

ALASKA LEGISLATURE SPECIAL COMMITTEE / SUBJECT FILES 8672

1041 SCOMM 28: JOINT GAS PIPELINE COMMITTEE. 1981-82

1041

cleaning, changing, repairing or adjustment of Seller's equipment or other equipment used in determining such shrinkage in gas volumes.

19.5 Seller agrees to restore (or cause to be restored) any pressure decline greater than fifty (50) psig measured from plant inlet to plant outlet resulting from such processing.

19.6 Seller shall return processed gas to Buyer which has a water content no greater than the lower of (a) the water content of the gas delivered by Buyer to Seller for processing; or (b) a water content of seven (7) pounds per 1,000,000 cubic feet of gas.

19.7 All Seller's gas processing operations shall be at Seller's sole cost and expense, and Seller shall be deemed to be in exclusive control and possession while the gas is in Seller's possession and shall hold Buyer harmless from all injuries or damages which may occur as the result of Seller's exercise of its right to process gas hereunder.

19.8 As consideration for transporting or arranging transportation and delivery of gas to Seller for processing, Seller shall pay Buyer the cost of transporting the volumes of gas lost as shrinkage or lost in the processing operation at such rates as the FERC and the National Energy Board (NEB) of Canada may allow; however, it is agreed that Seller shall have the option of using gas from other gas sources available to Seller for delivery to Buyer at the processing location and/or at a mutually agreeable point or points up to the extent of the Btu content of the volume of shrinkage

gas. The foregoing charge for transporting and delivering gas to Seller hereunder shall not be applicable if and to the extent that Seller restores the Btu equivalent of the gas used or lost in kind at the processing plant and/or at said mutually agreeable point.

ARTICLE XX.

MISCELLANEOUS AND ADDRESSES

20.1 No waiver by either party of one or more defaults by the other in the performance of any of the provisions of this Agreement shall operate or be construed as a waiver of any other or further default or defaults, whether of a like or of a different character.

20.2 This Agreement shall be binding upon and inure to the benefit of the legal representatives, successors and assigns of the respective parties hereto and shall be binding upon any purchaser or assignee of Buyer's properties or pipeline system and upon any purchaser or assignee of the properties of Seller which are subject to this Agreement, and Seller and Buyer both agree that no sale or assignment of said properties of Seller or any part thereof or all or substantially all of Buyer's system shall be made unless the purchaser or assignee thereof shall assume and agree to be bound by this Agreement insofar as it shall affect and relate to the property or interest sold or conveyed. It is agreed, however, that except as hereinafter provided, and as provided in Section 5.4, the respective rights and duties of the parties hereunder may not be assigned without the

written consent of the other, provided, however, that such consent shall not be unreasonably withheld.

(i) Seller may assign, transfer, convey, and hypothecate, in one or more transactions, all or part of the Leases, or create or carve out royalty or other interests in such Leases, but any such assignment, transfer or conveyance shall be expressly subject to this Agreement.

(ii) Either party hereto may assign its rights hereunder in whole or in part to a wholly-owned subsidiary or to an affiliate. An affiliate is defined as a corporation controlling, controlled by or under common control with such party. No such assignment shall relieve a party hereto of any liability or responsibility hereunder.

20.3 Notwithstanding any other actual or constructive knowledge of or notice to Buyer, no change or division in ownership in this Agreement by Seller shall be binding upon Buyer for any purpose until after Buyer receives, at the place provided for herein, copies of the instrument or instruments constituting or accomplishing the change in ownership from the party acquiring the interest or right in this agreement or from Seller.

20.4 This Agreement is subject to all applicable state and federal laws and all present and future applicable orders, rules and regulations of any governmental authority having jurisdiction, so long as such orders, rules and regulations shall be in force and effect, provided, however, that no such governmental order, rule or regulations shall be deemed

effective to enlarge or increase the obligations of either party except after final judicial determination to that effect or the consent of the party affected.

20.5 Buyer is and shall be deemed to be a purchaser and transporter of Seller's Gas only and is not and shall not be deemed to be an owner, operator, partner, venturer, agent, participant, or otherwise involved in any of Seller's operations or facilities. Seller will be responsible for and will hold Buyer harmless from any damages or death or injury or civil penalties caused by or happening in connection with such operations or facilities. Buyer will be responsible for Buyer's facilities and will hold Seller harmless from any damages or death or injury caused by or happening in connection with operation of such facilities.

20.6 The parties hereto recognize that all operations conducted by or on behalf of Seller hereunder together with determining ownership and allocation of (i) Seller's Gas sold and delivered to Buyer and (ii) natural gas liquids which may be extracted from Seller's Gas, shall be governed by and subject to the Prudhoe Bay Unit Agreement and the Prudhoe Bay Unit Operating Agreement. It is therefore agreed that should any conflict arise between the Unit Agreements and this Agreement, the terms and provisions of the Unit Agreements shall be controlling.

20.7 All notices, requests and demands provided for in this Agreement shall be in writing and shall be addressed to the parties as follows:

Seller - Exxon Corporation
ATTENTION: Natural Gas Department
P. O. Box 2180
Houston, Texas 77001

Buyer - Northern Natural Gas Company
ATTENTION: Supplemental Supplies Department
2223 Dodge Street
Omaha, Nebraska 68102

All statements and invoices provided for herein shall
be addressed to the parties as follows:

Seller - Exxon Company, U.S.A.
(a Division of Exxon Corporation)
ATTENTION: EPAC, Gas Accounting Services
P. O. Box 2180
Houston, Texas 77001

Buyer - Northern Natural Gas Company
ATTENTION: Transmission Operating Division,
Planning and Control Department
2223 Dodge Street
Omaha, Nebraska 68102

or such other address as either party may designate by notice.
Communications, including monthly statements and payments,
shall be considered as duly delivered when mailed by either
registered or certified mail.

IN WITNESS WHEREOF, this instrument is executed as of
the day and year first above written.

ATTEST OR WITNESS:

Edmunds Travis J.

SELLER:
EXXON CORPORATION

By: W. May Booth
Asst General Manager,
Natural Gas Department
Exxon Company, U.S.A.
(a division of Exxon Corporation)

ATTEST OR WITNESS:

Peacocks

BUYER:
NORTHERN NATURAL GAS COMPANY

By: Gordon Seneca
Group Vice President

EXHIBIT "A"
TO
GAS SALE AND PURCHASE AGREEMENT
PRUDHOE BAY UNIT, ALASKA

Seller's Leases - Initial Participating Areas

Oil Rim Participating Area

<u>Tract No.</u>	<u>ADL No.</u>	<u>Description of Tract</u>
18	28239	Secs. 27,28,33,34 T12N,R11E,UM
19	28238	Secs. 25,26,35,36 T12N,R11E,UM
26	28299	Secs. 29,31,32 T12N,R14E,UM
27	28300	Secs. 27,28,33,34 T12N,R14E,UM
28	28301	Secs. 25,26,35,36 T12N,R14E,UM
29	34628	Secs. 29,30,31,32 T12N,R15E,UM
30	34629	Secs. 27,28,33,34 T12N,R15E,UM
39	34631	Secs. 3,4,9,10 T11N,R15E,UM
40	34632	Secs. 5,6,7,8 T11N,R15E,UM
41	28302	Secs. 1,2,11,12 T11N,R14E,UM
42	28303	Secs. 3,4,9,10 T11N,R14E,UM
43	28304	Secs. 5,6,7,8 T11N,R14E,UM
50	28240	Secs. 1,2,11,12 T11N,R11E,UM

<u>Tract No.</u>	<u>ADL No.</u>	<u>Description of Tract</u>
52	28244	Sec. 15 T11N,R11E,UM
53	28245	Secs. 13,14,24 T11N,R11E,UM
61	28306	Secs. 15,16,21,22 T11N,R14E,UM
62	28307	Secs. 13,14,23,24 T11N,R14E,UM
63	28321	Secs. 17,18,19,20 T11N,R15E,UM
64	28322	Secs. 15,16,21,22 T11N,R15E,UM
65	28323	Secs. 13,14,23,24 T11N,R15E,UM
70	28324	Secs. 25,26,35,36 T11N,R15E,UM
71	28325	Secs. 27,28,33,34 T11N,R15E,UM
72	28326	Secs. 29,30,31,32 T11N,R15E,UM
73	28308	Secs. 25,26,35,36 T11N,R14E,UM
79	28264	Secs. 25,26,35,36 T11N,R12E,UM
82	28246	Sec. 25 T11N,R11E,UM
84	28265	Secs. 1,2,11,12 T10N,R12E,UM
88	28313	Secs. 5,6,7,8 T10N,R14E,UM

<u>Tract No.</u>	<u>ADL No.</u>	<u>Description of Tract</u>
91	28329	Secs. 5,6,7,8 T10N,R15E,UM
92	28328	Secs. 3,4,9,10 T10N,R15E,UM
93	28327	Secs. 1,2,11,12 T10N,R15E,UM

Seller owns a 50% working interest in all of the above listed leases.

Gas Cap Participating Area

<u>Tract No.</u>	<u>ADL No.</u>	<u>Description of Tract</u>
18	28239	Secs. 27,28,33,34 T12N,R11E,UM
19	28238	Secs. 25,26,35,36 T12N,R11E,UM
21	28258	Secs. 27,28,33,34 T12N,R12E,UM
26	28299	Secs. 29,31,32 T12N,R14E,UM
27	28300	Secs. 27,28,33,34 T12N,R14E,UM
40	34632	Secs. 5,6,7,8 T11N,R15E,UM
41	28302	Secs. 1,2,11,12 T11N,R14E,UM
42	28303	Secs. 3,4,9,10 T11N,R14E,UM
43	28304	Secs. 5,6,7,8 T11N,R14E,UM

<u>Tract No.</u>	<u>ADL No.</u>	<u>Description of Tract</u>
50	28240	Secs. 1,2,11,12 T11N,R11E,UM
52	28244	Sec. 15 T11N,R11E,UM
53	28245	Secs. 13,14,24 T11N,R11E,UM
61	28306	Secs. 15,16,21,22 T11N,R14E,UM
62	28307	Secs. 13,14,23,24 T11N,R14E,UM
63	28321	Secs. 17,18,19,20 T11N,R15E,UM
64	28322	Secs. 15,16,21,22 T11N,R15E,UM
65	28323	Secs. 13,14,23,24 T11N,R15E,UM
70	28324	Secs. 25,26,35,36 T11N,R15E,UM
71	28325	Secs. 27,28,33,34 T11N,R15E,UM
72	28326	Secs. 29,30,31,32 T11N,R15E,UM
73	28308	Secs. 25,26,35,36 T11N,R14E,UM
79	28264	Secs. 25,26,35,36 T11N,R12E,UM
82	28246	Sec. 25 T11N,R11E,UM
84	28265	Secs. 1,2,11,12 T10N,R12E,UM
88	28313	Secs. 5,6,7,8 T10N,R14E,Um

<u>Tract No.</u>	<u>ADL No.</u>	<u>Description of Tract</u>
91	28329	Secs. 5,6,7,8 T10N,R15E,UM
92	28328	Secs. 3,4,9,10 T10N,R15E,UM
93	28327	Secs. 1,2,11,12 T10N,R15E,UM
94	28345	Secs. 5,6,7,8 T10N,R16E,UM
97	28346	Secs. 17,18,19,20 T10N,R16E,UM
98	28332	Secs. 13,14,23,24 T10N,R15E,UM
104	47476	Secs. 13,14,24 T10N,R13E,UM

Seller owns a 50% working interest in all of the above listed leases.

Seller's interest in said leases insofar only as such leases cover the Prudhoe Bay (Permo-Triassic) Reservoir within the Initial Participating Areas constitute the "Leases" subject on this Agreement.

ARCO Oil and Gas Company
Post Office Box 2819
Dallas, Texas 75221
Telephone 214 651 4213
Danny D. Echols
Vice President
Natural Gas Department



September 10, 1979

Mr. J. H. Welsh, Jr.
Texas Gas Transmission Corporation
1100 Milam Bldg., Suite 1533
Houston, Texas 77002

Gentlemen:

ARCO Oil and Gas Company, a Division of Atlantic Richfield Company, and Texas Gas agree that they will enter into negotiations towards execution of a Gas Purchase Contract providing for the sale by ARCO Oil and Gas Company and purchase by Texas Gas for a primary term of twenty years of a daily volume of gas production attributable to an undivided twelve percent (12%) of ARCO's working interest in the Prudhoe Bay (Permo-Triassic) Reservoir. Title shall pass at a mutually agreeable delivery point in the field at or near the inlet of any required gas conditioning facility. The contract price shall be negotiated but shall not be less than the price set forth in Section 109 of the NGPA of 1978 plus severance taxes and reimbursement of any other costs incurred by Seller and allowed under Sections 110 and 502 (c) of the NGPA. Customary deregulation and price escalation provisions permitted by any future statute or regulation will be included.

The parties hereto agree to begin as soon as mutually convenient, but in any event within 90 days after the date of this letter, negotiations to conclude a definitive Gas Purchase Contract. If the parties, after good faith negotiations, fail to finalize the Gas Purchase Contract by May 1, 1980, either party may terminate this agreement by giving written notice thereof to the other party.

This agreement shall be of no force and effect unless executed by both parties within 15 days of the date first above written.

Very truly yours,

Danny D. Echols
Vice President

EW
EJK

DDE:nm

ACCEPTED AND AGREED this _____
day of September, 1979

TEXAS GAS TRANSMISSION CORPORATION

By _____

ARCO Oil and Gas Company
Post Office Box 2819
Dallas, Texas 75221
Telephone 214 651 4213
Danny D. Echols
Vice President
Natural Gas Department



September 10, 1979

Mr. D. L. Smith
United Gas Pipe Line Company
Post Office Box 1478
Houston, Texas 77001

Gentlemen:

ARCO Oil and Gas Company, a Division of Atlantic Richfield Company, and United Gas agree that they will enter into negotiations towards execution of a Gas Purchase Contract providing for the sale by ARCO Oil and Gas Company and purchase by United Gas for a primary term of twenty years of a daily volume of gas production attributable to an undivided fifteen percent (15%) of ARCO's working interest in the Prudhoe Bay (Permo-Triassic) Reservoir. Title shall pass at a mutually agreeable delivery point in the field at or near the inlet of any required gas conditioning facility. The contract price shall be negotiated but shall not be less than the price set forth in Section 109 of the NGPA of 1978 plus severance taxes and reimbursement of any other costs incurred by Seller and allowed under Sections 110 and 502 (c) of the NGPA. Customary deregulation and price escalation provisions permitted by any future statute or regulation will be included.

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This agreement shall be of no force and effect unless executed by both parties within 15 days of the date first above written.

Very truly yours,

Danny D. Echols
Vice President

DDE
EJK

DDE:nm

ACCEPTED AND AGREED this _____
day of September, 1979

UNITED GAS PIPE LINE COMPANY

By _____

ARCO Oil and Gas Company

Post Office Box 2819

Dallas, Texas 75221

Telephone 214 651 4213

Danny D. Echols

Vice President

Natural Gas Department



September 10, 1979

Mr. G. H. Ewing
Texas Eastern Transmission Corporation
Post Office Box 2521
Houston, Texas 77001

Gentlemen:

ARCO Oil and Gas Company, a Division of Atlantic Richfield Company, and Texas Eastern agree that they will enter into negotiations towards execution of a Gas Purchase Contract providing for the sale by ARCO Oil and Gas Company and purchase by Texas Eastern for a primary term of twenty years of a daily volume of gas production attributable to an undivided ten percent (10%) of ARCO's working interest in the Prudhoe Bay (Permo-Triassic) Reservoir. Title shall pass at a mutually agreeable delivery point in the field at or near the inlet of any required gas conditioning facility. The contract price shall be negotiated but shall not be less than the price set forth in Section 109 of the NGPA of 1978 plus severance taxes and reimbursement of any other costs incurred by Seller and allowed under Sections 110 and 502 (c) of the NGPA. Customary deregulation and price escalation provisions permitted by any future statute or regulation will be included.

The parties hereto agree to begin as soon as mutually convenient, but in any event within 90 days after the date of this letter, negotiations to conclude a definitive Gas Purchase Contract. If the parties, after good faith negotiations, fail to finalize the Gas Purchase Contract by May 1, 1980, either party may terminate this agreement by giving written notice thereof to the other party.

This agreement shall be of no force and effect unless executed by both parties within 15 days of the date first above written.

