Review Draft
Preliminary and Subject to Change

INTRODUCTION TO PETROLEUM REFINING AND PETROCHEMICALS

With Special Attention to Processing
of Hydrocarbons from Alaska's
Prudhoe Bay Field

Report Funded By
Joint Gas Pipeline Committee
Alaska State Legislature
and
The Ford Foundation

Institute of Social and Economic Research
University of Alaska
707 "A" Street
Anchorage, Alaska 99501

Arlon R. Tussing
Lois S. Kramer

June 1981

Review Draft
Preliminary and Subject to Change

INTRODUCTION TO PETROLEUM REFINING AND PETROCHEMICALS

With Special Attention to Processing
of Hydrocarbons from Alaska's
Prudhoe Bay Field

Report Funded By
Joint Gas Pipeline Committee
Alaska State Legislature
and
The Ford Foundation

Institute of Social and Economic Research
University of Alaska
707 "A" Street
Anchorage, Alaska 99501

Arlon R. Tussing
Lois S. Kramer

June 1981

CONTENTS

CONTENTS i

LIST OF FIGURES AND TABLES vii

PREFACE [To be added in final version] viii

NOTE ON VOCABULARY AND MEASURES [To be added in final version]

CHAPTER 1. GENERAL INTRODUCTION 1

CHAPTER 2. OVERVIEW OF PETROLEUM AND THE PETROLEUM INDUSTRY 6
International
Size and Capital Intensiveness
High Technology
Short- and Long-Term Flexibility
Long Lead Times
Risk
Vertical Integration
Goverment Involvement

CHAPTER 3. THE PETROLEUM INDUSTRY IN ALASKA 16

3.1 Hydrocarbon Resources, Reserves, and Production 16
Cook Inlet
Prudhoe Bay Area
The Outlook for Additional Discoveries
Royalty Oil and Gas

3.2 Hydrocarbons Processing in Alaska 21
Fuels Refineries
Facilities Using Cook Inlet Natural Gas

3.3 Prudhoe Bay Natural-Gas Reserves and ANGTS 25
ANGTS: The Alaska [Highway] Natural Gas Transportation System
SGCF: The Sales Gas Condtioning Facility
A Natural-Gas Liquids (NGL) Pipeline and Alaska Petrochemicals Production

CHAPTER 4. FUNDAMENTALS OF HYDROCARBONS CHEMISTRY . . . 30

4.1 General Introduction 30

4.2 Composition of Natural Hydrocarbons . . . 30

4.3 Chemistry 33
Paraffins
Naphthenes
Aromatics
Olefins

CHAPTER 5. FUELS REFINING 38

5.1 Petroleum Industry Structure 38
The Major Oil Companies
The Independents

5.2 Feedstocks and Petroleum Products 41
Introduction
Feedstock Characteristics
Density
Sulfur Content
Viscosity, Pour Point, and Wax Content
Refinery Products
First-stage products
End Products
Motor Gasoline
Diesel Fuel
Aviation Fuel
Gas and LPG
Distillate Fuel Oil
Residual Fuels
Lubricants
Petroleum Solvents
Asphalt
Product Mix
Feedstock Assay and Straight-Run Fraction Mix
Crude-oil Supply Conditions
Refined-Product Market Conditions
Refinery Flexibility Regarding Product Mix
Refinery Size and Affiliation

5.3 Refining of Petroleum 56
Distillation
Restructuring Hydrocarbon Molecules
Refinery Processes to Restructure Hydrocarbons
Cracking
Reforming
Polymerization and Alkylation
Isomerization
Hydrotreating

5.4 Refinery Technology and Design 63

5.5 Forces for Change 66
The OPEC Price Revolution
Consumption is Declining
Market Requirements are Changing
The Quality of Available Crude Oil is Expected to Decline

Security of Feedstock Supply is a Major Concern
Crude Oil Has Become Costlier

5.6 Outlook the 1980's 74

CHAPTER 6. PETROCHEMICALS 77

6.0 Introduction 77

6.1 Chemical Industry Structure 78

6.2 Petrochemical Feedstocks 80
Natural-Gas Liquids
Naphtha
Gas Oil
Natural Gas
Synthesis Gas

6.3 Petrochemical Product Groups 82
Primary Petrochemicals
Olefins
Ethylene
Propylene
Butane-Derived Olefins
Aromatics
Synthesis Gas
Ammonia
Methanol
Oxy Alcohols
Intermediates or Derivatives
End Uses

6.4 Petrochemical Processes and Plant Design 89
Natural-Gas Liquids to Ethylene and its Derivatives
Natural Gas to Methanol
Naphtha to Benzene
Petrochemical Complexes

6.5 Feedstock Supplies and Product Markets . 97
Feedstock Supplies
Future Feedstock Developments
Markets for Primary and Intermediate Petrochemicals
Captive Markets
Limits to Expansion

CHAPTER 7. SOCIOECONOMIC, HEALTH, SAFETY, AND ENVIRONMENTAL CONSIDERATIONS 104

7.0 General Introduction 104

7.1 Employment and Labor Demand 105

7.2 Water and Power Requirements 108
Water Use
Energy Requirements

7.3 Land and Water Pollution 112
Characteristics of Contaminants
Oxygen Demand
Taste and Odor
Acidity and Alkalinity
Toxicity
Turbidity and Suspended Matter
Temperature
Waste-Control Methods
Disposal of Spent Chemicals

7.4 Air Pollution 116

7.5 Health and Safety Issues 118
Carcinogens
Risk Assessment
Information and Expertise

7.6 Options for State Regulation 125
Prescriptive vs. Economic Remedies: Prescriptive Regulation
Litigation
Strict Liability
Insurance
Effluent Taxes and Hybrid Systems

CHAPTER 8. THE ECONOMICS OF HYDROCARBONS PROCESSING AND THE OUTLOOK FOR REFINING AND PETROCHEMICALS IN ALASKA 131

8.1 Hydrocarbon Transportation Economics . . 131
Waterborne Bulk Carriers
Gas Pipeline Transportation
TAPS vs. ANGTS

8.2 Transportation Cost and Plant Location . 134
Final-Product Manufacturing

8.3 Fixed Capital Costs 137
Fixed Costs vs. Variable Costs
The Outlook for Refinery Investment
The Outlook for Petrochemicals Investment
The Alaska Cost Differential

8.4 Feedstock Costs amd Feedstock Supply . . 139
Oil-Based Feedstock Costs
Gas-Based Petrochemical Feedstocks
Illustrations
Methanol and MTBE at Prudhoe Bay
NGL-Derived Olefins in Southcentral Alaska

Feedstock Value vs. Feedstock Price
Alternative Scenarios
No Gas Pipeline
The Effect of Wellhead Price Controls
Methane
Ethane
8.5 Economies of Scale 152
8.6 Analyzing Project Feasibility 153
Cash Flow and the Internal Rate of Return
Assessing Uncertainty and Risk
Sensitivity Analysis
Risk Analysis
8.7 Coping with Uncertainty and Risk 160
Long-term Contracts
Project Financing
Plant and System Flexibility

REFERENCES [To be added in final edition]

APPENDIX 1: GLOSSARY [To be added in final edition]

APPENDIX 2: INTERRELATIONSHIP OF PROPOSED GAS-BASED PETROCHEMICAL DEVELOPMENT AND THE ALASKA NATURAL-GAS PIPELINE PROJECT
[By Matthew Berman: to be added in final edition]

APPENDIX 3: NATURAL-GAS CONDITIONING AND PIPELINE DESIGN (A Technical Primer for Non-Technicians, with Special Reference to Hydrocarbons from Prudhoe Bay and the Alaska Highway Gas Pipeline [by Connie C. Barlow, March 1980]

CONTENTS 3-i
INTRODUCTION 3-ii
I. The Basics of Pipeline Design 3-1
A. Hydrocarbon Characteristics
1. Chemistry
2. Heating Values
3. Phase Characteristics
B. Gas versus Liquids Pipelines
C. Pressure Specifications

II. Gas Composition Decisions 3-12
A. Introduction
B. Phase Diagrams
C. The Relationship Between Gas Composition and Upset Conditions

D. Carbon Dioxide Content
1. The Effect of Carbon Dioxide on Hydrocarbon Dewpoints
2. The Effect of Carbon Dioxide on Pipeline Corrosion
3. The Effect of Carbon Dioxide on Down-Stream Gas Systems
4. The Effect of Carbon Dioxide on Project Economics

E. Volumes of Gas and Gas-Liquids Available for Shipment
1. Reservoir Production Rates
2. Gas Composition Changes
3. North Slope Fuel Requirements
4. Shipping Intermediate Hydrocarbons Through TAPS

LIST OF FIGURES AND TABLES

Figure 2-1	Crude-Oil Production and Consumption of Refined Products by Region, 1979	8
Table 2-1	Domestic and Foreign Capital Expenditures of the World Petroleum Industry	9
Table 2-2	Assets per Employee for the Fortune 500: Industry Medians	9
Figure 5-1	Crude-Oil Distillation	46
Figure 5-2	Simplified Flow Chart of a Refinery	66
Figure 6-1	Petrochemical Industry Flow Chart	78
Figure 6-2	Feedstocks, Primary Petrochemicals, and First Derivatives	82
Table 6-1	Primary Petrochemicals and Derivatives Considered for Production in Alaska	88
Figure 6-3	Ethylene Plant: Simplified Process Flow Diagram	92
Figure 6-4	Derivatives of Ethylene	94
Figure 6-5	Typical Methanol Process	94
Figure 6-6	Benzene, Toluene, and Xylenes by Reforming and Extraction	96
Figure 6-7	Aromatics Derivatives	97
Figure 6-8	Dow-Shell Petrochemical Project	98
Table 7-1	Estimated Workforce Requirements, Dow-Shell Project	105
Table 7-2	Dow-Shell Water-Use Estimates	111
Table 7-3	Potential Sources of Specific Emissions from Hydrocarbons Processing Plants	117
Figure 8-1	Netback Value of Prudhoe Bay Natural Gas	131
Figure 8-2	Ethane Cost at Cook Inlet Plant	133
Figure 8-3	Value vs. Opportunity Cost at Cook Inlet	134
Figure 8-4	Cook Inlet Ethane-Price Determination	135
Figure 8-5	Cook Inlet Price Determination Without ANGTS	137
Figure 8-6	Cook Inlet Methane Price Determination	139

CHAPTER 1

GENERAL INTRODUCTION

This primer on fuels refining and petrochemicals manufacture comes in the midst of a continuing debate over the economics and potential benefits to Alaska of processing hydrocarbons in the State. The object of this debate is what to do with the State's royalty share of the crude oil, natural gas and natural-gas liquids (NGL's) produced at Prudhoe Bay.

The first stage of the debate ended in 1977, when the Alaska Legislature conditionally sold its Prudhoe Bay royalty gas to subsidiaries of the El Paso Company, Tenneco, and Southern Natural Gas Company, hoping that the political influence of these companies would lead the federal government to select an "all-Alaska" pipeline route for the Alaska Natural Gas Transportation System (ANGTS). Under this plan, a gas-liquefaction (LNG) plant, and possibly other gas-processing facilities, would have been built at the pipeline's Gulf of Alaska terminal.

The royalty-gas sales contracts lapsed later in 1977, when the President and Congress, and the Canadian government, chose the Alaska Highway ["Alcan"] pipeline sponsored by Northwest Energy Company and the Foothills group, over El Paso's proposed LNG system and the Mackenzie Valley pipeline proposal advanced by the Arctic Gas group.

The second stage of the debate opened in 1978, when the Legislature considered a long-term contract to sell 80 percent of the State's North Slope royalty oil, up to 150 thousand barrels per day (mb/d), to the Alaska Petrochemical Company ("Alpetco") if the company built a "world-scale" petrochemicals plant in Alaska.

The Alpetco contract was later amended to permit the sponsors to build a 100 mb/d fuels refinery, which might or might not have produced petrochemicals. Several changes in the project's ownership structure led to its final sponsorship by the Alaska Oil Company, a subsidiary of the Charter Company. In May of 1981, Charter abandoned its plan for a refinery at Valdez, stating that it had been unable to obtain outside financing, and gave up its right to purchase 75 mb/d of State royalty oil prior to completion of the refinery.

Most recently, in 1980, the Alaska Department of Natural Resources (DNR) entered into an agreement with subsidiaries of the Dow Chemical Company, the Shell Oil Company, and a group of associated companies, to study the feasibility of transporting and processing Prudhoe Bay NGL's in Alaska. This study is scheduled for completion and delivery to the State in September, 1981. [For a full description and schedule for the Dow-Shell project, see Dow-Shell, 1980-1981.]

These proposals have been quite different technically, but each of them evoked similar hopes, fears, and controversy among Alaskans. The hopes and arguments favoring such ventures are increased local "value-added" from the State's natural resources (as opposed to their export in unprocessed form), and the contribution that this processing would make to the state's economic growth and economic diversity, a greater and more diversified tax base, new and more diverse job opportunities, and lower Alaska prices for fuels and other goods.

At the same time, some Alaskans have been skeptical about the underlying economic soundness of the proposals, and feared that they might ultimately have to be rescued by the State treasury. Another concern is that long-term royalty-gas export contracts could foreclose future opportunities for residential, commerical, industrial or electric-utility use of the gas in Alaska, and that long-term royalty-oil sales to export-oriented new refineries could leave exisitng refineries that serve Alaska customers short of raw material, if the decline in Prudhoe Bay production made the oil producers less willing to sell crude oil to these refineries. [For a perspective on this issue, see <u>House Research Agency</u> (1981).]

Other potentially adverse impacts are the prospects of deepening Alaska's already-excessive dependence on petroleum-related industry, and of once more repeating the State's familiar boom-bust cycle; new sources of pollution and other health, safety, or aesthetic hazards; and unwelcome changes in community values and life-styles.

To aid the rational discussion of such issues, this primer tries to set in context the basic technical and economic facts, analytical concepts, and policy considerations relevant to hydrocarbons processing in Alaska, in simple, straight-forward language accessible to legislators and other Alaska laypersons.

Many of the crucial questions have already found their way into public debate and set the stage for our discussion of the more technical aspects of fuels refining and petrochemicals processing. These questions, for example, include considerations of ---

- o <u>Feasibility</u>. Is Alaska a realistic location for nationally- or internationally-competitive fuels refining and petrochemicals manufacturing activity?

- o <u>Type of Industry</u>. For what specific kinds of facilities, if any, does Alaska have a special comparative advantage, and what kinds of facilities are especially <u>un</u>promising for Alaska?

- <u>Interrelationships</u>. What interrelationships exist among the projects that have been proposed? Are some of them mutually exclusive? How will decisions regarding the Alaska Highway gas pipeline affect the viability of n gas-liquids pipeline or gas-liquids-based petrochemicals production, and <u>vice-versa</u>?

- <u>Influence of the State</u>. What special ability does the State's ownership or royalty oil and gas, regulatory powers, taxing authority, or investment capability, give it to encourage or discourage investment, or to affect the character or location of facilities that process Alaska hydrocarbons? (And, to what extent is it proper or prudent in a society committed to private enterprise, or in the interests of Alaskans, that the State government deliberately use its powers to influence the course of development?)

- <u>Direct Economic Impacts</u>. How many jobs, of what character, will each proposed project offer in its construction and operational phase respectively, and who will fill these jobs? How will construction and operation of the facilities affect the demand for services in other local industries?

- <u>Indirect Development Impact</u>. To what extent will the existence of any project in question stimulate (or discourage) investment in complementary (or competing) industries, and what will their total impact on the state's economy be after taking into account all their short and long-term, direct, indirect, and multiplier effects?

- <u>Health, Safety, Environmental, and Aesthetic Considerations</u>. To what extent do the proposed projects (or their indirect developmental effects) have unavoidable adverse impacts, or create known or potential risks of adverse ipmacts on health, safety, the natural environment, or other dimensions of the quality of life in Alaska?

- <u>Conflicting Objectives</u>. To what extent do specific kinds of State efforts to attract refinery or petrochemical investments assist or conflict with other goals, such as maximization of royalty and tax revenue from oil and gas production, early completion of the natural gas pipeline, or availability of low-cost energy for local residential, commercial, or industrial consumption?

- o <u>Consequences</u>. What are the likely consequences of making an early commitment or not making such a commitment of the State's Prudhoe Bay royalty gas and/or gas liquids? Are there additional costs that State and local governments may incur as a result of their aggressive pursuit of petrochemical investment in Alaska?

These questions, while not exhaustive, are the major issues in the current public debate over State policies toward petrochemical development. Although the authors have tried to give general answers to some of these questions, the main function of the present paper is to provide its readers with some of the background necessary to develop their own answers.

CHAPTER 2

OVERVIEW OF PETROLEUM AND THE PETROLEUM INDUSTRY

Crude oil, natural gas, and natural-gas liquids are all "petroleum", which is the general term for hydrocarbons, compounds composed mainly of hydrogen and carbon atoms, found in the earth's crust. Hydrocarbons vary considerably in molecular size and structure, and each hydrocarbon compound can exist as a solid, a liquid, or a gas, depending on the pressure and temperature to which it is subjected.

Naturally-occurring deposits of hydrocarbons that are liquid at atmospheric pressure and temperature are termed "crude-oil" fields or reservoirs, while deposits containing hydrocarbons that are gases under the same conditions are regarded as "natural-gas" fields or reservoirs. The Prudhoe Bay field, like most commercially recoverable petroleum deposits, contains a mixture of liquid and gaseous hydrocarbons, which have to be separated in the field for transportation and processing.

The petroleum industry, as we define it for the purposes of this primer, includes businesses engaged in finding and extracting hydrocarbons from the earth, and their storage and transportation; the refining, distribution, and sale of fuels and lubricants; and related service and support activities. It also includes a "petrochemical" sector --- the manufacture and distribution of organic chemicals based upon petroleum feedstocks, often by affiliates of petroleum production and refining companies.

The most powerful influences on the structure of the petroleum industry are the location of hydrocarbon resources with respect to petroleum product markets, and the physical and chemical qualities of different hydrocarbon mixtures. The legal and regulatory treatment of various sectors of the industry are also important influences.

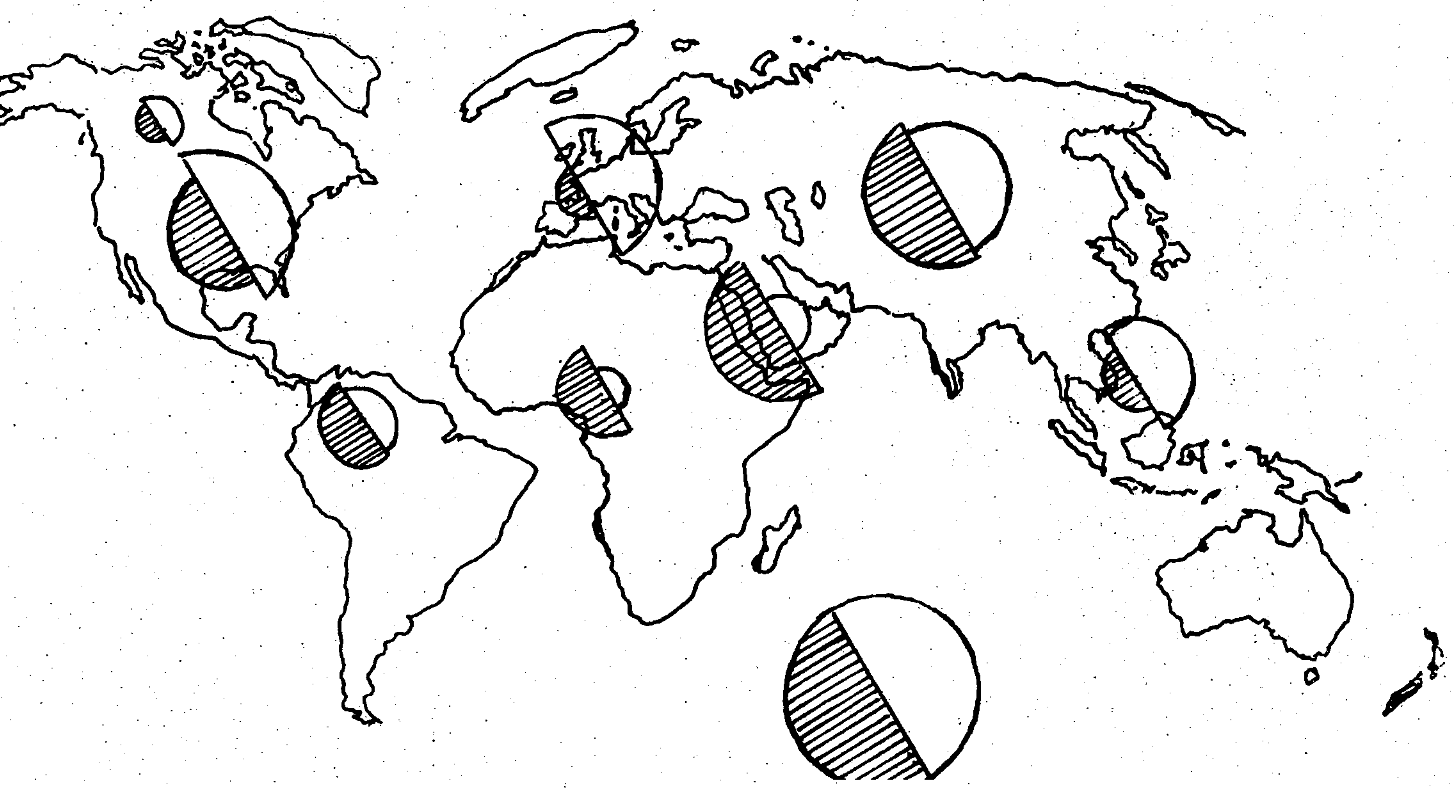
International. Petroleum is the most important commodity in world trade in both volume and value, and a large part of the world's total production of petroleum liquids is transported and processed by a few multi-national companies. The reason for the industry's exceptional internationalism is the widely differing location of the chief commerical petroleum-producing areas and the major markets for petroleum products. Figure 2-1 illustrates the geographic disparity between global oil production and consumption in 1979.

Size and Capital Intensiveness. The world petroleum industry is both very large, and as a whole, exceptionally capital-intensive. Six of the ten largest firms in the 1978 Fortune 500 were oil companies. Table 2-1 summarizes the Chase Manhattan Bank's survey of the petroleum industry's 1975-77 capital expenditures; the industry's new investments over the three years amounted to about $62 billion in the United States and $168 billion worldwide.

Table 2-2 shows that petroleum refining also had the highest ratio of assets per employee among the 29 industries included in the Fortune survey. The chemical industry ranked sixth. Petroleum was also in first place among all industries with respect to the ratio of assets to sales.

Not all phases of the industry are exceptionally capital-intensive, however. In the Middle East, for example, crude oil production costs --- the cost of wells, gathering lines, and separating facilities --- tends to be relatively low, ranging from about $100 to $500 per barrel of oil produced per day. At an oil price of $32 per barrel, even the higher of the two capital-cost figures means that only 16 days of production would be needed to recover the investment in field development.

Figure 2-1



CRUDE-OIL PRODUCTION & CONSUMPTION OF REFINED PRODUCTS BY AREA, 1979 (thousands of barrels)

	Production	Consumption
United States	3,111,625	6,728,410
Canada	545,675	691,675
Latin America	1,912,200	1,604,175
Middle East	7,803,700	542,025
Africa	2,401,700	478,150
Asia/Pacific	1,042,075	3,429,175
Western Europe	826,725	5,427,550
Communist Nations	5,120,950	4,688,425

Sources: British Petroleum Company, Basic Petroleum Data Book, 1980.

TABLE 2-1

DOMESTIC AND FOREIGN CAPITAL EXPENDITURES
OF THE WORLD PETROLEUM INDUSTRY

	PRODUCTION					TRANSPORTATION					REFINERIES & CHEM PLANTS				
	U.S.		FOREIGN		TOTAL	U.S.		FOREIGN		TOTAL	U.S.		FOREIGN		TOTAL
year	$ bil	%	$ bil	%	$ bil	$ bil	%	$ bil	%	$ bil	$ bil	%	$ bil	%	$ bil
1975	9.4	49	9.9	51	19.3	3.7	25	11.5	76	15.2	3.6	30	8.3	70	11.9
1976	13.4	52	12.3	48	25.8	3.9	24	12.4	76	16.3	3.8	33	7.6	67	11.4
1977	15.2	47	17.3	53	32.5	2.3	22	8.1	78	10.4	3.7	25	11.0	75	14.7

	MARKETING					OTHER CAPITAL SPENDING					TOTAL CAPITAL SPENDING				
	U.S.		FOREIGN		TOTAL	U.S.		FOREIGN		TOTAL	U.S.		FOREIGN		TOTAL
year	$ bil	%	$ bil	%	$ bil	$ bil	%	$ bil	%	$ bil	$ bil	%	$ bil	%	$ bil
1975	.6	30	1.5	70	2.2	.4	34	.7	67	1.1	17.7	36	31.9	64	49.6
1976	.6	29	1.6	71	2.2	.3	29	.8	71	1.1	22.1	39	34.6	61	56.7
1977	.8	29	1.9	71	2.7	.4	31	1.0	69	1.4	22.4	36	39.2	64	61.6

SOURCE: The Chase Manhattan Bank: Capital Investments of the World Petroleum Industry

TABLE 2-2

ASSETS PER EMPLOYEE FOR THE FORTUNE 500
INDUSTRY MEDIANS

Petroleum refining	$303,839
Mining, crude-oil production	254,336
Broadcasting, motion-picture production and distribution	108,772
Tobacco	81,937
Metal Manufacturing	79,868
Chemicals	77,947
Paper, Fiber, and wood products	76,141
Pharmaceuticals	66,543
Publishing, printing	56,129
Glass, Concrete, abrasives, gypsum	55,668
Industrial and farm equipment	53,361
Soaps, cosmetics	52,708
Metal products	50,103
Office equipment (includes computers)	49,507
Food	49,488
Motor vehicles	46,039
Shipbuilding, railroad, and transportation	43,941
Rubber, plastic products	42,563
Motor vehicles	37,768
Measuring, scientific, and photographic equipment	41,000
Aerospace	40,901
Musical Instruments, toys, sporting goods	37,666
Electronics, appliances	37,594
Textiles and vinyl flooring	26,431
Apparel	20,364
Leather	n.a
Furniture	n.a.
Jewelry, silverware	n.a
All Industries	55,505

SOURCE: Fortune, May 4, 1981

The capital cost per daily barrel for new production in the North Sea, the United States Outer Continental Shelf (OCS), or the Arctic, is typically much higher, however --- in the range of $5,000 to $10,000 per daily barrel. Synthetic oil and gas plants would be even more capital-intensive, with unit capital costs expected to be in the $10,000 to $40,000 range.

Refining and petrochemical plants also require very large capital additions, both absolutely and per unit of capacity: a completely new ["grass-roots"] state-of-the art oil refinery may cost up to a billion dollars --- at $5,000 to $10,000 or more per daily barrel of capacity, and a first-stage petrochemicals plant may cost even more. Even the extra equipment an existing refinery would need to process lower-quality ["heavy" or high-sulfur] types of crude oil tends to add $1,500 to $2,500, or more, per daily barrel of capacity.

High Technology. The search for natural hydrocarbons is reaching out to more remote and difficult locations: further below the earth's surface, under deeper water, and into the Arctic. Construction of production platforms in the North Sea was the first time engineers had installed permanent structures of any kind in such deep or wave-stressed waters, while TAPS required radically new pipeline design and construction techniques to cope with tundra and permafrost conditions.

Producing new categories of hydrocarbons, or even familiar resources in new environments (tar sands and oil shales, for example, or natural gas in coal seams, tight rocks, and pressurized brine solutions) also takes a constantly developing technology, as do the refining and petrochemical sectors, where new end-products appear frequently, and where both the demand mix and feedstock mix continue to change.

Short- and long-term flexibility. Part of the change in demand mix is temporary --- determined by the seasons and the weather, or by economic conditions. Gasoline consumption peaks in the summer, and heating oil consumption in the winter; warm weather increases gasoline demand, while cold weather favors heating-oil demand. Consumption of all petroleum products and petrochemicals tends to fall off in recessions, but not in constant proportions. These factors require that processors be able to vary the proportion of various products in their plant output, carry some surplus processing capacity, and maintain storage facilities for products that may be in excess supply today or in short supply tomorrow.

Another part of the change in demand is longer-term. It appears that the total consumption of petroleum products in the United States and the world as a whole peaked in 1978, and has entered a decline that will last the rest of this Century. Gasoline and residual oil demand, in particular, are expected to shrink, but the consumption of "middle distillates" (diesel fuel, home-heating oil, and jet fuel) and petrochemicals may level off or continue to grow. At the same time that gasoline consumption as a whole is shrinking, the U.S. Environmental Protection Agency [EPA] is requiring lead to be phased-out as a gasoline additive, compelling refiners to produce an essentially new kind of gasoline in order to obtain acceptable anti-knock ("octane") ratings.

These shifts in product demand are all occurring at a time when "heavy" crude oil containing a high proportion of residual oil is becoming a relatively larger part of the total oil supply. The continuing decline in Lower 48 natural-gas production from traditionally-exploited kinds of resources is also reducing the supply of NGL's, a major feedstock source to the petrochemical industry. As a result, an overall decline in the need for petroleum-processing capacity will go together with large investments in facilities to "upgrade" surplus residual oil into middle distillate fuels and petrochemical feedstocks like naphtha and gas oil.

Long Lead Times. Capital-intensiveness and high technology imply long engineering lead times and long construction schedules, with heavy capital outlays required far in advance of any return on investment. Refineries, petrochemical plants, frontier oil and gas development, and pioneering pipeline ventures like TAPS and ANGTS tend to require 3 to 8 years or even longer for their planning, design, construction, and shakedown.

Risk. Risk and uncertainty pervade all segments of the petroleum business. Geological or exploration risk --- the low percentage of "wildcat" wells that lead to commercial oil and gas discoveries --- probably receives the greatest emphasis in public discussions of petroleum industry risks. But a major petroleum company can "insure" itself against geological risk by conducting its exploration programs in a large number of prospective areas, and by engaging in joint ventures with other companies on unusually costly offshore or Arctic exploration projects.

The most significant risks in the industry today tend, rather, to concern costs, markets, and political and regulatory treatment. The large absolute size of individual projects, and the long time that typically elapses between the initial outlay and its return, make the economics of new refineries, processing plants, or transportation systems extremely sensitive to future raw materials costs, product markets, tax treatment, and government policies for long periods into the future. They are therefore exceptionally vulnerable to cost overruns, unforeseen changes in raw materials costs or supply interruptions, and to changes in product demand, tax treatment, regulation and other government policies.

Vertical integration. Vertical integration is primarily an attempt to reduce the supply or market risks faced by the various sectors of an industry. Primary raw materials producers are likely to integrate "downstream" into refining, chemical manufacturing, and distribution, in order to assure themselves a long-term market, while refiners and processers try to obtain control over producing properties in order to stabilize their raw materials costs and reduce the possiblity that expensive plants will become idle or customers go unserved in some future feedstock shortage. Crude oil pipelines are typically built and operated by major producers and/or refiners, because only they can assure that the pipeline will be used.

A relatively small number of multi-national firms produce, transport, refine, and market most of the petroleum liquids in the United States, but the major companies share the stage with independent and partially-integrated producers, refiners, resellers, and marketers of all sizes. As a result, the oil business is probably one of the most competitive of the major commodity industries.

The chemical industry is more concentrated than the oil industry: the five top chemical companies accounted for 60 percent of total U.S. sales in 1979, while the five top refiners accounted for 48 percent. In the last five years, however, growing downstream integration by major oil companies has given them a dominant role in production of primary petrochemicals, such as ethylene and benzene.

Government Involvement. Governments powerfully influence the structure and performance of the petroleum industry through their roles as landlords and royalty-owners; tax collectors; protectors of investors, consumers, and competitors, and of health, safety and the environment; price regulators and allocators; statisticians; traders; and promoters or investors.

Some government programs or policies have encouraged vertical integration (e.g., percentage depletion allowances prior to 1976, and the windfall profits tax since 1980); others have penalized it (e.g., the mandatory oil import program of 1958-1973 and especially its "sliding-scale" favoring small refiners, and the allocation system and small-refiner entitlements bias under the Emergency Petroleum Allocation Act between 1973 and 1980).

The government of Alaska is distinctive among the states because of the size of the petroleum resource base it controls. At year-end in 1980, the State's royalty interest in just proved reserves amounted to about 1.1 billion barrels of crude oil and NGL's, and 3.9 trillion cubic feet (TCF) of natural gas. Its taxing authority extended to another 8.6 billion barrels and 32.8 TCF. Further oil and gas discoveries will surely add to these totals.

With a 1980 Alaska resident population of about 400,000 persons, these supplies exceed by many times any reasonably foreseeable demand by the State's exisitng residential, commercial, or industrial consumers. The expected revenues from extracting these resources will likewise far surpass the population's needs for the ordinary services of State and local governments, leaving a large current revenue surplus available for long-term investments, industrial development projects, or direct distribution.

Thus, Alaska's discretionary powers over the oil and gas itself, and over the revenues they generate, are exceptional. The role of State government as resource owner, manager, regulator, and potential investor plunges the issues of refinery and petrochemical development squarely into the political arena. As Alaska's oil and gas industry is already more than 30 years old, a brief overview of its existing and contemplated developments will shed some light on how and where the industry may develop in the future.

CHAPTER 3

THE PETROLEUM INDUSTRY IN ALASKA

The kind, size, and location of existing petroleum-related activity in Alaska will doubtless have a large influence on the kind, size, and location of future refining and petrochemical investments.

3.1 Hydrocarbon Resources, Reserves, and Production.

Cook Inlet. In the modern era, the first commercial discovery of petroleum occurred in 1957 at Swanson River on the Kenai Peninsula, 100 kilometers Southwest of Anchorage. The last major oil discovery in the upper Cook Inlet region was in 1965, and the last important gas discovery was in 1966. Oil production peaked in 1970 at 229 thousand barrels per day (mbpd), averaged 85 mbpd in 1980, and is continuing to decline rapidly. Industry geologists believe it is unlikely that new discoveries in the Upper Cook Inlet area will reverse this trend.

Natural-gas production, other than volumes reinjected to maintain oil-field pressures, averaged about 600 million cubic feet (mmcf) per day in 1980. At the end of 1980, Cook Inlet's proved natural-gas reserves totalled more than 3.5 trillion cubic feet, about 16 years' production at the current rate. Because about half of the area's proved reserves are still not firmly committed to production, however, the industry's incentives to develop the additional discoveries which are known to exist (and thus to add them to the proved reserves category) has been rather weak. Thus, it is likely that Cook Inlet gas production could actually continue to increase for, say, another decade before beginning to fall off.

Prudhoe Bay Area. The Prudhoe Bay oil and gas field in Arctic Alaska, discovered in 1968, is relatively small compared to a few fields in the Middle East (and perhaps in the U.S.S.R.) but it is the largest crude-oil deposit yet discovered in the United States or Canada, and one of the Continent's three or four largest natural-gas deposits.

The main reservoir at Prudhoe Bay [the "Sadlerochit" formation] began producing crude oil in commercial quantities when TAPS was completed in 1977. Current production is at the reservoir's peak capacity of about 1.5 million barrels per day, about 18 percent of the total U.S. production of crude oil, and 15 percent of domestic petroleum liquids production (including natural gas liquids).

Other known reservoirs in the Prudhoe Bay field [the "Kuparuk" and "Lisburne" formations] and recent significant but still unmeasured discoveries nearby [at Point Thomson-Flaxman Island, Sag Delta-Duck Island, and Gwyrdyr Bay] will probably contribute an additional one or two hundred thousand barrels per day before production from the Sadlerochit reservoirs begins to decline in the mid-to-late 1980's. All of these deposits together might conceivably be producing 500 thousand barrels per day or more by the mid-1990's, but without further large discoveries, there is little chance that new fields on the North Slope will fully offset the falloff in Saldlerochit production.

Commercial production of natural gas from Prudhoe Bay awaits completion of ANGTS, no sooner than 1985. Gas producers and pipeline sponsors are counting on the Sadlerochit formation to produce at least 2.7 billion cubic feet (bcf) of raw, unprocessed gas per day, the equivalent of about 2.0 bcf per day of pipeline-quality gas, for 20 to 25 years. There are no authoritative public estimates of potential production from the other known reservoirs and recent discoveries in or around the Prudhoe Bay field, but they might increase these figures by another 25 to 50 percent by the time any gas transportation system is in place.

<u>The Outlook for Additional Discoveries</u>. Alaska and its offshore margins contain the bulk of the remaining unexplored petroleum-producing prospects in the United States, and major additional oil and gas discoveries are inevitable. Some areas in and adjacent to Alaska are regarded as the most promising acreage for petroleum exploration under the American flag. Three such areas are (1) portions of the Beaufort Sea where the State and Federal governments held an oil and gas lease sale in December 1979, (2) the St. George Shelf South of the Pribilof Islands in the Bering Sea, and (3) the Arctic National Wildlife Range (ANWR) in the extreme Northeast corner of Alaska.

On the basis of surface investigations and inferences from drilling elsewhere, geologists believe that each of these areas contains one or more geological "structures" capable of containing a "supergiant" oil and/or gas reservoir. [A supergiant oil field is one with recoverable crude oil reserves of one billion barrels or more, and a supergiant gas field is one with an equivalent amount of energy in the form of natural gas --- roughly 1.8 tcf.]

Supergiant discoveries are rare and random events, however, and the probability that another field the size of Prudhoe Bay will be discovered in this century is very slim. Moreover, there is still no way short of drilling to find out for sure whether even the most promising structure identified from the surface contains petroleum rather than, say, salt water.

The location and current status of the three exploration prospects illustrate the outlook for oil and gas production from frontier areas in Alaska generally. The first exploration well was "spudded" --- i.e., began drilling --- in the Beaufort Sea in November 1980, less than one year after the 1979 lease sale. Yet local village, whaling-interest, and environmental groups have filed lawsuits against drilling on both State and Federal acreage, and the possibilities for delay are substantial.

More important, however, are the delays that flow from short shipping season, the horrible weather, and the need to develop new engineering techniques for finding and producing oil from under ice-stressed seas. While at least one major oil discovery has already been announced (in the Duck Island - Sagavanirktok Delta area) and while many petroleum geologists consider the Beaufort Sea the nation's most promising exloration frontier, very few of them expect any commercial oil or gas production in less than 8 to 10 years.

The Beaufort Sea lease sale area is under shallow water within about a 200-kilometer radius of Prudhoe Bay and can rely to a large extent on the infrastructure created to serve Prudhoe Bay --- particularly on TAPS and ANGTS, should exploration be successful. The St. George Shelf where a Federal OCS lease sale is scheduled for 1982, is far from land in the Bering Sea, however; any exploration effort there must cope with much deeper water and high waves as well as different but equally unhospitable weather. And the petroleum industry has established neither staging areas nor even the beginnings of an oil or gas transportation system in the area. Finally, the State government itself is on record opposing petroleum exploration in the Bering Sea, along with some communities and local interests, fishermen, and conservationists.

The ANWR is on land, and although considerably farther from Prudhoe Bay, TAPS, and ANGTS than the 1979 Beaufort Sea lease sale area, exploration there would benefit considerably from existing development, and particularly from engineering techniques for Arctic tundra areas developed for Prudhoe Bay exploration and development. But no leases are yet scheduled for ANWR, and preservation of the wilderness status of the Range is one of the highest political priorities of national conservation organizations. As a result, the 1980 Alaska Lands Act closed most of the ANWR to exploration, except for a promising strip along the Arctic Coast, and even that parcel requires a 5-year geological and geophysical study by the government, followed by Congressional action, before any leasing would be permitted.

Every other prospective oil and gas exploration frontier in the State differs somewhat from the three we have used as illustrations, but in almost all of them, there are comparable obstacles to development in the form of remoteness, climate, novel engineering or environmental challenges, lack of an existing infrastructure, and/or local, statewide or national opposition.

In summary, therefore, Alaska doubtless has a great deal of undiscovered petroleum, and petroleum exploration will be an important activity in and offshore Alaska for many decades. Apart from the known deposits in and adjacent to the Prudhoe Bay field and in Upper Cook Inlet, however, how much oil and gas will actually be discovered and produced in the State, where, and when, are complete mysteries. In no case can these unknown resources be a basis for projecting the State's fiscal outlook, its future population and economic activity, or future investment in refining or petrochemical manufacturing.

Royalty Oil and Gas. Lease contracts covering the established production at Prudhoe Bay and in most of the Cook Inlet fields reserve a one-eighth royalty interest in the oil and gas produced, which the State may at its option take either "in value" [cash] or "in kind" [as oil and gas]. On many State leases not yet under production, including the Beaufort Sea lease area, the State's royalty share is larger. Taking royalty oil or gas in kind, in order to sell it to a prospective (or established) in-state hydrocarbons processor, has been and likely will continue to be one of the State's tactics in attempting to encourage refining and petrochemicals investment.

3.2 Hydrocarbons Processing in Alaska.

Fuels Refineries. Three refineries now exist in Alaska, operated by the Standard Oil Company of California [Chevron] at Swanson River on the Kenai Peninsula, by Tesoro Alaskan at Nikiski [Kenai], and by Mapco [Earth Resources Company of Alaska (ERCA)] at North Pole near Fairbanks.

