Section 3
LNG Plant

Section 3.1
Description of Facilities

SECTION 3.1

DESCRIPTION OF FACILITIES

Table of Contents

SECTION 3.1

DESCRIPTION OF FACILITIES

Table of Contents
(Continued)

SECTION 3.1

DESCRIPTION OF FACILITIES

Index to Figures and Tables

Page

Figures

Tables

SECTION 3.1

DESCRIPTION OF FACILITIES

General Description

The proposed LNG Plant will be located at the southern terminus of the proposed Alaskan Gas Pipeline near Prince William Sound on Gravina Peninsula. For project orientation, see Figure 3.1-F1 on the following page.

By the following scheme, the plant will treat, liquefy and store the natural gas so that it may be transported by ship to the contiguous United States:

1) Diglycolamine (DGA) Gas Treating -- This process will reduce the carbon dioxide content of the natural gas to prevent the formation of solid carbon dioxide in cryogenic facilities.

2) Molecular Sieve Gas Dehydration -- This process will reduce the water content of the natural gas to prevent the formation of ice in cryogenic facilities.

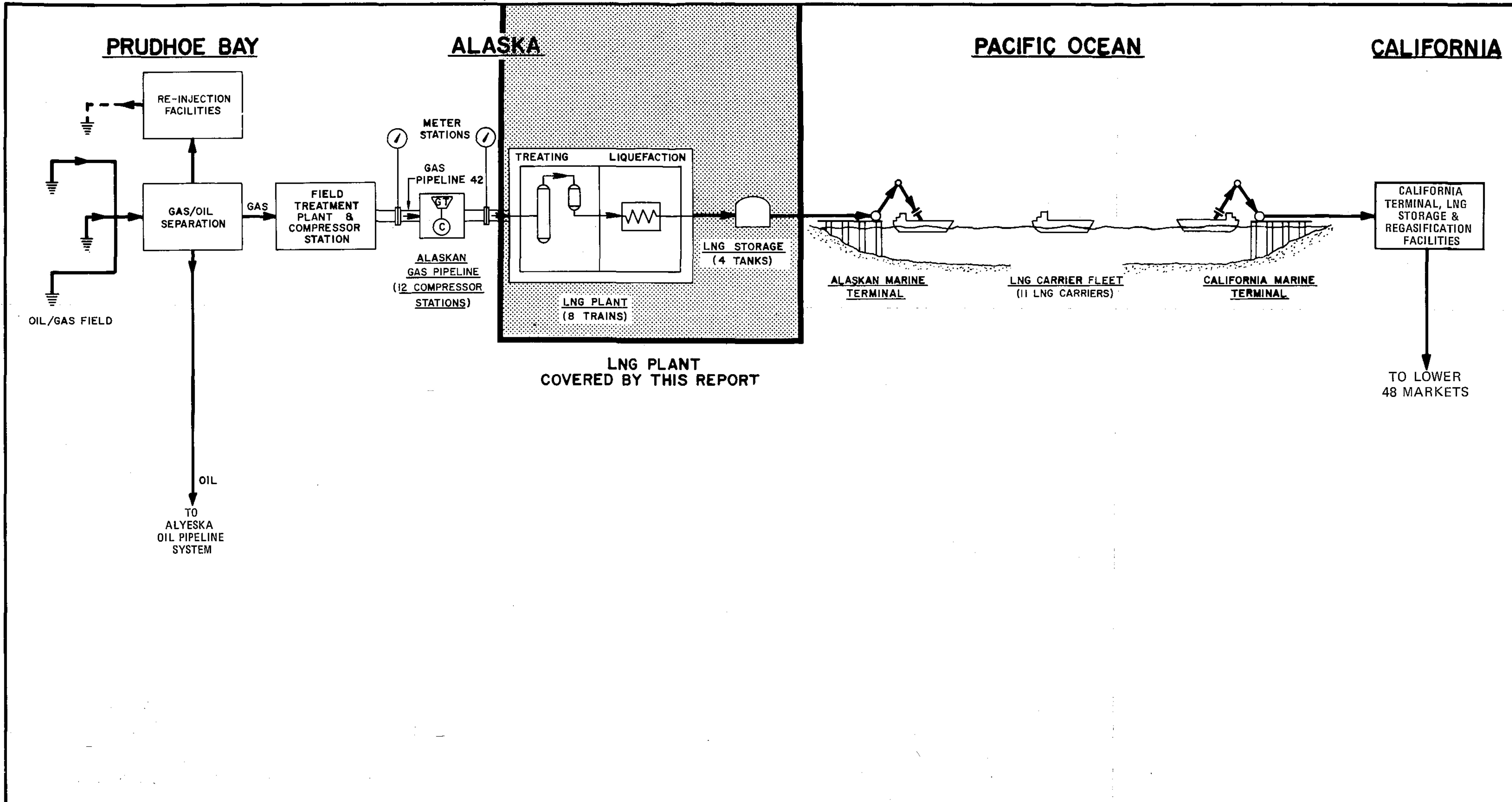
3) Liquefaction -- The process, developed by Phillips Petroleum Company and known as the "Optimized Cascade Cycle," will be used to liquefy the natural gas. The liquefaction is accomplished in stages by using three refrigeration processes: propane, ethane and methane.

4) Storage and Handling -- Four 550,000-barrel cryogenic storage tanks will hold the LNG until it is loaded onto the LNG carriers.

There will be eight independent, parallel processing trains, each having an inlet design flow rate of 421.88 million cubic feet per stream day (MMcf/sd). The resulting total plant inlet design flow rate of 3375 MMcf/sd will be adequate to process the 3190.07 million cubic feet per calendar day (MMcf/cd) of feed gas delivered to the LNG Plant by the Alaskan Gas Pipeline. Processing 3375 MMcf/sd of feed gas will result in LNG deliveries to the LNG Carrier Fleet equivalent to 3030.44 MMcf/sd of natural gas.