Very truly yours,

Danny D. Echols
Vice President

ROH
EPC

DDE:nm

ACCEPTED AND AGREED this _____
day of September, 1979

TEXAS EASTERN TRANSMISSION CORPORATION

By _____

ARCO Oil and Gas Company

Post Office Box 2819
Dallas, Texas 75221
Telephone 214 651 4213

Danny D. Echols
Vice President
Natural Gas Department



September 10, 1979

Mr. R. C. Dixon
Panhandle Eastern Pipe Line Company
Post Office Box 1642
Houston, Texas 77005

Gentlemen:

ARCO Oil and Gas Company, a Division of Atlantic Richfield Company, and Panhandle Eastern agree that they will enter into negotiations towards execution of a Gas Purchase Contract providing for the sale by ARCO Oil and Gas Company and purchase by Panhandle Eastern for a primary term of twenty years of a daily volume of gas production attributable to an undivided twenty percent (20%) of ARCO's working interest in the Prudhoe Bay (Permo-Triassic) Reservoir. Title shall pass at a mutually agreeable delivery point in the field at or near the inlet of any required gas conditioning facility. The contract price shall be negotiated but shall not be less than the price set forth in Section 109 of the NGPA of 1978 plus severance taxes and reimbursement of any other costs incurred by Seller and allowed under Sections 110 and 502 (c) of the NGPA. Customary deregulation and price escalation provisions permitted by any future statute or regulation will be included.

The parties hereto agree to begin as soon as mutually convenient, but in any event within 90 days after the date of this letter, negotiations to conclude a definitive Gas Purchase Contract. If the parties, after good faith negotiations, fail to finalize the Gas Purchase Contract by May 1, 1980, either party may terminate this agreement by giving written notice thereof to the other party.

This agreement shall be of no force and effect unless executed by both parties within 15 days of the date first above written.

Very truly yours,

Danny D. Echols

Danny D. Echols
Vice President *RRM*
e JK

DDE:nm

ACCEPTED AND AGREED this _____
day of September, 1979

PANHANDLE EASTERN PIPE LINE COMPANY

By _____

ARCO Oil and Gas Company
Post Office Box 2819
Dallas, Texas 75221
Telephone 214 651 4213
Danny D. Echols
Vice President
Natural Gas Department



September 12, 1979

Pacific Interstate Transmission Co.
Harry L. Lepape, President
720 West Eighth Street
Los Angeles, California 90017

Gentlemen:

ARCO Oil and Gas Company, a division of Atlantic Richfield Company, and Pacific Interstate agree that they will enter into negotiations towards execution of a Gas Purchase Contract providing for the sale by ARCO Oil and Gas Company and purchase by Pacific Interstate for a primary term of twenty years of a daily volume of gas production attributable to an undivided thirty-three percent (33%) of ARCO's working interest in the Prudhoe Bay (Permo-Triassic) Reservoir. Title shall pass at a mutually agreeable delivery point in the field at or near the inlet of any required gas conditioning facility. The contract price shall be negotiated but shall not be less than the price set forth in Section 109 of the NGPA of 1978 plus severance taxes and reimbursement of any other costs incurred by Seller and allowed under Sections 110 and 502 (c) of the NGPA. Customary deregulation and price escalation provisions permitted by any future statute or regulation will be included.

The parties hereto agree to begin as soon as mutually convenient, but in any event within 90 days after the date of this letter, negotiations to conclude a definitive Gas Purchase Contract. If the parties, after good faith negotiations, fail to finalize the Gas Purchase Contract by May 1, 1980, either party may terminate this agreement by giving written notice thereof to the other party.

This agreement shall be of no force and effect unless executed by both parties within 15 days of the date first above written.

Very truly yours,

Danny D. Echols

Danny D. Echols
Vice President

DDE:bb

ACCEPTED AND AGREED this _____
day of September, 1979

PACIFIC INTERSTATE TRANSMISSION CO.

By _____
Harry L. Lepape, President

Post Office Box 2819
Dallas, Texas 75221
Telephone 214 651 4213

Danny D. Echols
Vice President
Natural Gas Department



September 10, 1979

Mr. G. H. Ewing
Transwestern Pipeline Company
Post Office Box 2521
Houston, Texas 77001

Gentlemen:

ARCO Oil and Gas Company, a Division of Atlantic Richfield Company, and Transwestern agree that they will enter into negotiations towards execution of a Gas Purchase Contract providing for the sale by ARCO Oil and Gas Company and purchase by Transwestern for a primary term of twenty years of a daily volume of gas production attributable to an undivided ten percent (10%) of ARCO's working interest in the Prudhoe Bay (Permo-Triassic) Reservoir. Title shall pass at a mutually agreeable delivery point in the field at or near the inlet of any required gas conditioning facility. The contract price shall be negotiated but shall not be less than the price set forth in Section 109 of the NGPA of 1978 plus severance taxes and reimbursement of any other costs incurred by Seller and allowed under Sections 110 and 502 (c) of the NGPA. Customary deregulation and price escalation provisions permitted by any future statute or regulation will be included.

The parties hereto agree to begin as soon as mutually convenient, but in any event within 90 days after the date of this letter, negotiations to conclude a definitive Gas Purchase Contract. If the parties, after good faith negotiations, fail to finalize the Gas Purchase Contract by May 1, 1980, either party may terminate this agreement by giving written notice thereof to the other party.

This agreement shall be of no force and effect unless executed by both parties within 15 days of the date first above written.

Very truly yours,

Danny D. Echols
Vice President *DEH*
CGK

DDE:nm

ACCEPTED AND AGREED this _____
day of September, 1979

TRANSWESTERN PIPELINE COMPANY

By _____

**PLEASE NOTE: THE PRECEDING PAGES WERE TREATED
AS A UNIT IN THE ORIGINAL DOCUMENT.**

SCOMM

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**PLEASE NOTE: THE FOLLOWING PAGES WERE TREATED
AS A UNIT IN THE ORIGINAL DOCUMENT**

SEPTEMBER 1978 STUDY REPORT

VOLUME I - SUMMARY

SALES GAS CONDITIONING FACILITIES PRUDHOE BAY, ALASKA

AMERADA HESS CORPORATION
ATLANTIC RICHFIELD COMPANY-STUDY COORDINATOR
EXXON COMPANY, U.S.A.
GETTY OIL COMPANY
MOBIL OIL CORPORATION
NATURAL GAS CORPORATION OF CALIFORNIA
NORTHERN NATURAL GAS COMPANY
NORTHWEST PIPELINE CORPORATION
PACIFIC INTERSTATE TRANSMISSION COMPANY (ARCTIC)
PANHANDLE EASTERN PIPELINE COMPANY
PHILLIPS PETROLEUM COMPANY
SOHIO PETROLEUM COMPANY
SOUTHERN NATURAL GAS COMPANY
TENNESSEE GAS PIPELINE COMPANY
TEXAS EASTERN TRANSMISSION CORPORATION
TEXAS GAS TRANSMISSION CORPORATION
TRANSCONTINENTAL PIPELINE CORPORATION
UNITED GAS PIPELINE COMPANY

Job No. 5795-1

The Ralph M. Parsons Company

Engineers / Constructors



SALES GAS CONDITIONING FACILITIES STUDY
PRUDHOE BAY, ALASKA

VOLUME I - SUMMARY

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1. INTRODUCTION

In July, 1977, a group of companies, ultimately eighteen in number, implemented a study by The Ralph M. Parsons Company. The objectives of this Study were to:

- Develop a preliminary design for the Facilities necessary to condition gas produced from the Prudhoe Bay Unit for transmission to the "Lower 48."
- Develop milestone schedules and implementation plans for both a full-capacity startup by July 1, 1983 and a partial-capacity startup by January 1, 1983 with full capacity operation by July 1, 1983.*
- Prepare cost estimate with a plus or minus 20 percent accuracy for these Facilities.
- After appropriate compensation make the Study results available to those parties who ultimately build the Facilities.

In order to accomplish these overall objectives the following major tasks were undertaken:

- Screen the processes available and select a process for carbon dioxide removal and a process for hydrocarbon dewpoint control.
- Develop a process design for conditioning the gas to meet an assumed set of pipeline delivery conditions and quantity and quality specifications.
- Define the auxiliaries and support facilities required for the process plant.
- Prepare equipment data sheets for major equipment.
- Develop a plant layout.
- Identify the permit requirements in the areas of safety, environment and construction.
- Prepare a final report.

The use and availability of the existing first-stage gas injection compressors in the Prudhoe Bay Unit Central Compression Plant to boost the

*At the time this study was implemented the announced startup date for the gas transmission pipeline was January, 1983.

conditioned gas to pipeline pressure of 1440 psig* were assumed as the Study base case. The use of these compression facilities and certain other facilities, owned by the Prudhoe Bay Unit or others, has been assumed in this Study. There is no assurance that these facilities will be available nor have the present owners approved their use. A stand-alone compression plant was considered as an alternate case. The combination of these two compressor options and the two timing options resulted in four different study cases as follows:

- A full-capacity startup July, 1983, assuming use of existing Central Compression Plant first-stage injection compressors to boost gas to pipeline delivery pressure. (Base Case Full Startup.)
- A phased startup, partial capacity in January 1983, full capacity in July, 1983, assuming use of existing Central Compression Plant first-stage injection compressors to boost gas to pipeline delivery pressure. (Base Case Phased Startup.)
- A full-capacity startup in July 1983, using new stand-alone booster compressors to boost to pipeline delivery pressure. (Alternate Case Full Startup.)
- A phased startup, partial capacity in January, 1983, full capacity in July, 1983, using new stand-alone booster compressors to boost to pipeline delivery pressure. (Alternate Case Phased Startup.)

Several important factors which were considered in all aspects of the study included:

- The safety aspects of the Facilities from the point of view of both compliance to applicable regulations and conformance with good engineering practice.
- The continuity of the crude oil production from the Prudhoe Bay Unit.
- The continuity of gas pipeline deliveries.

The results of this study are contained in the following volumes of this report: Volumes II, V, and VI contain confidential SELEXOL® process information. This information has been extracted from distributions to those parties who have not executed a secrecy agreement with Allied Chemical Company.

*At the time the scope of study was defined, this delivery pressure appeared to be a most probable compromise between the economies of higher pressure transmission and the adherence to "proven pipeline technology." It should be noted that the process selected is independent of pipeline pressure within proposed pressure extremes.

- VOLUME I - SUMMARY
contains an overview and a summary of the Study.
- VOLUME II - FACILITY DESIGN
details the process selection work and design.
- VOLUME III - IMPLEMENTATION PLAN AND COST ESTIMATE SUMMARY
presents the plan for design, procurement and construction, and a summary of the cost estimate.
- VOLUME IV - APPENDIX 1
provides details on Study scope, schedule, and instructions, and a description of related facilities now located at Prudhoe Bay.
- VOLUME V - APPENDIX 2
contains equipment design specifications and data sheets.
- VOLUMES VI/VII - FACILITIES COST ESTIMATE, PARTS 1 AND 2
gives the detailed development of the cost estimate.

A detailed Table of Contents for the report is located at the beginning of volumes II through VII. All figures referenced herein are located at the rear of this volume.

2. OVERVIEW OF STUDY RESULTS

The Sales Gas Conditioning Facilities cost estimate was developed with an accuracy of plus or minus 20 percent before contingency was included. This estimate was based on a process design to condition Prudhoe Bay Unit gas to meet an assumed intermediate set of pipeline gas quality and delivery specifications based on the several filings for the proposed pipelines before the United States and Canadian Governments. This gas is sometimes referred to throughout this Report as "sales gas," without regard to the point of sale. The volume of gas available for delivery to the pipeline was as set forth in the Prudhoe Bay Unit Agreement of April, 1977, and in the Field Rules established by the State of Alaska, Division of Oil and Gas Conservation in May, 1977. Assumed study gas delivery and quality specifications were:

Delivery Volume (nominal)	2,000 MMSCFD
Delivery Pressure	1,440 psig
Delivery Temperature (max.)	25°F
Carbon Dioxide Content (max.)	1.0 volume %
Hydrogen Sulfide Content (max.)	1.0 grain/100 SCF
Hydrocarbon Dewpoint (max.)	-10°F @ 1,100 psia
Water Dewpoint (max.)	-35°F @ 1,100 psia

The specified sales gas volume requires a field production rate of 2,600 to 2,800 MMSCFD to account for projected total field and local fuel gas demands (170 to 345 MMSCFD) and shrinkage from gas conditioning (430 to 455 MMSCFD).

The investment requirements for the previously described four cases for the Facilities, including a contingency as determined by risk analysis, are estimated as follows:

	<u>1978 Dollars</u>	<u>Escalated Dollars</u>
Base Case Full Start	1,571,500,000	1,962,300,000
Base Case Phased Start	1,581,200,000	1,964,500,000
Alternate Case Full Start	1,688,400,000	2,109,700,000
Alternate Case Phased Start	1,701,700,000	2,107,200,000

A risk analysis was performed to assess the contingency required. In accordance with normal practice in the Engineering Contractor industry, the contingency included in the estimate provides a 90% probability that the project can be completed, as presently designed and scheduled, for the above estimated investment.

The bases and method of preparation for the cost estimate are summarized in Section 11 of this volume.

The process selected for carbon dioxide removal was Allied Chemical's SELEXOL physical solvent process. A mechanical refrigeration process was selected for hydrocarbon dewpoint control. Water dewpoint control is accomplished in the dehydration equipment located in the existing Prudhoe Bay Unit gas/crude oil separation sites called Gathering Centers and Flow Stations. The hydrogen sulfide content of the feed gas is less than maximum specification limit. The hydrogen sulfide removal by the SELEXOL process provides added assurance of meeting this specification. Therefore, it was assumed that no process equipment was required in the Sales Gas Conditioning Facilities for either water dewpoint control or hydrogen sulfide removal.

A Block Flow Diagram, Figure 1, illustrates the basic process flow of the Sales Gas Conditioning Facilities. Feed gas, originating from the gas/crude separators is compressed in the Gathering Centers and Flow Stations and flows to the inlet separation unit. The inlet gas streams are metered, and any solids or free liquids in the gas are removed at this point. The feed gas flows first to the Natural Gas Liquids Extraction section for hydrocarbon dewpoint control. The gas then flows to the SELEXOL section where the carbon dioxide is removed. The conditioned gas then goes to the gas compressors where it is boosted to pipeline pressure, then refrigerated for transmission.

A small portion of the feed gas is fed to the existing Prudhoe Bay Unit Field Fuel Gas Unit. Here a special low water dewpoint and hydrocarbon dewpoint fuel is produced for delivery to the Trans Alaskan Pipeline System to supply certain of its fuel requirements.

SELEXOL solvent characteristically absorbs, along with the carbon dioxide, a significant quantity of hydrocarbons, particularly the heavier hydrocarbons. During the regeneration of the SELEXOL solvent both the carbon dioxide (about 340 MMSCFD) and these hydrocarbons are flashed from the solvent. Thus, the flash gases from the SELEXOL solvent regeneration have a potentially usable fuel content.

To conserve this fuel content of the flash gases, a plan was developed whereby equipment to burn low heating value fuel was utilized in the Sales Gas Conditioning Facilities. Any excess flash gases over local needs would then be utilized in the Prudhoe Bay Unit Facilities after special heating value blending and with field handling precautions. The intermediate pressure (IP) flash gas is compressed and used directly as fuel. The low-pressure flash gas is compressed and fractionated in the Local Fuel Fractionator (LFF) for control of heating value, and the effluent gas is used as fuel. The carbon dioxide in these fuels, which are utilized in the fuel burning equipment, vents in the exhaust at dispersed locations throughout the field.

The hydrocarbon liquids from the NGL Extraction and SELEXOL low-pressure flash gas are separated in the fractionation unit into propane, butanes, and pentanes plus products to facilitate disposal. Some propane is used for heating value control of certain fuel streams. The remaining propane

is injected into the pipeline gas. The butanes are either injected into the pipeline gas up to hydrocarbon dewpoint limits or into the crude oil delivered to the Trans Alaskan Pipeline System. The pentanes-plus are injected into the same crude stream.

It has been assumed that any excess liquid streams and flash gases will be injected into the oil-producing reservoir during the following circumstances:

- Imbalance of supply/demand
- Startup or shutdown
- Equipment outage
- Unit upset
- Other emergencies

A summary material balance is presented in Table 2-1. Sufficient flexibility has been designed into the Sales Gas Conditioning Facilities so that a nominal 2,000 MMSCFD can be produced under virtually all circumstances. The material balance in this table reflects an operation at the maximum anticipated fuel demand for the Prudhoe Bay Unit. It is assumed, though neither assured nor approved, that the Prudhoe Bay Unit will accommodate, at some cost, the high carbon dioxide, high hydrocarbon dewpoint fuel.