Together the three refineries have been running slightly more than 100 mb/d of crude oil, and producing about 44 mb/d of refined products, principally fuels. [The balance is residual oil, which is shipped to the Lower-48 for further processing or for sale as electric-utility fuel. Estimates of 1980 Alaska petroleum products consumption [by five different authorities] range from 63 to 89 mb/d, of which about 28.5 mb/d appears to be jet fuel (much of it destined for international airlines and the military, and thus not strictly an in-state use). The remaining direct Alaska consumption of motor fuels, heating oil, and electric utility fuel in Alaska was somewhere in the range of 35 to 60 mb/d. We believe that the most likely figure is on the order of 45 mb/d. Nearly half of this total was imported from the Lower 48, much of it to Southeast and Western Alaska.

The Chevron refinery was built in 1963, has a crude-oil distillation capacity of 22 mb/d, and refined an average of 13.5 mb/d in 1980. The company is currently considering shutting-down this small and relatively inefficient plant, because of excess capacity in Chevron's larger West Coast refinery. The Tesoro refinery was built in 1966 expressly to run sweet [low-sulfur] light [high gasoline-content] crude oil, which it obtains in a long-term sale of Cook Inlet royalty crude by the State; the refinery can now run a mixture that includes about a 15 percent fraction of Prudhoe Bay crude oil, which has a higher sulfur content and lower "gravity" [less gasoline and more residual oil]. Its crude-oil distillation capacity is 48.5 mb/d, and it ran essentially at full capacity in 1980.

Both the Chevron and Tesoro refineries export about half their total product to the U.S. West Coast --- mainly residual oil and crude gasolines for blending --- and sell middle distillates (diesel, home heating oil, and jet fuel), gasoline [Tesoro] and asphalt [Chevron] in Alaska.

The North Pole refinery is less complex than that of Chevron or Tesoro. Its crude-oil processing capacity is 47 mb/d; in 1980 the refinery processed an average of 43 mb/d of crude oil taken from TAPS; the output consisted of 16 mb/d of middle distillates sold in Alaska, and 27 mb/d or residual oil, LPGs and crude gasoline reinjected into TAPS for processing by Lower-48 refiners.

The refinery proposed for Valdez by the Alaska Oil Company (Alpetco) to use Prudhoe Bay royalty oil would have been much more sophisticated than the existing Alaska plants in that it would have processed its entire crude-oil input of 100 mb/d into light fuels (including high-octane unleaded gasoline) and middle distillates. The refinery would have produced virtually no residual oil to sell in a shrinking market (most likely for an energy-equivalent price far less than that of the crude oil that is used to produce it).

<u>Facilities Using Cook Inlet Natural Gas</u>. Three major producing fields in the Cook Inlet area are the main support of Southcentral Alaska's natural-gas industry. The North Cook Inlet field was discovered in 1962, but the absence of a market delayed its development for several years. Eventually, the Phillips Petroleum Company arranged to sell the gas as liquefied natural gas [LNG] to two Japanese utilities. In 1967, Phillips bought out the other leaseholders and developed the field from a single platform. The gas is piped to shore through two undersea lines and then moves in a single line to the LNG plant at Nikiski, where it is cooled and liquefied. The LNG is then loaded into special "cryogenic" [supercooled] tankers, which ship the equivalent of 140 mmcf/d to Japan.

The Beluga River gas field is not yet completely developed. The gas from this field is "dry gas", gas that contains hardly any water or "condensate" (essentially the same thing as NGL's: hydrocarbons that are liquid under atmospheric conditions], and production operations are therefore relatively simple. The gas in this field has been sold to an Anchorage-based electric utility, the Chugach Electric Association [CEA], which uses it to fire combustion turbines at Beluga on the west shore of Cook Inlet.

The Kenai field is a large unitized gas field immediately south of Kenai along the west shore of Cook Inlet.

Most of the field is onshore, on acreage owned by CIRI [Cook Inlet Region, Inc., a Native corporation] as the result of a land-swap with the State. Some of the gas from the Kenai unit is produced for sale to the Alaska Pipeline Company [APC] which carries it to the Anchorage gas utility, an affiliate of APC. The balance is piped to Kenai, where it is used to manufacture aqueous ammonia and prilled urea fertilizer at a plant operated by the Collier Carbon and Chemical Company (a Union Oil Company subsidiary) on behalf of itself and Japan Gas Chemical Company. Some of the Kenai gas is liquified at the Phillips LNG plant, some is sold directly to the local gas utility in Kenai, and the remainder is sent to the Swanson River oil field where it is used to repressure that field.

The Pac-Alaska LNG project is a plan by two West Coast utilities to liquefy Cook Inlet natural gas and ship it as LNG to a terminal and regasification plant in California. Actual construction of the project is now doubtful, because of (1) the sponsors inability thus far to get sales commitments on the volume of gas necessary to support the plant, (2) a protracted contest before several regulatory agencies about the terminal site, and (3) a growing abundance of Lower-48 and Canadian gas that the California utilities can obtain directly by pipeline.

Residental consumers, industry, and electric utilities in the Anchorage-Cook Inlet region currently enjoy some of the lowest natural-gas prices in the United States. The average wellhead price in 1980 was about 27 cents per mcf compared to a national average of $1.61 per mcf, and a $4.91 border price for Canadian imports to the United States. The provisions of the present sales contracts would raise most Cook Inlet gas prices to the levels paid by the Pac-Alaska LNG plant, if that project is actually built.

3.3 Prudhoe Bay Natural-Gas Reserves and ANGTS

The Alaska Department of Natural Resources [DNR] in 1980 estimated the proved natural-gas reserves of the Prudhoe Bay Sadlerochit reservoir at 29 tcf, with 4.5 to 7.8 tcf in other nearby reservoirs. Thus far, only natural gas dissolved in the crude oil produced from the Sadlerochit reservoir has been produced and this gas is all being reinjected into the reservoir, except for a very small quantity used as local fuel in the field.

After a natural-gas pipeline is completed, however, the dissolved gas produced with the oil will be augmented with "gas-cap" gas produced from the part of the reservoir above the oil layer. The combined gas stream will then be stripped of water, carbon dioxide, and most of its natural-gas liquids [NGL's], and shipped through the pipeline to gas transmission companies in the Lower 48.

ANGTS --- The Alaska Natural Gas Transportation System. In 1977, the President and Congress awarded the Alcan Pipeline Company, a subsidiary of Northwest Energy Company, the right to build the Alaska segment of an Alaska Natural Gas Transportation System (ANGTS), which will consist of a pipeline laid parallel to TAPS as far as Fairbanks, whence it would follow the Alaska Highway into Alberta, where the system would branch into a "Western Leg" to California, and an "Eastern Leg" into the Midwestern States.

Alcan has now been succeeded by the Alaskan Northwest partnership; the Canadian sections would be built by a group of companies operating under the name Foothills; the Eastern Leg is known as the Northern Border system, and is now under construction by a partnership headed by InterNorth; while the Western Leg is being built by Pacific Gas Transmission Company [PGT].

The sponsors plan to design ANGTS for an inital though-put of 2.0 bcf per day, beginning in 1985; they have already received a number of important regulatory approvals in both the United States and Canada, including final authorization to "pre-build" the Southernmost sections designed to carry Canadian as well as Alaska natural gas. The 1977 Presidential Decision selecting ANGTS, however, has several provisions that have effectively blocked financing of the rest of the more-than-$20 billion system, and a deadlock exists among the pipeline sponsors, the Prudhoe Bay gas producers, and federal authorities over how to resolve the impasse. Accordingly, there is little probability that the pipeline will actually be built and completed on schedule so that it can carry gas by 1985.

<u>The Sales Gas Conditioning Facility [SCGF]</u>. Natural gas from the Sadlerochit reservoir is relatively "sweet" and "wet" [devoid of hydrogen sulfide, but saturated with NGL's], and has a high carbon-dioxide [CO_2] content (about 13 percent). A "sales gas conditioning facility" [SCGF], with a cost on the order of $2 billion, would reduce the level of CO_2 in the "sales gas" [gas shipped through ANGTS] to a level consistent with "pipeline quality." Preliminary designs for the SCGF, prepared for the gas producers and the ANGTS sponsors, would use a physical (rather than chemical) process called <u>Selexol</u> to remove CO_2 from the raw gas.

The Selexol process separates the components of the produced-gas stream according to their different boiling points. Because the boiling point of ethane [C_2H_4] is close to that of CO_2, most of the ethane remains mixed with the CO_2 in a "waste gas" that can be used for local fuel use in the field, but which is unsuitable for shipping further. As the SCGF and nearby pumps, compressors, and heaters must use some fuel or another in large quantities, this arrangement is an excellent one if there is no better use for the ethane.

Ethane, however, may be an exceptionally-desirable raw material for an Alaska-based complex to produce ethylene and its derivatives, providing the ethane can be delivered to an appropriate plant site at an acceptable cost. The CO_2-removal process chosen for the SCGF may thus directly affect the availablity of ethane for petrochemcial use in Alaska.

A Natural Gas Liquids (NGL's) Pipeline and Alaska Petrochemicals Production. Prudhoe Bay natural gas contains other NGL's in addition to ethane [C_2]: propane [C_3], butanes [C_4], and pentanes-plus [C_{5+}], each of which has several alternative uses. Propane and butane can be used directly as home heating or industrial fuels in the form of "bottle-gas", or used along with ethane to produce "olefins", such as propylene, butylene, and their derivatives. Butane may be used as the principal raw material for methyl tertiary butyl ether [MTBE] and other synthetic high-octane gasolines. The Exxon Chemical Company and the Dow-Shell group are independently studying the economic feasibility of NGL's-based petrochemicals production in Alaska.

The outlook for such a chemical industry is intimately intertwined with decisions concerning Prudhoe Bay hydrocarbons production and ANGTS. For example:

1. The SCGF must be modified to produce pipeline-quality sales gas and at the same time separate sufficient quantities of ethane from the CO_2 to justify construction of the NGL's pipeline and an ethylene plant.

2. If the ethane-CO_2 mixture is not used as local fuel at Prudhoe Bay, another fuel must be used that is economical and acceptable to the gas producers and the pipeline operators --- the most obvious alternative is methane, the main component of the sales gas, but by reducing the sales-gas volume, choice of methane could seriously affect the economics of ANGTS.

3. Exxon and ARCO, owners of the bulk of the Prudhoe natural gas and NGL's, are major chemical producers, and they must either be interested themselves in building (or participating in) an NGL's line and an ethylene plant, or be willing to sell other parties like Dow-Shell sufficient volumes of NGL's to support both the pipeline and the petrochemical facility.

4. The feasibility of building and operating an NGL's line and an Alaska-based worldscale ethylene plant must be demonstrated.

A single worldscale ethylene plant would require only about 35 mb/d of ethane; some additional ethane could conceivably be sold as electric utility fuel in Interior and Southcentral Alaska, but the total assured demand within Alaska would be considerably less than the volume of liquids [at least 150 mb/d] necessary to justify construction of a new pipeline.

As shipment of surplus ethane beyond Alaska would require cryogenic tankers similar to those used to move LNG, large volumes of propane and butanes (which can be shipped in conventional tankers) would have to be saleable in export markets in order to cover the pipeline cost, at least until two or more ethylene plants were warranted in Alaska.

Propane and butanes may be marketed and shipped as liquefied petroleum gas (LPG) or sold in Alaska as heating fuel (bottle gas) or as feedstock for the manufacture of alcohols or octane-enhancing gasoline additives such as MTBE. Ethylene remains a gas unless it is chilled to -155° F [-104° C]; sometimes it is shipped by sea on a small scale in cryogenic vessels similar to those used for LNG, but costs probably rule out this strategy for a world-scale Alaska facility. The chemical companies that have expressed interest in producing ethylene from ethane in Alaska contemplate further processing of ethylene into compounds such as polyethylene, ethylene glycol, or stryrene, which are solids or liquids under normal atmospheric conditions and are thus easier to transport.

CHAPTER 4

FUNDAMENTALS OF HYDROCARBONS CHEMISTRY

4.1 General Introduction.

Fuels refining and petrochemicals manufacturing are both hydrocarbons processing industries. They begin by taking mixtures of hydrocarbons from crude oil or natural gas as raw materials, separating them into components, and altering the molecules in various ways to produce a range of products for final consumers or for use as inputs to other industries.

The two industries overlap technically, using many of the same processes and intermediate products. The chief distinction between them is their respective "product slates". The greatest part of refinery output is made up of liquid hydrocarbon mixtures. While some of these products are sold for use as lubricants, solvents, or raw materials for the petrochemical industry, the main business of the refining sector is fuels production.

Petrochemicals manufacturing includes practically any hydrocarbons processing operation whose principal output is not liquid hydrocarbon fuels (or certain by-products of fuels refining, such as asphalt or petroleum coke). Petrochemical products may be liquid, gaseous, or solid: they include synthetic fibers, plastics, synthetic rubber, paints and varnishes, resins, food additives, medicines, industrial reagents, and much more.

To understand better how these products are made, it is useful to review the chemistry of hydrocarbons.

4.2 Composition of Natural Hydrocarbons.

Natural hydrocarbons are complex mixtures of carbon and hydrogen that are usually found underground in combination with impurities such as water, sulphur and carbon dioxide. Conventionally, hydrocarbons are grouped according to the number of carbon atoms [C_n] in each molecule. However, the variations of hydrocarbon mixtures are vast and every accumulation of oil and gas is unique.

The following table lists the simpler, smaller-molecule hydrocarbons found in crude oil and natural gas reservoirs, and alludes to the existence of others with dozens of carbon atoms in each molecule.

Compound	Chemical Formula	Principal Names
methane	CH_4	Dry gas
ethane propane butane	C_2H_6 C_3H_8 C_4H_{10}	Natural gas liquids (NGLs) or condensate.
pentane hexane heptane octane	C_5H_{12} C_6H_{14} C_7H_{16} C_8H_{18}	Natural gasolines, naphtha, or pentanes-plus.
--- --- ---		Oils, waxes, tars, bitumen, asphalt
etc.	$C_{100+}H_{200+}$	

The lightest and most stable hydrocarbon is methane [CH_2], the chief component of natural gas and building block for other hydrocarbons. Methane and ethane [C_2H_6] are usually transported from the field in gaseous form and sold to long-line gas transmission companies, which in turn sell them to local gas distribution companies, most of whose customers use gas directly as fuel without further processing. The methane of natural gas is, however, also used frequently as a petrochemical feedstock for making synthesis gas for processing into methanol, ammonia, urea, amines, and their derivatives.

The bulk of the natural-gas liquids [NGLs], which may or not include the produced ethane, is usually separated in the field and sold for use as LPG (liquefied petroleum gas) fuel or as feedstocks for petrochemical manufacturing.

The term "crude oil" usually refers to the heavier hydrocarbon fractions, composed of molecules with five or more carbon atoms. Crude oils are very complex mixtures with many thousands of individual hydrocarbon compounds ranging from light gases to viscous, semi-solid materials such as the bituminous tar sands at Fort McMurray in Northern Alberta.

Each hydrocarbon compound in crude oil has its own boiling temperature, with the heavier compounds (those having a greater number of carbon atoms in each molecule) having higher boiling temperatures and lighter compounds boiling at lower temperatures.

Compound	Formula	Boiling Temperature	Weight Pounds/Gallon
Propane	C_3H_8	-44° F	4.2
n-Butane	C_4H_{10}	31° F	4.9
n-Decane	$C_{10}H_{22}$	345° F	6.1

Every crude oil produced has a distinctive mixture of compounds, ranging from very <u>light</u> mixtures with about 75 percent of the hydrocarbons in the gasoline-naphtha range [C_5 to C_{10}] to <u>heavy</u> oils that are solid or nearly solid at atmospheric temperatures.

Crude oils also contain small amounts of sulfur, nitrogen, heavy metals, and other contaminants. The percentage of sulfur varies from as low as 0.03 percent in some crude oils from Bolivia and Argentina, to as high as 7.3 percent in oil from the Qayarah field in Iraq. Alaska's Cook Inlet crudes are regarded as very low sulfur supplies or "sweet" crude, at 0.1 percent. Other important sources of low-sulfur crude oil are Alberta, Indonesia, Nigeria, and Libya. Prudhoe Bay Sadlerochit crude oil, with about 1.0 percent, is described as medium-sulphur or intermediate sweet. Quayarah crude oil is considered extremely "sour".

4.3 Chemistry.

The mixture of hydrocarbon compounds and the kind and amount of impurities in a crude oil generally determine the yield of gasoline, distillate fuels, lubricating oils and petrochemical feedstocks. To obtain these products, refineries and petrochemical plants subject the hydrocarbon mixtures to a number of processes that separate the compounds into fractions or cuts, remove the impurities, recombine or convert the hydrocarbons into other forms, and blend them into products for sale or further manufacturing. Every refinery and petrochemical plant has different types of equipment for altering the chemical structure of hydrocarbons and will thus yield different product slates even from the same crude oil.

The chemical composition of hydrocarbons is the basis for development of refining and processing techniques, improvements in product quality and the manufacture of a wide range of petroleum chemicals and synthetic products. The chemistry of hydrocarbons is, therefore, an important prelude to further discussions about fuels refining and the manufacture of petrochemicals.

<u>Paraffins</u>. Paraffins or alkanes represent a large proportion of the hydrocarbons present in crude oil. The paraffin series is composed of compounds having straight chains of linked carbon atoms, and their corresponding <u>isomers</u> or iso-alkanes --- compounds with the same numbers of carbon and hydrogen atoms, but with branched-chain molecules. Both have the general formula C_nH_{2n+2}, and the names of individual hydrocarbons in the series end with "-ane". Methane and ethane are the simplest paraffins, having the following structures:

```
     H                 H H
     |                 | |
   H-C-H             H-C-C-H
     |                 | |
     H                 H H
```

Methane (CH_4) Ethane (C_2H_6)

Similarly, propane is:

```
   H H H
   | | |
 H-C-C-C-H
   | | |
   H H H
```

Propane (C_3H_6)

Hydrocarbons containing more than three atoms of carbon in each molecule may form isomeric, branched-chain forms, for example:

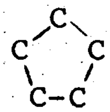
```
                              H
                              |
                            H-C-H
   H H H H                  H | H
   | | | |                  | | |
 H-C-C-C-C-H              H-C-C-C-H
   | | | |                  | | |
   H H H H                  H H H
```

Normal or n-butane (C_4H_{10}) Iso- or i-butane (also C_4H_{10})

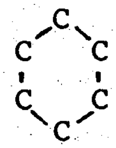
Butane has only these two isomers. As the number of carbon atoms increases, however, the number of possible structural combinations increases geometrically. For instance, pentane [C_5H_{12}] has three isomers, nonane [C_9H_{20}] has 35, and duodecane [$C_{12}H_{26}$] has 355.

Although paraffins and their isomers have the same number of atoms, they boil at different temperatures, have different gravities, and participate in different chemical reactions.

Naphthenes. Hydrocarbons with more than four carbon atoms can be linked in ring-like central structures and have the general formula C_nH_{2n}. [For simplicity, we have omitted the H symbols for any hydrogen atom linked directly to one of the carbon atoms comprising a ring.]

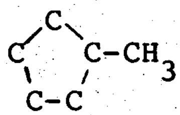


Cyclopentane
(C_5H_{10})



Cyclohexane
(C_6H_{12})

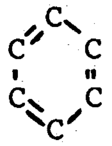
The five- and six-membered ring is present in every naphthene. Other members of the series form by the addition of branches of carbon atoms to the outside of the ring. Methyl cyclopentane, for example, is an isomer of cyclohexane:



Methyl Cyclopentane (C_6H_{12})

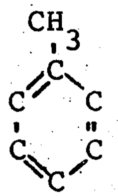
Cyclopentane and cyclohexane are the only hydrocarbons in the series that occur in nature. The number of compounds which, in the course of refining processes, may attach in different combinations to the outside of the ring can be very large, however.

Aromatics. The simplest member of the aromatic series and the building block for all other aromatics is benzene, composed of a six carbon-atom ring with six associated hydrogen atoms and three double bonds alternating between the carbon atoms in the ring:

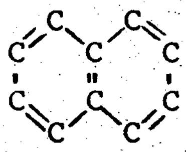


Benzene (C_6H_6)

Aromatics include any compounds that have a benzene ring in them. These compounds are formed when hydrogen atoms on the outside of the ring are removed and paraffins or other benzene rings substituted. The new compounds are called alkyl benzenes, e.g.:



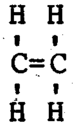
Toluene
($C_6H_5CH_3$)



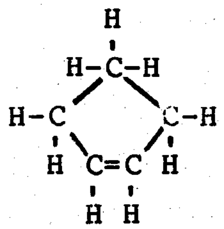
Naphthalene
($C_{10}H_8$)

The double bonds in the benzene ring are very unstable and chemically reactive, and thus the alkyl benzene series are important building blocks for refined and chemical products.

Olefins. This series of hydrocarbons is not found in crude oil, but are manufactured by one of several cracking processes. They resemble paraffins and naphthenes in structure, but like the alkyl benzene series, they have double and sometimes triple bonds between carbon atoms.



Ethylene
(C_2H_4)



Cyclopentene
(C_5H_8)

The double and triple bonds are deceiving because, contrary to appearances, these bonds are weaker than a single bond, making the compound unstable. If every carbon bond is linked to an atom of hydrogen (or some other element), the hydrocarbon would be saturated and therefore relatively stable. Olefins and aromatics are said to be unsaturated because they contain double or triple bonds. The unsaturated hydrocarbons are valuable to the chemical industry because they typically react directly with other chemicals. For instance the olefin ethylene (C_2H_4) reacts with chlorine to form a vinyl chloride monomer, which in turn is used to produce polyvinylchloride (PVC) resin used for the manufacture of plastics.

CHAPTER 5
FUELS REFINING

The manufacture of refined products begins with hydrocarbon compounds and involves the tearing down, rebuilding and restructuring of molecules to produce saleable products. The main business of the refining sector is fuels production. Before the 1900's, a typical refinery simply broke down the crude oil by distillation into a series of cuts or fractions, often referred to as straight runs. Today, almost all petroleum products are specially tailored in their physical and chemical properties and freedom from impurities to meet exacting market demands.

5.1 Petroleum Industry Structure.

The refining sector is an integral part of a petroleum industry made up of thousands of companies that are exceedingly varied in size, functions, geographical sphere of operations, and structure.

The Major Oil Companies. Big Oil consists of seven, twelve, sixteen, or twenty "major" or "multinational" corporations, depending upon the statistical authority. However many Sisters one chooses to count, what distinguishes the major oil companies is both their great size and their vertical integration: they produce crude oil; own crude-oil and petroleum-product pipelines, tankers, and barges; refineries; tank farms and terminals; and operate retail outlets. Many of the majors are engaged in other related businesses, such as natural-gas production and processing, and petrochemicals manufacturing. These major companies vary greatly in size, and no two of them have the same mix of functions, so that some majors are net sellers and others net buyers of crude oil; some are net sellers of refined products at wholesale and others net buyers, and in many different degrees.

In 1979, the top 16 integrated companies produced about 60 percent of U.S. crude-oil output, and accounted for about 12 million barrels per day (mmbpd) of refining capacity, or about two-thirds of the national total. The same companies also marketed about two-thirds of the refined products sold in the United States.

The Independents. A significant part of the business in each sector of the petroleum industry is conducted, however, by "independents" --- specialized or only partially-integrated firms that compete both with the majors and with one another: there are independent exploration companies and producers, independent oilfield service companies and gathering companies, independent oil-pipeline and tanker-transportation companies, independent refiners, resellers and brokers, jobbers, marketers, and retailers.

The independent sector is deeply rooted in U.S. oil-industry history: From its earliest days, the production of crude oil in the United States was widely dispersed among many producing companies, largely because it occurred in fields of many sizes located on privately-owned tracts where farmers, ranchers, and other owners held the subsoil mineral rights as well as the surface estate. Although the top 20 integrated oil companies have acquired control of about two-thirds of the crude-oil output in the United States and three-fourths of the reserves, many fields have several operators and royalty owners, and data from Windfall Profits Tax collections reveal that there are literally tens of thousands of crude-oil producers and about two million royalty owners.

The majority of oil-field discoveries onshore in the Lower-48 appear to have been made by independent "wildcat" exploration companies, and they continue to contribute a smaller yet significant portion (about one-third) of the new crude-oil reserves added annually. Because their cost structures and exploration strategies differ from those of the majors, there is a tendency for independent explorationists to sell their discoveries to major producers, while the majors often sell off nearly depleted fields and high-cost "stripper-well" (wells producing less than 10 barrels per day production) to specialized independents.

The situation is somewhat different on the Outer Continental Shelf (OCS) and Alaska, where the ownership of prospective petroleum acreage is concentrated in the Federal and State governments, and where lease tracts are much larger than the typical Southwestern farm property. In these areas, the high costs of exploration tend to restrict activity to the major companies and joint ventures of the larger independents. Even so, OCS and Alaska State lease auctions typically attract 10 to 50 different bidding combinations, representing a similar number of separate companies.

About 6 mmbpd, or 34 percent of the total U.S. refining capacity were owned by non-integrated refining companies in 1979. As one might expect, the independent refiners depend far more heavily on crude oil from independent producers than do the refining divisions of the major companies. In retailing, the majors tend to sell their own refined products, or refined products exchanged with other majors, under their respective brands, while independent marketers buy their products at wholesale from major companies, independent refiners, and resellers.

5.2 Feedstocks and petroleum products.

Introduction. Within rather narrow limits, the characteristics of a refinery's crude-oil supply and its initial design determine the possible mix of its refined product output. Refineries are planned, therefore, to match their product slates as closely as possible to the mix of product demand in the areas the refinery serves. North American refineries, for example, have been generally designed to emphasize gasoline production, and secondarily, that of middle distillates (heating oil, diesel fuel, and jet fuel), at the expense of heavy fuel oils.

Closer to home, Chevron's Kenai refinery processes crude oil to serve local markets for jet fuel, diesel fuel, and home heating oil. Mapco's North Pole refinery near Fairbanks cuts the "tops" and "bottoms" out of the crude oil, in order to sell the middle distillates, and the Tesoro refinery produces gasoline as well as middle distillates. Each of them, however, exports a large part of each barrel to other states in the form of residual oil, for which there is no significant demand in Alaska. If it were actually built, Charter's proposed Alaska Oil Company refinery at Valdez would have been unique in Alaska, as it would begin as a "complex" refinery, capable of processing all the residual oil from the distillation tower into lighter refined products.

Refinery design also reflects the grade and quality of crude oil to be processed. Refinery complexity, fixed costs, and operating costs depend principally upon the match or mismatch between feedstock characteristics and the products to be produced. Thus, light (high-gasoline) and sweet (low-sulfur) crude oils have long been preferred refinery feedstocks in North America, where motor fuels have been an exceptionally large part of total petroleum demand

and where air quality has been a major concern. Fortunately, the grade and quality of North American crude oils (other than in California) have tended to be well matched to domestic product slates.

Feedstock Characteristics. The characteristics of different crude oils determine, to a large extent, the refinery processes needed to make a particular product slate. Each crude oil is unique, yielding different amounts of different fractions upon distillation, and different mixtures of compounds within each fraction. These characteristics are ascertained by means of a crude-oil assay involving controlled fractionation in the laboratory and qualitative analysis of each fraction. The assay results typically describe a crude oil in terms of the proportion of its total weight falling into each straight-run fraction, and its density, sulfur content, viscosity, pour point, metal content, and often the proportion of straight-line paraffins, branched-chain paraffins, naphthenes, and aromatics.

Density is a single-number index of the relative proportions of the different hydrocarbon fractions, with the compounds with the largest number of carbon atoms per molecule having the greatest density, and the smaller-molecule LPG's and natural gasolines the least. The density measure is also affected by the proportions of the four major hydrocarbon types, as the individual densities of compounds with a given number of carbon atoms per molecule diminishes in the following order: aromatics > naphthenes > isoparaffins > normal paraffins.

A low-density crude oil can yield more than half of its weight in straight-run LPG's, gasoline, kerosene, and naphtha, while there are high-density California crudes whose weight contains as little as 6 percent in these fractions. Alaska North Slope crude oil is somewhere in the middle at about 30 percent. Density can be measured in terms of specific gravity (kilograms per liter) but the petroleum industry generally prefers to use "API gravity", denominated in degrees, by which lighter or low-density crude oil is referred to as having a "high API gravity", in a confusing violation of the layman's common intuition. A high-density crude oil is similarly referred to as having a "low API gravity."

The total sulfur content is measured in terms of the proportion it occupies of the weight of the crude oil, and thus the volume of sulfur compounds likely to be present in the refinery products. Cook Inlet, Albertan, and Nigerian crude oils tend to be have relatively low sulfur contents at less than 0.3 percent; Prudhoe Bay crude oil is regarded as a medium-sulfur product at about 1 percent, while some "sour" California crudes contain more than 3 percent sulfur.

Since 80 to 90 percent of the sulfur typically remains in the residuum, the acceptability of heavy fuel oils under prevailing air-quality standards is largely a function of the sulfur content of the crude oil. High-sulfur crudes tend to leave impermissable amounts of corrrosive and polluting sulfur compounds in the lighter refined products as well, requiring costly hydrotreating before the products can be marketed. The processing of high-sulfur crude oils also tends to require special catalysts and more sophisticated refinery metallurgy, with the combined result that a high sulfur content in the refinery feedstock makes it considerably more costly to convert into a given slate of refined products.

Viscosity, pour point, and wax content indicate how easily crude oil will flow through pipelines and into or out of tanks and tankers, and the degree to which solid deposits are likely to build up on pipeline or storage-tank walls. All of them are, therefore, crucial variables in designing pipelines and storage facilities. Pour point is the lowest temperature at which oil will pour or flow in response to gravity. Examples of pour points are:

Bonny Light (Nigeria)	+5° F
Prudhoe Bay Sadlerochit	-5°
Saudi Arabian Light	-30°

Viscosity is a measure of the rate of flow at a given temperature and pressure, and increases as temperature declines. A high wax-content crude oil like Indonesian Minas crude tends to clog pipelines, so that they have to be "pigged" (scraped out by a special cylinder sent through the line) frequently.

Generally speaking, crude-oil types and qualities are categorized as follows:

	Atmospheric residuum (>1050° F) by weight	
	Less than 15%	More than 15%
Sulfur by weight		
less than 0.5%	light low-sulfur	heavy low-sulfur
0.5% to 1.0 %	light medium-sulfur	heavy medium-sulfur
more than 1.0%	light high-sulfur	heavy high-sulfur

In addition to these characteristics, there are a host of other features of crude oil from different sources that affect its product yield and cost of refining: the most important are probably the relative proportions of paraffinic and naphthenic hydrocarbons, and the metals content.

Refinery Products. Refined products include a full spectrum of intermediate and consumer products.

First-stage products. Distillation to separate the crude oil into fractions is the first step in all petroleum-refining operations, and yields a set of straight-run "cuts" or product mixes that are the intermediate building blocks for refined products. These fractions are characterized by their boiling ranges --- the hydrocarbons with the lowest boiling points being the lightest compounds.

Figure 5-1 illustrates the relationships among cut points, straight-run fractions, and refinery end-products. Each of the various end products is composed of hydrocarbons having a rather broad range of boiling points, while different end products have boiling ranges that overlap. As a result, refiners are able to vary the proportions of different products made by a given refinery by varying the temperatures or cut-points that separate the different distillation products. Adjusting refinery operations to raise the cut-point temperature at which straight-run gasolines are separated from naphtha means that (1) less gasoline and more naphtha will be produced (perhaps for use as military jet fuel), and (2) the produced gasoline and naphtha will both be lighter than they otherwise would have been.

Distillation of two different crude-oil types in the same refinery will, moreover, yield gasoline of different octane ratings and a light gas-oil fraction of different cetane ratings. Thus, the amount of reforming and other processing required to turn different crudes into marketable products varies widely.

End Products. Different refineries produce radically different petroleum slates, however, end-products can be grouped as follows:

FIGURE 5-1: CRUDE-OIL DISTILLATION

Hydrocarbon type	Temperature cut-points	Distillation products	End-products
C_1		methane	natural gas
C_2		LPG	
through	<100° F		LPG
C_4	100		motor gasoline
C_5	150	straight-run gasoline	naphtha petro-chemical feeds
	200		
through	250	naphtha	military jet fuel
C_{10}	300		civil jet fuel
C_{10+}	350	kerosene	No. 1 diesel & stove oil
	400		
	450		No. 2 diesel & stove oil
	500	light gas-oil	
	550		No. 4 turbine fuel
	600		
	650	heavy gas-oil	gas-oil petro-chemical feeds
	700		
	750		No 6 fuel oil
	800		
	850	residuum	residual fuel oil
	900		
	950		
	1000		bunker "C"
	>1000° F	coke	
			asphalt
			petroleum coke

Motor Gasoline. At one time, light naphtha fractions were sold as straight-run gasoline; however, in today's cars they would run very poorly. Refiners have altered the composition of gasoline considerably by means of reforming, blending, and additives, in order to control premature ignition and detonation ("knocking"), vapor pressure, gum formation in the engine, and odor.

For several decades, refiners have produced and marketed at least two octane levels of leaded gasoline (regular and premium). Since the early 1970's, changes in automobile design intended to reduce air pollution have forced refiners to offer, in addition, at least one grade of unleaded gasoline; the sale of premium leaded gasoline is now being phased out with the decline in the number of cars that require it.

Diesel Fuel. Refineries manufacture diesel fuel for high-speed stationary and marine diesel engines from the middle distillate fractions of the crude oil. Fuel quality requirements depend largely on engine rotational speeds. Fuel for high-speed diesel engines is made from the lighter portions of the distillate cut, and overlaps to some extent with kerosene.

Engines used for electrical generation or marine propulsion run at lower rotational speeds than automotive engines and will accept a lower quality fuel. A marine diesel fuel, therefore, often consists of a blend of distillates and heavy gas oil.

Like motor gasoline, distillate diesel fuels for use in automotive engines have improved during the past several years to meet requirements imposed by changes in engine design and operation. The most significant change in diesel fuels has been the use of hydrogen treating in refineries, primarily to reduce sulfur content. Fuels have also been improved to decrease engine deposits and reduce smoke and odor. The use of additives in diesel fuels has become common for the purpose of lowering "pour points" (insuring that the fuel continues to flow at low temperatures), increasing stability in storage, and improving the ease of ignition.

Aviation Fuel. Aircraft fuels are of two quite different kinds: aviation gasoline ("Avgas") for piston-engined craft, and jet fuels for use in turbine engines. Aviation gasoline generally requires higher anti-knock ratings and, because of the greater range of atmospheric pressures and temperatures, more exacting vapor-pressure standards than motor gasoline.

A satisfactory turbine fuel must ignite easily and burn cleanly; and because jet fuels are exposed to both high and low temperatures in use, they must therefore have very low freezing points and at the same time be stable at high temperatures. These qualities are less demanding on refinery design and operation, however, than those that are critical in fuels for internal-combustion engines. As a result, marketable jet fuels can be produced even in relatively simple refineries, like Mapco's North Pole plant, and tend to be cheaper than the same amount of energy in the form of Avgas.

An alternative jet fuel used mainly by the military is known as "wide-cut" gasoline and is, as its name suggests, a product blended from straight-run fractions ranging from the light naphthas to heavy gas oil (but mainly the former). This fuel, known as "aviation turbine gasoline" or JP-4, is easily manufactured, and because of its wide cut, refiners can obtain a high yield from each barrel of crude oil.

<u>Gas and LPG (Liquefied Petroleum Gas)</u>. Various refining processes liberate considerable volumes of gaseous hydrocarbons (methane, ethane, propane and butanes). These gases are typically used as fuel within the refinery itself. Refinery gases, particularly methane and ethane, are also important feedstocks for the manufacture of petrochemicals, including methanol, ammonia, ethylene and their derivatives. Butane and isobutane are blended directly into motor gasoline to increase its vapor pressure and, hence, to assure that it will ignite.

The butanes and propane ("liquefied petroleum gases" or LPG) released during refining also become feedstocks for certain intermediate processes in the manufacture of motor gasoline and additives like MTBE (methyl tertiary butyl ether), which raise the octane ratings of gasoline. Under moderate pressure butanes and propane remain liquid at ambient temperatures, and can therefore be marketed safely as "bottle gas" for space heating and cooking. Gas utilities mix propane with air to form an additive or substitute for natural gas during peak-demand periods, and there are a large number of industrial uses of propane, including metal cutting using oxy-propane torches, and as process fuels.

Distillate Fuel Oil. Distillate fuel oil includes the Nos. 1, 2, and 4 heating oils; and the term is often used to include diesel fuels as well, which are almost identical to distillate heating oils. No. 1 stove oil is the lightest of the distillates and, because it remains liquid and ignites readily at very low temperatures, is the main home-heating fuel in Alaska's interior. No. 2 heating oil is the most common home and commercial heating oil nationally and worldwide. The price of No. 2 fuel oil is the most frequently used indicator of petroleum product costs.

Since World War II, refiners have improved the quality of distillate heating oils to reduce the quantity of ash or other deposits left when the fuel is burned and by removing, through hydrogen treating, sulfur and nitrogen. Just as they do for gasoline and diesel fuels, refiners adjust the hydrocarbon blend in each grade of distillate heating oil to match the particular season and location.

Residual fuels. Residual fuels are made from the heaviest hydrocarbon fractions and are commonly marketed as Nos. 5 and 6 heating oils, heavy diesel, heavy industrial, and Bunker C fuel oils. Residual fuel oil has a higher energy content per unit of volume (e.g., per gallon) than other petroleum fuels, but it must be heated before it will flow through a pipe or burn in a furnace or turbine. Typically, therefore, these fuels are used to provide steam and heat for industry and large buildings, to generate electricity, and to power marine engines.

Residual fuel oil potentially competes with coal or natural gas in most of its markets. While there are serious regulatory obstacles to using these substitutes as electric-utility and industrial boiler fuels, the rapid runup in crude-oil prices since 1973 has tended to make residual oil more valuable as intermediate products for the manufacture of gasoline and distillate fuel oils. Relative prices increasingly favor substitution of coal, natural gas, and nuclear energy for residual oil as industrial fuel, therefore, and investment in new crackers and cokers to break up the residuum into lighter hydrocarbon mixtures that can be processed and sold for higher prices.

Lubricants. Lubricants are a diverse group of specially-blended products falling into three general categories: automotive oils, industrial oils and greases. Engine oils, gear oil, and automatic transmission fluids are three major lubrication products used in automotive operations. These products function to lubricate, seal, cool, clean, protect, and cushion metal parts. Industrial oils are blended to perform a variety of functions, including lubrication, friction modification, heat transfer, dispersancy, and rust prevention. Greases are basically gels and are composed of lubricating oil in a semi-rigid network of gelling agents such as soaps and clays.

Petroleum Solvents. Although they represent a much smaller market than, say, motor fuels, petroleum solvents are made in many grades for a variety of uses. Solvents are a major component of paint thinner, printing inks, polishes, adhesives and insecticides. They are also used extensively by dry cleaners. The manufacture of these products requires careful refining to remove unwanted odors and maintain consistent product quality.

Asphalt. The heaviest fractions of many crude oils include natural bitumens or asphaltenes and are generally called asphalt. This material is the oldest product of petroleum and has been used throughout recorded history. Because of its adhesive, plastic nature and waterproofing qualities, it is widely used for road-making purposes.

Product Mix. Individual refineries have considerable discretion in the product slates they produce, even from a single mix of crude-oil feedstocks. For this reason, it is important to understand the factors that influence product-slate decisions; these factors include --- in no particular order of logic ---

Feedstock assay and straight-run fraction mix
Crude-oil supply conditions
Refined product market conditions
Refinery flexibility regarding product slate
Refinery flexibility regarding feedstock mix
Refinery size and affiliation

Feedstock assay and straight-run fraction mix. The discussion of first-stage products has already shown that the hydrocarbon composition of crude oil determines the volumes of different straight-run fractions into which the crude oil can be separated by simple distillation.

markets and each refinery, in turn, is normally designed to produce a product slate that corresponds to local demand.

The mix of petroleum-product demand tends to vary geographically according to a region's climate, level of economic development, industrial character, and supply of competing fuels. U.S. West Coast refineries have been designed largely to produce motor and aviation fuels, because of (1) the region's mild climate, (2) the mobility of its population, and (3) relatively abundant regional supplies of natural gas and hydroelectric energy. In the Northeast, on the other hand, climate, lifestyles, and energy costs combine to encourage relatively greater dependence upon heavy fuel oils. The design of refineries in the two regions reflects these differences in demand mix.

Product demand also varies seasonally: Gasoline consumption typically peaks in the summer, but winter is the peak season for home heating oil. Refineries are generally designed with sufficient flexibility to accomodate a part of this seasonal demand swing. Because increasing degrees of product-slate flexibility comes only at increasing costs, however, the seasonal supply strategy of major refiners also involves "winterfill" and "summerfill" --- putting the product in seasonally excess supply into storage for sale when the demand pattern reverses itself.

Different types of fuels require quite different degrees of precision in their product specifications. The performance of industrial and electric-utility boiler fuels, for example, is relatively insensitive to the exact character or size of hydrocarbon molecules burned. Product specifications for middle distillates --- stove oil, diesel fuel, and jet fuels --- focus on easy ignition, clean burning, pour points and vapor pressures, but the demands these characteristics make on refinery design and operation are rather moderate, because there is a broad range of straight-run hydrocarbon blends that are able to meet the requirements for any of these fuels. Motor gasolines, however, have to be more closely controlled with respect to molecular structure and impurities in order to assure ignition and to avoid vapor lock, knocking, and unacceptable engine wear.

