is greater. Fixed costs are projected on the assumption that an equal investment in 1978 dollars is made in each year beginning in 1978, and that the charges for each year's investments are "levelized", so that the fixed charge per mmbtu in (say) 1985 is *an average* of the various years' current dollar equivalents of $2.00 in 1978 dollars. Distribution costs are estimated as follows: The 1976 average of $1.02 per mmbtu as assumed to be composed of one-fourth variable costs and three-fourths fixed costs. It was assumed that no addition to fixed costs was required to carry and distribute supplemental gas, so no allowance was made for added fixed costs; variable costs, however, increase at 6 percent per year along with general inflation.

NOTES FOR TABLE 5

a) through (c) Same as for table 2.

d) Same as for table 4.

e) The cost of supplemental gas was calculated on the same basis as in Table 4, on the assumption that the 1978 cost would have been $4.00 per mmbtu delivered into the existing transmission and distribution system. Additional investments in transmission, storage and distribution are required, however, and their costs are projected from the 1976 average of $1.02 per mmbtu. Again, this figure was divided into one fourth variable costs projected as for table 4, and three-fourths fixed costs, projected as an average of annual inflated values equal to $.765 in 1976, for each year beginning in 1978

CHAPTER VI

RATE PROFILES: THE ALLOCATION OF FIXED COSTS OVER TIME

6.1 Introduction. The most important theme of Chapter IV was the crucial place which rate design occupies in determining the amount of gas that can be sold. While the supply preferences of gas companies and regulators and the decision whether or not to regulate domestic wellhead price also influence gas marketability, the key factors seem to be (1) the cost of substitute fuels and (2) where the authorized rate structure falls within the spectrum of possible utility pricing rules --- where it falls, that is, between pure value-of-service pricing and a strictly inverted rate structure.

In Chapter IV's illustrations, the choice of ratemaking principles alone varied the size of the market for gas by a factor of two or more, regardless of the assumptions we adopted about supply costs. There we considered rate "structure" as the allocation of costs among different uses and classes of consumers. This chapter considers the implications of different rate "profiles" -- the allocation of costs over time.

Just as there are a host of different possible rules for allocating gas costs among different end uses and users, all consistent with the public utility "revenue constraint," there are also an unlimited variety of possible rules for allocating the fixed costs of a supplemental gas producing or transport facility over its productive life. Any of these rules may also be made consistent with the revenue constraint and, like the choice of rate *structures*, the choice among rate *profiles* can have a powerful effect on the marketability of supplemental gas in a world where prices for substitute fuels are changing and the old gas subsidy cushion is shrinking over time.

6.2 Conventional utility rate profiles: straight-line depreciation. The most common formula actually used to recover the fixed costs of utility investments requires construction costs and the interest and return to equity incurred before the date on which the facility goes into service to be "capitalized." The sum of direct capital outlays and the interest and return accrued during construction together determine the facility's "rate base" as of that date. Prices or tariffs include a "depreciation" charge that amortizes this rate base in equal annual installments over the anticipated project life; the depreciation allowance drops abruptly to zero at the end of the period because the original investment has been paid off. This is the "vanishing rate base" phenomenon to which we alluded earlier.

As depreciation of the utility's original equity over a nominal accounting life of (say) 20 years steadily reduces its "book value," the amounts a company is allowed to include in its charges for interest and for return to equity also decline in a straight-line, again falling to zero at the end of the project's accounting life (even if the facility remains in service for many more years). If production or throughput remains the same, therefore, the charge for "return of" and "return to" capital for each unit of gas produced or transported tends to decline over time. Unless "variable" costs for operations and maintenance rise more than enough to offset this decline in fixed costs, the result is a steadily declining price per unit.

Table 6 shows the profile of such a tariff for a facility with a $1 billion original cost, incurred at the rate of $200 million per year over 5 years of construction. For simplicity, we have not separated the original investment into equity and debt; we assume that the regulators allow a 12 percent annual return to debt and equity capital combined.

TABLE 6 CONVENTIONAL TARIFF PROFILE: STRAIGHT-LINE DEPRECIATION OF FIXED COSTS

YEAR OF SERVICE	(1) CONST- RUCTION COSTS	(2) 12 % RETURN DURING CONST- RUCTION	(3) YEAR END RATE BASE	(4) ANNUAL STRAIGHT LINE DE- PRECIA- TION --- 20 YEARS	(5) 12 % RETURN ON RATE BASE	(6) TOTAL FIXED COSTS (5 + 6)	(7) FIXED COSTS PER MMBTU	(8) VARIA- BLE COSTS PER MMBTU	(9) TOTAL GAS PRICE PER MMBTU
	$mil	$mil	$mil	$mil	$mil	$mil	(56.7 trillion btu per year)	(6% in- flation)	
-5	200								
-4	200	24.0							
-3	200	50.0							
-2	200	81.0							
-1	200	114.7	1270.6						
1			1207.1	63.5	152.5	216.0	$3.81	$1.00	$4.81
2			1143.5	63.5	144.8	208.4	3.68	1.06	4.74
3			1080.0	63.5	137.2	200.8	3.54	1.12	4.66
4			1016.5	63.5	129.5	193.1	3.41	1.19	4.60
5			953.0	63.5	122.0	185.5	3.27	1.26	4.53
6			889.4	63.5	114.3	177.9	3.14	1.34	4.48
7			825.9	63.5	106.7	170.3	3.00	1.42	4.42
8			762.4	63.5	99.1	162.6	2.87	1.50	4.37
9			698.8	63.5	91.5	155.0	2.73	1.59	4.32
10			635.3	63.5	93.8	147.4	2.60	1.68	4.28
11			571.8	63.5	76.2	139.8	2.47	1.79	4.26
12			508.2	63.5	68.6	132.1	2.33	1.90	4.23
13			444.7	63.5	61.0	124.5	2.20	2.01	4.21
14			381.2	63.5	53.4	116.9	2.06	2.13	4.29
15			317.7	63.5	45.7	109.3	1.93	2.26	4.29
16			254.1	63.5	38.1	101.6	1.70	2.40	4.20
17			190.6	63.5	30.5	94.0	1.66	2.54	4.20
18			217.1	63.5	22.9	86.4	1.52	2.69	4.21
19			63.5	63.5	15.3	78.8	1.39	2.85	4.24
20			0.0	63.5	7.6	71.2	1.26	3.03	4.29
21			0.0	0.0	0.0	0.0	$0.00	$3.21	$3.21

Costs are current nominal dollars.