Table 2-1. Summary Material Balance

Stream	Volume (MMSCFD)(1)	BPD
Sales Gas (net before any NGL blending)	2000.6	-
Propane (balance over fuel blending)	37.2	24,270
Butanes	41.3	31,290
Pentanes-plus	31.9	28,700
Fuels [approximately 50% CO ₂](2) 689.0		-
Total Feed	2800.0	
(1) Standard Conditions 14.65 psia and 60°F.		
(2) Virtually all the CO ₂ removed from the feed gas is reinjected into the fuel streams.		

The Facilities require 682,000 total installed horsepower including motors, power recovery units and gas turbines. The bulk of this horsepower is developed by 17 operating gas turbines with 6 spare gas turbines. The flow diagram (Figure 1) shows blocks reflecting the major process and auxiliary systems required. The major auxiliary systems include:

- Refrigeration
- Offsite and general utilities
- Power Generation

A more detailed process flow is shown in Figure 2.

To support the preparation of the estimate at a plus or minus 20 percent accuracy level, the following estimate bases, in addition to the process flow diagrams, were prepared:

- Data sheets for major processes and equipment.
- Detailed plant and support facilities module layout drawings.
- Major piping layout drawings.
- Project implementation plan.

The site location in respect to the entire Prudhoe Bay complex is shown in Figure 3. Figure 4 is a base case design layout of the plant, and also illustrates location of modules for alternate cases and future expansion.

An Implementation Plan provides details for the Facilities funding, design, procurement, fabrication, logistics, and installation.

A full startup of the Sales Gas Conditioning Facilities, by July, 1983, requires strict adherence to the Plan.

A critical timing factor in any construction program at Prudhoe Bay is the "ice window" in the Beaufort Sea. Major plant components can only be delivered via ocean-going barges during the short (4-6 weeks) period each year when the "ice window" is open. Failure to deliver any critical major component during the scheduled period would effectively delay full-capacity startup by one full year.

A milestone schedule for this implementation plan is shown in Figure 5. The critical elements of this schedule include:

- Completion of the process design by January, 1979.
- Timely preparation of all background material, particularly environmental information, necessary to obtain the required permits.

- Long-lead-time equipment to be ordered during the first quarter of 1979.
- Resolution of the impact on and the use of existing facilities at Prudhoe Bay.
- Selection of "Lower 48" fabrication sites.

3. DESIGN BASIS AND CONSIDERATIONS

The Sales Gas Conditioning Facilities preliminary design developed for this Study is based on conditioning gas from the Prudhoe Bay Unit to meet the assumed set of specifications for the pipeline gas as set forth in the Overview (Section 2 of this volume).

The feed gas to the Sales Gas Conditioning Facilities originates from the gas/crude oil separators located in the three Gathering Centers on the West side of the field and the three Flow Stations on the East side of the field. This gas is presently dehydrated in the Gathering Centers and Flow Stations. It was assumed that no further dehydration over current design capability is required to meet the sales gas water dewpoint specification of -35°F @ 1,100 psia. The hydrogen sulfide content of the feed gas is sufficiently low (0.50 grain/100 SCF) so that no hydrogen sulfide removal is required to meet the sales gas specification of 1.0 grain/100 SCF.

For design purposes the feed gas composition was assumed to be that associated with a crude production of 1,500,000 BPD with equal amounts of both crude and feed gas being produced from the East and West sides of the field. The gas composition derived from this crude oil production rate results in a maximum quantity carbon dioxide and NGL feed to the facilities. Lower crude rates would result in increased NGL blending in the pipeline gas and a slightly lower volume of NGL delivered to the Trans Alaskan Pipeline System.

Module and facility layout and design considered the following factors:

- Safety.
- Constraints because of Prudhoe Bay climatic conditions.
- Reliability of operation.
- Ease and economy of construction.

The remoteness and the severe environmental conditions at Prudhoe Bay impose limitations on both the process and mechanical design of the Facilities. The low ambient temperatures (-60°F) and high winds dictate that all equipment be housed in totally enclosed modules for protection of both personnel and equipment. The study assumed the use of safe and efficient methods for Arctic construction used by ARCo., EXXON and SOHIO during development of the Prudhoe Bay Field. Modules with contained equipment are to be fabricated in the "Lower 48." They would be sea-lifted to Prudhoe Bay by ocean-going barges. At Prudhoe Bay they would be offloaded by crawler transporters or rubber-tired vehicles and moved to their pile supports on graveled sites. The pile supports, gravel insulation and an air space below the modules prevent the permafrost from thawing.

Transport by the combination of barge and crawler or rubber-tired vehicles imposes both weight and height limitations on the modules. This in

turn establishes the number of carbon dioxide removal trains at four because of the weight and height limitations for the carbon dioxide absorbers. Weight limitations, to some extent, dictated equipment layout. The use of pile supports plus fully housed equipment made it desirable to minimize plot area or "footprint." Thus, vertical vessels were utilized in preference to horizontal vessels. Equipment is stacked wherever possible to minimize footprint.

The process and mechanical design safety factors adopted were consistent with industry practice and recognized the unique conditions prevailing at Prudhoe Bay.

The reliability philosophy that was adopted for the Facilities was aimed at insuring continuity of pipeline gas flow so as not to adversely affect Prudhoe Bay Unit oil production. Several different approaches were utilized to implement this philosophy:

- The use of a spare parallel train such as the fourth train in the carbon dioxide removal section.
- The use of spare equipment such as pumps and compressors.
- The use of commercially proven technology.
- The use of alternate "handling" such as injection for NGL.

Application of this approach generally led to the selection of conservative processing techniques and proven mechanical equipment.

The safety of personnel and equipment was a major design consideration. The following factors were included:

- Compliance with applicable safety regulations.
- Conformance with good engineering practice.
- Consideration of Prudhoe Bay environment.

Where one design was obviously more economical to install and/or operate than another, the less costly was chosen. In some cases process or equipment selections were made without detailed study because the available economic guidelines did not clearly indicate which was preferable. In some cases additional study of these alternatives has been recommended for the future detailed engineering design phase.

Space was allowed and the major process lines were sized to permit a 50% expansion of the gas conditioning capacity. The allowance included space for both process and auxiliary equipment.

4. PROCESS SELECTION

In July of 1977 a Sponsor Study Team was formed to screen various processes for removal of carbon dioxide (CO₂) from gas produced from the Prudhoe Bay Unit. With the support of The Ralph M. Parsons Company, potentially competitive commercialized processes were evaluated including:

Allied Chemical	SELEXOL*
Fluor	Propylene Carbonate
Shell	SUFINOL*
Union Oil	SORBCO-2*
Lotepro	RECTISOL*
Lurgi	PURISOL*
Open-art	DEA

As the result of this study it was determined that the Lotepro, Lurgi and Open-art DEA processes were not competitive in this application and the Union Oil process did not have adequate commercial experience.

Following this initial evaluation the decision was made by the Sponsor's Technical Advisory Committee to evaluate the Allied Chemical, Fluor and Shell processes in more detail. In addition various processes for hydrocarbon dewpoint control (NGL extraction) were to be screened in combination with the CO₂ extraction processes.

The selection of an NGL extraction process was significantly influenced by the pressure level for CO₂ removal. Three primary schemes were considered:

- NGL extraction at 540 psia by mechanical refrigeration, compression to 1400 psia, followed by CO₂ removal at 1400 psia.
- Compression to 1500-1800 psia, expansion to 1000 psia with NGL extraction by expansion refrigeration, CO₂ removal at 1000 psia, followed by booster compression to pipeline pressure.
- NGL extraction by mechanical refrigeration and CO₂ removal at 540 psia, followed by compression to pipeline pressure.

The last scheme, with both NGL extraction and CO₂ removal at 540 psia, was selected.

Preliminary appraisal of the first scheme appeared attractive since, for both physical and chemical CO₂ removal processes, both the solvent circulation rates and the equipment sizes were smaller at the higher pressures. However, it was found that at high pressure, all of the CO₂ removal processes required more absorption columns because the resulting heavier-walled columns exceeded module transport capacity limitations. Also, the additional operating cost of compressing the CO₂ to high pressure before removal proved to be unattractive. While this scheme made the most efficient use of the existing compressors and minimized solvent circulation it was dropped for the reasons cited.

The second scheme was a compromise to allow efficient use of existing compressors while reducing the CO₂ removal pressure. The number of CO₂ absorbers was reduced, but was still greater than the number required at 540 psia. Additional problems were encountered in the NGL extraction section with this scheme because the hydrocarbon extraction at 1000 psia is much less selective than at lower pressures. This requires the use of two low-temperature deethanizers, resulting in higher operating and capital costs. This scheme also had many of the disadvantages of the first scheme and was dropped.

The final selection of the CO₂ removal process was based on comparative equipment requirements, fuel usage and an approximate module count.

The Sponsor Study Team concluded that, in this application, a physical solvent process is preferred to a chemical solvent process based on the following advantages and disadvantages:

Physical Solvent Advantages

- Less major equipment - potentially lower investment.
- Less process fuel - more Btu's available for delivery to the sales gas pipeline.
- Inherently better extraction of NGL - better selectivity for disposal and pipeline gas blending.
- Dry process and no water required - no additional dehydration.
- No known corrosion problems.
- No special air coolers - no freezing problems.

Physical Solvent Disadvantages

- More rotating equipment (compressors) vs. static equipment (heaters, exchangers, coolers).
- Less flexibility in achieving a fuel balance.

The major disadvantage of the physical solvents involves the desirability of recovering the hydrocarbons in the CO₂ flash gas streams which requires a much greater number of compressors. The compressors, however, are relatively high-volume, low-pressure units which are well within the proven state-of-the-art. The physical solvent regeneration flash gases have a low heating value and must be blended with higher heating value streams to meet the minimum heating value requirements of various fuel streams. The increased operating problems of fuel blending and balance and compressor maintenance were deemed preferable to operating a potentially corrosive and wet SULFINOL system requiring additional dehydration and reboiling and having potential freezing problems. The higher operating costs

for the compressors in the physical solvent system were judged to be more than offset by a greater heating value to the gas pipeline.

The SELEXOL process has the following advantages over the other physical solvent processes:

- Fewer process trains - less major equipment - potentially lower investment.
- No vacuum flash in the regeneration system.
- Better NGL extraction and disposition selectivity for gas or crude blending.
- More potential for optimization.

During the process screening effort it was concluded that the most appropriate method of CO₂ disposal was in the fuel systems. It was assumed that the Prudhoe Bay Unit would accommodate this CO₂ in its fuel.

As a result of these conclusions the Sponsor Study Team recommended to the Technical Advisory Committee:

- That SELEXOL be selected as the carbon dioxide removal process.
- That mechanical refrigeration be used for hydrocarbon dewpoint control.
- That the operating pressure for both hydrocarbon dewpoint control and carbon dioxide removal be about 540 psia.

This above recommendations were accepted by the Technical Advisory Committee.

5. PROCESS DESCRIPTION

The Facilities process systems shown in block diagram form in Figure 1, and in more detail in Process Flow Diagram, Figure 2, include inlet separation and field fuel gas facilities, NGL extraction, CO₂ removal, sales gas compression and chilling, CO₂ solvent regeneration, and NGL fractionation. The process flow is similar for the four cases which were developed.

5.1 INLET SEPARATION AND FIELD FUEL GAS FACILITIES

Feed gases originating from the Gathering Centers and Flow Stations enter the Sales Gas Conditioning Facilities through the existing Central Compressor Plant inlet separators. These separators serve as liquid slug catchers and, in conjunction with downstream filter separators, serve to remove and recover any entrained liquids or particulates from the feed gases. Feed gas for the existing Field Fuel Gas Unit is withdrawn downstream of the filter separators. The Field Fuel Gas Unit feed is compressed in one of the existing first-stage injection compressors to between 1700 and 1800 psig. In the Field Fuel Gas Unit, the gas is cooled to -40°F at 850 psig by heat exchange and Joule-Thompson expansion. Cold vapor and condensed liquid are separated and the net Field Fuel Gas Unit conditioned gas is warmed by heat exchange with feed gas and goes to the Trans Alaskan Pipeline System fuel line. Cold separator liquid is also warmed by heat exchange with feed gas and is partially vaporized at about 635 psig. The separator vapor returns to the main Sales Gas Conditioning Facilities feed, and the net separator liquid joins the deethanizer feed stream.

5.2 NGL EXTRACTION

The feed stream from the inlet separators flows to the four parallel gas conditioning trains of the NGL Extraction and CO₂ Removal processes. Each train can condition 33% of the total flow, thus effectively providing one spare train. Within each of these trains the feed gas is combined with the SELEXOL stripper overhead gas and cooled to -30°F by heat exchange and propane refrigeration. Condensed liquids are separated from the cooled feed stream in the low-temperature separator and pumped through a feed gas heat exchanger where they are heated to 15°F. A partial demethanization flash occurs in the deethanizer feed flash drum, and the remaining liquid is heated to about 88°F by further exchange with feed gas and fed to the deethanizer. This 15°F flash separation serves to simplify both the design and operation of the deethanizer.

5.3 CO₂ REMOVAL

The vapor from the low-temperature separator is heated to about 20°F by exchange with feed gas and fed to the SELEXOL absorber along with deethanizer feed flash drum vapor, deethanizer overhead product gas, and SELEXOL recycle flash gas. In the absorber the feed gas is contacted countercurrently with lean SELEXOL solvent which absorbs the CO₂, a substantial portion of methane and ethane, most of the propane and essentially all of the heavier hydrocarbons from the gas. Cooling is required

in the circulating solvent system to maintain the design operating temperatures. A propane refrigerated intercooler is provided on the absorber to effect this cooling. Absorber overhead gas is warmed by heat exchange with feed gas and then routed to the pipeline gas compressors.

5.4 PIPELINE GAS COMPRESSION AND CHILLING

The conditioned gas streams from the four NGL extraction/CO₂ removal trains are combined. The net propane product and most of the butanes product from fractionation can be vaporized into the combined gas stream at this point. After compression and aftercooling in the existing Central Compressor Plant equipment, the conditioned gas stream is chilled to 25°F for delivery to the gas pipeline.

5.5 CO₂ SOLVENT REGENERATION

The SELEXOL solvent system is a simple recirculating loop. Solvent rich in CO₂ first flows from the absorber through a hydraulic power recovery turbine to a recycle flash drum. In the recycle flash drum a large percentage of the methane coabsorbed with the CO₂ is vaporized and compressed back to the absorber feed. Rich SELEXOL from the recycle flash drum flows through another hydraulic turbine to an intermediate pressure (IP) flash drum. A large part of the coabsorbed ethane, as well as CO₂ vapors, are released in the intermediate pressure flash. Solvent from the intermediate pressure flash drum is routed to the atmospheric, or low-pressure flash drum where the bulk of the absorbed CO₂ and coabsorbed propane and heavier hydrocarbons are released. The low-pressure flash gases are compressed to a nominal 325 psig level and routed to the local fuel fractionator. A stripper is required to reduce the CO₂ content of the lean solvent to the level required to condition gas to the 1 percent CO₂ level. Solvent from the low-pressure flash drum is pumped to the SELEXOL stripper where it contacts a slipstream of treated gas from the absorber. The stripping gas from the absorber is depressured through two expander stages for power generation and refrigeration recovery. Stripper overhead vapor is compressed back to feed gas pressure and recycled to the feed gas NGL extraction system for recovery of stripped hydrocarbons. Stripped lean solvent is pumped from the stripper back to the absorber, thus completing the circuit.

5.6 NGL FRACTIONATION

The single-train fractionation facilities consist of the local fuel fractionator, deethanizer, depropanizer, and debutanizer. All of these columns are reboiled by direct fired heaters. Compressed SELEXOL low-pressure flash gas is fed to the local fuel fractionator to recover the bulk of the propane and heavier hydrocarbons from the gas. The column has a refrigerated overhead condenser and is similar to a deethanizer. Separate feed-overhead heat exchangers are used for the local turbine and heater fuel portions of the overhead product. Propane is added to the turbine fuel portion of the overhead product for enrichment. This propane is vaporized in the feed-overhead exchanger. Local fuel fractionator bottoms product is fed to the depropanizer.