Aviation gasolines must meet the most severe product specifications of any petroleum fuel, both because of the extreme combustion conditions encountered in high-performance piston engines, and because of the potentially disastrous consequences of engine failure. It is probably the risk of legal liability from alleged quality shortcomings that has so far deterred any Alaska refiner from producing Avgas for local consumption, despite the relatively high demand for the product in the state.

<u>Refinery flexibility regarding product mix</u>. Adding a hydrocracking or coking unit to an existing refinery enhances its processing flexibility by allowing it to upgrade its straight-run residuum and heavy gas oils into gasoline and middle distillates.

Tesoro recently installed a new hydrocracker at its Kenai plant. The refinery was originally designed to run light Cook Inlet crude oil, but as the supply of that feedstock declined, Tesoro was faced with the choice of (1) cutting back production accordingly, (2) running the heavier Prudhoe Bay crude oil, and thus producing less gasoline and middle distillates and more residual oil to be exported from Alaska beacuse of the lack of a local market, or (3) adding equipment to upgrade the greater quantities of residual oil produced by distilling Prudhoe Bay crude.

The refiner chose the third alternative, installing a hydrocracker to process about 7,500 bpd of residual oil and heavy gas oil --- about 11 percent of the crude oil input to the refinery --- into motor gasolines, jet fuel, and diesel fuel. Falling residual-oil demand coupled with a fall in the average API gravity of crude-oil inputs is encouraging refiners to take similar action everywhere in the United States: The Oil and Gas Journal reported an increase in total U.S. hydrocracking capacity of close to 30 percent between year-end 1979 and year-end 1980.

Refinery size and affiliation. Independent refineries in the United States with less than 30 mbpd capacity --- especially the "bias-babies" spawned by the federal entitlements system between 1973 and 1980 --- are typically simple atmospheric distillation units producing a relatively large proportion of residual oil and heavy refined products. Not only do larger refineries tend to be more complex and more flexible with respect to both feedstocks and product slates but, all other things being equal, a large company with many refineries has greater system-wide flexibility because of its ability to produce different product slates in different plants equipped to complement one another.

Of all the refineries operating in Alaska, for example, the Chevron Kenai facility has from the beginning produced the narrowest range of end-products --- distillate heating oil, diesel fuel, jet fuels, and asphalt. Much of the heavy gas oil from Kenai is sent, along with the residual oil, to the company's Richmond plant, which already processes the heavier Prudhoe Bay crude oil that Chevron buys from Sohio. In the face of surplus system-wide capacity, moreover, Chevron recently suspended production of military jet fuel in Alaska, instead choosing to ship the straight-run gasoline from Kenai to its El Segundo refinery for conversion to benzene.

5.3 Refining of Petroleum.

Petroleum refining and the manufacture of organic chemicals involves the tearing down, rebuilding and restructuring of hydrocarbon molecules to produce saleable products. In the oil industry's early years, refineries simply broke down the crude oil by distillation into a series of cuts or fractions, often referred to as straight runs. Today, almost all petroleum products are specially tailored in their physical and chemical properties and freedom from impurities to meet exacting market demands. Because most products are blends, refining involves not only the separation of crude oil into fractions and removal of impurities, but also the restructuring and blending of hydrocarbons and addition of other compounds as required.

Distillation. All refinery operations begin with the distillation of a crude-oil feedstock into petroleum fractions. The crude oil can either be heated through a series of temperature steps, and the vapors condensed at each step, or a large portion of the crude oil can be vaporized and the vapor cooled in a series of temperature steps. Either way, the crude oil is separated into fractions, each composed primarily of hydrocarbons having similar boiling-point ranges. The boiling point ranges of the more common products are shown below:

Boiling Range °F	Product
< 90	propane/butane
90-220	gasoline
220-315	naphtha
315-450	kerosene
450-800	gas oil
> 800	residuum

In a typical refinery, the crude oil is heated to about 650°F as it enters the atmospheric distillation tower. The vapors rise in the tower, are cooled and condensed at various levels on trays, and withdrawn. Those heavy portions that do not vaporize are withdrawn at the base of the tower and sent to a vacuum distillation tower. Under reduced pressure, additional hydrocarbons vaporize, rise in the tower and are separated as the vapors cool. The heavy residue remaining is withdrawn at the base of the vacuum tower.

Restructuring Hydrocarbon Molecules. The separated fractions undergo further processing. Typically, the "light ends" from the top of the fractionating column go to the gas plant for further fractionation; the straight-run gasoline is blended; naphtha is sent to the reformer for processing, kerosene to a hydrotreater for clean-up, light gas oil to distillate-fuel blending, heavy gas oil to the cat cracker; and straight-run residue is fed to the flasher.

Beyond distillation, refiners restructure the hydrocarbon molecules either by making the molecules smaller or larger or by rearranging the molecular structure of a hydrocarbon without changing the number of atoms. In restructuring molecules, extensive use is made of catalysts, substances that cause an acceleration of a chemical reaction without itself being permanently affected. A catalyst may offer a surface structure that increases the rate of reaction, or it may cause certain reactions that would not otherwise occur. In many refining processes, the use of different catalysts results in a different yield, such as a higher proportion of aromatics. As a consequence, the refining and petrochemical industries are continually searching for new and superior catalyst materials.

Refinery Proceses to Restructure Hydrocarbons. Various processes have been given different names by their inventors, but basic refinery operations can be classified into the following categories:

Process	Basic Function
Cracking	Breaking (or cracking) large molecules into small ones. [Cracking processes may also yield some larger molecules.]
Reforming	Dehydrogenation -- removal of hydrogen --- for example, converting saturated straight-chain hydrocarbons into unsaturated aromatics.
Polymerization and alkylation	Combining smaller molecules into larger ones; polymerization combines identical molecules, while alkylation combines different-type molecules.
Hydrogenation or hydrotreating	The addition of hydrogen, to convert unsaturated hydrocarbons to saturated hydrocarbons, or to replace various chemical radicals with hydrogen.
Isomerization	Rearrangement of the structure within a molecule without changing the number of atoms.
Treating	Converting a contaminant into an easily removable or non-objectionable form.
Coking	A form of thermal cracking conducted under high pressure, promoting the formation of coke as well as yielding lighter products.

Cracking. When hydrocarbons are heated to temperatures exceeding about 450° C (842°F), the molecules break down or split. The reaction is very complex and a number of different products are formed, including heavier products as well as the predominantly lighter products.

In cracking, refiners heat a mixture of heavy hydrocarbons to a high temperature under pressure. This process causes the larger molecules to split; the result is a new mix of new molecules, but one with a much higher proportion of lighter hydrocarbons, from methane through the gasoline, naphtha, and middle-distillate ranges.

As large molecules break up through cracking, the lack of sufficient hydrogen atoms to saturate all the carbon bonds causes the carbon atoms to bond to one another forming olefins, smaller aromatic and naphthenic rings, and coke. The lighter products of this process are important chemical feedstocks --- ethylene, propylene and butylenes. However, the majority of heavy distillates and residual fuels cracked in refineries goes into the production of gasoline. Crude oils that yield only 15 to 20 percent gasoline-range products through distillation can yield 60-70 percent gasoline when subjected to cracking.

There are basically three cracking processes: thermal cracking, catalytic cracking and hydrocracking. Thermal cracking was the earliest process used to break large hydrocarbon molecules, by simply heating them to temperatures exceeding 450°C. At one time, thermal cracking was widely used to improve the octane number of naphthas and to produce gasoline and gas oil from heavy fractions. However, because thermal cracking of heavy distillates for gasoline production produces substantial quantities of less valuable gases and low-quality gas oils, the process has largely fallen out of use.

About forty years ago, catalysts were introduced into the cracking process to produce a higher quality gasoline. Catalysts enable cracking to take place at lower temperatures, and yield a heavier, more valuable gas.

Higher volumes of C_3 and C_4 products (propane and propylene; butane, butene and butadiene) are produced, offsetting lower volumes of methane and ethane. Catalytically-cracked gasolines contain more branched-chain hydrocarbons, have higher yields and are generally superior to thermally-cracked gasolines. As a consequence, most refineries that make gasoline from heavy distillates and gas oil use catalytic crackers.

The major problem with catalytic cracking is that the catalyst quickly becomes contaminated with coke deposits. Spent catalysts must be continually separated and regenerated.

Hydrocracking is a process designed to increase the yields of high-value gasoline components, usually at the expense of the gas-oil fraction. Hydrocracking involves cracking in the presence of both a catalyst and hydrogen gas. In thermal cracking, olefins (which have a lower hydrogen/carbon ratio than paraffins) are produced and in catalytic cracking, olefins are produced and carbon eliminated by deposition on the catalyst. In hydrocracking, most of the olefins that are produced immediately combine with hydrogen to form short branched-chain paraffins.

The process is very flexible and can produce high yields of either gasoline or gas oil form the heavier crude-oil fractions. Tesoro Alaska has recently added a hydrocracker to its Kenai refinery in order to obtain an 11 percent increase in the yield of gasoline and middle distillates from each barrel of crude oil processed.

Reforming. Catalytic reforming, like cracking, is one of the most important processes in the production of gasoline. The process typically uses straight-run naphtha as feed and alters the chemical composition of the hydrocarbons by removing hydrogen. Major changes in the composition of the naphtha include conversion of:

- o paraffins to isoparaffins
- o paraffins to naphthenes
- o naphthenes to aromatics

Sometimes paraffins, naphthenes or side chains break up in the reformer to form butanes and lighter gases, but the principal object of reforming is to raise the octane number of the gasoline. Aromatics have higher octane numbers than paraffins and naphthenes; long-chain paraffins have low octane numbers.

An ideal catalyst for reforming gasoline would convert the long-chain hydrocarbon molecules in the naphtha feed to aromatics or branched-chain paraffins. Platinum catalysts appear to be the most selective in achieving this outcome and also, the most active in speeding the rate of reaction. They are also the most expensive. Other dehydration and reforming catalysts include molybdena, chromia, and cobalt molybdate.

The main product from a reformer is called "reformate". The butanes and lighter gases released in the process are taken off overhead and used as fuel or processed elsewhere in the refinery. Hydrogen is also an important reformer byproduct used in other parts of the refinery mainly for desulphurisation.

Polymerisation and Alkylation. When refiners pass crude oil through a catalytic cracker, the lighter olefins (butylenes and propylenes) that are produced are too volatile to stay dissolved in the gasoline blends. Polymerization and alkylation were invented to combine the smaller hydrocarbon molecules into larger ones. Polymerization combines identical molecules, while alkylation combines different types of molecules. Thus, butenes (C_4H_8) are polymerised to octenes (C_8H_{16}); similarly propylene (C_3H_6) becomes hexene (C_6H_{12}). Propylene and butene will combine through alkylation to form heptene.

The use of alkylation has grown at the expense of polymerization, primarily because alkylation yields more product from the same quantity of olefin feedstock and the resulting alkylate has superior gasoline-blending qualities. Alkylation is also used to manufacture petrochemical derivatives. For example, benzene and ethylene may be combined to form ethylbenzene, which in turn, is used to make styrene and synthetic rubber.

Isomerization. Isomerization involves changing the structure of a hydrocarbon to yield a different, more valuable isomer. In most cases, normal paraffins are changed with the aid of a catalyst to branched-chain paraffins. An original application of isomerzation was the conversion of normal butane to isobutane for use as an alkylation feedstock. However, with incresed yields of isobutane from reforming operations, this application is limited. Most isomerization units now convert low octane-rated pentane and hexane into their high-octane isomers.

Hydrotreating. As petroleum fractions move through a refinery, impurities in the crude oil can have a detrimental effect on equipment, catalysts, and quality of the finished product. Hydrotreating removes most contaminants by mixing hydrogen with the crude-oil fractions and then heating the mixture under high temperature and pressure in the presence of a catalyst. Several reactions can take place:

Hydrogen combines with sulfur atoms to form hydrogen sulfide (H_2S).

Some nitrogen compounds are converted to ammonia.

Metals entrained in the oil are deposited on the catalyst.

Some of the olefins, aromatics or naphthenes become hydrogen-saturated, and some cracking takes place, causing the creation of some methane, ethane, propane and butane.

Hydrotreating is used both to remove impurities and to alter the composition and characteristics of refined products. Gasoline may be treated in order to hydrogenate olefins and diolefins in order to reduce gum formation. Reformer feedstocks and other feedstocks may be treated to remove sulfur, nitrogen and other impurities that could "poison" and deactivate the catalysts. Kerosene and lube oils may be treated to reduce both sulfur and the proportion of aromatics. Many refineries have also added hydrotreating units to desulfurize residual fuels in order to meet environmental specifications.

5.4 Refinery technology and design.

Refinery design and the choice of refinery processes depend upon several factors, including the type of crude oil available as feedstock, the desired product slate, product quality requirements, and economic considerations such as relative crude-oil prices, product values, availability of electricity and water, air and water emissions standards, and the cost of land, equipment, and construction labor.

Complexity of product slates adds to the complexity of a refinery and thus to its fixed and variable costs, as does a mismatch between the grade and quality of available feedstocks and the desired product slate. Thus, refinery capital and operating costs tend to be higher on the West Coast of the United States, where product slates emphasize lighter products and air-quality standards are more critical, and where the typical crude oil is, unfortunately, of lower gravity and higher sulfur content than elsewhere in the United States.

A typical U.S. refinery that produces more than one grade of gasoline and several kinds of middle distillate products is likely to have a fairly complex array of processes, as indicated by the flow chart in Figure 5-2 from the National Petroleum Council's refinery flexibility study. This complexity has evolved over a period of many decades, in response to a growing diversity of petroleum-product demand, and ever more critical product specifications generated by more sophisticated fuel-using equipment.

Although "downstream" process complexity, pressure and temperature controls, and other dimensions of refinery technology have advanced continually over the years, crude-oil distillation remains the heart of the refining business, and its technology remains much as it was decades ago. All refining operations begin with the separation of crude oil into various fractions with different boiling-point ranges. This is where the similarity ends. Some small refineries, like Mapco's North Pole plant and the Chevron Kenai refinery, are simple "topping plants", selling a narrow range of straight-run distillates as final products, exactly like the typical refinery of one hundred years. The essential difference is only that the "top" and "bottom" ends of the crude-oil barrel are no longer discarded, but are now sent on to more complex refineries that can process them, or sold for electric-utility boiler fuel or ship's bunker-oil use, where product quality is not a critical factor.

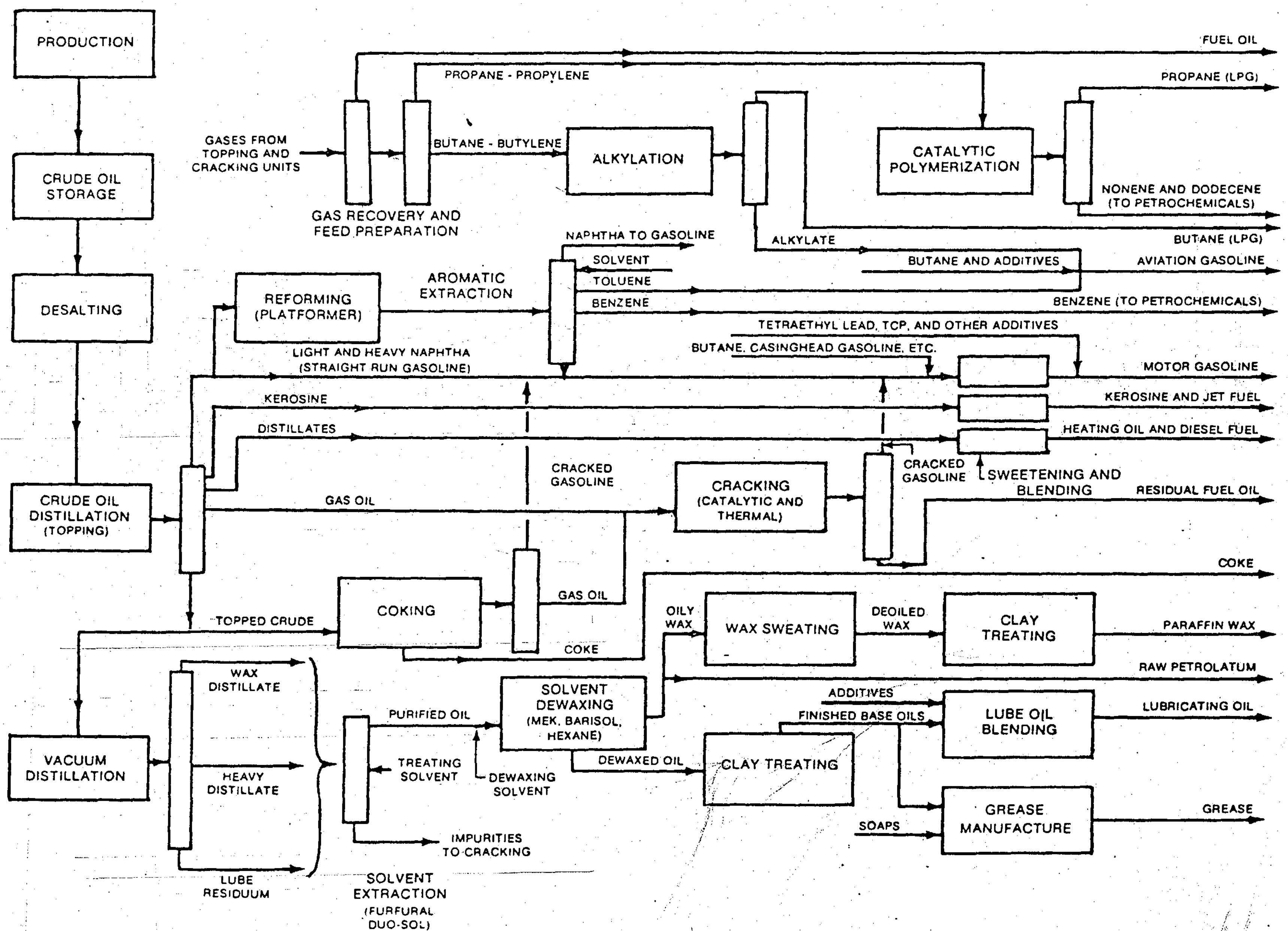
Other, more complex refineries like Tesoro's Kenai plant process the straight-run distillation products much further and crack much of the heavier fractions into more valuable refined products. The state of the art today is represented by complex refineries like the one depicted in Figure 5-2, and that which Charter Oil contemplated for Valdez, in which the entire crude-oil barrel would have been processed into gasoline, middle distillates, and petrochemicals.

5.5. Forces for Change

The OPEC Price Revolution. The recent "energy crisis" began in 1973-74 with the Arab oil embargo, which came (1) just at the peak of an unprecedented world-wide economic boom that had stretched global oil-producing capacity to its limit, and (2) just as U. S. crude oil production had reached full capacity and peaked out. The Organization of Petroleum Exporting Countries (OPEC) seized upon the shortage caused by the embargo to increase world crude-oil prices more than four-fold. A second supply pinch, and a further threefold price increase, came in 1979-80, when the Iranian revolution and the subsequent war between Iran and Iraq deeply curtailed production in both countries, the world's number-two and number-three exporters respectively.

Higher oil prices and the fear of future supply interruptions have created strong incentives for energy conservation, fuel-switching (from oil to coal, for example), petroleum exploration outside the OPEC countries, and

Figure 5-2 Simplified Flow Chart of a Refinery



Source: National Petroleum Council

development of alternative energy sources. The full adjustment of the industrial economies to higher oil-price levels and supply insecurity would have been gradual under any circumstance, because fuel-use patterns are embodied in buildings, appliances, transportation equipment, and industrial processes that take several years to wear out, become obsolete, or in many cases, even to become economic to retrofit. It also takes several years to mobilize and carry out successful oil and gas exploration programs or to design and build substitute-fuel production facilities (for shale oil extraction, synthetic fuels, etc.).

In the United States, the adjustment was delayed even further, because the initial policy response to the events of 1973-74 was to impose price controls on domestically-produced oil in order to shelter consumers as much and for as long as possible from the impact of rising OPEC prices. The average inflation-adjusted retail price of gasoline, for example, was only 10 percent higher in 1978 than it was in 1973. Not only did crude-oil price controls maintain the level of U.S. petroleum-product consumption higher than it otherwise would have been, but the crude-oil price-averaging mechanism (the "entitlements" system) that went with it effectively subsidized the domestic refining sector and protected it from foreign competition.

The temporary fool's paradise that petroleum price controls and allocation created for consumers and refiners alike is now over. As a result, five interrelated factors are now pressing the U.S. petroleum-refining industry --- (1) an overall decline in petroleum products consumption, (2) a shift in the mix of products demanded, (3) a worsening of the average quality of crude-oil supplies, (4) a less-secure crude oil supply, and of course, (5) higher crude-oil prices.

Consumption is declining. Total U. S. consumption of petroleum products fell from 18.8 million barrels per day (MMB/d) in 1978 to about 17.0 MMB/d in 1980, and in April 1981 was less than 16.0 MMB/d. Declining product sales have resulted in redundant refining, storage, transportation, and distribution capacity. Intense consumer resistance to higher gasoline and fuel oil prices has joined with higher crude-oil costs to create and intense profit squeeze on refiners, distributors, and retailers alike.

Market requirements are changing. Higher oil prices and federal regulations have combined to create a trend away from lighter and heavier petoleum products (e.g., gasoline and residual oil) toward middle distillates (e.g., jet fuel, diesel fuel, and No. 2 heating oil), and a shift from leaded to unleaded gasoline. Higher crude-oil prices have tended to shift petroleum product demand away from heavy fuel oil, which can rapidly be supplanted by coal or natural gas in most of its uses, while voluntary conservation and more fuel-efficient cars (with some help from the economic recession) have already reduced overall U. S. gasoline consumption by more than 15 percent below its 1978 peak. The National Petroleum Council (NPC), nevertheless, forecasts demand for high-octane unleaded gasoline to double by 1990. Consumption of gas, oil and naphtha as petrochemical feedstocks is also expected to increase as demand continues to grow for synthetic textiles, fertilizers, plastics, and other chemical products.

The quality of available crude oil is expected to decline. Light (high-gasoline) and sweet (low-sulfur) crude oil have long been preferred refinery feedstocks, particularly in North America, where motor fuels have been an exceptionally large part of total petroleum demand and where air quality became a major concern earlier than in Europe and East Asia. Fortunately, the grade and quality of North American crude oils (other than in California) has tended to be well suited to the mix of domestic product demand.

Throughout the 1970's, crude-oil production from historical domestic sources declined, however; as a result, price premiums for light, sweet crudes have widened, and U.S. refiners have had to turn increasingly to heavier, higher-sulfur crude oil supplies, both domestic and imported. According to the National Petroluem Council (NPC) study of Refinery Flexibility [1980], 80 percent of the world's remaining crude-oil reserves have a high sulfur-content, but 54 percent of the raw material run in U. S. refineries in 1978 was low-sulfur crude oil. Low-sulfur crudes will make up only 41 to 45 percent of total feedstocks in 1990, the NPC forecasts.

These trends have convinced industry analysts that the trend toward heavier, higher-sulfur feedstocks will continue, and will require major modifications in existing U. S. refineries, above and in addition to those investments needed to deal with the shifting demand mix.

Security of feedstock supply is a major concern. For several decades before 1973, a large excess of oil-producing capacity existed in Texas, Louisiana, and other states, and production in these states was controlled and allocated by State oil-conservation authorities. Excess capacity in the oil-producing nations of the Middle East and the Caribbean was even greater, and the vast bulk of this capacity was controlled by the major multinational (mainly U. S.) oil companies. As a result, many North American refiners were self-sufficient in crude oil or nearly so.

Domestic and world crude-oil markets were normally buyers' markets, therefore, and access to crude oil was not a major concern to most refiners. The upheavals of the 1970's, however, made security of crude-oil supply of paramount interest to refiners as well as governments. First, U. S. domestic production peaked in 1970 and declined throughout the decade, while consumption continued to climb until 1978, leading to an ever-greater dependency on imported oil. At the same time, foreign oil-producing countries were in the process of nationalizing the oil concessions of the multinational companies. The combined effect of these two trends was to place almost every refiner in North America in a position of depending on other domestic or foreign producers for a large part of their refinery feedstocks.

Because of the two major interruptions of Middle Eastern production that occurred during the 1970's, markets for both foreign and domestic crude oil became dominated by political considerations. Not only does total world supply now appear to be subject to curtailment at the whim of a handful of governments (or perhaps of a handful of terrorists), but even in the absence of an overall supply crisis, the price that different refiners have to pay for crude oil of a given grade and quality might vary by several dollars per barrel, depending on the refiner's relationship with the Saudi Arabian or other OPEC producer governments, or (at least until January 1981) on the company's regulatory status under U. S. oil price and allocation rules.

In the "seller's market" that prevailed during the 1970's, an assured supply of crude oil seemed to be very important to the long-term viability of existing refineries, an important precondition for financing the construction of any new refinery, and an absoultely necessary condition for financing any <u>independent</u> refinery. Would-be independent refiners, like the various groups that promoted the Alpetco project at Valdez, seemed to center their entire investment strategy on the search for assured crude-oil supplies, on the apparent theory that such a supply was not only <u>necessary</u> but sufficient for project success.

As a result, there have consistently been companies willing to pay premimums over the benchmark price applicable to a given kind of crude oil, like the official Saudi government price or Alaska's "Exhibit B" price (the weighted-average of prices posted by the North Slope producers), in order to secure captive reserves, long-term purchase contracts, or long-term allocations by governments.

Any large new source of secure domestic crude oil that was not yet under the control of a major refiner thus became a particularly attractive property, and was eagerly sought-out by refiners or by speculators confident that control over crude oil would either make them into refiners or allow them to capture part of the premiums that refiners would pay to be assigned the right to that crude oil.

In this situation, Alaska's right under its oil and gas lease contracts, to take oil royalties either in money or in kind has given the State two special choices for using its North Slope royalty crude: This option could be used, on the one hand, to attract to refinery and petrochemical investment in Alaska, seemingly even <u>without any discount</u> on royalty-oil feedstocks below the "in-value" price --- the amount the State would have received if it took its royalties in cash from the North Slope producers. Alternatively, royalty oil taken in kind could be sold on long-term contract to Alaska or Outside refiners <u>at a premium</u> above its in-value price.

An example of the first strategy was the State's contract with a series of groups --- most recently a Charter Oil subsidiary (the Alaska Oil Company) to sell 100 mb/d of North Slope royalty oil at the "Exhibit B" price, conditional upon the company building a worldscale refinery in Alaska. The second strategy is illustrated by the State's 1980 auction of North Slope royalty oil in approximately 5 mb/d lots for a one-year term beginning in July 1981: the high bidders in this auction offered premiums ranging up to almost $3.00 per barrel above the price the state would have received if it had left the royalty oil under control of the North Slope producers and taken payment "in value" --- that is, in cash rather than oil.

Crude Oil Has Become Costlier. The average price U.S. refiners paid for crude oil increased more than seven-fold, from an average of $4.11 per barrel in 1973, to $31.39 in December 1980. [The price peaked at about $36.00 in March, 1981, and is currently (June, 1981) falling.] Because crude-oil costs are the major part of the wholesale price of petroleum products, large consumer-price increases were inevitable. In the absence of government price controls, the rise in retail prices would have led to sharply curtailed consumption of petroleum products, refinery and distributor margins would have fallen nearly to zero, and there would have been little incentive for anyone to think of investing in new refinery capacity.

Until the beginning of 1981, however, ceilings on the domestic price of crude oil were augmented by an elaborate system of "entitlements" under which refiners who processed price-controlled domestic oil subsidized refiners who depended on imported crude-oil, and by which the major companies subsidized small refiners. Because U.S. refiners could buy crude oil at lower average prices than in any other advanced country except Canada, their domestic oil-product markets were in effect insulated from competition by products refined abroad.

Moreover, by limiting the price increases reaching final consumers, the control system permitted U.S. petroleum consumption to keep growing through 1978. Despite the lip-service that federal policy paid to energy conservation, the apparent demand for new refinery facilities in the United States continued to grow apace.

In addition, refiners and distributors were generally able to pass through the crude-oil price increases that the system did permit, and even to increase their markups, because domestic product-demand remained strong at the same time that domestic refiners were sheltered from worldwide competition. Also, the strong profit outlook that this situation generated, plus the subsidy element in the entitlements system, encouraged the oil industry to invest in both "grass-roots" (entirely new) refineries and in the expansion or retrofitting of existing refineries.

Finally, and rather amazingly in retrospect, almost all of the concerned parties in industry and government seem to have expected these market conditions to continue forever. Throughout the 1970's, oil-company trade associations, the Department of Energy, and both liberal and conservative members of Congress, deplored the growing "shortage" of refinery capacity in the United States (which each of them tended to blame on different parts of the federal regulatory apparatus), and sponsored legislation to create new incentives for domestic refinery investment.

The most important effect, for the purposes of our discussion, was the way in which the conditions we have described have, in fact, encouraged industry to plan new domestic grass-roots refineries; these were not confined to the "bias-babies" created in response to the subsidy element of the entitlements system. One such proposal was, of course, the Alpetco project at Valdez.

Alpetco and other U.S. refinery-construction projects planned in the late 1970's rested on the assumption the 1980's, like the 1970's, would be another decade of (1) growing petroleum-products consumption and (2) sellers' markets for crude oil. If these two assumptions had been valid, they would have meant that an assured supply of crude oil almost guaranteed the profitability of any new refinery. The absence of <u>either</u> condition, however, jeopardizes all current plans for domestic grass-roots refinery construction, and also casts a shadow over many the planned expansions and retrofits of existing refineries.

5.6 <u>Outlook for the 1980's</u>.

It is likely that the current [April 1981] oil "glut" foreshadows an entirely different kind of petroleum market in the 1980's from that which prevailed in the previous decade. World oil consumption may well have peaked-out in 1978, and world energy prices prices may have reached their long-term summit at the beginning of 1981, at least in constant-dollar terms. The buyers' market that exists today could even, conceivably, become a rout in which OPEC prices collapse nearly as fast as they rose. More likely, prices will remain well above 1973 and even 1978 levels, but neither refiners nor governments will any longer seem desperate to obtain crude oil at almost any cost.

Other scenarios are also plausible. The current glut depends both on falling world consumption and on the decision of the Saudi Arabian government to maintain high production levels in order to assert its own control over OPEC. Saudi policy could change radically overnight, the present regime might be overthrown, or a wider war could sharply curtail exports from the entire Middle East. If any or all of these events came about, we would once more see world oil prices soar, until a new equilibrium (and a new oil glut) was established at the new price level.

If oil is in fact plentiful enough during the 1980's to exert a continuing downward pressure on world oil prices, the consequences for oil-producing regions like Alaska would, of course, be profound. Not only would their oil-sales revenue be far lower than they now anticipate, but the attraction of long-term feedstock-supply security would no longer tend to override the transport and construction-cost handicaps of frontier regions as a site for worldscale refining operations.

Ironically, however, the resumption of real-price increases for crude oil would not improve the generally-dim outlook for new refinery construction in areas like Alaska, because higher prices would cause domestic and world oil consumption to decline even further. The present excess of refinery capacity in the United States and elsewhere would continue to grow, probably assuring that no new export refinery anywhere --- and certainly no such refinery in a comparatively high-cost environment --- would be profitable.

One way of viewing the impact of declining consumption on <u>the need to modify existing refineries</u> is to assume that refiners generally prefer to run lower-sulfur, higher-gravity feedstocks because they are cheaper to process, but that the refining industry was facing a steady decline in the physical availablity of such crude oils. However, a one-percent annual decline in overall petroleum-product consumption, or even a one percentage-point reduction in the expected rate of consumption growth, would more than offset the roughly one-percent annual decline expected in the supply of higher-quality crude oils.

At lower overall consumption levels, therefore, the need to run inferior feedstocks would be considerably less than expected. Moreover, with refineries operating at less than 70 percent of capacity in North America, and at even lower utilization rates elsewhere, the flexibility of the refining sector as a whole would be greatly enhanced. As a result, the ability to process heavy, high-sulfur crudes in existing equipment would improve at the same time the need to do so would be far less pressing. Circumstantial evidence of such a tendency has already appeared this year, in the form of lower world-market price premiums on light, low-sulfur crudes --- a significant reversal of the trend that dominated the 1970's.

Thus, even the current drive to modify existing Lower-48 refineries in order to produce a different product mix, or to run a different mix of crude-oil feedstocks may be a movement whose time has passed. It is important to note that the most definitive studies of refinery flexibility were completed before the latter half of 1980 --- when it first became impossible to ignore the powerfully depressing effect on oil consumption of the 1978-79 round of crude-oil price increases.

CHAPTER 6
PETROCHEMICALS

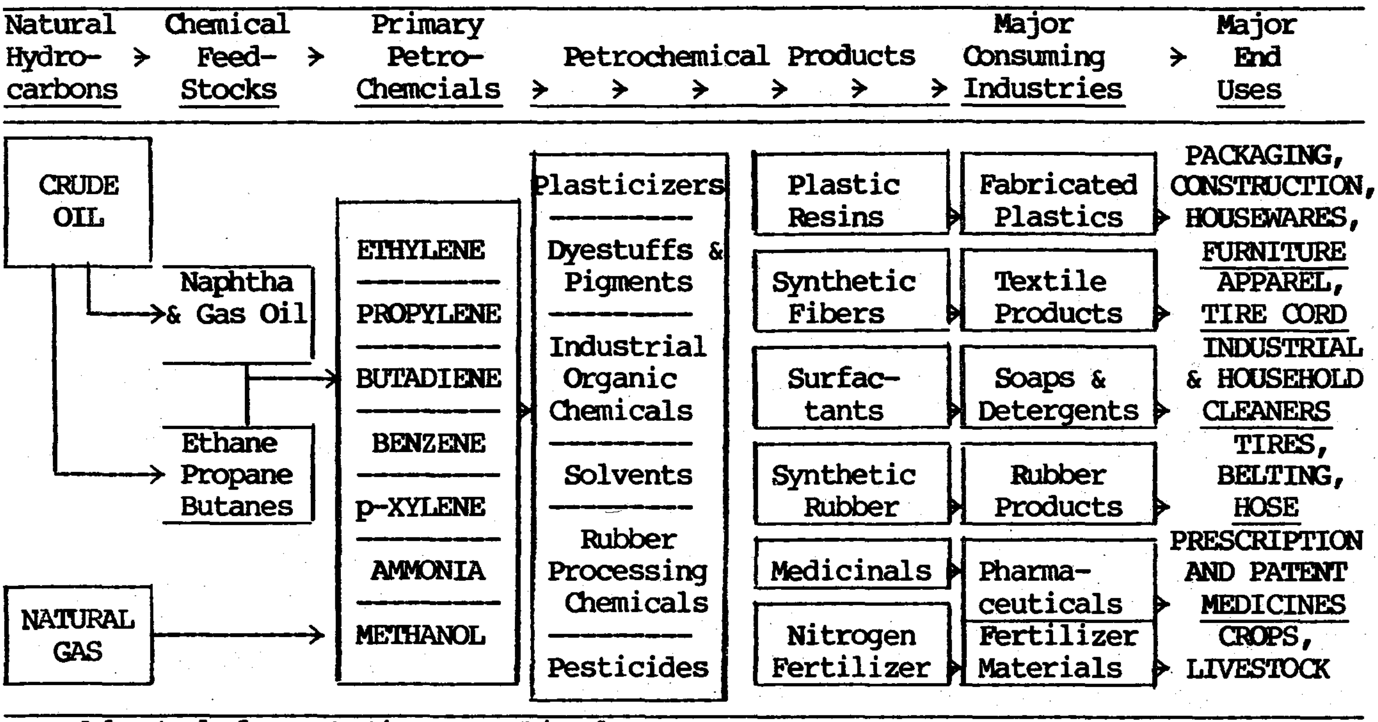
6.0 Introduction

The manufacture of most organic chemicals begins with transformation of natural hydrocarbons into primary petrochemicals such as ethylene, benzene, ammonia, and methanol. These petrochemicals, in turn, are processed further into thousands of products used in the production of food, clothing, building materials, machinery, medicines, and the like. (See Figure 6-1)

The boundaries of the petrochemical industry are therefore rather fuzzy. On the "upstream" end, they blend into the petroleum refining sector which furnishes a major share of petrochemcial feedstocks; "downstream", it is often impossible to draw a clear line between petrochemicals manufacturing and other organic chemistry-based industries such as plastics, synthetic fibers, agricultural chemicals, paints and resins, and pharmaceuticals.

For the primary petrochemicals and their first derivatives, however, the chemical industry is its own best customer. An extremely important first derivative of ethylene, for example, is ethylene oxide, which serves as an intermediate in the manufacture of antifreeze, detergents, and a host of second- and higher-order derivatives. About 5.6 billion pounds of ethylene oxide were produced in the United States in 1979. A large part of this output was used by the companies that produced it, usually within the same plant or complex, and a significant amount was sold to other chemical companies, but very little ethylene oxide was marketed outside the chemical industry itself. The same pattern exists for propylene, ethylene dichloride, and a number of other primary petrochemicals and derivatives.

Figure 6-1 Petrochemical Industry Flow Chart



Adapted from Arthur D. Little, Inc.

6.1 Chemical Industry Structure

The chemical industry is large and complex, no matter how narrowly its boundaries are drawn, and it is highly international. Four of the world's twelve largest chemical companies --- DuPont, Dow, Union Carbide, and Monsanto --- are headquartered in the United States, and each of these companies is among the 50 largest industrial corporations in the country, with total sales of more than $40 billion in 1980.

Most large integrated oil companies also manufacture chemicals; the worldwide chemical sales of Exxon and Shell, for example, would rank them among the top dozen chemical producers. The large-scale entry of the major oil companies into the chemical industry is a phenomenon of the last ten years, reflecting largely the comparative advantage that control over hydrocarbon feedstock supplies has given them over independent chemical producers.

Another sector of the petrochemical industry whose growth is based upon control of feedstocks is composed of government enterprises (or their joint ventures with international companies) in petroleum-producing states and other Third World countries seeking industrial diversification. In the oil-producing nations, local petrochemicals manufacturing can provide an outlet for natural gas and NGL's that would otherwise be flared in the oil fields.

What distinguishes the different participants are the upstream and downstream boundaries of their participation in the chemical industry. Because of their historical preoccupation with the extraction, production, and refining of hydrocarbons, the oil companies and the national enterprises of developing countries have concentrated on producing a few primary petrochemicals --- olefins and aromatics, for example, and, to a lesser extent, first derivatives for sale to the chemical industry.

The chemical companies themselves generate many captive product streams for which no public sales occur. Some, like Dupont and Monsanto, tend to be concentrated in the manufacture of chemical intermediates and final consumer products, while Dow and Union Carbide, for example, produce significant volumes of primary petrochemicals for their own use and for sale, as well as a large variety of patented brand-name "downstream" products.

The forces for vertical integration work in both directions, because integration has advantages for both the feedstock producer and the processor: Chemical companies are integrating backwards in an attempt to reduce uncertainty regarding both the prices and availability of raw materials. Forward integration by oil companies and producer-nation enterprises reflects both the apparent advantage that assured access to raw materials and influence over their costs gives them today, and their desire to obtain assured markets for their future crude oil, natural gas, NGL's, and refinery production, which may turn out to be in excess supply. Recent national and worldwide declines in gasoline and fuel-oil consumption particuarly encourage refiners to treat petrochemicals as a potential outlet for surplus naphtha and gas oil.

6.2 Petrochemical Feedstocks

The primary petrochemical feedstocks include naphtha and gas oil from crude-oil distillation; ethane, propane, and butane, mainly from natural-gas liquids (NGL's) but also from oil refineries; methane from natural-gas wells; and synthesis gas, a carbon monoxide-hydrogen mixture that can be produced from crude oil, natural gas, or coal.

Any primary petrochemical can ultimately be made from any of these feedstocks, but the mixture of products from the first stage of processing varies considerably. When very light hydrocarbons (C_2-C_4) are cracked, they produce virtually nothing but few light olefin compounds, mainly ethylene plus some propylenes, butylenes, and butadiene. The cracking of gas oil, on the other hand, yields a great number of different compounds, including the light olefins, but also gasolines and aromatics, in varying proportions depending upon the pressure and temperature in the cracker and the catalyst used.

Natural-gas liquids are the principal raw material for ethylene manufacturing in North America, accounting for about two-thirds of total ethylene production. NGL's output in the Lower 48 levelled off in the 1970's along with natural-gas production, however, and most forecasters expect U.S. output to decline or at best to remain steady in the 1980's. Thus, while imported LPG's may supplement domestic supplies, new ethylene capacity in the Lower 48 will probably rely largely on naphtha and gas oil from oil refineries. The ethylene-based petrochemical industry of Alberta is growing rapidly, however, because of abundant supplies of NGL's from the Province's natural-gas producing industry, and the availability of large volumes of NGL's is the present feature of Alaska most likely to attract chemical industry investment to the state.

Naphtha is used as a raw material for making two classes of primary petrochemicals. The most important use is for cracking into olefins, but naphtha is also a major feedstock for the production of aromatic hydrocarbons --- benzene, toluene, and xylene (BTX) --- either in the naphtha reformers of oil refineries, or as part of the gasoline that is a coproduct of olefin-producing naphtha crackers. Gas oil is expected to become much more important as a cracker feedstock to produce olefins as the supply of NGL's and the demand for refined petroleum products both decline.