Thus, construction costs plus this 12 percent return would total $1,270.6 million at the time they entered the rate base. If the facility's accounting life were set at 20 years, the rate base would be depreciated in 20 equal annual installments of $63.6 million. A 12 percent annual rate of return would then be allowed on the rate base remaining after each year's depreciation.

The sum of depreciation charges and the allowed return to capital constitute the facility's total "fixed costs." Fixed costs per mmbtu are calculated by dividing total fixed costs by an assumed annual output of 56.7 million btu of gas energy per year.[7] "Variable" costs (purchased gas, LNG or coal, labor, fuel, etc.) are $1.00 per mmbtu in the first year increasing annually at the 6 percent rate of general inflation. The sum of fixed and variable costs is an average cost of service beginning at $4.82 per million btu in the first year, falling to $4.20 in the 14th to 17th year and increasing again to $4.29 in the 20th year of service. In view of the fact that these prices are in current dollars, the constant dollar price charged to consumers under this rate design would fall by about 70 percent between the first and twentieth year.

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7. The authors chose this output figure arbitrarily in order to give a 1978 total cost of $4.00 per mmbtu in the levelized capital charge scenario.

6.3 Levelized capital charge rate profiles. Alternative formulas might be designed in which the same fixed charge per btu would be levied in each year over the design life of the facility in order to recover the original capital and cover earnings on it. Such an amortization schedule would be like that of a home mortgage, where in the early years the level payment consists mainly of interest, with contributions for repayment of principal increasing over time so that the sum of the two remains the same in each year. Table 7 shows one such scheme. Under the same construction and variable cost assumptions as the example in Table 6, a tariff that levelized fixed costs would charge customers $170.1 million per year in order to cover both the amortization of the original investment and a 12 percent return to remaining undepreciated capital over 20 years. With a steady output of 56.7 trillion btu per year, this capital charge would remain at $3.00 per million btu throughout the 20 years. Adding variable costs (beginning at $1.00 per mmbtu in 1978 and increasing with inflation at 6 percent per year) will raise the total price from $4.00 per mmbtu in the first year to $7.03 in the 20th year. At a general inflation rate of 6 percent per year, consumers would pay declining real prices in this case too, but constant dollar prices would fall by only 50 percent over the 20 years in

TABLE 7 LEVELIZED FIXED-COST TARIFF PROFILE

YEAR OF SERVICE	(1) CONST-RUCTION COSTS	(2) 12 % RETURN DURING CONST-RUCTION	(3) YEAR END RATE BASE	(4) IMPUTED DERRECI-ATION *(6)-(5)*	(5) 12 % RETURN ON RATE BASE	(6) LEVEL-IZED FIXED COST	(7) FIXED COSTS PER MMBTU	(8) VARIA-BLE COSTS PER MMBTU	(9) TOTAL GAS PRICE PER MMBTU
	$mil	$mil	$mil	$mil	$mil	$mil	(56.7 trillion btu per year)	(6% in-flation)	
-5	200								
-4	200	24.0							
-3	200	50.0							
-2	200	81.0							
-1	200	114.7	1270.6						
1			1253.0	17.6	152.5	170.1	3.00	1.00	4.00
2			1233.2	19.8	150.4	170.1	3.00	1.06	4.06
3			1211.1	22.1	148.5	170.1	3.00	1.12	4.12
4			1186.3	24.8	145.3	170.1	3.00	1.19	4.19
5			1158.6	27.7	142.4	170.1	3.00	1.26	4.26
6			1127.5	31.1	139.0	170.1	3.00	1.34	4.34
7			1092.7	34.8	135.3	170.1	3.00	1.42	4.42
8			1053.7	39.0	131.1	170.1	3.00	1.50	4.50
9			1010.0	43.7	126.4	170.1	3.00	1.59	4.59
10			961.1	48.9	121.2	170.1	3.00	1.68	4.69
11			906.3	54.8	115.3	170.1	3.00	1.79	4.79
12			845.0	61.3	108.8	170.1	3.00	1.90	4.90
13			776.3	68.7	101.4	170.1	3.00	2.01	5.01
14			699.3	77.0	93.2	170.1	3.00	2.13	5.13
15			613.1	86.2	83.9	170.1	3.00	2.26	5.26
16			516.6	96.5	73.5	170.1	3.00	2.40	5.40
17			408.5	108.1	62.0	170.1	3.00	2.54	5.54
18			287.4	121.1	49.0	170.1	3.00	2.69	5.69
19			151.8	135.6	34.5	170.1	3.00	2.85	5.85
20			0.0	0.0	18.2	170.1	3.00	3.03	6.02
21			0.0	0.0	0.0	0.0	0.00	3.21	3.21

contrast to the 70 percent decline under the conventional cost recovery procedures of Table 6.

A more elaborate form of capital cost "levelization" is sometimes advocated to take into account expected variations in output or throughput over the life of a facility. A gas pipeline may be built primarily to serve a single field, whose production is expected to build up from zero as the field is developed, reach a peak in (say) the fourth year, remain at this peak level for five years, and then decline gradually as gas pressures are depleted. Simply levelizing *total* fixed costs would result in a tariff with very high (and perhaps unacceptable) rates in the first few years of production build-up and in the latter years of production decline.

One way to mitigate these problems would be to assign the same depreciation charge to each unit (e.g., mcf) of throughput. This charge at any time would simply be the value of the remaining rate base at that time, divided by the remaining number of units in the reserves dedicated to the pipeline. Such a rule is called a "units of production" depreciation schedule. Even more elaborate cost levelization schemes exist, requiring more complicated formulas, to make the *total* fixed charge per unit (depreciation *plus* return) remain stable or nearly so in the face of varying outputs or throughputs.