The deethanizer feed is made up of deethanizer feed flash liquids and NGL from the Field Fuel Gas Unit. The deethanizer operates at a nominal 450 psig with a propane-refrigerated condenser. Deethanizer overhead vapor product is compressed and can go either to field fuel or to SELEXOL absorber feed. Deethanizer bottoms product is fed to the depropanizer along with local fuel fractionator bottoms. The depropanizer produces a liquid propane overhead product stream. The low propane content depropanizer bottoms product can be blended directly into crude oil or fed to the debutanizer. The debutanizer produces a liquid butanes overhead product and a pentanes-plus bottoms product. The debutanizer overhead product can be almost totally injected into the pipeline gas without exceeding the pipeline gas hydrocarbon dewpoint specification or can be blended into the crude oil up to true vapor pressure limitations. The process design included the cooling facilities required for NGL and crude blending. These facilities are excluded from the summary cost estimate but are included in the cost estimate details in Section 11 of this volume.

A system is provided to inject the liquid feed for any column in the fractionation facilities alternatively into the producing formation. Therefore, an upset or equipment failure in the unsparred fractionation facilities will not impair either crude oil production or pipeline gas deliveries.

A small sidestream rectifier is utilized on the depropanizer to provide refrigerant grade propane as makeup for the refrigeration system. This column draws a small ethane-free vapor feed from below the depropanizer feed tray and produces a very pure propane overhead product. The bottoms are pumped back to the depropanizer.

5.7 FUEL SYSTEMS

The intermediate-pressure flash gas is collected from the CO₂ removal trains and compressed to a nominal 500 psig for use in the field fuel. Compressor discharge heat is used to vaporize propane. The propane is injected into this stream for heating value control. Field fuel requirements greater than those available from this flash gas stream are met by adding Field Fuel Gas Unit conditioned gas (in excess of Trans Alaskan Pipeline System requirements), deethanizer overhead vapor, and low temperature separator vapor in that order. The combined field fuel gas has a relatively high hydrocarbon dewpoint. This gas is heated to 140°F by exchange with the exhaust gas from the field fuel gas compressor turbine driver to prevent condensation in the insulated field fuel distribution system.

In situations where the field fuel requirement is relatively low, there may be an excess of SELEXOL intermediate-pressure flash gas. At these times, excess field fuel compressor discharge will be bled into the local turbine fuel system. This, in turn, will create an excess of local fuel fractionator overhead vapor. During this operation, the excess CO₂-rich local fuel fractionator overhead can be compressed and reinjected into the producing formation. If the local fuel fractionator is shut down, the feed to this column can be used for local fuel, and the excess feed can be injected using both CO₂ compressors. Also, during periods of high local fuel demand, field fuel compressor discharge can be used to supplement local fuel fractionator overhead.

6. PLANT YIELDS

In addition to the nominal 2,000 MMSCFD of pipeline gas conditioned by the Facilities there are a number of other streams that are separated incidental to the pipeline gas conditioning. These include the high CO₂ content flash gases from the regeneration of the SELEXOL® solvent and the NGL. The flash gases are utilized as fuel in the Facilities and to supply the fuel requirements of the Prudhoe Bay Unit. The NGL, which includes separate propane, butane, and pentanes-plus streams, may be blended into either the fuel streams (propane) to control heating value, the pipeline gas to the hydrocarbon dewpoint limitation (propane or butane) or into the crude (butane or pentanes-plus) as limited by the vapor pressure specification.

Figure 8 is a block flow diagram of plant stream sources and disposition and shows one possible blending scheme for the various products. The design anticipates that there will be a significant variation in the fuel requirements of the Facilities between the extremes of summer and winter operation. The demand for fuel by the Prudhoe Bay Unit will vary both as a function of season and time as well as oil production rates. The blending of butanes into either pipeline gas or crude is controlled by the pipeline hydrocarbon dewpoint limitation or by economics. These variations have been allowed for in the design of the Facilities. Thus an almost infinite number of blending schemes is possible permitting effective and economic utilization of all streams from the Facilities. The scheme illustrated in Figure 8 represents the maximum anticipated demand for fuel by the Prudhoe Bay Unit (Field Fuel) and assumes no blending of butanes to the pipeline gas; in actuality about 97.8% of the butanes can be blended into the pipeline gas without exceeding the assumed hydrocarbon dewpoint specification. (See Volume II for butanes blended into 1260 pipeline case.)

The gas requirements of the Trans Alaskan Pipeline System will normally be provided by gas conditioning in the existing Field Fuel Gas Unit. The flash liquid and vapor streams resulting from this operation will be processed in the Sales Gas Conditioning Facilities.

Tables 6-1, 6-2, 6-3, and 6-4 show the quantities, properties and compositions for the various feed and product streams for the same case as Figure 8. In addition, Tables 6-1 and 6-3 show the same information for the maximum butanes blended into pipeline gas. Depending upon the particular case there will be some variation in the quantities, properties and compositions of all streams. For design purposes material balances have been developed only for the minimum and maximum Prudhoe Bay Unit fuel gas demands.

Table 6-1. Feed From Gathering Centers and Flow Stations

6-1A. <u>SOURCES AND COMPOSITIONS</u>	From Gathering Centers	From Flow Stations	Total
Feed Gas (MMSCFD)(1)	1400.0	1400.0	2800.0
Compositions - Volume % as Gas			
H ₂ S (ppmv)	8 ppmv	8 ppmv	8 ppmv
CO ₂	12.72	12.54	12.63
N ₂	0.45	0.49	0.47
Methane	74.35	74.00	74.17
Ethane	6.33	6.61	6.47
Propane	3.43	3.52	3.48
Butanes	1.60	1.72	1.66
Pentanes-plus	1.12	1.12	1.12
	<u>100.00</u>	<u>100.00</u>	<u>100.00</u>
6-1B. <u>OVERALL MATERIAL BALANCE</u>			
<u>Stream</u>	<u>Volume (MMSCFD)(1)</u>		
Feed from Gathering Centers	1400.0		
Feed from Flow Stations	1400.0		
Total Feed	2800.0		
Sales Gas-Net	2000.6		
Propane-Balance over fuels	37.2		
Butanes	41.3		
Pentanes-plus	31.9		
Fuels	689.0		
Total Product	<u>2800.0</u>		

(1) Standard Conditions - 14.65 psia and 60°F.

Table 6-2. Pipeline Gas

	As Conditioned	Propane Blended (6)	Propane Plus Butane Blended (7)
Volume Produced - MMSCFD (1)	2000.6	2037.8	2078.2
MMSCFD (2)	1989.7	2026.7	2067.0
CO ₂ content - vol.% (3)	0.50	0.49	0.49
Hydrocarbon Dewpoint @ 1100 psia-°F	-60 approximate	-50 approximate	-10.
Heating value			
Higher heating value - Btu/SCF (4)	1034	1061	1106
- Btu/SCF (5)	1022	1048	1092
Lower heating value - Btu/SCF (8)	930	955	994
H ₂ S content Grains/100 SCF	<1.0	<1.0	<1.0
Water Dewpoint @ 1100 psia -°F	-35°	-35°	-35°
Composition Volume % as Gas			
H ₂ S	1 ppmv	2 ppmv	2 ppmv
CO ₂ (3)	0.50	0.49	0.49
N ₂	0.62	0.61	0.60
Methane	94.29	92.57	90.77
Ethane	4.47	4.50	4.41
Propane	0.08	1.75	1.72
Butanes	0.03	0.07	1.95
Pentanes	0.01	0.01	0.06
	<u>100.00</u>	<u>100.00</u>	<u>100.00</u>

(1) Standard conditions - 14.65 psia and 60°F (State of Alaska Base).

(2) Standard condition - 14.73 psia and 60°F (FERC Base).

(3) SGCF was designed at 0.5 vol. % CO₂ to guarantee 1.0 vol. % max. in Pipeline Gas.

(4) Gross, dry, actual at 14.65 psia and 60°F.

(5) Gross, wet, actual at 14.73 psia and 60°F.

(6) This is the as-conditioned gas when blended with propane in excess of fuel requirements.

(7) This is the as-conditioned gas when blended with propane in excess of fuel requirements plus butanes to the hydrocarbon dewpoint limitation.

(8) Net, dry, ideal at 14.65 psia and 60°F.

Table 6-3. Fractionator Products

	Propane	Butanes		Pentanes-plus
Net Extracted				
BPD	52,350	31,290		28,700
MMSCFD (1)	80.3	41.3		--
Disposition		Min.	Max.	
To Pipeline Gas				
BPD	24,270	-0-	30,602	-0-
MMSCFD (1)	37.2	-0-	40.4	-0-
To Fuel Gas Systems				
BPD	28,080	-0-	-0-	-0-
MMSCFD (1)	43.1	-0-	-0-	-0-
To Crude				
BPD	-0-	688	31,290	28,700
Composition - Volume % as gas				
H ₂ S	38 ppmv		-	-
CO ₂	0.01		-	-
Ethane	6.40		-	-
Propane	91.59		0.17	-
Butanes	2.00		97.31	6.01
Pentanes-plus	-		2.52	93.99
	<u>100.00</u>		<u>100.00</u>	<u>100.00</u>

(1) Standard Conditions - 14.65 psia and 60°F.

Table 6-4. Fuel Streams

	For TAPS	For Prudhoe Bay Unit (Field Fuel)	For Local Turbine	For Local Heater
MMSCFD (1)	40.9	399.4	192.0	56.7
Lower Heating Value-Btu/SCF	851	825	475	212
MM Btu/hr.	1,450	13,729	3,800	500
Hydrocarbon Dew Point -°F (2)	-40°F @ 840 psig	27°F @ 500 psig	17°F @ 300 psig	60°F @ 60 psig
Composition - Volume % as gas				
H ₂ S	4 ppmv	22 ppmv	38 ppmv	40 ppmv
CO ₂	11.44	36.40	75.08	87.21
N ₂	0.58	0.13	-	-
Methane	81.54	37.73	2.71	1.46
Ethane	4.70	16.24	9.23	9.04
Propane	1.37	8.84	12.67	2.29
Butanes	0.31	0.60	0.30	-
Pentanes-plus	0.06	0.06	0.01	-
	100.00	100.00	100.00	100.00

(1) Standard conditions - 14.65 psia and 60°F.

(2) Pressures are system-operating pressure.

7. PROCESS AUXILIARY SYSTEMS

Utility systems for the Sales Gas Conditioning Facilities were developed to the detail necessary for estimating cost. They include:

- Electrical power generation system.
- Glycol cooling medium system.
- Glycol process heating medium.
- Glycol module heating medium system.
- Nitrogen inert gas system.
- Service and instrument air systems.
- Closed hydrocarbon drainage system.
- Potable and utility water system.
- Sanitary sewer system.
- Hydraulic power center systems.
- Communication systems.
- Safety and fire protection system.

The peak electrical power requirement for the Facilities is about 65 megawatts. Power recovery generators on the stripping gas expanders and solvent streams provide 12 megawatts of this power. The balance is generated by a three-generator unit utility power plant. An on-line spare generator unit is provided during all load conditions. Lower loads during cold ambient temperature conditions permit shutting down a unit for planned maintenance without affecting the minimum design spare generating capacity. Emergency power for critical control, lighting, fire protection and heating systems is provided by smaller turbine generator units.

8. FACILITY LOCATION AND ARRANGEMENT

Because this Study assumed use of the existing first-stage injection compressors as a base case, the Sales Gas Conditioning Facilities were located close to the Central Compressor Plant. This location takes advantage of the existing field gas gathering lines to the Central Compression Plant and the existing gas injection wells near the Central Compression Plant. Its proximity to the existing docks reduces time required for low-speed transporter movement of the large number of modules from the docks to the site. A site location plan is shown as Figure 3.

Modular construction is a proven, cost effective method for constructing facilities at Prudhoe Bay. Modular design utilizes a structural steel base supporting a steel frame building housing the equipment. The module size and base structure are designed to allow movement by low-speed transporters. Modules are assembled to the maximum extent possible at the "Lower 48" fabrication site to avoid the significantly higher North Slope costs. The modules are then barged to the North Slope and set on prepared gravel and piling sites. The modules are interconnected after placement, and utilidors (enclosed pipeways/walkways) are used where required to provide the necessary safe module separation.

The layout of the modules included in the facilities is centered around the four gas conditioning trains with space reserved for up to a 50% capacity expansion. Process and support facilities are centrally located near the gas conditioning trains. This was done, without compromising general safety separation criteria, to service the gas conditioning trains as efficiently as possible. The emergency flares are located a safe distance from the process facilities. The crude cooling and NGL crude blending facilities are located near the Trans Alaskan Pipeline System Pump Station No. 1. The Construction Camp and Operations Center are located a convenient but safe distance from the process facilities and the pipeline routes. Overall module layouts of the process facilities and the camps are shown on Figure 4.

Figure 7 illustrates a typical layout drawing for a 33% capacity gas conditioning train, which includes nine modules and one utilidor.

9. MODULE FIRE AND SAFETY CONSIDERATIONS

Totally enclosed modularized facilities are ideal for providing controlled environmental conditions during construction and operation on the North Slope. However, modular construction requires special ventilation and fire protection measures. The modules are maintained within a controlled temperature range using heated makeup air. Exhaust fans insure proper ventilation and prevent an accumulation of hydrocarbons. Other protective measures and safety systems considered in this study include:

- Emergency Shutdown System for process isolation of all or portions of the Facilities.
- Process area isolation to prevent the spread of hydrocarbon vapors or fire.
- Gas Detection and Fire Sensing Systems.
- Halon inerting and fire extinguishing systems.
- Firewater backup extinguishing systems.
- Liquid hydrocarbon and firewater drainage systems.
- Relief, vent and flare systems.
- Mobile fire fighting equipment

10. IMPLEMENTATION PLAN

The implementation plan provides a sequenced checklist of scheduled events for the entire project from initiation of detailed design engineering through startup of the Facilities. The plan provides the basis for estimating the cost of engineering, procurement, fabrication, logistics and erection activities. The plan assumes early and effective use of proven scheduling, quality assurance, cost control, and material control procedures to assure completion of the Project on time and within the authorized funding.

10.1 SCHEDULE

The implementation plan schedule milestones illustrated in Figure 5 show an exceptionally tight sequence of activities from initiation of final process design to startup. With careful planning, timely funding, and absence of regulatory or legal delays it would be possible to complete the Facilities with a 4-1/2 year lead time.

In order to have a 66% capacity startup in January, 1983, it is necessary to initiate final process design in September, 1978. Full capacity startup is not possible before July, 1983. In order to achieve either schedule, it is necessary to conclude detail design engineering contractor selection no later than January, 1979. Final process design must be completed by December, 1978, and detailed mechanical design must commence no later than January 1, 1979. Time sensitive activities during the first three months of detailed design include:

- Preparation of specifications and requisitions for critical delivery equipment and materials such as turbines, compressors, heavy-wall vessels, and low-temperature piping.
- Design of the first phase of the Construction Camp and its associated facilities to support a spring 1980 installation at Prudhoe Bay.
- Initiation of permitting activities including the gathering of baseline air quality data required for construction permits in support of 1980 and 1981 Prudhoe Bay erection activities.

10.2 FUNDING

Required funding approvals are shown on the schedule, phased as required to support critical design and procurement activities. To meet the schedule, funding for these activities should be provided by late 1978 and preferably prior to engineering contract negotiations. Total project funding is required by December, 1979, which coincides with award date for fabrication contracts. Prior to December, 1979, total project funding approval, commitments totaling approximately \$500,000,000 will be required for engineering and ordering critical equipment.

10.3 PROCUREMENT

Given present market conditions and recognizing possible impact of concurrent projects such as the Alaska Highway Gas Pipeline System and the Prudhoe Bay Unit production facility work, procurement of long lead items included in the 1981 sealift should begin in March, 1979.

10.4 CONSTRUCTION

The general construction plan assumes three phases of work involving a small sealift in 1980 supplemented by truck hauling followed by two major sealifts in 1981 and 1982. Pre-sealift work must be initiated in 1980 both at "Lower 48" fabrication sites and at Prudhoe Bay.

The implementation plan assumes an optimized North Slope labor force of 1,000. This manpower level dictates the Construction Camp size and associated support costs for Prudhoe Bay. It also indirectly dictates the fabrication manpower level. Scheduled and peak manpower requirements are shown in Table 10-1.

Table 10-1. Manpower Requirements

BASE CASE	"Lower 48" Fabrication		North Slope Erection	
	Total Manhours	Peak Manpower (Year)	Total Manhours	Peak Manpower (Year)
Full Startup	9,366,000	3,000 (81,82)	5,435,000	800 (82)
Phased Startup	9,387,000	4,500 (81)	5,389,000	1,000 (81,82)
ALTERNATE CASE				
Full Startup	10,141,000	3,500 (82)	5,720,000	800 (82)
Phased Startup	10,134,000	4,750 (81)	5,656,000	1,000 (81,82)

The fabrication sites are assumed to be located adjacent to major deep-draft waterways which will accommodate ocean-going barges. West Coast fabrication sites were assumed for planning purposes. The West Coast provides favorable weather conditions, adequate manpower and the shortest shipping distance. Fabrication site size requirements are estimated at 200 acres for 1981 and 80 acres for 1982. The job size and construction manpower requirements indicate that at least two sites must be considered as a planning basis. The estimate basis assumes that sites are completely unimproved and require grading, compacting and construction of module pads, offices, shops, warehouses, utility distribution systems, fencing, and barge loading facilities.