Site Location

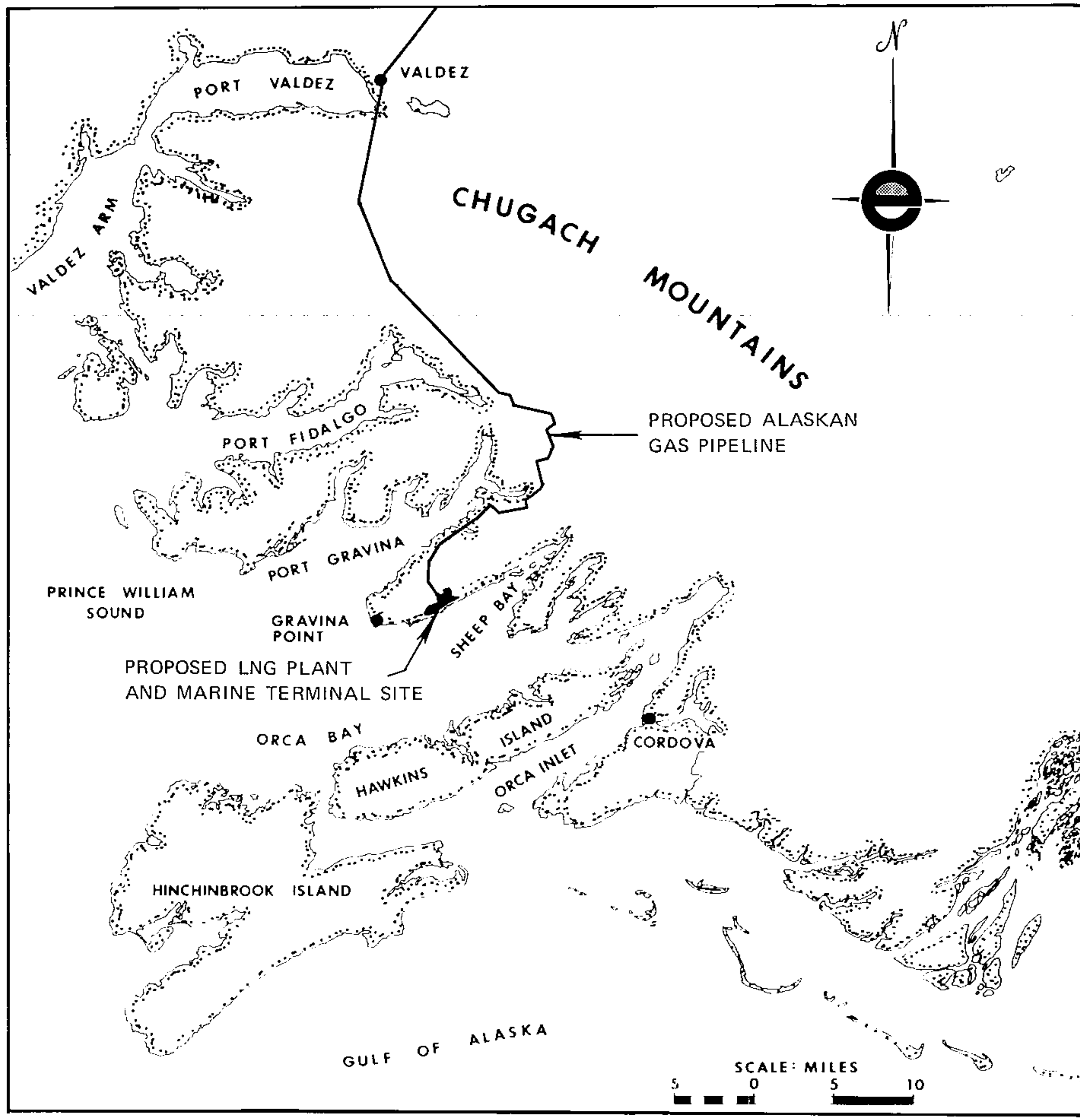
The location of the proposed LNG Plant is shown on Figure 3.1-F2 on page 3.1-3. As indicated on the map, the site is located on the eastern portion of Prince William Sound, on the southern shore of Gravina Peninsula four miles east of Gravina Point. The site was selected following examination of numerous sites along the southern coast of



TRANS-ALASKA GAS PROJECT

LNG PLANT
PROJECT ORIENTATION

FIGURE 3.1–F1



TRANS-ALASKA GAS PROJECT

LNG PLANT SITE LOCATION

FIGURE 3.1–F2

Alaska from Cook Inlet to the mouth of the Copper River. The site is within the Chugach Mountain Range which runs along the northern shore of the Gulf of Alaska. East-trending ridges dominate the higher ranges of these mountains; lower elevations consist of discrete, massive mountains separated by intersecting narrow valleys and passes that are eroded along joint and cleavage systems. The entire range has been glaciated, and the coast is deeply indented by fjords and sounds.

Site Description

The LNG Plant site has a southeasterly exposure to Orca Bay and Prince William Sound. Deep water is close to shore and provides a suitable location for the marine facility and for navigation of LNG vessels.

The site is located on a sloping terrace with the angle of the slope being approximately 15% away from the shoreline. The site is bounded by a 50 to 100 foot high sea cliff and a narrow beach on the south, Harris Creek on the east, and an unnamed mountain on the north and northwest. Site topography is low and rolling with occasional irregular ridges. The maximum elevation on the site is about 500 feet. Portions of the site are heavily wooded.

Over most of the terrace area, bedrock is believed to consist of jointed and fractured slate. The bedrock is less than 30 feet below the ground surface, and there is some outcropping.

Soil cover on the terrace consists of organic silts and peat covered by grasses and trees. The steeper slopes are generally wooded and covered with an organic mat less than five feet thick near steep slopes, and as much as ten feet thick elsewhere. Gravel occurs under the organic silts on the terrace. The glaciated valleys adjacent to the site may have granular soils twenty feet thick overlying silty glacial till.

Drainage on the steeper slopes is good. The flatter slopes and low-lying areas are poorly drained and have ponded water and boggy ground. Some of the organic soils form an impermeable surface and are in part responsible for the poor drainage and ponding in low-lying areas. Harris Creek has an overall gradient of about 5%, with several waterfalls and steeper gradients locally.

Water depths of sixty feet are located about 1,200 feet offshore.

Foundations

For foundation of major structures, such as LNG storage tanks, compressors and other large equipment, overburden will be removed and equipment will be founded on concrete mats placed directly on bedrock.

Where excavation to bedrock is not practical, these structures will be constructed on caissons founded in bedrock. Other structures will be placed on shallow spread footings, provided soil conditions are suitable.

Plot Plan

The overall facilities will be oriented as shown in Figure 3.1-F3, following. LNG storage tanks and the associated pumping station will be near the berthing facilities. LNG tanks will be diked to form a common impounding basin which will contain spills. Finger dikes will direct flow to the common impounding basin and away from adjacent tanks.

The process units and LNG storage tanks will be set at an approximate elevation of 150 feet above sea level. The eight LNG processing trains will be oriented across the site to minimize excavation work. Some terracing may be required.

The control building of the LNG Plant will be centrally located to serve both the LNG processing trains and the utilities. All plant and ship loading operations will be monitored from this control building.

A cooling water system with the intake located offshore will take seawater from Orca Bay, circulate it through a heat exchanger and discharge it through an outfall system for distribution and mixing with bay water.

