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Draft
Final Report

CAPITAL REQUIREMENTS
FOR THE TRANSPORTATION
OF ENERGY MATERIALS:
1979 ARC ESTIMATES

MASTER

Prepared for:

U.S. Department of Energy
Energy Information Administration
Office of Industry Analysis
Washington, D.C.

(Contract Number DE-AC-1080EI10617)

August 13, 1980

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PREFACE

In September 1977, TERA, Inc. was retained by the Office of Mid-range Analysis of the Energy Information Administration (EIA) to develop and implement at the Department of Energy a user-interactive system for estimating investment requirements in the transportation of energy materials. Subsequent to the completion of this work, EIA's Office of Energy Industry Analysis awarded a contract to TERA, Inc. to estimate investment requirements in the transportation sector for the energy supply and demand scenarios developed by EIA in support of the 1977 and 1978 Annual Reports to Congress (ARC). This study again revises and updates transportation capital requirements for the 1979 ARC. TERA's methodology and estimates for three Mid-range energy supply/demand scenarios are outlined in this report.

TERA's work was monitored by Dr. Suraj Kanhouwa under the overall supervision of Mr. John Mitirisin of the Financial and Industry Studies Division of the Office of The Assistant Administrator for Applied Analysis. TERA's Project Manager was Mr. Michael Kendrick and the Principal Investigator was Mr. Mustafa Akan. Dr. Robert Brooks developed the natural gas network analysis and Mr. Marty Johnson provided the extensive research into FERC filings on natural gas projects. The assistance provided by Dr. W. Charles Mylander and Mr. Richard L. Thrasher and Mr. Brad Wing of EIA in the computer implementation of the earlier study as well as in this study is especially appreciated.

EXECUTIVE SUMMARY

Background

This report contains TERA's estimates of capital requirements to transport natural gas, crude oil, petroleum products and coal in the United States by 1990. It is a continuation of studies in 1978 and 1979 to perform similar analyses on 1977 and 1978 ARC scenarios. The Low, Medium and High world oil price scenarios from the EIA's Mid-range Energy Forecasting System (MEFS), as used in the 1979 Annual Report to Congress (ARC), were provided as a basis for the analysis and represent three alternative futures. TERA's approach varies by energy commodity to make best use of the information and analytical tools available:

- Natural Gas: Investment projections are derived from summaries of planned pipeline and LNG projects and a network analysis of the Lower 48 pipeline system to identify potential bottlenecks in the existing transmission system. Costs of expanding the gas pipeline network are computed using TERA's Gas Pipeline Investment Algorithm.
- Crude Oil: A network representation of the crude oil pipeline system is analyzed to identify needed capacity in pipelines; projected import levels are compared to deepwater port plans; and tanker requirements are projected for Alaskan oil movements. Costs for pipelines are computed using TERA's Oil Pipeline Investment Algorithm. Barge and towboat requirements are based on average utilization rates and projected modal shares.
- Petroleum Products: Due to the general decline in demand for petroleum products and the locational stability of supply and demand, no pipeline investment estimate is made. An analysis of planned products pipeline investments reveals support for this position except in the case of LPG pipelines which are quoted as planned. Water vessel investment is confined to replacement of the existing fleet as needed in a declining market.

- Coal: Coal cars and locomotives are computed by railroad region based on originating coal traffic and general utilization ratios. A discussion on rail track and way maintenance and investment is reproduced from a recent Department of Transportation report to the Congress summarizing capital needs for railroads. These joint costs are allocated to coal based on proportion of ton miles. Barge estimates are made based on general utilization rates while Collier investment estimates are made for average conditions on the Great Lakes and East coast trade routes.

Findings

Summaries of transportation investment requirements through 1990 are given in Table 1 for the low, medium and high scenarios. Total investment requirements for the three modes and the three energy commodities can accumulate to a \$49.9 to \$50.9 billion range depending on the scenario.

The scenarios are distinguished primarily by the world price of oil which, given deregulation of domestic oil prices, affects U.S. oil prices even more profoundly than in the past. The high price of oil, following the evidence of the last year, is projected to hold demand for oil below the recent past. Despite the overall decrease in traffic some investment in crude oil and LPG pipelines is necessary to reach new sources of supply. The Northern Tier pipeline is the most significant investment in oil carriage in the next ten years. This pipeline is not assured to be built but was used by the DOE in its MEFS assumptions.

Although natural gas production and consumption is projected to decline through 1990, new investments in carrying capacity also are required due to locational shifts in supply. The

Table 1
 Transportation Investment by Mode, Material,
 and Scenario 1990
 (1980 dollars million)

	OIL	GAS	COAL	TOTAL
<u>Low Scenario</u>				
Pipelines	1922.3	21,227.5	NA	23,149.8
Railroads	NA	NA	21,323.0	21,323.0
Waterways	1265.5	624.5	3,571.9	5,461.9
TOTAL	3187.8	21,852.0	24,894.9	49,934.7
<u>Medium Scenario</u>				
Pipelines	2198.2	21,247.9	NA	23,446.1
Railroads	NA	NA	21,694.4	21,694.4
Waterways	605.4	624.5	3,715.9	4,945.8
TOTAL	2803.6	21,872.4	25,410.3	50,086.3
<u>High Scenario</u>				
Pipelines	2220.4	21,291.7	NA	23,512.1
Railroads	NA	NA	22,590.4	22,590.4
Waterways	380.1	624.5	3,766.3	4,770.9
TOTAL	2600.5	21,916.2	26,356.7	50,873.4

NA: Not Analyzed or Not Applicable.

Alaska Natural Gas Transportation System is the dominant investment for energy transportation in the next ten years. Other pipeline expansion beyond planned and recently completed additions to the network will also be needed to carry projected supplies from the Overthrust area.

The outlook for coal in this year's ARC is optimistic and new rail, barge and deep-draft vessel capacity will be needed to carry it to market. This years report focuses attention on waterborne coal transportation to the northeast states in keeping with a return to significant coal consumption projected for this area. Not since the early 1960's has there been any significant coastwise movement of coal to the north-east. A resumption of such shipments will require a completely new fleet.

The investment estimates given in this report identify capital required to transport projected energy supplies to market. The requirement is strategic in the sense that other reasonable alternatives do not exist or that a shared load of new growth can be expected. Not analyzed or forecasted are investments in transportation facilities made in response to local conditions such as extending a pipeline to a new customer, or investments made for competitive reasons, such as expanding pipeline capacity to capture traffic from water carriers. The total investment figures, therefore, represent a minimum necessary capital improvement to respond to changes in interregional supply conditions.

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CHAPTER I. INTRODUCTION

As a part of the Department of Energy's overall Mid-Range Energy Forecasting System (MEFS) effort, impacts analyses are made on capital requirements in energy production and processing industries. This report is the third to deal with the impact of DOE energy forecasts on capital requirements in the transportation industries. The first was completed as part of the 1978 series of forecasts made by the Department for its 1977 Annual Administrator's report to Congress.⁽¹⁾ The second developed capital estimates for the forecasts of energy supply and demand given in the 1978 Annual Report to Congress.⁽²⁾ This year's report analyses capital requirements for transportation of energy materials in the three scenarios run for the 1979 Annual Report to Congress (ARC).

The Mid-Range Energy Forecasting System (MEFS) is an integrating model of several models. The MEFS supply model computes production and processing levels for various energy forms based on costs and prices. The demand model computes desired levels of consumption of various energy commodities based on price elasticities and cross elasticities of demand. Both the supply and the demand models are made dependent on various exogenous factors which are constructed into a scenario for analysis.

(1) U.S. Department of Energy, "Capital Requirements for the Transportation of Energy Materials Based on PIES Scenario Estimates," Analysis Memorandum, DOE/EIA-0102/47 prepared by TERA, Inc., Arlington, VA., for the Energy Information Administration, Washington, D.C., January 1979, (Available from NTIS and USGPO).

(2) U.S. Department of Energy, Capital Requirements for the Transportation of Energy Materials Based on 1978 ARC Estimates, DOE/EIA-8596-1 prepared by TERA, Inc., Arlington, VA. for the Energy Information Administration, Washington, D.C., October 1979, (Available from NTIS and USGPO).

The scenarios are constructed based on low, medium and high projections for the world oil price. Table I-1 shows the consumption levels for coal, oil and gas in 1985, 1990 and 1995 as projected by the EIA. These are the figures for which transportation capital requirements are estimated in this report.

Considerable investment in transportation may be undertaken by various enterprises in the United States in order to rationalize individual businesses, capture markets from competitors (either other suppliers of energy or other suppliers of transportation) or to make delivery to a new customer who has just moved or changed its operations. This report does not attempt to forecast total investment in transportation facilities. Aside from a few obvious omissions-such as trucks-the main purpose of the following report is to focus on only that investment which is strategic. That is, that investment in major facilities and equipment which must be made in order either to transport growing volumes of a commodity to market, such as coal, or to respond to shifting sources of supply as with crude oil and natural gas.

The following report is organized in chapters by energy material: Natural Gas, Crude Oil, Petroleum Products, and Coal. Each chapter is subdivided by mode of transport. The analysis is conducted for 1990 in all cases. The 1985 estimates given in the summary table in each chapter are based on an interpolation of the 1990 results from the historical year of reference. The 1995 estimate is based on extrapolation.

Table I-1

Annual Consumption of Energy
in the United States

Scenario	Coal (million tons)	Oil (million barrels)	Gas (billion cu.ft.)
1978	640.94	6,845.06	20,887.00
1979	762.56	6,793.01	21,100.64
1985			
Low	1,033.95	5,955.07	18,714.73
Med	1,045.81	5,632.35	18,348.27
High	1,044.66	5,475.94	18,371.35
1990			
Low	1,197.49	6,376.14	19,408.37
Med	1,237.01	5,711.43	18,845.44
High	1,246.80	5,444.80	18,841.61
1995			
Low	1,451.66	6,854.93	18,856.51
Med	1,574.73	5,705.58	18,048.64
High	1,577.15	5,257.89	18,270.03

SOURCE: Historical: U.S. Department of Energy, Energy Data Reports.

Projected: U.S. Department of Energy, Mid-Range Energy Forecasting System.

CHAPTER II. NATURAL GAS

Introduction

Natural gas is transported primarily via pipeline. Gas imported from overseas sources is transported in liquid form as liquified natural gas (LNG) to receiving terminals where it is gasified and moved via pipelines to final consumption areas. Pipelines constitute a large fixed investment with limited flexibility to adjust to geographic changes in supply and demand.

Table II-1 compares historical to projected consumption of gas. Although 1990 projected consumption of gas in the United States may be as little as 80 percent of its 1973 peak, shifting sources of supply, together with restrictions on certain uses, will result in a continuing need to build pipelines.

One growing source of supply for natural gas is through importation. Some import receiving terminals for LNG are (or are planned to be) near to the final demand areas. Other import terminals are planned near the head of major interstate pipeline systems and will supplement the decline in domestic production which historically supplied these pipelines. In both cases, some new pipeline construction is needed to connect these terminals with the existing transmission and distribution networks.

Table II-1
U.S. Supply of Natural Gas

Year	Marketed Production ^{1/} (BCF)	LNG Imports ^{2/} (BCF)
1973	23,603	3
1978	20,887	84
1979	21,101	253
1985 L	17,342	753
M	17,683	753
H	17,706	753
1990 L	17,106	753
M	18,413	753
H	18,506	753
1995 L	16,350	753
M	17,999	753
H	18,220	753

SOURCE: Historical: DOE, Energy Data Reports; Projected; MEFS

^{1/} Less exports

^{2/} From overseas origins

A second major source of new gas supply is anticipated to be from the Arctic regions of Alaska and Canada. Significant new investment, greater than all other planned investments in gas transportation combined, will be required to get this supply to market. These new sources of supply, together with less important new gas discoveries in the Lower 48, will load the gas transmission network differently than what it was originally designed for. Consequently, some "spot" shortages or bottlenecks in capacity will occur.

The following analysis outlines major new investments for Alaskan and imported gas. The impact of shifting supply on the existing network will be analyzed assuming that all of the network will be used in an optimal way; that is, a way which results in the lowest overall cost of operation. For this reason the estimates given may be considered optimistic. Contractual obligations, lack of cooperation between organizations and imperfect knowledge all work against such optimality in the use of the network. At less than optimal conditions, more investment will be needed to overcome bottlenecks that develop among the many transmission systems which are characterized in this analysis as a single network. Notwithstanding this difficulty in the analysis, the results anticipate many existing plans and reinforce conventional wisdom in many cases. There are also a few surprises which suggest need for closer examination of transportation requirements in certain areas.

Importation of Natural Gas

Terminals and Pipelines

Three import locations presently bring LNG into the U.S. Two are included under the heading of El Paso I in Table II-2.

Table II-2

LNG Importation Facilities
Modeled in MEFS

Project Name	1990 Projected Use (MMCF/D)		
	High	Medium	Low
Existing Projects:			
Distrigas	112	112	112
El Paso I	1,000	1,000	1,000
Proposed Projects:			
El Paso II	0	0	0
Pac-Indonesia	504	504	504
Trunkline ^{1/}	449	449	449
Columbia ^{1/}	0	0	0

^{1/} Represents an addition to the El Paso I project which includes Columbia LNG at Cove Point, Maryland and Southern LNG at Elba Island, Georgia.

In addition, four proposed projects are available to the MEFS supply model depending on the costs and alternative encountered under different scenarios. The throughputs selected by MEFS for 1990 are given in Table II-2. In the solution process used by MEFS, the proposed projects are bounded by a maximum but not by a minimum level. Consequently, they may differ from the throughput volumes projected by the proponents of each project.

Plans for the proposed El Paso II project with a capacity of 1 billion cubic feet per day have been changed entirely. No LNG terminal will be built by the El Paso Co. on the East Coast. Attention has shifted to a proposal to build a terminal at Matagordo Bay, Texas on the Gulf of Mexico. The original El Paso II plan, to receive Algerian LNG on the East Coast, was totally frustrated by the Algerian Government's demand for a higher price. El Paso's original application was conditionally denied. At present, the proposal to build a terminal and related facilities at Matagordo Bay awaits confirmation of a source of supply.⁽¹⁾

Because El Paso II was not selected by the MEFS supply model in any scenario, its projected cost for terminal and pipelines is not included among the capital requirements computed for this study. This also holds true for the Columbia gas LNG expansion at Cove Point, Maryland.

Fundamental decisions have been made in regard to the Pac-Indonesia project. Two of the three proposed LNG terminal/pipeline sites have been ruled out. Construction of an LNG facility at Los Angeles was prohibited by a state

⁽¹⁾Robert Harber, El Paso Co., Washington, D.C., telephone conversation, 25 June 1980.

pollution control act. The proposal to build a facility at Oxnard, CA. has been abandoned as such a project could not meet state remote population - density regulations. The proposal to build an LNG terminal and facilities at Pt. Conception is the only one still under active consideration. The plan is to build a complete terminal, vaporization facilities, and two 46" parallel pipelines from Pt. Conception to Arvin, CA. Actual construction of a Pt. Conception terminal and related facilities has been blocked by court action. Opponents of the project contend that seismic activity in the environs of Pt. Conception would make LNG facilities a severe threat to health and the environment.⁽²⁾

Given the status of the Pt. Conception proposal before FERC and the California legislature's rejection of the Oxnard and Los Angeles proposals, even if Indonesian gas should remain available for U.S. consumption, the question of where to receive LNG on the West Coast remains unanswered. Because the Pac-Indonesia facility is selected by MEFS for a delivery of 504 mcf per day a portion of its original design cost of \$721.9 million in 1974 dollars is added to investment requirements. Its original design capacity is 4000 mcf per day. One fourth of its original cost estimate plus two of the originally intended nine LNG Tankers are costed for inclusion in investment requirements for 1981 through 1990. These are \$180.5 million in 1974 dollars plus \$292.0 million in 1978 dollars respectively.

⁽²⁾FERC Docket LP75-83; Larry Dervico, ERA (DOE), telephone conversation, June 20, 1980.

The "Trunkline, LNG project is planned to feed into major interstate pipelines from a gasification plant and terminal at Lake Charles, Louisiana connected by 45.8 miles of 30" pipe. Import agreements have been made for 168 billion cubic feet per year (460 million cf/d). The MEFS supply model permits a maximum of 449 million cf/d (164 bcf/y) throughput which is used in all scenarios. The Trunkline project is currently in a construction/pre-delivery stage with the 1st quarter of 1981 as a target for completion of the entire project. The thirty inch 45.8 mile pipeline from Lake Charles to main transmission lines has already been completed. The project's overall cost will be approximately \$430 million, (LNG plant and pipeline) an increase from the original estimate of \$193.1 million.⁽⁴⁾ A contract for channel dredging has been awarded by the U.S. Army Corps of Engineers for \$4.9 million. Dredging costs are continuing costs and have not been included in the capital cost summary.⁽⁵⁾

As of June 17, 1980, five tankers have been committed to the project, 2 U.S. owned vessels and 3 Algerian ships. One U.S. tanker is operational, the other will undergo sea trials during the Summer of 1980. Two the the Algerian owned tankers have been completed and the third Algerian tanker is expected to be finished by the end of 1980.⁽⁶⁾ All Trunkline costs having been committed are not included in the total for investment required in the period January 1980 through 1990.

⁽³⁾ Stan Wallace, V.P./Public Relations, Panhandle Eastern Pipeline Co., Houston, TX, per phone, June 17, 1980.

⁽⁴⁾ FERC Docket CP74-139, February 18, 1977.

⁽⁵⁾ Ibid.

⁽⁶⁾ Stan Wallace, stet.