Support facilities at Prudhoe Bay include a temporary Construction Camp and a permanent Operations Center along with required power generation, water supply, and sewage and water treating facilities. The Construction Camp would be erected in two phases. The first phase, erected during early 1980, would provide lodging and support for the approximately 450 staff and craft personnel involved in gravel, piling, and other early construction work from June, 1980, to June, 1981.

Since the peak period of North Slope construction is scheduled for the fall of 1981, the second phase of camp construction would be completed during the spring of 1981. This expansion increases the size of the construction camp to accommodate the projected peak construction manpower of 1,000.

The completed Construction Camp will include lodging, kitchen, dining room, recreational facility, laundry, medical room, and office space. Utility buildings will include garages, warehouses, miscellaneous flammable liquid storage, bulk gasoline and diesel fuel storage and dispensing terminal, welding shop and fabrication shop. Facilities are provided for emergency power generation, mobile fire protection, waste incineration, water treatment, and sewage treatment. Some of these will be permanent facilities associated with the Operations Center.

The Operations Center erected in 1981 will be a 200-man modular facility designed to house and support permanent operations, maintenance, and staff personnel. During construction, the Operations Center would be used to house Plant Owner/Operator representatives, operators, and startup and maintenance personnel assigned to monitor and inspect construction activities. Included in initially installed facilities are utilities which will be used to support both the Construction Camp and the Operations Center. These will be trucked overland in 1980. Operations Center units delivered in the 1981 sealift will include administrative offices, kitchen, medical room, laundry, recreational facility, and support systems similar to those erected earlier for the Construction Camp.

10.5 LOGISTICS

Docking facilities at fabrication sites should be capable of dead loading modules; i.e., loading a barge that is flooded and bottomed. A general cargo storage and staging area should be provided with appropriate lighting and support equipment. Both 1981 and 1982 module loadout programs will require approximately 30 days each to complete preceded by approximately two weeks of module preparation.

Barge requirements to move the completed modules and general cargo are estimated as follows:

	PHASED STARTUP			FULL STARTUP		
	1980	1981	1982	1980	1981	1982
BARGES REQUIRED	2	25	11	2	24	16

The two startup cases require approximately the same square footage of barge space. In the phased startup, larger barges but fewer are required.

Two possibilities were considered for module offloading at Prudhoe Bay as follows:

- (1) A new separate causeway and dock for the Facilities could be constructed independent of existing North Slope facilities. Offloading of modules would then be independent of the other projected Prudhoe Bay Unit projects.
- (2) The existing dock facilities owned by SOHIO/ARCO./ EXXON could be expanded and the offloading coordinated with concurrent North Slope projects.

The latter approach is assumed for our planning basis. This approach results in less capital expenditure and tends to minimize environmental impact. The use of these facilities would require close coordination between the Sales Gas Conditioning Facilities project and other concurrent North Slope projects to ensure timely offloading of all modules and general cargo. Module offloading, estimated to take 21 to 34 days, can be accomplished through the use of both crawler transporters and newly developed rubber-tired vehicles.

10.6 STARTUP

Facilities startup activities will begin approximately six months prior to mechanical completion. It is assumed that an Operator/Owner startup team will be formed and used in a technical and supervisory capacity with regular operating personnel performing the physical startup of the facility.

11. ESTIMATED COSTS

The Sales Gas Conditioning Facilities cost estimates were prepared on a mid-1978 cost basis. Escalation was estimated on an item by item basis and is extremely sensitive to implementation schedule.

11.1 ESTIMATING METHOD

The estimating method utilized the modular construction cost experience of Atlantic Richfield Company (Unit Operator - East) and The Ralph M. Parsons Company, from production facilities development on the east side of the Prudhoe Bay Field.

The estimate was developed from:

- Individual Module Layouts to Determine Size and Weight.
- Major Equipment Estimating Quotations.
- Major Piping Layout.
- Single-Line Electrical Drawings.
- Detailed Analysis of "Lower 48" and North Slope Labor Requirements.
- Logistics Analysis.

The estimate basis is presented in detail in Volume of this Report.

11.2 ESTIMATED COSTS

Estimated costs, including contingency and excluding the Crude Oil Cooling Facilities, for each of the four cases studied are tabulated below:

	<u>Mid-1978 Basis</u> <u>(Dollars)</u>	<u>Escalated Basis</u> <u>(Dollars)</u>
Base Case Full Startup	1,571,500,000	1,962,300,000
Base Case Phased Startup	1,581,200,000	1,964,500,000
Alternate Case Full Startup	1,688,400,000	2,109,700,000
Alternate Case Phased Startup	1,701,700,000	2,107,200,000

A Unit detail of these costs is shown in Table 11-1.

The escalation applied to each of the four cases is based upon a Ralph M. Parsons Company composite analysis of various inflation forecast

sources listed in the estimate basis. (Detailed in Volume III Section 12.) The escalation percentages were then applied to the costs in accordance with the implementation schedule. Based on the current plan and schedule, a weighted average annual escalation of 6.73% was applicable.

11.3 CONTINGENCY ANALYSIS

Contingency funds were included in the costs presented in this report; the contingency percentage used was determined by risk analysis using RISKAN.* Each major cost account was evaluated for probable accuracy variation taking into account the engineering design basis, extent and accuracy of material takeoffs and estimating and pricing methods. Where escalation was included in the costs, the escalation was considered in the risk analysis. The details of the risk analysis are shown in Volume III of this report.

The contingency selected gives a 90 percent probability that the estimated cost including contingency will not be exceeded, provided the design and schedule are followed as planned in this study.

11.4 OTHER FACILITY COSTS

Crude oil cooling facilities costs are excluded from the total cost of the Facilities. These costs are shown separately in Table 11-2.

11.5 DELAY COST TREND

Delays in proceeding with this project will increase the cost of the facilities in accordance with escalation forecasts. Delay cost trends calculated for delay of completion year to 1984, 1985, and 1986 are as follows when utilizing the same 4-1/2 year implementation plan:

Full Capacity Delivery Year	Incremental Delay Cost	
	Base Case (Dollars)	Alternate Case (Dollars)
1984	\$160,000,000	\$170,000,000
1985	\$350,000,000	\$370,000,000
1986	\$540,000,000	\$580,000,000

Delay costs are calculated by an application of escalation to equipment and materials, labor and support, engineering design and management and plant operator's costs, then with recalculation of contingency using RISKAN procedure. This procedure indicates a delay cost of approximately 9 percent per year. These costs are not included in the project estimated costs presented in subsection 11.2.

11.6 COSTS INCLUDED IN THE ESTIMATES

The following costs have been included in the estimates. The estimate detail (Volumes VI and VII) provides information on these costs:

- Engineering, Procurement

- Equipment and Materials
- Module Fabrication
- North Slope Erection
- Construction Management and Supervision
- Fabrication Site Lease, Site Development and Temporary Facilities
- North Slope Camp and Other Temporary Facilities
- Barging Costs
- Operations Center
- SELEXOL® License Fee
- Initial Charge of Chemicals and Operating Supplies.
- Spare Parts
- Dual fuel system and combustor retrofit in Central Compression Plant
- Costs Paid Directly by the Plant Operator/Owner (Plant Operator Cost):
 - Preliminary Engineering Design Study *
 - Plant Operator Engineering and Construction Supervision
 - Plant Operator Commissioning and Startup Costs *
 - Alaska ad Valorem and Borough Taxes *
 - Dock Use Charges

11.7 COSTS EXCLUDED

Costs excluded from the estimate are:

- Financing Costs
- Reimbursement for cost of Prudhoe Bay Unit Central Compression Plant

*Normally expensed by Operator/Owner

- Operating Costs
- Operating Supplies (SELEXOL, Glycol, Lube Oils), except Initial Charge Included in Estimate
- Sales Tax on In-Transit Materials
- Cost for Lost or Damaged Materials (or Insurance for)
- All-Risk Insurance
- Land/Mineral Leases at Prudhoe Bay
- Permit and Environmental Impact Statement Costs
- Unexpected Deviation from, Adverse Interpretation of, or Revision to Current Environmental Regulations
- Landing Strip or Airport Facilities at Prudhoe
- Dock Expansion Costs (Dock Use Charge Included)
- Use of Prudhoe Bay Unit Roads and the haul road from Fairbanks to Prudhoe Bay
- Facility Removal Costs at End of Production Life
- Revision to Schedule or Major Delays
- Salvage, Scrap or Transfer Value of Surplus or Cancelled Equipment/Material
- Process Optimization Engineering Cost
- Contingency for significant scope changes

11.8 CASH FLOW

Projected cash flow including contingency and escalation, but exclusive of Crude Oil Cooling Facilities (Unit 62), for the four cases included in this study are tabulated in Table 11-3. The base case, full startup commitment and expenditure curves are shown on Figure 9. The commitment curve reflects material commitments when ordered whereas construction costs are committed as spent.

TABLE 11-1. ESTIMATE SUMMARY
TOTAL DOLLARS IN MILLIONS

UNIT No.	DESCRIPTION	MID-1978 DOLLARS				ESCALATED DOLLARS			
		BASE CASE		ALTERNATE CASE		BASE CASE		ALTERNATE CASE	
		FULL STARTUP	PHASED STARTUP	FULL STARTUP	PHASED STARTUP	FULL STARTUP	PHASED STARTUP	FULL STARTUP	PHASED STARTUP
31-34	NGL Extr. & CO ₂ - Train #1-4	177.6	177.6	177.6	177.6	177.6	177.6	177.6	177.6
41	Sales Gas Compression	6.7	6.7	-	-	6.7	6.7	-	-
42	Inlet Separation	-	-	7.8	7.8	-	-	7.8	7.8
43	Sales Gas Compression	-	-	59.2	59.2	-	-	59.2	59.2
45	Refrigeration	81.1	81.1	81.1	81.1	81.1	81.1	81.1	81.1
46	Field Fuel & CO ₂ Fac.	28.3	28.3	28.3	28.3	28.3	28.3	28.3	28.3
51	NGL Fractionation	51.3	51.3	51.3	51.3	51.3	51.3	51.3	51.3
61	Utilities/Pipeways	140.5	140.5	141.8	141.8	140.5	140.5	141.8	141.8
63	Power Generation	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2
80	Operations Center	22.2	22.2	22.2	22.2	22.2	22.2	22.2	22.2
	Total Equipment & Material	527.9	527.9	589.5	589.5	527.9	527.9	589.5	589.5
	Lower 48 Labor & Support	256.1	259.4	272.7	276.7	256.1	259.4	272.7	276.7
	North Slope Labor & Support	401.7	403.2	416.5	419.2	401.7	403.2	416.5	419.2
	Engineering, Design & Mgmt.	91.0	91.0	98.0	98.0	91.0	91.0	98.0	98.0
	Plant Operator's Costs:								
	Owner/Operator Engr. Teams	44.9	45.0	47.8	48.0	44.9	45.0	47.8	48.0
	Dock Use Charge	7.6	7.6	8.0	8.0	7.6	7.6	8.0	8.0
	Commissioning & Start-up	49.0	49.0	49.1	49.1	49.0	49.0	49.1	49.1
	Ad Valorem & Borough Taxes	63.5	67.5	67.4	72.7	63.5	67.5	67.4	72.7
	Mid-1978 Subtotal	1441.7	1450.6	1549.0	1561.2	1441.7	1450.6	1549.0	1561.2
	Escalation	-	-	-	-	294.9	287.9	318.0	303.6
	Contingency (#9% '78 Dollars #13% Esc. Dollars)	129.8	130.6	139.4	140.5	225.7	226.0	242.7	242.4
	Total Facility Estimate	1571.5	1581.2	1688.4	1701.7	1962.3	1964.5	2109.7	2107.2

NOTE: This estimate summary excludes Unit 62, Crude Oil Cooling Facilities.

TABLE 11-2
CRUDE OIL COOLING FACILITIES - UNIT 62
ESTIMATE SUMMARY
TOTAL DOLLARS IN MILLIONS
(ALLOCATED FROM TOTAL ESTIMATE)

UNIT No.	DESCRIPTION	MID-1978 DOLLARS				ESCALATED DOLLARS			
		BASE CASE		ALTERNATE CASE		BASE CASE		ALTERNATE CASE	
		FULL STARTUP	PHASED STARTUP	FULL STARTUP	PHASED STARTUP	FULL STARTUP	PHASED STARTUP	FULL STARTUP	PHASED STARTUP
62	Crude Oil Cooling Facilities	22.4	22.4	22.4	22.4	22.4	22.4	22.4	22.4
	Gravel	.3	.3	.3	.3	.3	.3	.3	.3
	Total Equipment & Material	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7
	Lower 48 Labor & Support	13.0	13.2	12.9	13.1	13.0	13.2	12.9	13.1
	North Slope Labor & Support	10.2	10.2	9.9	10.0	10.2	10.2	9.9	10.0
	Engineering, Design & Mgmt.	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
	Plant Operator's Costs								
	Owner/Operator Engr. Teams	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
	Dock Use Charge	.3	.3	.3	.3	.3	.3	.3	.3
	Commissioning & Start-up	1.9	1.9	1.7	1.7	1.9	1.9	1.7	1.7
	Ad Valorem & Borough Taxes	2.5	2.6	2.4	2.6	2.5	2.6	2.4	2.6
	Mid-1978 Subtotal	55.8	56.1	55.1	55.6	55.8	56.1	55.1	55.6
	Escalation	-	-	-	-	13.1	11.2	12.9	11.1
	Contingency (29% '78 Dollars @13% Esc. Dollars)	5.0	5.0	5.0	5.0	9.0	8.7	8.8	8.7
	Total Unit 62 Estimate	60.8	61.1	60.1	60.6	77.9	76.0	76.8	75.4

Table 11-3. Cumulative Cash Flow
(Millions of Dollars)

Year	Quarter	Base Case		Alternate Case	
		Phased Startup	Full Startup	Phased Startup	Full Startup
1978	1-4	1.7	1.7	1.7	1.7
1979	1	8.0	8.0	8.0	8.0
	2	51.0	35.0	57.0	48.0
	3	100.0	60.0	117.0	87.0
	4	200.0	122.0	223.0	163.0
1980	1	288.0	189.0	319.0	231.0
	2	431.0	309.0	484.0	344.0
	3	584.0	457.0	658.0	487.0
	4	733.0	626.0	834.0	654.0
1981	1	887.0	798.0	1,015.0	852.0
	2	1,053.0	984.0	1,211.0	1,066.0
	3	1,172.0	1,127.0	1,321.0	1,211.0
	4	1,291.0	1,271.0	1,432.0	1,355.0
1982	1	1,396.0	1,434.0	1,606.0	1,537.0
	2	1,492.0	1,584.0	1,767.0	1,705.0
	3	1,626.0	1,635.0	1,824.0	1,762.0
	4	1,741.0	1,678.0	1,873.0	1,810.0
1983	1	1,821.0	1,795.0	1,958.0	1,935.0
	2	1,875.0	1,874.0	2,015.0	2,018.0
	3	1,938.0	1,936.0	2,080.0	2,082.0
	4	1,964.5	1,962.3	2,107.2	2,109.7

12. FUTURE DESIGN CONSIDERATIONS

A number of ideas were developed during the progress of the Study which, if determined to be viable and incorporated into the final design, could potentially result in significant capital savings and/or reduction in operating cost. It was not possible to evaluate all of these ideas during the Study because of schedule limitations.

Although some of these ideas apparently have obvious cost benefits and need only to be developed, others require economic evaluation and justification before they could be implemented. More detailed information on Facility ownership, value of conditioned gas, value of fuel gas, value of NGLs, transportation tariff, etc., must be known before these studies can be concluded. Some of these ideas may be evaluated concurrently with the development of the final design. These ideas are put forth in Volume IV.

Other of these ideas will impact the schedule and should be the first item of work if the Facilities are to be completed by July, 1983. The decision as to whether or not these ideas are to be incorporated in the final design should be made before starting the final design because:

- Incorporation will influence the scope of work for the final design.
- Time is required for the development work necessary for their application.

These ideas, which impact schedule, are outlined below and developed in detail in Volume II.