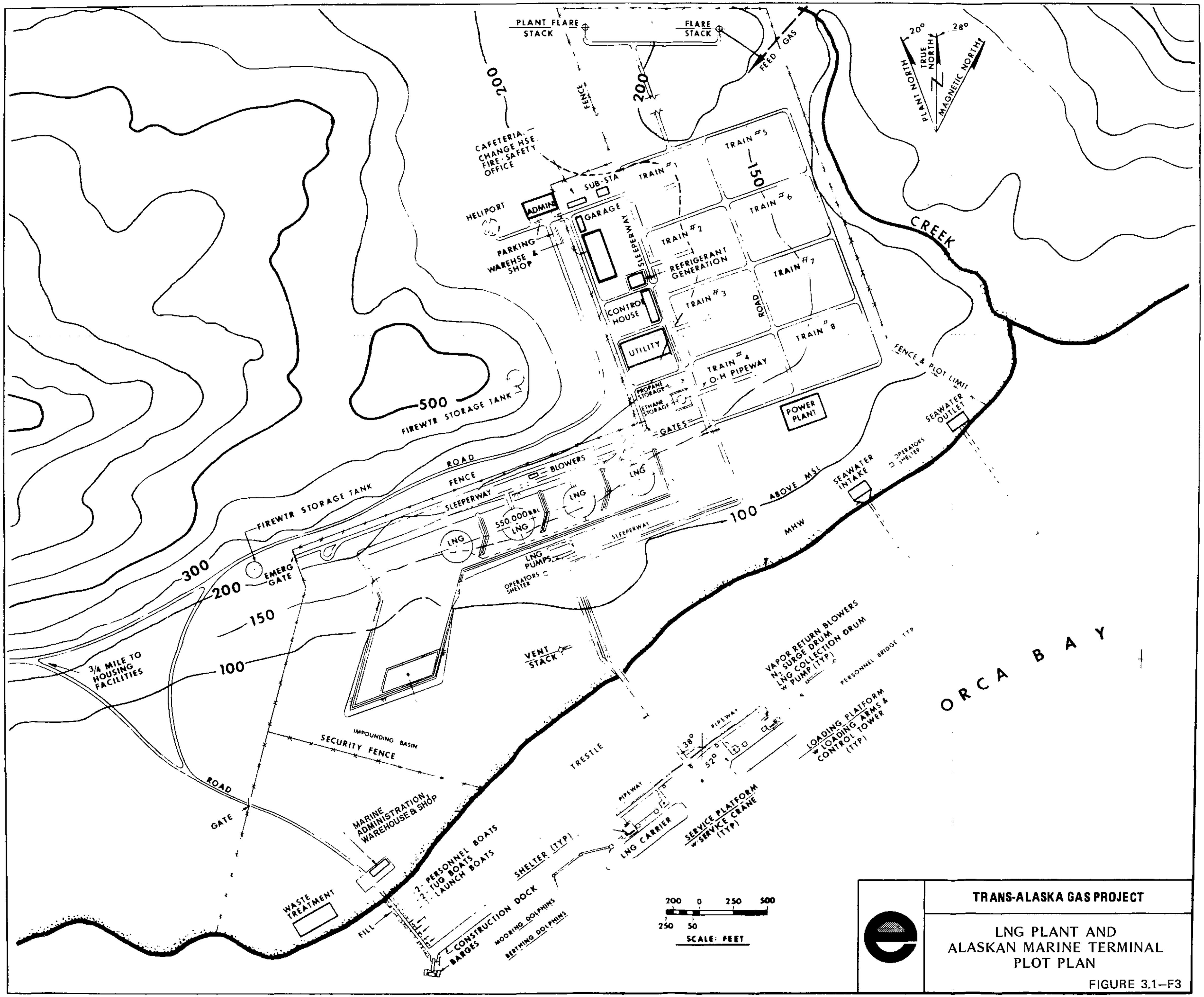
The plant flare stack and the pipeline flare stack will be located on higher ground north of the plant site.

The administration building and other plant support buildings and a heliport will be located west of the process area. This location is higher than the process area due to the natural slope of the site.

Paved roadways will be provided for access to all process and utility units and the marine facility. A six-foot security fence will surround the plant.

The nearby Marine Terminal will include a harbor to berth tugs and small boats. In the harbor, a construction dock and ferry landing will be built to handle construction and maintenance materials, and to provide a landing for the personnel ferry carrying LNG Plant operators that do not live at the site. (The Marine Administration Building which includes the marine warehouse and shop will be located onshore north of the harbor.)

Construction camp facilities will be located to the west of the marine facility. Temporary shops and storage areas will be near the plant sites and in the vicinity of the permanent shop building areas.



TRANS-ALASKA GAS PROJECT

LNG PLANT AND ALASKAN MARINE TERMINAL PLOT PLAN

FIGURE 3.1–F3

Housing for key operating personnel will be provided approximately 3/4 mile to the west along the shoreline. Housing will be located well above expected tsunami wave run-up.

The LNG Plant land requirements will be 395 acres, as shown on Figure 3.1-F3 on page 3.1-6 by the fence at the plot limit. Essentially all of the land area within the plot limit will be used during plant construction.

Construction of auxiliary facilities outside of the plant limits will take place adjacent to the proposed plant site. These auxiliary facilities include housing facilities, Marine Administration Building, waste water treatment facility, LNG Plant Administration Building, a heliport and roads connecting such facilities to the LNG Plant. The land requirement for these auxiliary facilities is estimated to be 55 acres.

A 750-acre greenbelt, which will not be cleared or otherwise removed from present land uses, will effectively insulate the LNG Plant and auxiliary facilities from future developments on adjacent land. The area required for the greenbelt, plus the 450 acres required for the fenced plant area and auxiliary facilities, brings the total LNG Plant land requirements to 1,200 acres.

Process Units

Each train of the LNG Plant will include the following units: Diglycolamine (DGA) Gas Treating; Molecular Sieve Gas Dehydration; and Liquefaction.

The feed gas to each train will first be treated in the DGA gas treating unit where the CO_2 will be removed. The gas will then be dried by molecular sieves in the dehydration unit before it flows to the liquefaction unit. There, the gas will be converted to liquid in the liquefaction unit and will be sent to LNG product storage tanks. The LNG product will be loaded from the storage tanks into LNG carriers at the nearby marine terminal.

Diglycolamine (DGA) Gas Treating

The DGA gas treating unit will reduce the carbon dioxide content of the pipeline feed gas from 1.02 Mol% to 50 ppm. This will prevent any deposits of solid CO_2 in the cryogenic equipment.

The removal of CO_2 to low concentrations is accomplished by a high pressure treating process which uses aqueous 65% DGA solution as the reactant. The DGA solution will be continuously regenerated to remove captured CO_2 and recycled.

The design treating capacity will be 450 MMcf/sd for each of the eight process trains.

The DGA process has been selected over those using other amines or activated potassium carbonate because DGA has the lowest circulation rate; the lowest regeneration steam rate; the potential for partial dehydration; minimal solution degradation problems, and little probability of freeze-up due to the low DGA freezing temperatures.

The DGA treating unit has the ability to meet product specifications with variations in inlet rates, pressures, or CO_2 contents. The features which provide the flexibility to meet these variations follow:

1) Residual CO_2 content of the treated gas is 50 ppm, based on a normal CO_2 concentration of 1.02 Mol% in the feed gas. The expected maximum CO_2 concentration of 2.0 Mol% in the feed gas can be reduced to a residual CO_2 content of 100 ppm in the treated gas which is within the liquefaction unit acceptance limits.

2) The DGA treating unit has an overdesign capacity of approximately 7%.

3) A conservative DGA/CO_2 mol ratio of four to one has been used which provides additional reserve capacity in the system.

4) Contactor operating pressure may vary from 665 to 730 psig. The design is based on a minimum pressure of 665 psig. Any pressure increase above 665 psig increases the CO_2 removal efficiency.

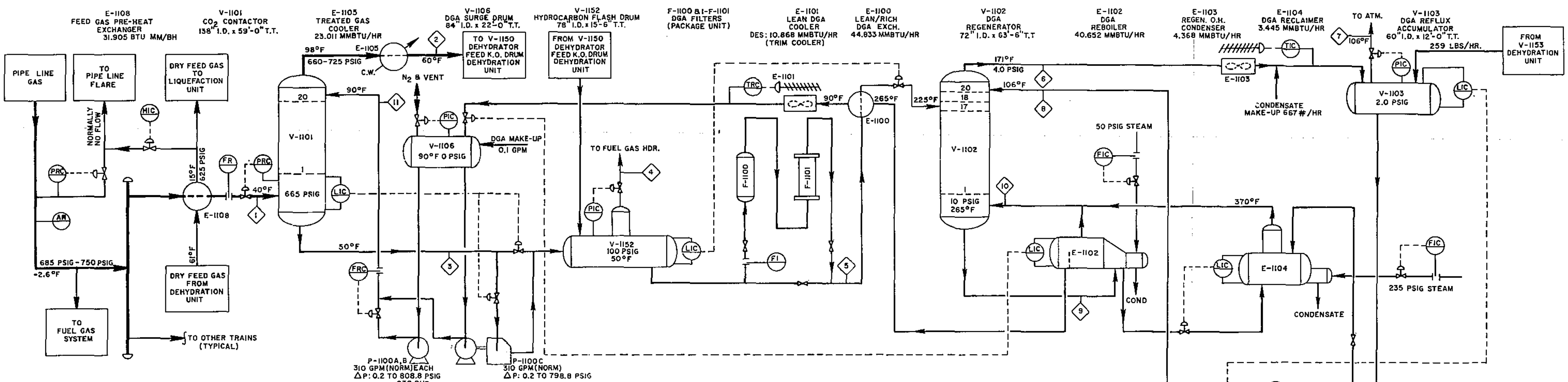
Process Flow Description

The following description corresponds to the schematic presented in the Process Flow Diagram in Figure 3.1-F4 on the next page.