Construction of the Trunkline project was delayed because of the U.S. Government's concern over possible supply disruptions and Trunkline's dependency on Algerian LNG. Trunkline gas is destined for the U.S. midwestern market. Trunkline LNG Co. has maintained that Algeria is a relatively stable source of supply and plans to import 168 billion cubic feet/year for twenty years have not been altered.⁽⁷⁾

Over the next two decades, LNG may constitute a significant addition to the U.S. supply of natural gas. But a brief look at the recent experience of an existing project illustrates some of the risks involved with dependency on imported LNG.

The El Paso I Experience

From 1978 until recently, the El Paso I project at Cove Point, Maryland operated as the nation's first terminal to import LNG for year round transmission to customers. LNG was transported from Arzew, Algeria to a 380 million dollar terminal/regasification facility at Cove Point. Six 900 foot tankers were committed to the project. Every fourth day, a tanker arrived carrying enough LNG to yield approximately 2.6 billion cubic feet of natural gas for East Coast utilities serving seven states.⁽⁸⁾

⁽⁷⁾ Ibid., July 21, 1980.

⁽⁸⁾ New York Times, "A Test of Wills on Algerian Gas", July 15, 1980, Page D-1.

In March 1980, Sonatrach, the Algerian Government owned oil and gas company, gave the El Paso Co. an ultimatum: either pay a new price of \$6.00 per 1,000 cubic feet of gas or face a complete cut off of supply. When shipping and regasification costs are added to the \$6.00 price Algeria has demanded the new delivery price of Algerian LNG would amount to almost \$8.00 per 1,000 cubic feet. The previous Sonatrach - El Paso contract price was \$1.95 per 1,000 cubic feet F.O.B. Algeria.⁽⁹⁾

El Paso refused to pay the new price demanded by Sonatrach. No tankers have left Arzew for Cove Point since April 11, 1980. El Paso is losing \$7 million per month as a result of the supply cut off. The 6 LNG tankers are laying idle at European and Mediteranean ports. At present, the regasification plant at Cove Point is operating at 1% of its planned 650 mcf/d capacity by drawing LNG from 4 storage tanks which are yet empty.⁽¹⁰⁾ Because LNG from other sources is not available in the immediate future, operations at Cove Point will probably shut down entirely by the end of 1980 if shipments from Algeria cannot be resumed.

The governments of the U.S. and Algeria are scheduled to commence a third round of gas price negotiations on July 15. Since trade in LNG requires expensive, special tankers and unconventional terminal facilities, some observers believe that Algeria will soon recant its demands and again sell LNG near market price. Regardless of the outcome of negotiations however, events during the past 8 months have shown that Algeria is not a reliable source of LNG supply.

⁽⁹⁾ Ibid.

⁽¹⁰⁾ Ibid.

Given this experience with political pricing of international gas together with the immediate term stability of supply from domestic sources many investors may delay further investment in LNG transport facilities until the need is more pressing.

The Alaska Natural Gas Transportation System

Overview of ANGTS

Total production of natural gas in Alaska is projected to range from 1091.9 to 1093.3 bcf per year. 876.1 bcf of which is to come from the North Slope fields. The remainder, produced in the south, is assumed in MEFS to be consumed locally.

The Alaska Natural Gas Transportation System is a 4,800 mile pipeline system beginning at Prudhoe Bay, Alaska, extending through Western Canada, and ending at two different points in the United States. The pipeline system's purpose is to transport a total of 2.4 bcf/d (876.1 bcf/y) of natural gas from Prudhoe Bay to the Lower 48. The pipeline system will split into two separate pipelines in Southern Alberta, Canada, just before entering the United States, as shown in Figure II-1. From near the U.S.-Canadian border, two separate legs of the system, the Eastern Leg (Northern Border) and the Western Leg, will carry gas to existing transmission lines in the eastern and western United States.

When the system is complete, small quantities of Prudhoe Bay gas will be tapped from the Canadian segment of the pipeline for use in small towns alongside the pipeline. Southern Canadian gas will be injected into the

FIGURE II-1
ALASKAN NATURAL GAS TRANSPORTATION SYSTEM

system to replace whatever quantity of gas is used in Canada. In essence, 100% of investment in the ANGTS project is for supplying 2.4 bcf/d to the U.S. Lower 48. The entire ANGTS will cost approximately \$21.8 billion (U.S. 1980 \$).

Prebuild Segments

Original plans for ANGTS included a plan to pre-build certain parts of the pipeline system to allow delivery of Canadian natural gas to the U.S. Lower 48 before gas from Prudhoe Bay would be available. Under the pre-build plan, parts of the Eastern and Western Legs would be completed early, as would a southern Canada portion of the pipeline system.

Two major sets of regulatory problems have inhibited prebuilding. First, Canadian government regulations controlling Canadian export volume and the price of Canadian gas altered previous economic/profit calculations relating especially to the Western Leg. Second, the U.S. Federal Energy Regulatory Commission's official cost estimates served to box in the Northern Border Pipeline Company's depreciation allowances and amortization schedule, thus imperiling the financial viability of the Eastern Leg.

Recently, the outlook for prebuilding has changed. On June 20, 1980, the FERC offered Northern Border a de-

preciation adjustment⁽¹¹⁾ and on July 2, 1980, Northern Border announced that it would build its originally planned 821 mile prebuild segment if the Canadian government will allow the export of Canadian gas at a reasonable price.⁽¹²⁾ If the Canadian government decides to allow the export of Southern Canadian gas at an acceptable price, it is possible that 240 MMcf/d will flow from Canada into the U.S. Western Leg and 800 MMcf/d into the Eastern Leg by November, 1981.⁽¹³⁾ This total early transmission capability of 1,040 MMcf/d presupposes that Foothills, Ltd. will have completed the Southern Canada prebuild portion of the system by November, 1981. On June 9, 1980, the Canadian Cabinet's Committee on Priorities gave Foothills conditional approval to build the Southern Canada portion of the pipeline.⁽¹⁴⁾ On July 17, it was formally announced that the Canadian government has granted approval of the project.⁽¹⁵⁾ Foothills will begin construction this summer.

Alaska Segment

The general plan for construction of a 731 mile pipeline from Prudhoe Bay, Alaska to the U.S.-Canadian (Yukon Territory) border has not changed, although cost estimates have been revised, and delays have occurred, due primarily to financial problems and the controversy over construction of a necessary gas conditioning plant. It is now estimated that the Alaska segment of the pipeline

(11) FERC Docket CP78-123 etc.al; June 20, 1980.

(12) New York Times, July 2, 1980, Page D-3.

(13) Oil and Gas Journal, June 9, 1980; January 21, 1980.

(14) New York Times, July 14, 1980, "Pipeline Advances".

(15) New York Times, July 18, 1980 at A-21, "Canadian's Approve Start for Alaska Gas Pipeline Segment".

will cost \$11 billion (U.S. 1980).⁽¹⁶⁾ Because actual use of the Alaska segment is dependent upon the existence of a gas conditioning plant, the Alaska segment will probably not be operational until the winter of 1985-1986,⁽¹⁷⁾ when the gas conditioning plant has been completed. Construction will not commence until financial arrangements are settled. Thus far, Prudhoe Bay gas producers have not been willing to help finance the Alaskan segment because they are prohibited by law from owning equity interest in the pipeline. The law prohibiting them from holding equity interest in the pipeline may be repealed or altered if no other source of financing can be found.

Western Leg

Pacific Gas Transmission Company's planned 160.5 mile loop sections of the Western Leg segment are under construction and should be completed by March, 1981.⁽¹⁸⁾ No material delays are expected in construction of these loop sections. Northwest Pipeline Corp. has installed its planned 100 miles of 30" loop pipeline and 250.9 miles of 24" pipeline to transport gas between Stassfield, Oregon and Ignacio, Colorado. The El Paso Natural Gas Co. has installed planned compression facilities in the San Juan Basin Triangle and on its mainline transmission facilities.⁽¹⁹⁾

⁽¹⁶⁾ Oil and Gas Journal, February 18, 1980; (also, note: a spokesman at N.W. Alaska Pipeline Co. would not deny this figure).

⁽¹⁷⁾ Helen Burke, N.W. Alaskan Pipeline Co., telephone conversation, June 16, 1980.

⁽¹⁸⁾ Mr. Essley, ANGTS Project, FERC, telephone conversation, June 16, 1980.

⁽¹⁹⁾ Ibid.

Barring unforeseen difficulties, the Western Leg segment should be operational when Pacific Gas loop sections are completed in March, 1981, assuming that the southern Canada prebuild segment is completed by then. A total of 116.0 million dollars is required for the project of which nearly all has been spent. Remaining expenditures are not known and not included.

The Northern Border (Eastern Leg)

The Eastern Leg is to be built as planned, from Port of Morgan, Montana to Dwight, Illinois (90 miles southwest of Chicago). Cost of the Eastern Leg is now estimated at \$2.5 billion.⁽²⁰⁾ Ultimately, the Northern Border pipeline will deliver 2.2bcf/d to inland and northern states. Financial problems, the Alaskan gas conditioning plant controversy, and Canadian export controls (volume and price) have all caused delays in actual construction of the Eastern Leg.

Nevertheless, the Eastern Leg will be built, with 1986 as the target for completion of the project.⁽²¹⁾ Major regulatory problems have been resolved. The FERC fully approved Northern Border Pipeline Company's application to build the Eastern Leg (including the 821 mile prebuilt segment),⁽²²⁾ and the Canadian Government has decided to permit the export-sale of surplus Alberta gas to the United States. Foothills Pipelines (Yukon) Ltd.

⁽²⁰⁾ The Northern Border Pipeline Project, Northern Border Pipeline Co.

⁽²¹⁾ Mr. Essley, Op.Cit.

⁽²²⁾ New York Times, July 3, 1980, "U.S. Approves Pipeline Project".

recently received permission from the Canadian Government to prebuild the 527 mile southern Canada sections; therefore, Northern Border should have an early transmission capability by 1981.

Canada Segment

The Candian segment of the pipeline (not including the southern Canada prebuild portions) is expected to be completed by 1985. Presumably, construction of the Canada segment will not commence until a substantial portion of the Alaska segment has been laid. All construction in Canada (including prebuild) is estimated to cost \$8.3 billion (in 1980 Canadian dollars).⁽²³⁾

Network Impacts

The Network Solution

New sources of supply, together with restrictions on certain traditional, industrial, and utility demands, will cause shifts in the distribution patterns of natural gas. These shifts were analyzed using a network model of the U.S. gas transmission system.⁽²⁴⁾ The completed modeling framework was designed to disaggregate MEFS regional based supply and demand projections to 173 BEA Economic Areas. Supplies are then allocated to demands in a manner which makes most efficient use of existing pipeline capacity.

(23) Trish Lortie, 1st Sec'y., Canadian Embassy, Washington, D.C., telephone conversation, July 8, 1980.

(24) Developed by TERA and Robert Brooks & Associates based on Robert Brooks & Associates' GASNET3 system.

Figure II-2 shows a schematic representation of the natural gas pipeline network which was used in this study. Existing pipelines and some proposed pipelines are characterized as a single system of links and nodes connecting BEA Economic Areas. The proposed pipelines in the network include all pipeline connections from proposed LNG import facilities, the Western Leg and Northern Border sections of the Alaskan pipeline project, and two proposals for the Rocky Mountain region called "Trailblazer" and "Pathfinder."

The Trailblazer System is a natural gas pipeline system extending from Summit City, Utah to Beatrice, Nebraska. Its purpose is to carry new gas being produced in Utah, Idaho, Wyoming, and Colorado to markets in the Midwest and Eastern states.

The Trailblazer System is composed of three pipeline segments. From west to east they are called Overthrust, Colorado Interstate, and Trailblazer. For convenience they are sometimes referred to as the western, central, and eastern legs. The entire system is expected to be completed by November 1, 1981.⁽²⁵⁾

The western segment (Overthrust), built by Mountain Fuel Supply Co. will be 88 miles of 36" pipeline (not 30" as originally planned). This segment stretches from a point near Summit City, Utah to Rock Springs, Wyoming. Total cost

⁽²⁵⁾ Northern Natural Pipeline Co., brochure, "Trailblazer."

Figure II-2

Natural Gas Pipeline Network
Representation

LEGEND:

- Link and node
- Importation node

for the segment are estimated at \$56.7 million (1981 dollars). It is designed to have a final capacity of 440mcf/d, but initial capacity will be approximately 174 mcf/d. Construction is scheduled to start by May 15, 1981 (assuming no major snow storm in May). (26)

The central segment (Colorado Interstate), built by the Colorado Interstate Gas Co., will consist of 264 miles of 36" pipeline, from Rock Springs, Wyoming to Rockport, Colorado. The latest cost estimate for this segment of the system is \$195.4 million (1981). This segment will have an initial capacity of 447 mcf/d. Between 1983 and 1984, capacity may be increased to 665 mcf/d. (27) Construction of Colorado Interstate will begin in April, 1981.

The eastern segment (Trailblazer) of the pipeline system, built by the Natural Gas Pipeline Co. of America, will stretch from Rockport, Colorado to Beatrice, Nebraska, a distance of 445 miles. 36" pipeline will be used on this segment; estimated cost of the eastern leg is \$281 million (1981). This portion of the line will have an initial capacity of 525 mcf/d with potential for future capacity increases through looping. Construction work on the eastern leg will be completed by November, 1981, at the same time the other two segments are completed. (28)

(26) Mr. Stouss and Mr. Zabriskie, Mt. Fuel Supply Co., telephone conversation, June 27, 1980.

(27) Mr. Gilman, Colorado Interstate Gas Co., telephone conversation, June 27, 1980.

(28) Leon Kreisler, National Gas Pipeline Co. of America, telephone conversation, July 1, 1980.

The total length of the entire Trailblazer System is approximately 800 miles. All construction will employ 36" pipe. The total cost of the entire system is \$553.1 million (1981). 440-525 mcf/d should be flowing through the system by the end of November 1981.

Pathfinder, proposed by Cities Service Company, consists of two major segments; reconstruction and conversion of the Arapahoe Oil Pipeline from Marino County, Wyoming to Humbolt, Kansas, ⁽²⁹⁾ and a segment of new 20" line to Hesston, Kansas where it connects to existing Cities Service transmission lines. The project capacity is designed to transport 185,000 thousand cf/d at a total project cost in 1979 dollars of \$97.0 million. ⁽³⁰⁾

With these few proposed links added, the network is complete. Each link in the network is described as to origin and destination BEA, transmission cost per thousand cubic feet, and line capacity in thousands of cubic feet per day. Because the amount of gas tendered exceeds the amount finally delivered by the amount of gas transmission losses, each link is also characterized by the percentage of gas lost in transmission. Each link in the network is also given a second much higher cost to permit shipment of gas over and above 90 percent of the line's capacity. This permits the model to select certain links for expansion of the pipeline network if existing

⁽²⁹⁾The Arapahoe pipeline (with a parallel Amoco pipeline) connects Region 05 to Region 09 in the crude oil pipeline network (see Chapter III). New pipeline construction will be required in this region to transport shale oil to market in 1990 medium and high scenarios.

⁽³⁰⁾FERC Docket CP76-500.

links are inadequate. Ninety percent is generally regarded as a high utilization rate. This assumption results in a conservative estimate for needed capacity.

The network is "solved" by allocating supplies to demands through use of a linear programming algorithm with an objective function to minimize total system operating costs. Due to the fact that additional capacity beyond what exists or is planned is priced so much higher than the base operating costs, the network solution maximizes use of the existing and planned network.

Figures II-3, II-4 and II-5 show the location and direction of expanded links for the low, medium and high scenarios respectively. Needed new capacity in the Rocky Mountain regions exceeds already planned additions. This reflects MEFS' optimistic outlook for discovery of gas in Montana and Wyoming. The network solution calls for more than planned capacity along the Northern Border pipeline route evidently as a means of getting Montana gas to Midwest markets. The Trailblazer system from the Overthrust area, around western Colorado, is designed to allow some expansion which the MEFS projection and network solution indicates will be needed.

Gas pipeline expansion indicated within Texas may be the result of insufficient data on intrastate pipelines in Texas; therefore, these results are difficult to assess. Pipeline expansion between New York and Connecticut appears to be necessary to supplement loss of Canadian gas to New England. Demand growth accounts for the instances of network restrictions on the west coast

Figure II-3
Pipeline Links Requiring Expansion
of Capacity
1990 Low Scenario

Figure II-4
Pipeline Links Requiring Expansion
of Capacity
1990 Medium Scenario

Figure II-5
Pipeline Links Requiring Expansion
of Capacity
1990 High Scenario

The Cost of the Network Solution

The additional capacity required on each link was costed using the Gas Pipeline Investment Algorithm developed by TERA in an earlier phase of this study.⁽³¹⁾ The algorithm computes an optimal pipeline for a given volume of throughput, distance and location (onshore or offshore) for the pipeline. A second routine varies the throughput in increments of 10 percent of the design throughput beginning with one-half the design volume and ending after 20 increments or complete looping, whichever comes first. A sample output from the algorithm is given in Figure II-6.

In only one case the expanded link required a new pipeline. In the other cases, the existing line was given greater capacity through additions to horsepower. The existing capacity of the link was input to the algorithm which specified an ideal pipeline for the link which may actually be the sum of many pipelines. The variable throughput costs are examined to determine the cost of adding horsepower and looping to meet the required extra capacity. If the pipeline cannot be expanded to meet the required new throughput, the new throughput was input to the algorithm to compute the cost of building a new pipeline. Tables II-3, II-4, and II-5 outline the new construction and investment costs in 1975 dollars for each link requiring expansion of capacity as found in 1990 low, medium and high scenarios respectively. The origin and destination BEA Areas are as shown in Figure II-7.

(31) U.S. Department of Energy, "Capital Requirements for the Transportation of Energy Materials Based on PIES Scenario Estimates, "Analysis Memorandum," DOE/EIA-0102/47 prepared by TERA, Inc., Arlington, VA, for the Energy Information Administration, Washington, D.C., January 1979, (Available from NTIS).