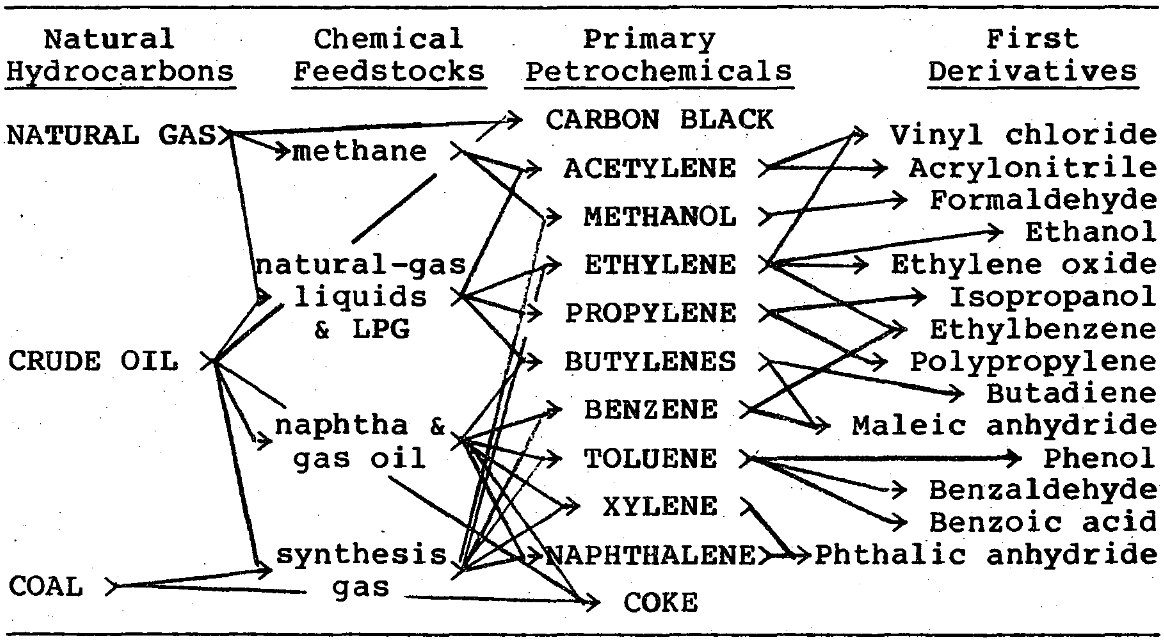
Natural gas is the principal raw material in North America for the production of synthesis gas which is, in turn, the main feedstock for producing ammonia, urea, methanol, formaldehyde, and chlorinated hydrocarbons (e.g., carbon tetrachloride and chloroform). Elsewhere, synthesis gas for these uses is produced from petroleum fractions or coal. Several chemical and fuels plants using coal-based synthesis-gas are currently planned in the United States and Canada (including a fuel-grade methanol plant on the West Side of Cook Inlet), but the general outlook for coal-based processes is uncertain, as it depends largely upon an uncertain supply and price picture for natural gas, which is the principal competitor of coal as the raw material for making synthesis gas.

6.3 Petrochemical Product Groups.

Petrochemicals can be grouped into three general categories: 1) primary petrochemicals, (2) intermediates, and (3) final or fabricated products.

Primary petrochemicals are compounds with relatively small molecules that are made directly from hydrocarbon feedstocks, and include ethylene, propylene, butylenes and butadiene, benzene, para-xylene, ammonia, and methanol. Most of them are relatively reactive chemically because of their multiple carbon bonds (except in the case of ammonia and methanol), and it is this quality that makes them useful for processing into thousands of more complex chemical products.

Figure 6-2 Feedstocks, Primary Petrochemicals, and First Derivatives



As Figure 6-2 suggests, most primary petrochemicals can be made from natural gas, oil, or coal. The most economical processes, however, use natural gas to make ammonia and methanol; naphtha and gas oil to make aromatics; and NGL's or LPG to make ethylene and butylenes. But because cracking of the heavier feedstocks always yields some ethylene, which is the most important primary petrochemical, a considerable portion of the total ethylene supply comes from naphtha and gas oil.

Olefins. Olefins are primary and intermediate petrochemicals that serve as building for a wide variety of chemical products. They are not found in nature, but are obtained when hydrogen atoms are removed from natural hydrocarbons, usually by cracking. The resulting olefins are characterized by branched or straight-chain hydrocarbons with double bonds between the carbon atoms:

Ethylene (C_2H_4)   Propylene (C_3H_6)

The double bonds are less stable than the single bonds and thus the olefins will readily combine or react with other compounds.

Ethylene is by far the most important olefin for the manufacture of petrochemical products. A typical worldscale ethylene plant will manufacture more than one billion pounds of ethylene per year and in 1980, 28 billion pounds were produced in the U.S. alone.

Ethylene is a colorless, flammable gas which, because of its extremely low boiling point (-155° F), cannot be shipped long distances except by high-pressure pipelines or very costly cryogenic (refrigerated) tankers like those used for liquefied natural gas (LNG). In the Lower 48 and Canada, ethylene has typically been produced in separate plants and piped to other petrochemical producers. In the U.S. Gulf Coast region, an elaborate pipeline system evolved to connect ethylene producers and manufacturers of ethylene derivatives such as styrene and polyethylene.

Pipeline or cryogenic-tanker shipments of ethylene from Alaska are not likely to be warranted economically, so any ethylene-based petrochemical industry in the State would probably process the ethylene further into derivatives that are solids or liquids under atmospheric conditions. Because the first derivative products rarely find their way to final consumers, they are not well known. However, they are the products which might be produced in Alaska if a gas-liquids-based petrochemical plant is built:

Propylene is another important olefin used as a chemical building block. It differs from ethylene in that there are no processes for which propylene is the principal product; it is strictly a by-product of the processing of ethane, propane, butane, or naphtha in ethylene plants or catalytic crackers. Consequently, propylene supply is a function of the demand for gasoline and ethylene.

Butane-derived olefins (C_4's) are manufactured in a variety of ways --- butenes (or butylenes) from catalytic cracking and butadiene by dehydrogenation of either butane from natural gas or the butene-butane stream from a catalytic cracker. As with the other olefins, the product group derived from the C_4 olefins is diverse and includes solvents, synthetic rubber, plastics and raw material for nylon.

<u>Aromatics</u>. In the petrochemical industry, the "aromatic" hydrocarbons are a family of basic chemicals --- benzene, toluene and xylenes (sometimes BTX) --- characterized by the "benzene ring" molecular structure, which has six carbon atoms and alternately-spaced double bonds. The group is named for the distinctive odors typical of this chemical family.

Toluene and benzene are colorless, flammable liquids, which together constitute the principal building blocks for many chemical intermediates. Toluene and benzene are intimately related, not only because they are produced from the same processes, but also because the principal chemical use for toluene is the manufacture of benzene. Benzene, in turn, is used to make a number of products, the most notable and important of which is styrene.

Other outlets for benzene are phenol, an intermediate for resins; cyclohexane, an intermediate for nylon production; dodecyl benzene for detergents; aniline for dyestuffs and rubber additives; and maleic anhydride, a raw material for polyester glass-fiber plastics. Toluene is used to make plastic foams, TNT and solvents.

Xylene is available from refinery catalytic reforming processes in great abundance, but very few of the mixed xylenes from this source have chemical applications as yet. The major outlets for xylenes are polyester fibers, resins, and solvents.

Most aromatics for the U.S. petrochemical industry are derived from petroleum refining. It is not uncommon, for example, to locate a petrochemical plant whose product slate includes styrene, polystyrene plastics and synthetic rubber, near a refinery producing benzene.

Synthesis Gas. The term "synthesis gas" refers to a mixture of carbon monoxide gas (CO) and hydrogen in any proportion. In the United States, synthesis gas is made primarily from the steam reforming of natural gas and then processed into three major intermediate chemicals --- ammonia, methanol and oxo alcohols.

Ammonia is one of the world's most important commercially produced chemicals. It is a colorless gas with a characteristically pungent odor and is used as the basic raw material for many different forms of nitrogen-containing chemical compounds. These products and end uses include fertilizers, refrigerants, nitric acid, water-treatment chemicals, synthetic plastics and fibers, animal feed, explosives, rocket fuels, and many others.

Methanol or methyl alcohol is one of the largest-volume organic chemicals produced synthetically. A major use is as a raw material for formaldehyde, but large quantities are also used as antifreeze, solvent and chemical intermediates. Until 1923, methanol was produced by the destructive distillation of wood, from which it obtained its common name --- wood alcohol. Today, nearly all methanol is made from natural-gas feedstock. However, there has been considerable recent interest in manufacturing methanol from coal. A coal-to-methanol facility is, in fact, now on the drawing boards for the West side of Cook Inlet.

Synthesis gas, under special conditions and in the presence of a catalyst, will react with olefins to produce alcohols. The resulting oxy alcohols do not often find their way into consumer markets. Some are used to make solvents; but most oxy alcohols are integral to the manufacture of plasticzers that keep polyvinyl chloride and other resins soft and pliable.

Intermediates or Derivatives. Each of the primary petrochemical compounds is converted into a variety of intermediate products or derivatives, most of which are not sold in final consumer markets, but serve as inputs for further processing operations. Figure 6-2 shows the feedstocks and primary petrochemicals used to produce several of the most important petrochemical first derivatives.

Derivative products from ethylene are of particular interest to Alaskans because the proposed Dow-Shell petrochemical project features extraction of gas liquids from Prudhoe Bay natural gas, and shipment of the NGL's by pipeline to tidewater in Southcentral Alaska. There the ethane would be separated and made into ethylene and ethylene derivatives, and the remainder of the liquids exported by tanker. The derivative products that Dow-Shell have mentioned for possible production in Alaska are summarized in Table 6-1.

End uses for petrochemicals are numerous. Petrochemical intermediates are converted into fertilizers; plastics; into all varieties of rubber and urethanes; into fibers, especially nylon, polyesters and acrylics; into paints, into drugs and pharmaceuticals such as aspirin and thiamine; and into detergents. Primary and intermediate petrochemicals are also key ingredients in making lubricating oil additives, pesticides, solvents, and much more. It is unlikely that large quantities of intermediates manufactured in Alaska will remain in the state for processing and fabrication into final products, however, primarily

Table 6-2. Primary Petrochemicals and Derivatives Considered for Production In Alaska

PRIMARY PETROCHEMICAL	DERIVATIVE	PRODUCT FORM	INTERMEDIATE AND END-USES
ETHYLENE	Low-Density Polyethylene (LDPE)	Resin sold as pellets, packaged in bags, hoppers or containers.	Film for food wrap, garbage bags; housewares, wire and cable insulation, paper milk-carton coatings.
	High-Density Polyethylene (HDPE)	Same as LDPE.	Blow-molded articles, injection-molded bottles, pipe and films.
	Ethylene oxide (EO)	Gas in water solution.	Intermediate for EG.
	Ethylene glycol (EG)	Liquid shipped in tanks and drums.	Antifreeze, intermediate for polyester fiber, film, resins.
ETHYLENE plus CHLORINE	Ethyl Dichloride	Gas --- seldom shipped.	Intermediate for VCM.
	Vinyl Chloride Monomer (VCM)*	Liquid shipped in tanks	Intermediate for PVC.
	Polyvinyl Chloride (PVC)*	Solid sold as pellets, packaged in bags or in bulk	Irrigation and sewer pipes, electrical conduit, vinyl floor tiles, rigid sheet packaging material.
ETHYLENE plus BENZENE	Ethylbenzene	Gas --- seldom shipped	Intermediate for styrene monomer.
	Styrene monomer*	Liquid shipped by pipeline or in tanks	Intermediate for polystyrene, synthetic rubber.
	Polystyrene	Solid sold in pellets, sheets, and blocks.	Disposable drinking cups, resin for toys, football helmets, etc.
AMMONIA	Urea	Solid, sold as prills in bags or in bulk.	Nitrogen fertilizers; intermediate for urea and melamine resins and plastics, explosives.
	Hydrogen cyanide*	Very toxic gas --- seldom shipped	Intermediate for methacrylate, acrylonitrile.
	Acrylonitrile*	Liquid shipped in drums or tanks.	Intermediate for acrylic resins and plastics, synthetic rubber.
METHANOL		Liquid shipped by pipeline or in tanks.	Direct fuel use, intermediate for formaldehyde.

*) Likely Alaska product not explicitly listed in Dow-Shell study plan.

because it is easier and cheaper to ship intermediates long distances than to ship fabricated products.

6.4 Petrochemical Processes and Plant Design

Petrochemical complexes are often laid out like large industrial parks. They can include plants that manufacture any combination of primary, intermediate, and end-use products. For example, some ethylene plants are single-purpose facilities that ship a single product via pipeline to other chemical companies for further processing. Alberta Gas Ethylene's ethane-to-ethylene plant at Joffre is such an instance. Other petrochemical complexes are composed of a number of largely discrete, specialized plants and laboratories that manufacture a variety of chemicals and share common power generation and wastewater treatment facilities.

Product slates at petrochemical complexes evolve over time, reflecting changes in market conditions and technology. For example, in 1959, Dow Chemical Company of Canada purchased a 700-acre site at Fort Saskatchewan. Initial facilities included ethylene glycol, ethanolamine, choloro-phenol, agricultural chemical and chlor-alkali plants. Within a few years, the site had more than doubled in size to 1,450 acres and new plants were built to manufacture caustic soda, chlorine, ethylene dichloride, vinyl chloride monomer and ethylene oxide/ethylene glycol. The Dow Chemical Company facility in Midland, Michigan, a much older facility, manufactures approximately 400 chemicals in 500 plants and laboratories.

In general, petrochemical plants are designed to attain the cheapest manufacturing costs and as such, they are highly "synergistic". That is, product slates and system designs are carefully coordinated to optimize the use of chemical by-products and to use heat and power efficiently. For example, exothermic (heat-generating) processes provide heat for endothermic (heat-absorbing) processes; hydrogen-producing processes are coupled with hydrogen-using processes; acid wastes are stored in lagoons with basic wastes to reduce the cost of neutralization; and plant fuel is provided in part by unmarketable hydrocarbon by-products (e.g., methane) from various processing operations.)

The Dow-Shell group would take advantage of this type of synergism in the design of an Alaska petrochemical complex, which might produce a variety of petrochemical from several feedstocks --- natural gas from Cook Inlet, natural gas liquids from Prudhoe Bay, naphtha and light gas oil refined from Prudhoe Bay crude oil, and possibly Healy or Beluga coal. One distinctive feature of the petrochemical complex the Dow-Shell group contemplates for Alaska is the participation of several large companies with already-established markets for their respective chemical products. If an Alaska petrochemical complex should be built by this group, it would be patterned after an industrial park where companies operate individual plants, but they would also take advantage of economies of scale by sharing infrastructure and transportation facilities.

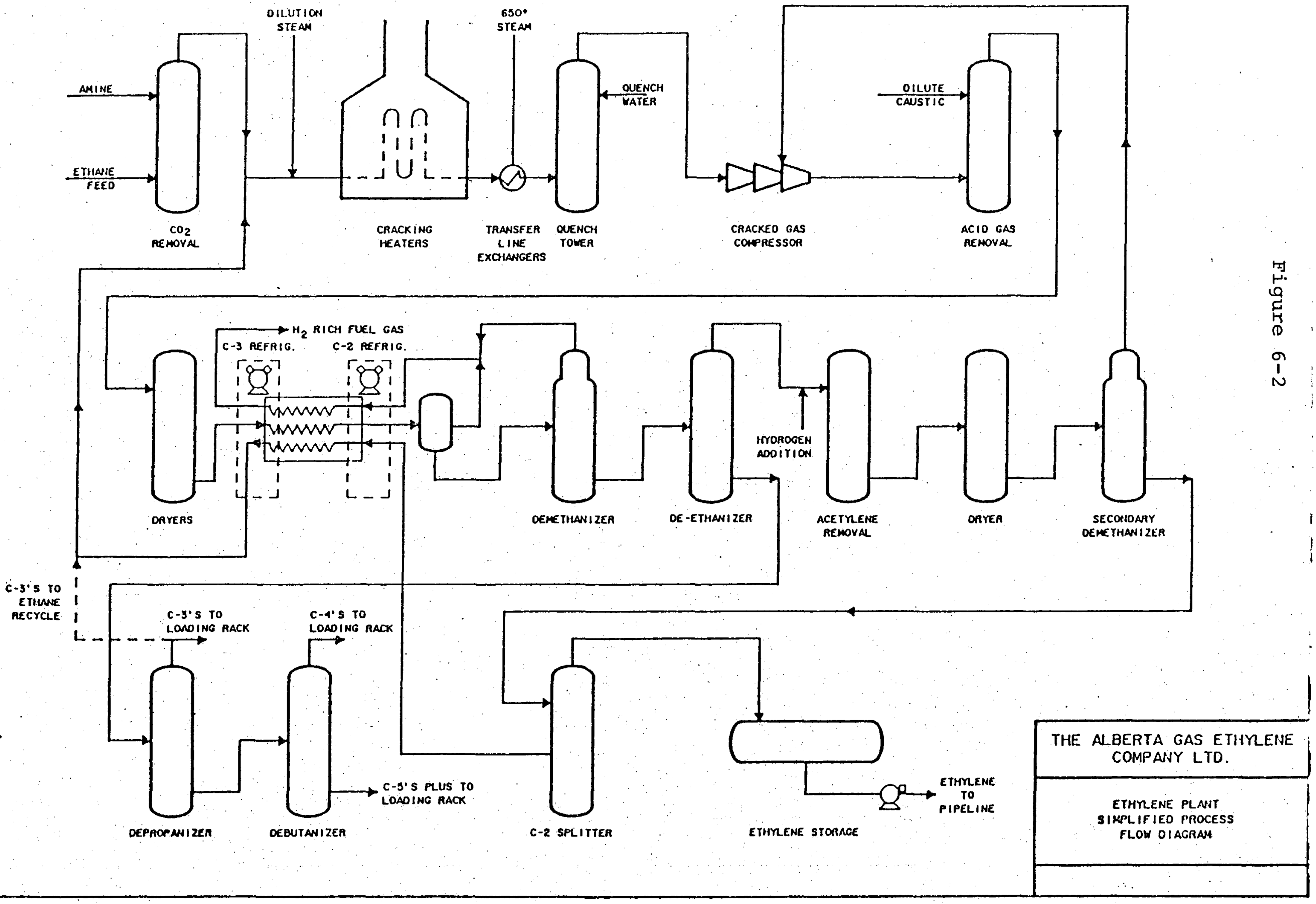
To understand how an Alaska complex might be designed and organized, the following section presents three examples of primary petrochemical operations.

Natural Gas Liquids to Ethylene and its Derivatives. Ethylene is the primary petrochemical that is manufactured in the greatest volume, and is made from feedstocks that range from ethane to heavy gas oil, depending on economic conditions. In North America, ethylene is most economically made from ethane. An ethane-to-ethylene plant is primarily a large cracker whose output is mainly ethylene with small quantities of by-products, mostly LPG's. A "worldscale" plant is one with a capacity on the order of 1 billion pounds per year.

Figure 6-3 is a flow diagram of the ethylene plant operated by the Alberta Gas Ethylene Company, Ltd., at Joffre, near Red Deer, Alberta. The ethylene is manufactured as follows:

> Ethane feedstock is vaporized and scrubbed to remove carbon dioxide, preheated, and sent to the cracking heaters.
>
> The ethane is then cracked to yield ethylene and by-products. The cracked gas is cooled by direct contact with quench water and sent on to the cracked-gas compressor.
>
> The cracked gas is compressed, scrubbed with dilute caustic to remove any traces of acid gases, and dried to remove all traces of water.
>
> The dried gas is progressively chilled and partially condensed at progressively lower temperatures.
>
> The condensate from the chilling train is separated into its components by distillation. The condensate is first fed to a demethanizer where methane goes overhead to the fuel-gas system, and the remaining components go out the bottom of the column to a deëthanizer.
>
> The bottoms from the deëthanizer go to a depropanizer and debutanizer, where the material is

Figure 6-2



O:[176.5]O6B3 GPC,1

split into C_3, C_4, and C_5 fractions, which are either used as plant fuel or sold.

The overhead from the deethanizer goes to an acetylene-removal system where the acetylene is converted with hydrogen to ethylene or ethane.

The stream is then dried again to remove any traces of water and then it is sent on to a secondary demethanizer. High purity ethylene is taken overhead, condensed and stored for use by derivative plants.

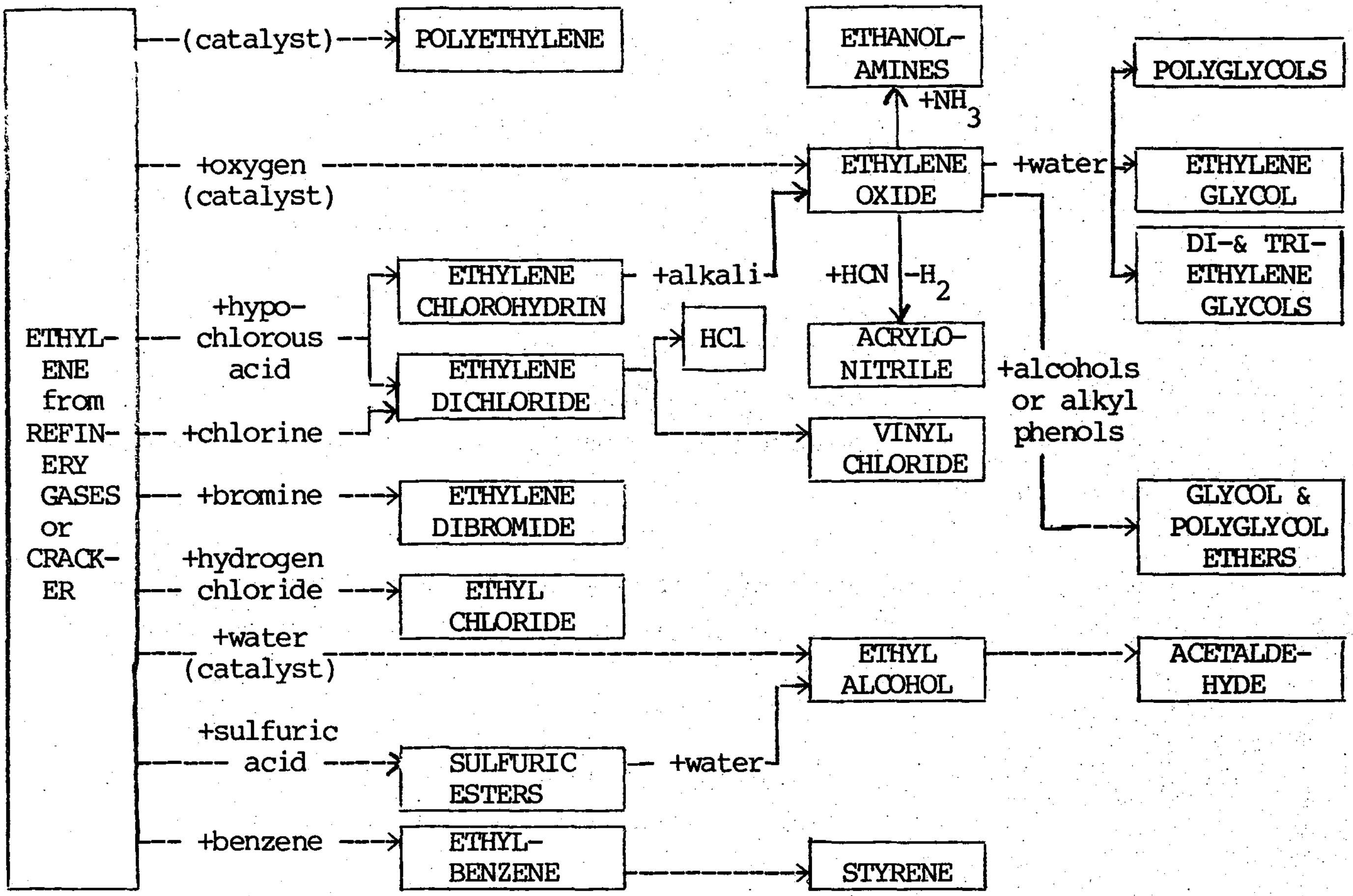
Figure 6-4 illustrates the wide range of derivatives that can be manufactured from the primary petrochemical ethylene.

Natural Gas to Methanol. Methanol is produced from natural gas as indicated in Figure 6-5, and as described by the following process steps:

First, the natural gas feedstock is desulfurized, and the hydrocarbons are then decomposed in a steam reformer. The synthesis gas thus obtained consists mainly of CO, CO_2 and H_2. The high-grade waste heat is used for generating steam, and some residual heat is dissipated to the air or cooling water.

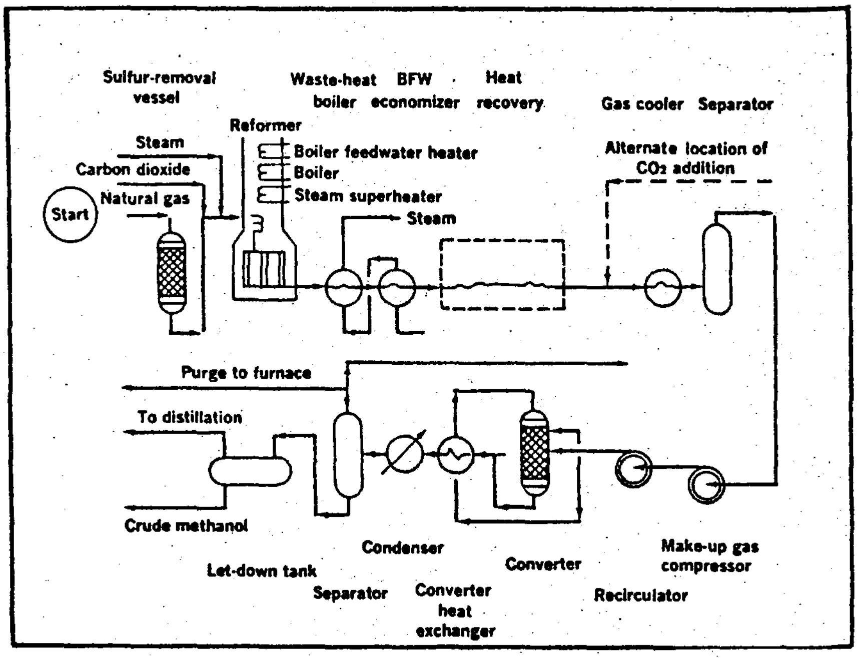
In the next process step, the synthesis gas is compressed to the synthesis pressure: Methanol synthesis is performed at pressures on the order of 50 atmospheres and temperatures around 500°F, using a copper catalyst. The heat of the reaction is used for generating steam, and the methanol-gas mixture is further cooled with the aid of water and/or air,

Figure 6-4 Derivatives of Ethylene



Adapted from Shreve & Brink, Chemical Process Industries

Figure 6-5 Typical Methanol Process



Source: Brownstein, Trends in Petrochemical Technology causing the methanol to condense. The unconverted gas is returned to the reactor.

The resulting mixture of methanol, water, and traces of synthesis by-products (such as higher alcohols and dissolved gases), is purified by distillation.

The purified methanol is then stored ready for transportation or further processing.

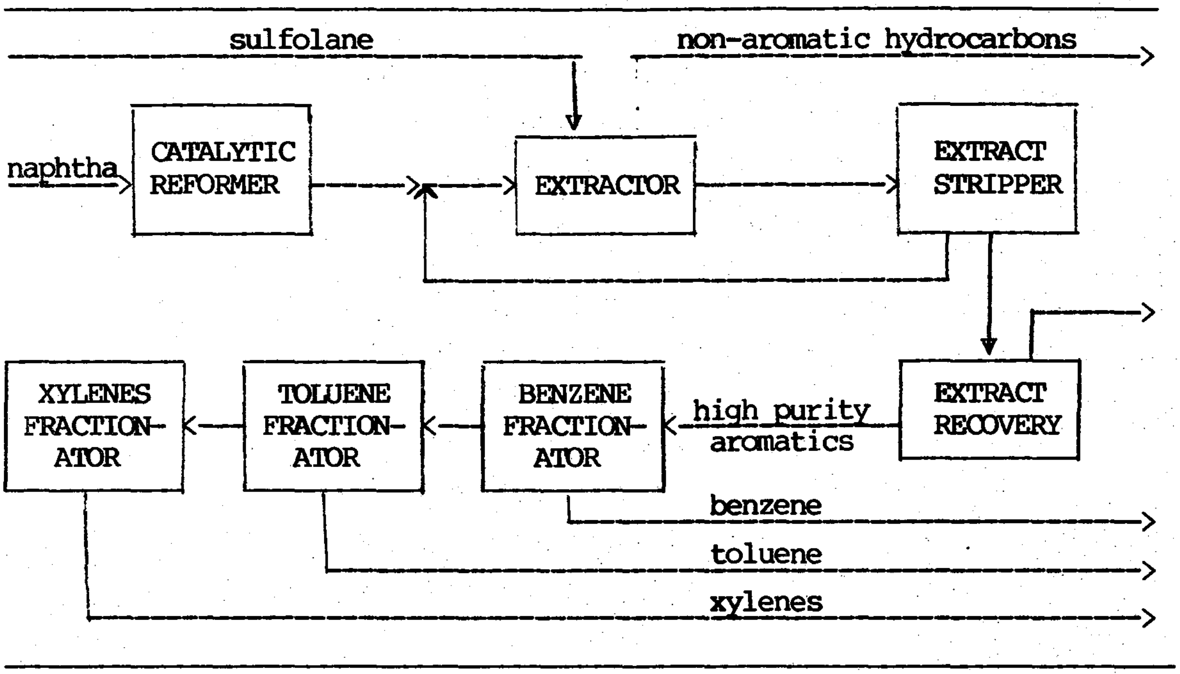
Methanol made in this way can be used directly as fuel or it can be further processed into formaldehyde, methyl chloride, chloroform or carbon tetrachloride. Mobil Oil has developed a process to produce synthetic gasoline from methanol.

<u>Naphtha to Benzene</u>. Mixtures of aromatic hydrocarbons --- benzene, toluene, and xylenes, are produced as coproducts or byproducts in several refinery and petrochemical plant processes, including cracking of ethane, naphtha, and gas oil to olefins. Most of the aromatics produced, however, come from catalytic naphtha reformers that convert paraffins to cycloparaffins and cycloparaffins to aromatics. A flow sheet for the process is presented in Figure 6-6.

Because the aromatics leave the reformer in a mixture containing other hydrocarbons of the same boiling range, the recovery process consists of extracting the aromatics using an organic solvent and subsequent fractionation of the individual aromatic compounds.

Benzene is obtained from the mixture of aromatics either by direct extraction or by the hydro-dealkylation of toluene. In this process, fresh toluene feed is combined with hydrogen and heated. The temperature rise resulting

Figure 6-6. Benzene, Toluene, & Xylenes by Reforming and Extraction

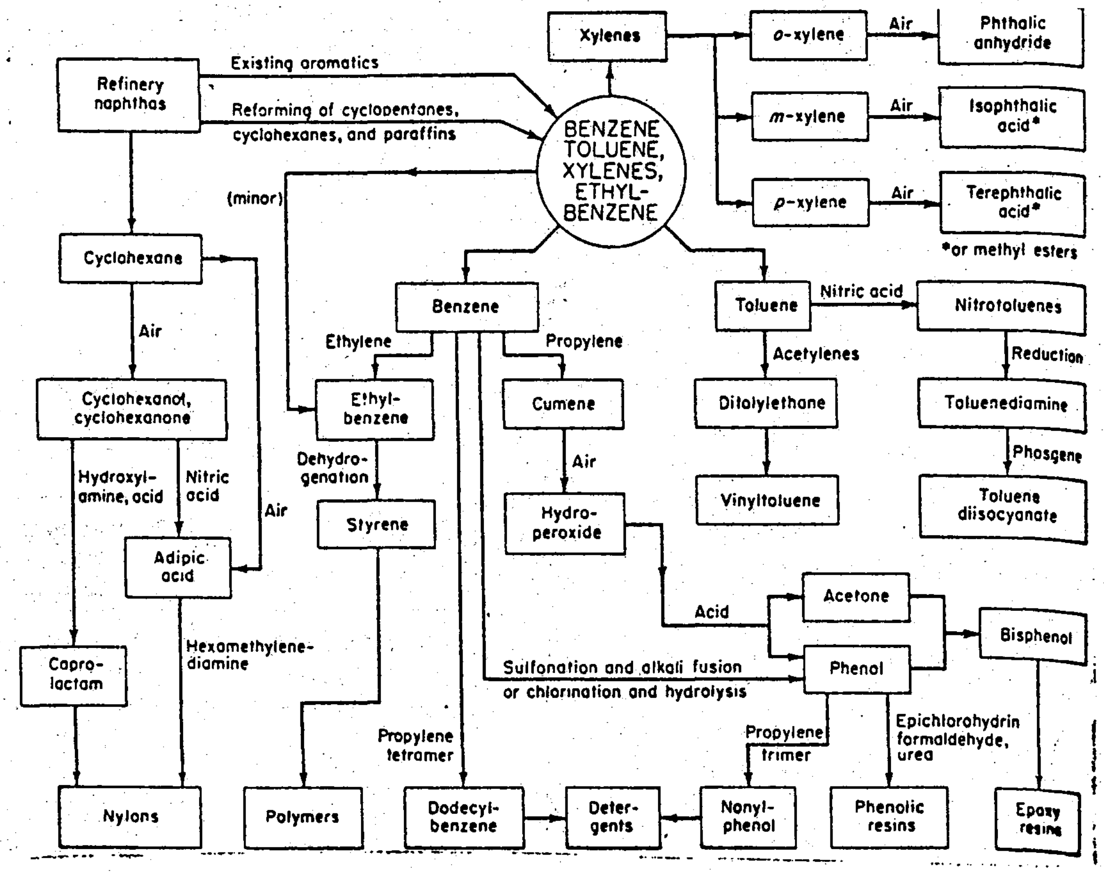


from the exothermic reaction is controlled by quenching with hydrogen-rich gas. The gas stream is drawn off, cooled and recycled. The liquid is stabilized to remove light paraffins and olefins, treated, and sent to a fractionator where the benzene is separated out.

As figure 6-7 suggests, benzene and the other aromatics are important primary petrochemicals for the manufacture of styrene, nylon, detergents, epoxy resins and more.

Petrochemical Complexes. Petrochemical complexes often combine the manufacture of several primary petrochemicals and derivative operations. Figure 6-8 lays out the different processes contemplated for Phase I and Phase II of the Dow-Shell Group project. Considered schematically, the Alaska project would apparently use a variety of petroleum feedstocks and employ a diverse set of processes to achieve the proposed product slate. Sufficient energy for power and heat is an important design component. Excess ethane and

Figure 6-7 Aromatics Derivatives



Source: Shreve and Brink, Chemical Process Industries

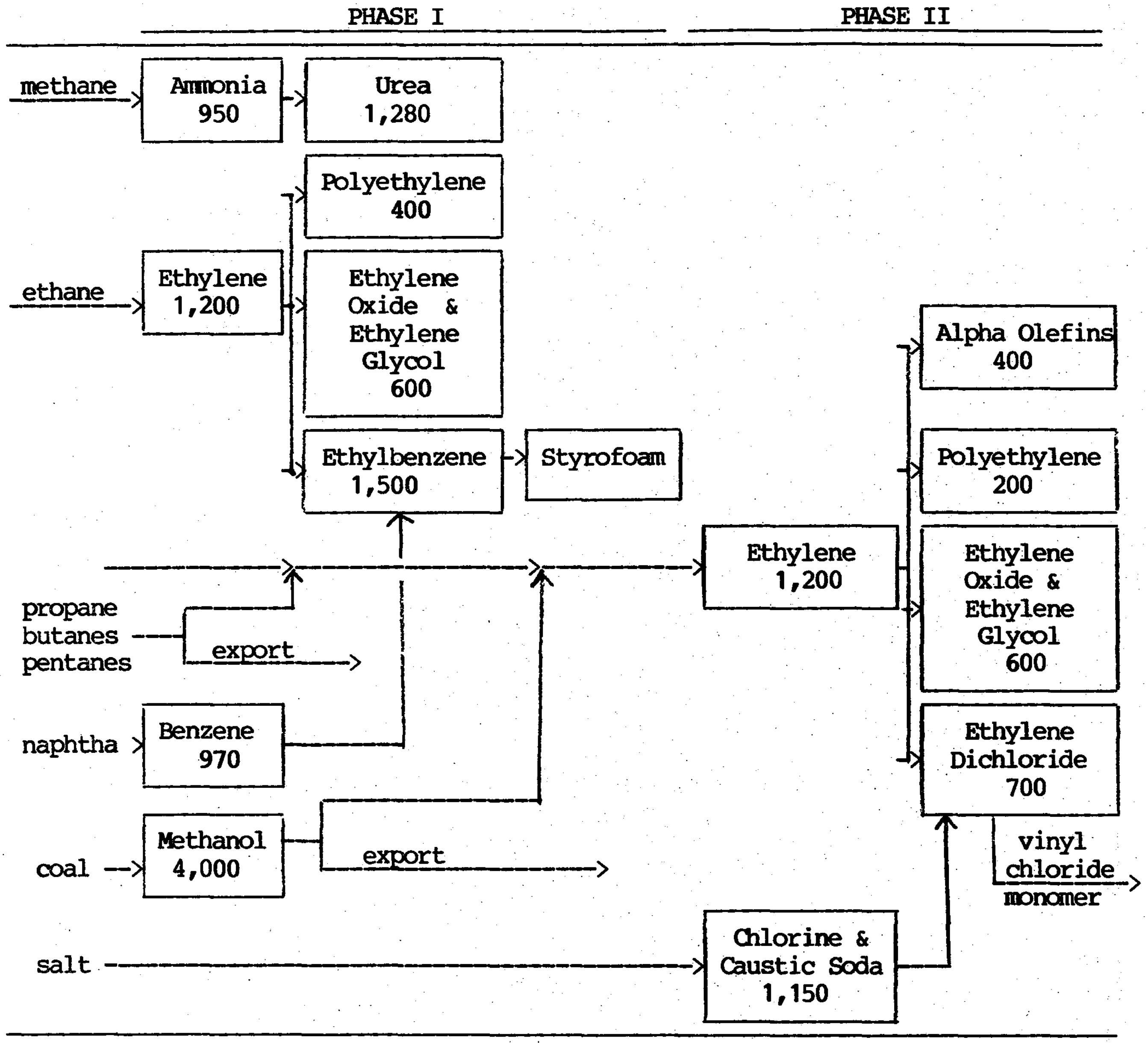
and LPG's will be used for plant fuel in Phase I; methanol production from coal is also being considered.

6.5 Feedstock Supplies and Product Markets.

The feasibility of the Alaska project will ultimately hinge on factors that go beyond mere availablity of Prudhoe Bay NGL's, namely, the price of those feedstocks, and the cost of getting them to the plant, plus:

Markets for any North Slope gas liquids not used for petrochemical manufacturing in Alaska;

Figure 6-8 Dow-Shell Petrochemical Project (million pounds per year)



U.S. and world market conditions for alternative petrochemical feedstocks;

U.S. and world markets for petrochemical products;

Transport costs to Outside markets for Alaska petrochemicals;

Plant construction costs, and operating costs other than for feedstocks; and

Legal and regulatory considerations.

Feedstock Supplies Historically, the availability and prices of different feedstocks account for both the development of the petrochemical industry and regional variations in its evolution.

In the United States, the dominant factors for development of the petrochemical industry were cheap natural gas and natural gas liquids, and elevated production levels for high-octane gasoline. Abundant methane and NGL's made possible the manufacture of low-cost ammonia, methanol, ethylene and propylene. Demand for high-octane gasoline made aromatic naphtha available, and thus benzene and xylene were relatively inexpensive to extract.

In Western Europe and Japan, gasoline accounted for a smaller proportion of total petroleum consumption. Excess European refinery capacity made the naphtha abundant and as the petrochemical industry developed, naphtha became the main feedstock for production of olefins and aromatics, and even ammonia and methanol.

By the early 1970's, the petrochemical industry was growing rapidly and enjoying expanding markets and relatively stable costs. However, even before the 1973-74 oil embargo, some concerns were starting to emerge:

In the United States, annual natural gas and oil discoveries during the 1960's had been far smaller than drawdowns.

In Europe, high standards of living increased gasoline consumption, leading to forecasts of naphtha shortages.

All over the world, the crude oil reserves being proved tended to be heavier than in the past, causing concern over the long-range sufficiency of light distillate feedstocks for the petrochemical industry.

And finally, developing nations wanted to start building their own chemical manufacturing capacity, particularly when they owned the low-cost hydrocarbons themselves.

These pre-1973 trends 1970's, became the major concerns of the mid-to-late 1970's, dominating the planning and development of new capacity in the chemical industry.

Future Feedstock Developments. The total world demand for petrochemical feedstocks, and the factors affecting feedstock choices in the 1980's and 90's are subject to many uncertainties, including global and national economic growth trends and the overall world oil-supply outlook, and specific regional circumstances. The latter include, for example, the availability of large NGL volumes in the Middle East, Alberta, or the North American Arctic.