Natural gas from the Alaskan Gas Pipeline will enter the battery limits at a design temperature of -2.6°F and will be heated in a preheat exchanger to 40°F by dry gas from the dehydration unit. The feed gas will then enter the DGA unit under pressure control and flow up through the CO_2 contactor column, countercurrent to the lean DGA solution. The lean DGA solution will enter the top of the contactor at a temperature of 90°F and at a rate of four mols of DGA per mol of CO_2. In the contactor, the DGA will react with the CO_2.

The treated gas stream in the DGA contactor will be warmed to 98°F from the heat of reaction. The treated gas will leave the top of the contactor partially saturated with water and will be cooled before it enters the dehydrators.

The DGA solution leaving the bottom of the contactor will be rich in CO_2 and must be regenerated by steam stripping before reuse. The solution will leave the contactor at a relatively high pressure (665-730 psig) and flow through a hydraulic turbine and into a flash drum, thus



STREAM NO.		1	2	3	4	5	6	7	8	9	10	11
DESCRIPTION		FEED GAS	TREATED GAS	RICH DGA	FLASH GAS	RICH DGA	OVH'D VAPOR	GAS TO ATMOS.	REFLUX COND.	LEAN DGA	REGEN/RECLAIM VAP.	LEAN DGA
COMPONENT	MW	MOL %	MOL %	MOL %	MOL %	MOL %	MOL %	MOL %	MOL %	MOL %	MOL %	MOL %
N_2	28	0.75	0.76	0.00	0.75	0.00	0.01	0.01				
CO_2	44	1.02	(50 PPM)	5.67	1.02	5.66	66.30	92.13				
C_1	16	85.91	86.71	0.36	85.92	0.06	0.68	0.94				
C_2	30	7.77	7.84	0.03	7.77	0.01	0.06	0.08				
C_3	44	3.93	3.97	0.02	3.93	0.00	0.03	0.04				
iC_4	58	0.26	0.26	0.00	0.26	0.00	0.00	0.00				
nC_4	58	0.30	0.30	0.00	0.30	0.00	0.00	0.00				
iC_5	72	0.03	0.03	0.00	0.03	0.00	0.00	0.00				
nC_5	72	0.02	0.02	0.00	0.02	0.00	0.00	0.00				
C_6+	86	0.01	0.01	0.00	0.00	0.00	0.00	0.00				
DGA	105			22.79		22.78	0.00	0.00		19.68	1.95	24.12
H_2O	18		0.10	71.13		71.49	32.92	6.80	100.00	80.32	98.05	75.88
TOTAL		100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
LBS/HR		931,352	909,447	348,261	595	348,278	26,665	22,849	4,647	367,789	41,529	326,355
MOL. WT.		18.834	18.575	39.333	18.823	39.324	35.243	41.957	18.000	35.152	19.702	39.022
GPM				621		621			9.3	754		620
MMSCF/SD		450.000	445.543		0.288		6.887	4.956			19.181	

NOTE:
1. ONLY ONE TRAIN SHOWN

TRANS-ALASKA GAS PROJECT

DGA GAS TREATING UNIT
PROCESS FLOW DIAGRAM

FIGURE 3.1–F4

reducing the pressure to 100 psig. Energy extracted from the hydraulic turbine will be used to drive one of three DGA circulation pumps (two operating, one standby). The flashed gas will then be routed under pressure control to the fuel gas system.

The cool, rich solution will be preheated in a shell-and-tube exchanger by the hot, lean solution before entering the DGA regenerator. The rich solution will enter the regenerator at 225°F, flow downward and contact hot vapors at 265°F flowing upward. The CO_2 will be stripped from the solution and will leave the regenerator in the overhead vapor. A shell-and-tube, kettle-type steam heated reboiler will be used to produce stripping steam vapor.

The hot, lean solution withdrawn from the reboiler, will exchange heat with the rich solution stream, be cooled (if necessary), be accumulated in a surge drum and be pumped back to the contactor to complete the cycle.

The overhead stream from the regenerator, containing CO_2, water vapor and trace hydrocarbons, will be cooled, partially condensed and vented to the atmosphere. The condensate will be collected and returned to the regenerator as reflux. Water balance will be maintained by adding make-up water (steam condensate from the reboiler) to the reflux accumulator.

The DGA solution eventually will become contaminated during operation by side reactions which produce nonregenerable compounds and by the formation and collection of insoluble material, such as pipe scale. The non-regenerable compounds will be removed by distilling the DGA in the reclaimer. A portable drum will collect the residue to be sent to disposal facilities in a sludge form.

Non-soluble, solid impurities will be removed from the circulating solution by continuous slipstream filtration. Carbon and cartridge filters located in series downstream of the hydrocarbon flash drum will filter 10% of the circulating rich solution.

An agent will be added to the DGA to prevent foaming. Foaming, if permitted, decreases plant throughput, increases DGA losses, prevents adequate regeneration and adversely affects the sweetening efficiency.

The circulating DGA solution will be moderately corrosive due to oxidation and decomposition products of amine. In addition to designing the plant to metallurgically withstand this corrosive solution, provisions will be made for adding a corrosion inhibitor.

Molecular Sieve Gas Dehydration

The gas stream from the DGA gas treating unit will be dehydrated from 0.03 Mol% H_2O to less than 1 ppm by a molecular sieve gas dehydration unit. Dehydration to less than 1 ppm of H_2O will prevent the moisture from freezing and plugging cryogenic equipment in the liquefaction plant.

Three separate beds of 4-Angstrom molecular sieve adsorbent will be used to dry the feed stream to the liquefaction section. Molecular sieves will selectively adsorb H_2O molecules while letting natural gas molecules pass through. Two beds will operate in parallel while the third is under regeneration. The drying and regeneration cycles will be automatically alternated on a regular schedule.

The unit will be designed to supply dehydrated gas at a rate of 445 MMcf/sd to each of the liquefaction trains. This rate is 5 MMcf/sd less than the design feed to the DGA gas treating unit because of the volume of CO_2 removed in the DGA unit.

Process Flow Description

The process description is presented in the flow diagram, Figure 3.1-F5, following.

Cooled, treated gas containing water condensate and some entrained DGA solution will enter the dehydrator feed knockout drum where liquids will be separated from the gas. Liquid will be returned to the hydrocarbon flash drum in the DGA plant.