12.1 BASIC SELEXOL PROCESS DESIGN

The basic NGL/CO₂ extraction processes can potentially be modified by increasing the operating temperature of the low-temperature separator, altering the feed gas chilling and altering SELEXOL solvent chilling systems. The above changes would reduce both capital and operating costs.

12.2 REFRIGERATION SYSTEM OPTIMIZATION

Several possible configurations for the refrigeration facilities were examined in the Study. A centralized system with parallel compressors was selected. Further optimization of this system is possible. There are a number of areas where either the refrigeration level or load can be reduced. The impact of these improvements would be to reduce both the capital and operating costs of the refrigeration system. During the selection of the final configuration, it is suggested that a detailed analysis of the refrigeration process control system be conducted.

12.3 WASTE HEAT RECOVERY

Potential exists for further fuel conservation via additional waste heat recovery from the gas turbine exhaust gas. This potential is over

and above the heat recovery by using regenerative gas turbines in the design. The potential uses for this heat include:

- Reboiling of the fractionator towers
- Module heating

The impact of using waste heat would be to increase available gas for future disposition. The evaluation should consider the additional requirements for disposal of surplus low heating value gas during early and late years of the Facilities and Field operation.

12.4 REEVALUATION OF THERMODYNAMIC DATA

The proper selection and sizing of process equipment for the Facilities is largely dependent on thermodynamic data. For the purposes of this study the best available data were used. The quality of this data and hence the quality of the final design may be improved by:

- A comprehensive literature search and data evaluation covering the expected composition and operating conditions for this facility.
- Generation of new data for these facilities in the laboratory, where suitable data are not in the literature.

12.5 PIPELINE GAS SPECIFICATIONS

The gas pipeline specifications and delivery pressure adopted for this Study were established on the basis of the best available knowledge at the time the Study was started. A higher allowable CO₂ content of the delivered gas will have a significant impact on the facilities costs. It is recommended that the cost impact of the possible alternative specification for CO₂ content and gas pipeline pressure be evaluated for the overall conditioning and gas transmission system.

12.6 GAS TURBINE COMBUSTORS

It was determined that gas turbines with the proper combustor and control configuration can burn both low-Btu/high-CO₂ content fuel gas and normal-Btu fuel gas. Combustor testing and development will be required for the specific fuels available from these facilities. This work by the selected vendor or vendors should begin in the first quarter of 1979 to insure timely delivery of the gas turbines. In addition, data from these tests will be required to obtain permits.

12.7 SELEXOL ABSORBER/STRIPPER INTERNALS

There are several vendors of tower packings who claim very high hydraulic capacity for some of their packings. If these claims are valid it

would be possible to eliminate one SELEXOL train. However, these claims should be validated by independent testing prior to use of these packings.

12.8 ENVIRONMENTAL

Administration by local agencies of the Clean Air Act and Amendments of 1977 could impose requirements not perceived by this Study. Upon project initiation, the requirements should be determined as soon as possible and the impact on Facilities design and implementation should be established.

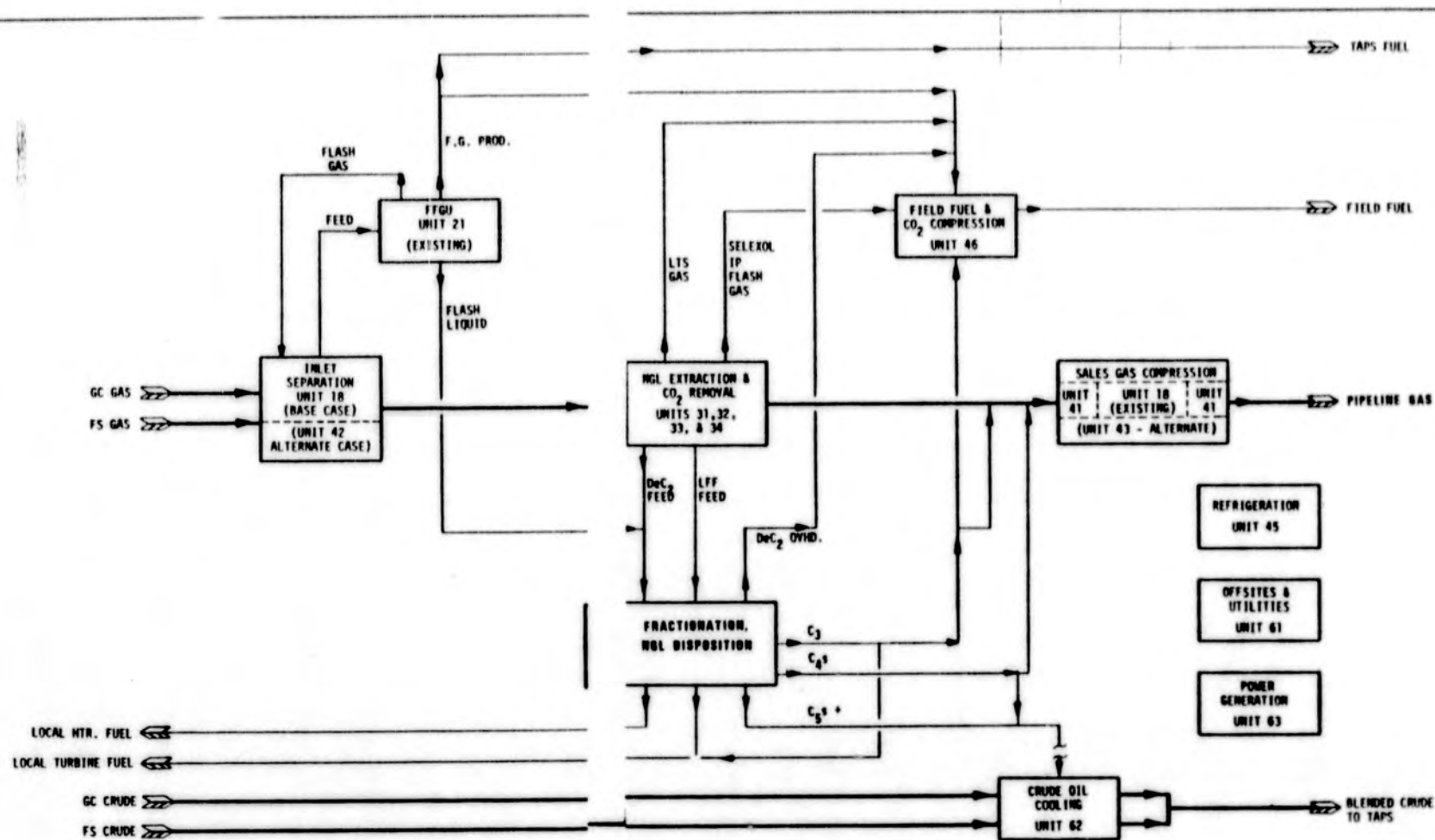
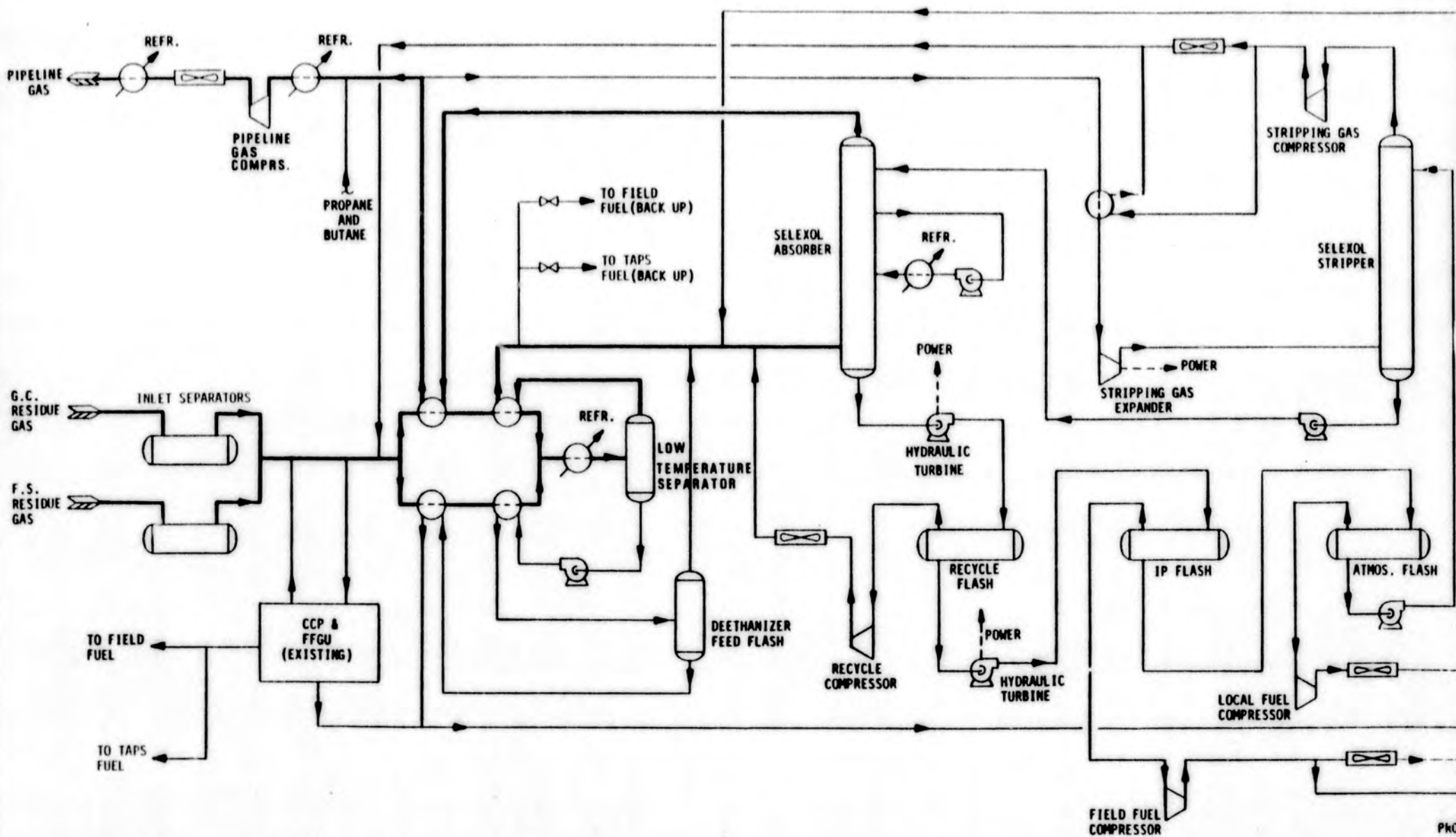


Figure 1
Block Flow Diagram
Sales Gas Conditioning
Facilities



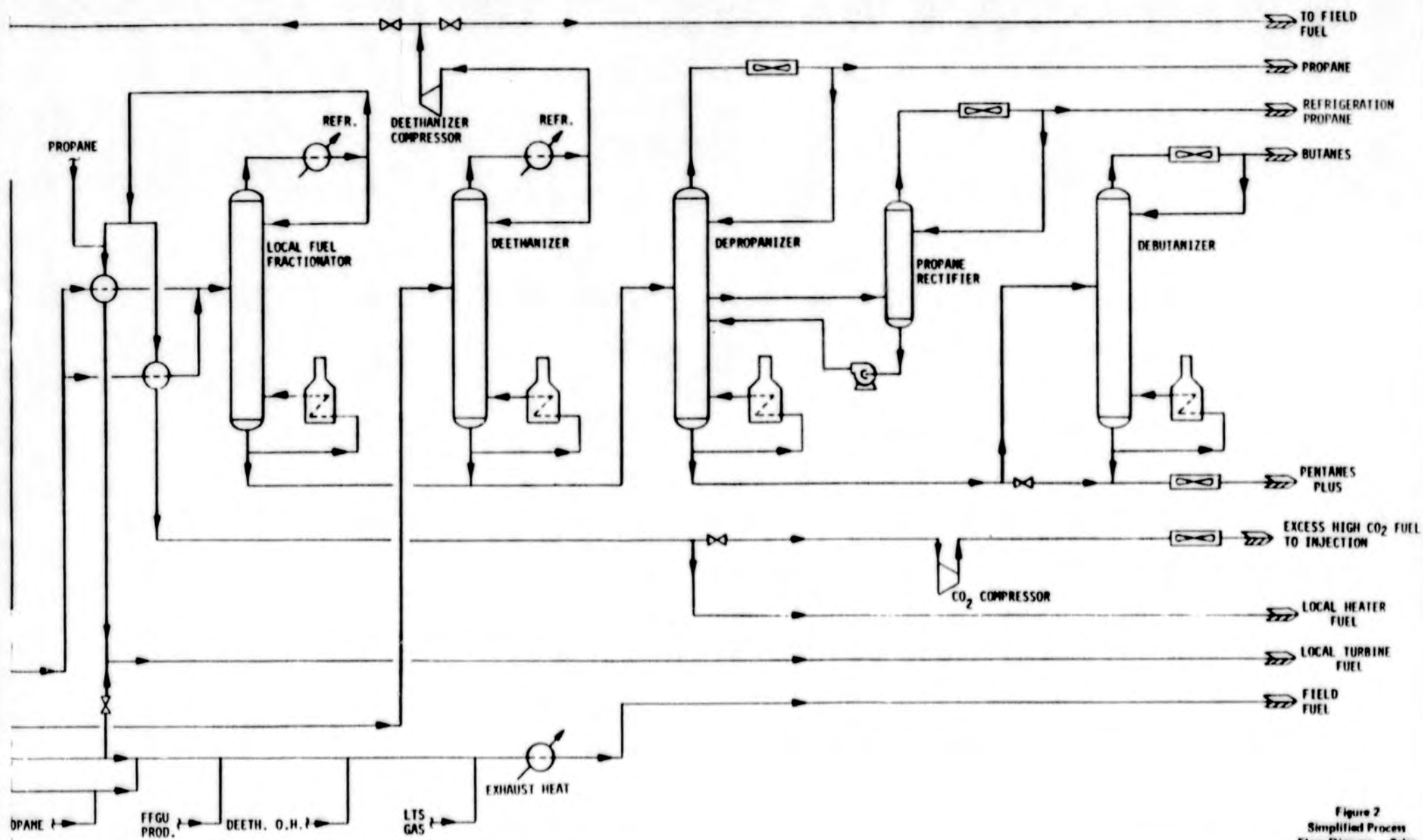
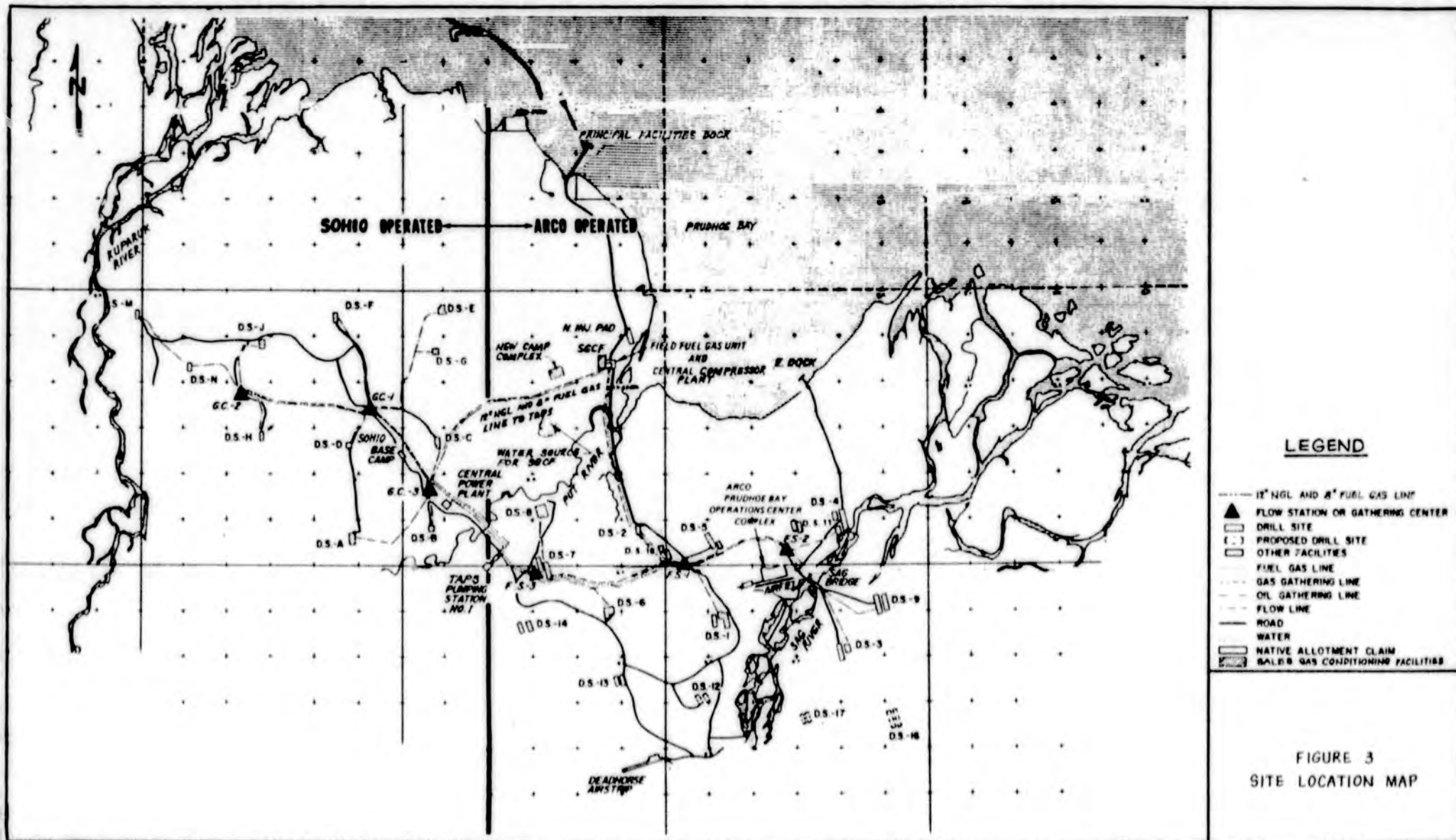
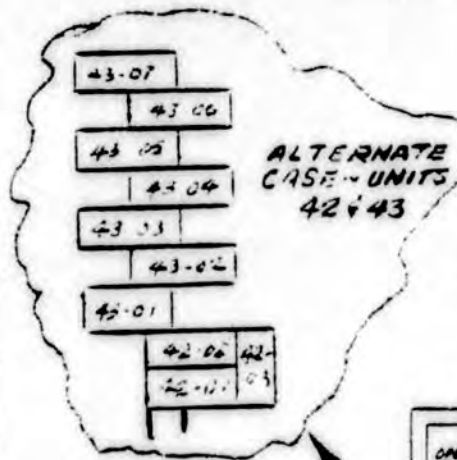