Raw materials "availability" and supply security will remain important considerations in the choice of feedstocks, but they may not loom as large in the investment decisions of the 1980's and 1990's as most analysts assumed only one year ago, because buyers' markets appear to be emerging for crude oil and possibly for natural gas as well, and may persist for many years. Nevertheless, oil and gas prices will remain substantially above the levels that prevailed in the early 1970's. As a result, costs rather than availability *per se* will probably play the more crucial role in the selection of future chemical feedstocks, plant locations, and processes for converting feedstocks to derivatives and end-products.

Fuel prices and processing economics will combine to determine which hydrocarbons are to be processed to petrochemicals, and which are more valuable as fuels. The one most important influence on this decision will be the ratio of natural gas prices to oil prices after the former are deregulated in 1985. If Lower-48 natural-gas supplies do not expand rapidly in response to higher prices, residential and commercial consumers could bid the price of gas substantially above that of oil-based fuels.

In this circumstance, methane would cease to be an attractive chemical feedstock in the United States, and the incentive of gas producers to extract ethane from the pipeline-gas stream would be greatly weakened. Two probable effects are apparent: (1) New investment in ammonia and methanol production might shun the United States altogether, moving to Canada or the Middle Eastern countries where low-cost natural-gas reserves could support production for export, and (2) domestic olefins production would depend increasingly on gas oil as feedstock.

Likewise, if No. 2 fuel oil prices rose faster than the prices of other hydrocarbons, new olefins production would either move to countries with surplus LPG supplies, or U.S. plants will increasingly tend to make ethylene from naphtha or natural gas liquids.

In general, therefore, the physical supply of feedstocks does not seem to be a limiting factor for Lower-48 primary petrochemical production, but the relative costs of various feedstocks in the 1980's and 90's remains uncertain, and one explanation of an industry-wide reticence to announce construction plans for new petrochemical facilities.

Excess refinery capacity is providing the flexibility and added incentive to market and sell the otherwise surplus portion of the crude-oil barrel, possibly as petrochemical feedstock. The supply of natural gas liquids to existing U.S. plants remains ample thus far, and in fact, as Saudi Arabia and other oil-producing nations export ever greater quantities of LPG's, competition to find markets for LPG supplies may intensify, and seriously impinge on the marketability of NGL's from Alaska.

Markets for Primary and Intermediate Petrochemicals. Several factors shape the character of markets for primary and intermediate petrochemical products and will influence the development of an Alaska petrochemical industry.

(a) Captive markets. Many petrochemicals are manufactured expressly for captive product streams. Twenty percent or more of all organic chemicals produced in the United States remain within the same company for further processing or are sold to other chemical companies on long-term "take-or-pay" contracts. For example, all of the ethylene produced in the Alberta Gas Ethylene (AGE) No.1 plant at Joffre was committed to Dow Chemical Company prior to construction. AGE's proposed Plant No.2 plant already has customers ready to enter into long-term purchase contracts for the ethylene it will produce. Captive streams of primary petrochemicals and first derivatives are thus the rule, rather than the exception, and help to assure chemical companies manufacturing second- or higher-order derivatives and fabricated products a secure supply of raw materials.

(b) Limits to Expansion. The substitution of petrochemical products for natural materials is reaching a saturation point in the United States, particularly in the fiber and rubber industries. The rapid growth of petrochemical markets has occurred largely because low costs of and the resulting consumer acceptance of synthetic petrochemical-based products in place of natural materials. Many analysts believe that fabricated plastics may continue to displace metals, wood, paper and glass as structural materials, but that domestic markets for other synthetic materials are near saturation.

The maturity of the petrochemical industry in U. S. markets tends to make further growth in the industry depend on the expansion of consumer markets for commodities such as automobiles, home construction and clothing. In mature industrial economies, the demand for these products is "income-inelastic", meaning that their consumption tends to grow more slowly than personal income or the GNP. The overall rate of economic growth in the U.S. and other advanced countries slowed down markedly in the 1970's, and is unlikely to return to the levels achieved in the 1950's and 60's. The petrochemical industry therefore seems to face a period of rather modest growth relative to earlier years.

For the rest of this Century, the greatest growth in petrochemicals markets may be in lower-income countries that are undergoing substantial economic development, including those Middle Eastern countries who themselves are becoming primary and intermediate petrochemical producers. Saudi Arabia, for example, through the Saudi Basic Industries Corporation (Sabic), plans to build three ethylene plants with a total capacity of 3.3 billion lbs. per year.

CHAPTER 7
SOCIOECONOMIC, HEALTH, SAFETY, AND ENVIRONMENTAL CONSIDERATIONS

7.0 General Introduction.

Choosing and developing a plant site, plant design, and the staging of construction and operations are critical elements in the private industrial developer's planning process. These aspects of a new project are frequently the subject of public debate --- inevitably so in Alaska, where almost all parties regard government as the engine of economic development and as their first and last recourse regarding any economic or social issue.

The bitter controversy in 1978 and 1979 over the Alpetco contract and the process that led to the Dow-Shell study in 1980 illustrate the intensely political character of siting and design decisions when it is the State government, through its ownership of royalty oil and gas and of the choicest industrial sites, that decides from the very beginning which private firms shall build what kind of facility, and where.

Even more than the economic interest Alaska may have in expanding the processing of hydrocarbons within the state, other issues have dominated public discussion, and will probably continue to do so. A recent survey by the Alaska Department of Environmental Conservation identified the largest public concerns with respect to petrochemical industry development as the transportation of chemicals, public health, air and water quality, and disposal of hazardous wastes, while employment, population growth, and impact on public services, seemed to be less important.

These very issues, and other related ones, were raised during the Alpetco debate and will surely surface again if the Dow-Shell group or some other entity decides that petrochemicals development in Alaska is economically feasible and moves toward design and construction of transportation and processing facilities.

7.1 Employment and Labor Demand

Construction of major industrial facilities will produce many short-term jobs. Construction of either a refinery or a petrochemical plant would require a large temporary labor force, but the gas-liquids extraction plant, pipeline, and petrochemical complex contemplated by Dow-Shell would require substantially greater capital resources and labor-time than a worldscale refinery like the proposed Alpetco plant.

Dow-Shell estimates that 5,000 person-years, with a peak employment of 2,400, would be necessary to build the proposed facilities:

Table 7-1. Estimated Workforce Requirements, Dow-Shell Project

Facilities	Construction Man-Years	Construction Peak Number
Liquids Recovery	200	100
Liquids Pipeline	2,500	1,200
Liquids Terminal	600	300
Petrochemical Plants	1,700	800
TOTAL	5,000	2,400

The project by itself would employ a large proportion of the resident Alaska construction workforce, and the numbers above probably exceed the number of unemployed Alaskans who would actually be available for work on such a project. Moreover, if experience with the Cook Inlet refineries, LNG plant, and ammonia-urea plant; TAPS; and the Alberta petrochemicals facilities is any guide, the actual workforce requirement will be considerably greater than these early estimates.

In 1975, for example, when TAPS construction was already under way, the Alyeska Pipeline Service Company estimated peak employment requirements for pipeline and terminal construction at 14 thousand. In August of 1976, however, Alyeska reported 26,770 persons employed, almost double the previous year's projection. In view of the Dow-Shell project's need to build a gas-liquids extraction facility, a gas-liquids pipeline from Prudhoe Bay to tide-water, a worldscale ethane cracker, several derivatives plants, and a marine terminal, it would not be surprising if actual construction labor demand peaked at several times the sponsors' original estimates.

If construction of other large capital projects in Alaska, such as the Susitna Dams, the gas pipeline, and new North Slope oil and gas development were to occur at the same time the petrochemical complex was being built, the employment boom could surpass that of TAPS construction in 1974-76. In this case, there would be a torrent of workers and job seekers from outside the state, and it is impossible to predict the net impact of construction on resident Alaskan unemployment.

<u>The petrochemical and refining industries are capital- and not labor-intensive</u>. While the estimated cost of building a one-billion-pound-per-year ethylene plant in Alaska is somewhere in the neighborhood of $400 million, the Dow Chemical Company estimates the total number of permanent

jobs associated with the facility at only 115, or one job for every $3.5 million invested.

For Alberta Gas Ethylene Company's [AGE's] second ethylene plant at Joffre, total capital costs were estimated in 1979 at $372 million and the additional jobs created at 83 --- one job for every $4.7 million. The Alpetco sponsors expected to create one permanent job for every $3.1 million invested. Historical experience regarding such estimates is exactly the opposite of those for construction employment: just as the sponsors of large projects typically underestimate their construction-labor requirements (and thus their own capital costs), they tend to overestimate their operating workforce (and thereby their permanent contribution to the community). [A plausible hypothesis is that project design tends to become more capital-intensive during the course of planning and construction: perhaps construction-cost overruns spur project engineers to find ways to limit labor and other recurring costs.]

As one might expect, production of chemical derivatives and final products is progressively more labor-intensive as the process moves "downstream". While none of the firms that are actively studying petrochemcials investments in Alaska currently contemplates in-state processing beyond the manufacture of first-derivatives, Dow-Shell have published the following estimate of employment "created by" [more accurately, associated with] the downstream processing of product from a one-billion-pound ethylene plant:

Ethylene Plant	115
First Derivatives	595
Second Derivatives	1,315
Third Derivatives	29,290
	31,315

Construction and operation of both refineries and petrochemical facilities employ the following types of personnel:

Construction	Operation
Carpenters	Operation Technicians
Insulators	Chemical Technicians
Electricians	Maintenance Personnel
Iron Workers	Office Workers
Laborers	Computer Operators
Millwrights	Supervisors
Pipefitters/Welders	Accountants
Instrument Mechanics	Engineers
Engineers	Chemists
Supervisors	Industrial Hygenists
Equipment Operators	Medical Personnel
Boiler Makers	Safety Personnel
Cement Finishers	Security Personnel
Truck Drivers	
Painters	
Riggers	

Refineries and petrochemical complexes generally operate 24 hours per day on three shifts. The number of administrative jobs created in Alaska will depend on how operations are organized and the degree to which outside companies will establish a local administrative structure.

In addition to direct employment in the operating companies and their contractors, construction and operation of facilities creates a demand for transportation and utilities, and for a variety of supplies and services provided by local businesses. Spending of construction and construction-derived incomes, moreover, creates demand for consumer durables, goods, and services, and thus additional employment.

These secondary and indirect employment effects of construction and operation of any of the proposed pipelines, refineries, and petrochemical plants are fairly speculative, but Dr. O. Scott Goldsmith of the University of Alaska's Institute of Social and Economic Research has estimated that approximately one such job will be created for every construction job on an Alaska petrochemical project. This "multiplier" coefficient is very close to the value observed during construction of the Trans Alaska oil pipeline. The actual net impact of any new construction project, however, will depend on a number of factors including:

- Location of the facilities;
- Nature of feedstock and product transport;
- Size of new populations;
- Alaska markets, if any, for second- and third-derivative industries.

7.2 Water and Power Requirements

Water Use. Water serves a variety of refining and petrochemical needs including cooling, processing, steam generating, potable water use and sanitation.

Relatively little water is actually consumed by refineries and petrochemical plants, however, huge quantities of water are used for cooling and condensing. In many chemical and refining processes, the feed is heated or vaporized to promote the desired reaction or permit the required separation of products. The products, in turn, must be condensed to a liquid and cooled to a safe temperature for storage or product blending.

A large amount of heat is recovered by the use of heat exchangers to transfer heat between fluids; e.g., heat contained in a hot product that must be condensed or cooled is transfered to a cooler feed stream that must be heated. This arrangement conserves fuel and reduces cooling water requirements. Most cooling water, moreover, is pumped within a closed systems, where it is generally not subject to contamination and thus can be reused repeatedly.

Refineries and petrochemical plants also require large quantities of water to generate steam for power, evaporation heating, and drying. Most of the steam is condensed in closed systems and is normally reused. Water suitable for steam generation, however, requires extensive treatment because as the water is evaporated, solids in the boiler water become concentrated and can cause overheating. Also, gases dissolved in the water or liberated from dissolved minerals will corrode pipes and fittings.

Much smaller quantities of water are required for process purposes. In refineries, crude oil normally contains salt and other matter that is removed by water-washing to avoid corrosion or fouling of process equipment. Where water is used to separate oil and water phases, to wash traces of treating chemicals from product streams or to flush lines and other equipment, the possibilities for water contamination are high and for water reuse, very low.

Finally, potable-water requirements for drinking and sanitation are relatively small compared to other water uses.

The quantity and quality of available water is an important consideration in plant design and operation. Water demands for a refinery are estimated at 77,000 gallons per 100 barrels of crude oil or 7.7 million gallons per day for a 100,000-barrel-per-day-refinery. The Dow-Shell Group estimates the following water needs in gallons per minute:

Table 7-2. Dow-Shell Water Use Estimates

	Phase I	Phase II	Total
Demineralized Water	15	300	315
Boiler Feed Water	2,750	1,200-1,400	4,000
Cooling Water	340,000	160,000	500,000
	[Recirculation Rate]		
	6,800-13,600	3,200-6,400	10,000-20,000
	[Make Up (estimated)]		
Potable Water	200	100	300
Process Water	60	250	310
Fire Protection	15,000	15,000	15,000

The total requirements for demineralized water, boiler feed, and potable water in the petrochemical complex approximate 6.6 million gallons in a 24-hour period. This figure excludes cooling water and water for fire protection, but it is still large compared to municipal water needs of many Alaska communities. For example, average water use in the City of Kodiak is 3 to 3.5 million gallons per day; when the fish processing plants are operating at peak, daily consumption rises to about 10 to 12 million gallons.

Energy Requirements. Both the chemical and refining sectors are substantial users of energy for boiler and process fuel, refrigeration, pumps and compressors, etc., in addition to their feedstock requirements. The chemical industry consumes more than one third of the energy used by all manufacturing industries in the United States. Because it is a significant cost factor, plants are carefully designed to use energy synergistically and are often located in places where electricity is relatively cheap.

The complex contemplated by the Dow-Shell group would use feedstock hydrocarbons and byproducts for most plant-fuel requirements, but Phase II of the petrochemical complex would require 225 MW of electricity in addition. This is a staggering amount, considering that the average consumption in the Municipality of Anchorage is currently about 600 MW. The Alpetco sponsors estimated the project's electrical consumption at 45 MW for process units and 25 MW for offsite operations.

7.3 Land and Water Pollution

Refineries and petrochemical plants handle various types of liquid and solid waste including oil-contaminated water, water used in cooling and processing, and sanitary and storm waste water. In addition, there are sludges from storage tanks, chemical treating and other operations which must be treated or somehow disposed of.

Contamination from oil is the most serious pollution problem in refining and some petrochemical operations. Hydrocarbons can enter the waste-water system directly from a spill, leaks from lines, valves or vessels, leaks around pump packaging, product sampling, etc. Contamination may also occur when oil and water are brought into direct contact as from crude desalting operations or product washing following chemical treating.

Characteristics of Contaminants. Industrial engineers and regulatory agencies have developed a number of measures for various types of land and water pollution.

Oxygen Demand. Because specific oxygen levels in a stream are necessary to sustain plant life and organisms, effluents from industrial plants are monitored to maintain a certain amount of dissolved oxygen when they are introduced into receiving waters. Oxygen demand is measured either as chemical oxygen demand (COD) or biochemical oxygen demand (BOD). COD is the amount of oxygen expressed in milligrams per liter required to oxidize components of a waste by chemical reaction. BOD is the amount of oxygen expressed in milligrams per liter utilized by microorganisms in stabilizing the waste in a specific time period.

Taste and odor are particularly important for potable water supplies. In natural waters, taste and odor can be caused by algae or other natural factors and by various compounds in waste water. Hydrocarbons, sulfur compounds, phenolics and nitrogen compounds are substances that can contribute to taste and odor.

Acidity and alkalinity can have profound effects upon the ecology of receiving waters. Leaks or losses of acid or caustic solutions or improper disposal of chemical solutions can cause undesirable pH in waste waters.

The toxicity of a substance is its presence in sufficient concentrations to cause harm to plant or animal life. Sources of toxicity include condensates containing sulfides, ammonia, phenolics, spent caustic, mercaptans or phenols, and chemicals used to control growths in circulating water systems.

Turbidity and suspended matter refer to finely-divided particles that settle slowly or not at all. In addition, the terms refer to heavier particles that may settle even in flowing streams. Suspended matter can adversely affect aquatic life by exclusion of light and buildup of bottom deposits. Excessive suspended matter in a refinery waste system can also make oil removal much more difficult.

Finally, <u>temperature</u> is another characteristic of water that is a controlling factor in chemical and biological reaction rates. Solubility of oxygen, so important to aquatic life, varies inversely with temperature. Chemical companies generally take great efforts to release treated wastewater at the same temperature as the receiving waters.

<u>Waste-Control Methods.</u> A wastewater system is an essential part of every refinery and petrochemical installation and typically includes the following components:

<u>Collection and segregation</u> systems to prevent contaminated waters from flowing into receiving waters;

<u>Loss-prevention</u> to avoid small losses of products during processing, handling and storage;

<u>Oil removal</u> including various methods such as gravity separation, sedimentation, flotation, filtration, etc., to remove and save hydrocarbons that could be reprocessed;

<u>Recovered-hydrocarbon treatment</u> to clean up the recovered hydrocarbons by physical, electrical and chemical methods and make them suitable for reprocessing; and

<u>Ballast-water treatment</u> to dispose of ballast water from tankers and barges.

<u>Disposal of spent chemicals</u>. Chemical disposal is normally considered a waste-control problem, but because it may have special significance to Alaskans, further elaboration is useful. The disposal of spent chemicals is achieved by sale, disposal at sea or by chemical methods, incineration, or in deep wells.

Sale of spent chemicals is the most attractive method of disposal. It usually requires separation of spent chemicals from other wastes at the time of processing, sometimes requiring special planning of operational procedures. It is not uncommon, for example, to return spent sulfuric acid from alkylation to the acid manufacturer for reprocessing, or to sell sulfide-rich caustic to pulp and paper mills.

At one time, containerized disposal at sea was a popular and common practice among chemical companies and some refineries. Recently, however, because in some instances, insecure containers were used, chemical spills have occurred after containers deteriorated and broke.

Regeneration, air oxidation and neutralization are the major chemical methods used to minimize the production, handling or disposal of spent caustic solutions.

Incineration is not a common method of disposing of spent chemicals, primarily because of air emission problems. However, it is used to dispose of materials released from neutralization of spent caustics.

Flaring of hydrocarbon wastes is another common practice but, as the relative cost of plant fuels has risen, processes are designed and operated to conserve combustible wastes for use as plant fuel. (Some of the perpetual flares seen at refineries and chemical plants are not actually for waste disposal, but are "pilot lights" on safety vents, to assure that any gases that have to be vented in a plant emergency are ignited immediately.)

Deep-well disposal can provide a method for concentrated, toxic or odorous wastes (e.g. spent caustics or foul condensates). The method involves the underground storage of wastes in the pores of a geological formation which already contains unusable water.

Currently, the federal Department of Transportation regulates the movement of hazardous substances, and the Environmental Protection Agency regulates the disposal of hazardous wastes. Most State, in addition, have their own standards and machinery to assure compliance. Alaska is an exception thus far, and although the Legislature is now considering regulation of hazardous-waste disposal in connection with legislation governing nuclear power, there are currently no State standards regarding the transportation and handling of dangerous materials.

7.4 Air Pollution

Major refinery and petrochemical emissions that contribute to air pollution are sulfur compounds, hydrocarbons, nitrogen oxides, particulates including smoke and carbon monoxide. Other emissions of lesser importance are aldehydes, ammonia and organic acids. Table 7-1 illustrates the potential sources of the various contaminants and illustrations the major operations involved.

The character and quantity of atmospheric emissions vary greatly from plant to plant. Controlling factors include plant capacity, type of feedstock, complexity of processing employed, air-pollution control measures in use and the degree of maintenance and housekeeping procedures in force. Also important are the existing level of emissions, and the weather and geography of the area surrounding the plant. In Valdez, for example, where inversions and mountain barriers may exacerbate air pollution problems, the Environmental Protection Agency (EPA), through the Alaska Department of Environmental Conservation (DEC), requires careful monitoring of air quality around the Alyeska terminal, and would consider permit applications for petrochemical plants in the area very cautiously.

Table 7-3 Potential Sources of Specific Emissions from Hydrocarbons Processing Plants

Emission	Potential Sources
Sulfur Compounds	Boilers, process heaters, catalytic-cracking unit regenerators, treating units, H_2S flares, decoking operations.
Hydrocarbons	Loading facilities, turnarounds, sampling, storage tanks, wastewater separators, blowdown systems, catalyst regenerators, pumps, valves, blind changing, cooling towers, vacuum jets, barometric condensers, air-blowing, high-pressure equipment handling volatile hydrocarbons, process heaters, boilers, compressor engines.
Oxides of Nitrogen (NO_x)	Process heaters, boilers, compressor engines, catalyst regenerators, flares.
Particulate matter	Catalyst regenerators, boilers, process heaters, decoking operations, incinerators.
Aldehydes	Catalyst regenerators.
Ammonia	Catalyst regenerators.
Odors	Treating units (air-blowing, steam-blowing), drains, tank vents, barometric condenser sumps, waste-water separators, flares.
Carbon Monoxide	Catalyst regeneration, decoking, compressor engines, flares, incinerators.

The major opportunities for emissions occur when plant operations start up, combustion of fuel in boilers for steam generation and in process heaters, and combustion of carbon during regeneration of cracking catalysts. The combustion of fuel in boilers and process heaters poses general problems especially where sulfur dioxides and are present (depending on the kind and quality of fuel burned). The combustion of carbon from a catalyst produces carbon monoxide and the entrainment of small catalyst fragments.

The art and science of atmospheric pollution control are still being fine-tuned and are the subject of much debate over cost-effectiveness, as well as much scientific and engineering research. Most refineries and petrochemical plants have yet to achieve the distinction of being "unheard, unseen and unsmelled."

7.5 Health and Safety Issues

Evolutionary adaptation has made humans and other organisms relatively immune to small internal doses or surface contact with most chemical substances that occur in nature. The toxic character of many other naturally occurring chemicals is obvious, causing immediate death, sickness, or readily detectable biological reactions in organisms that come into contact with them. There are a few well-known exceptions, such as poisioning from heavy metals (e.g., lead, arsenic, mercury, and cadmium) that can accumulate in the body over many years from natural sources.

There is a twofold problem with some synthetic organic chemicals, however. They are, on the one hand, very active chemically and biochemically. On the other hand, they are not found in nature, even in minute quantities, and for that reason, evolution has had no opportunity to create natural defenses against them (by permitting only the most resistant individuals to survive and reproduce themselves).

Carcinogens. The most perncious of the new bioactive substances are those that have an affinity for the genetic materials in cell nuclei. Only one molecule of such a substance needs to come into contact with one DNA molecule in one cell for it to produce a cancer or, in the case of a reproductive cell, a defective birth. Thus, just as in the case of atomic radiation, there is no "safe" dose.

Reducing any individual's exposure reduces that individual's statistical risk of contracting cancer or producing defective offspring; but if the exposed population is large enough, the presence of any of the substance at all guarantees that there will be some harm to someone.

This kind of poisoning has some very troublesome implications. There may be long lags between exposure and appearance of any symptoms. One noteworthy instance is DES (diethyl silbesterol), which appears to produce cervical cancer in the grown daughters of women who took the drug two or three decades earlier.

Even without such delays in the the appearance of harmful effects from a chemical, moreover, it may be years or decades before a sufficient statistical base accumulates to suspect that the substance is a carcinogen, much less to establish the fact conclusively. The first suspicion may arise, for example, only when a public health statistician notes that there have been three cases of a certain rare form of cancer over the previous 25 years among the more than seven thousand workers who have worked in a particular plant, while the average incidence in a national population sample of that size would have been less than one.

It is conceivable, indeed, that a powerful new carcinogen might <u>never</u> be detected. A few kilograms of a given long-lasting substance vented into the atmosphere or carried off in the drain and diluted throughout the world's oceans over a period of years might increase the worldwide incidence or cancer or, say, mongolism by tens of thousands of cases per year. These cases, however, could be widely dispersed geographically and be overwhelmed statistically by the hundreds of other things that influence the world's mortality and morbidity trends.

There are now thousands of experts engaged in testing the effects of acute and long-term exposure to various chemicals, but little is really known. More than fifty thousand synthetic chemicals are currenty produced in commercial quantities, and about six thousand new chemicals are introduced commercially each year. Only a tiny fraction of these substances were tested for carcinogenic effects before being marketed. The chemical industry and federal regulatory agencies have been continually expanding their testing programs for newly introduced substances, but a stupendous effort would be necessary in order to bring our knowledge of the thousands of untested chemicals that have been marketed for years up to the standards which apply to new products.

The development of a petrochemical industry in Alaska inevitably involves the production, handling, storing, transportation, and disposal of substances that are or may be hazardous to human life and health. Three of the chemicals the Dow-Shell group contemplates producing in Alaska are known carcinogens --- benzene, ethylene oxide, and ethylene dichloride. Two others are suspected carcinogens --- ethylbenzene and ethylene glycol. Moreover, most petrochemical complexes of the same type that Dow-Shell are studying also produce vinyl chloride monomer and acrylonitrile, both of which are known to cause cancer.

Since World War II, sufficient evidence has accumulated to establish that aromatic hydrocarbons produced in refineries, and several products of petrochemical plants, pose health hazards when a major spill or accident occurs or when people are exposed to repeated or prolonged contact with even minute amounts.

Prolonged exposure to benzene is known to cause irreversible damage to the bone marrow where red and white cells and platelets are formed. Benzene exposure can cause aplastic anemia, a form of leukemia, chromosome damage in white blood cells, and can induce acute myleogenous leukemia. Benzene is also a central-nervous-system depressant.

At the present time, the federally regulated occupational exposure level for benzene is 10 parts per million (ppm), averaged over an eight-hour day. The Occupational Safety and Health Administration (OSHA) regards this level of exposure to be too high and recommends a standard of 1 ppm, a standard which was recently rejected by the Supreme Court in a 5-4 decision.

These standards apply principally to refinery and chemical plant workers, but we know almost nothing about the health effects, if any, of the tons of benzene that are released into the atmosphere every day when automobile gasoline tanks are filled. Little consideration has yet been given, moreover, to systematically measuring, much less controlling, exposure to aromatics on the part of those who may conceivably comprise the most numerous and severely impacted occupational group --- filling-station attendants.

Ethylene dichloride is another chemical also in the midst of regulatory controversy. It is a major ingredient for manufacture of vinyl chloride monomer, a known carcinogen and appears to pose some danger itself. The current regulated level of exposure of ethylene dichloride is 50 ppm; however, in 1975, the National Institute for Occupational Safety and Health (NIOSH) recommended a revised standard of 5 ppm because impairment of the central nervous system and increased morbidity (especially diseases of the liver and bile ducts) were found in workers chronically exposed to ethylene dichloride at concentrations below 40 ppm and averaging up to 15 ppm.

In addition to exposure problems within the petrochemical plants, there are also risks associated with the transfer and shipment of chemicals. Again, as with exposure in the workplace, the implications of and dangers posed by a chemical spill are not precisely known. Petrochemicals do, however, present a hazard to marine ecosystems both in terms of an acute spill situation and chronic exposure to small dosages. The acute toxicity of ethylbenzene to marine organisms occurs at concentrations as low as 0.43 ppm, for example, but little is known about the toxicity to marine animals chronic exposure to lower concentrations of ethylbenzene or other chemicals.

A petrochemical complex in Alaska does not by itself pose great health, safety, or aesthetic risks. Production of some first-stage petrochemicals such as ethylene and methanol is virtually odorless and, with the sometime exception of large quantities of water vapor and occasional flaring, they are not only fairly safe but quite inconspicuous. Collier Carbon and Chemical Company has made aqueous ammonia and prilled urea in Kenai for 15 years, with almost no complaints from the plant's neighbors or from federal, State or local environmental-protection personnel.

The production of benzene, ethylene dichloride, vinyl chloride monomer, or acrylonitrile, however, presents a new dimension of risk for Alaska industry and to the communities in which the plants would be located. Acceptable levels of exposure are the subject of much dispute and debate even within the responsible federal agencies (OSHA and NIOSH).

Alaskans will have to make their own judgments on the risks in the face of great uncertainty.

Policy Dilemmas and Dimensions. In summary, the hard facts about chemical health hazards are sparse, and even where the facts are known, the policy conclusions are not obvious. There is an undeniable statistical association between exposure to aromatic hydrocarbons, for example, or VCM, and the incidence of cancer, and there is reason to believe that there is an inescapable risk of exposure and some risk of contracting cancer wherever these products are produced, stored, transported, or used. But society tolerates cigarettes, firearms, motorcycles, and a host of other products whose association with death and sickness is far more obvious than that of benzene or VCM. Neither Congress nor the American people would vote to ban high-perfomance gasoline or PVC products because of the health hazards connected with them.

The economic value of life and health, and the trade-offs among life and health, convenience and prosperity, and personal and economic freedom, are difficult even to think about systematically, and it is vain to expect any political consensus regarding them. The people of Alaska will, nevertheless, have to make some practical decisions about how to deal with the health and safety risks --- known, unknown, and imagined --- of hydrocarbons processing in the state.

Information and Expertise. In order for Alaskans to evaluate the risks associated with hydrocarbons-processing projects, they will need detailed technical information on the immediate and cumulative effects ---

of chemicals accidentally released in the plant or in transit to and from the plant;

on water and air quality from normal plant operation and abnormal occurrences;

of solid and liquid waste disposal; and

of induced economic and population growth.

Risk Assessment. A comprehensive risk-assessment requires the following types of information:

Detailed Process Diagrams, showing chemical processes, volumes of intermediate compounds and final products, material balances, and catalysts used;

Changes in Chemical Processes and Product Slates that are planned, likely, or plausible over the economic life of the initial facilities;

Markets, initial and planned, likely, or plausible, with the transportation options for each, in sufficient detail to permit identification of associated spill hazards;

Transportation of Chemicals, including the common and scientific name of each susbtance to be moved in or out of the facility by transport mode (pipeline, rail, truck, barge or ship), the volume per shipment by type of container, annual volume, and shipment destinations;

Hazardous-Waste Disposal, including the qualities and chemical composition of Class I wastes generated by the proposed facility (including incidental products of processes such as quencing, cracking, distillation, oxidation, acidification, and hydrodealkylation); composition and volumes of spent catalysts; and the methods of disposal for each; and

Air-Quality Effects --- the types of volumes of normal emissions; and those likely or possible in plant malfunctions, the probabilities of their occurrence.

In order to assess the risks associated with establishment of a petrochemical facility, Alaska needs expertise that is not now available in the state. Currently, EPA has only one person assigned to the Alaska Region, and OSHA is has no staff at all in Alaska to monitor the chemical industry. Because of the technical complexities involved, an adequate public examination of any specific proposal for a petrochemical venture will require the help of chemical and process engineers, and hazardous-materials and waste-disposal experts not affiliated with sponsors or prospective contractors on the proposed projects.

7.6 Options for State Regulation.

Many States have adopted standards and regulations that govern the handling, processing, strorage, and handling of hazardous wastes. Alaska currently relies on EPA and OSHA to establish air and water-quality standards, waste-disposal regulations, and occupational-safety standards, although several State agencies are involved with the enforcement of Federal standards.

With the relatively small chemical industry that exists in Alaska today, the Federal regulatory machinery is probably sufficient. The prospect of large-scale petrochemical development in Alaska, however, suggests the wisdom of at least investigating and comparing the various systems that might be implemented at the State level to protect human life and the natural environment.

Prescriptive vs. Economic Remedies: Prescriptive Regulation. There are two polar approaches to control of health and safety hazards and environmental quality, and a number of in-between measures. At one extreme are prescriptive regulations, which state in categorical terms what industry may or may not do, what facilities are acceptable, and exactly how certain equipment is to be designed.

Traditional building codes are of this kind, attempting to limit fire hazards by prescribing lath-and-plaster walls, protecting sanitation by requiring cast-iron drain pipes of a certain diameter, and the like. Many of the Interior Department's stipulations governing the construction of TAPS were also of a prescriptive character. Effluent and emissions standards that set the maximum absolute volume, or maximum concentration, of some pollutant that may be released by a single plant, or from a single point, are also prescriptive standards.

The advantages of prescriptive regulations are their relative clarity and ease of enforcement. Their disadvantages are their inflexibility and their insensitivity to costs. Obsolete building codes, for example, have frequently delayed the introduction of cheaper, stronger, and safer building materials; a categorical Federal requirement for secondary treatment of municipal waste-water has imposed extravagant sewage-treatment costs on many small communities (including Alaska communities), with no perceptible contribution to human health, yet leave alone serious water-quality hazards in other areas which could be resolved at comparatively low costs.

At the other extreme are purely economic incentives that leave design and operational details, and the risks attendant upon them, entirely up to management. The heart of this approach, in its traditional form, is the right of injured parties to sue and recover damages for loss of life, or injury to persons or property.

<u>Litigation</u>. This approach relies on the possilility of lawsuits and expensive court awards to induce industry to spend just about as much on health, safety, and environmental protection as the risks of measurable (and litigable) damage warrant. The effectiveness of litigation as a deterrent to (as well as a remedy for) private or public injury has been greatly enhanced in recent years by

(1) the possibility of "class action" suits, in which large numbers of parties claiming relatively small individual injuries can group together to litigate, (2) the increasing tendency of State and local governments to institute proceedings to recover for alleged damages to public values in cases where it would be difficult to show or measure individual damages, and (3) the publicity accorded to a few huge settlements and court awards in occupational-injury and product-safety proceedings.

Strict Liability. Traditionally, civil remedies for injuries to health, safety, or the environment are available only to injured parties who can prove that there was misconduct or negligence on the part of the firm that caused the problem. The very existence of a refinery, tanker terminal, or petrochemical plant, however, creates a statistically certain risk of damage to someone, sometime, even without provable misconduct or negligence on the part of anyone. (Suppose a wholly unanticipated natural disaster ruptures a tank full of poisonous gas; or suppose that a chemical which was rigorously tested turns out to have horrible long-term effects that no one reasonably could have been expected to anticipate?)

Thus, for the possibility of litigation to be an adequate remedy, legislation is necessary to make the legal liability for certain kinds of damage "strict", or "absolute" --- not conditional upon proof of negligence, in other words. Alaska law establishes strict liability for damages from marine oil spills, for example.

Individual litigation is inadequate or totally inapplicable, even with strict liability, wherever damage is likely to be distributed randomly over a large and hard-to-define population (as is often the case with carcinogens), so that responsibility cannot clearly be assigned, where the values to be protected are not privately owned (as in the case of a commercial fishery stock), or difficult or impossible to evaluate (air clarity, or the ability of an area to support a wild bird population).

Insurance. Another problem with civil remedies as remedies and as deterrents is the cost of litigation , its uncertainty, and the long time that typically elapses between the damage and its compensation. Insurance, and particularly insurance funds administered by an independent party, can benefit both industry and the public by cutting legal costs, delays, and the uncertainty of the outcome. Insurance can be either voluntary or madnated by law: There are a number of Federal, State, and cooperative insurance funds for clean-up after major accidents.

The Trans-Alaska Pipeline Liability Fund is the first Congressionally created entity of its kind, receiving a fee of five cents per barrel lifted at the Valdez terminal by the TAPS owner companies. The purpose of the fund is to pay legitimate claims for damages, including clean-up costs, resulting from oil discharges between Valdez and any other U.S. port; the Fund is liable without regard to fault for that increment of damages in excess of $14 million but not in excess of $100 million per oil-spill incident.

Insurance also has its shortcomings, however. As many readers who have had difficulty with an auto insurance claim may recall, it sometimes requires litigation to collect an insurance claim, even against one's own carrier. Diluting the penalty a firm pays for a given injury also dilutes the incentive to avoid the injury. Premiums in private insurance programs are normally adjusted to the experience of the individual enterprise as well as the industry, but rigorous, actuarially-based payments seem to be the exception in governmentally-sponsored no-fault compulsory insurance programs. A further dilemma in these cases is whether to make the insurance a substitute for all other legal remedies on the part of those who are injured, or to let them retain all or part of the rights they would otherwise have under civil law. Details of the issue are beyond the scope of this report, but ether choice can create serious inequities.

Effluent Taxes and Hybrid Systems. There are a variety of health, safety, and environmental regulation techniques that are not based purely on an economic assessment of risk, but neither are they purely prescriptive. Toward the economic end of the spectrum, there is a growing interest in the use of emissions and effluent taxes. A State environmental protection authority would, for example, establish a tax or penalty per kilogram of sulfur dioxide (SO_2) discharged into the air. Each operator of an electrical generating plant or refinery would decide whether it was cheaper to reduce emissions or to pay the tax. The SO_2 tax rate could be adjusted periodically to create just enough pressure on industry as a whole to hold the concentration of SO_2 in the atmosphere below some target level.

A related regulatory technique is to establish prescriptive standards for some aspect of environmental quality, but to allow a "market" in pollution rights. EPA, or a State agency under EPA authority, may establish standards for the maximum concentration of certain pollutants in the region's air or water, and for emissions or effluents from individual plants. In order to exceed its single-source quota, or to initiate a new source of pollution, a firm could receive credit for reducing emissions somewhere else. California's Air Resources Board, for example, would not permit Sohio to establish a tanker terminal at Long Beach to serve its proposed Pactex pipeline unless Sohio could arrange for a greater reduction in certain pollutants from other sources in the Los Angeles airshed than the terminal operation would add. Sohio's solution was to pay for smokestack scrubbers on electrical generating plants owned by Southern California Edison.

The control system ultimately established to control the health, safety, and environmental risks of hydrocarbons processing will undoubtedly differ from the current mix of prescriptive, proscriptive, and economic regulation that exists in Federal law or in the laws of other States (or other nations). It is in order, however, for Alaska to begin a systematic review of these systems, their effectiveness, and their cost-effectiveness.

CHAPTER 8

THE ECONOMICS OF HYDROCARBONS PROCESSING AND THE OUTLOOK FOR REFINING AND PETROCHEMCIALS IN ALASKA

Three cost factors dominate investment and location decisions for hydrocarbons processing facilities: (1) transportation costs, (2) feedstock and fuel costs, and (3) plant construction costs.

8.1 Hydrocarbon Transportation Economics.

Transportation cost is the single most powerful economic influence on the location of refineries and petrochemical plants, and one of the most important considerations in choosing their product slates. Two fundamental axioms govern the relationship between transport costs and the choice of transportation systems and plant location:

> (1) Light hydrocarbons cost more to ship per unit of weight or energy than heavy hydrocarbons. COROLLARY: Gases cost more to ship than liquids or solids.

> (2) Tankers are the most efficient long-distance transportation mode for hydrocarbons that are liquid under atmospheric conditions, while pipelines are the most efficient mode for gases.

The first axiom and its corollary rest on elementary physical principles. Under given conditions of pressure and temperature, solids and liquids pack more matter and more energy into the same pipeline or tanker space than gases; a cubic foot of propane gas contains more energy than the same volume of methane gas; and a barrel of crude oil or residual oil contains more energy than lighter petroleum liquids like gasoline or naphtha, or light chemical derivatives such as methanol.

Water-borne bulk carriers. The second axiom reflects the fact that water-borne transport is generally the cheapest way of moving a given weight or volume of any bulk commodity. Crude oil, in turn, is almost an ideal cargo for large ocean-going vessels. It has just the right density --- slightly lighter than water --- to allow the entire hull-space to be filled with cargo and at the same time to produce a low center of gravity, which provides vessel stability. A liquid at atmospheric pressures and temperatures, crude oil does not require closely-controlled conditions en route, is easy to load and unload, and is relatively insensitive to contamination.

In order to ship gases by tanker, on the other hand, they must be chilled and liquefied in a costly plant and with a substantial loss of energy. The lightest hydrocarbons such as methane, ethane and ethylene have very low boiling points, moreover, and tankers designed to carry them must be very costly, specially-designed cryogenic (refrigerated) vessels.

The heavier propane and butanes (LPG), however, require much less energy to liquefy, and will remain in the liquid state at atmospheric temperatures if they are confined in tanks under very modest pressures. Thus, while ocean-transport costs for LPG are substantially higher per unit of energy than for crude oil, it is much less troublesome to move by ship or barge than natural gas, ethane, or ethylene.

Gas pipeline transportation. Pipelines are the ideal transport mode for gases. In a pipeline, extremely high pressures can be used to squeeze even the lightest hydrocarbons into dense-phase fluids that contain nearly as much energy per unit volume as a liquid, and these fluids can be pumped long distances with only a relatively modest loss of energy in the form of compressor fuel. [See the Appendix: "Introduction to Natural Gas Conditioning and Pipeline Design."]

TAPS vs. ANGTS. In Alaska, these principles can be seen in the contrasting choices of transportation modes for North Slope oil and gas. Before deciding to build an oil pipeline, the North Slope producers investigated the feasibility of a sea route directly from Prudhoe Bay to the U.S. East Coast. The all-tanker system was rejected in favor of a pipeline only because of the delays it would have entailed in perfecting ice-breaking tankers.

While an all-pipeline system across Canada would have been the cheapest way to take Alaska oil to the Upper Midwest, the companies finally chose TAPS because it was the shortest land route to a year-round ice-free port, from which tankers could carry crude oil for well under $1 per barrel to any Pacific Coast port in either North America or Asia.