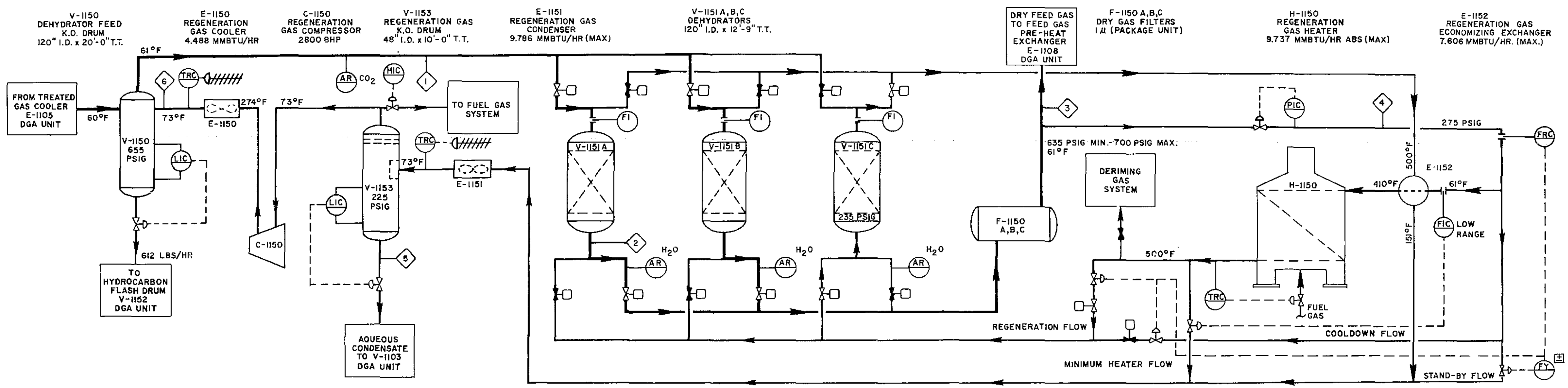
Liquid-free gas will leave the dehydrator feed knockout drum and flow down through two parallel dehydrators where moisture content will be reduced to less than 1 ppm by adsorption in fixed beds of the molecular sieves. Particles of pipe scale and desiccant dust greater than one micron in size will also be filtered out before the gas enters the liquefaction unit.

Each desiccant bed will contain 39,000 pounds of 4 Angstrom molecular sieve pellets. The entire weight of each bed will be borne by graded sizes of inert support media filling the bottom heads of the vessels. A layer of inert balls will also be positioned on top of the desiccant bed to improve gas distribution.

Three dehydrators per train will be operated cyclically. At any given time, two dehydrators will be operating while the third will be undergoing regeneration. A staggered, 18-hour overall cycle will be employed with each dehydrator so that a fresh dehydrator is placed in service every six hours. The cycle includes the following steps:

Gas drying	12.0 Hours
Standby	0.5
Depressurizing	0.5
Regeneration - Heating	2.8
Regeneration - Cooling	1.2
Repressurizing	0.5
Standby	0.5
	18.0 Hours

Each dehydrator will be automatically regenerated after twelve hours service by recycled, hot, dry feed gas at 500°F and 235 psig. The



STREAM NO.		1	2	3	4	5	6
DESCRIPTION		FEED TO DEHYDRATORS *	ADSORBING BED	DRY FEED GAS TO LIQUEFACTION	REGENERATION GAS	CONDENSATE	REGENERATION GAS TO FEED K.O. POT
COMPONENT	MW	MOL %	MOL %	MOL %	MOL %	MOL %	MOL %
N_2	28	0.76	0.76	0.76	0.76		0.76
CO_2	44	(50 PPM)	(50 PPM)	(50 PPM)	(50 PPM)		(50 PPM)
C_1	16	86.77	86.80	86.80	86.80		86.69
C_2	30	7.85	7.85	7.85	7.85		7.84
C_3	44	3.97	3.97	3.97	3.97		3.96
iC_4	58	0.26	0.26	0.26	0.26		0.26
nC_4	58	0.30	0.30	0.30	0.30		0.30
iC_5	72	0.03	0.03	0.03	0.03		0.03
nC_5	72	0.02	0.02	0.02	0.02		0.02
C_6+	86	0.01	0.01	0.01	0.01		0.01
H_2O	18	0.03	(1 PPM)	(1 PPM)	0.00	100.00	0.13
TOTAL		100.00	100.00	100.00	100.00	100.00	100.00
LBS/HR		945,628	472,661	908,577	36,745	259	36,793
MOL. WT.		18.576	18.576	18.576	18.576	18.000	18.576
GPM						0.518	
MMSCF/SD		463.244	231.547	445.093	18.000		18.024

* INCLUDES REGENERATION GAS

NOTE:
1. ONLY ONE TRAIN SHOWN

TRANS-ALASKA GAS PROJECT

MOLECULAR SIEVE DEHYDRATION PROCESS FLOW DIAGRAM

FIGURE 3.1–F5

entire regeneration cycle will be preprogrammed and initiated by an automatic timer. This timer will activate motor operated valves that control all phases of drying, regeneration, cooling, pressurizing and depressurizing of the adsorbent bed.

A controlled standby flow around the dehydrators will be maintained during the standby period. The flow will be sufficiently high to avoid other process upsets during this period. A cooling period after the heating cycle will allow the desiccant bed to sufficiently cool to avoid thermal shock in the liquefaction cycle and improve the adsorption efficiency.

All operating conditions relative to proper performance of the dehydrators will be transmitted to a central control room for monitoring by operating personnel. Thus, mechanical malfunctions or abnormal conditions will be detected and corrected with a minimum of interruption to normal operations.

Moisture analyzers will be provided at the outlet of each dehydrator to continuously monitor the moisture content of the dehydrated stream. Thus, loss of sieve adsorptive capacity or impending breakthrough will be detected in the early stages and corrected before the bed allows the passing of excessive moisture.

A vent valve on the gas header leading to the liquefaction system will allow the treated gas to be diverted to the flare system during abnormal conditions.

The regeneration gas heaters will be important for both dehydration and liquefaction unit operations and, therefore, spares are to be provided. One heater will be provided as a common spare for two trains. This arrangement will allow both emergency and routine maintenance and repair on any heater without reducing normal plant throughput.

The regeneration gas heaters are also provided with necessary monitoring equipment and controls to stop burner fuel flow in the event of flame failure, low regeneration gas flow, low fuel gas pressure or high temperature. The outlet regeneration gas will be temperature controlled to prevent possible damage to the molecular sieve desiccant.

A provision for routing regeneration gas to the liquefaction plant will provide a means of removing frost and ice from the cryogenic section of the plant.

Liquefaction

The liquefaction process selected for this project is the Phillips Petroleum Company "Optimized Cascade Cycle." This process utilizes three refrigerants: propane, ethane and methane. The propane and ethane will be conventional closed systems with two and three stages, respectively. The methane system will be an open system using methane-rich gases flashed at four pressure levels from the liquefied natural gas.

Liquefaction will be accomplished by reducing the temperature of the feed gas by sequentially subjecting the gas to propane, ethane and methane refrigerants. The process stream will then be flashed to remove nitrogen. This flash will provide most of the plant fuel requirements. After a final flash, the LNG will be pumped to storage. Vapors generated in storage or from LNG carrier loading will be returned to the liquefaction unit for product and refrigeration recovery.

The eight liquefaction trains are identical. Design liquefaction capacity for each train is the LNG volume equivalent of 378.81 MMcf/sd of gas loaded on LNG carriers. The operating basis is 345 stream days per calendar year.