Figure II-6
Sample Output:

GAS PIPELINE INVESTMENT ALGORITHM

*** GAS PIPELINE PROJECT DESCRIPTION ***

THROUGHPUT (MMCF/D)	207.
DISTANCE (MILES)	86.
REGION	ONSHORE
NOMINAL DIAMETER (INCHES)	16
PIPE WALL THICKNESS (INCHES)	0.3794
HORSEPOWER PER STATION	1455.
NUMBER OF STATIONS	2
STATION SPACING (MILES)	43.00
TOTAL INVESTMENT (\$ MILLION)	15.624
AVERAGE COST (\$/MCF)	0.0287

THROUGHPUT (MMCF/D)	* AVERAGE COST AT VARIABLE THROUGHPUT * LOOP PER STATION	REQUIRED HORSEPOWER	ADDITIONAL INVESTMENT	AVERAGE COST (\$/MCF)
103.50	0.	181.	0.0	0.0514
124.20	0.	309.	0.0	0.0433
144.90	0.	489.	0.0	0.0377
165.60	0.	731.	0.0	0.0337
186.30	0.	1048.	0.0	0.0308
207.00	0.	1455.	0.0	0.0287
227.70	0.	1972.	0.366	0.0276
248.40	0.	2620.	0.782	0.0270
269.10	0.	3431.	1.257	0.0269
289.80	0.	4443.	1.800	0.0272
310.50	0.	5713.	2.426	0.0280
331.20	0.	7318.	3.154	0.0292
351.90	0.	9379.	4.015	0.0310
372.60	0.	12094.	5.058	0.0336
393.30	0.	15827.	6.372	0.0373
414.00	0.	21363.	8.144	0.0431
434.70	4.	28640.	10.763	0.0509
455.40	19.	31194.	13.776	0.0535
476.10	35.	33821.	17.120	0.0561

Table II-3
Natural Gas Pipeline Network Investment
1990 Low Scenario

Origin BEA	Destination BEA	Miles	Base Capacity mmcf/d	Additional Volume	New P/L Size (inches)	Horsepower per Station		Investment (millions of 1975 dollars)
						new	incremental	
14	5	125	767	43			1,500	1.1
95	96	86	261	187			11,000	5.0
96	97	145	1682	561			13,000	6.5
97	98	145	1680	50			3,000	1.9
98	99	95	1680	36			1,500	0.6
124	126	97	919	366			11,000	4.2
132	134	25	404	364			10,000	2.4
142	141	129	7327	540			41,000	14.0
148	102	192	350	170			6,000	7.4
149	146	93	1482	9				*
149	147	97	37	34	8	370		6.8
152	159	140	354	10			900	0.3
166	171	238	1209	109			2,000	2.6
TOTAL								52.8

*Additional volume is insignificant

Table II-4
Natural Gas Pipeline Network Investment
1990 Medium Scenario

Origin BEA	Destination BEA	Miles	Base Capacity mmcf/d	Additional Volume	New P/L Size (inches)	Horsepower per Station		Investment (millions of 1975 dollars)
						new	incremental	
14	5	125	767	31			1,500	1.1
93	96	145	1680	10				*
95	96	86	261	205			15,000	6.3
96	97	145	1682	651			19,000	9.2
97	98	145	1680	140			3,000	1.9
98	99	95	1680	126			3,300	1.3
99	104	97	1680	92			3,300	1.3
102	108	149	396	137			6,400	6.3
109	111	84	3111	17				*
118	117	86	764	73			1,600	0.8
124	126	97	919	827			46,000	13.6
148	102	192	350	298			18,000	18.3
149	146	93	1482	42			1,000	0.4
149	147	97	37	34	8	370		*
TOTAL								67.3

*Additional volume is insignificant

Table II-5
Natural Gas Pipeline Network Investment
1990 High Scenario

Origin BEA	Destination BEA	Miles	Base Capacity mmcf/d	Additional Volume	New P/L Size (inches)	Horsepower per Station		Investment (millions of 1975 dollars)
						new	incremental	
14	5	125	767	120			3,500	2.4
80	79	82	3312	33				*
93	95	145	1680	535			13,000	6.5
95	95	86	261	235			20,000	8.1
96	97	145	1682	1204			48,000	20.1
97	98	145	1680	687			19,000	9.2
98	99	95	1680	673			19,000	6.1
99	104	97	1680	638			19,000	6.1
102	108	149	396	99			4,000	4.7
106	113	64	616	251			4,800	2.4
109	111	84	3111	22				*
124	126	97	919	572			20,000	7.2
148	102	192	350	294			18,000	18.3
149	146	93	1482	36			1,000	0.4
149	147	97	37	34	8	370		6.8
TOTAL								98.3

*Additional volume is insignificant

Figure II-7.
BEA Economic Areas

Summary

The cost estimates given in this chapter are stated in dollars of many different years both past and projected. Table II-6 gives factors assumed in this study for conversion to 1980 dollars. These factors are used to adjust the investment amounts given in this chapter. Canadian dollars are assumed to convert at 0.86 U.S. dollars.⁽³²⁾ The total investment requirement is given in Table II-7 in 1980 U.S. dollars for the 10-year period to 1990. Projects to be completed by 1985 plus one-half of projects not completed until 1990 are summed to compute 1985 investment requirements. An analysis of 1995 investment requirements in a declining market requires detail equivalent to the 1990 estimate and is beyond the scope of this study.

⁽³²⁾ 1979-1980 Average rounded - Riggs National Bank, Washington, D.C.

Table II-6
Assumed GNP Deflators
1972 = 1.000

Year	Index	Factor to 1980 Dollars
1974	1.160	1.548
1975	1.271	1.412
1976	1.337	1.344
1977	1.417	1.267
1978	1.520	1.182
1979	1.655	1.086
1980	1.796	1.000
1981	1.944	0.924
1982	2.106	0.853

SOURCE: EIA (Historical series
based on U.S. Department of Commerce statistics.)

Table II-7
Summary of Natural Gas
Transportation Investment Requirement
(1980 dollars in millions)

Project	SCENARIO		
	Low	Medium	High
Pac Indonesia	279.4	279.4	279.4
LNG Tankers	345.1	345.1	345.1
Pathfinder Pipeline	105.3	105.3	105.3
Trailblazer Pipeline	492.6	492.6	492.6
Alaska:			
Alaska Segment	11,000.0	11,000.0	11,000.0
Canadian Segment	7,055.0	7,055.0	7,055.0
Northern Border	2,500.0	2,500.0	2,500.0
Network Expansion	74.6	95.0	138.8
TOTAL 1990	21,852.0	21,872.4	21,916.2
1985	11,397.5	11,407.7	11,429.6

CHAPTER III. CRUDE OIL

Introduction

Table III-1 shows historical and projected data for oil demand. Demand for crude oil is projected to decline through 1985 at a rate somewhat behind of the demand for final products reflecting a trend toward greater reliance on domestic refining capacity. After 1985, the growth in demand for crude oil corresponds more closely with the growth in demand for refined products. The medium and high world oil price scenarios reflect the effect of price on domestic oil production, demand for oil and therefore on imports of crude oil. In the low price scenario imports of crude oil must grow beyond an initial drop through 1985 to offset lagging production (neither shale nor syncrude is economic in the low price scenario) and meet higher demands.

Domestic demand for crude oil, together with the decline of crude oil imports, is the result of lower demand and increased new domestic supplies from non-traditional sources, especially in the medium and high world oil price scenarios. Some investment in the transportation facilities, primarily pipelines, will be necessary to ship these new supplies to refineries. These new supplies include increased production in Alaska, new shale oil and synthetic crude projects, production from the Atlantic outer continental shelf, and enhanced oil recovery in traditional areas. The enhanced oil recovery retards the decline of production in traditional producing areas which are already amply supplied with transportation capacity. New sources of supply on the other hand, will require new facilities to bring crude oil to refineries.

Table III-1
U.S. Oil Demand
(Thousands of Barrels)

Year	CRUDE OIL			PETROLEUM PRODUCTS*		
	Growth (%)	Total Demand ¹	Imports	Growth (%)	Demand ²	Imports
1973		4,537,254	1,234,157		6,317,303	1,049,336
1974	2.1	4,631,602	1,313,383	-3.8	6,078,239	917,564
1975	1.7	4,709,283	1,511,166	-2.0	5,957,515	699,169
1976	7.9	5,081,361	1,946,747	7.2	6,390,750	729,664
1977	7.6	5,468,348	2,425,566	5.3	6,727,468	788,902
1978	0.6	5,500,780	2,329,729	1.8	6,845,057	722,885
1979	-0.8	5,456,668	2,384,946	-0.8	6,793,014	685,119
1985 L	-0.03	5,443,870	1,692,810	-2.1	5,968,410	401,250
M	-1.0	5,123,940	1,759,300	-3.0	5,645,690	395,940
H	-1.5	4,994,520	1,583,790	-3.5	5,490,150	373,110
1990 L	1.2	5,790,840	2,553,370	1.4	6,391,860	439,930
M	0.2	5,185,080	1,678,540	0.3	5,727,150	396,910
H	-0.1	4,967,200	1,341,650	-0.1	5,461,400	364,440
1995 L	0.6	5,978,950	3,033,500	1.5	6,874,630	675,910
M	0.2	5,233,540	1,701,530	0.3	5,808,080	390,860
H	-0.4	4,870,000	1,043,420	-0.3	5,372,550	345,540

SOURCES:

¹Historical: Energy Data Reports: Gross input to refinery distillation units.

Projected: MEFS: Crude plus co-products supply/demand balance.

²Historical: U.S. Department of Energy, Energy Data Reports: All products of refineries less changes in stocks.

Projected: MEFS: Demand for all oils including liquified gasses and refinery fuel.

*Inputs to refineries plus product imports are less than demand by the amount of refinery gain plus the amount of unrefined products, principally liquid gasses, plus statistical errors. In the projected data the difference is equal to refinery gains plus calculation differences between the supply and demand models in MEFS.

The modal characteristics in the shipment of crude oil are summarized in Table III-2. The most consistent data sources are reports from refineries indicating method or mode of receipt of crude oil. Since this is taken at one point in the process, the modal shares are additive. However, a pipeline receipt or other modal receipt at a refinery may have begun its journey on another mode. Obviously, overseas crude oil at inland refineries came first by tanker to a port and subsequently by another mode, most likely pipeline. If Canadian crude oil is subtracted from foreign pipeline receipts and the remainder added to foreign water receipts, the amount is still only 85 percent of what water carriers reported as total carriage of foreign crude oil imports. Much of the difference may be due to transshipment by other modes, changes in storage, and statistical errors between the two separate sources. Despite these difficulties, it is important, though often overlooked, to assess the degree of intermodalism when discussing modal shares in the movement of any commodity. From the data given on Table III-2 it would appear that 36 percent of crude oil employed some intermodal transportation. This figure is probably understated by the amount of movement by intrastate pipelines.⁽¹⁾

The approach to analysis in this chapter relies on a simple network structure illustrated in Figure III-1. Intermodalism is permitted in the network, particularly for Alaskan and foreign tanker movements to port areas. An analysis of the degree of intermodalism in the network solution for the medium scenario shows a 30 percent or greater intermodal interaction. Additional intermodalism is possible due to the

⁽¹⁾The 64 percent pipeline share includes only major interstate pipeline systems.

Table III-2

1977 Crude Oil Transportation by Mode
(thousands of barrels per year)

Crude Receipts by Refineries ^{1/}	5,344,834	Percent
Pipeline: Total	3,096,694	58
Foreign (101,778 Canadian)	567,752	
Domestic	2,528,942	
Tank Cars and Trucks	94,393	2
Water: Total	2,153,747	40
Foreign	1,834,668	
Domestic	319,079	
	TOTAL %	100
Total Waterborne Carriage ^{2/}	3,276,443	61
Foreign	2,708,172	
Domestic	568,271	
Barge	329,808	(6)
Tanker	238,463	
Interstate Pipeline Originations (1976) ^{3/}	3,434,362	64
Class I Railroad Originations ^{4/}	3,487	0
Class I Motor Carriers Originations ^{5/}	8,205	
All Motor Carriers ^{6/}	601,771	11
	TOTAL %	136

- SOURCES: 1/ Dept. of Energy, Energy Data Reports.
2/ Corps of Engineers, Waterborne Commerce Statistics.
3/ Interstate Commerce Commission, Transport Statistics, Part 6: Pipelines (1976 data is latest).
4/ I.C.C., Freight Commodity Statistics, Class I Railroad.
5/ I.C.C., Freight Commodity Statistics, Motor Carriers of Freight.
6/ Association of Oil Pipelines estimate based on data from Source 1/ and the American Trucking Assoc.

lack of modal specification in the network for "local" shipments to refineries within the oil producing regions. These are outlined in heavy black in the figure. Local shipments may cover a very large area to refineries within each oil region. Sixty-five percent of receipts in the network solution were local shipments. This percentage contains pipelines, barges, trucks and railroads which may be combined intermodally to obtain an even higher intermodal interaction.

In the following analysis, pipelines and tankers are considered within the context of the network only. Pipeline capacity inside of a local shipment area is assumed to be sufficient. Barge and towboat requirements are computed on the basis of 6 percent of the total volume of crude oil.⁽²⁾ Rail tank cars have less than 1 percent of the traffic and are not considered in the study. Also, due to sketchy data and the short haul nature of truck shipments, this mode is excluded.

The Network Analysis of Pipelines and Tankers

In Figure III-1 the MEFS oil producing regions, labeled 02 through 0C, are redrawn as noncontiguous regions depicting the areas of most significant oil producing activity and most intensive pipeline gathering systems.⁽³⁾ These oil producing regions were drawn with the aid of maps prepared by the American Petroleum Institute (API).⁽⁴⁾

⁽²⁾ Only 0.3 percent is specifically accounted for in the network. The remaining 5.7 percent occurs in the local shipment areas of the network.

⁽³⁾ Regions 01 and 0D are Alaska and Alaska, North Slope respectively and are not on the figure.

⁽⁴⁾ API, Crude Oil Pipeline Map of the United States and Southern Canada, 1975.

In addition to defining the geographic scope of the MEFS oil producing regions, the MEFS refining regions were subdivided to identify refineries located within oil producing regions and those located outside of the oil producing regions. The API map and a NPC publication on pipeline capacities ⁽⁵⁾ were referenced and updated to draw the pipeline connections characterized as arrows on Figure III-1. These arrows represent one or more pipelines. The solid line arrows represent existing pipelines; the dashed lines, planned pipelines; and the dashed-dotted lines, products pipelines which ship crude oil in batches. The Northern Tier pipeline is specified in the MEFS assumptions for transshipment of Alaskan crude inland. The assumed capacities for each pipeline link are given in the figure. These were taken from data provided in the NPC publication on capacity. ⁽⁶⁾

The subdivision of MEFS refining regions into 28 refining centers was done on the basis of proportion of existing and planned capacity of refineries. Table III-3 gives the capacity data and final allocations of crude to 28 refining regions for each of the three scenarios analyzed in this study.

The MEFS solutions are computed based on a 14 by 7 inter-regional transportation cost of matrix. The resulting inter-regional flows are greatly simplified from what may reasonably be expected. While the supply-demand balance computed by MEFS is the product of a sophisticated analysis, the distributional patterns computed are not. Therefore, the allocation of crude oil supply regions to refining regions must

⁽⁵⁾ National Petroleum Council, Petroleum Storage and Transportation Capacities, Vol. III Petroleum Pipeline, NPC, Washington, D.C., Dec. 1979.

⁽⁶⁾ Ibid.

TABLE III-3

Allocation of Projected Refinery
Receipts to Sub-Regions
(000 bbls per day)

Refining Center*	Capacity in Place 1/1/79 (000) <u>1</u> /	Planned New Capacity <u>1</u> /	1990 Crude Receipts MEFS Scenarios		
			High	Medium	Low
R1	1,591.4		1,551.0	1,551.0	1,551.0
R1.1	1,404.8	37.5	1,370.8	1,370.8	1,370.8
R1.2	79.6	3.0	78.5	78.5	78.5
R1.3	107.0		101.7	101.7	101.7
R2	2,782.7		3,068.0	3,068.0	3,068.0
R2.1	1,971.0	71.0	2,195.5	2,195.5	2,195.5
R2.2	767.8		825.3	825.3	825.3
R2.3	43.9		47.2	47.2	47.2
R3	7,559.1		3,114.3	3,712.6	4,980.6
R3.1	6,985.4	652.8	2,896.6	3,453.4	4,632.6
R3.2	48.0		18.4	21.5	28.9
R3.3	214.9		81.6	97.3	130.6
R3.4	168.5		63.9	76.4	102.4
R3.5	93.0		35.4	42.0	56.5
R3.6	49.2		18.4	22.0	29.6
R4	572.0		417.2	436.7	486.7
R4.1	374.5	7.8	275.4	287.9	321.0
R4.2	34.6		24.4	26.0	29.0
R4.3	163.0		117.4	122.8	136.7
R5	2,933.0		2,521.3	2,479.7	2,891.2
R5.1	1,099.0	4.0	925.0	909.8	1,060.8
R5.2	1,297.0	69.1	1,145.9	1,128.0	1,314.0
R5.3	397.4		333.3	327.8	382.2
R5.4	95.6		80.3	77.9	92.0
R5.5	44.0		36.8	36.2	42.2

* Refining centers are as shown in Figure III-1 with the exception of Alaska, R5.4 and Hawaii, R5.5.