For Prudhoe Bay natural gas, on the other hand, most parties favored an all-pipeline route across Canada over a liquefied natural gas (LNG) tanker system from the beginning, because of the latter's higher capital cost and greater fuel consumption. Even now, if transportation of North Slope gas by means of the proposed Alaska Highway pipeline turns out to be so expensive that the gas cannot be marketed in the Lower 48, the gas producers are unlikely to reconsider the all-Alaska pipeline-LNG concept. A more promising alternative is probably to process the natural gas in Alaska into liquid products like methanol or synthetic gasoline that can be shipped in conventional tankers.

8.2 Transportation Costs and Plant Location.

The two axioms above also have important implications for decisions on siting refineries and petrochemical plants:

(1) Petroleum refineries tend to be located near their markets;

(2) Naphtha and gas-oil based petrochemical plants tend to be located near refineries; and

(3) Natural-gas-based petrochemical plants tend to be located near their raw-materials sources.

Refined petroleum products cost more to ship long distances than crude oil, only partly because of their lower energy-density. Refineries produce a variety of products with different viscosities and vapor pressures, and with different degrees of flammability, toxicity, etc. Individual refinery products are therefore typically shipped in relatively small batches and tend to require specialized treatment to avoid loss or contamination, fire hazards, and the like. Thus, refineries are usually located to take advantage of the relatively low cost of crude-oil transportation, and designed to produce a product slate that matches a local or regional demand mix.

The same principles apply to petroleum (naphtha and gas-oil) based petrochemicals manufacturing. Crude oil is cheaper to transport than the primary and intermediate petrochemicals or end-user products made from it. In addition, the initial distillation of crude oil, and the subsequent cracking or reforming of naphtha or gas oil, produce a great variety of hydrocarbons. Some of these products are suitable for petrochemical use, but others are more valuable as gasoline, jet-fuel, or fuel-oil blending stocks. Thus petroleum-based petrochemical plants are generally planned as a part of refinery complexes, or are at least located near refineries. As a result ---

Transportation economics do NOT favor Alaska locations for petroleum refineries (except to serve in-state demand) or oil-based petrochemical plants.

These principles help explain why oil-industry and energy analysts almost unanimously doubted the economic viability and financibility of the Alpetco proposal from the beginning, both in its original petrochemical-plant incarnation and in its recent refinery version.

Natural gas and the lighter natural-gas liquids like ethane, on the other hand, are usually more costly to ship than the liquid or solid petrochemicals that are made from them. Generally, therefore, it makes sense to convert methane and ethane to substances that are liquid or solid under atmospheric conditions before shipping them long distances.

Accordingly, gas-based methanol plants, and ethane-to-ethylene plants are almost invariably located in gas-producing areas. As ethylene is itself a light gas, which can be moved by sea only as a chilled liquid in costly cryogenic tankers, it is usually processed further into liquid or solid petrochemical derivatives such as ethylene oxide or polyethylene before being transported to distant markets. As a result ---

If Alaska natural gas or ethane is to be converted to petrochemicals anywhere, transportation economics favor an Alaska plant location.

This principle is the rationale behind the Dow-Shell group's strategy. Methane or ethane would have to be shipped by pipeline at relatively high unit costs, or by cryogenic tankers at even higher costs, to feed petrochemical plants in the Lower 48 or, say, Japan. Converting methane to methanol in Alaska, or ethane to ethylene and then to polyethylene, would facilitate their transportation and hence reduce the final cost of the chemical products.

Final-Product Manufacturing. The advantage of locating gas-based hydrocarbon-processing facilities near their feedstock sources does not extend indefinitely "downstream." Just as in other Alaska resource-based industries --- wood products and fisheries, for example --- the state's comparative advantage in manufacturing generally ends with those kinds of processing that reduce shipping costs by decreasing the bulk, weight, or perishability of the product. For a long time to come, the more complicated and labor-intensive, or weight- or bulk-increasing, manufacturing activities will be cheapest to carry out in populous areas close to major markets. For this reason ---

> Alaska petrochemicals manufacturing will probably end with first or second derivatives that can be shipped as liquids or solids for further processing and fabrication elsewhere.

High capital, labor, and transportation costs make it unlikely, in other words, that a petrochemcial complex in Alaska (or in Saudi Arabia) would produce and package fibers, textiles, or apparel; housewares; rubber or rubber products; pharmaceuticals, etc. Although the public-relations literature of the various chemical companies emphasizes the vast number of final products made from, say, ethylene derivatives, the Dow-Shell reports make it clear that the group is not actively considering processing Alaska hydrocarbons beyond the first form in which they can be shipped economically to other markets.

8.3 Fixed Capital Costs.

The foregoing principle by itself does not guarantee that it is economically feasible to make petrochemcials in Alaska from North Slope hydrocarbon gases. Nor does it necessarily dictate where in Alaska a plant should be located. Fixed capital costs --- essentially plant construction costs --- are also a crucial element in investment and plant-location decisions. But because refining and petrochemicals are unusually capital-intensive industries, production labor and other operating costs are relatively unimportant.

Fixed Costs vs. Variable Costs. No new hydrocarbons processing facility is likely to be built unless its sponsors and their lenders are convinced that project sales revenues will be sufficient to cover the full cost of production; that is, to recoup both (a) fixed costs --- the entire original investment plus a competitive return on that investment --- and (b) variable costs --- feedstock costs and and other operating expenses.

Because an individual plant or complex costs hundreds of million or even billions of dollars, cost overruns, mistaken product-market or feedstock-supply forecasts can be catastrophic, so that investors normally demand that their feasibility studies demonstrate a substantial safety margin. Therefore:

(1) Investors in a NEW plant will insist that expected sales revenues cover fixed costs, but

(2) Once a plant is built, sunk costs do not affect operating decisions.

An established plant will tend to operate at virtually full capacity so long as its product sells for more than its feedstock and other operating costs, even if it is not covering its depreciation or debt service, or generating any net profit. In such a situation, in other words, the goal of plant management is to minimize losses rather than to maximize profits; refineries or chemical plants will stay in service whenever they would lose more money by shutting down than by continuing to operate.

The Outlook for Refinery Investments. Oil-refining is now a money-losing business almost everywhere, and will remain a money-losing business for many years. The nearly-zero margins that generally prevail in the refining business today would probably have been fatal to the Alpetco refinery scheme even if it did not have to face Alaska's transportation and construction-cost disadvantages.

Because of the huge overhang of excess refining capacity, both in the U.S. and globally, the current prices of petroleum products tend to represent little more than the cost of feedstocks, and contain no allowance for the amortization of fixed costs or any return to the investment in existing facilities. Such a market is even less likely to provide the substantial margin above operating costs that is necessary to justify building a new refinery, unless that plant has some exceptional offsetting advantage in the form of low-cost feedstocks, captive markets, or a direct government subsidy.

The Outlook for Petrochemicals Investments. New investments in producing ethylene and ethylene derivatives might seem to face the same difficulties as refinery investments, because substantial excess plant capacity exists for olefins both nationally and worldwide. The crucial difference in outlook between refining and petrochemicals, however, is that petrochemical consumption is expected to keep growing, while there is little prospect that the expansion of oil-product consumption will resume in the foreseeable future. There is also a good prospect that prices of gaseous feedstocks in remote producing regions like Alaska or Saudi Arabia will be sufficiently below world prices for competing oil-based feedstocks that new gas-based plants will be profitable even in the face of idle capacity elsewhere.

The Alaska Cost Differential. It is a commonplace that plants built in Alaska will be more costly than their equivalents built in more developed temperate regions. Transportation costs for equipment and materials and labor expense are higher, and labor productivity is lower, than in the Lower 48, Europe, or East Asia, while the facilities themselves must be designed to withstand more severe environmental stresses.

Local construction expenses, chiefly site preparation and on-location labor costs, are usually assumed to be 50 to 60 percent higher at tidewater in Southcentral Alaska (e.g., at Anchorage, Kenai, or Valdez) than on the U.S. Gulf Coast; about 100 percent higher in Interior Alaska; and about three times as high in the Arctic. The latter figures, incidentally, are comparable to the typical cost differential for refinery or chemical-plant construction in the Middle East. Therefore ---

> If a processing plant in Alaska (or, say, in Saudi Arabia) is to be competitive, the sum of its transportation and feedstock-cost advantages must be sufficient to overcome a large construction-cost disadvantage.

8.4 Feedstock Costs and Feedstock Supply.

Feedstock and fuel costs (which are usually but not always the same) are a crucial factor in deciding the feasibility of any refinery or petrochemical investment.

Oil-Based Feedstock Costs. Low ocean-transport costs have created an articulated market world market for crude oil in which prices everywhere move more or less in unison, and in which differences in the price of crude oil between various tidewater locations around the world are relatively small.

Petroleum refining and petroleum-liquids-based petrochemical manufacturing tend, therefore, to be "price-taker" industries. Long-term crude-oil or petroleum-product sales contracts at fixed prices, or even at fixed formula prices (say, at the Saudi Arabian "marker-crude" price plus or minus a location and quality differential) are very rare. Individual operators of petroleum-liquids processsing plants thus have little opportunity to control their raw-materials costs, but typically must accept whatever prices world markets (or government regulators) dictate. This is the case even for a refiner or chemical producer that owns and processes its own crude-oil supplies, because the true index of feedstock costs to such a producer is the price the oil might have commanded on the open market.

In assessing the economic feasibility of a fuels refinery or oil-based petrochemical plant, therefore, the sponsors have to make judgments about future oil prices and their relation to the market value of the fuels or petrochemcials derived from them. This task is not quite as hopeless as the turbulent history of world oil prices might suggest, because the market prices of petroleum-derived products from competing plants will also vary with the price of crude oil. And although substantial volumes of petrochemicals are produced from feedstocks other than crude-oil fractions, it is the cost of petrochemicals derived from oil that will determine the product-price levels that the output from any new chemical plant must meet.

The feasibility analysis for a new hydrocarbon-liquids processing plant need not concentrate on the absolute level of oil prices, therefore, but only on ---

(1) The cost of feedstocks for the proposed plant, RELATIVE to the expected costs for its competitors (e.g., the difference between naphtha prices in region A and gas-oil prices in region B); and

(2) The effect of oil-price levels on total product demand.

The Alpetco project, for example, would clearly have failed the first test whether its product to be was petroleum fuels or petrochemicals. Unless Alaska were willing to sell royalty oil at less than market value, project sponsors had no reason to expect their oil feedstock costs to be significantly less than those of Lower-48 or East Asian refiners or oil-based petrochemical manufacturers.

As a refinery, at least, Alpetco would have failed the second test too: Higher oil prices were persuading consumers worldwide to reduce oil consumption, idling a high proportion of existing refinery capacity in the United States, the Caribbean, Europe, and East Asia. The result has been --- and will continue to be --- petroleum-product price levels that reflect near-zero operating profits for refineries everywhere. Unless the State sold its crude-oil at a very deep discount, therefore, no hope would exist for Alpetco to recover its investment or earn any return on it.

Gas-Based Petrochemical Feedstocks. Natural gas and natural-gas liquids markets are quite different from those for crude oil. Because of high costs for marine transport of liquefied gases, a single world market for methane or ethane does not exist as it does for crude oil and petroleum products, while the market for LPG's is far less developed than for crude oil. Even in North America, the huge investments necessary to bring Arctic gas to market would guarantee large regional differences in the wellhead value of natural gas and gas liquids. For this reason, gas-based petrochemical plants in Alaska or the Middle East are likely to be "price-makers" rather than price-takers.

This means, simply, that local petrochemical manufacturing (together with local gas-fired electrical generation) may be the "highest and best" use of gas reserves located great distances from major energy markets, and would thus be able to offer the producers a higher price than they would get by shipping the gas to those markets by pipeline or as LNG.

Illustrations. Natural gas is interchangeable with fuel oil in most end uses; suppose, then, that the value of North Slope natural gas used as fuel in the Lower 48 is roughly equal to the price of oil at, say, \$6.00 per million btu (mmbtu), which is equivalent to oil at \$33.00 per barrel. If the cost of transporting North Slope gas to Lower 48 consumers is \$4.00 per mmbtu, its netback value on the North Slope would only be \$2.00. Thus, the gas producers would gain if they sold North Slope feedstocks that would be worth \$6.00 in the Lower 48 for local processing at any price above \$2.00.

Figure 8-1. Netback Value of Prudhoe Bay Natural Gas

Lower 48 Markets	Natural Gas Pipeline	Prudhoe Bay
NATURAL GAS VALUE (\$6.00 per mmbtu) equals the OIL PRICE (\$33 per barrel)	> less pipeline transportation cost (\$4.00) >	NETBACK GAS VALUE (\$2.00 per mmbtu)

Methanol and MTBE at Prudhoe Bay. In 1980, a group that included the Arctic Slope Regional Corporation (ASRC), Davy-McKee International (DMI), and Westinghouse proposed to build a complex that would produce methanol and MTBE (methyl tertiary butyl ether, a high-octane synthetic gasoline) at Prudhoe Bay for shipment either through TAPS or through a new light-liquids pipeline.

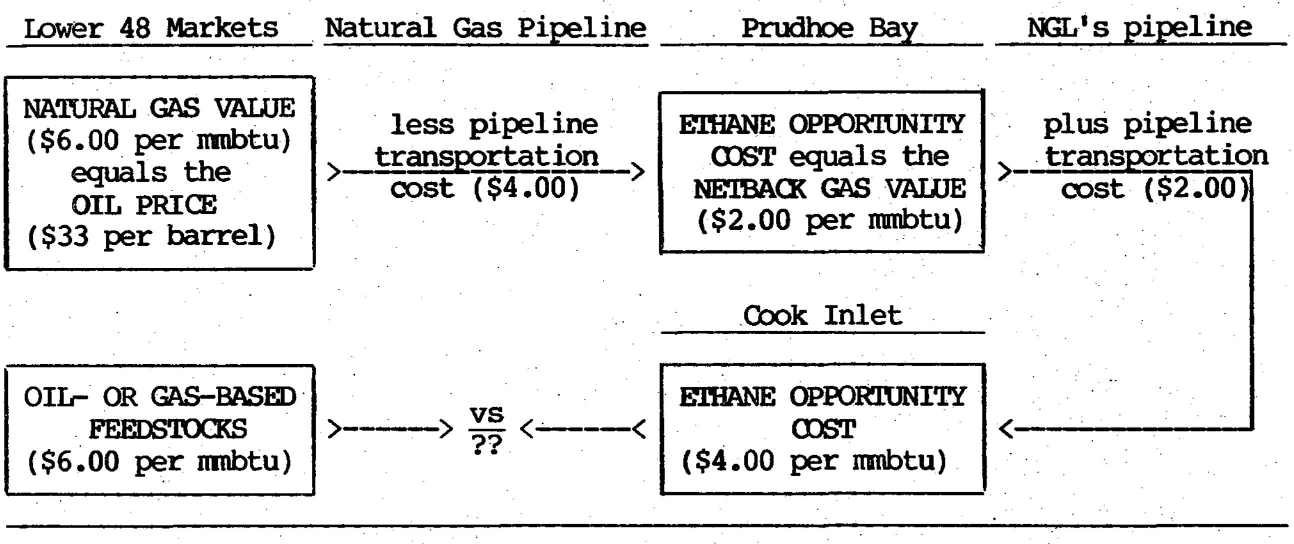
The viability of the North Slope methanol-MTBE proposal would depend on whether (1) the ability to obtain feedstocks for about one-third of the Lower 48 price ($2.00+ vs. $6.00) would offset (2) the higher cost of transporting the petrochemical products to market plus (3) the higher capital cost of building a complex in the Arctic. (Because of the highly-automated, capital-intensive character of the plants, higher operating costs would not be a major factor.)

NGL-Derived Olefins in Southcentral Alaska. Under the same assumptions, namely, that both oil and gas feedstocks sell for about $6.00 per mmbtu in the Lower 48, and that the netback value of North Slope gas is $2.00, the gas producers could (1) sell the ethane from their North Slope natural gas liquids for shipment to the Lower 48 as part of the pipeline-gas stream at a wellhead price of $2.00, (2) extract the ethane for use as plant fuel at Prudhoe Bay, thus freeing additional methane worth $2.00 when shipped through the gas pipeline, or (3) extract the ethane from the natural gas either on the North Slope or at Fairbanks for shipment through a new pipeline to a petrochemical complex at Valdez, Anchorage, or Kenai.

Suppose, further that the cost of moving the ethane from the North Slope to the petrochemical complex were $2.00 per mmbtu. The producers would gain, therefore, at any tidewater price for ethane that exceeded $4.00 --- the

$2.00 they could get by shipping the ethane (or the methane it displaced as North Slope plant fuel) to the Lower 48 through the gas pipeline, plus the $2.00 transportation charge.

Figure 8-2. Ethane Cost at Cook Inlet Plant

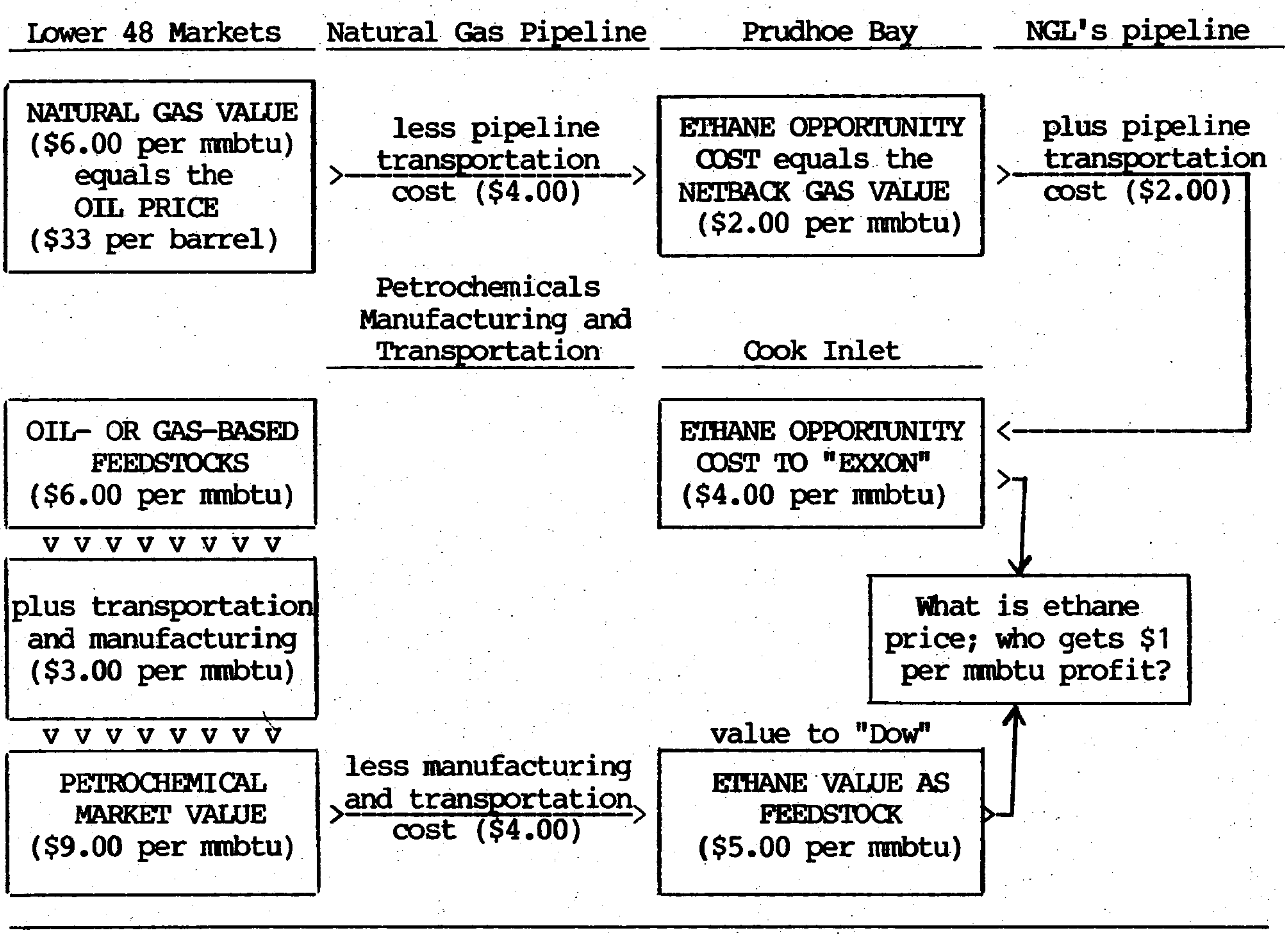


This, basically, is the Dow-Shell concept. The economic viability of the proposed NGL's pipeline and olefins plant would depend on whether (1) the plant's ability to get feedstocks at about two-thirds of the Lower-48 price ($4.00+ vs. $6.00) would be sufficient to offset (2) any product-transportation cost disadvantage, plus (3) the capital-cost disadvantage of a plant in Southcentral Alaska (which would presumably be less, however, than the cost disadvantage of building at Prudhoe Bay).

Feedstock Value vs. Feedstock Price. The value of North Slope methane or ethane as pipeline gas or LNG in distant markets typically establishes its opportunity cost in any sale for use as a petrochemical feedstock in Alaska, but this cost does not automatically determine the market price.

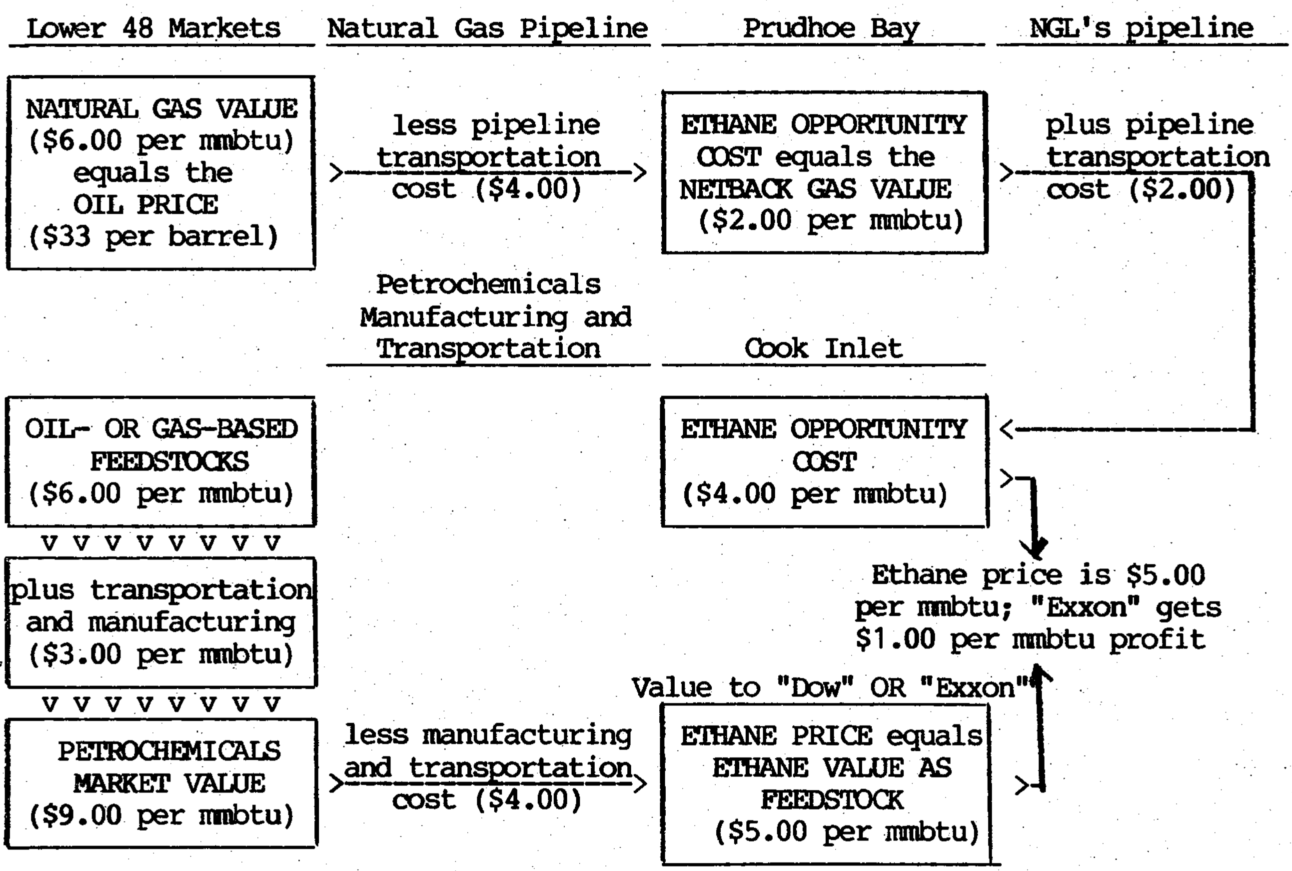
Suppose, as before, that a gas producer ("Exxon") could get $2.00 per mmbtu for ethane shipped to the Midwest via the natural gas pipeline, and that the same ethane would cost $2.00 to ship from Prudhoe Bay to an ethylene plant in the Cook Inlet region. And suppose, further, that a chemical company ("Dow") determines that it could produce petrochemicals worth $9.00 in that plant from each mmbtu of ethane feedstock at a manufacturing cost of $4.00. Thus the value of the ethane at Cook Inlet would be $5.00 per mmbtu ($9.00 less $4.00), and "Dow" would make a profit so long as it could get the feedstock for less than $5.00.

FIGURE 8-3. Value vs. Opportunity Cost at Cook Inlet



"Exxon's" opportunity cost of $2.00 per mmbtu plus transportation costs of $2.00 would establish a $4.00 floor price at the ethylene plant, while the $9.00 product price less "Dow's" $4.00 manufacturing cost would establish a $5.00 ceiling price. Figure 8-3 asks at what price between the floor and the ceiling, then, would "Exxon" be likely to sell its ethane to "Dow"; how would the $1.00 per mmbtu gain be shared between them? Figure 8-4 explains the answer.

Figure 8-4. Cook Inlet Ethane Price Determination



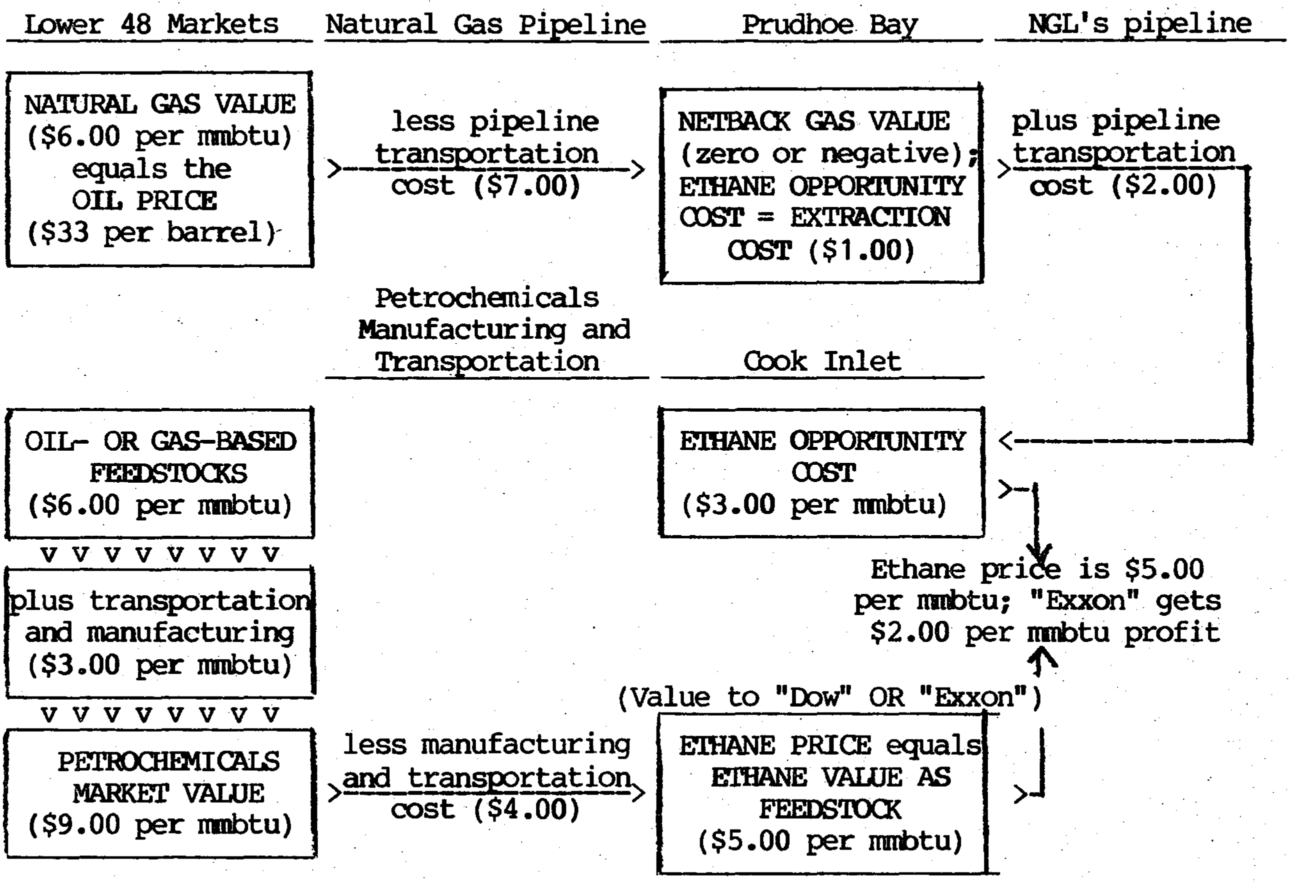
In general, it is hard to predict what kind of bargain a pair of "bilateral monopolists" will ultimately reach, but in the specific case at hand, there is reason to expect the actual sales price to be nearer the ceiling (ethane's value to "Dow") than the floor ("Exxon's" opportunity cost). The explanation is that "Exxon" in fact has choices beyond selling the ethane to some other party either (1) as part of the natural-gas pipeline stream or (2) for petrochemical feedstocks.

The real-life Exxon is itself a major petrochemical company, as is Arco, the other principal North Slope gas producer. If "Dow" determined that the most-likely value of North Slope ethane as feedstock for a Cook Inlet ethylene plant was $5.00 per mmbtu, it is reasonable to suppose that "Exxon's" chemical subsidiary would also value ethane as a feedstock for a Cook Inlet ethylene plant at about $5.00. It is not likely, therefore, that "Exxon" would "leave money on the table" by selling feedstocks to a competitor for less than this price.

<u>Alternative Scenarios</u>. It is instructive to examine two variations on this scenario: (1) in which the Alaska gas pipeline is not built, and (2) in which wellhead price controls on Prudhoe Bay natural gas influence the producers' decision on the disposition of North Slope hydrocarbons.

(1) <u>No Gas Pipeline</u>. It is conceivable that North Slope natural gas will cost more to ship to the Lower 48 by pipeline than it is worth as fuel when it arrives, so that its netback gas value at Prudhoe Bay would be zero or negative. Or, alternatively, the gas pipeline may not be built for some financial or political reason. In either of these cases, it would not be the value of ethane as part of a gas stream destined for the Lower 48 that would establish the producers' opportunity cost for the ethane. Figure 8-5 illustrates a case in which the absence of an alternative market establishes a producer floor price for ethane feedstocks at approximately the cost of extracting it from the produced natural gas, which they would reinject or flare.

Figure 8-5 Cook Inlet Price Determination Without ANGTS

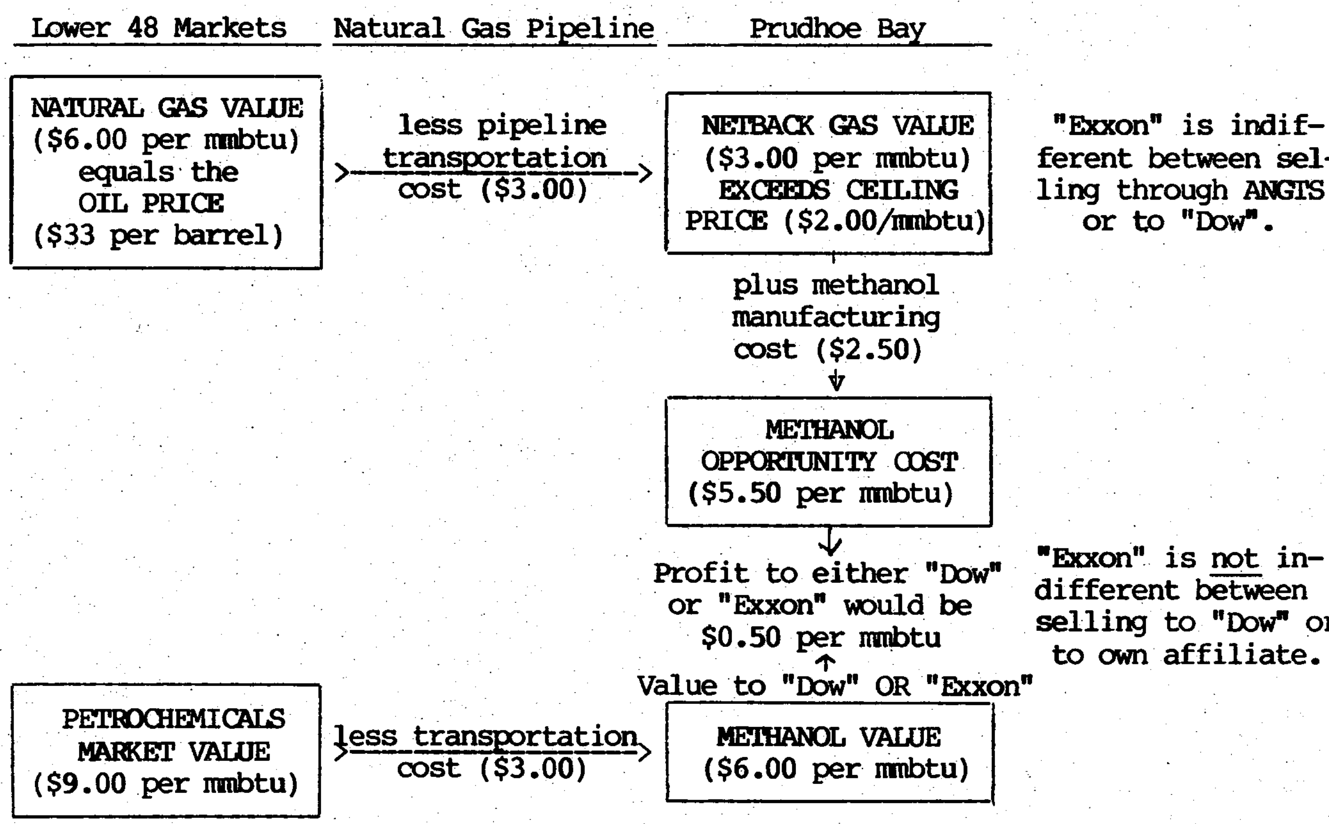


If the added out-of-pocket cost of extracting and gathering the ethane were $1.00 per mmbtu, "Exxon's" floor price for ethane at Cook Inlet would be $3.00 ($1.00 plus $2.00 transport cost). But so long as "Exxon" itself had the option of processing the ethane into ethylene, its ethane sales price would not be affected by the loss of the pipeline-shipment option, because that sales price would still reflect the $5.00 value of the ethane as petrochemical feedstock in Cook Inlet, just as it did in Figure 8-4.

This comparison illustrates our earlier remark that a gas-based petrochemical plant could be a raw-materials price-maker rather than a price-taker (like oil-based petrochemical plants). So long as ethane's feedstock value is higher than its opportunity cost or its out-of-pocket cost to the producers, that value will tend to determine the price.

(2) <u>The Effect of Wellhead Price Controls: Methane</u>. The Natural Gas Policy Act of 1978 establishes a ceiling price for Prudhoe Bay natural gas. Let us assume again that the value of North Slope natural gas delivered to the Lower 48 is $6.00 per million btu, but in Figure 8-6 pipeline transportation costs are only $3.00, instead of $4.00 as in the cases illustrated in Figures 8-1 through 8-4. Here the netback <u>value</u> of North Slope gas at the wellhead is $3.00 ($6.00 less $3.00) If the wellhead price is subject to a federal ceiling of $2.00, however, the ceiling price (rather than the $3.00 netback value) would establish "Exxon's" opportunity cost for the gas.

Figure 8-6. <u>Cook Inlet Methane Price Determination</u>



Let us further assume that each mmbtu of methane could be converted on the North Slope into methanol worth $5.50 after the subtraction of shipping charges (both on TAPS and by tanker from Valdez to California), at a manufacturing cost of $3.00. Thus, the netback value of North Slope methane would be $3.00 ($6.00 less $3.00) if it were shipped to the Lower 48 as pipeline gas, and only $2.50 ($5.50 less $3.00) if shipped as methanol. "Exxon", however, would be forbidden to charge more than $2.00 in either case. How would the gas actually be used, and what would its actual sales price be?

On the basis of the facts stipulated above, the sales price on "Exxon's" books would be $2.00. Although the "best and highest" use of the methane would be to ship it through the natural-gas pipeline, the existence of the $2.00 ceiling price would tend to favor using it as raw material for methanol production. Because the use would not affect the wellhead price, "Exxon" as producer of the gas would be indifferent to how it was used. Because the gas is worth $2.50 as a chemical feedstock, however, any chemical company to whom Exxon sold its gas at $2.00 would reap a 50 cent windfall. The obvious course for "Exxon" is to avoid arm's-length sales entirely, and to sell its North Slope gas to its own chemical subsidiary.

(3) The Effect of Wellhead Price Controls: Ethane. If ethane and other NGL's are extracted from Prudhoe Bay natural gas in the field, before they enter an interstate natural gas pipeline, they are not subject to federal ceiling prices under the Natural Gas Policy Act or other provisions of federal law governing "natural gas". If the ethane and other NGL's were to be shipped through any part of the Alaska Highway gas pipeline "commingled" or "entrained" with methane destined for the Lower 48, however,

federal law might conceivably treat them as "natural gas" and, moreover, as "natural gas in interstate commerce" --- even if they are extracted for sale within Alaska.

The extent of federal regulatory jurisdiction over North Slope ethane can not be forecast precisely today, but it is likely that the Federal Energy Regulatory Commission (FERC) and the Department of Energy will try to claim <u>some</u> jurisdiction over their prices, transportation, and/or end-uses. Some private party will, moreover, surely demand that the Commission exercise such jurisdiction.

If North Slope ethane is extracted, say, at Big Delta for shipment through an NGL's pipeline to a petrochemical plant in Valdez or Kenai, federal regulation could create the same kind of incentive for the producers to avoid arms-length sales, to Dow-Shell, for example, and to maintain control of the feedstock as we described in the case of price-controlled methane.

The foregoing scenarios have been for the purpose of illustration only; their price assumptions have not been intended to be realistic. The Prudhoe Bay gas producers, moreover, may have considerably less control over the disposition of their natural gas than some of the examples suggest, because they have already sold that gas, at least conditionally, to Lower-48 gas pipeline companies. Nevertheless, these examples point to one often-overlooked fact about the disposition of North Slope oil, gas, and NGL's.

> <u>The ultimate disposition of the different North Slope hydrocarbons, and their allocation among pipeline gas, petrochemical feedstocks, and field fuels, will be determined mainly by the gas producers' perception of their own interests</u>.

The Northwest Alaskan partnership, the State of Alaska, and potential outside purchasers (like Dow and Shell, ASRC or Doyon) will have comparatively little influence on these decisions.

8.5 Economies of Scale

The term "economies of scale" refers to situations in which increasing the size of a plant or system reduces its unit cost of production, processing, or transportation. Several elementary physical principles contribute to economies of scale in petroleum refining, pipeline transportation, and petrochemicals manufacturing: for example ---

> The amount of steel in a pipe increases roughly in proportion to its diameter; but its volumetric capacity increases with its cross-sectional area, which is proportional to the square of its diameter; and, because friction is proportional to the inner surface area (rather than the cross-sectional area), the fluids-carrying capacity of the pipe increases more than proportionally to the square of the diameter.
>
> The amount of steel in a refinery or chemical-plant processing vessel, and its heat loss by radiation, are proportional to its surface area, which increases with the square of each of its linear dimensions, while its volumetric capacity is proportional to the cube of its dimensions.
>
> Increasing the size of a given piece of equipment does not necessarily require any increase at all, and almost never requires a proportional increase, in its operating and supervisory manpower, or in the investment in control-system equipment.

A common (but imprecise) rule of thumb with resepct to both process equipment and pipelines is that fixed costs tend to increase with the six-tenths power of capacity. That is, if a 50 mb/d refinery costs $500 million, a comparable 100 mb/d refinery can be expected to cost about $760 million ($50 million x $2^{.6}$). Thus, doubling the refinery's size reduces its unit fixed cost 24 percent, from $10,000 per barrel of daily capacity to $7,600.

Comparable rules of thumb are (a) that operating labor requirements increase with the one-fifth power of size, and (b) that fuel consumption increases with its eight-tenths power. If a 50 mb/d refinery needed 100 workers, therefore, a 100 mbd refinery would need 115 workers (100 x $2^{.2}$); a doubling of capacity would increase total fuel requirements by 76 percent (1 - $2^{.8}$), meaning that fuel cost per barrel processed would fall about 12 percent.