Figure 2
Simplified Process
Flow Diagram - Sales
Gas Conditioning Facilities

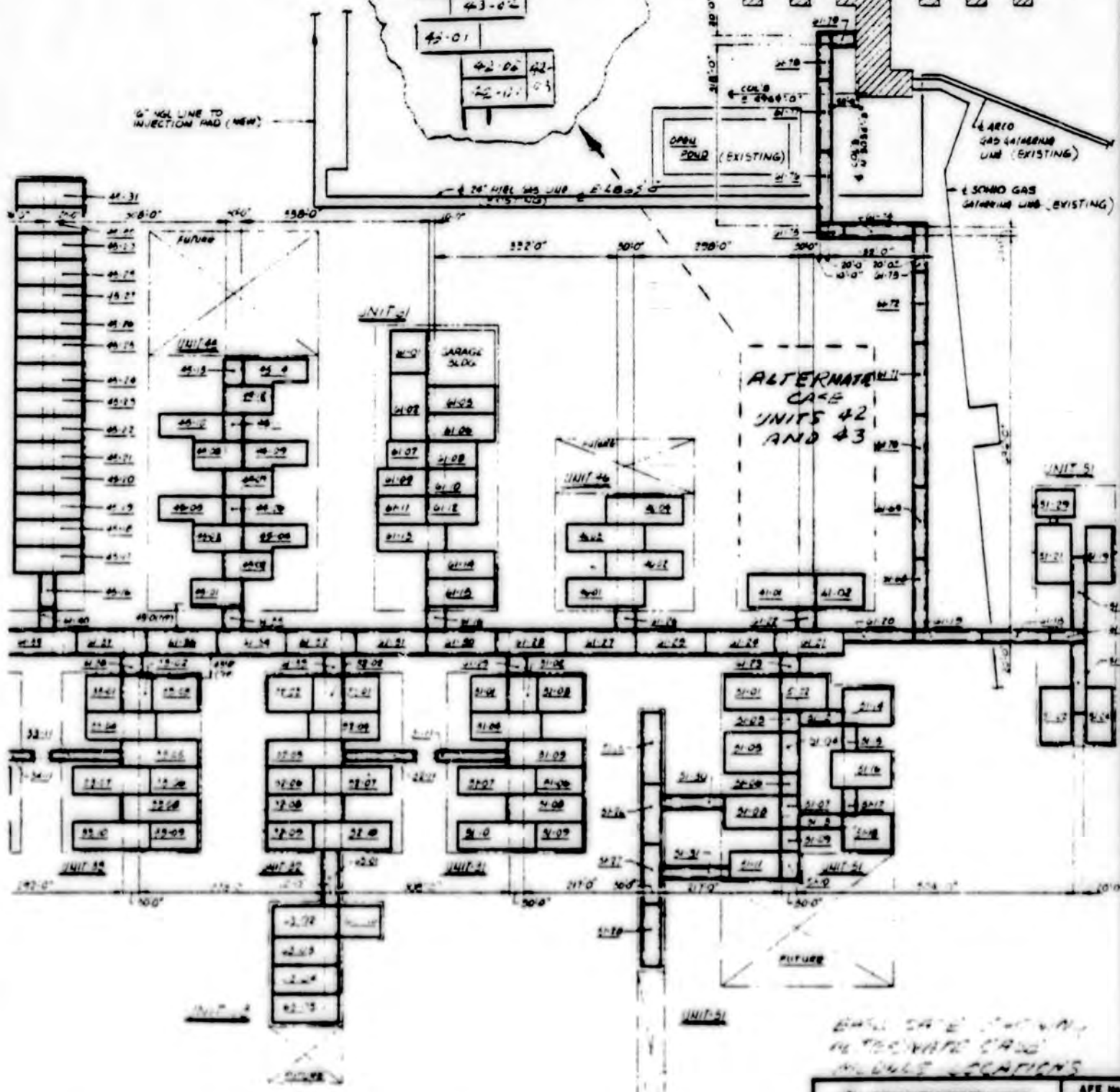




UNIT 52
SEE DWG #5743 D-5A-4 OVERALL
FACILITIES MAP FOR PLOT LOCATION



6" NGL LINE TO
INJECTION PAD (NEW)



BASE CASE PLANTING
ALTERNATE CASE
MODULE LOCATIONS

Atlantic Richfield Company North American Producing Division General Engineering Service, Dallas, Texas	AFE No.
PRUDHOE FACILITIES PROJECT - PRUDHOE BAY, ALASKA OVERALL MODULE INDEX PLAN SALES GAS CONDITIONING FACILITIES	
THIS DRAWING IS THE PROPERTY OF ATLANTIC RICHFIELD COMPANY	FIGURE 4

FIGURE 5
SALES GAS CONDITIONING FACILITIES
IMPLEMENTATION PLAN
MILESTONE SCHEDULE

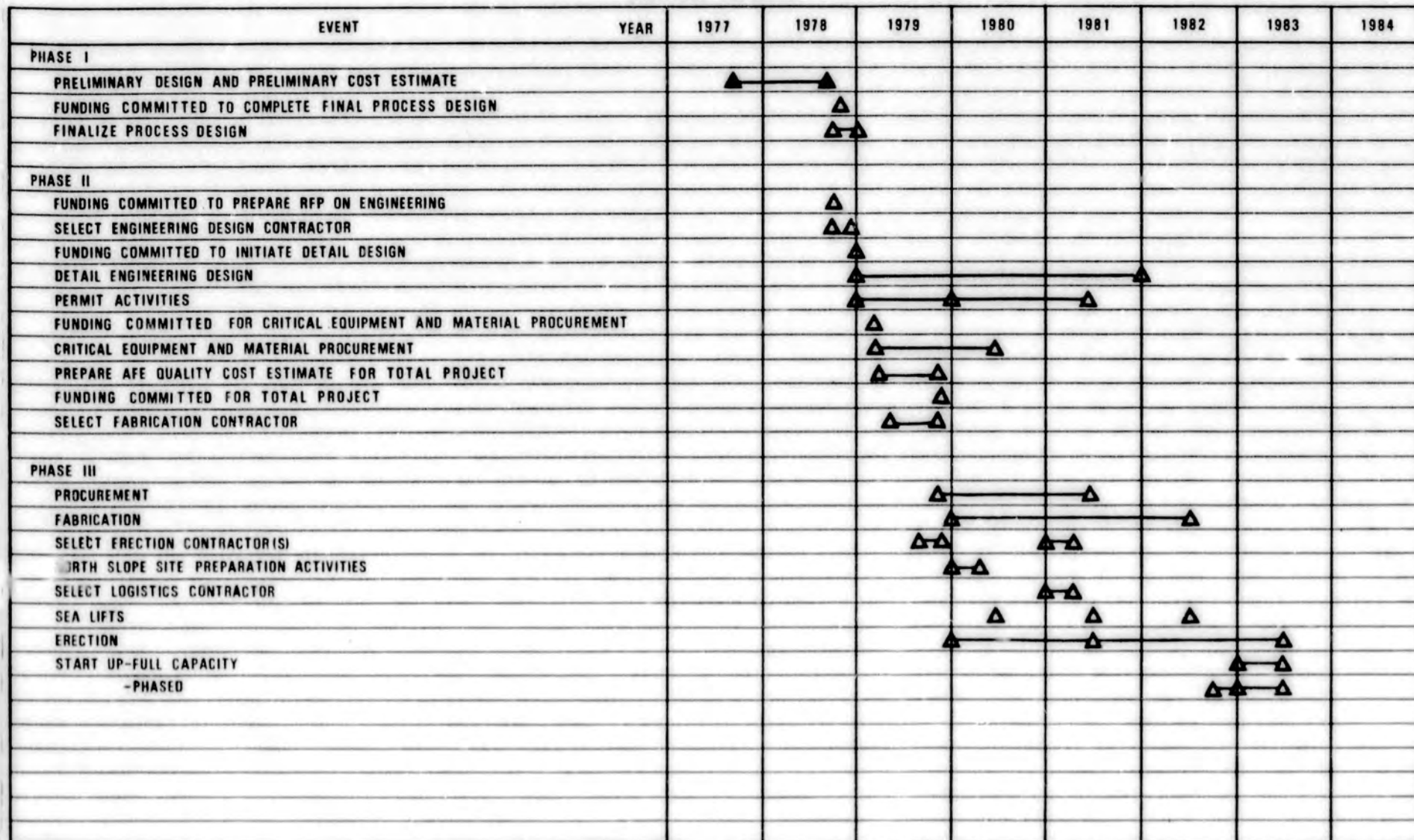
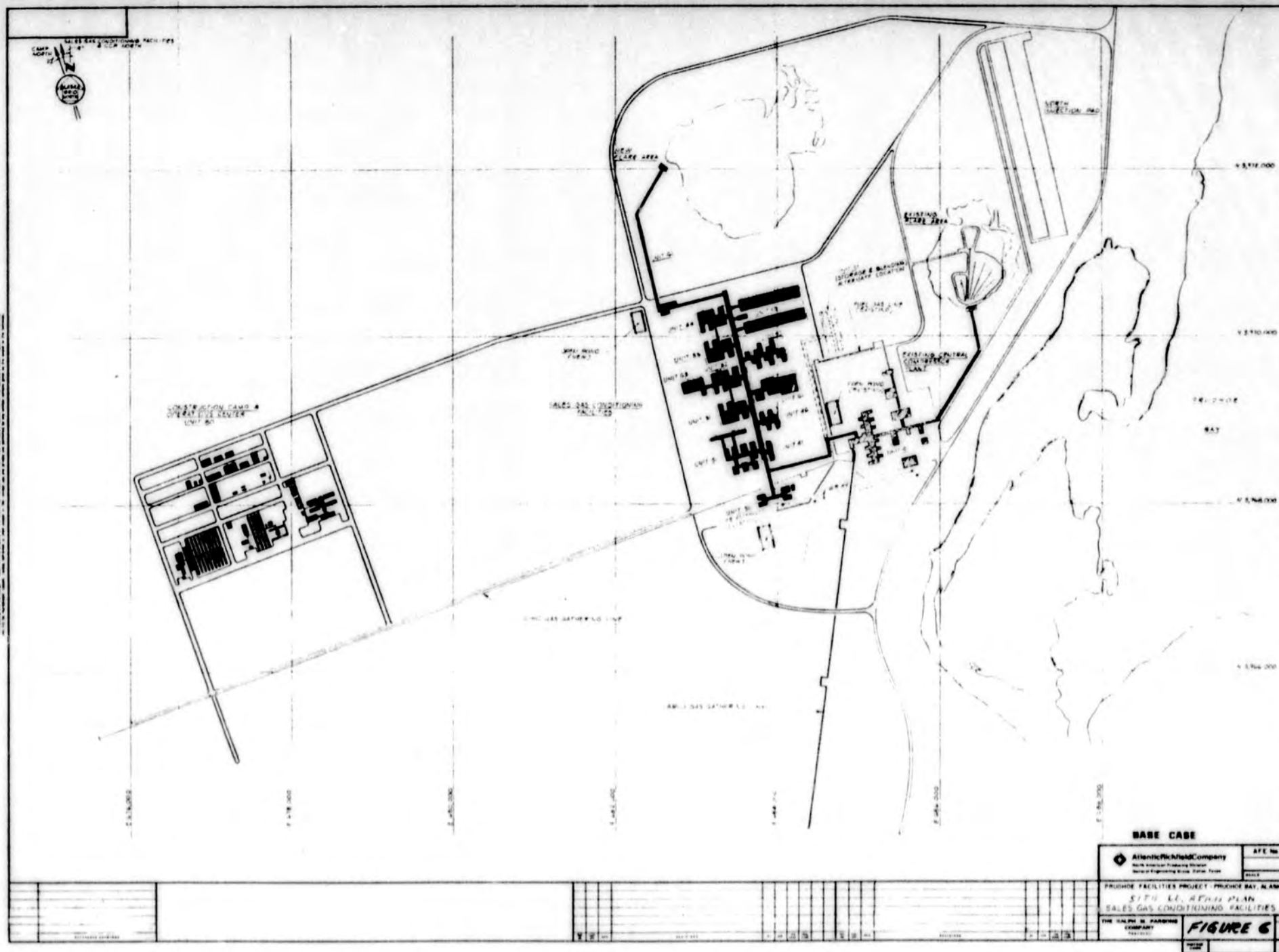