6.4 <u>Fully indexed and escalating rate profiles</u>. It is conceivable that rate-making rules could be designed so that recovery of a gas project's capital cost could track the course of general inflation rather accurately, resulting in a level chage per unit in *constant* dollars. Because financing of gas supply projects must be arranged without certain knowledge of future inflation rates, however, the practical difficulties of building a perfectly indexed utility rate profile -- without either violating the revenue constraint or changing the accounting life of the facility in midstream -- are probably insurmountable. Oil pipeline rates regulated by the Interstate Commerce Commission have been partly indexed by the use of a rate base ("valuation") that reflects replacement cost as well as original cost. Even with a more conventional public utility rate base definition, however, tariff profiles could be designed in which capital recovery charges *increase* at a predetermined rate over the life of the facility; that rate of increase might be set to equal the *expected* rate of inflation.

6.5 <u>Front-end loaded rate designs.</u> In contrast to the levelized and indexed rate designs, which *offset* the tendency of conventional rate making to allocate a disproportionate share of a project's fixed costs to its early years of service, there are other designs that would accentuate this "front-end load." At one extreme, construction costs could be treated as current expenses to be recovered from consumers as they are incurred, so that rates (after the project went into service) would need to be only high enough to recover variable costs. Short of this extreme, there are two relatively respectable rate design approaches that would shift a larger share of capital costs forward in time than with conventional straight line depreciation.

One such device is to treat investment in unfinished facilties -- construction work in progress (CWIP) -- as part of the rate base. Instead of keeping a separate account for new facilities and adding their construction costs plus accumulated interest to the rate base only when the facility goes into service, these outlays could be included in the rate base as soon as they are incurred, so that the return to CWIP is added to consumers' current bills.

Another effective means of moving recovery of fixed

TABLE 8 FRONT-END LOADED TARIFF PROFILE

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(9)
YEAR OF SERVICE	CONST-RUCTION COSTS	12 % RETURN DURING CONST-RUCTION	YEAR END RATE BASE	DECLIN-ING BAL-ANCE DEPRE-CIATION AT 10%	12 % RETURN TO RATE BASE	TOTAL FIXED COST	FIXED COST PER MMBTU	TOTAL GAS PRICE PER MMBTU
	$mil	$mil	$mil	$mil	$mil	$mil		
-5	200					0		
-4	200	24				24.0	∞	∞
-3	200	48				48.0	∞	∞
-2	200	72				72.0	∞	∞
-1	200	86	1,000.0			96.0	∞	∞
1			900.0	100.0	120.0	220.0	$3.88	$4.88
2			810.0	90.0	108.0	198.0	3.49	4.55
3			729.0	81.0	92.2	178.2	3.14	4.26
4			656.1	72.9	87.5	160.4	2.82	3.80
5			590.5	65.6	78.7	144.3	2.54	3.80
6			531.4	59.0	70.9	129.9	2.29	3.63
7			478.3	53.4	63.8	116.9	2.06	3.44
8			430.5	47.8	57.4	105.2	1.86	3.36
9			387.4	43.0	51.7	94.7	1.67	3.26
10			348.7	38.7	46.5	85.2	1.50	3.18
11			313.8	34.8	41.8	76.7	1.35	3.14
12			282.4	31.4	37.7	69.0	1.22	3.12
13			254.2	28.2	33.9	62.1	1.10	3.11
14			228.8	25.4	30.5	55.9	.99	3.12
15			205.9	22.9	27.4	50.3	.89	3.15
16			185.3	20.6	24.7	45.3	.80	3.20
17			166.8	18.5	22.2	40.8	.72	3.26
18			150.1	16.7	20.0	36.7	.65	3.34
19			135.1	15.0	18.0	33.0	.58	3.43
20			121.6	13.5	16.2	29.7	.52	3.55
21			109.4	12.2	14.6	26.7	.47	3.68

costs forward in time is by accelerating the depreciation schedule. Table 8 shows the effect of using both of these measures, namely treating the return on CWIP as a current expense and the use of a declining balance depreciation schedule, under which each year's depreciation allowance is 10 percent of the remaining rate base (and thus 10 percent less than the previous year's depreciation allowance). The resulting charges for both depreciation and return to capital start at relatively high levels and decline exponentially over the design life of the facility. Consumers -- the customers of transmission companies who have contracted to buy gas from the project -- begin paying the fixed costs of the new gas supply as part of their regular gas bills *even before it goes into service.* In this illustration, therefore, the consumer cost per unit of gas from the project is "infinite" during its first four years. The cost of service for gas actually delivered to consumers, however, declines from $4.88 per mmbtu in the first year of service to $3.11 in the thirteenth and rises again to $3.55 in the twentieth year. With 6 percent annual inflation, this is a fall of 76 percent in constant dollar terms.

Table 9 compares the tariffs resulting from the three types of rate profiles illustrated previously. With the

TABLE 9 COMPARISON OF SUPPLEMENTAL GAS PRICES IN SELECTED YEARS: VARIOUS TARIFF PROFILES

YEAR OF SERVICE	TYPE OF TARIFF PROFILE: CONVENTIONAL	LEVELIZED CAPITAL CHARGE	FRONT-END LOADED
	CURRENT DOLLARS PER MMBTU		
-1	$ .00	$ .00	∞
1	$4.82	$4.00	$3.88
6	4.49	4.4	3.63
11	4.27	4.79	3.14
20	4.29	6.02	3.55
21	3.21	3.21	3.68
	CONSTANT DOLLARS OF YEAR 1 (6% ANNUAL INFLATION)		
-1	$ .00	$ .00	∞
1	$4.82	$4.00	$4.88
6	3.36	3.14	2.71
11	2.38	2.67	1.75
20	1.42	1.99	1.17
21	1.00	1.00	1.14

values we assumed for the examples (an initial 3 to 1 ratio of fixed to variable costs) all three types result in declining real costs over time, but there is a substantial range of difference among them.