Limits to Economies of Scale, and the Optimum Scale. Economies of scale always have some upper limit dictated by physical or economic factors. The size of refinery or chemical-plant process vessels, for example, is limited by the strength of the materials, safety considerations, and the consequences for the owners's operations of the scheduled or unscheduled shutdown of the largest single unit. Thus, there tends to be an optimum (or lowest unit-cost) size for each kind of facility. Actually, the optimum size for a particular kind of facility tends to be a rather broad range of sizes, over which unit costs at a given percentage of capacity utilization (say, 90 percent) is rather flat. There almost always seems to be a region, in other words, in which the economies of scale in some elements of the system tend to offset diseconomies of scale in others.

The optimum scale for a complex fuels refinery nowadays appears to be in the 100-to-250 mb/d range. The optimum scale for oil tankers in intercontinental service (e.g., between the Persian Gulf and the U.S.) seems to be 250 to 500 thousand tons (mt), but the optimum size on shorter hauls (e.g, Valdez to Puget Sound) is considerably less, because the supertanker's lower sailing cost per kilometer is more than offset by the fact that on short hauls, it would be spending a relatively large part of its service life sitting in port for loading and unloading.

The optimum size for ethane crackers is between 1 and 1.5 billion pounds per year, and the optimum size for oil and gas pipelines seems to be in the 48 to 56 inch range. All these figures tend to increase over time, largely in response to development of stronger steels.

"Worldscale" facilities are ones whose size is not limited by feedstock supplies or the size of its market. Hence it can be of the optimum technical scale, and competitive in world markets. Collier Carbon and Chemical Company's ammonia-urea plant at Kenai is worldscale; the Alpetco project was planned as a worldscale facility; and the Dow-Shell study envisions a worldscale petrochemical complex. Alaska's existing refineries were not, of course, designed to be competitive in world markets, and their size is a function of the size of the Alaska market rather than an attempt to minimize the unit cost of processing.

8.6 Analyzing Project Feasibility.

Refinery and petrochemical plant investment decisions depend on several variables, including the ones that this chapter has already considered in some detail (transportation, construction, and feedstock prices), plus ---

- Feedstock requirements
- Feedstock characteristics
- Process engineering and operation
- Fuel and energy supplies and prices
- Labor, materials, utilities, and services needs and prices
- Product slates and volumes
- Product prices
- Capital structure
- Interest rates
- Inflation rates
- Federal, state, and local taxes
- Health, safety, and environmental regulation

A companion volume to this report [Zinder Energy Processing, "Preliminary Economic Evaluation of NGL-Based Petrochemical Production in Alaska, October 1980] provides a useful accounting framework for most of these variables, and a rudimentary economic model for relating them to one another with respect to a project similar to that contemplated by the Dow-Shell group.

The final product of most economic feasibility studies includes (1) <u>a pro-forma income statement</u>, and (2) <u>a discounted cash-flow</u> (DCF) or <u>"internal" rate-of-return analysis</u>. The income statement lists and sums the major cost and revenue elements for each year over the project's economic life, usually 20 to 25 years. The DCF analysis calculates the rate of return on investment (ROI) implied by the whole stream of negative and positive cash-flow figures in the income statement. Judgments on project feasibility, then, depend upon the DCF rate-of-return estimate: Is it high enough to justify the investment?

Economic feasibility reports vary greatly in sophistication and detail, depending on the project and sponsor, and on the purpose of the report. In general, a preliminary "reconaissance" study will use far more general assumptions and simpler models than a report prepared for prospective lenders, who usually insist on a completed engineering design and detailed market analysis, among other things.

Assessing Uncertainty and Risk. Greater methodological sophistication and detail do not necessarily improve the quality of an economic feasibility study, however. The most critical factors determining the economic feasibility for refineries and petrochemical plants are often judgmental assumptions, for which the most rigorous engineering or econometric methods give little hope of precision.

The one most powerful variable in determining the outlook for any new worldscale hydrocarbons-processing plant is the outlook for world oil prices. Through their influence on petroleum-product and petrochemical prices, oil prices determine the level of consumption and the rate of demand growth. Demand trends in turn determine the future spread between crude-oil prices and the prices of petroleum products and petrochemicals, which are crucial in predicting whether any new facility can make a profit. Since the prices of crude-oil, natural gas, LPG's, coal, and other feedstocks do not necessarily move together, the outlook for crude-oil prices is central to the choice of raw-materials and to plant location.

Expert opinions about real crude-oil prices over a period as short as five years vary by a factor of two or three, however. The weighted-average wellhead price of Prudhoe Bay crude oil has quadrupled in a little over two years, reaching an all-time peak of about $26 per barrel in March 1981; it has now [June 1981] begun to fall; few analysts would be startled by 1985 prices as low as $15 or as high as $45. Because of the crucial role oil prices play in determining both the costs and revenues of any new refinery or petrochemical plant, the range of uncertainty about oil prices probably swamps out the influence of all other economic assumptions combined.

The level of oil prices, and the many other variables that are powerfully influenced by oil prices, are not the only factors that are essential inputs to any feasibility analysis yet subject to horrible uncertainties. Capital-cost estimates for large construction projects are notoriously unreliable --- TAPS would have been the largest economic debacle in U.S. history if its huge cost overruns had not be offset by an even larger, unanticipated, leap in the price of imported oil. There is, likewise, no scientific way to determine future inflation rates.

Unfortunately, the feasibility reports of major energy projects that are offered to investors, government officials, and the public, are usually designed primarily as means of persuasion rather than business-decision tools. Most such reports present a single pro-forma income table and DCF-ROE figure, concluding that the "<u>most-likely</u>" rate of return on equity (ROE) from the project in question is, say, 15 percent. At most, the authors will offer several "scenarios" that correspond to different pre-packaged sets of assumptions and show different ROE's, but which give the reader little basis for choosing one scenario over another.

Sensitivity Analyses. A relatively simple device for improving the usefulness of feasibility analyses, but one which has been absent in the public literature regarding Alpetco, the Alaska Highway gas pipeline, and the like, is a sensitivity analysis that tells the reader which assumptions are truly critical, and how critical they are. Even the Zinder report regarding NGL-based petrochemicals in Alaska, cited above, fails to tell its readers how its final results would be affected by a $5.00 per barrel change, plus or minus, in world oil prices; or by a given percentage construction-cost overrun; or a specified change in the project's capital structure, or in interest rates, etc. The Zinder model does allow users in state government to vary inputs one by one, and to observe any change in the result, but this computing capacity is no substitute for a clearly presented sensitivity analysis.

Risk Analysis. One step beyond sensitivity analysis is risk analysis, which explicitly incorporates uncertainty into its calculations. If experts are willing to attach probability figures to their assumptions, a "Monte Carlo" or "decision-tree" risk-analysis program will produce conclusions in terms of probabilities.

A risk analysis, on the other hand, can offer the investor or public official a much more powerful decision tool than a single "most likely" figure, or even a set of "high", "medium", and "low" estimates. The risk analysis of a given hypothetical project might begin with a set of expert judgments on the probability distributions of cost overruns, completion delays, future oil-price trends, product-market conditions, interest rates, and general inflation, and conclude as follows ---

"There is a 50-percent probability that the DCF ROE will be 15 percent or higher." [This means, of course, there is an even chance that it will be lower than 15 percent.] "There is, however, a 20-percent risk that the ROE will be zero or less, and a 10-percent risk that the project will default on its debt."

Equity investors might consider a 15-percent profit expectation (the weighted average of all probable outcomes) as adequate, and be willing to accept a one-in-five risk of losing money if this risk is offset by a "fair gamble" of earning much more than 15 percent. The 10-percent risk of default, however, would probably be intolerable to prospective lenders, however. The risk analysis might also say of the proposed investment, that ---

"Changing the debt-equity ratio from 75:25 to 50:50 would reduce the chance of default from one-in-ten to one-in-fifty; the probability of just breaking even or losing money would fall from one-in-five to one-in-ten. But reducing the "leverage" of the project's capital structure in this way would also reduce the expected ROE from 15 percent to 11.5 percent."

In this case the risk of default might be low enough, but the expected ROE inadequate. Combining risk analysis and sensitivity analysis gives us one more powerful decision tool. Consider this observation about another fictional project ---

"Although the expected rate of return and risk of default are both acceptable, we must point out that this project will never make a profit in the unlikely event that world oil prices stablize at their current levels or continue to decline. To achieve a 50 percent expectation of a 15 percent ROE, we must assume that oil prices advance at an average annual rate at least two percent faster than general inflation."

The intuition of the investor or policy maker on how "unlikely" it is that world oil prices will stabilize may be just as good as that of the experts who carried out the analysis. In any event, the user of the analysis now has the information with which to make his own policy judgment. Finally, risk analysis could offer the following kind of observation on a hypothetical royalty-oil sales proposal:

> "The proposed project has a better-than-even chance of standing on its own feet. In order to reduce the probability of default to less than 5 percent so that private debt financing can be obtained, however, the State must be prepared to discount its royalty oil by as much as $5.00 per barrel if necessary to meet debt-service demands. The likelihood that a subsidy of this magnitude will be necessary is less than 7 percent but there is an almost one-third chance that <u>some</u> discount on feedstocks will ultimately be required."

The contract between the State of Alaska and the Battelle Northwest Laboratories analyzing the proposed Susitna hydroelectric project and its alternatives requires Battelle to provide a full range of sensitivity analyses, to be specific about the probabilities assigned to key assumptions, and to present its results in the form of probability distributions. To our knowledge, this is the first time the State has made such an assigment --- but the Susitna project is one that could involve a direct outlay of billions of dollars of State money.

8.7 Coping with uncertainty and risk.

The analytical methods described in the previous pages do not reduce or control business risks, but only identify and attach numbers to them. There are, however, a number of means by which refiners and petrochemical manufacturers can reduce their exposure to surprises, and the damage caused by them. The chief measures are long-term contracts, plant and system flexibility, vertical integration, horizontal concentraion, risk-spreading through diversification.

Long-term contracts. Investors in refineries and petrochemical plants can reduce their capital costs and certain kinds of business risks by building a highly specialized facility designed to process a single feedstock into a predetermined product slate for a predetermined customer or group of customers.

This kind of arrangement is much more common in oil and gas transportation, and among utility companies, than it is in either refining or chemicals manufacturing. A propspective shipper on a proposed pipeline may offer the carrier (the pipeline company) a "throughput and deficiency agreement," under which the shipper promises to pay the carrier a minimum bill proportional to the desired transport capacity, even if the shipper does not use that capacity.

Likewise, a utility that buys coal, natural gas, or electricity, may bind itself in a "take-or-pay" contract to pay for a specified amount of coal, gas, or electricity, on a specified schedule, whether or not the utility actually takes the contracted amount. A particularly strict version of the minimum-bill throughput or take-or-pay contract, which greatly facilitates debt financing, is the "all-events" or "hell-or-high-water" provision, which requires the shipper or purchaser to pay the minimum bill even if the carrier or seller can not perform (because of project non-completion or breakdown, for example).

Facilities with "back-to-back" raw-materials purchase and product-sales contracts are generally easy to finance with very high debt-to-equity ratios. One example is the Alberta Gas Ethylene Company's Joffre plant, which has long-term contracts from its parent (Nova, Ltd.) for ethane feedstock, and a long term "cost-of-service" ethylene sales contract with Dow Canada.

Project financing. One advantage of projects with back-to-back purchase and sales contracts is that they can, at least in principle, be "project-financed" with "non-recourse" debt. Project financing establishes a new corporate entity to own and operate the project, and the non-recourse feature means that the project's owners are not responsible for debt service; their exposure is limited to their equity contribution --- which may be comparatively small.

Project financing is not a method of eliminating risk, however, but only of shifting it to other parties through take-or-pay or similar contracts, and its feasibility depends both upon the creditworthiness of those parties and the tightness of their contractual obligations. For this reason, it is mostly regulated public utilities that use this financing technique, and it is feasible even for them only where State and Federal regulatory agencies can assure in advance that debt-service charges will be "perfectly tracked" to a captive market of final consumers.

The sponsors of many, if not most, large-scale energy ventures have hoped that they could project-finance them with a high ratio of non-recourse debt --- the Alaska Highway natural gas pipeline, Alpetco, and the Northern Tier oil pipeline are familiar examples. Very few have ever been successful, and we not aware of any such financing that has yet been carried out for a major energy-industry project, where some creditworthy third party has not agreed to pay off the debt even if the facility is never completed. Two maxims will be useful to Alaskans in evaluating future industrial proposals ---

(1) <u>Lending institutions are not willing to bear the completion, technical, and marketability risks for large-scale resource-extraction, transportation, or processing ventures in Alaska; and</u>

(2) <u>Unless the sponsors are able and willing to provide the project's equity capital and to guarantee the project's entire debt (at least until it goes into operation), it is reasonable to assume that the facility will not be built</u>.

<u>Plant and System Flexibility</u>. Although plant specialization tends to reduce technical risks and construction costs, it magnifies feedstock-supply and market risks. Most refineries and petrochemical complexes built in recent years have considerable built-in flexibility --- in the case of refineries, to run a wide range of crude-oil mixtures and to vary their product slates. Petrochemical complexes have been built, where feasible, to include (or provide room for future addition of) both an ethane cracker and a naphtha cracker.

A large company with several plants of different design, adapted to different feedstocks and different product slates, will have much more flexibility to deal with changes in raw-material supply and market conditions than a smaller, single-plant enterprise, even if the large firm's individual plants are relatively specialized.

The advantages of system-wide flexibility encourage horizontal concentration --- the tendency for big firms to get bigger. In the 1980's, for example, Dow and its affiliated ventures and joint ventures will be producing (or buying on long-term contract) ethylene from naphtha and gas oil on the U.S. Gulf, in Europe, and in East Asia, and from NGL's produced and marketed under radically different circumstances in the Southwestern United States, Alberta, Saudi Arabia, and perhaps Alaska. Obviously, not all of these ethylene supplies will be relatively low-cost supplies, and some of these ventures may well be money-losers. But with this broad, diversified base, Dow is very unliklely to do worse than the industry average, and unless the world market for ethylene derivatives totally stagnates, Dow should do very well in the next decade.

Vertical integration. An earlier chapter of this report alluded to the historical tendency of crude-oil producers to integrate downstream into refining and product marketing in order to assure themselves product outlets and thus to retain their market shares in periods of surplus. BP's acquisition of Sohio and much of the Sinclair system is a doubly outstanding example --- first because of the obvious logic of the combination, and second because it was only partially successful.

BP had almost overnight become one of the top crude-oil producers in the United States, but it had no refineries or retail outlets, and hence no assured market. Sohio, on the other hand, was the nation's largest "independent" refiner --- a refiner, that is, with almost no crude-oil production.

In this sense the marriage was perfect. The geography of the merger has turned out to be abominable, however, particularly in light of the Congressional restrictions on foreign exchanges of North Slope crude oil: Unlike Arco and Exxon, which have West Coast refineries and dealer netweorks, Sohio had none, and thus the BP group still has no properly situated outlets for its crude oil. As a result, Sohio has to absorb two or three dollars per barrel in added transport costs for oil sold or exchanged East of the Rockies --- a burden that Arco and Exxon are spared on most of their Alaska production.

"Upstream" or "backward" integration of refiners or petrochemical companies into crude-oil prroduction not only gives the processor a more secure raw-materials supply, but helps stabilize feedstock costs as well. During the first quarter of 1981, for example, the most recent round of OPEC price increases together with the deregulation of domestic crude-oil prices raised the average cost of raw materials to U.S. refiners several dollars per barrel, but market conditions did not allow them to recover these higher costs in petroleum-product prices. This situation put most independent refiners and refiners with low crude-oil self-sufficiency ratios into a no-profit or operating-loss position. To the extent a refiner was self-sufficient in crude oil, however, each dollar less in refining profits was partially offset by an additional dollar in crude-oil production profits. (The offset was usually not total, because of the higher royalty, severance-tax, and Windfall Profits Tax liabilities that resulted from higher wellhead prices.)

The unreliability of foreign crude-oil supplies in recent years has made upstream vertical integration highly sought-after at the same time that it has become increasingly expensive to achieve. The decline in Lower-48 crude-oil production and the major companies's loss of overseas concessions have drastically reduced their self-sufficiency ratios. As a result, almost every refiner of any size has attempted to become a crude oil producer as well: with the acquisition of Sohio by BP in the early 1970's, Ashland and Clark are the last large (> 100 mb/d) independent refiners. After several Middle-Eastern oil-supply interruptions, almost every large refiner and petrochemical producer, regardless of its existing degree of backward integration, has been trying to get direct control of as much crude oil as its can or, failing that, to work out some kind of marriage or joint venture with a crude-oil producer.

In 1977-78, Ashland attempted to sell a major share of the company to the National Iranian Oil Company (NIOC) in exchange for a long-term crude-oil guarantee. In 1979 Getty Oil bought Reserve Oil Company, whose subsidiary Western Crude Oil gathers and markets crude oil for hundreds of small producers. Just this year, the Hawaiian Independent Oil Company announced a major investment by Kuwaiti interests, who would presumably be responsible for providing oil to the Hawaii refinery.

The Alaska NGL-based petrochemical scenario set out on pages 145 and 146 of this chapter offer a final illustration of the risk-reducing value of vertical integration. In this scenario, a prospetive feedstock seller ("Exxon") and the prospective buyer ("Dow") are both confident that the value of Prudhoe Bay ethane as feedstock for an ethylene cracker at Cook Inlet is about $1.00 per mmbtu more than its value as part of the natural-gas sales-gas stream in the Alaska Highway natural-gas pipeline.

Neither party realy knows what the NGL's extraction plant and pipeline, or the petrochemicals plant will cost, or what world market conditions will be for ethylene derivatives five or ten years from now. Accordingly, the anticipated profit per mmbtu of ethane shipped and processed, while always positive, might be considerably less than $1.00, or more than $1.00. But any feedstock price low enough to insure "Dow" against loss would be considerably less than the "most-likely" value of the material according to "Exxon's" estimate. Thus, the obvious resolution of this dilemma would be for Exxon to sell its NGL's not to "Dow" but to an "Exxon" subsidiary (or perhaps to a "Dow-Exxon" joint venture). This way, "Exxon" would receive the whole profit (or nearly the whole profit), whether it turned out to be large or small.

A related uncertainty creating an incentive for vertical integration concerns transportation charges on the NGL's pipeline. It is impossible to tell in advance who (the Federal Energy Regulatory Commission [FERC] or the Alaska Public Utilities Commission) would regulate charges on the pipeline, or what rule that agency would use. Federal regulation of oil pipelines has historically used a "fair-value" rate base, which permits charges to increase over time, but a FERC administrative law judge recommended in 1980 that TAPS transportation tariffs be set on the basis of "depreciated original cost," which results in declining charges. The choice between the two rules may vary the first-year transportation charges on an Alaska NGL's line by two or three times or even more. This uncertainty about pipeline charges thus may lend great uncertainty to any assessment of the feasibility of NGL's-based petrochemical manufacturing in Alaska.

Once more, the resolution of the dilemma may consist of vertical integration. If the major shipper owns the pipeline, the tariff as such does not much matter (apart from its effect on tax and royalty collections) --- pipeline transportation charges are largely a bookkeeping shift of profits (or losses) from one pocket to another. The most risk-protected system for Alaska petrochemicals, therefore, would appears to be the combination of a producer participation in pipeline ownership and producer participation in the petrochemical complex.

APPENDIX 3

NATURAL GAS CONDTIONING AND PIPELINE DESIGN

A Technical Primer for Non-Technicians,
With Special Reference to Hydrocarbons from Prudhoe Bay
and the Alaska Highway Gas Pipeline

By CONNIE C. BARLOW

Originally Prepared by
Arlon R. Tussing and Associates, Inc.
For the State of Alaska
Department of Natural Resources
(March 11, 1980)

TABLE OF CONTENTS

Page

TABLE OF CONTENTS.. i

INTRODUCTION... ii

I. THE BASICS OF PIPELINE DESIGN............................. 1

A. Hydrocarbon Characteristics............................. 1

1. Chemistry... 1

2. Heating values.. 2

3. Phase characteristics................................. 4

B. Gas Versus Liquids Pipelines............................ 5

C. Pressure Specifications................................. 6

D. Hazards of Two-Phase Flow............................... 9

II. GAS COMPOSITION DECISIONS................................ 12

A. Introduction.. 12

B. Phase Diagrams.. 13

C. The Relationship Between Gas Composition and Upset Conditions.. 16

D. Carbon Dioxide Content.................................. 19

1. The effect of carbon dioxide on hydrocarbon dewpoint.. 20

2. The effect of carbon dioxide on pipeline corrosion... 20

3. The effect of carbon dioxide on downstream gas systems... 22

4. The effect of carbon dioxide on project economics.......... 23

E. Volumes of Gas and Gas Liquids Available for Shipment.......... 25

1. Reservoir production rates............................. 25

2. Gas Composition changes................................ 26

3. North Slope fuel requirements.......................... 28

4. Shipping intermediate hydrocarbons through TAPS............ 34

INTRODUCTION

The State of Alaska faces a variety of questions related to the proposed Alaska Highway Gas Pipeline which combine highly technical engineering considerations with important public policy issues. These questions include:

— location, design, and ownership of the gas conditioning plant,
-- choice of fuel for North Slope operations, and
— pressure and diameter specifications of the pipeline itself.

Some grasp of the engineering jargon and basic principles is essential if Alaska's elected officials and agency staff are to identify the State's priorities correctly: What issues really affect the State's interests, and to what extent? Which, if any, of the other parties --- the producers, gas shippers, and federal authorities --- are likely to share the State's interests in each of these questions, and to what extent? How much can Alaskans depend on others, therefore, to look after the State's interests? How formidable is opposition likely to be to the State's position, and what burdens would the State's demands impose on others? Overall then, where should the State realistically direct its efforts?

This report, in itself, will not answer those questions; it should, however, make State decision-making a bit easier. We have tried to distinguish scientific facts from matters of differing engineering judgment, and both from differences of economic interest; and to present the range of opinions fairly. Our goals have been to develop a primer on gas conditioning and pipeline transportation that is relevant to Alaskans, speaks to non-technicians, yet is precise and complete enough to survive the scrutiny of experts.

Special thanks goes to Harold R. Galloway and James L. Shanks, Jr. of Exxon, D. J. Pritchard of Sohio, W. S. Dickinson of Arco, A. J. Green of Westcoast Transmission, Robert M. Maynard of the State of Alaska's Department of Law, and Robert H. Loeffler of Morrison & Foerster, the State's Washington counsel.

I. THE BASICS OF PIPELINE DESIGN

A. HYDROCARBON CHARACTERISTICS

1. Chemistry

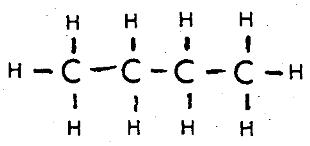
The crude oil and natural gas produced from Alaska's Prudhoe Bay reservoir are mixtures of hydrocarbons (compounds of carbon and hydrogen), plus impurities like water and carbon dioxide. The most fundamental classification of hydrocarbon compounds is in terms of the number of carbon atoms in each molecule.

TABLE 1

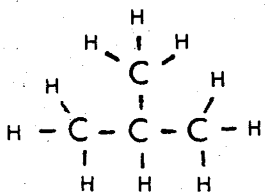
Reservoir Fluid	Compound	Chemical Formula	Abbreviation	Commercial Product
natural gas	methane	CH_4	C_1	dry gas
natural gas	ethane	C_2H_6	C_2	natural gas liquids (NGLs) or condensate
natural gas	propane	C_3H_8	C_3	natural gas liquids (NGLs) or condensate
natural gas	butane	C_4H_{10}	C_4	natural gas liquids (NGLs) or condensate
natural gas / crude oil	pentane	C_5H_{12}	C_5	natural gasolines, naphtha, or pentanes-plus
crude oil	hexane	C_6H_{14}	C_6	natural gasolines, naphtha, or pentanes-plus
crude oil	heptane	C_7H_{16}	C_7	natural gasolines, naphtha, or pentanes-plus
crude oil	octane	C_8H_{18}	C_8	natural gasolines, naphtha, or pentanes-plus / oils, waxes, tars
crude oil	-	-	-	oils, waxes, tars
crude oil	-	-	-	oils, waxes, tars
crude oil	etc.	C_nH_m	C_n	oils, waxes, tars

Hydrocarbons containing more than three atoms of carbon in each molecule have several different configurations. These forms or "isomers" often have different physical characteristics. For example, Table 2 shows that "normal" butane [n-butane] can remain in a liquid state in the TAPS oil pipeline at higher temperatures than can the branched isomer "iso" butane [i-butane].

FIGURE A: NORMAL AND ISO-BUTANE



"normal" (n) butane



"iso" (i) butane

2. Heating values

The heating value of each hydrocarbon reflects, in part, the number of carbon atoms that will oxidize as the fuel is burned. Table 2 shows the heating values of light hydrocarbons and their isomers, both in liquid and vapor states. Normally, heating values are expressed in gross BTU's[1], also called the higher heating value. The expected heating value of gas that will be shipped through the Alaska Highway gas pipeline (or Alaska Natural Gas Transportation System [ANGTS]), for example, is invariably expressed in gross terms.

The lower heating value, measured in net BTU's, serves a very limited function, primarily in describing the fuel requirements for various types of machinery and processes. Net BTU's for hydrocarbon vapors have been used by some parties involved in the design of the North Slope gas conditioning plant; Table 2, therefore, includes net measurements for hydrocarbon vapors.

The difference between gross and net BTU's is highly technical. The reader need only remember that (1) unless specifically designated as net BTU's, one can assume that all heating value data represent gross measurements; and (2) like apples and oranges, the two should never be confused or mixed in heating value calculations.

---

1) A British Thermal Unit (BTU) represents the amount of heat required to raise the temperature of one pound of water by one degree F.

TABLE 2

HYDROCARBON	VAPOR HEATING VALUE		LIQUID HEATING VALUE
	BTU/scf* gross	BTU/scf net	BTU/barrel** gross
Methane	1010	909	2,512,818
Ethane	1769	1618	2,771,916
Propane	2518	2316	3,824,730
i-butane	3253	3001	4,158,924
n-butane	3262	3010	4,325,538
i-pentane	4000	3698	4,569,180
n-pentane	4010	3708	4,624,284

Source: Natural Gas Processors and Suppliers Association, Engineering Data Book, 1979.

---

* A Standard Cubic Foot (scf or cf) is the amount of gas that would fill a cubic foot of space at 60 degrees F. and standard atmospheric pressure. The following abbreviations are often used to represent large volumes:

Mcf = thousand cubic feet
MMcf = million cubic feet
bcf = billion cubic feet
Tcf = trillion cubic feet

** One barrel = 42 U.S. gallons.

3. Phase characteristics

The more carbon atoms a molecule contains, the heavier it is. The heaviness of a particular hydrocarbon will influence whether it exists in a vapor or liquid phase at various combinations of temperatures and pressures. Table 3 shows the boiling points of light hydrocarbons. At temperatures below the boiling point, a hydrocarbon is a liquid; above, it is a vapor.

TABLE 3

SUBSTANCE	MOLECULAR WEIGHT	BOILING POINT (F.) [at atmospheric pressure]
C_1	16.043	-258.69
C_2	30.070	-127.48
C_3	44.097	- 43.67
i-C_4	58.124	+ 10.90
n-C_4	58.124	+ 31.10
i-C_5	72.151	+ 82.12
n-C_5	72.151	+ 96.92
n-C_6	86.178	+155.72
n-C_7	100.205	+209.17
n-C_8	114.232	+258.22
CO_2	44.010	-109.30

Source: Natural Gas Processors and Suppliers Association, Engineering Data Book, 1979.

Oil is now injected into the Trans Alaska oil pipeline (TAPS) at a temperature of 142 degrees F. At times, the oil may experience pressures enroute as low as normal atmospheric conditions. Under these circumstances, Table 3 shows that hexanes (C_6) and all heavier hydrocarbons would always remain in a liquid phase during shipment through TAPS. Mixtures of heavy hydrocarbons also have the ability to carry small quantities of C_5 and even C_4 without vapor formation. On the other hand, mixtures of the lightest hydrocarbons (C_1, C_2, and C_3) remain in the vapor phase even in a chilled gas pipeline, and can likewise absorb some C_4 and possibly C_5 without condensation.

The question of how much of these intermediate hydrocarbons (C_4 and C_5) will be carried as vapors by ANGTS, shipped as liquids in TAPS or in a third "gas-liquids" pipeline, used for fuel on the North Slope, or routed to some other purpose, remains open. Resolution of this issue depends upon a whole array of decisions, including pressure and temperature specifications for operation of both the gas and oil pipelines, the amount of CO_2 permitted in the gas pipeline, the choice of gas conditioning process, the kinds and amounts of fuel used in the field and for pipeline pumps and compressors, and oil and gas production rates. This report examines each of those factors, their relationships, and the ultimate effect such decisions may have on the kinds and amounts of hydrocarbons transported.

B. GAS VERSUS LIQUIDS PIPELINES

Pipelines carrying hydrocarbons in a liquid phase (such as the TAPS oil line and a proposed gas liquids line) use pumps to move these materials. Pipelines designed for gaseous hydrocarbons, such as the proposed Alaskan Northwest pipeline, use compressors. The difference is subtle, but important.

In liquids, the individual molecules are packed tightly together and, for all practical purposes, cannot be compressed into a smaller volume. Instead, as more molecules are pumped into a pipe, they shove the mass of hydrocarbons in front of them into the next pump station, like a train of boxcars pushed from behind. Naturally, the greater the distance (and the greater the rise in elevation) between pump stations, the greater is the horsepower required.

Gaseous hydrocarbons, like all vapors, are compressible. Each compressor station on a gas pipeline draws vapor into its inlet at a relatively low pressure (called the suction pressure), compresses it into a smaller volume, and expels it at a higher pressure, known as the discharge pressure. As the gas expands between the outlet of one compressor station and the inlet of the next, pressure again falls, and this pressure drop or differential causes the gas to flow through the pipe. It is the discharge or operating pressure, being the greatest pressure experienced by the pipeline, that is limited by the strength of the steel pipe.

C. PRESSURE SPECIFICATIONS

Pressure drop is usually measured as a ratio to distance, psi per mile.[2] Being the stimulus for gas movement through a pipeline, it is therefore one of several factors that determine how much gas can be transported each day. Throughput is determined by the following components:

(1) Discharge pressure, (2) Suction pressure, and (3) Compressor Station spacing determine the pressure drop, and thereby the SPEED of flow, while

(4) Pipeline diameter determines the AMOUNT of gas that can be shipped through a pipeline at any given speed.

---

2) Pressure is measured in pounds per square inch (psi). Objects at sea level are subjected to an atmospheric pressure of about 14.7 psi (which results from the weight of several miles of air resting on the earth's surface). Instruments designed to measure artificially induced pressures like those inside gas pipelines, record or guage pressures in excess of this ever-present atmospheric pressure (psig). Absolute pressure measurements include the 14.7 psi exerted by the atmosphere (psia). Hence, 1680 psig is the same as 1694.7 psia.

Of these four variables, a pipeline's diameter and the maximum discharge pressure that it can accomodate (that is, the pipeline's operating pressure) are the only ones that cannot be altered once the pipe is laid. The other two can, in theory, be modified to accomodate changes in throughput: Throughput can be increased either by adding more compressor stations or by increasing the suction power of existing compressors.

There are, of course, practical and economic constraints on the number of compressor stations that can be added. Likewise, the suction power of compressors experiences a marked drop-off in efficiency beyond a given range of compression ratios.

The compression ratio is the ratio between a compressor's discharge pressure and its suction pressure. Compression ratios are generally in the vicinity of 1.2 to 1.3. Table 4 shows the suction pressures corresponding to a compression ratio of 1.25 at four operating pressure levels heretofore considered for the Alaskan and Canadian sections of the Alaska Highway Gas Pipeline.

TABLE 4

Operating pressure	Efficient Delivery Pressure
1680 psig	1350 psig
1440 psig	1150 psig
1260 psig	1010 psig
1080 psig	860 psig

The National Energy Board (NEB) has approved construction of a 1080 psig 56 inch diameter pipeline in Canada. Though some contention still exists on the matter, the Federal Energy Regulatory Commission (FERC) has approved the design proposed by the pipeline sponsor, Northwest Alaskan, with an operating pressure of 1260 psig for a 48 inch pipeline in Alaska. Exxon, ARCO, and the State of Alaska have advocated higher operating pressures, such as 1680 or even 2160 psig for a 48 inch or smaller (42 inch) diameter pipeline.

The controversy over the pipeline's operating pressure and diameter stems, in part, from a recognition that manipulating discharge and suction pressures or even building more compressor stations after the pipe is laid are not necessarily the most economic or practical responses to future changes in throughput. For these reasons, designers must choose pipeline diameter and wall thickness specifications and compressor station locations that reflect a realistic judgment of likely throughputs over the life of the facility. FERC and Northwest concluded that a 1260 psig 48" diameter pipeline is the most efficient and economic compromise for the volume of gas expected from the main Prudhoe Bay reservoir (about 2.0 bcf/day). However, they agree that at a throughput somewhere between 2.6 and 2.9 bcf per day, a 1680 psig line would make more sense. ["Report of the Alaskan Delegate on the System Design Inquiry", FERC, May 17, 1979; p. 27.]

Unfortunately, the additional volumes of North Slope gas likely to become available during the expected 20 or 25 years of gas pipeline operations are both uncertain and controversial. No one can know with confidence whether the 1260 psig system ultimately will prove to be the best choice.

A related issue that must be addressed during engineering design is the need for <u>crack arrestors</u>. Even if a pipeline's wall thickness is sufficient to withstand its own INTERNAL gas pressures, pipeline designers have to safeguard against the effects of catastrophic EXTERNAL forces --- such as a misguided bulldozer or a saboteur's bomb.

Obviously, localized damage cannot be prevented entirely. In a large diameter, high pressure gas pipeline (unlike TAPS), however, even a small injury to the pipe can result in a fracture that spreads explosively up and down the system, perhaps destroying pipe for tens of miles. Girdling the pipe at regular intervals with sturdy metal crack arrestors is one solution.

Virtually everyone agrees that a 1680 psig, 48 inch diameter pipeline must be equipped with crack arrestors. Opinions, however, vary with respect to a 1260 psig system. Since crack arrestors are a significant expense, no conclusive judgment about the relative economic advantages of a 1260 psig system can be reached in the absence of a decision on the need for crack arrestors.

Probably the biggest source of controversy with respect to the selection of an operating pressure for the Alaska Highway Gas Pipeline centers, however, on the ability of higher pressure pipelines to carry heavier hydrocarbons without risking two-phase flow.

D. HAZARDS OF TWO-PHASE FLOW

Long-distance pipelines must be designed to carry hydrocarbons either in a vapor phase (like the Northwest pipeline) or in a liquid phase (like TAPS and the proposed gas liquids line). Transporting vapors and liquids together in one stream results in a condition called two-phase flow. The dangers of two-phase flow are as follows:

(1) General problems of two-phase flow. A pump or compressor is designed to operate on material of a certain density. Encountering bubbles of vapor in a stream that should be totally liquid is a little like swinging a bat at a baseball and missing; while coming across droplets or, worse yet, big "slugs" of liquid in a stream that should be all vapor is like being hit with a barrage of snowballs. Either event can be rather jarring to the system.

(2) "Surge" and "slug" problems of two-phase flow. If droplets of liquids condense in the vapor stream, they tend to settle and accumulate in low spots along the pipeline, constricting the room available for vapor flow. As the amount of trapped liquid grows, pressure builds --- eventually forcing the liquid up and over the next hump. Large slugs of dense liquids are, therefore, accompanied by an uneven or surging flow of fluids. Extreme surging conditions can cause severe damage when a slug enters a compressor station.

It should be noted that some pipelines are intentionally operated in two-phase flow conditions, while gathering "wet" (unconditioned) gas in the field, or bringing gas from offshore wells to shore-based facilities. Usually, however, these pipelines are quite short and undersized; no pumps or compressors that could be damaged by surging slugs are located along the way. In fact, some offshore pipelines for which slug formation cannot be avoided empty onshore into several miles of convoluted pipeline called slug catchers. Here the tremendous force of the slugs is dissipated, and the liquid itself is "scrubbed" out of the gas, prior to entering pumping, processing, or compressing facilities.

Designers and operators of long-distance gas pipelines, like the ANGTS which has several compressor stations and many ups and downs enroute, can take a variety of actions to reduce the hazards of two-phase flow. They can:

* <u>Avoid building an oversized line.</u> One way to prevent the accumulation of liquids at low points along the line is to ensure that vapors flow at a high speed. This means choosing a pipeline diameter appropriate to the expected throughput, maintaining a high pressure drop, or both. If a system is designed to carry an average of 3.0 bcf/day and only 2.0 bcf/day is available for shipment, pressure drop would have to be reduced in order to ensure a steady flow of the smaller volume of gas. The result is a slower movement of gas and, hence, a greater danger of slug formation and surging.

* <u>Equip the line with drains</u>. Valves to drain off accumulated liquids can be inserted in low spots along the pipeline.

* <u>Ensure against sloppy pipeline operations</u>. If drains are installed, they must be used properly. If adequate drainage is impractical, the line should receive more frequent "pigging" (insertion of a solid object, or <u>pig</u>, which pushes accumulated liquids out ahead of it). If throughput is raised or lowered, changes in the input and output pressures must be synchronized. If the line is shut down temporarily, special care must be taken when operations resume to prevent the passage of entrained liquids that may have formed during the outage. For these reasons, no matter how free of droplets the sales gas may be when it enters the pipeline, sloppy operations can result in dangerous two-phase flow conditions.

None of the above precautions are of much use in long-distance pipelines, however, unless pipeline operators also:

* Restrict the volume of heavy hydrocarbons. Pipelines must transport only hydrocarbon mixtures that pose no threat of condensation at any combination of temperatures and pressures likely to be encountered under either normal or abnormal conditions. Determining the optimum mixture is rather complicated, as the next chapter shows.

II. GAS COMPOSITION DECISIONS

A. INTRODUCTION

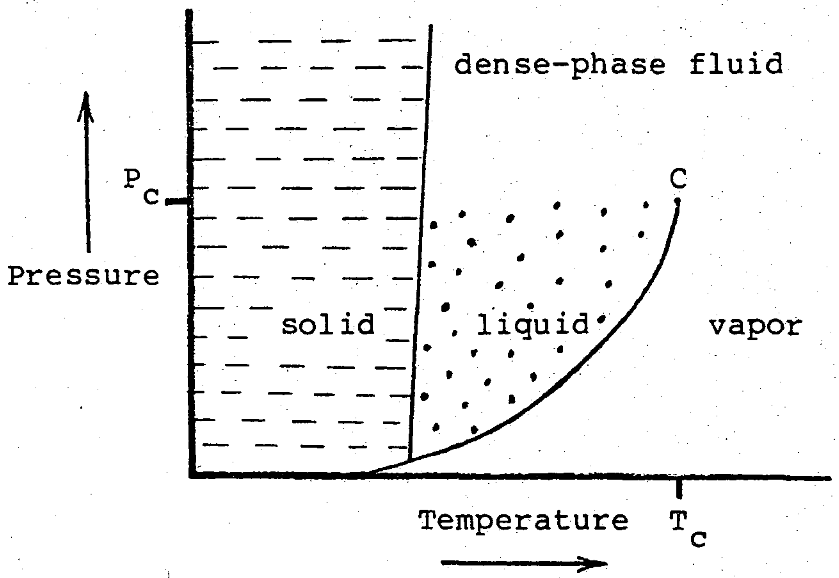
In designing a gas transportation system, everything seems to affect and be affected by everything else. We have seen, for example, that decisions about pipeline diameter, operating pressure, suction pressure, and compressor station spacing are all interdependent. Further, these specifications cannot be set intelligently except with reference to some volume or range of volumes for expected throughput. The same holds true with respect to determining the optimum chemical composition of pipeline quality gas; that is, the relative amounts of methane, ethane, propane, butane, heavier hydrocarbons, carbon-dioxide, water, and sulphur compounds in the gas delivered to the pipeline.

Temperature and pressure are the two factors that determine whether any particular hydrocarbon or mixture of hydrocarbons will be present in a vapor or in a liquid phase. Thus, pipeline designers must choose a balanced combination of pressure, temperature, and composition specifications that will ensure safe operations and avoid two-phase flow.

B. PHASE DIAGRAMS

Almost everyone is familiar with "bottle gas" -- pressurized containers of propane and butane used to fuel appliances in isolated homes, mobile homes, and recreational vehicles, and for camping stoves and lanterns. The propane or butane exists as a liquid inside the containers, but vaporizes upon release. Heavier hydrocarbons like gasoline and diesel fuel are liquids at atmospheric pressures and temperatures but vaporize when heat is added. These are all examples of phase changes. Each hydrocarbon has its own phase diagram, like that of Figure B, which shows how changes in pressure and temperature affect its physical characteristics.