FIGURE 5

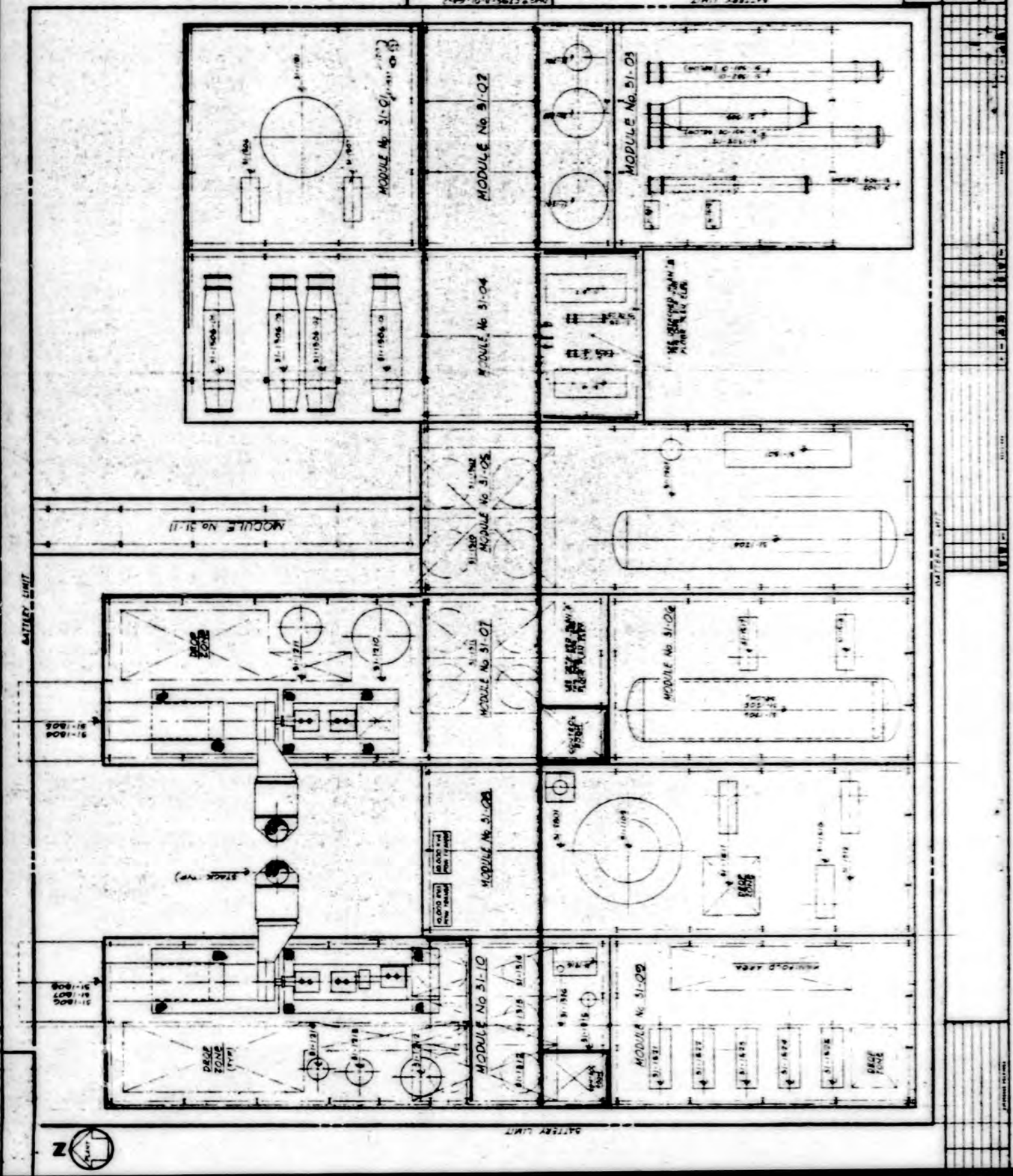


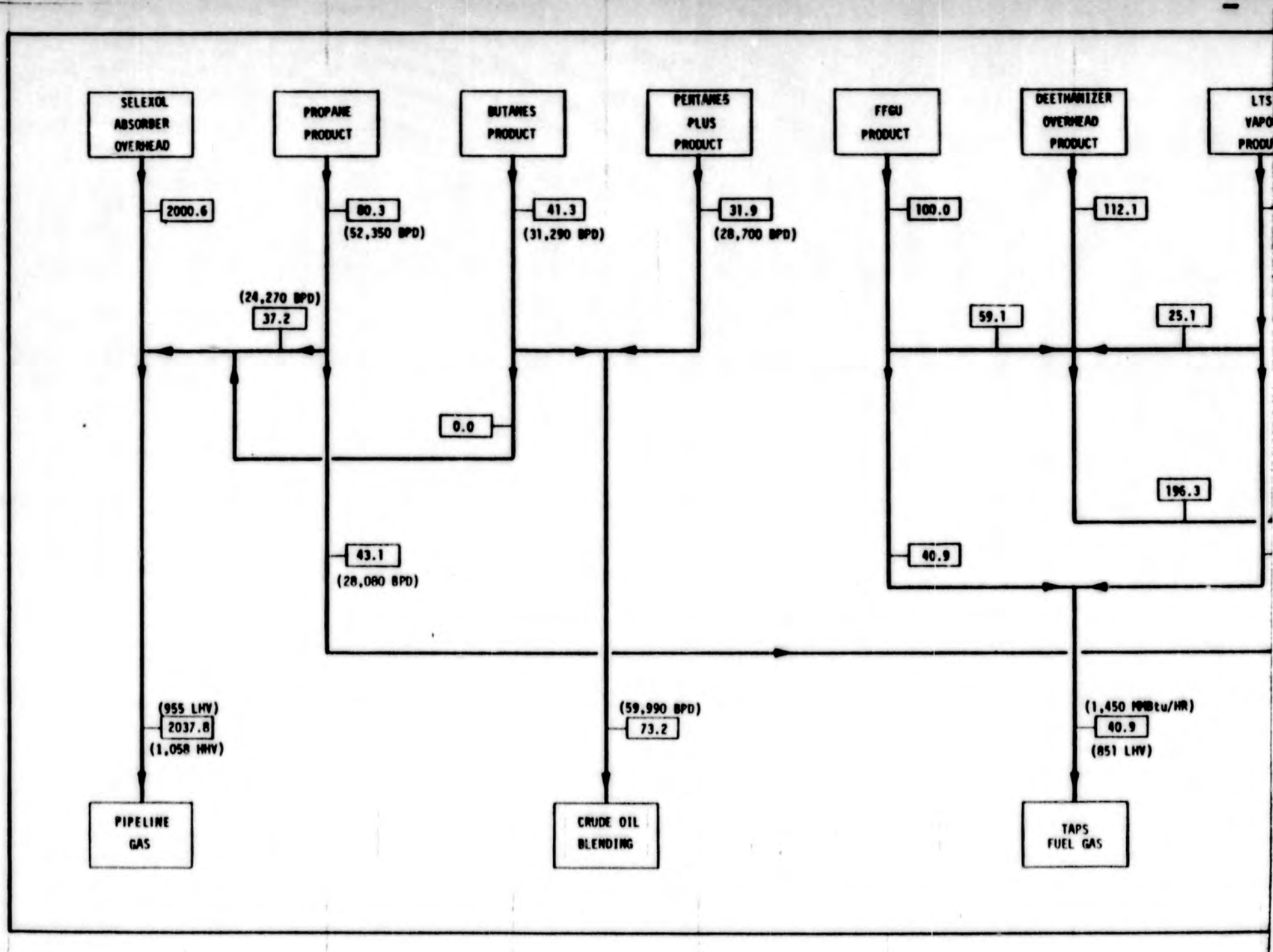
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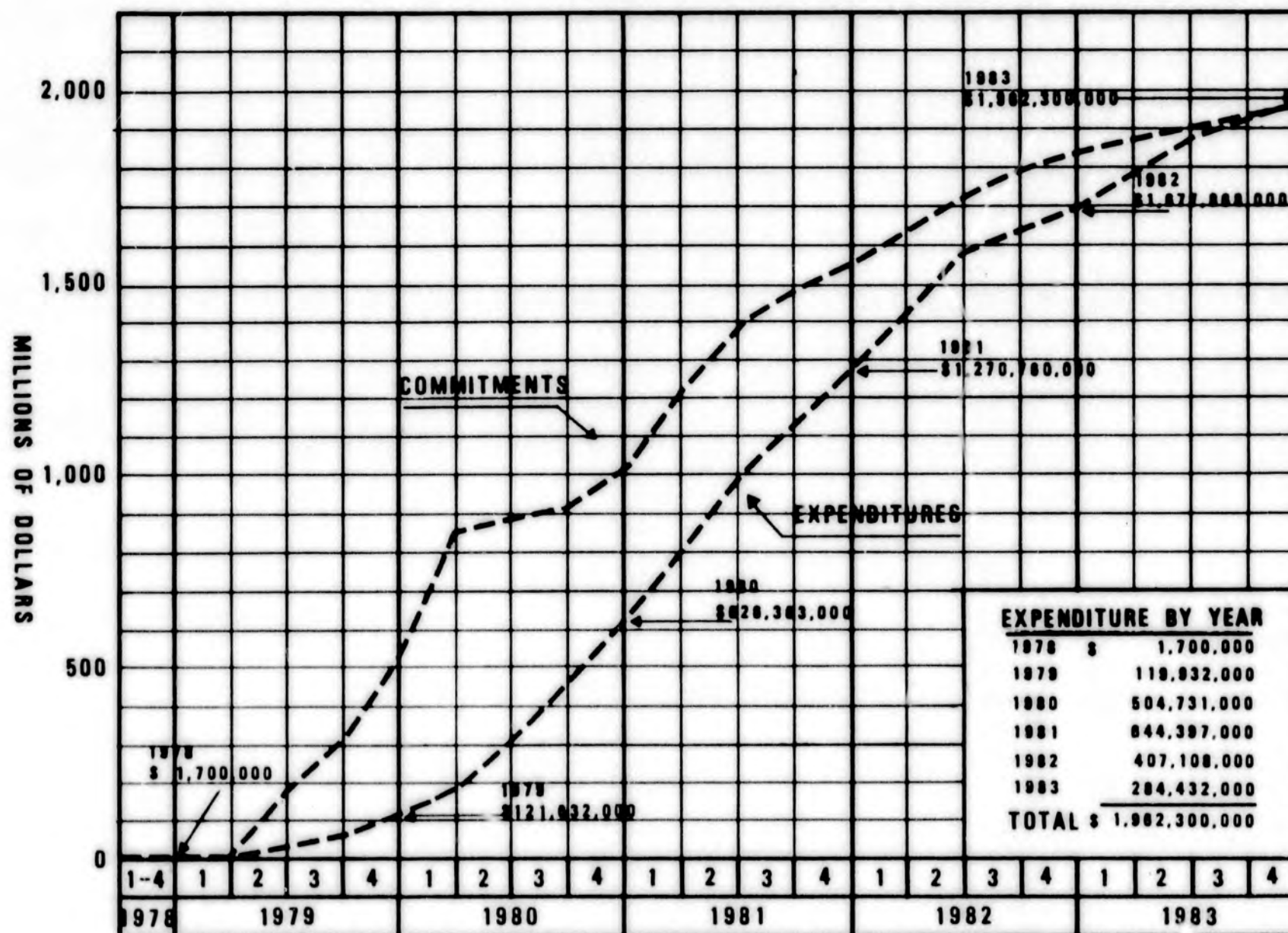


FIGURE 9
SALES GAS CONDITIONING FACILITIES
PATTERN OF COMMITMENTS AND EXPENDITURES
(BASE CASE - FULL-CAPACITY STARTUP)

RMP

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AS A UNIT IN THE ORIGINAL DOCUMENT.**

**PLEASE NOTE: THE FOLLOWING PAGES WERE TREATED
AS A UNIT IN THE ORIGINAL DOCUMENT**

M.A. See me

NORTHWEST ALASKAN PIPELINE COMPANY

LUCIUS D. LEGG
VICE PRESIDENT
PROJECT OPERATIONS

PRO-80-2200

P. O. BOX 1526
SALT LAKE CITY, UTAH 84110
801-534-3697

3333 MICHELSON DRIVE
IRVINE, CALIFORNIA 92730
714-975-3401

December 30, 1980

507.0

The Honorable Terry Miller
Lieutenant Governor of the
State of Alaska
State Capitol Building
Pouch AA
Juneau, AK 99811

Dear Sir:

Subject: Draft Report on Alternatives for Gas
Conditioning Facility Location

During the August 22, 1980, meeting of the Alaskan Northwest Natural Gas Transportation Company Board of Partners, held in Salt Lake City, you requested that a report be prepared on the alternatives to locating the Alaska Gas Conditioning Plant at Prudhoe Bay. The enclosed draft has been prepared by Northwest Alaskan Pipeline Company in conjunction with producer company representatives. It provides a technical and economic evaluation of five alternative cases, four of which involve some degree of gas conditioning in the interior of Alaska. It concludes that the case based on conditioning at Prudhoe Bay is the preferred alternative.

To facilitate review of this draft, we are sending C. E. Behlke a copy of the report and this letter. I will be pleased to meet with him at his convenience to further discuss the draft and to arrange further discussions with the authors prior to final drafting.

At this time, NWA is continuing the design and planning activities necessary for construction of the Alaska segment of the Alaska Natural Gas Transportation System based on a design concept of constructing a single gas conditioning facility at Prudhoe Bay and utilizing a buried chilled 48" diameter pipeline, with an operating pressure of 1260 psig, as prescribed by the

The Honorable Terry Miller
December 30, 1980

PRO-80-2200
Page 2

Federal Energy Regulatory Commission. We trust that having studied the enclosed report you will concur in the design concept.

Very truly yours,


L. D. Legg

LDL/bjb

Enclosure

cc: C. E. Behlke w/att.

ALASKA NATURAL GAS TRANSPORTATION SYSTEM

REPORT ON ALTERNATIVES FOR
GAS CONDITIONING FACILITIES LOCATION

- I. PURPOSE AND OBJECTIVES
- II. SUMMARY OF CONCLUSIONS
- III. BACKGROUND AND GENERAL CONSIDERATIONS
 - A. Gas Conditioning Requirements - General
 - B. Prudhoe Bay Gas Conditioning Requirements
- IV. CASE STUDIES OF ALTERNATE DESIGNS
(Descriptions of Five Major Alternatives)
 - A. Objectives
 - B. Technical Requirements
 - C. Facilities Description
 - D. General Discussion of Case
 - 1. Cost
 - 2. Schedule and Permit Approvals
 - 3. Technical Risks
 - 4. Personnel Requirements
 - 5. Environmental and Resource Requirements
- V. COMPARISON OF ALTERNATES
 - A. Costs
 - B. Approvals and Permits
 - C. Schedule
 - D. Technical Factors and Risks
- VI. OTHER FACTORS
 - A. NGL Recovery
 - B. Alternate Plant Fuels
 - C. Construction Considerations
 - D. Personnel and Operating Factors

DATE

DEC 22 1980

FIGURES AND TABLES

Figure 1A Prudhoe Bay Raw Gas Composition

Figure 1B Phase Envelopes for Prudhoe Bay Gas

Figure 2A-2E Schematic Diagrams of Cases A - E

Table 1 Summary of Estimated Investment Costs and Fuel Consumption

Table 2 Summary of Estimated Operating and Maintenance Costs and
Manpower Requirements

DEC 22 1980

ALASKA NATURAL GAS TRANSPORTATION SYSTEM

REPORT ON ALTERNATIVES FOR GAS CONDITIONING FACILITIES LOCATION

I. PURPOSE AND OBJECTIVES

The purpose of this report is to provide information to the State of Alaska which documents the decision of the interested parties to plan for location of gas conditioning facilities for Prudhoe Bay at the North Slope of Alaska in the Prudhoe Bay Field. The decision was based on both economic and technical factors related to the requirements for this multi-billion dollar facility, which will be one of the critical elements in the transportation of natural gas from the Prudhoe Bay Field via the Alaska Natural Gas Transportation System (ANGTS) through Alaska, Canada, and ultimately to the "Lower 48" United States consumers.

II. SUMMARY OF CONCLUSIONS

The economics of various plant locations and the attendant pipeline designs have been developed and are discussed in detail in Section IV. The options considered cover technically feasible cases, although the operational safety and life-cycle economics of higher pressure and/or warm, aboveground gas pipelines are somewhat controversial. The technically feasible cases are as follows:

Case A: Conditioning Plant at Prudhoe Bay - 1260 psig chilled gas pipeline: This is the case required for the Federally approved pipeline design specifications, per the Alaska segment.

Case B: Hydrocarbon dew point control at Prudhoe Bay and CO₂ removal in interior Alaska. A 1260 psig chilled gas pipeline is used and all technically possible facilities are located in interior Alaska.

PRELIMINARY DRAFT For Discussion Purposes Only	
DRAFT #4	
DATE	
DEC 22 1980	

Case C: All gas conditioning is done in interior Alaska; a 455-mile, 675 psig warm gas pipeline is used to minimize facilities at Prudhoe Bay.

Case D: All gas conditioning is done in interior Alaska; a 455-mile, 1680 psig warm gas pipeline system is used, with compression facilities at Prudhoe Bay.

Case E: All gas conditioning is done in interior Alaska; a 455-mile, 2160 psig chilled gas pipeline is used with compression and cooling facilities at Prudhoe Bay.

The estimated costs are shown in Table 1. Costs of all other cases considered exceed the cost of Case A by 584 to 7539 million 1980 dollars. Risk costs have been estimated and do not significantly change the relative comparisons.

It should be noted that risk costs for possible difficulty in achieving completely successful sealifts to Prudhoe Bay were investigated. Relative to the range of contingencies which confront large projects in any location, the seasonal regularity of the Arctic ice movement is very predictable and the normal Prudhoe Bay sealift plan has a high probability of success. Sealifting to Prudhoe Bay has been conducted since 1970. Only one of the 11 sealifts (1975) has encountered serious delay, and the only major cost effect of that delay was additional construction labor at the North Slope. In the Alaska projects, only one barge has sunk -- a load of pipe enroute from Japan in the open ocean. It should be recognized that interior Alaska also presents some construction delay and cost risks: severe winds, ice fog, closure of roads or railways by weather and traffic accidents, unforeseen soil conditions, etc. The estimated contingency costs for these risks are shown on Table 1.

It should also be noted that all the cost estimates for Cases B through E are "order-of-magnitude"; i.e., estimates for these alternative designs were developed in far lesser detail than the Parsons Study and the ANNGTC