6.6 <u>A strategy to assure marketability</u>. In the emerging climate of relative oil and gas abundance, however temporary it may be, supplemental gas projects will have to be authorized and financed under present authority including the terms of the Natural Gas Policy Act of 1978. Congress at present (and predictably into the future) refuses to authorize taxpayer guarantees for supplemental gas -- with the exception of a few *demonstration* coal gasification plants. But if the national Administration and FERC believe that LNG, coal gasification and the Alaska Highway gas pipeline would be cost-effective in the long run and are strategically necessary, FERC's discretion over rate profiles may give it sufficient authority to assure that gas from such projects would be marketable. This strategy would sidestep the danger pointed out in Chapter III, that gas distributors might be crushed between inflexible, high-cost gas purchase obligations and a declining market.

The chief means to accomplish these ends would be for

FERC to authorize financing and tariffs for supplemental gas projects with the heaviest "front-end load" that would meet the legal test of reasonableness. Such tariffs would include CWIP in project rate bases, and depreciation charges themselves would be computed by the double declining balance method on the basis of the shortest acceptable accounting life.

This approach is, of course, based upon the assumption that any marketability problem would come *later* in a project's life rather than now. Granted, both the official stance of the federal government and the expectations of most project sponsors are that the world price of oil will increase, allowing high-cost gas to be marketed. But it is the undeniable *possibility* that prices may not increase which creates the market risk; meanwhile the only certain marketing guarantee -- the "cushion" low-priced old gas -- is vanishing year by year.

Tables 2 and 3 in Chapter V projected a total old gas cushion of $5.9 billion in 1976 and a range of $2.1 to $22.8 billion in 1985, depending on what happens to world oil prices and conventional gas supplies. Table 10 is derived from these projections; it suggests that $17 to $87 billion

TABLE 10 CUMULATIVE VALUE OF THE OLD GAS CUSHION: 1979-1985

(10 percent annual inflation)

YEAR OF SERVICE	VALUE OF OLD GAS CUSHION WITH LOW CONVENTIONAL GAS SUPPLY			VALUE OF OLD GAS CUSHION WITH HIGH CONVENTIONAL GAS SUPPLY		
	RISING OIL PRICE	CONSTANT OIL PRICE	FALLING OIL PRICE	RISING OIL PRICE	CONSTANT OIL PRICE	FALLING OIL PRICE
BILLIONS OF CURRENT DOLLARS						
1979	9.3	8.1	6.3	8.2	6.5	4.2
1980	10.7	9.0	6.4	9.1	6.7	3.7
1981	12.5	9.9	6.6	10.1	6.9	3.3
1982	14.5	11.0	6.7	11.3	7.2	3.0
1983	16.8	12.3	6.9	12.6	7.4	2.6
1984	19.6	13.6	7.0	14.0	7.7	2.3
1985	22.8	15.1	7.2	15.6	7.9	2.1
TOTAL	106.2	79.0	47.1	80.9	50.3	21.2
BILLIONS OF CONSTANT 1978 DOLLARS						
1979	8.8	7.6	5.9	7.7	6.1	3.9
1980	9.5	8.0	5.6	8.1	5.8	3.3
1981	10.5	8.3	5.5	8.5	5.8	2.8
1982	11.2	8.7	5.3	8.9	5.7	2.4
1983	12.6	9.2	5.2	9.4	5.5	1.9
1984	13.8	9.6	4.9	9.8	5.4	1.6
1985	15.1	10.0	4.8	10.4	5.3	1.4
TOTAL	81.5	61.4	37.2	62.8	39.6	17.3

(1978 dollars) could conceivably be raised from consumers *above and beyond the prices they will pay for conventional gas supplies* in the years 1979 through 1985, for the purpose of financing new supplemental gas projects. The lower end of the range represents the old gas cushion that would exist over the seven year period if oil prices did not increase even in current dollars, and if new conventional gas supplies were sufficient to offset the decline in production from established sources. Even in this conservative case, rate base treatment of CWIP and the use of accelerated depreciation could *prepay* all of the capital costs for the Alaska Highway gas pipeline and buy three or four LNG or coal gasification projects. In any of the five other scenarios, the old gas cushion that will exist between 1979 and 1985 could easily prepay the capital costs of *every* supplemental gas project under active consideration today. Tariff schedules could be arranged, in other words, which required consumers to pay only the variable costs of the projects, beginning as early as 1986.

Even short of such an extreme front-end tilt -- which would not be necessary in any case -- the quick amortization of debt would in itself make any of the proposed facilities more attractive to lenders. Equally important, the rapid shrinking of project rate bases would sharply reduce prices after the first few years, when the ability of the old gas cushion to assure marketability through rolled-in pricing is more doubtful.

If carried out forcefully, such a regulatory strategy by FERC might stir opposition from consumer advocacy groups, members of Congress, and state commissions. Resistance from outside of the federal Administration to rate increases implemented today for the sake of an assured supply of energy in the future will reflect, among other things, public doubts about the Administration's assessment of the future, but that problem is unavoidable with any long-term policy initiative based upon belief in an imminent energy crisis.

CHAPTER VII

REFLECTIONS ON REGULATION

7.1 Policy tradeoffs and uncertainty. Throughout this paper, we have assumed that the most crucial decisions relating to supplemental gas supplies would be made by government -- from overall supply strategies, through certification decisions and the design of rate structures, and finally, to consideration of consumer or taxpayer guarantees. With respect to each of these issues, the "right" course of action does not become apparent simply by fine-tuning supply and demand forecasts or even by conducting more rigorous marketability tests. Instead, it is ultimately grounded on the policy makers' perceptions of the need for supplemental gas in the first place.

As we pointed out in Chapter II, there is very little inherent consumer need or demand for gas *per se*. The demand for gas is essentially a demand for energy, and is determined largely by the price of gas relative to other fuels. Thus, forcing consumers to pay for high cost gas may not, in fact, be in their best interest.

The need for supplemental gas, instead, can be measured only against a variety of separate (and often competing) national goals. Does the nation need supplemental gas as a political response to offset its vulnerability to OPEC or Middle Eastern politics, or as an economic response to a chronic foreign exchange deficit? Is gas to be preferred over oil, even at a higher price per unit of heating value, because of its relatively low impact on air quality? Or is there a need for additional gas only so long as it can be delivered at a price at or below that of available alternate fuels? And if the justification is a combination of all these values, which of them takes priority and at what expense to the others in deciding to certify supplemental projects, attach public loan guarantees, approve rate structures, etc.?