The Phillips Optimized Cascade Process provides several favorable design features:

1) Plant turndown from 100% to 0% is possible without process upset;

2) Refrigerant is not lost during short shutdowns;

3) High efficiency results from minimum horsepower requirements per unit of product;

4) Simple instrumentation and control systems are employed;

5) A fuel draw from the methane system removes most of the nitrogen from the feed gas, thereby minimizing compression horsepower requirements. The gas from the fuel flash drum will furnish most of the plant fuel requirements;

6) LNG storage tank vapors will be returned by blower to the low pressure methane vapor system. By flashing the LNG into a final flash drum at low pressure, the possibility of excessive vapor in the LNG storage will be eliminated; and

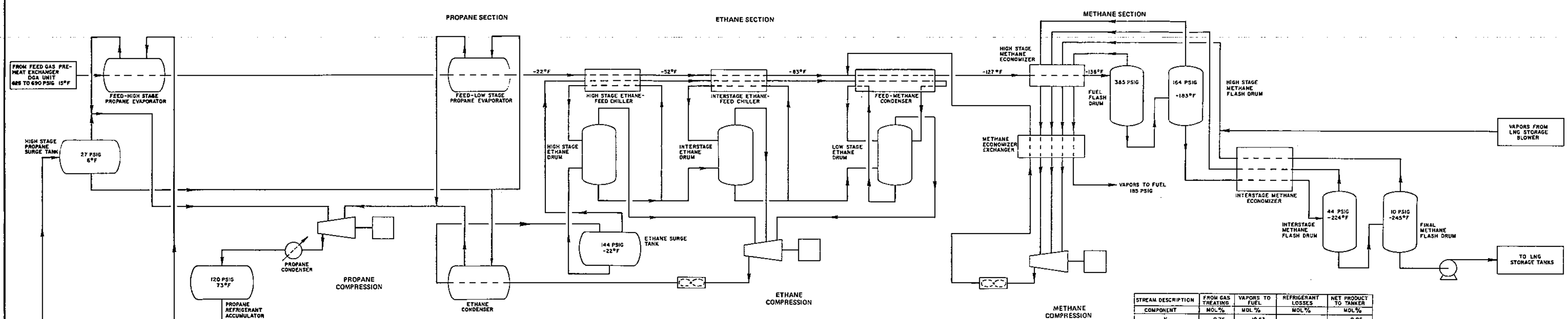
7) Refrigeration will be recovered from the storage tank return vapors by using economizing heat exchangers.

The Liquefaction Unit Schematic Flow Diagram (Figure 3.1-F6 on the following page) depicts the major components of the liquefaction and refrigeration systems.

The plant process description is divided into three sections: (1) Natural Gas Liquefaction; (2) Refrigeration Systems; and (3) Refrigerant Production.

Natural Gas Liquefaction Process

The flow of the feed gas stream, from its entry into the liquefaction units through the LNG product pump to its entry into storage, is described in this section. Also included is the fuel gas draw stream.



STREAM DESCRIPTION	FROM GAS TREATING	VAPORS TO FUEL	REFRIGERANT LOSSES	NET PRODUCT TO TANKER
COMPONENT	MOL %	MOL %	MOL %	MOL %
N_2	0.76	10.53		0.06
C_1	86.80	89.03	42.86	86.66
C_2	7.85	0.43	32.65	8.37
C_3	3.97	0.01	24.49	4.25
iC_4	0.26			0.28
nC_4	0.30			0.32
iC_5	0.03			0.03
nC_5	0.02			0.02
C_6^+	0.01			0.01
TOTAL FLOW MMSCF/STREAM DAY	406.00	27.05	0.14	378.81
HHV, BTU/SCF	1141.59	912.01	1630.72	1157.80
GROSS HEAT VALUE, MMMBTU/STREAM DAY	463.48	24.67	0.23	438.56

NOTES:

1. TOTAL BRAKE HORSEPOWER REQUIREMENTS FOR PROPANE, ETHANE AND METHANE COMPRESSORS IS 137,324 BHP/TRAIN.
2. ONLY ONE LIQUEFACTION TRAIN SHOWN.

TRANS-ALASKA GAS PROJECT

LIQUEFACTION UNIT SCHEMATIC FLOW DIAGRAM

FIGURE 3.1-F6

Feed gas from the gas treating and dehydration units will enter the liquefaction unit at approximately 15°F and at a pressure which can range from 625 to 690 psig. To avoid exceeding the design pressure within the unit, pressure regulation to a maximum of 650 psig will be maintained as the gas enters the propane section.

The feed gas will be first cooled by high and low stage propane refrigerant to -22°F. Partial condensation occurs in each exchanger as the feed is progressively cooled beyond this point. Upon leaving the propane section evaporators, feed gas will be cooled by high stage and interstage ethane. The natural gas stream will then be joined by the open cycle methane compressor discharge stream and the mixture will enter the feed-methane condenser and be refrigerated by low stage boiling ethane.

The process stream will be further cooled in exchange with cold methane vapors and then be flashed to approximately 385 psig. The flashed vapors will become a fuel stream containing most of the nitrogen in the feed gas. This stream will then be reduced to fuel gas pressure and flow through the high stage methane economizer and the methane economizer exchanger before entering the fuel system at 185 psig.

Liquid from the fuel flash drum will be flashed in the high-stage methane flash drum to about 164 psig and the vapors will become the high-stage methane refrigerant. The liquid will be further cooled by heat exchange with interstage and low-stage methane flash vapors, and then be flashed to 44 psig. The liquid will be flashed a final time to 10 psig into the final methane flash drum.

The vapor streams from the interstage and final methane flash drums will be passed through the three economizing heat exchangers to recover the refrigeration. With the exception of the fuel gas stream, all of these vapors will be recompressed to approximately 635 psig by the methane compressor.

The methane compressor discharge will be cooled by an air cooler, flow through the methane economizer exchanger and join the feed gas stream ahead of the feed-methane condenser, as described above.

Liquid from the final flash drum will be pumped to LNG storage. Vapors produced in the LNG storage tanks will be returned by the vapor blowers to the liquefaction unit to join with the low-stage methane refrigerant vapors.

Refrigeration Systems - Propane

The propane refrigeration system produces two levels of refrigeration. Part of the condensed propane at 120 psig in the propane refrigerant accumulator will be reduced to the high-stage pressure of approximately 27 psig and used to first cool the feed gas. The remaining propane refrigerant will be flashed into the high-stage propane surge tank. Propane from the high-stage surge tank will then be reduced to the low-stage pressure of 5 psig and used to cool the feed gas further and to condense the ethane refrigerant.

Propane vapors from each of the two stages will be sent independently to the propane compressor and will be compressed to 125 psig and condensed with sea water. Since the compressor is a centrifugal unit, a minimum flow through the unit must be maintained to avoid surging. This is accomplished by a recycle system which will permit surge-free operation of the liquefaction unit from zero to one hundred percent of capacity.

Automatic valves will close between the compressor and the liquefaction section whenever the compressor stops. This will retain the propane in the liquefaction unit because the equipment design pressure is high enough to eliminate the need to vent the unit.

The driver for the propane compressor will be a General Electric two-shaft Frame 7 gas turbine. Exhaust gases from the turbine will be used in a supplementary fired waste heat boiler to produce 1200 psig, 900°F steam for driving steam turbines to power the ethane and methane compressors.

Refrigeration Systems - Ethane

The ethane refrigeration system will have three stages of refrigeration. The refrigerant vapor from the compressor will be reduced in temperature in an air cooler and then condensed by the low-stage propane refrigerant in the ethane condenser.

Liquid from the ethane surge tank will be flashed in series to the high-stage, interstage and low-stage ethane drums. Liquids remaining after the flashes will be used to cool the feed gas and condense the feed gas-methane refrigerant mixture.

The ethane refrigerant will contain a small percentage of methane. The ethane-rich vapor will be drawn from the surge tank, condensed and subcooled through three stages of the ethane refrigeration process before being flashed, and evaporated to condense the feed methane refrigerant stream.

The ethane centrifugal compressor will receive vapors from the liquefaction section at three pressures. Automatic recycling will be provided to prevent compressor surge. This will permit the liquefaction unit to be operated from zero to one hundred percent of capacity. As with the propane compressor, whenever the compressor stops, automatic valves will close between the compressor and the liquefaction section.