Table III-3 (Continued)

Refining Center*	Capacity in Place 1/1/79 (000) <u>1/</u>	Planned New Capacity <u>1/</u>	1990 Crude Receipts MEFS Scenarios		
			High	Medium	Low
R6	272.5		272.0	272.0	272.0
R6.1	208.0		203.9	203.9	203.9
R6.2	19.6		19.2	19.2	19.2
R6.3	44.9	5.0	48.9	48.9	48.9
R7	1,424.4		1,437.0	1,437.0	1,437.0
R7.1	912.2	22.0	928.2	928.2	928.2
R7.2	187.0		185.8	185.8	185.8
R7.3	257.9		256.2	256.2	256.2
R7.4	61.6		61.2	61.2	61.2
R7.5	5.6		5.6	5.6	5.6

SOURCES: 1/ DOE/EIA, "Petroleum Refineries in the U.S. and U.S. Territories as of January 1, 1979, Energy Data Reports, June 1979.

be adjusted to make rational use of the existing pipeline network. The principal form of adjustment allows small amounts of crude to be shifted from one refining region to another to permit local shipment of crude to all refineries within the boundaries of an oil region. The second form of adjustment shifts imported crude oil from East Coast receiving points to Gulf Coast receiving points because some eastern region refineries are served via pipeline from inland not coastal sources. Tables III-4 through III-9 give the original and modified interregional flows for each of the three scenarios. The column and row totals are the same in both cases in order to be true to MEFS. The distribution is changed only as necessary to be rational with the network given in Figure III-1.

Interregional Pipeline Requirements

The modified distribution is input to the network and solved by hand, using a flow chart method. Figures III-2, III-3 and III-4 are the flow chart solutions to each scenario. The result of each network solution is an allocation of needed new capacity to specific pipeline links.

The new capacity required by the network solution is given an estimated capital cost through use of the Oil Pipeline Investment Algorithm developed in an earlier phase of this study.⁽⁷⁾ This algorithm is similar to the Gas Pipeline Investment Algorithm described in the previous chapter. Tables III-10, III-11 and III-12 summarize new pipeline building called for in the network with the outputs of the

⁽⁷⁾ U.S. Department of Energy, Capital Requirements for the Transportation of Energy Materials, prepared by TERA, Inc., Arlington, VA, for the Federal Energy Administration, Washington, D.C., February 1978.

TABLE III-4

Projected Interregional Flows of Crude Oil 1990 Low Scenario
(thousands of barrels per day)

Oil Region	Refining Region							Totals
	R1	R2	R3	R4	R5	R6	R7	
OD/01	25.0		125.0	301.4	1326.6	25.0		1803.0
02					1452.3			1452.3
03					112.3			112.3
04							322.0	322.0
05		270.6		185.3				455.9
06		21.8					1115.0	1136.8
07		128.6	1003.1					1131.7
08			272.1			245.6		517.7
09		412.8						412.8
0A		268.8						268.8
0B						1.4		1.4
0C	76.3							76.3
S1								
SY								
Domestic	101.3	1102.6	1400.2	486.7	2891.2	272.0	1437.0	7691.0
Foreign	1449.7	1965.4	3580.4					6995.5
TOTAL	1551.0	3068.0	4980.6	486.7	2891.2	272.0	1437.0	14686.5

TABLE III-5

Projected Interregional Flows of Crude Oil 1990 Low Scenario (Modified)
(thousands of barrels per day)

Oil Region	Refining Region							Totals
	R1	R2	R3	R4	R5	R6	R7	
OD/01	25.0	45.3	27.3	36.4	1326.6	25.0	317.4	1803.0
02					1452.3			1452.3
03					112.3			112.3
04			97.7				224.3	322.0
05				450.3			5.6	455.9
06		249.1					889.7	1136.8
07		226.3	905.4					1131.7
08			517.7					517.7
09		412.8						412.8
0A	78.5	171.1				19.2		268.8
0B						1.4		1.4
0C	76.3							76.3
S1								
SY								
Domestic	179.8	1102.6	1548.1	486.7	2891.2	45.6	1437.0	7691.0
Foreign	1371.2	1965.4	3432.5			226.4		6995.5
TOTAL	1551.0	3068.0	4980.6	486.7	2891.2	272.0	1437.0	14686.5

TABLE III-6

Projected Interregional Flows of Crude Oil 1990 Medium Scenario
(thousands of barrels per day)

Oil Region	Refining Region							Totals
	R1	R2	R3	R4	R5	R6	R7	
OD/01	25.0	263.34	125.0	436.66	1000.8	25.0		1875.9
02			177.5		1363.2			1540.7
03					115.7			115.7
04							359.3	359.3
05		502.0						502.0
06		128.9					1077.7	1206.6
07		134.1	1043.5					1177.6
08			284.2			245.0		529.2
09		439.0						439.0
0A		282.7						282.7
0B						2.0		2.0
0C	77.6							77.6
S1			250.0					250.0
SY								
Domestic	102.6	1750.04	1880.2	436.66	2479.7	272.0	1437.0	8358.2
Foreign	1448.4	1317.9	1832.4					4598.8
TOTAL	1551.0	3067.94	3712.6	436.66	2479.7	272.0	1437.0	12956.9

TABLE III-7

Projected Interregional Flows of Crude Oil 1990 Medium Scenario (Modified)
(thousands of barrels per day)

Oil Region	Refining Region							Totals
	R1	R2	R3	R4	R5	R6	R7	
OD/01	25.0	165.7	125.0	186.7	1000.8	25.0	347.7	1875.9
02			177.5		1363.2			1540.7
03					115.7			115.7
04			97.7				261.6	359.3
05		502.0						502.0
06		128.9	250.0				827.7	1206.6
07		231.8	945.8					1177.6
08			303.4			225.8		529.2
09		439.0						439.0
0A	78.5	185.0				19.2		282.7
0B						2.0		2.0
0C	77.6							77.6
S1				250.0				250.0
SY								
Domestic	181.1	1652.4	1899.4	436.7	2479.7	272.0	1437.0	8358.3
Foreign	1369.9	1415.6	1813.2					4598.7
TOTAL	1551.0	3068.0	3712.6	436.7	2479.7	272.0	1437.0	12956.0

TABLE III-8

Projected Interregional Flows of Crude Oil 1990 High Scenario
(thousands of barrels per day)

Oil Region	Refining Region							Totals
	R1	R2	R3	R4	R5	R6	R7	
OD/01	25.0	282.8	125.0	17.2	1031.8	25.0		1906.8
02			189.1		1370.8			1559.9
03					118.7			118.7
04							376.0	376.0
05		520.9						520.9
06		145.7					1061.0	1206.7
07		137.9	1071.0					1208.9
08			294.2			244.3		538.5
09		457.1						457.1
0A		298.1						298.1
0B						2.7		2.7
0C	78.4							78.4
S1			400.0					400.0
SY		32.4						32.4
Domestic	103.4	1874.9	2079.3	417.2	2521.3	272.0	1437.0	8705.1
Foreign	1447.6	1193.1	1035.0					3675.7
TOTAL	1551.0	3068.0	3114.3	417.2	2521.3	272.0	1437.0	12380.8

TABLE III-9

Projected Interregional Flows of Crude Oil 1990 High Scenario (Modified)
(thousands of Barrels per day)

Oil Region	Refining Region							Totals
	R1	R2	R3	R4	R5	R6	R7	
OD/01	25.0	185.1	125.0	17.2	1031.8	25.0	497.7	1906.8
02			189.1		1370.8			1559.9
03					118.7			118.7
04			97.7				278.3	376.0
05		520.9						520.9
06		145.7	400.0				661.0	1206.7
07		235.6	973.3					1208.9
08			313.4			225.1		538.5
09		457.1						457.1
0A	78.5	200.4				19.2		298.1
0B						2.7		2.7
0C	78.4							78.4
S1				400.0				400.0
SY		32.4						32.4
Domestic	181.9	1777.2	2098.5	417.2	2521.3	272.0	1437.0	8705.1
Foreign	1369.1	1290.8	1015.8					3675.7
TOTAL	1551.0	3068.0	3114.3	417.2	2521.3	272.0	1437.0	12380.8

Figure III-2
Crude Oil Pipeline Network Solution Flow Chart
1990 Low Scenario

Figure III-3

Crude Oil Pipeline Network Solution Flow Chart
1990 Medium Scenario

Figure III-4

Crude Oil Pipeline Network Solution Flow Chart
1990 High Scenario

Table III-10
Crude Oil Pipeline Investment
1990 Low Scenario

Origin Destination	Throughput (MBD)	Distance (miles)	Elevation Change (feet)	Pipe Diameter & Wall Thickness (inches)	Pumping Station Horsepower	Number of Stations	Investment Millions of 1980 Dollars	Comment
Four Corners - Midland, TX	277.7	500	-3500	28 X .2201	1567	5	145.4	New pipeline parallel to 16" Tex.-N.M. line
Port Angeles, WA Clearbrook, MN	399.1						1548.0	Northern Tier Proposal
Beaumont, TX - Cushing, OK	71.6	480	+1000		add 1200	5 & 6	.8	Expansion of Texoma and Seaway
St. James, LA - Patooka, IL	99.1	624	+ 500		add 2900	9	9.6	Expansion of Capline
Baltimore Canyon- Shore Line	76.3	75	+ 600	14 X .1948	1233	2	42.2	New line offshore
Shore Line - Philadelphia	76.3	60	+ 50	16 X .1643	867	1	9.7	New line
TOTAL							1755.7	

Table III-11
Crude Oil Pipeline Investment
1990 Medium Scenario

Origin Destination	Throughput (MBD)	Distance (miles)	Elevation Change (feet)	Pipe Diameter & Wall Thickness (inches)	Pumping Station Horsepower	Number of Stations	Investment Millions of 1980 Dollars	Comment
Long Beach - Four Corners	149.6	600	+4500	16 X .1455 loop	add 1000	11	101.8	Loop and increase of hp on existing 16" line
Four Corners - Midland, TX	472.9	500	-3500	34 X .2631	1644	5	192.9	new pipeline parallels to 16" Tex.-N.M. line
Fort Angeles WA- Clearbrook, MN	700.0						1548.0	Northern Tier Proposal
Gurnsey, WY - Humbolt, KS	92.1	730	-5000	18 X .1569	822	7	121.9	New line parallel to 24" AMOCO line
Shale Region - Wyoming P/L	250.0	50	0	26 X .2066	1666	1	14.0	New line
Baltimore Canyon- Shore line	77.6	75	+ 600	14 X .1994	1288	2	42.4	New line offshore
Shore line - Philadelphia	77.6	60	+ 50	18 X .1569	508	1	10.6	New line
TOTAL							2031.6	

Table III-12
Crude Oil Pipeline Investment
1990 High Scenario

Origin Destination	Throughput (MBD)	Distance (miles)	Elevation Change (feet)	Pipe Diameter & Wall Thickness (inches)	Pumping Station Horsepower	Number of Stations	Investment Millions of 1980 Dollars	Comment
Long Beach - Four Corners	161.1	600	+4500	16 X .1455 loop	add 1100	11	102.1	Loop and increase hp on existing 16" line
Four Corners - Midland, TX	504.7	500	-3500	36 X .2783	2030	5	209.7	New pipeline parallels to 16" Tex.-N.M. line
Port Angeles, WA- Clearbrook, MN	700.0						1548.0	Northern Tier Proposal
Gurnsey, WY - Humbolt, KS	93.9	730	-5000	18 X .1590	889	7	122.4	New pipeline parallels to 24" AMOCO line
Shale Region - Wyoming P/L	400.0	50	0	32 X .2483	2233	1	18.6	New line
Baltimore Canyon Shore line	78.4	75	+ 600	14 X .2023	1323	2	42.4	New line offshore
Shore line - Philadelphia	78.4	60	50	18 X .1569	523	1	10.6	New line
TOTAL							2053.8	

Oil Pipeline Investment Algorithm. These outputs describe the pipeline to be built and give its cost in 1980 dollars. The pipelines are designed on the basis of lowest average unit cost for the desired throughput, distance and change in elevation. In some cases an existing pipeline is duplicated with the Algorithm and additional horsepower computed to expand its capacity to meet the larger throughput. These investments constitute strategic requirements under the definition given in Chapter I. Localized adjustments in gathering facilities and new pipeline interconnections may be undertaken for a variety of purposes beyond the scope of this study to examine.

Tanker Requirements

Most foreign oil imported into the United States via tanker is shipped in foreign flag tankers. These are excluded from the U.S. investment total not because they do not represent U.S. investment but because the world tanker fleet still exceeds requirements and additions to the fleet may be made by other than U.S. firms. Domestic crude oil movements by tanker will be concentrated in the Alaskan trade. At present, approximately 1.5 MMB/D of oil is being shipped from Alaska to destinations in the lower 48 states. The fleet available to carry that traffic consisted of 28 vessels totalling 3,088,500 deadweight tons of capacity.⁽⁸⁾ This results in an average efficiency of 177 barrels delivered per year per deadweight tons of capacity. Assuming an average of 8 barrels per deadweight ton each vessel makes an approximately of 22 trips per year.

(8) U.S. Maritime Administration, Merchant Fleets of The World as of 04-30-80, Computer printout of U.S. Tankers processed May 22, 1980. Totals assembled by TERA. (See Chapter IV, Table IV-4 - for summary of U.S. Tanker Fleet).

If present distribution patterns were to prevail in 1990, the Alaska throughput levels of 1711.0, 1798.0 and 1826.5 MB/D for low, medium and high scenarios would require respectively 435, 615 and 673 thousand DWT of additional capacity. However, significant amounts of Alaskan oil must be transshipped to the Gulf and east coasts via the Panama Canal. With the existence of the Northern Tier pipeline assumed in DOE's 1990 projections, the average trip length would be greatly reduced and the average productivity of the fleet increased more than the 22 percent maximum increase in the projected traffic. Therefore, given investment in the Northern Tier pipeline, no new investment will be required in tankers. However, because that investment is not assured investors may build new tankers for the Alaskan trade during the next few years until the pipeline controversies are resolved. If a pipeline is built these new tankers will either hasten the retirement of very old petroleum products carriers in the domestic trade or enter the international trade routes depending on relative economics and U.S. Maritime Administration subsidy restrictions to the extent that they apply.

The oldest tanker in the Alaska trade was built in 1958. A total of 4 tankers (189.5 DWT including one at 113.9 DWT) will be greater than 25 years old in 1990.⁽⁹⁾ Whether these or any others will be retired and replaced by that time will depend on the economics of the tanker trade during the intervening years. Considering that at present 26.4% of the tankers in domestic trade (20.4% of the capacity) are greater than 25 years old, (16.6% of tankers are greater than 30 years old) no vessels currently in the Alaskan trade will be assumed to be retired by 1990. Tankers carrying

(9) Ibid.

crude oil on other domestic routes represent a minor part of the remaining tanker fleet. Analysis of these will be included with petroleum products tankers in Chapter IV.

Deepwater Port Requirements

A significant development in the transportation of crude oil in the United States is the shift to deepwater ports. These offshore unloading facilities enable crude oil to be received in tankers too large to enter a coastal port. These tankers, often called Very Large Crude Carriers or VLCC's, are the dominate mode of long distance water transportation of oil. At present, most of the crude oil being shipped the United States from origins in the Middle East comes to Caribbean ports in VLCC's and is transshipped from there to U.S. ports in smaller tankers.

The Louisiana Offshore Oil Port (LOOP) is scheduled to begin operating sometime during the 1st quarter of 1981. Estimated total cost of the project is \$600 million (1980). Consturction of LOOP is slightly behind schedule because drilling and leaching operations (drilling the salt dome caverns) are taking twice as much time as was originally expected.

Construction work on the LOOP is more than half completed. The project entails putting bouys, gathering lines, and a pumping platform offshore in the Gulf of Mexico; and connecting the pumping platform to onshore storage coverns (Clovelly salt domes) by offshore and onshore pipelines. Four or more carrier pipelines will transport crude from the storage caverns to refining centers. One of these lines, known as "Lo-Cap" will run from Clovelly salt dome to St. James, Florida, where it will feed into the existing cap-line crude line.

Three storage cavities should be ready for use by 1981, giving LOOP an operating capacity of 525,000 barrels per day. By 1982, five more cavities will be ready for use, boosting LOOP's capacity to 1.4 MB/D. Crude from North Africa, West Africa, and Mideast and the North Sea will be brought by supertankers to the Gulf of Mexico. The supertankers will anchor at three single-point mooring buoys; and 56" gathering lines will transfer the oil to the pumping platform. The pumping platform legs have been erected in 110 feet of water on the Gulf. The actual platform and equipment should be installed by early August (1980). Forty-seven miles of 48" onshore and offshore pipeline will connect the pumping platform with Clovelly salt dome (storage caverns). The onshore line has been completed; the offshore line is now (July 8, 1980) being buried in the Gulf.

Approximately 60 percent of the crude entering the U.S. through LOOP will be fed into the Capline crude pipeline. The remaining 40 percent will be distributed by pipeline within Louisiana. Exxon plans to have a line running from Clovelly to Baton Rouge; Shell will build a line from Clovelly to Norco, Louisiana; and Texaco-City Service plans to operate a line from Clovelly through Lake Charles, Louisiana, to Port Arthur, Texas.⁽¹⁰⁾ The cost of these three connecting pipelines is estimated to be \$66.6 million.⁽¹¹⁾

Receipts of foreign crude oil at Gulf coast ports are outlined in the network to be at most 5.5 MMB/D in the low scenario. The medium and high scenarios project 3.1 and 2.2 MMB/D respectively. This foreign crude comes from unspecified

(10) Data on LOOP and connecting pipelines provided by LOOP Inc., telephone conversation.

(11) TERA, Oil Pipeline Investment Algorithm.

sources some of which may be only as far away as Venezuela. In 1979 imports via the Gulf amounted to approximately 4.2 MMB/D of which 0.7 MMB/D came from South America. All of this was handled without LOOP. Even if the higher volumes of imports projected in the low scenario occur, with the addition of LOOP the present ports would be required to handle no more than they handled in 1979. Therefore, no additional deepwater port capacity needs to be built in a strategic sense. Other reasons exist to invest in more deepwater port capacity but these are not strategic in the sense of this report therefore no estimate for investment of this type is included. The remaining unspent funds for LOOP are included in the total.