Such policy judgments are difficult enough to make in light of present uncertainties and political realities, but they become particularly painful in light of the irreversible consequences of certain federal decisions. Financing these massive LNG, Alaskan, or coal gasification projects requires commitment of private capital for 20 years or more --- in turn requiring that federal actions with respect to tariff conditions, rate design, and government debt guarantees be set beforehand and likewise remain intact (or at least become no less favorable) for the same length of time. Thus, the policy basis for making such public commitments should be expected to remain tolerably acceptable to the industry and the public for a good many years as well.

It is interesting to note that certain other high-cost gas supplies, for example, Canadian and Mexican pipeline imports, do not carry quite the same public risks and commitments. At present, neither Canada nor Mexico *wants* to extract long-term purchase agreements from U. S. companies; U. S. plant additions (and the consequent need to amortize investment) would be minimal; and the U. S. government is not forced to make any unusual commitments beforehand, granting favorable rate structures or public guarantees.

Perhaps, the most critical task now is for federal officials to meet these policy questions head on -- to use marketability analyses and supply and demand projections in assessing how a variety of federal responses might work toward or go against a host of national goals; and, in light of the best guesses about an uncertain future, to make some hard choices as to the relative importance of each objective.

Our previous chapters concluded that projects that would deliver base-load supplemental gas at real costs substantially higher than the current cost of fuel oil make sense from a consumer or national interest standpoint only on the assumption that imported oil will be more costly in real terms and/or its supply less reliable in the early years of project operation than it is today. Because the projected cost of gas from different supplemental sources will vary widely, the future prices of oil and the availability of cheaper conventional gas will determine which proposals (if any) are economically desirable and which are not.

The central problem for industy and government alike is uncertainty. All of the proposed gas supply projects are capital intensive; they would take two to seven years to build, and then would require fifteen, twenty or more years of profitable operation to justify the original investment. Cost estimates for large, custom-engineered projects are notoriously imprecise, and no one can confidently project the real price of crude oil or the availability of conventional natural gas (including pipeline imports from Canada and Mexico) ten years hence. In light of this uncertainty, policy-makers must consider the consequences of encouraging supplemental projects that later prove to be "unneeded", (that is, if less costly or more desirable fuels are plentiful) or, worse yet, prove unmarketable somewhere along the chain of buyer - seller transactions. Likewise, the adverse effects of inhibiting -- or failing to encourage -- the development of supplemental gas sources must be weighed: What if cheaper fuels or fuels that more closely conform to national goals are *not* adequate to meet the volume of U. S. energy needs? And in light of an ever-growing need for a limited supply of capital, the nation as a whole has a stake in the wisdom of private as well as public investment decisions.

7.2 Once more on incentives in a regulated industry. If the gas industry were not a regulated industry, those investors who were most optimistic about their ability to control costs and about future markets would gamble their own money on the basis of their judgments about costs and future markets, raising only as much debt as lenders felt would be safe under the worst plausible combination of cost overruns and market collapse. The owners' risk of loss or (what is just about the same thing) a less than adequate rate of return to equity, would be balanced by the hope of "abnormally" high returns if everything went well.

Public utility-type regulation changes all of this:

Owners are forbidden a rate of return exceeding a "just and reasonable" level, usually reflecting some kind of *average* return in long-term capital markets. In compensation for giving up the hope of an exceptionally high return, investors are given exceptional protection --- freedom from competition, and an assurance that tariff adjustments can be used to cover unforeseen costs or inadequate demand and thereby to achieve a fair and reasonable return. Moreover, regulation awards a high degree of immunity from the consequences of private misjudgment or mismanagement.

Since the gas industry is in fact highly regulated, we cannot know for certain how much risk capital would be available for investment in supplemental gas projects in the absence of regulation, what rates of return equity investors would aim for as compensation for their risks, and what debt ratios lenders would demand. We do know, however, that the uncertainty about costs and future market prices for gas, and the total investment required in an LNG system or coal gasification facility, is not overwhelmingly greater than for a new automobile factory, chemical plant, oil refinery or frontier drilling program --- ventures in which hundreds of millions of dollars of corporate equity are routinely invested without any governmental assurance of markets or profits.

7.3 Why regulation? In choosing to regulate the gas industry, government has taken upon itself three kinds of decisions that capitalist economics usually leaves along with their consequences to private entrepreneurs. These are (1) the decision whether or not to go ahead with a project; (2) control of its construction and operating costs; and (3) determination of prices and terms of service.

It is easy to understand why most local gas companies are regulated as public utilities. Distribution of gas to homes and businesses is an example of "natural monopoly", in that it would not be efficient to have more than one local gas company competing for customers in the same service area. Where competition is either impractical or prohibited, an unregulated gas distributor could impose on consumers all the classic evils of monopoly exploitation --- excess capacity, restricted service and supplies, overpricing, and discrimination.

The same rationale applies to the natural gas transmission industry with somewhat less force than to local gas distribution. Gas pipelines have economies of scale; that is, one large-diameter pipeline is more efficient than two smaller lines, all other things being equal. Moreover, when

Congress passed the Natural Gas Act in 1936, local distribution companies typically had access to only one pipeline supplier, and gas producing areas typically had access to only one pipeline purchaser. Today, the case for utility-type regulation of the interstate gas transmission business is less compelling than it once was. There is now a complex gas transmission network on a national scale; most major market areas and producing areas are attached to more than one pipeline, and most of these pipelines have spare capacity. Thus, for much of the United States, competition among pipelines (either as buyers and sellers, or as carriers of gas) would be a viable alternative to FERC regulation for protecting both consumer and producer interests. Nevertheless, deregulating the gas transmission industry does not seem to be even a remotely viable option, at least in the foreseeable future (although one could have said something similar about airline deregulation only a few years ago). Some market areas are still served by pipeline monopolies and some producing areas are still subject to pipeline monopsonies; and the interstate gas transmission industry has developed within the confines of utility regulation almost from its beginning. Moreover, the national trend is still toward more detailed regulation of the energy industries (witness the Natural Gas Policy Act of 1978).