The ethane compressor driver will be an extraction turbine using steam produced by the waste heat boiler at 1200 psig and 900°F. Approximately 50% of the steam will be extracted at 250 psig to power boiler fans and feedwater pumps. The remaining steam will be condensed by sea water at four inches of mercury absolute pressure. The condensate will be pumped to the deaerator in the boiler feedwater system.

Refrigeration Systems - Methane

The four pressure levels of methane to be used as refrigerants in the open-cycle methane system were previously discussed under the heading "Natural Gas Liquefaction Process." Three of these streams enter the suction of the methane compressor at their respective pressure levels, and the fourth stream will be depressured to the plant fuel gas system.

The methane compressor system will be similar to that of the ethane compressor just described. The compressor discharge will be cooled first by air coolers and then in the methane economizer exchanger before re-entering the main process stream upstream of the feed-methane condenser.

The methane compressor will also be a centrifugal unit. It will be equipped with a recycle system to allow flow through the compressor to prevent surge. This will permit operation of the liquefaction train from zero to one hundred percent of capacity. As with the other compressors, a shutdown will automatically block in the compressor system isolating it from the liquefaction system.

The steam turbine driver will be similar to that for the ethane system. Only 16% of the steam will be extracted from the turbine at 65 psig to supply part of the low pressure process steam requirements, such as deaerators, gas treating plant and desalination units. The remaining 84% will be condensed by seawater at four inches of mercury absolute pressure.

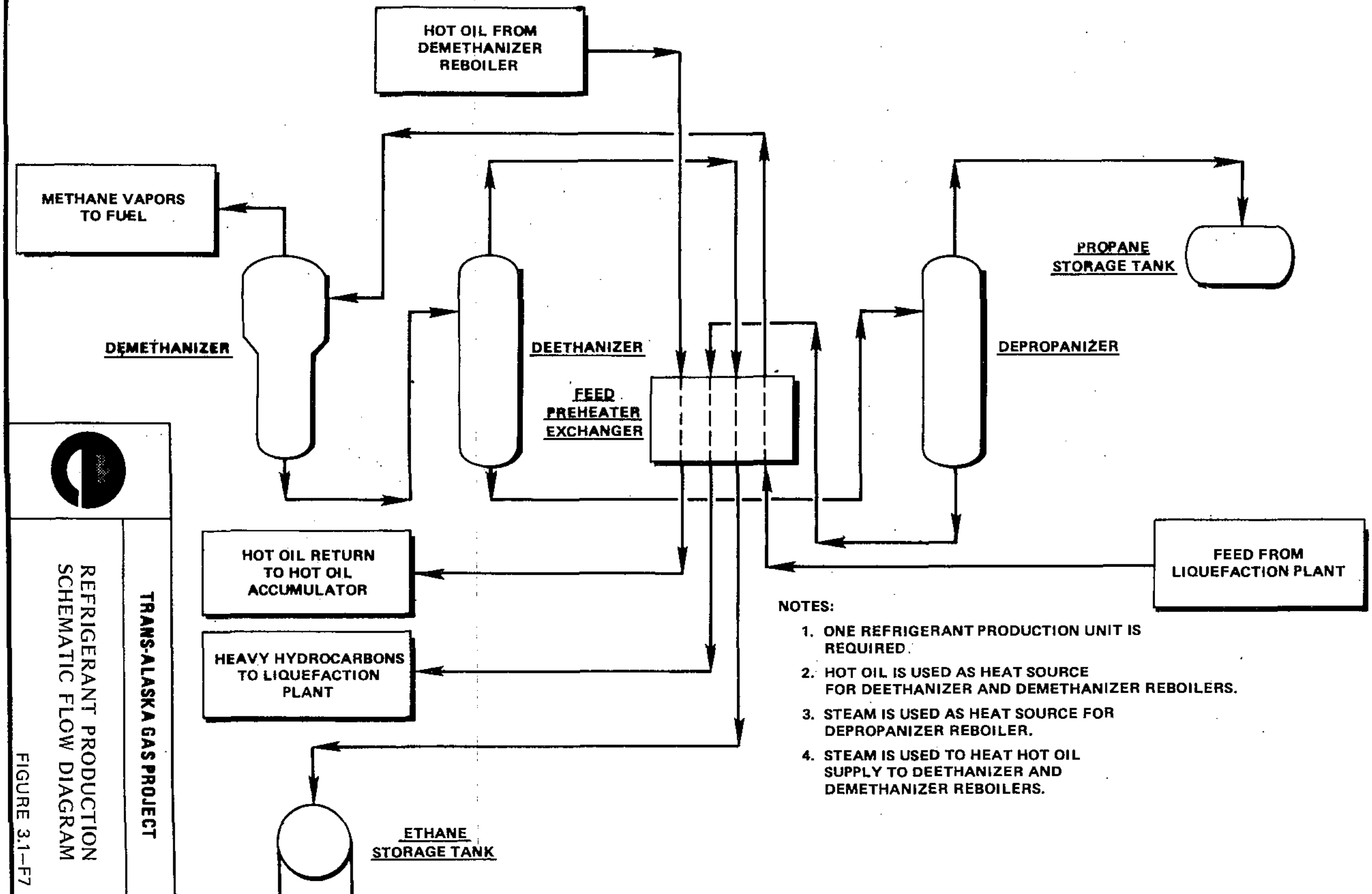
Refrigerant Production

A refrigerant production unit will provide refrigerant make-up for all of the liquefaction trains. This unit will consist of a de-methanizer, de-ethanizer and de-propanizer system which is shown in Refrigerant Production Schematic Flow Diagram, Figure 3.1-F7 on page 3.1-19. The system will operate as follows:

Feed to the refrigerant production unit will be taken as a liquid from upstream of the feed-methane condenser in any of the liquefaction trains. It will be preheated and flashed to remove most of the methane. The remaining methane will be stripped out in the de-methanizer to be used as fuel.

De-methanizer bottoms will flow to the de-ethanizer. The de-ethanizer overhead product will be the ethane refrigerant.

The de-ethanizer bottoms will flow to the de-propanizer column. The de-propanizer overhead product will be the propane refrigerant. The de-propanizer bottoms product will be chilled by the methane feed stream and reinjected into the LNG.



NOTES:

1. ONE REFRIGERANT PRODUCTION UNIT IS REQUIRED.
2. HOT OIL IS USED AS HEAT SOURCE FOR DEETHANIZER AND DEMETHANIZER REBOILERS.
3. STEAM IS USED AS HEAT SOURCE FOR DEPROPANIZER REBOILER.
4. STEAM IS USED TO HEAT HOT OIL SUPPLY TO DEETHANIZER AND DEMETHANIZER REBOILERS.

TRANS-ALASKA GAS PROJECT

REFRIGERANT PRODUCTION SCHEMATIC FLOW DIAGRAM

FIGURE 3.1–F7

The propane will be stored in a conventional ambient temperature, LPG storage tank. The ethane will be stored in a refrigerated storage tank designed for -80°F and a pressure rating of 85 psig. Propane and ethane refrigerant storage capacity will be sufficient to charge one liquefaction train.

LNG Product Storage and Handling

The LNG product will be stored in four 550,000 barrel, aboveground tanks at a temperature of about -256°F and a pressure of about 15.2 psia. A schematic showing the product storage and handling system is shown in Figure 3.1-F8 on page 3.1-21.