Analysis of Barge and Towboat Requirements

Table III-13 shows data used to estimate total barge capacity in barrels for tank barges certificated to carry oil in 1977. Many of these barges may also carry other hazardous substances. During 1977 total domestic barge traffic amounted to approximately 1,750,608,000 barrels of crude oil and liquid bulk petroleum products.⁽¹²⁾ Dividing total carried by carrying capacity yields a utilization rate of approximately 31 barrels delivered per year per barrel of barge capacity.

A profile of the fleets of 16 Major Regulated Barge Carriers shows an average of 23.8 Barges per towboat in the fleet.⁽¹³⁾ Although these are not major carriers of oil, this average will be assumed for the lack of the more

⁽¹²⁾ Computed by converting ton data to barrels. U.S. Army Corps of Engineers, Waterborne Commerce of the United States: Calendar Year 1977, District Engineer, Vicksburg, MS. (See Table III-2 and IV-3).

⁽¹³⁾ A.T. Kearney Inc., Domestic Waterborne Shipping Market Analysis, Inland Waterways Trade Area, Final Report, Feb. 1974, p. I-A-8.

Table III-13
Inspected Tank Barges That
May Carry Oil

April 1979

Route	No of Barges	Average Capacity (bbls)
Ocean	241	28,227
Coastwise	105	20,716
Lakes, Bays & Sounds	2997	14,319
River	262	9,008
Great Lakes	20	29,092
Coastwise/ Great Lakes	33	21,785
Other	204	17,796
Total	3862	15,324
Gross Capacity		59,183,155
less 1978 Barges	195	15,324
1977 Gross Capacity		56,194,975

SOURCE: U.S. Coast Guard, Inspected Tank Barge File, Subchapter D and O/D Tank Barges. Average Capacity computed from a sample of barges listed in a computer printout obtained from the USCG.

comprehensive data. The barges typically used by such carriers measure 195 X 35 feet with 9 foot draft. This corresponds to a 13,000 barrel capacity tank barge. At 7.4 barrels per long ton this converts to 41,800 deadweight tons (DWT) per towboat. This ratio is used to compute the number of towboats required to handle any additional barge capacity to meet 1990 traffic levels and to estimate total towboats in oil carriage service in 1977 for purposes of computing towboat fleet retirements by 1990.

Table III-14 gives an age profile of the oil tank barge fleet by percent of capacity. If the same profile is assumed to prevail in 1990, then 14.6 percent of the 1980 fleet would have to have been retired. Based on 6 percent of 1978 (peak year) crude oil volumes, 330 million barrels shipped by barge would require 10.6 million barrels of barge capacity. At 14.6 percent, 1.6 million barrels of capacity must be retired by 1990. This translates to approximately 210 thousand deadweight tons.

Table III-15 shows an age and size profile of all inspected towboats in the United States. If a similar profile is assumed to exist in 1990, then approximately 24 percent of boats presently in use would have to be retired and hence replaced. However, boats are not often fully retired, they are sold and put into less strenuous service as their age increases. The distribution of towboats is not weighted by level of service. Therefore, a more accurate representation of retirement cannot be found. The 24 percent total retirements by 1990 represents an approximately 2 percent annual retirement rate from a stable fleet size and less than 2 percent for a growing fleet. This would correspond to an average life of 50 years or more. The average age of the fleet is about 22 years, but this is heavily influenced by the larger number of vessels built in recent years. Without data

Table III-14
Age Profile Oil Tank Barge Fleet

Barges Built Before	Percent of Capacity
1949	8.8
1957	20.8
1963	35.7
1967	48.6
1970	62.8
1973	77.0
1979	100.0

SOURCE: Compute from a sampling
of the U.S. Coast Guard,
Inspected Tank Barge File,
Subchapter D and O/D Barges.

Table III-15
Profile of Towboat Fleet

Built After Jan 1	Ave HP	Horsepower Distribution (%) ^{1/}							Age Distribution (%)	No of Boats
		≤250	≤500	≤1000	≤2000	≤4000	≤8000	>8000		
1850	<u>2/</u>								1.9	130
1900	533	48.3	24.1	6.9	20.7				14.0	958
1940	1017	21.2	21.2	18.2	27.3	12.1			15.9	1089
1950	706	23.4	31.9	25.5	12.8	6.4			22.7	1554
1960	778		41.2	47.0	5.9	5.9			8.2	561
1965	1283	10.0	33.3	20.0	13.3	20.0	3.3		14.5	993
1970	1722	3.8	11.5	30.8	34.6	7.7	7.7	3.8	12.6	863
1975	3574		9.5	19.0	19.0	14.3	28.6	9.5	10.2	698
HP Distribution (%)		17.7	25.1	22.7	19.2	9.4	4.4	1.5	100.0	6846
Total/Ave	1250	1189	1686	1525	1289	631	295	101	6716	

SOURCE: Three percent sample of U.S. Coast Guard, Inspected Vessel File: Boats in Towing Service.

^{1/} Distribution adds across to 100 percent.

^{2/} Boats built before 1900 are not analyzed.

on the number of vessels built each year it is impossible to compute a true average life. Therefore, this study will assume that the age profile of vessels will remain constant until 1990 which results in a 24 percent reduction in the present fleet from service.

Assuming that the pattern of replacement and growth exists in 1990 as it has since 1975, then the distribution of towboat sizes will be the same as given in Table III-15 for boats built after January 1, 1975. Using data given in Table III-16, an average cost of \$1,871,000 in 1976 dollars is computed for boats built after January 1, 1975.

Barge sizes vary considerably depending on the area of service. Therefore, barge requirements are measured in a common unit of deadweight tons. Table III-17 presents data for computing the average cost per deadweight ton of both single skin and double skin barges. From 1970 to 1977, 33 percent of the new tank barges built were constructed with full double hulls and 20 percent with partial double hulls. The U.S. Coast Guard is presently undergoing rule-making procedures to make full double hulls mandatory on all new barges.⁽¹⁴⁾ Considering this likelihood and the wide acceptance by the industry of double hulls, the value of \$200 per DWT will be used in computing investment requirements. Table III-18 summarizes the foregoing analysis and presents the investment totals for 1990.

(14) Johnson, LCDR E. K., U.S. Coast Guard Implementation of Presidential Initiative for an Evaluation of Design, Construction and Equipment Standards for Tank Barges Which Carry Oil, U.S. Coast Guard, August 1, 1978.

Table III-16
Towboat Costs by Size
(\$1976 thousand)

Horsepower	Cost
400 - 600	300
800 - 1200	550
1400 - 1600	1,000
2800 - 3400	1,700
4000 - 4400	2,200
5000 - 6000	2,600
6100 - 7000	3,100
7100 - 8000	3,500
8100 - 9000	3,900
10,000	4,500

SOURCE: U.S. Army, Corps
of Engineers,
Unpublished.

Table III-17
Cost of Barges
(\$1976 thousand)

Size	Capacity ^{1/} (DWT)	Single Skin ^{2/}	Double Skin ^{2/}
195' X 35'	1300	275	310
240' X 50'	2800	435	515
290' X 50'	3800	570	710
Ave Cost per DWT		185	200

SOURCES: ^{1/} Capacity estimated by TERA from representative barges in USCG inspected tank barge file.

^{2/} Costs obtained from U.S. Army Corps of Engineers, unpublished data.

Table III-18
Barge and Towboat Investment
Crude Oil

	S c e n a r i o		
	Low	Medium	High
1990 Barge Traffic ^{1/} (thousand bbl.)	347,450	311,104	298,032
1978 Barge Traffic ^{2/}	330,047	330,047	330,047
Incremental Traffic (000bbl)	17,403	-18,943	-32,015
Required New Barges ^{3/} (000 DWT)	67.1	none	none
Required New Towboats ^{4/}	1.6	none	none
Replacement Barges (000 DWT)	210.0	136.9	86.4
Replacement Towboats	23.4	21.7	20.4
Total Barges (000 DWT)	277.1	136.9	86.4
Total Towboats	25.0	21.7	20.4
Investment (\$1976 million)			
Barges	55.4	27.4	17.3
Towboats	46.8	40.6	38.2

^{1/}Equal to 6 percent of U.S. crude oil demand

^{2/}U.S. Army Corps of Engineers, Waterborne Commerce of the United States. Ton data converted to barrels by a factor of 7.4 bbl/T.

^{3/}Incremental traffic divided by 31 bbl per year and bbl of capacity divided by 7.4 bbl/T.

^{4/}Based on 41,800 DWT per towboat.

^{5/}Based on \$200 per DWT average.

^{6/}Based on \$1,871,000 per towboat average.

Summary

Table III-19 summarizes the foregoing estimates of investment requirements by scenario and category of investment converted to 1980 dollars using factors given in Table II-6. Investment requirements in 1985 were computed at one half of 1990 requirements for all values except LOOP and connecting pipelines which was included in total. Accumulative investment totals by 1995 show increases over 1990 only for barge and towboat replacement. Other pipeline investments could be estimated only through additional network analyses which are beyond the scope of this study.

Clearly the Northern tier pipeline dominates the strategic investment picture for crude oil transportation in the coming years. Whether or not the Northern tier system is finally built, the problem of distributing Alaskan oil to markets in the United States remains the chief need requiring large investments in crude oil transportation facilities.

The medium and high world oil price scenarios accent on new pipeline building due to relatively greater supplies from nontraditional sources. The low world oil price scenario requires less investment in pipelines but due to growing consumption of oil will require more investment in non-pipeline modes such as barges and towboats. Investment in these modes can be made in smaller increments to respond more closely to fluctuations in demand for transportation. U.S. tanker capacity for domestic trades was considered sufficient for the immediate future.

Table III-19
Summary of Crude Oil Transportation Investment Requirements
(\$1980 millions)

	S c e n a r i o		
	low	medium	high
Interregional pipelines	207.7	483.6	505.8
Northern Tier Pipeline	1548.0	1548.0	1548.0
LOOP and connecting pipelines	366.6	366.6	366.6
Barges	74.5	36.8	23.2
Towboats	62.9	54.6	51.3
TOTAL 1990	2259.7	2489.6	2494.9
1985 ^{1/}	1313.2	1428.1	1430.8
1995 ^{2/}	2383.7	2586.4	2635.2

NOTES: ^{1/} 1985 investment equals $\frac{1}{2}$ of all values except LOOP plus all of LOOP and connecting lines.

^{2/} 1995 investment includes additions for barge and towboat only. Other investments which may be necessary to respond to shifting supplies and new discoveries is beyond the scope of the study.

CHAPTER IV. PETROLEUM PRODUCTS

Introduction

Total demand for petroleum products is projected to decrease by 1990 with a noteable drop from 1978 demand in 1985 for all three scenarios. Table IV-1 shows historical and projected demand for all petroleum products by product type. Also listed is a total for products capable of being shipped in pipelines.

Nearly 79 percent of all products capable of being shipped in pipelines are shipped in pipelines. Table IV-2 presents data used to calculate modal share for products pipelines. This modal share is stated in terms of share of pipeable products. As a share of all products of petroleum refineries, pipelines constitute approximately 60 percent.

Tankers and barges, on the other hand, may carry any petroleum products. Table IV-3 shows the amount of various liquid bulk products carried by barge and tanker in 1977. compared with total production for 1977, barges and tankers show a 21.7 and a 14.5 percent modal share, respectively. Because of the way that the data was collected, these shares are additive for a total of 36.2 percent for water modes in the transportation of petroleum products.

Both trucks and railroads carry petroleum products. However, railroads have a very small share in the total volume produced and transported. Therefore, they are excluded from the analysis. Trucks are excluded because they are used almost exclusively for local distribution of products.

The following analysis is based on the assumption that present modal shares will prevail.

Table IV-1

Production of Petroleum Products
(millions of barrels per year)

Year (Scenario)	Gasoline	Jet Fuel	Distillate Fuel Oil	Residual Fuel Oil	Liquid Petroleum Gasses	Naptha	Other	Total ^{1/}	Total ^{2/} Pipeable	
1976	2567.2	361.4	1208.6	1025.1	696.9		349.9	6209.1	4834.1	
1977	2633.5	379.3	1287.3	1120.9	740.3		375.0	6536.3	5040.4	
1978	2719.5	385.7	1316.6	1103.2	774.5		380.3	6679.8	5196.3	
1979	2580.1	391.7	1276.3	1029.9	869.4		377.6	6525.0	5117.5	
1985	low	2345.8	540.1	1105.2	487.9	453.4	448.7	316.6	5697.7	4893.2
	med	2276.8	410.9	1045.0	449.3	444.6	445.6	315.5	5387.7	4622.9
	high	2134.9	498.0	1000.5	429.1	425.1	442.2	314.3	5244.1	4500.7
1990	low	2323.2	629.6	1230.9	585.8	455.3	552.7	360.2	6094.4	5195.4
	med	2170.4	446.5	1106.8	406.2	428.6	542.9	358.0	5459.4	4695.2
	high	1974.2	542.8	1034.7	369.7	402.3	533.3	355.7	5212.7	4487.3
1995	low	2529.5	732.3	1325.2	428.5	456.6	644.9	403.6	6520.6	5688.5
	med	2251.1	487.4	1113.9	236.6	412.1	626.6	400.6	5527.9	4890.7
	high	1956.8	588.5	981.8	199.6	375.2	611.4	453.5	5166.8	4513.7

1/ Still gasses omitted

2/ Equal to gasoline, jet fuels, distillate, LPG, and Naptha.

SOURCE: Historical: U.S. Department of Energy, Energy Data Reports, Petroleum Statement, Annual.
Projected: U.S. Department of Energy, Mid-Range Forecasting System.

Table IV-2

Pipeline Modal Share Petroleum Products
(millions of barrels per Year)

Year	Trunkline Movements <u>1/</u>	Pipeable Products Demand <u>2/</u>	Modal Share
1973	3633.1	4737.9	.7668
1974	3588.8	4579.4	.7837
1975	3645.5	4544.9	.8021
1976	3813.2	4834.1	.7883
TOTAL	14680.6	18696.3	.7852

SOURCES: 1/ Interstate Commerce Commission, Transport Statistics in the United States, Part 6: Pipelines

2/ U.S. Department of Energy, Energy Data Reports, Petroleum Statement, Annual; and
U.S. Bureau of Mines, Mineral Industries Surveys, Petroleum Statement, Monthly; Annual Summary

Table IV-3

Tank Barge and Tanker Totals
 Petroleum Products 1977
 (millions of Barrels per Year)

Product	Barge	Tanker
Gasoline	410.3	308.8
Jet Fuel	44.5	44.3
Kerosene	17.0	21.2
Distillate Fuel Oil	333.9	267.7
Residual Fuel Oil	523.9	253.3
Lube Stocks	17.5	17.8
Napthas & Solvents	26.3	18.1
Asphalt	34.5	17.5
LPG's	12.9	-
TOTAL Water Mode	1420.8	948.8
TOTAL Production	6536.3	6536.3
Modal Share (%)	21.7	14.5

SOURCE: U.S. Army, Corps of Engineers,
Waterborne Commerce of the United
States, Calendar Year 1977. Ton
 data converted to barrels.

Investment in Products Pipelines

Figure IV-1 shows a graph of historical and projected volumes of production and consumption of pipeable petroleum products. The 1978 peak production level of 5196.3 million barrels is not exceeded until approximately 1991 in any of the scenarios. Until that time no investment would be needed strictly to handle expanded demand. Some potential investment may be required to respond to shifts in population and, hence, the location of demand. Unlike crude oil and natural gas pipelines which may require significant new plant in years of declining production and consumption due to large shifts in the location of supplies, the locational relationship between supply and demand for petroleum products is subject only to show evolutionary change resulting from interregional differences in population growth or decline and interregional differences in refinery capacity expansion. Neither of these influences are expected to change the regional supply/demand balance enough to require new pipelines in a period of declining or stable consumption.