We shall quickly bypass all the tired arguments about wellhead price regulation of natural gas, save two. The proposition that the gas producing industry requires regulation because it is a monopoly does not appear to have been a consideration either in the original Congressional deliberations over the Natural Gas Act or in the Supreme Court's divided 1954 opinion that compelled the FPC to regulate wellhead prices. Some defenders of the regulatory *status quo* have raised the monopoly issue from time to time, but the analytically respectable arguments for regulation have to do with the allocation of "differential rents" from low-cost gas fields. The essential question is how should producers and consumers split the "windfall" from gas that costs producers (say) 30 cents per mmbtu to produce, but is worth (say) $2.50 to consumers; and is there any way that consumers can reap the surplus is these cases, without deterring the industry from producing gas that costs (say) $1.75? In any event, Congress now seems to have decided that the nation would be better off in the long run without wellhead price regulation of natural gas.

7.3.1 The case for deregulating supplemental gas. What then are the grounds for regulating the production or sale of supplemental gas? While some projects (the proposed

Alaska Highway pipeline in particular) would be very large, none of them would be anything near a monopoly supplier to the nation, to any region, or even to a single transmission company. Each project would sell its output into an articulated national transmission network that could deliver gas to almost any distribution company or industrial customer in the 48 conterminous states, by exchange or displacement if not directly. Gas supplies from various projects could therefore compete nationally with one another and with other new gas supplies -- new domestic discoveries, reserves previously funnelled by regulation to intrastate markets, and pipeline gas from Canada and Mexico. Moreover, the producer surpluses or differential rents that have contributed so much heat to the debate over wellhead price regulation are absent here: There will be no thirty cent or fifty cent or even two dollar LNG, Alaskan gas or high btu coal gas to generate "windfalls" for producers who can sell it for $2.50 or $3.00. The problem with the supplements is just the opposite -- how to apportion the *losses* if gas which costs four to five dollars or more can be sold for only two or three.

In this situation, why couldn't a company be allowed to build whatever supplemental gas producing facility it could finance; why couldn't the transmission and distribution companies be trusted to shop around and bargain for whatever supplies could meet their customers' expected needs at prices they would be willing to pay?

The case for a "hands-off" policy toward supplemental gas projects (subject only to reasonable safety, environmental and foreign policy review) is an appealing one. The main merit of the "free enterprise" approach as opposed to public utility regulation is the economic discipline it imposes on project sponsors and investors. In unregulated industries, a penalty for misjudgment of the market, poor management or cost overruns is imposed first and foremost on the responsible parties, and the reward for a sage assessment of the market, good management and cost savings is an exceptional profit. Sponsors would likely be more objective about costs and markets, more ruthless in screening out bad projects, and more strongly motivated in controlling costs than they are under the present regime --- where cost and market projections are carefully crafted to convince regulators that a project is in the public interest and ought to be licensed, where inflated costs can mean an inflated rate base and higher earnings, and where a regulatory commission, by granting a "certificate of public convenience and necessity", takes on a moral obligation, if not a legal one, to allow the project to earn its target rate of return.

7.3.2 The necessity for some regulation. The main reason -- perhaps the only good reason -- for economic regulation of supplemental gas projects is that the efficiency incentives characteristic of free markets cannot be expected unless deregulation applies to all companies engaged in the project, so that normal market incentives motivate all the companies purchasing the project's gas. As things stand, transmission companies have an incentive to sponsor projects which may not be cost-effective from the standpoint of consumers or the national economy. Thus, federal authorities need to hold some kind of check on supplemental gas sales in order to promote economic efficiency. As *purchasers*, the same gas companies can use rolled-in pricing to assure a market for gas whose cost may exceed its value to consumers. Therefore, regulation in the usual sense cannot be expected to achieve consumer protection. Perhaps the ideal approach with respect to high-cost supplemental gas is a carefully structured blend of regulation and free enterprise.

The Natural Gas Act of 1938, including the amendments contained in the Natural Gas Policy Act of 1978, may have been designed to create and then restore the right balance of regulation and non-regulation. However, not only are these laws intended to suit the average circumstances within the whole realm of natural gas marketing, but they are in one case outdated, and in the other a perfect example of mindless political compromise. For these reasons, a good case can be made for evaluating and pricing supplemental gas by other than conventional public utility standards.

7.4 Incremental pricing -- a market test of costs and benefits. "Incremental pricing," in the meaning it originally had at the FPC, is one possible innovation that would screen out unnecessary or uneconomic projects. If project sponsors had to sell gas from their proposed facilities under separate service agreements providing for separate rate schedules, they would initiate supplemental gas ventures only if they were truly convinced (and, likewise could convince a sufficient number of purchasers) that the resulting supply would be competitive with substitute fuels. There would, presumably, be no need for FERC to determine whether the price was just and reasonable. Direct industrial consumers would have to believe that the gas in question would be cheaper than oil (and less subject to curtailment), while gas distributors (and the state commissions with jurisdiction over them) would want to be sure that no cheaper source of gas would be available *and* that the cost of the supplemental gas was not so high as to make it unmarketable.

However, even a separate rate schedule would not necessarily screen out all supply projects whose costs exceeded their market value unless distributors were also required to resell the gas on an incremental rather than rolled-in cost basis, either on a separate rate schedule or under a marginal-cost rate schedule.

Another problem accompanying the use of separate rate schedules is that project financing of supplemental gas would probably be possible if and only if distributors were willing to sign gas purchase or transportation contracts on a minimum-bill or full cost-of-service basis for at least the duration of the long-term financing. Cost-control incentives would be as weak under a cost-of-service tariff as they would under direct utility-type regulation, and at least part of the risk that the gas might ultimately prove too expensive would rest on the distributors, as it would if prices were rolled-in and combined into a single tariff by the transmission companies. Despite these problems, a separate tariff approach for supplemental gas would allow each distribution company (together with the regulatory commission holding jurisdiction over it) to assess these risks for itself on the basis of its own expected costs and benefits.