FIGURE B: PHASE DIAGRAM OF A PURE SUBSTANCE



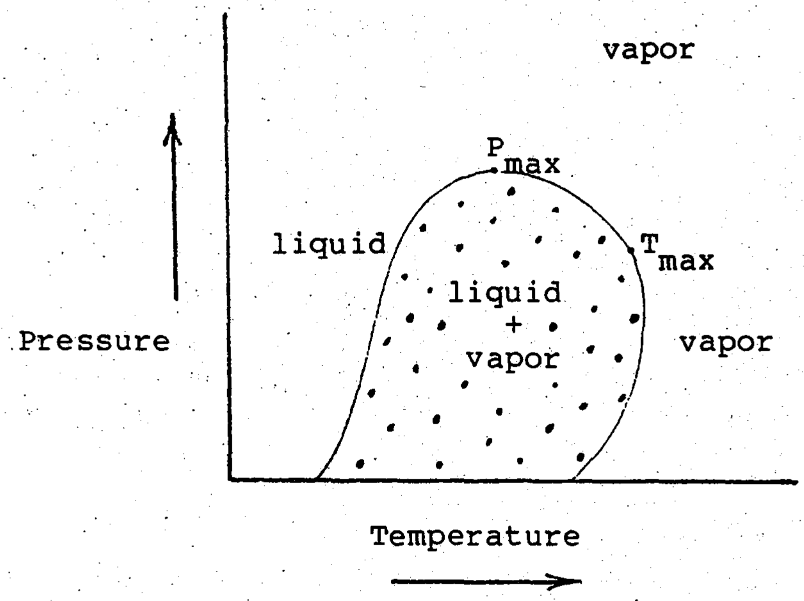
Notice first, that four phases are shown: solid, liquid, vapor, and something called dense-phase fluid. Unlike the other phases, it is hard to pinpoint where the dense phase fluid starts and ends; but we do know that it occurs only at extremely high pressures. It is also difficult to describe: A dense-phase fluid is dense like a liquid, but compressible like a vapor. And unlike solids, liquids, and vapors, which we all encounter in our daily lives, dense-phase fluids exist only deep inside the earth and within artificially created environments like natural gas pipelines.

While this high pressure phase is technically a creature unto itself, for our purposes there is no practical distinction between such fluids and vapors, and we shall generally use the word vapor for both.

Point C in Figure B is called the critical point. For any pure substance, no liquid can exist at pressures above the critical pressure (P_c) --- no matter how far the temperature drops. Likewise, no liquid can exist at temperatures beyond the critical temperature (T_c) --- again, no matter how much pressure is exerted.

Unfortunately phase diagrams of hydrocarbon MIXTURES, like that of Figure C, are more complicated to read and understand than are the diagrams of pure substances. For volumes containing only a single hydrocarbon type, two phases will coexist only at pressure-temperature combinations represented by the thin line separating liquid and vapor phases. But for hydrocarbon mixtures, the net effect of all the individual phase diagrams is a tongue-shaped region or phase-envelope in which both gas and liquid states are present. To avoid two-phase flow in pipelines, therefore, any combination of temperature and pressure falling inside the phase envelope must be avoided. Liquids pipelines must operate to the left of the phase envelope, while gas pipelines must function above or to the right of it.

FIGURE C: PHASE DIAGRAM OF A MIXTURE



The temperature and pressure combinations that delineate the right and upper boundaries of the phase envelope are called <u>dewpoints</u>, marking the conditions at which droplets first begin to appear in a vapor as the temperature or pressure falls. The combinations along the left side of the phase envelope are called <u>bubblepoints</u>, marking the conditions at which bubbles of vapor first appear in a liquid. TAPS engineers, therefore, worry about bubblepoints, while ANGTS engineers fret over dewpoints. The next chapter will examine how engineers use phase diagrams to determine what mixtures of light hydrocarbons can be handled safely in ANGTS.

THE RELATIONSHIP BETWEEN GAS COMPOSITION AND UPSET CONDITIONS

While the choice of operating (or discharge) pressure has thus far dominated the discussion of two-phase flow, the operating pressure in itself does not limit the allowable range of gas mixtures. Likewise, the temperature at which gas is discharged from each compressor station is not the limiting factor. Instead, project engineers concern themselves with the combination of pressure and temperature conditions that would occur in a system upset.

As the term implies, upset conditions are those that occur when the system malfunctions. Engineers study upset conditions in order to forecast the most troubling combination of temperature and pressure (from the standpoint of two-phase flow) that vapors moving through the gas pipeline are likely to encounter. Since ANGTS will be designed to carry light hydrocarbons in a high pressure vapor phase (more precisely, a dense-phase fluid), upset conditions denote the LOWEST expected combinations of temperature and pressure.

How are upset conditions determined? First, the normal operating window of pressures and temperatures must be calculated. This represents the range of conditions likely to occur, assuming that the system is functioning properly. The lowest pressure experienced under these normal conditions is the suction pressure, which occurs at the entrance to each compressor station.

Calculating the lowest temperature likely to occur under normal operating conditions is more difficult. It depends, in part, upon the temperature at which gas is ejected from the compressor stations. Interestingly, the Canadian pipeline segments south of Whitehorse have an advantage on this point. Compressor stations in Alaska must discharge gas with a temperature no higher than 32 degrees F., in order to prevent melting of permafrost through which the buried pipeline is laid. However, south of Whitehorse permafrost is a relatively minor problem and discharge temperatures, therefore, can be higher.

The lowest limit of acceptable gas temperatures is a function of the pipe's ductility and other physical characteristics. In the present preliminary design, this lower limit is -10 degrees F. Minimum normal operating temperatures are, in turn, determined mainly by the <u>Joule-Thompson</u> cooling effect: a gas naturally falls in temperature as it expands between its discharge from one compressor and its delivery to the next. The lowest operating temperature also depends upon what ground or air temperatures the designers expect to occur along the pipeline route. As long as the pipeline in Alaska is buried, the temperature it encounters will average about 30 degrees F. and fall no lower than about 10 degrees F. seasonally. If any section of the pipeline is constructed above ground, however, the cold Arctic winters become a real concern.

Once pipeline designers determine the <u>normal operating window</u> of temperatures and pressures, they can forecast the effects of specific malfunctions. Calculation of the resulting upset conditions reflects the designer's judgment as to WHICH malfunctions must be accomodated. Generally, upset conditions that have been discussed with respect to the Alaska gas pipeline reflect an assumption that the worst case would be one in which a single compressor station is totally shut down for repairs. But the implications of this assumption depend also on WHICH station is out of service. Moreover, the worst conditions under which the system will operate are also a function of how much the pipeline's designers and operators are prepared to reduce throughput in case of an upset: Will they simply route the

the gas past the ailing station without increasing the suction capability downstream? Or will the next station be forced to work harder in an attempt to keep throughput from falling too severely? Again, determining how much the operator can manipulate suction pressure at the downstream station depends upon the minimum stress temperature of the steel pipe (-10 degrees F, as we mentioned previously), the mechanical limitations of the machinery, and the dewpoint characteristics of the gas itself.

Figure D plots the temperatures and pressures of assumed upset conditions for the several pipeline operating pressures under consideration, and illustrates how close these points come to the two-phase flow conditions of various North Slope hydrocarbon mixtures. While an understanding of the basic physical principles reviewed here is important, no one can precisely assess the system's upset temperatures and pressures except in conjunction with detailed engineering and contingency plans. This explains why different parties have projected different upset conditions for ANGTS.

Figure D shows, for example, why upset conditions for the Canadian pipeline sections are of no real concern with respect to choice of gas composition. Even though the Canadian pipeline will function at a lower operating pressure (1080 psig, with a corresponding upset pressure of about 860 psig), it will have a significantly higher upset temperature (around 30 to 40 degrees F.) because the lack of permafrost south of Whitehorse permits higher compressor discharge temperatures. If one plots the intersection of 860 psig and 35 degrees F., it is evident that the design of the <u>Alaska</u> portion of the pipeline will be what limits the volume of intermediate hydrocarbons shipped through the entire system.

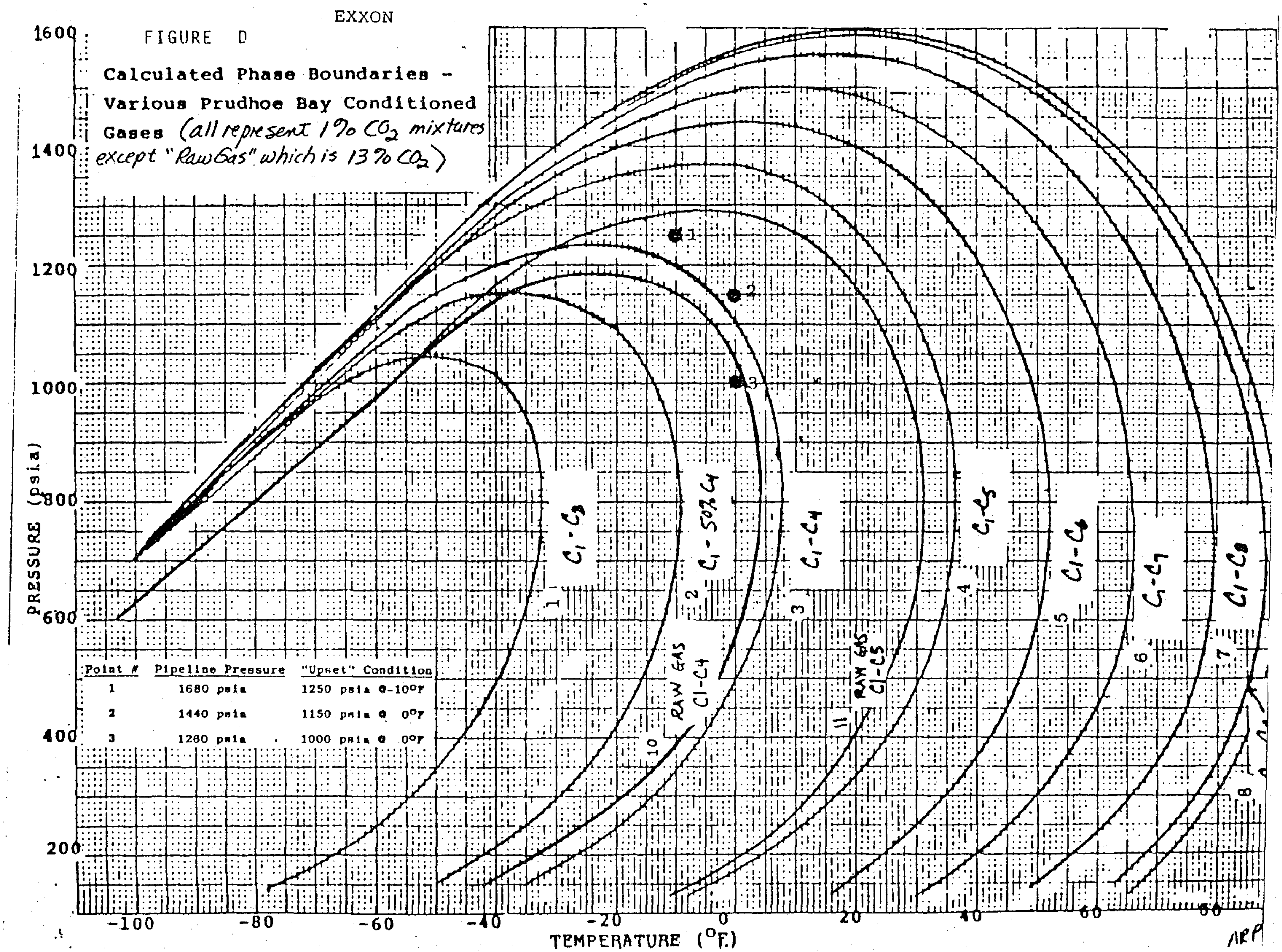
EXXON

VARIOUS PRUDHOE BAY CONDITIONED GAS COMPOSITIONS
(Mole Percent)

Component	Unconditioned Separator Off-Gas	1 C_1-C_3	2 $C_1-50\%C_4$	3 C_1-C_4	4 C_1-C_5	5 C_1-C_6	6 C_1-C_7	7 C_1-C_8	8 C_1-C_8	9 C_1-C_9	10 Off-Ga C_1-C
N_2	0.484	0.564	0.559	0.554	0.551	0.550	0.549	0.549	0.549	0.549	0.48
CO_2	12.659	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	12.77
C_1	74.706	87.053	86.296	85.554	84.964	84.818	84.742	84.695	84.679	84.676	75.38
C_2	6.428	7.491	7.426	7.362	7.311	7.299	7.292	7.288	7.287	7.287	6.48
C_3	3.340	3.892	3.859	3.826	3.799	3.793	3.789	3.787	3.786	3.786	3.37
$i-C_4$	0.450	--	0.260	0.515	0.512	0.511	0.511	0.510	0.510	0.510	0.45
$n-C_4$	1.038	--	0.600	1.189	1.181	1.179	1.178	1.177	1.177	1.177	1.04
$i-C_5$	0.217	--	--	--	0.247	0.247	0.246	0.246	0.246	0.246	--
$n-C_5$	0.383	--	--	--	0.435	0.435	0.434	0.434	0.434	0.434	--
C_6	0.148	--	--	--	--	0.168	0.168	0.168	0.168	0.168	--
C_7	0.081	--	--	--	--	--	0.091	0.092	0.092	0.092	--
C_8	0.047	--	--	--	--	--	--	0.054	0.054	0.054	--
C_9	0.016	--	--	--	--	--	--	--	0.018	0.018	--
C_{10}	0.003	--	--	--	--	--	--	--	--	0.003	--
Molecular Wt.	22.7	18.5	18.8	19.2	19.5	19.7	19.8	19.8	19.8	19.9	22.2
Heating Value (Btu/cf*)	1027	1095	1113	1131	1150	1156	1160	1163	1164	1164	996

*Gross, Wet, Actual @ 60°F., 14.73 psia

3-7-78


EXXON
FIGURE D
Calculated Phase Boundaries - Various Prudhoe Bay Conditioned Gases (all represent 1% CO2 mixtures except "Raw Gas" which is 13% CO2)
Point #
Pipeline Pressure
"Upset" Condition
1
1680 psia
1250 psia @-10°F
2
1440 psia
1150 psia @ 0°F
3
1260 psia
1000 psia @ 0°F
PRESSURE (psia)
TEMPERATURE (°F)
1600
1400
1200
1000
800
600
400
200
-100
-80
-60
-40
-20
0
20
40
60
80
C1-C3
C1-50% C4
C1-C4
C1-C5
C1-C6
C1-C7
C1-C8
RAW GAS C1-C4
RAW GAS C1-C5
1
2
3
4
5
6
7
8
10
11
ARP

Alaska state officials thus far have argued that decisions regarding pipeline design and gas composition should not preclude shipment of intermediate hydrocarbons such as butanes. (This position will be discussed in more detail later.) However, when the time comes to develop firm contingency plans for upset conditions, the State's interest in shipping intermediate hydrocarbons through the gas pipeline may well be surpassed by its likely --- and conflicting --- interest in maintaining high throughput levels: As the preceding discussion shows, in the event of upset, maintenance of throughput depends on an ability to reduce the suction pressure at the next compressor station, which in turn is partly limited by the proportion of intermediate hydrocarbons in the gas stream.

D. CARBON DIOXIDE CONTENT

Produced gas from the field (sometimes called raw gas) contains about 13 percent carbon dioxide (CO_2). Whether that amount is allowed to remain in the pipeline quality gas, or is removed via conditioning[3] down to a 1 percent or 3 percent level, depends on several factors:

---

3) Some parties with an interest in ANGTS have used the words "gas conditioning" and "gas processing" interchangeably; and in many Lower 48 producing areas, the boundary between the two stages of natural gas treatment is hard to define. With respect to Prudhoe Bay natural gas, these two phrases have distinct regulatory definitions, which may result in very real differences in the price the law allows gas producers to receive. As a result, the producers are easily aggrieved by any "misuse" of the two terms. We will make no attempt here at a rigorous distinction between gas processing and conditioning; the reader should simply be aware of the sensitivity of this matter.

1. The effect of carbon dioxide on hydrocarbon dewpoint. Figure D shows that a 13 percent CO_2 mixture enables the introduction of greater quantities of heavy hydrocarbons than would be safe with a 1 percent CO_2 mixture, but the effect is really rather small. Instead, the choice of CO_2 concentration must be made on other grounds.

2. The effect of carbon dioxide on pipeline corrosion. Under certain conditions, carbon dioxide will combine with water to form carbonic acid. If present in the sales gas stream, carbonic acid will corrode the steel walls of the pipeline. The question, then, is how various concentrations of CO_2 affect the risk that carbonic acid will seriously damage the pipeline during the twenty-plus years of gas shipments.

The producers collectively argue that carbonic acid corrosion in the Alaskan section of the gas pipeline is a false issue, in part, because it takes two to tango. Carbon dioxide in any concentration cannot turn into carbonic acid except in the presence of "free" water (water that condenses out of the vapor phase). Since enough water must be removed to meet WATER dewpoint specifications of -35 degrees F. for the section of pipeline in Alaska, no problem should ensue unless the temperature within the pipeline falls below that point; but the HYDROCARBON dewpoint specification will have to be much higher --- somewhere around 0 degrees F. in order to maximize shipment of intermediate hydrocarbons. Thus, before carbonic acid formation could pose a serious threat to the pipeline, hydrocarbons present in two-phase flow conditions would already have made the system inoperative.

Northwest Pipeline Company counters the producers' arguments with a different concern from its own standpoint as pipeline operator. While the sales gas containing more than 1 percent CO_2 may indeed ENTER the pipeline at Prudhoe Bay in a dehydrated condition that poses no threat of corrosion, the pipeline operator must ensure that the gas REMAINS corrosion-free throughout the several thousand miles of its journey. Apparently, some water is expected to contaminate the sales gas not only as a result of upset conditions, but even during hydro-testing associated with pipeline start-up. Whether Northwest's demand for a 1 percent CO_2 specification, therefore, is reasonable, has not yet been decided by FERC.

Because of permafrost problems in Alaska, the temperature of the gas must be held below the freezing point of water. Hence, if any water drops out in Alaska, it will likely do so in the form of ice or more precisely, <u>hydrates</u>, which are like ice crystals but encapsulate molecules of light hydrocarbons or sulphur compounds within their structures. At the planned operating temperatures for the Alaska pipeline segment, free water will form hydrates at temperatures as high as 60 degrees F. But ice and hydrates, unlike water, cannot combine with CO_2 to form an acid. Instead of gradual corrosion, the presence of solids will present a more immediate problem: blockage of the pipeline and its valves.

The Canadian section of the pipeline poses, perhaps, an even more fundamental concern. Canadian regulators have given preliminary approval to a water dewpoint specification for gas added to pipeline sections south of Whitehorse that is less stringent than specifications proposed for the

Alaska section. This difference, however, does not indicate any malfeasance by Canadian pipeline owners and regulators, but rather a difference in judgment about what constitutes acceptable risks in the face of added costs for prevention.

3. The effect of carbon-dioxide on downstream gas systems. Purchasers of Prudhoe Bay gas have argued that a high CO_2 content would adversely affect their interests in several ways.

In its July 1979 comments to FERC, the Natural Gas Pipeline Company of America states that a gas of 13 percent CO_2 would create corrosion problems within its own pipeline system, because that system's low-CO_2 gas from other sources has a relatively high water content. In addition, if Alaska gas contained excessive amounts of CO_2, it would have to be mixed with large quantitites of gas from elsewhere in order to ensure consistent burning characteristics.

Northern Natural Gas Company in its letter to the Alaskan Gas Project Office of FERC (dated December 7, 1978), advocates even more stringent CO_2 standards. It claims that its purchased volumes of Alaska gas will first be stored as LNG and, as such, cannot tolerate a CO_2 content that exceeds about 200 parts per million (ppm). But as the State of Alaska observed in its reply comment of June 1979, all pipeline gas must undergo CO_2 removal at the LNG plant site. The State concluded, therefore, that Northern's concern should not influence the choice of CO_2 specifications for North Slope gas.

The valid point raised by Northern, however, was that most LNG facilities are now designed to treat pipeline gas whose CO_2 content does not exceed 1 percent. Hence, the additional expense that shippers must bear to treat 3 percent CO_2 gas must be taken into account in assessing the conditioning and transportation costs for Prudhoe Bay gas.

4. <u>The effect of carbon dioxide on project economics</u>. One other area of concern has entered the debate on CO_2 specifications --- overall project economics. How would different CO_2 levels affect the cost of conditioning versus the cost of pipeline transportation?

The Ralph M. Parsons Company (in its February 1979 CO_2 specification study[4]) estimates that by relaxing the CO_2 removal process to yield a sales gas of 3 percent CO_2 instead of 1 percent, the conditioning plant construction costs could be pared down by about 7 percent. If no CO_2 removal facilities were built (yielding a sales gas of 13 percent CO_2), construction costs would be about half as much. Fuel requirements for the scaled-down conditioning plant would decrease by 8 percent in the 3 percent CO_2 case, and would drop by about one-third in the 13 percent case.

TABLE 5

COSTS OF CONDITIONING	1% CO_2 (base case)	3% CO_2	13% CO_2
Construction cost	100%	93%	54%
Fuel requirements	100%	92%	66%

---

4) The Ralph M. Parsons' studies of conditioning processes and facilities were financed jointly by the North Slope producers and a half dozen likely gas shippers (interstate gas transmission companies). It was conducted about two years ago and, necessarily, had to adopt some working assumptions in spite of the many unknowns. Consequently these assumptions and the study conclusions are not totally satsifactory to all of the sponsoring parties. The study is, however, the only in-depth analysis that presently exists; and it is, therefore, widely quoted.

Table 5 suggests that from the standpoint of conditioning costs and fuel requirements on the North Slope alone, the 13 percent CO_2 case is a clear winner. One must remember, however, that such high CO_2 levels would impose greater transportation costs, additional capital costs downstream (since CO_2 must be removed prior to customer distribution), and it threatens pipeline corrosion. The table also shows that a 3 percent CO_2 specification is preferable to one percent, but not overwhelmingly so.

On the other hand, Northwest Alaskan Pipeline Company in its February 1979 "CO_2 Transportation Study", shows that a 3 percent or 13 percent CO_2 specification would cost MORE than a 1 percent specification from the standpoint of pipeline transportation costs. (While the added volume of CO_2 contributes no additional heating value to the gas stream, it does require an increased investment in compression equipment and more fuel during pipeline operations.) But here too, the cost differences between the 1 and 3 percent CO_2 specifications are not very substantial.

In comparing how much money would be SAVED in the conditioning process by moving from a 1 percent CO_2 specification to 3 percent, versus how much additional money and fuel would be SPENT for pipeline transportation, even Northwest admits that the conditioning cost savings are of greater importance [p 5. of Northwest's "CO_2 Transportation Study"]. The difficulty for FERC will be in judging the significance of this net cost savings compared to the pipeline corrosion and downstream marketing problems previously discussed. FERC has, at least for the present, ruled that the cost of reducing CO_2 content below 3 percent, if required, is to be treated as a conditioning cost. Until the issue of conditioning cost allocation is finally decided, however, we cannot know whether it is the producers (and the State of Alaska) or the gas consumers who would benefit from an attempt to optimize total project costs.

E. VOLUMES OF GAS AND GAS LIQUIDS AVAILABLE FOR SHIPMENT

No intelligent discussion about sales gas composition can take place without some agreement as to what volumes and kinds of hydrocarbons will actually be AVAILABLE for shipment through the gas pipeline. Previous debate on the matter of gas composition has, in fact, been clouded by differing outlooks on gas availability. Worse yet, those discrepancies in underlying assumptions have largely been overlooked. Again, whether all the intermediate hydrocarbons will be ALLOWED to enter the gas pipeline for shipment is a complex question with which the rest of this report is concerned --- but that is all the more reason to make sure that hidden differences in assumptions about hydrocarbon availability are not ultimately responsible for disagreements on other matters.

This section will examine the three factors that determine how much and what kind of hydrocarbons are available for shipment through the gas pipeline: (1) reservoir production rates, (2) North Slope fuel requirements, and (3) the ability of the TAPS oil pipeline to carry intermediate hydrocarbons.

1. Reservoir production rates.

The field rules for the Prudhoe Bay reservoir currently limit raw gas production to 2.7 bcf per day, and it is expected that this rate can be maintained for 25 or more years. This rate, in turn, will yield about 2.0 bcf per day of conditioned gas. No one, of course, can guarantee that such offtake levels will indeed be physically possible, or that Alaska's Oil and Gas Conservation Commission will approve them throughout the life of the field, because the reservoir's production capabilities are based on predictions of FUTURE performance; but no one is now arguing seriously that any other figure makes more sense from the standpoint of today's planning needs.

2. Gas composition changes.

The expected hydrocarbon composition of that steady 2.7 bcf per day, however, IS expected to change through time. During the early years of gas sales, solution gas bubbling out of the crude oil will comprise the greater portion of total gas volume. But as crude oil production drops off, so will the volume of solution gas. The 2.7 bcf per day, instead, will increasingly consist of gas that comes directly out of the gas cap. Since gas cap gas is "leaner" in heavier hydrocarbons than the solution gas, the combined gas mixture, as well, will grow leaner through time.

ARCO [Dickinson letter to Tussing; January 3, 1980] estimates that by the 25th year of gas offtake, the natural gas liquids (NGL) content of the produced gas will have dropped by about 17 percent. Similarly, SOHIO [Pritchard letter to Barlow; January 23, 1980] estimates a drop-off in the ethane-propane NGL component of roughly 20 percent. The crucial issue is not, however, the absolute volumes of NGL's that must transit TAPS, but the PROPORTION of butanes in the oil stream, a ratio that promises to increase over time as oil production declines. It is nevertheless doubtful whether this trend is significant enough to merit any real consideration in system planning and design --- especially given the likelihood that during the 25 year operating period other gas reservoirs with different gas compositions will be tapped.

While the changing hydrocarbon content of PRUDHOE BAY natural gas may not be a major consideration in the design of ANGTS, system engineers do have to take into account the likelihood that gas produced from other, still undiscovered or undeveloped reservoirs on the North Slope may differ significantly in chemical composition. Prudhoe Bay gas is relatively sweet and wet (low in sulfur compounds and rich in NGL's), and has a relatively high CO_2 content. A conditioning plant designed to treat this raw gas stream, or a pipeline designed to carry it, would be uneconomic or even inoperable for gas from another reservoir which happened, for example, to be sour and dry, and contained little CO_2.

Under the present plan for ANGTS, the initial conditioning plant will be located on the North Slope and designed expressly to treat the volume and mixture of compounds the Prudhoe Bay reservoir is expected to produce. If new and different gas mixtures later came on stream from other reservoirs, the existing plant could be modified or new facilities added at the same place or elsewhere specifically to accommodate the new supply. In either case, the pipeline itself can be built to accommodate pipeline-quality (fully-conditioned) gas from any source in Arctic Alaska. If the conditioning plant were at Fairbanks or further downstream on the pipeline, however, system engineers would face the far more difficult task of designing both the pipeline and the conditioning plant to handle a stream of raw gas whose characteristics might change radically over time.

Thus, the possible need for ANGTS to handle different (and yet unknown) gas mixtures over its operating life is one reason why the gas producers, Northwest Alaskan, the prospective gas shippers, and FERC all seem to agree that the conditioning plant for Prudhoe Bay gas should be located on the North Slope, despite the belief of many Alaskans that construction and operating costs would be less, and local economic benefits greater, in an Interior Alaska location.

3. North Slope fuel requirements.

It takes a good deal of energy to produce, clean and condition, and transport oil and gas from the North Slope. This energy must be drawn out of the stream of produced hydrocarbons. There are three general categories of North Slope fuel uses: (1) FIELD FUEL, (2) TAPS FUEL, and (3) PLANT FUEL (for the gas conditioning plant).

(1) FIELD FUEL is needed for all of the activities relating to oil and gas PRODUCTION. In addition to actual oil production at the wells, energy is consumed in gathering the oil into facilities where the crude can be separated from the solution gas, dehydrated of its water content, and cleaned of its impurities. Field fuel is also consumed by the Prudhoe Bay electric generating plant. Produced gas in excess of fuel requirements is currently compressed to about 4000 psi for reinjection into the reservoir, pending the onset of gas sales. This function is performed in the Central Compressor Plant, which, likewise, requires a a good deal of energy.

Estimates of future field fuel requirements, such as those used in the Ralph M. Parsons Company report, must also provide for additional production activities, which will include more elaborate facilities for injecting back into the reservoir the produced water that is separated from the crude, and for the injection of source water from the Beaufort Sea in order to maintain reservoir pressure. (This is sometimes called waterflooding.) The "maximum" field fuel case used in the Parsons report takes all of these activities into account.

(2) TAPS FUEL is that which is needed to run the first four pump stations of the Trans-Alaska oil pipeline. While pump stations south of Station #4 provide for their own fuel

requirements by processing a portion of the crude oil into diesel fuel in individual topping plants, the TAPS owners decided that it would be cheaper to supply the more northerly pump stations with North Slope gas by means of a buried gas pipeline beside the oil line. Unlike the TAPS oil pipeline, the Alaska Highway gas pipeline will transport a mixture of hydrocarbons that can be used directly in its compressor stations, thus no provision has been made for supplying even its northern portions with a separate energy stream.

(3) PLANT FUEL is needed for all aspects of the gas conditioning process --- for (a) separating and fractionating propanes, butanes, and pentanes-plus from the lighter hydrocarbons; (b) for removing carbon dioxide from the remaining methane-ethane stream; and (c) for chilling and compressing the conditioned gas to meet the requirements for shipment through the gas pipeline. Sometimes PLANT FUEL is discussed more specifically as HEATER FUEL and TURBINE FUEL. The distinction is made because while heaters can run on a relatively low BTU fuel, turbines have more stringent requirements.

Where does all this fuel come from? Currently, the Field Fuel Gas Unit conditions a portion of the raw gas to provide energy for most ongoing field activities and for TAPS.[5] Since the TAPS fuel gas line experiences extremely cold temperatures enroute to the pump stations, the Field Fuel Gas Unit yields a gas stream with exceptionally stringent specifications --- a -40 degree F. hydrocarbon dewpoint and a -60 degree F. water dewpoint. When waterflooding begins, the Field Fuel Gas Unit can be expanded to

---

5) The gathering centers in the western part of the field furnish their own fuel.

accomodate the new demand. Or, as the Parsons study anticipates, additional FIELD FUEL requirements can be met by fuel generated at the conditioning plant. The Parsons study has chosen the latter technique in an attempt to optimize the entire system, disregarding ownership responsibilities. In so doing, an outlet is found for the ethane-rich CO_2 "waste" gas that is a by-product of the CO_2 removal process selected by Parsons. This stream is enriched with propane to provide a fuel suitable for field activities.[6]

Nevertheless, the producers make a point of emphasizing that they have several options for taking care of all their own fuel needs in the field and for TAPS, and they have not yet decided whether it would be in their interest to enter into an arrangement with the owner of the conditioning plant (whoever that may be) simply for the sake of overall project optimization. After all, their gas sales contracts commit for sale only the gas that is EXCESS to field and TAPS requirements. The producers further stress the potential disadvantages of making their crude oil production, processing, and transportation facilities dependent upon a stream of by-products from the gas conditioning plant. This concern would probably be even greater if the conditioning plant were operated and controlled by another party, such as the state.

Of course, the PLANT FUEL requirements will have to be met by the owners of the conditioning plant. Parsons Company, in its proposed plant design, has selected what it

---

6) No one knows exactly how much field and TAPS fuel will be needed in the future. Moreover, those requirments will vary almost daily. Parsons, therefore, calculated both a "maximum" and a "minimum" field fuel case. Most parties believe the "maximum" case data is the more relevant for planning.

considers to be the most economical CO_2 removal process, given the raw gas composition and the probable gas pipeline specifications. The process chosen by Parsons, however, results in a waste gas that also contains about half of the ethane that enters the plant.[7] Accordingly, Parsons recommends using the ethane-CO_2 by-product for fuel. Given the fact that SOMETHING has to be burned as fuel, this is not necessarily a bad thing --- unless there is some reason to view the ethane (and the propane that enriches it) as exceptionally valuable hydrocarbons for which a better use exists. There is little argument within Alaska that ethane would be the most desirable feedstock for a local petrochemical industry. It is still unclear, however, whether an ethane based petrochemical plant is economically feasible in Alaska, and even if it were, whether all of the ethane would, in fact, be required for such a facility. For example, the November 1979 study prepared by Bonner & Moore Associates for the State of Alaska indicates that only about one-fourth of the ethane is needed to feed a "world-scale" petrochemical plant, in which case, the CO_2 removal process chosen by Parsons Company in itself should cause no alarm.[8]

One other major point of controversy arises with respect to design of the CO_2 removal process and PLANT FUEL requirements. The ethane-rich CO_2 waste gas has a lower heating value (net BTU) of about 200 to 220 BTU per cubic foot. While this mixture may be adequate for use in

---

7) The Parsons design absorbs CO_2 via a physical, rather than a chemical, process. This process is much like fractionation in that the components are separated by their different boiling points. Given that the boiling point of ethane is relatively close to that of CO_2 (see Table 3), some of the ethane necessarily will "flash" off with the CO_2.

8) Bonner and Moore Associates, Inc., Promotion and development of the Petrochemical Industry in Alaska (November 1, 1979). See also the author's critical review of the Bonner and Moore report, "Prudhoe Bay Natural Gas Liquids, the Alaska Highway Gas Pipeline, and Petrochemical Development in Alaska" (January 20, 1980).

the plant heaters, it must be enriched to meet the specifications of the local turbines and field equipment. The Parsons Company design raises the BTU content by propane "spiking" to achieve a net heating value of about 475 BTU/cf for local turbine fuel, and 825 BTU/cf to suit the design limitations of existing field equipment. The controversy lies in the fact that while propane can easily be shipped south in the gas pipeline, butanes are more troublesome. Therefore, wouldn't it make more sense to use butane rather than propane for spiking purposes?

Unfortunately, the answer is not so simple. Butane could create the same hazards in the fuel system that it poses in the Alaska Highway gas pipeline --- condensation at low temperatures. In addition, its burning characteristics are different from those of propane, because it packs a bigger wallop of combustible carbons in each molecule. While use of butane instead of propane is not entirely out of the question, those responsible for smooth operations on the North Slope naturally will look for system designs and fuel compositions that promote simplicity and reliability. Unless the State of Alaska can demonstrate a special interest in the propanes or butanes that differs markedly from that shared by the other gas owners, any second-guesses the State might make with respect to fuel enrichment decisions would probably be viewed by others as unduly meddlesome.

Table 6 provides a perspective on North Slope fuel consumption. Of the hydrocarbons in the raw gas stream, about 15 percent will be consumed as field fuel, by the TAPS pump stations, and during the conditioning process.

TABLE 6

NORTH SLOPE FUEL REQUIREMENTS[1]

	Produced Gas[2]	FFGU Outlet[3]	Conditioning Plant Inlet	Field Fuel[4]	Plant Fuel[5]	Available Hydrocarbons[6]
Billion BTU/day (gross)	2849	[95]	2754	[214]	[113]	2427
Million cf/day	2700	[100]	2603	[236]	[248]	2104
Average BTU/cf (gross)	1055	953	1058	906	456	1154

NOTES:

1. Source: Exxon, personal communication (February 1980). Exxon personnel calculated these data using the Parsons reports maximum field fuel case.

2. An offtake rate of 2.7 bcf/day is assumed, consistent with the Prudhoe Bay reservoir field rules set by the Alaska Oil and Gas Conservation Commission. Parsons assumed a 2.8 bcf/day offtake rate.

3. FFGU Outlet signifies the fuel products of the Field Fuel Gas Unit that are used in the northern pump stations of TAPS and for a variety of field activities. Heavier hydrocarbons removed during that process are routed (along with the rest of the produced gas) to the conditioning plant and its fractionators.

4. Field Fuel designates those North Slope energy requirements that exceed the output of the Field Fuel Gas Unit. The present capacity of the Field Fuel Gas Unit is 100 million cubic feet per day. Parsons assumes that this capacity will be utilized fully, but that additional field fuel needs will be met by products of the conditioning plant, rather than by an expansion of the FFGU.

5. Plant Fuel includes both turbine and heater fuel for the conditioning plant. 456 BTU per cubic foot, therefore, represents the weighted average of the heating values for the relatively high BTU turbine fuel, and the low BTU heater fuel.

6. Available Hydrocarbons are the final product streams available for shipment through the gas pipeline or blended into TAPS crude.

4. Shipping intermediate hydrocarbons through TAPS.

As mentioned earlier, the Alaska Highway Gas pipeline will have no problem carrying light hydrocarbons (C_1, C_2, and C_3) in a vapor phase, while the TAPS oil pipeline can easily handle heavy hydrocarbons (C_6+) in a liquid phase. The question, then, is whether both systems together can support shipment of all of the intermediate hydrocarbons (C_4 and C_5) without encountering the hazards of two-phase flow.

Referring once again to Figure D, the reader will note that upset conditions attendant to a 1260 psig system limit the amount of butanes that can be transported through the Alaska Highway Gas Pipeline. The phase diagrams show that while 50 percent of the available butanes might be handled safely, shipping all of the available butanes would not be possible. Nobody can precisely judge what will constitute a safe limit, of course, until the pipeline engineering and contingency plans are completed. But it is clear that all of the pentanes and something less than half of the butanes will have to find another means of transport, such as TAPS.

Right now, crude oil enters the TAPS oil pipeline on the North Slope at 142 degrees F. Table 3 (on page 4) shows that at 142 degrees F., C_6 is a liquid but that C_5 and lighter hydrocarbons would be present in a vapor phase[9] What are the prospects for lowering the TAPS inlet temperature to enable it to accept all the pentanes and maybe even some of the butanes?

---

9) The table, however, makes no provision for the fact that hydrocarbon MIXTURES can safely accomodate some small volume of light hydrocarbons which, as pure substances, would exist as vapors.

Most parties agree that the inlet temperature of TAPS can not feasibly be reduced below about 110 to 112 degrees F. Three factors account for this limitation:

(1) Even if the inlet temperature were reduced, say, to 100 degrees F., the warm summer months combined with the heat naturally generated by the friction of flow would result in somewhat higher temperatures in certain parts of the pipeline. Thus the temperature threshold that limits the introduction of intermediate hydrocarbons into the crude cannot effectively be reduced beyond about 100 degrees [Pritchard letter to Barlow; January 23, 1980].

(2) On the other hand, if the TAPS inlet temperature is reduced, the heavy components of the crude oil ("waxes") will solidify more readily, slowing the flow and thereby reducing the daily throughput. At lower inlet temperatures, the line will have to be "pigged" more often to strip away the wax build-up. Moreover, if inlet temperature specifications were relaxed, TAPS would face a greater risk that wax solidification might cause real problems if the line experiences an extended shut-down during the winter cold.

(3) Even if both of the previous limitations were ignored, there are practical constraints on the amount of intermediate hydrocarbons that can be shipped through TAPS. In order to control air pollution in the Los Angeles basin, government regulations permit no landing of crude oil with <u>vapor pressures</u> higher than 11.1 psia at storage temperatures of, say, 85 degrees F. That is, crude must emit no vapors when subjected to pressures at or above 11.1 psia and to temperatures at or below 85 degrees. Since the lowest pressure at which TAPS operates is around the atmospheric pressure of 14.7 psia, rather than 11.1 psia, a TAPS bubble-point specification compatible with California's standard would have to reflect a correspondingly higher temperature.

Given all three constraints just discussed, most parties seem to believe that a reasonable minimum inlet temperature for TAPS is about 110 to 112 degrees F. At that temperature, both ARCO [Dickinson letter to Tussing; January 3, 1980] and the Ralph M. Parsons Company [September 1978 study report, Volume II, page 2-271] believe that essentially all of the available pentanes and butanes could be transported through TAPS, at peak crude oil throughput rates. SOHIO, however, suggests that only some of the butanes can be accomodated [Pritchard letter to Barlow; January 23, 1980].[10]

Nevertheless, assuming that the gas pipeline can safely handle at least 50 percent of the available butanes as previous discussed,[11] there appears to be little chance that butanes will be stranded on the North Slope --- at least in the early years of gas shipments. As oil production declines, however, the ability of TAPS to carry intermediate hydrocarbons will drop accordingly. This decline is expected to occur much faster than the offsetting feature of a progressively "leaner" raw gas stream mentioned earlier. For example, assuming (1) a 1985 start-up for the gas pipeline, (2) ARCO's oil production forecast [Dickinson letter to Tussing; January 3, 1980], and (3) the Parsons' phase diagrams [Volume II, pp. 2-287, 2-297, of the September 1978 conditioning study], all of the "available" pentanes and butanes could be shipped through TAPS initially, but the oil line could no longer accept ANY butanes by the seventh year of gas shipments.

---

10) Before one focuses on the apparent disagreement, it must be remembered that all calculations to date have been rough and possibly based on different crude oil assays, or different decline rates for crude oil production. Sohio is scheduled to complete a more refined analysis of this matter in early 1980.

11) Most parties agree that it is realistic to assume that ANGTS can accommodate about 85 percent of the butanes available after removal of the various fuel streams in the Parsons' maximum field fuel case. The State believes, however, that if NO ethane or propane is burned on the Slope, and those hydrocarbons are instead shipped through the gas pipeline, only about 25 percent of the butanes could be accommodated in ANGTS.

Is there, then, any real cause for alarm? First, putting things in perspective, even in the early years of gas production when butane content is greatest, it will comprise less than 2 percent of the gaseous hydrocarbon volume (though about 5 percent of the total BTU content of the raw gas stream). Moreover, unless there is some reason to believe that the producers and their gas purchasers have less interest than the State in getting as many of the North Slope BTU's to market as possible, here too, it may be unreasonable for the State to make second-guesses on the best overall system design.