Some short distance products pipelines may be built during the period 1980-1990 in response to local conditions. These are beyond the scope of this study since such conditions cannot be anticipated. Several pipeline projects of local interest can be seen in Table IV-4 which presents a list of recently completed, under construction and currently planned products pipelines. All pipelines except LP Gas pipelines, are being built under conditions of an overall declining market. In some cases, like the Colonial Pipeline projects and the Transgulf pipeline proposal, the expansion of pipeline capacity is being made to capture traffic presently carried by water vessels. The Colonial system is catching up to demand in the Northeast and Mid-Atlantic States

Figure IV-1
Consumption of Pipeable
Petroleum Products
(MMbbl)

Table IV-4

Recently Completed or Planned
Products Pipelines

Owner	Description	Completion Date
Buckeye Pipeline	10 inch, 22 miles Lawrenceville, IL to Robinson IL	Fall 1980
Calner Pipeline	6 inch, 54 miles George AFB to Edwards AFB, CA (under construc- tion)	July 1980
Colonial Pipeline	36 inch, 140 miles Richmond, VA to Baltimore, MD (Mitchell Jct. to Dorsey Jct.)	November 1980
	12 inch, 31.6 miles Dorsey Jct. to Baltimore	December 1980
	8 inch, 8.6 miles to BWI Airport	December 1980
Exxon Pipeline	8 inch, 11 miles (ethylene) Exxon Chemical to Georgia Pacific in Baton Rouge, LA	---
	6 inch, 15 miles (ethylene) Vulcan to BF Goodrich in Baton Rouge, LA	---

Table IV-4 (Continued)

Owner	Description	Completion Date
Getty Pipeline	16 inch, 25 miles Delaware City, DE to Marcus Hook, PA	---
Gulf Central Pipeline	4.5 inch, 10 miles Argele, IA to Ft. Madison, IA	Fall 1980
Hydrocarbon Transportation Inc.	10 inch, 160 miles (LP) Bushton, KS to Plattsburg, MO (under construction)	August 1980
Mapco Inc.	8 or 10 inch, 860 miles (LP) Rock Springs, WY to Seminole, TX (planned)	1981
Shell Oil	6 inch, 11 miles Sorrento, LA to Convent, LA (planned)	March 1981
	24 inch, 14 miles Norco, LA to Garyville, LA	January 1981
	6 inch, 1.6 miles Plaquimine, LA	September 1980
Sun	12 inch, 4 miles Deleware County, PA	June 1980
	10 and 16 inch, 5 miles Corpus Christi, TX	June 1980

Table IV-4 (Continued)

Owner	Description	Completion Date
Texas Eastern Pipeline	8 inch, 33 miles Baytown, TX to LaGloria, North Houston	October 1980
	8 inch, 12.2 miles Mount Belview, TX to Baytown, TX	October 1980
Transgulf Pipeline	24 inch, 16 miles and 18 inch, 6 miles and 14 inch, 60 miles Baton Rouge to Ft Lauderdale (before FERC)	1983

the growth of which has been served by tanker. When the market becomes established it is captured by the pipeline through expansion of capacity. Any further expansion of Colonial's capacity is dependent on the long-range stability of that portion of the market being served by tankers and Colonial's access to it as well as the future growth of demand for petroleum products in the Northeast. The latter eventuality is not projected to occur and therefore, in a strategic or logistics sense, no additional capacity is needed to serve these markets. However, if for competitive reasons Colonial wishes to expand it is within that company's purview to do so. It is outside of the scope of this study to anticipate such investment.

The Transgulf pipeline proposal also represents a pipeline project undertaken for competitive rather than strategic reasons. It consists of a proposal to abandon a natural gas pipeline from Louisiana to Florida and convert it to petroleum products carriage. At present all of Florida's petroleum products needs are being supplied by barges and tankers from refineries mostly located on the Gulf coast. The Transgulf pipeline proposal is currently being contested in proceedings before the Federal Energy Regulatory Commission (FERC). With the potential for court action it is unlikely that the published schedule can be met and possibly the project never will be built. Irrespective of whether it is built or not, an assessment of investment for competitive as opposed to strategic purposes is beyond the scope of this study.

Two additional projects of significant interregional impact are shown in Table IV-4. Both of these, Mapco and Hydrocarbon Transportation Inc. (HTI), involve the construction of LP gas pipelines. LPG pipelines are specialized

facilities since these products cannot be shipped in conventional products pipelines.

As can be seen in Table IV-1 the class of products consisting of LPG and Naptha show continued growth in production and consumption through 1985, 90 and 95. The HTI pipeline essentially loops its existing line in order to provide additional capacity for a growing market. In addition to a growing market, LP Gas transportation differs from the transportation of refined petroleum products in that 70 to 80 percent of the product originates at natural gas processing plants located in and near the natural gas producing fields. Therefore, even in a market of stable or declining supply, the sources of supply will shift as new fields are opened and old ones closed. The Mapco project is planned in response to just this sort of development. It will ship LP Gasses from natural gas plants in the developing Overthrust belt to markets and interconnecting pipelines in Texas. Both of these projects fit the definition of strategic investment required to get supplies to market.

The HTI project is complete now and undergoing pressure testing prior to commencement to service. The Mapco line will cost approximately \$100 million. This much is included in the total for pipeline investment. Other potential LPG pipeline investment projects of significant size could not be determined from available information. It was suggested that significant new natural gas finds in Canada could yield a production of liquids in excess of Canadian needs and therefore available for export to the U.S. Such export is not projected by MEFS so investment to handle it is not included.

Investment in Tankers

The present U.S. tanker fleet carrying crude oil, petroleum products and other liquid bulk products in domestic trade totals 7,622,600 deadweight tons (DWT) of capacity for 163 vessels. Table IV-5 summarizes the U.S. domestic tanker fleet by trade route and age of vessels. A certain amount of flexibility exists in the use of these tankers although the largest of them are used almost exclusively in the crude oil trade where individual shipments may be made in large lots and where segregation of products is not needed.

Given that the demand for petroleum products in 1990 is lower than the 1978 peak year in all scenarios and that pipeline construction projects such as the expansion of the colonial pipeline are being undertaken which have the effect of reducing the nation's dependence on tankers in certain trade routes, the requirements for new tankers over the next ten years will be for replacement only allowing for some overall shrinkage in the size of the fleet.

From Tables III-2 and IV-3 modal shares for tankers carrying crude oil and petroleum products are 4.5 percent and 14.5 percent respectively. The crude oil modal share computed for 1977 may be regarded as a pre-Alaska pipeline modal share, valid for all other movements of crude. Using the gross production/consumption figures given for 1979 in Table III-1 an overall carriage of oil in tankers may be estimated at 1,230,537,000 barrels. Dividing by

Table IV-5

U.S. Flag Tanker Fleet in Domestic Trade
(Deadweight Tons in Thousands)

Year Built	Atlantic		Gulf		Pacific		Gulf/ Atlantic		Gulf/ Pacific		Alaska		VI & PR		TOTAL		Total ex. Alaska	
	NO	DWT	NO	DWT	NO	DWT	NO	DWT	NO	DWT	NO	DWT	NO	DWT	NO	DWT	NO	DWT
38	1	4.0	0		0		0		0		0		0		1	4.0	1	4.0
39	0		0		0		0		0		0		0		0		0	
40	1	1.5	0		0		0		0		0		0		1	1.5	1	1.5
41	0		0		0		0		0		0		0		0		0	
42	0		1	29.8	1	27.0	0		0		0		0		2	56.8	2	56.8
43	2	44.5	3	60.3	1	25.2	1	25.2	1	24.4	0		2	41.0	10	220.6	10	220.6
44	6	148.9	4	104.1	1	25.1	1	30.4	0		0		1	24.4	13	332.9	13	332.9
45	5	92.7	3	69.6	4	98.2	0		0		0		1	24.4	13	284.9	13	284.9
46		1.5	0		0		0		0		0		0		1	1.5	1	1.5
47			0		1	1.9	0		0		0		0		1	1.9	1	1.9
48			0		0		0		0		0		0		0		0	
49			0		1	28.4	0		0		0		0		1	28.4	1	28.4
50	0		0		0		0		0		0		0		0		0	
51	0		1	32.0	0		0		0		0		0		1	32.0	1	32.0
52	0		1	17.7	0		0		0		0		0		1	17.7	1	17.7
53	4	117.0	2	72.2	1	17.1	0		0		0		2	72.2	9	278.5	9	278.5
54	4	133.0	3	72.2	2	33.8	0		0		0		0		9	239.0	9	239.0
55	3	90.8	0		0		0		0		0		0		3	90.8	3	90.8
56	0		2	76.8	0		1	2.0	0		0		1	32.8	4	111.6	4	111.6
57	1	31.0	1	38.0	2	66.1	1	34.7	0		0		0		5	169.8	5	169.8
58	1	29.2	2	66.3	2	55.2	2	33.0	0		1	23.7	0		8	217.4	7	193.7
59	3	92.5	2	62.9	1	30.1	0		0		1	2.7	0		7	188.2	6	185.5

Table IV-5 (Continued)

Year Built	Atlantic		Gulf		Pacific		Gulf/ Atlantic		Gulf/ Pacific		Alaska		VI & PR		TOTAL		Total ex. Alaska	
	NO	DWT	NO	DWT	NO	DWT	NO	DWT	NO	DWT	NO	DWT	NO	DWT	NO	DWT	NO	DWT
60	4	146.6	0		0		0		0		0		0		4	146.6	4	146.6
61	1	17.3	1	25.5	1	28.7	0		0		1	49.2	0		4	120.7	3	71.5
62	0		1	45.1	1	59.6	0		0		1	114.9	0		3	197.6	2	83.6
63	1	25.4	0		0		1	25.7	0		0		0		2	51.1	2	51.1
64	1	25.4	0		0		0		0		0		1	50.0	2	75.4	2	75.4
65	0		1	16.5	0		0		0		1	67.8	0		2	84.4	1	16.6
66	3	98.1	1	36.0	0		0		0		0		0		4	134.1	4	134.1
67	0		4	114.3	0		0		0		0		0		4	114.3	4	114.3
68	0		0		0		0		0		0		0		0		0	
69	0		1	37.8	0		0		0		2	112.9	0		3	150.7	1	37.8
70	1	37.1	0		1	27.3	0		0		2	256.6	0		4	221.0	2	64.4
71	1	37.7	1	31.8	0		2	60.8	0		4	301.8	0		8	432.1	4	130.3
72	1	70.4	0		2	140.4	0		0		1	129.0	0		4	339.8	3	210.8
73	0		0		1	81.1	0		1	226.2	0		0		2	307.3	2	307.3
74	0		0		0		0		0		2	241.2	0		2	241.2	0	
75	1	11.9	1	41.8	1	40.1	0		0		1	123.4	2	130.6	6	347.8	5	224.4
76	0		0		2	298.6	1	18.0	0		1	34.5	1	91.8	5	442.9	4	408.4
77	1	90.4	1	42.0	2	74.0	0		0		3	515.6	0		7	722.0	4	206.4
78	0		0		0		0		0		3	469.7	0		3	469.7	0	
79	0		0		0		0		0		4	746.5	0		4	746.5	0	
TOTAL	47	1346.9	37	1081.8	28	1157.8	10	229.8	2	250.6	28	3088.5	11	467.2	163	7622.6	135	4534.1

SOURCE: Computed from: U.S. Maritime Administration, Merchant Fleets of The World as of 04-30-80, Computer printout "United States Tankers, Report No. E2-08", May 22, 1980.

4,534,100 DWT capacity in the non-Alaska trade yield an average utilization rate of 271 barrels per DWT of capacity. Using this utilization rate and the historical modal shares the projected fleet requirement for 1990 (other than Alaska) is as given in Table IV-6.

Assuming that the oldest vessels in the fleet in 1990 will be no older than the oldest vessels in the present fleet (32 years) then a total of 904,500 DWT of present capacity must be retired by 1990. This leaves 3,629,600 DWT of the present fleet to serve in 1990. Therefore, at an average cost of \$1300 per DWT⁽¹⁾ the necessary replacement fleet will require investment as given in Table IV-7.

Investment in Barges and Towboats

In Chapter III barge and towboat requirements were estimated based on a utilization factor 31 barrels per year per barrel of barge capacity. Towboat requirements were computed on the basis of 41,800 DWT per towboat. Retirement of the fleet is based on 1978 peak level fleet requirement times 14.6 percent for barge and 24 percent for towboats. The data supporting these retirement rates are given in Chapter III. Actual fleet capacity in 1978 as shown in Table III-13 exceeds required fleet capacity as computed based on 1977 statistics. A more sophisticated utilization rate would require consistent data for more than one year. Such data is not readily available in summary form. Therefore, the utilization factor of 31 barrels delivered per year per barrel of capacity will

(1) TERA, Inc. compiled from new tanker costs published in The Journal of Commerce.

Table IV-6

Total Capacity of Tankers Required for
Crude Oil and Petroleum Products
Except Alaska Trade 1990
(barrels in thousands)

	Scenario		
	Low	Medium	High
Total Petroleum Products	6,094,400	5,459,400	5,212,700
Crude Oil	5,790,340	5,185,080	4,967,200
Tanker Movements Petroleum Products @ 14.5%	883,688	791,613	755,841
Crude Oil @ 4.5%	260,588	233,329	223,524
Total Tanker	1,144,276	1,024,942	979,365
Required DWT (thousands)			
@ 271 bbl/DWT	4222	3782	3614

Table IV-7

Investment in Tankers for Crude Oil
and Petroleum Products
Carriage in 1980 to 1990
(DWT in thousands)

	Scenario		
	Low	Medium	High
1980 Fleet Retirement to 1990	4534.1 904.5	4534.1 904.5	4534.1 904.5
Remaining Fleet	3629.6	3629.6	3629.6
Required Fleet	4222.0	3782.0	3614.0
Replacement Fleet	592.4	152.4	- 0 -
Investment (1980 \$, million)	770.1	198.1	- 0 -

be used to estimate fleet requirements in 1990 and the excess fleet in 1978 will be subtracted from the new investment requirement.

Towboat requirements will be estimated based on the 1978 barge requirement, the 1990 barge requirement and a 24 percent retirement of 1978 fleet. The net fleet of Barges and Towboats is computed as shown in Table IV-8. Required capacity for 1990 and investment in the period 1980 to 1990 is given in Table IV-9.

Summary

The foregoing estimates are converted to 1980 dollars using factors given in Table II-6 and presented in Table IV-10.

Table IV-8

Barge and Towboat Fleet
Remaining in 1990

	Capacity and Traffic in millions of barrels
1978 Barge Traffic	1449.5
1978 Required Capacity	
Barges	46.8
Towboats (no.)	151.3
Retirements to 1990	
Barges	6.8
Towboats (no.)	36.3
Excess 1978 Barge Fleet	1.8
1990 Fleet	
Barges	41.8
Towboats (no.)	115.0

Table IV-9
Barge and Towboat Investment
Petroleum Products

	Scenario		
	Low	Medium	High
1990 Barge Traffic (MMbbl)	1322.5	1184.7	1131.2
1990 Required Capacity			
Barges (MMbbl)	42.7	38.2	36.5
Towboats (no.)	138.0	123.5	118.0
Remaining Fleet			
Barges (MMbbl)	41.8	41.8	41.8
Towboats (no.)	115.0	115.0	115.0
Required Capacity			
Barges (MMbbl)	0.9	0	0
Towboats (no.)	18.0	8.5	3.0
Investment (1976 \$ million)			
Barges	\$ 24.3	0	0
Towboats	\$ 33.7	\$ 15.9	\$ 5.6

Table IV-10

Summary of Petroleum Products Transportation
Investment Requirements
(\$1980 million)

		Scenario		
		Low	Medium	High
Pipelines		100.0	100.0	100.0
Tankers		770.1	198.1	- 0 -
Barges		24.3	- 0 -	- 0 -
Towboats		33.7	15.9	5.6
TOTAL	1990	928.1	314.0	105.6
	1985 ^{1/}	514.1	207.0	102.8
	1995 ^{2/}	1407.1	421.1	108.4

^{1/} 1985 values equal $\frac{1}{2}$ 1990 for water vessels plus 100% of pipeline investment.

^{2/} 1995 values extrapolated from 1990 based on growth in production plus $\frac{1}{2}$ of replacement investments.

CHAPTER V. COAL

Introduction

Coal production to 1990 is projected to increase greatly from current levels, Table V-1 contrasts the coal production in the MEFS regions in 1975 with 1990. A greater than two-fold increase is projected in all scenarios.

The analysis of transportation is done primarily on the basis of historical modal shares. Table V-2 summarizes data on modal activity in 1975 collected from several sources. The effects on intermodalism can be clearly seen in that the modal shares sum to greater than the production of coal. Truck movements are understated in the table by the amount transshipped from the mine to water and rail carriers. Since most coal shipments by truck are local, truck investment requirements are not estimated in this study.

The water mode in Table V-2 must be further broken down into barge traffic, domestic self-propelled vessels on the Great Lakes, in coastal trades, and in overseas trades. This is done with data given in Table V-3. No intermodalism is assumed within the water modes due to incomplete data.

The following analysis discusses each mode separately.

Table V-1
Production of Coal by Region
(million tons per year)

Region	1975	1990 Scenario		
		low	medium	high
(C1) North Appalachia	178.58	280.8	285.2	289.6
(C2) Central Appalachia	193.85	184.3	184.3	184.3
(C3) South Appalachia	24.06	13.2	13.2	13.2
(C4) Midwest	141.02	320.4	324.6	331.1
(C5) Central-West	21.10	19.1	19.1	19.1
(C6) Gulf	<u>1/</u>	71.8	71.8	71.8
(C7) North-East Great Plains	8.52	34.0	34.0	34.0
(C8) North-West Great Plains	46.34	259.0	287.7	286.1
(C9) Rocky Mountains	15.71	41.8	42.1	42.1
(CA) Southwest	14.76	65.3	66.5	66.5
(CB) Northwest	4.51	8.5	9.2	9.6
(CC) Alaska	<u>2/</u>	6.7	5.7	5.7
TOTAL	648.44	1303.8	1343.3	1353.1

SOURCES: Historical: U.S. Bureau of Mines, Coal - Bituminous and Lignite, Annual, 1975, Feb. 10, 1977.

Projected: U.S. Department of Energy, Mid-Range Energy Forecasting System.

1/ Included in C5.

2/ Included in CB.

Table V-2
Coal Modal Shares
1975
(thousand tons per year)

MEFS Coal District	Production	Mine <u>1/</u> Mouth & Truck	Rail	Percent of Region	Water <u>2/</u>	Percent of Region
C1	178,578	59,898	93,348	52	60,150	34
C2	193,852	20,384	147,552	76	107,169	55
C3	24,056	8,502	14,403	60	7,889	33
C4	141,018	26,503	99,712	71	43,561	31
C5 <u>3/</u>	21,103	15,852	5,251	25	176	1
C7	8,515	4,168	4,347	51		
C8	46,341	7,520	38,821	84		
C9	15,712	3,014	12,698	81	47	-
CA	14,755	11,471	3,284	22		
CB <u>4/</u>	4,509	3,884	625	14		
TOTAL	648,438	161,196	420,042		218,992	

SOURCE: TERA; Estimated based on Data from the U.S. Bureau of Mines, Interstate Commerce Commission and U.S. Army, Corps of Engineers. Modal estimates sum to greater than production due to multi-modal movements.