Even with incremental pricing and in the absence of long-term contracts, (both of which are branded as totally unworkable by the industry spokesmen today), supplemental gas projects might, nevertheless, seem to be worthwhile gambles to those investors truly convinced that the prices of alternative fuels will indeed increase. Project financing, however, would not be possible; and lenders would probably not be willing to contribute more than about half of the project's total investment -- which is a common capitalization ratio for conventional gas transmission projects, manufacturing plants, etc. It is impossible to say whether the ultimate price of the gas would be higher or lower under this kind of capital structure than under a more highly leveraged structure that could only be attained by use of long-term sales contracts (with their own attendant evils as discussed above). One point is clear: just as investors would have to be rewarded for the *risk* of earning less than a public utility "fair rate of return" by the *opportunity* to earn more, *purchasers* would have to accept the *risk* that prices would exceed a public utility "cost of service" in exchange for the *opportunity* to turn away gas whose price exceeded its value.

All in all, it is likely that American business could find *some* way to finance supplemental gas that had to be sold (or even resold) on separate rate schedules or otherwise at a marginal cost price -- *if the economic case for supplemental gas were wholly convincing.* Granted, gas men and their underwirters claim to be convinced that higher and higher oil prices are inevitable even in real terms, but this conviction is both costless and self-serving in a system where project approval by government carries with it an earnings guarantee whether or not the investment could stand on its own in an unregulated market. The fact that gas companies cannot or will not find the capital to back up their beliefs without consumer or taxpayer guarantees is a better index of their true convictions than their statements before regulatory commissions or Congressional committees.

The free enterprise approach fails because the case for supplemental gas is ultimately a political one, resting on public concern about air quality, the balance of payments, or vulnerability to political upheavals in the Middle

East -- none of which can be translated directly into dollars at the burner tip. Stated bluntly, policy makers are not willing to accept the verdict of the market, lest it reject projects that they judge desirable on other grounds. Hence, the FPC backed off on its proposal that the LNG from the Trunkline project be sold on a separate rate schedule, on the grounds that this treatment would make financing impossible. And Congress adopted, under the name "incremental pricing," a scheme that permits, (if it does not require) value-of-service pricing under which high-priority gas consumers will eventually subsidize low-priority uses.

7.5 Commodity value pricing. Another compromise between a thoroughgoing free enterprise approach and the conventional public utility treatment of supplemental gas would be for FERC to determine a maximum "commodity value" price at the burner tip, at the "city gate" (the sale from the transmission company to the local distribution company), or at the point the gas entered the existing transmission and distribution system. Such an approach would screen out economically undesirable projects, protect consumers against costs for gas that exceeded its value, and relieve the regulatory authorities of the burden of any additional economic evaluation or surveillance over supplemental gas sources.

The New York Public Service Commission argued persuasively for this kind of approach in the FPC proceeding on the Alaska natural gas transportation system. Setting a price downstream rather than at the wellhead, the Commission urged, would maximize the sponsors' incentive to control costs, motivate the gas producers and the State of Alaska to provide capital backstopping, and relieve the FPC of a largely unnecessary regulatory burden. Ownership and financial structure, and the responsibility for gas conditioning, together with the apportionment of the netback revenues, would be negotiated among the producers, the state, and pipeline sponsors and their lenders. If the project could not be financed under these conditions, there was a good presumption that it didn't make economic sense and ought not be certified anyway. The FPC, in its 1977 recommendation to the President, proposed a less audacious commodity value pricing scheme, in which the Commission would determine the wellhead price of Alaska gas by subtracting transportation costs (determined in the conventional manner) from the "market value" of the gas at the city gate.

Unlike incremental pricing (in its original meaning), commodity value pricing of supplemental gas can take into account whatever non-market benefits (or costs) the regulators deem appropriate -- air quality, national energy self-sufficiency, the balance of payments or whatever, in addition to the market value of gas as measured by the price of some substitute fuel. A commodity value price could also be adjusted to account for the fact that current oil prices may not represent the marginal or replacement costs of oil because of price controls or entitlement subsidies. If the regulators believed that domestic natural gas deserved a premium price compared with domestic (or imported) oil, that premium could be made quite specific and put into effect directly as part of the commodity value price. A gas supply that could not survive the market test of marginal cost pricing might be made economically viable, *if* its market value as measured by the price of substitute fuels *plus* its non-market benefits as determined by FERC (or the Economic Regulatory Administration of the Department of Energy) exceeded its costs, provided the rolled-in pricing cushion was available to cover the cost of the non-market benefits.

A commodity value price could be determined periodically (e.g., annually) on the basis of actual prices of substitute fuel (as done in Canada) along with the regulators' changing assessments of the non-market benefits from having additional gas. This kind of pricing rule would accurately test a project's benefits, but it would impose onerous risks on investors. Project financing would surely be impossible unless the prices or pricing formulas were set in advance for at least the life of the long-term debt. While it is arguable that equity investors might be found for conventionally-financed projects who would face the full brunt of market uncertainty in the hope of a higher than cost-of-service return to capital, it is not likely they would seek out the *combination of market and regulatory* risks posed by the periodic redetermination of the commodity value.

On balance, we do not believe that a *pure* market test of project viability in the form of separate rate schedules for each supplemental gas project, or a *pure* commodity value pricing system with prices redetermined regularly on the basis of changing prices for fuel oil and shifting assessments of the premium value of gas, are practical options in an otherwise highly regulated industry. Either of these regimes would do away with at least some of the evils of the *status quo,* they would surely weed out those projects that do not make sense from a consumer or national standpoint, and protect consumers from paying prices higher than that of substitute fuels, even for those projects which did get approved and built. But either of these rules would also focus the risks from misjudging costs or the market almost entirely upon investors. Because of the large size, and capital-intensiveness of supplemental gas facilities it is not reasonable to expect investors to make such risky commitments of funds for the long times required to recover their investments. A rigorous market-value pricing scheme, without the protections of long-term contracts that assure project revenues, would inevitably condemn ventures that had a better-than-even chance of economic viability, as well as the white elephants and gold-plated boondoggles.