1/ Mine Mouth Generation plus complete shipments by Truck plus other.

2/ Includes Exports plus Imports.

3/ Includes C6

4/ Includes CC

Table V-3
Water Carriage of Coal
1977
(000 short tons)

	Barge	Self-Propelled	Total
Imports		1,722	1,722
Coastwise Exports		37,058	37,058
Lakewise Exports (Canada)		16,880	16,880
Coastwise	3,607	55	3,662
Lakewise		22,248	22,248
Internal	127,627	1	127,628
Local	2,758		2,758
TOTAL	133,992	77,964	211,956

SOURCE: U.S. Army, Corps of Engineers, Waterborne Commerce of the United States: Calendar Year 1977, Engineer Division, Vicksburg, Miss.

Investment in Railroad Cars and Locomotives

Railroads are the principal carriers of coal, hauling 65 percent of production in 1975. Railroads' share in 1990 will depend upon the modal characteristics in the coal-producing regions. Data from Tables V-1 and V-2 are used to compute coal originations on railroads for the three 1990 scenarios. These originations by MEFS coal regions are allocated to the railroad regions shown in Figure V-1, by factors given in Table V-4. The resulting originations for coal by railroad region are given in Table V-5 for each scenario. These values are divided by productivity measures for cars and locomotives to obtain total fleet requirements for 1990. The present fleet remaining in use in 1990 is then subtracted from the total requirement to estimate the need for new equipment. The new equipment is multiplied by a current price to obtain the total cost for the equipment.

Productivity of Cars and Locomotives

Table V-6 presents data obtained through a survey of major coal hauling railroads in the three railroad regions shown in Figure V-1. As can be seen from the table, the utilization characteristics for coal fleets differ between the regions. Since growth in coal production varies between the regions considerably, the use of separate utilization rates is essential to obtain reasonable estimates of future requirements.

In any particular year, the utilization rates (computed by dividing total originations by total number of cars) can

Figure V-1

Regional Rail Association Territories

Table V-4

Allocation of MEFS Coal Regions
to Railroad Regions

PIES Coal Region ^{1/}	Railroad Region	Percent Allocation
C1	1 Eastern	100
C2	1 Eastern	34
	2 Southern	66
C3	2 Southern	100
C4	1 Eastern	60
	2 Southern	40
C5	3 Western	100
C6	3 Western	100
C7	3 Western	100
C8	3 Western	100
C9	3 Western	100
CA	3 Western	100
CB	3 Western	100
CC	(Alaska)	-

SOURCE: TERA, Inc.

Table V-5
Coal Originations on Regional Railroads
(million tons per Year)

Railroad Region	S c e n a r i o		
	low	medium	high
Eastern	330.13	334.20	339.27
Southern	191.33	192.52	194.38
Western	308.03	332.76	331.36
TOTAL	829.49	854.48	865.01

Table V-6

1974 Productivity Measures for
Rail Transportation of Coal

Region	Originated Tons per Car per Year	Originated Tons per Locomotive per Year
Eastern	1,540	196,593
Southern	2,739	163,022
Western	4,631	152,670

SOURCE: Anderson and Desai, Rail Transportation Requirements for Coal Movement in 1980, prepared for the U.S. Department of Transportation by Input Output Computer Services Inc., Cambridge, MA, December 1976.

be influenced by factors beyond the control of the railroads. Strikes or poor weather can idle either the roads or the mines. Table V-7 presents a historical series of utilization rates for the entire nation. Data for regionalization of such a series is not available. The year 1974 was relatively high in utilization of equipment. The large increase in average car utilization in 1979 represents evidence of the increased demand for coal in 1979 carried by a decreasing fleet. This shows that car utilization can be improved in the short run. However, this may have been achieved at a loss of reliability in service and will not be considered a trend until better established. Therefore, the 1974 regional utilization rates were used to project 1990 equipment needs based on coal originations in the railroad regions.

Current Rail Fleet in Coal Service

A survey of major coal carrying railroads taken in 1974 resulted in the fleet projections given in Table V-8. The values in Table V-8 are the sample values, not the totals. The Association of American Railroads uses an estimating factor of 80 percent of all open top hopper cars and 10 percent of all gondola cars to compute the coal carrying fleet. Virtually all of the gondolas used in coal service are privately owned and used in local service. These are not analyzed in this study. Eighty percent of the entire hopper car fleet, both railroad owned and privately owned, was standardized to cars of 100 ton equivalent and listed in Table V-9 for 12 years. The 1974 total in Table V-9 is greater than the total in Table V-8 because the data reported in Table V-8 is based on a sample of railroads.

Table V-7

Average Coal Car Utilization Rates

Year	Coal Tons Originated ^{1/} (000)	Hopper Fleet ^{2/} (100 ton equiv.)	Tons per Car per Year
1968	400,142	243,905	1641
1969	405,194	241,193	1680
1970	425,920	243,935	1746
1971	380,309	247,023	1540
1972	399,525	246,501	1621
1973	400,327	238,197	1681
1974	415,632	238,226	1745
1975	429,880	244,933	1755
1976	430,007	250,020	1720
1977	437,245	247,970	1763
1978	400,300	247,010	1621
1979	473,840	241,567	1961

SOURCES: Economics and Finance Department, Association of American Railroads.

^{1/}Based on ICC Statistics.

^{2/}Based on 80 percent of total Hopper Fleet.

Table V-8
Existing and Projected Coal Carrying Equipment

	1974	1980
Eastern Region:		
Cars <u>1/</u>	126,372	151,990
Locomotives <u>2/</u>	990	1,126
Southern Region:		
Cars	40,317	54,183
Locomotives	675	801
Western Region:		
Cars	14,206	59,916
Locomotives	-	1,890
TOTAL:		
Cars	180,895	266,089
Locomotives	-	3,817
Cars per Locomotive		69.7

SOURCES: Anderson and Desai, Rail Transportation Requirements for Coal Movement in 1980, prepared for the U. S. Department of Transportation by Input Output Computer Services, Inc., Cambridge, MA, Dec. 1976. Based on a survey of major coal carrying railroads.

1/ 100 Ton equivalent.

2/ 3000 hp equivalent.

Table V-9
Open Hopper Car Turnover

Year	Coal Hopper Fleet ^{1/}	Delivered ^{2/} New Cars	Annual Retirements	Percent ^{3/}
1968	243,905	11,770	-	-
1969	241,193	8,006	10,718	4.4
1970	243,935	11,945	6,203	2.3
1971	247,023	14,034	10,946	4.5
1972	246,501	6,149	6,671	2.7
1973	238,197	2,526	10,830	4.4
1974	238,226	6,321	6,292	2.6
1975	244,933	17,878	11,171	4.7
1976	250,020	14,944	9,857	4.0
1977	247,970	8,850	10,900	4.4
1978	247,010	12,164	13,124	5.3
1979	241,567	10,056	15,499	6.3
Average				4.1

SOURCE: Computed from Data given in Association of American Railroads, "Coal and the Railroads - 1979," Background on Transportation, a 1979 update paper to be published in June 1979.

^{1/} 100 Ton equivalent.

^{2/} Assumed to be 100 Tons each.

^{3/} Percent of previous year's fleet retired by the year indicated.

The 1974 survey also provided information on locomotives in coal service. Although the western railroad owners said that they drew their locomotives for coal from a general pool, they did project locomotive requirements for coal service in 1980. Given these projections, an overall ratio of 69.7 cars per locomotive is computed for coal service. This is used to compute the number of locomotives in coal service for 1979 based on 241,567 cars (see Table V-9).

Not all of the cars and locomotives presently in service will continue to be used in 1990. To compute the new and rebuilt cars which will be needed for coal carriage in 1990, the remaining fleet of those cars now in use must be computed. Table V-9 shows a computation of average retirements of hopper cars as a percent of the total fleet. Eleven years times the average annual retirement equals 108,947 cars which need to be purchased just to maintain the 1979 fleet size in 1990. Similarly, data from Table V-10 permits calculation of average retirements for locomotives. The 1979 locomotive fleet in coal service is estimated, based on 69.7 cars per locomotive, to be 3,466. In order for that many locomotives to be available in 1990, a total of 1,525 locomotives must be purchased in the intervening years to replace retirements.

Investment in Cars and Locomotives

In addition to the cars and locomotives purchased to maintain present fleet levels, growth in coal traffic will require additional equipment purchases. Using the data given in Tables V-5 and V-6, total regional fleet requirements were computed for three scenarios in 1990.

Table V-10
Locomotive Fleet Turnover

Year	Locomotives in Service	Locomotives Installed	Retirements	Percent
1970	17,086	1093	-	-
1971	27,189	1287	1184	4.4
1972	27,364	1577	1402	5.2
1973	27,800	1384	948	3.5
1974	28,084	1395	1111	4.0
1975	28,210	840	714	2.5
1976	27,609	567	1168	4.1
1977	27,667	992	934	3.4
1978	27,772	1322	1217	4.4
1979 (p)	28,402	1931	1301	4.7
Average				4.0

SOURCE: Economics and Finance Department, Association of American Railroads, Yearbook of Railroad Facts, 1979, and unpublished table: "Diesel Locomotives Installed," Revised May 14, 1979. Updated to 1979, AAR, Telephone conversation.

Table V-11 summarizes the equipment needs for 1990 for each scenario. The coal cars are stated in 100 ton equivalents.

A 100 ton open hopper car in 1979 cost approximately \$34,585 and a 3,000 horsepower locomotive cost \$587,800. The cost for a rebuilt car or locomotive is, on the average, one-half of the new price. In the past several years, rebuilds have averaged 4.7 percent of new and rebuilt cars, and 11.9 percent of new and rebuilt locomotives delivered to operating companies. Therefore, the average unit cost for open hopper cars is \$33,772 and for locomotives \$552,835. These values are used to compute total investment requirements in Table V-11.

Capital Expenditures for Rail Track and Way

Expenses for railroad track and way are not commodity specific but relate to the total volume and dispersion of traffic. Much of the expenditure is mandated by law in order to maintain service availability. Yet not all such expenditures have been made as needed, resulting in a significant account for deferred maintenance and delayed capital improvement. As of June 30, 1976 deferred maintenance of way of all Class I railroads totaled \$1,345.8 million and delayed capital improvement of roadway \$1,134.1 million.⁽¹⁾ Deferred maintenance is a deterioration of the rail plant permitted to occur either through lack of funds

⁽¹⁾ A Preliminary Report by the Secretary of Transportation, A Prospectus for Change in the Freight Railroad Industry, October 1978, p. 24.

Table V-11
Investment Requirements for Coal Cars and Locomotives

	S c e n a r i o		
	low	medium	high
Eastern Region			
Coal Cars ^{1/}	214,370	217,013	239,995
Locomotives ^{2/}	1,679	1,699	1,726
Southern Region			
Coal Cars	69,854	70,288	70,967
Locomotives	1,173	1,180	1,192
Western Region			
Coal Cars	66,514	71,854	71,552
Locomotives	2,017	2,179	2,170
Total: Coal Cars	350,738	359,155	382,514
Locomotives	4,869	5,058	5,088
Cars needed to Maintain 1979 Fleet	108,947	108,947	108,947
Cars needed for Growth	199,171	117,588	140,947
Total New & Rebuilt Cars	218,118	226,535	249,894
Cost of New Cars ^{3/} (Million dollars, 1979)	\$7,544	\$7,834	\$8,642
Locomotives needed to Maintain 1979 Fleet	1,250	1,250	1,250
Locomotives for Growth	1,403	1,500	1,530
Total New and Rebuilt Locomotives	2,653	2,750	2,780
Cost of New Locomotives ^{4/} (million dollars, 1979)	\$1,467	\$1,520	\$1,537

1/ All cars in 100 ton equivalents.

2/ All Locomotives in 3000 hp equivalents.

3/ Assumes 4.7 percent of new cars are rebuilt at $\frac{1}{2}$ cost of new (1979 dollars).

4/ Assumes 11.9 percent of new locomotives are rebuilt at $\frac{1}{2}$ cost of new (1979 dollars).

or a conscious decision to disinvest. The latter may anticipate a request for permission to abandon service.

Since maintenance of way resumed on a normalized schedule would eventually result in catch up on deferred maintenance, and because cycles in catch up of maintenance of track and way beget more cycles, the Secretary of Transportation has recommended that no significant bulge of expenditures be made to catch up on deferred maintenance.⁽²⁾ Assuming a 25 percent catch up on deferred maintenance of way and equipment over 10 years from 1976 to 1985, the Federal Railroad Administration computes a total outlay of \$2,837 million for catch up of deferred maintenance. At a 50 percent catch up rate the outlay would be \$6,065 million.⁽³⁾ The outlays from 1980 to 1985 are given in Table V-12 for the 25 percent scenario with a projection to 1990 based on growth rates used in the Federal Railroad Administration (FRA) Analysis.

In addition to maintenance of the way the FRA also projected investment in road property from 1976 through 1985. Table V-13 is reproduced from the "Prospectus" study cited above. Using a similar approach as was used to project maintenance of way expenditures, capital expenditures for road property are computed to be \$10,097 million in current (inflated) dollars for the period 1980 through 1990.

(2) Ibid.

(3) Ibid., current dollars.

Table V-12

Maintenance of Way and Catch-up on Deferred Maintenance
1980 through 1990
(current \$ million)

	Deferred Maintenance	Total Maintenance of Way
1980 - 1985	1,495	28,675
1986 - 1990	1,723	33,053
TOTAL 1990	3,218	61,728

SOURCE: Computed from data given in: A Preliminary Report by the Secretary of Transportation, A Prospectus for Change in the Freight Railroad Industry, October 1978, Appendix A.

Table V-13
Projected Sources and Uses of
Funds, 1976-1985^a
(million \$)

Category	Scenario 1		Scenario 2	
	Constant \$	Current year \$	Constant \$	Current year \$
Sources of funds:				
Funds from operations	12,551	10,142	10,569	6,999
Sales of equipment obligations ^b	11,237	16,755	11,237	16,755
Sale of equity and/or debt	1,664	1,664	1,664	1,664
Other sources	457	911	457	910
Total	25,909	29,472	23,927	26,328
Uses of funds:				
Investment in road property	4,333	6,819	4,333	6,819
Investment in equipment	14,362	21,491	14,362	21,491
Repayment of funded debt	1,643	1,644	1,643	1,644
Repayment of equipment debt	7,688	9,095	7,688	9,095
Increase in working capital	853	3,168	859	3,185
Other uses	0	258	0	258
Total	28,879	42,475	28,885	42,492
Additional funds required ^c	2,970	13,003	4,958	16,164
Peak additional funds required	4,557	13,140	5,364	16,164

^aRepresents annual charge to retained earnings (i.e., ex dividends), net of noncash items.

^bConditional sales agreements and equipment trusts.

^cThese amounts are net of annual funding surpluses.

NOTE: Current year dollar amounts reflect the effect of inflation as opposed to constant dollar amounts which do not reflect the effect of inflation and which, therefore, are equivalent in value from year to year.

SOURCE: Federal Railroad Administration study.

SOURCE: Reproduced from: A Preliminary Report by the Secretary of Transportation, A Prospectus for Change in the Freight Railroad Industry, October 1978.

Coal traffic accounts for 25 percent of the tonnage of Class I railroads and 11 percent of the revenues. The most appropriate measure of productive output for transportation, however, is ton-miles. Coal traffic constitutes 18 percent of total Class I railroad ton-miles.⁽⁴⁾ Arbitrary as it may be, 18 percent may be used to allocate such joint costs as track and way expenditure to coal traffic. The results of this computation, plus a deflation to 1980 dollars, is given in Table V-14.

Investment in Coal Barges, Towboats and Colliers

Independent data on coal barge fleet and collier fleet are not available. Therefore, utilization ratios computed for petroleum barges are assumed to hold true for coal barges. Total barges required are computed on the basis of 31 tons per year delivered per ton of barge capacity in use. The same ratio applies to both 1979 and 1990 traffic levels to compute existing barge fleet and future barge requirements. Collier requirements for the Great Lakes and Tidewater movements are computed using average trip lengths. Table V-15 gives the total carriage of coal by water routes for 1977 and 1990.

Barge and Towboat Investment

Based on the barge traffic projections given in Table V-15, estimates for needed barge capacity are computed as shown in Table V-16. As with petroleum barge movements, a single barge is assumed to carry 31 times its capacity in a year. The standard coal barge is a 195-foot by 35-foot

⁽⁴⁾ 1976 Carload Waybill Statistics, U.S. Department of Transportation, Washington, D.C., July 1977.

Table V-14
Investment and Maintenance
of Track and Way
1990

	Current Dollars Million	1980 Dollars <u>1/</u> Million
Deferred Maintenance	3,218	2,748
Normal Maintenance	61,728	52,717
Investment	10,097	8,623
Total Capital Expenses	75,043	64,088
18 percent Allocation <u>2/</u> to Coal	13,508	11,536

1/ Based on FRA ratio of inflated to 1976 dollars adjusted to 1980 dollars.

2/ Based on proportion of ton-miles.

Table V-15
Carriage of Coal By Water Mode
(million tons per year)

Mode	1977	1990 Scenario		
		Low	Medium	High
Total Water Mode	211.96	409.51	417.59	420.82
Overseas Exports	37.06	83.63	83.63	83.63
Barge Traffic	133.99	236.45	242.95	245.72
Lake Traffic	39.13	63.63	64.71	65.17
Canadian Exports	16.88	24.37	24.37	24.37
Domestic	22.25	39.26	40.34	40.80
Coastwise Vessels	.06	25.80	26.30	26.30

NOTES: a/ Total equal to modal shares of regional production as found in Table V-2 plus new coastwise movements plus increase in exports (from non-traditional areas) plus 1/6th of increase in NE Great Plains production.

b/ Canadian exports taken from MEFS solution file.

c/ Large increase in Northeast coal demand assumed to be delivered $\frac{1}{2}$ by coastwise vessels.

Table V-16
Investment in Coal Barges and Towboats

	S c e n a r i o		
	low	medium	high
Barges:			
Total Required	5,085	5,225	5,284
Remaining Fleet	2,756	2,756	2,756
New Barges	2,321	2,461	2,528
Cost (1976 \$ million)	\$371.4	\$393.8	\$404.5
Towboats:			
Total Required	214	220	222
Remaining Fleet	103	103	103
New Towboats	111	117	119
Cost (1976 \$ million)	\$207.7	\$218.9	\$222.6

open hopper capable of loading 1500 tons of coal. This barge was estimated to cost approximately \$160,000 in 1976.⁽⁵⁾ The economic life of an open hopper barge is assumed to be the same as a tank barge for which data is presented in Chapter III. The remaining fleet was computed based on 1979 barge traffic and a retirement of 14.6 percent of the fleet over 10 years. 1979 Barge traffic is assumed to be 12 percent greater than the 1977 figure for which water carriage data is available.⁽⁶⁾

Towboats are required in proportion to the number of barges needed. A fixed ratio of 23.8 barges per towboat assumes no substantive change in barge distribution patterns from the historical base. The ratio of barges to towboats was obtained from a survey of major regulated barge carriers.⁽⁷⁾ Retirement rates for towboats were computed for the entire fleet of towboats in all services and apply to coal service as well as oil service. It is assumed that 24 percent of the towboat fleet will be retired by 1990. The cost of towboats is based on a distribution of towboats by horsepower purchased since 1975 and costs for towboats of various horsepower provided by the Corps of Engineers.⁽⁸⁾

⁽⁵⁾ U.S. Army, Corps of Engineers, "Estimated Operating Costs of Barges on the Mississippi River System," December 1976, Unpublished table.

⁽⁶⁾ 1979 Coal production exceeds 1977 production by 12 percent as reported in: U.S. Department of Energy, Energy Data Report, "Bituminous and Subbituminous Coal and Lignite Distribution" Calendar Year 1979, Washington, D.C. April 21, 1980.

⁽⁷⁾ A.T. Kearney Inc., Domestic Waterborne Shipping Market Analysis Inland Waterways Trade Area, Final Report, February 1974, p. 1-A-8.

⁽⁸⁾ U.S. Army, Corps of Engineers, "Estimated Operating Costs of Towboats on the Mississippi River System," December 1976, Unpublished Table (See Table III-22).

Collier Investment

There is considerable potential for deep-draft vessel carriage of coal. Much of this potential is being realized on the Great Lakes. Much more may be realized on the east coast as large numbers of power plants in the northeast convert to coal and new coal burning plants are built. Most of these power plants are located on a navigable waterway accessible by deep-draft coastwise vessels, either barges or colliers. For the purpose of this analysis they will be considered identical since they are similar and including the tugboat usually permanently attached in coastwise trade, may exhibit similar costs per deadweight ton. An average of \$1200 per DWT is assumed for coastwise or lakewise vessels of all types.

Assuming an average haul of 800 miles on the Great Lakes, a vessel may make 14 trips during a normal nine-month season. On this basis the productivity of the average vessel is 15.4 tons per year per deadweight ton of capacity,⁽⁹⁾ and the total required capacity of lake colliers is as given in Table V-17 for domestic routes. Canadian routes are assumed to be handled by Canadian vessels.

The coastwise trade is a largely brand new trade with only nominal equipment presently available for a handful of generally small shipments. Therefore, the entire requirement must be purchased during the next ten years to respond to the projected growth in this trade. Not since the early 1960's has there been any significant coastwise movement of domestic coal. The assumptions in this analysis are based on TERA's judgement which is in turn based on a broad continuing involvement in coal transportation problems in the northeast.

⁽⁹⁾ Coal demand is measured in short tons of 2000 lbs. while deadweight tons are long tons of 2200 lbs.

Table V-17
Investment in Deep-draft Vessels for
Coastwise and Lakewise Carriage of Coal
(1980 \$ million)

	S c e n a r i o		
	low	medium	high
Great Lakes			
Required Capacity (thousand DWT)	2549	2619	2649
Remaining Capacity ^{a/}	1228	1228	1228
New Capacity	1321	1391	1421
Investment	\$1585.2	\$1669.2	\$1705.2
Coastwise			
Required Capacity (thousand DWT)	1173	1195	1195
Investment	\$1407.6	\$1434.0	\$1,434.0

NOTES: ^{a/} Assumes 15 percent of the fleet capacity
will be retired by 1990.

Assuming an average trip length of 600 nautical miles an average vessel would complete 20 round trips in a year for an overall utilization rate of 22 tons delivered per year per DWT of capacity. Total investment to move assumed coal volumes is given in Table V-17.

Summary

Table V-18 presents a summary of the coal transport investment requirements computed in this chapter. All dollar values have been converted to 1980 dollars using the factors given in Table II-6. Investment in 1985 and 1995 are estimated based on the percentage growth from 1979 coal production of 762.56 million tons as shown in Table V-19.

Table V-18
Summary of Coal Transportation
Investment Requirements
(1978 dollars in millions)

	S c e n a r i o		
	low	medium	high
Railroad Equipment			
Coal Cars	\$ 8,193.8	\$ 8,507.7	\$ 9,385.2
Locomotives	1,593.2	1,650.7	1,669.2
Rail Track and Way	11,536.0	11,536.0	11,536.0
Inland Waterways			
Barges	371.4	393.8	404.5
Towboats	207.7	218.9	222.6
Great Lakes Colliers	1,585.2	1,669.2	1,705.2
Coastwise Colliers	1,407.6	1,434.0	1,434.0
TOTAL: 1990	\$24,894.9	\$25,410.3	\$26,356.7
1985	\$15,555.5	\$15,187.9	\$15,371.1
1995	\$39,455.1	\$43,523.9	\$44,356.8

Table V-19
Summary of Coal Projections

	S c e n a r i o		
	low	medium	high
1979	762.56	762.56	762.56
1985	1033.25	1045.12	1043.97
1990	1195.77	1235.30	1245.09
1995	1449.14	1572.29	1574.63

SOURCE: Historical, U.S. Department of Energy, Energy Data Reports, "Bituminous and Subbituminous and Lignite Distribution," Calendar Year 1979, Washington, D.C., April 21, 1980.

Projected: U.S. Department of Energy, Mid Range Energy Forecasting System.

CHAPTER VI. CONCLUSIONS

Findings

Summaries of transportation investment requirements through 1990 are given in Table VI-1 for the low, medium and high scenarios. Total investment requirements for the three modes and the three energy commodities can accumulate to a \$49.9 to 50.9 billion range depending on the scenario.

The high world oil price scenario requires the most investment but not very much more than the low price scenario. However, there are some shifts in emphasis between the scenarios which reflect differences in the primary sources of supply for energy in each scenario. The low world oil price scenario, following more traditional patterns of growth in supply, require more imports of oil and hence more pipeline building from the Gulf coast to inland points. Since the low price encourages growth in demand, water carrier capacity must expand to carry the increased load. In the other two scenarios total water carrier capacity may shrink and less than full replacement of vessels is required. However, due to the high price level, exotic sources of domestic oil such as shale and increased Alaskan production require greater pipeline building than the low price scenario. The most dominant investment in the carriage of oil in all scenarios is the assumed Northern Tier pipeline. This route for Alaskan oil was specified in MEFS. If it is not built some other invest-

Table VI-1

Transportation Investment by Mode, Material,
and Scenario 1990
(1980 dollars million)

	OIL	GAS	COAL	TOTAL
<u>Low Scenario</u>				
Pipelines	1922.3	21,227.5	NA	23,149.8
Railroads	NA	NA	21,323.0	21,323.0
Waterways	1265.5	624.5	3,571.9	5,461.9
TOTAL	3187.8	21,852.0	24,894.9	49,934.7
<u>Medium Scenario</u>				
Pipelines	2198.2	21,247.9	NA	23,446.1
Railroads	NA	NA	21,694.4	21,694.4
Waterways	605.4	624.5	3,715.9	4,945.8
TOTAL	2803.6	21,872.4	25,410.3	50,086.3
<u>High Scenario</u>				
Pipelines	2220.4	21,291.7	NA	23,512.1
Railroads	NA	NA	22,590.4	22,590.4
Waterways	380.1	624.5	3,766.3	4,770.9
TOTAL	2600.5	21,916.2	26,356.7	50,873.4

NA: Not Analyzed or Not Applicable.

ment in either pipelines or tankers must be made to carry the load. Since, in all scenarios the level of demand for petroleum products is below that of 1978 no pipeline building was deemed necessary in a strategic sense except for specialized pipelines to transport liquid gasses. The demand for liquid gasses shows small growth to 1990 from historical levels. However, it is the shifting of sources of supply to follow new natural gas discoveries that is the primary reason for the need for new pipelines. Only one planned LPG pipeline from the developing Overthrust region was included in the investment total due to lack of information from which to make an independent estimate of need.

The natural gas investment picture is clearly dominated by the Alaska Natural Gas Transportation System (ANGTS). The ANGTS project is the largest single project in the entire report. Waterway investment for LNG reflects current pessimism concerning sources and reliability of foreign suppliers and optimism concerning the availability of domestic supplies. Natural gas demand remains below peak historical demands through 1990. However, the shifting sources of supply in all three scenarios requires new additions to capacity in the pipeline network. The minor differences between the investment estimates for natural gas in each scenario arise from differences in impact on the existing network of gas pipelines.

Production and consumption of coal increases by 57 to 63 percent over 1979 levels, requiring the addition of as much as 140,000 hopper cars to the fleet in addition to investment in replacement vehicles. Also, as much as

2500 new and replacement open hopper barges will be needed. However, despite all of the additional carrying capacity required the largest single figure in the investment total for coal is an allocated portion of projected new investment and maintenance of way for rail track and way expenditures. This figure is not tied explicitly to the projections for coal supply and demand used in this study. Such an estimating procedure would require a sophisticated network analysis not authorized for this study. The difference between the scenarios in investment for coal arise simply from differences in the cars and locomotives required to carry different total traffic levels.

One important consideration in coal transport included in this year's study is the effect that large increases in coal demand in the northeast will have on the now nearly extinct coastwise coal trade for deep-draft vessels. It is apparent from other studies that TERA is involved in concerning northeast coal demand that a large number of electric utilities are located on navigable coastal waterways and will opt for water transport of coal when expanding coal generating capacity or converting from oil fuels. Not since the early 1960's has there been a truly significant domestic trade in coal for coastwise vessels. Many new barges, integrated tug-barges or colliers will be built for this trade. TERA assumed that one half of the growth in coal demand from 1978 to 1990 in the northeast would be transported by water. In addition to this new trade, TERA assumed, on the evidence of current investment trends on the Mississippi river, that a portion of Western coal which did not formerly impact the inland waterways would reach the market in part by barge or Great Lakes vessel.

Comparison of 1979 ARC Estimates
with 1977 and 1978
Estimates

The projections used in TERA's previous two reports on Capital Requirements for Transportation of Energy Materials for the 1977 and 1978 ARC differ in some important respects from this year's projections as shown in Table IV-2. The projections for demand for oil are down and so is the investment requirement in pipelines and waterways. Waterways investment is further lowered by intervening progress on the LOOP deepwater port and the omission of SEADOCK from any of the scenarios. Tables IV-3 and IV-4 gives the investment requirement computed for the 1978 and 1977 ARC's respectively.

Projections for natural gas are up mildly from a year ago. However, projections for the cost of the Alaska natural gas system are up sharply. In addition, last year's report mistakenly shared some of the Canadian costs when the entire project is being built for the benefit of the U.S. consumer. LNG projections are down this year due to the substantial completion of the Trunkline project and the lower LNG import projections in two of the scenarios.

Coal demand is up in all scenarios as is the estimate of needed investment. Investment in track and way appears to have been incorrectly computed from the DOT report last year and that revision has added \$5 billion to the total. Also, more equipment is required to carry the large volumes projected. This year an important analysis of coastwise vessels and an allowance for retirement of the Great Lakes fleet have increased the estimate of capital needs.

It is important to remember in this year's estimate as in past years the capital requirements computed for

Table VI-2

Annual Consumption of Energy in the United States
Comparison of 1979 ARC Projection with
1978 and 1977 ARC Projections

	1977 ARC		1978 ARC		1979 ARC	
	Scenario		Scenario		Scenario	
OIL (MMB)						
1978		6,845.06		6,845.06		6,845.06
1979		6,793.01		6,793.01		6,793.01
1985	A	8,049.66	B	6,603.48	L	5,955.07
	C	7,960.65	C	6,982.42	M	5,632.35
	E	7,690.16	D	6,649.66	H	5,475.94
1990	-		B	6,974.56	L	6,376.14
	-		C	7,156.44	M	5,711.43
	-		D	7,403.55	H	5,444.80
GAS (BCF)						
1978		20,887.00		20,877.00		20,887.00
1979		21,100.64		21,100.64		21,100.64
1985	A	20,348.08	B	18,652.63	L	18,714.73
	C	18,547.89	C	19,439.28	M	18,348.27
	E	17,086.82	D	19,800.47	H	18,371.35
1990	-		B	17,416.71	L	19,408.37
	-		C	18,838.81	M	18,845.44
	-		D	18,521.60	H	18,841.61
COAL (MMT)						
1978		640.94		640.94		640.94
1979		762.56		762.56		762.56
1985	A	962.42	B	1,020.03	L	1,033.95
	C	960.98	C	959.64	M	1,045.81
	E	944.88	D	941.29	H	1,044.66
	-		B	1,476.33	L	1,197.49
	-		C	1,384.56	M	1,237.01
	-		D	1,254.20	H	1,246.80

Table VI-3

Transportation Investment by Mode, Material
and Scenario 1978 ARC

1990

(1978 dollars in millions)

	OIL	GAS	COAL	TOTAL
<u>Scenario B</u>				
Pipelines	2,614.2	13,133.0	NA	15,747.2
Railroads	NA	NA	15,207.0 to 15,416.0	15,207.0 to 15,416.0
Waterways	5,805.7	3,932.0	1,068.4 to 1,844.2	10,806.1 to 11,581.9
TOTAL	8,419.9	17,065.0	16,275.4 to 17,260.2	41,760.3 to 42,745.1
<u>Scenario C</u>				
Pipelines	3,025.4	13,123.6	NA	16,149.0
Railroads	NA	NA	14,073.0 to 14,282.0	14,073.0 to 14,282.0
Waterways	4,168.5	2,764.0	1,427.6 to 2,203.3	8,270.1 to 9,045.8
TOTAL	7,193.9	15,797.6	15,500.6 to 16,485.3	38,492.1 to 39,476.8
<u>Scenario D</u>				
Pipelines	2,339.3	13,127.7	NA	15,467.0
Railroads	NA	NA	13,047.0 to 13,256.0	13,047.0 to 13,256.0
Waterways	4,285.5	2,280.0	1,258.9 to 2,034.6	7,824.4 to 8,600.1
TOTAL	6,624.8	15,407.7	14,305.9 to 15,290.6	36,338.4 to 37,323.1

NA: Not Analyzed or Not Applicable.

SOURCE: U.S. Department of Energy, Capital Requirements for the Transportation of Energy Materials Based on 1978 ARC Estimates, DOE/EIA-8596-1 prepared by TERA, Inc., Arlington, VA. for the Energy Information Administration, Washington, D.C. October 1979, (Available from NTIS and USGPO).

Table VI-4

Transportation Investment by Mode, Material,
and Scenario 1977 ARC

1985

(1975 dollars million)

	OIL	GAS	COAL	TOTAL
<u>Scenario A</u>				
Pipelines	6,770.6	11,231.4	NA	18,002.0
Railroads	NA	NA	2,650.0 to 5,807.0	2,650.0 to 5,807.0
Waterways	5,495.2 to 5,565.9	2,578.0	887.0 to 1,604.0	8,960.2 to 9,747.9
TOTAL	12,265.8 to 12,336.5	13,809.4	3,537.0 to 7,411.0	29,612.2 to 33,556.9
<u>Scenario C</u>				
Pipelines	6,357.4	11,230.7	NA	17,588.1
Railroads	NA	NA	2,958.0 to 6,275.0	2,958.0 6,275.0
Waterways	5,545.2 to 5,615.9	4,593.6	848.0 to 1,616.0	10,986.8 to 11,825.5
TOTAL	11,902.6 to 11,973.3	15,824.3	3,806.0 to 7,891.0	31,532.9 to 35,688.6
<u>Scenario E</u>				
Pipelines	5,588.2	10,825.1	NA	16,413.3
Railroads	NA	NA	2,667.0 to 5,866.0	2,667.0 to 5,866.0
Waterways	5,416.9 to 5,487.6	5,272.6	752.0 to 1,498.0	11,441.5 to 12,258.2
TOTAL	11,005.1 to 11,075.8	16,097.7	3,419.0 to 7,364.0	30,521.8 to 34,537.5

NA: Not Analyzed or Not Applicable.

SOURCE: U.S. Department of Energy, "Capital Requirements for the Transportation of Energy Materials Based on PIES Scenario Estimates," Analysis Memorandum, DOE/EIA-0102/47 prepared by TERA, Inc., Arlington, VA, for the Energy Information Administration, Washington, D.C., January 1979, (Available from NTIS).

the transportation of projected energy supplies focuses on strategic investment only. That is, investment which is strictly necessary to ship new or expanding supplies to market. It does not include that investment in transportation facilities which may be undertaken by various firms in free economy for competitive reasons: to take traffic away from other carriers capable of doing the job or to open up new markets for the firm in areas already served by others. At times such investments may be profitable and will be undertaken. This report, then, does not constitute a forecast of investment, rather it is an assessment of needs.

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