7.6 Is there a practical compromise? Consumers and/or government will have to bear a substantial portion of these risks in some form. The authors see nothing intrinsically wrong for consumers to accept *some* chance that they will end up paying higher prices for energy than they would have had to pay if they had accurately foreseen the future. By investing in high-cost supplemental energy sources today, they are buying insurance against the possibility that alternate energy sources will be even more costly or unavailable. The question is, are there feasible procedures and policies that will provide this insurance without lifting the penalties for mismanagement and waste from project planners and managers, without subsidies that give consumers the wrong "signals" about the true cost of gas, and without forcing unacceptable financial risks on the gas distributors?

A practical, albeit less exact, approach to commodity value pricing would be for the regulatory authorities to determine a "commodity value" schedule for the life of each project on the basis of their best projections of market values at the time it is certified. This method would require speculation about conditions far into the future, but no more than the speculations FERC now has to engage in when it decides whether a project or a contract that carries a full cost-of-service tariff is in the national interest. A predetermined commodity value schedule (as opposed to a cost-of-service tariff) would still leave some risk with respect to both fixed and variable costs on the owners -- a desirable feature in most cases, because this risk is probably the most effective incentive to plan realistically and to control costs.

A simple version of such a schedule would be composed of a base period commodity value and an escalator. For example, a supplemental gas project serving the Midwest could have calendar 1978 as a commodity value base period, and the Chicago city gate as a basing point. The base period commodity value would be the substitute fuel price (the average Chicago area price per btu of <1 percent sulfur No. 6 oil), *plus* an adjustment for the underpricing of domestic petroleum relative to a world market or replacement costs (the btu value of the net entitlements subsidy for imported crude oil), plus an air quality premium (say, 50 cents per mmbtu). The price escalator would be 5.5 percent annually for the life of the project.

With a predetermined schedule of annual commodity values, project investors would still bear the risks of overruns and other contingencies that might increase costs, but they would be relieved of much or all of the marketability risk. FERC, in approving a tariff that satisfies its own commodity value projections over the life of a project would be making an implicit guarantee of project revenues -- even if FERC's price projections turned out to be unrealistic. The commodity value approach, therefore, is not necessarily compatible with a strict commitment to marginal cost pricing; it implies that federal and/or state regulators must retain the ability to make up revenue shortfalls out of the old gas cushion, by means of rolled-in pricing.

Another departure from pure commodity value pricing which may be warranted concerns the *profile* of the commodity value schedule over time. In Chapter V we pointed out that there is no single correct rule for allocating the fixed *costs* of an investment over its economic life; there is likewise no single right princple for allocating the *benefits* of a long-lived project over time. The kind of commodity value schedule described above, indexed to anticipated inflation, may not have the best possible rate *profile*. What is crucial to the social efficiency of a supplemental gas project is not that its prices meet a commodity value test *in each and every year* of operation, but that it meet such a cost-benefit test *over its operational life taken as a whole* (i.e. discounted present costs must not exceed discounted present benefits).

A levelized tariff or, better yet, a front-end loaded tariff that met this cost-benefit test would have two advantages over an escalating one: (1) amortizing the investment earlier should make financing easier and lower the needed rates of return to both debt and equity, and (2) prices higher than the *current* commodity value of gas could be rolled-in with the old gas cushion in the projects' early years to assure that the gas would be marketable then, while the lower prices scheduled for the later years would be sufficient even if the real prices of substitute fuels were to fall.

There are further departures from strict commodity value pricing which would soften the external risks faced by investors without relieving them of the planning and cost control responsibilities that are most effectively left to them: FERC might approve tariffs that provided for adjustments to the commodity value price for events outside the control of the sponsors, for example:

(1) Higher (or lower) than anticipated fixed costs attributable to higher (or lower) than expected rates of *general* inflation during the construction period;

(2) Delays or changes in the scope of the project caused unilaterally and wholly or primarily by governmental regulation; and

(3) Higher (or lower) than anticipated variable costs attributable to higher (or lower) than expected rates of *general* inflation.

A pricing system that relies on twenty year market projections by a government agency, front-end loaded tariff profiles, and rolled-in pricing to screen uneconomic projects and encourage desirable ones is a far cry from the free enterprise principles we argued at the beginning of this chapter. It is no longer even fair to call it commodity value pricing. Yet this mixture of policies could well accomplish both the legitimate ends of regulation while preserving most of the benefits of deregulation:

(1) The effective test of a project's desirability would encompass the whole range of social concerns, not just private pecuniary benefits either as measured by the current price of substitute fuels or by the artificial demand created by rolled-in pricing --- but the regulators' valuation of non-market benefits would have to be made explicit.

(2) Once the regulators approved a price schedule based upon their best estimates of future commodity values, it would be the responsibility of the private promoters to negotiate the necessary arrangements with suppliers, lenders and other "upstream" collaborators to meet this price. If the price cannot be met -- i.e.

if costs turn out to be excessive -- it is up to the investors to decide whether to abandon the project or to accept a lower rate of return.

(3) The absence of a cost-of-service tariff (or at least its subordination to commodity value-based cost ceilings) would give sponsors a powerful incentive to design the optimum system and to control costs -- the reward for savings would be mostly their own. It would also relieve federal regulators of the necessity for periodic rate proceedings, and economic surveillance of supplemental gas projects generally.

(4) Rolled-in pricing would be available to guarantee investors the revenues they contracted for when they accepted a certificate of public convenience and necessity (but not any predetermined level of profits) --- yet no project would be approved that was planned *to depend upon rolled-in pricing* or any other consumer subsidy (except to the extent of the estimated non-market benefits).

(5) Flexibility with respect to rate profiles, (consistent with a favorable cost-benefit test based

upon the projected commodity value of gas) would permit the present old gas cushion to help finance risky projects and mitigate marketability risk in the years after the old gas cushion has disappeared.

The present report is not intended as a brief in favor of any particular set of policies toward supplemental gas. Its chief purpose has been to identify some of the concerns and offer some insights that have not been at the center of recent gas policy debates. The authors have offered the policy suggestions in this chapter, not as a coherent program for the certification and regulation of supplemental gas projects, but as illustrations of some of the direction that might be combined to deal with the economic and policy concerns we have introduced in earlier chapters.