The LNG carrier marine terminal facility located south of the storage tanks will be designed to handle an average rate of 58,000 gpm simultaneously to each of two LNG carriers. The facility will include the capability of recovering all LNG vapors from such sources as tanks and carrier cool-down, loading displacement and storage boil-off for return to the LNG Plant.

The pressure of each tank will be individually controlled based on absolute pressure settings. There will also be a gauge pressure override. This independent control minimizes tank pressure fluctuations during the loading operation.

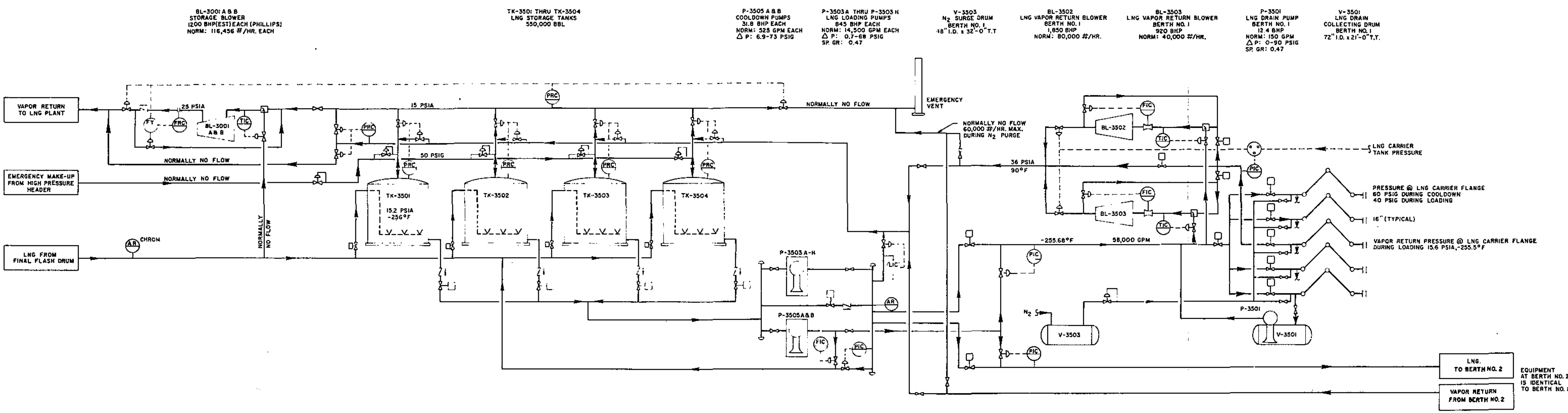
When an LNG carrier returns from dry dock, the nitrogen purge from its tanks will be discharged at the loading facility without interfering with simultaneous loading operations of an adjacent carrier.

The LNG Product Storage and Handling System, shown in Figure 3.1-F8, following, is described below:

Storage

LNG product will be pumped from the final flash drum in each train through a common header to the LNG tankage area. The four storage tanks will be designed to handle the plant production through a top-fill connection with an internal line extended to near the tank bottom to provide adequate mixing. Vapor flash and normal tank boil-off will be returned under tank pressure control through the vapor blower to the low-stage methane compressor suction in the liquefaction unit. Normal boil-off from the tanks will be less than 0.1% per day.

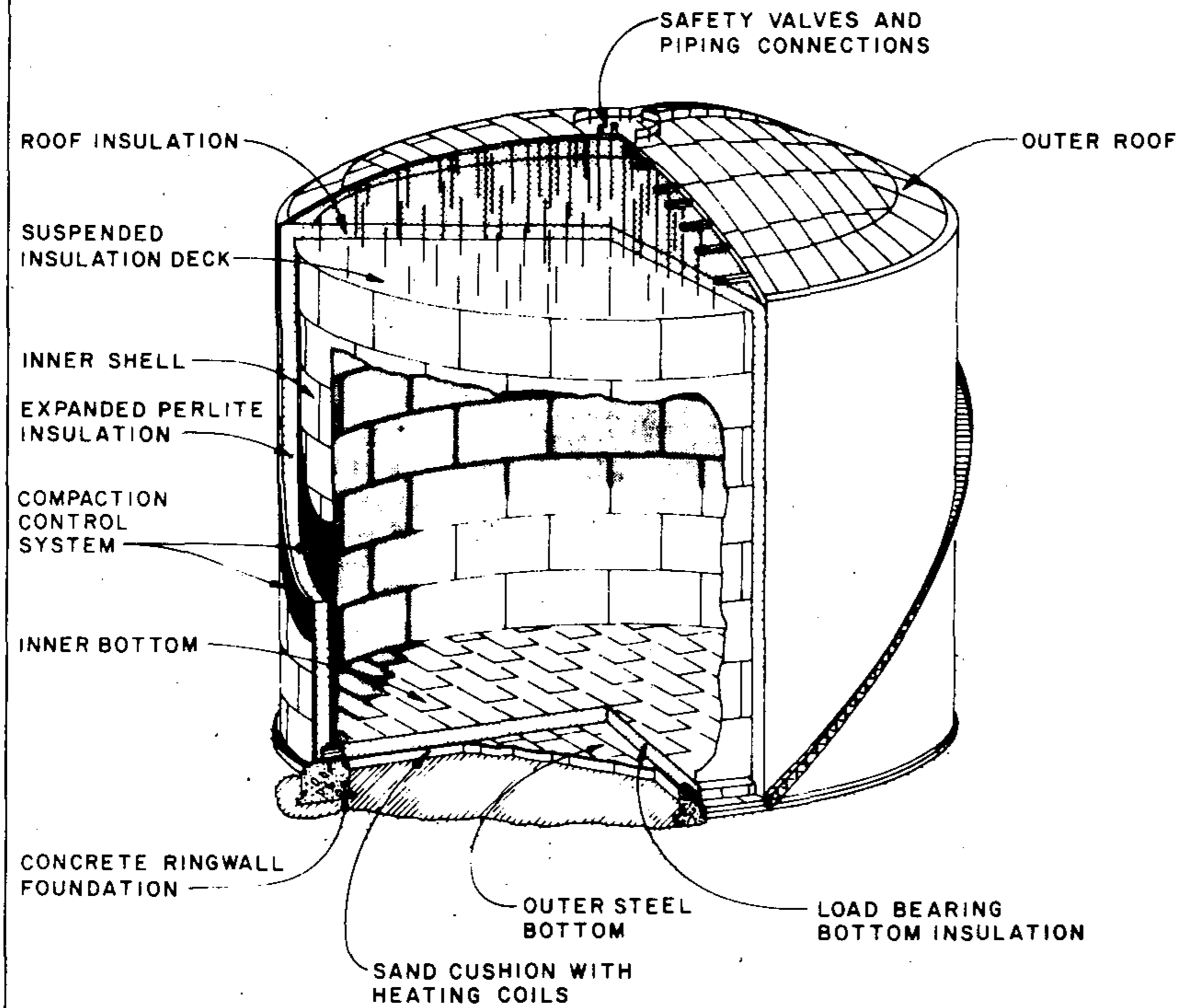
Four 550,000 barrel, flatbottom, double-wall, suspended-roof, above ground cryogenic storage tanks will be provided. A typical tank is shown in Figure 3.1-F9 on page 3.1-22. The tank construction will include a 9% nickel steel inner tank and killed carbon steel outer shell. The complete ring-walled base will be electrically heated to prevent frost heaving. Ground temperatures will be continuously monitored in the central control room.



TRANS-ALASKA GAS PROJECT

LNG PRODUCT
STORAGE & HANDLING PROCESS
FLOW DIAGRAM

FIGURE 3.1-F8



TRANS-ALASKA GAS PROJECT

SCHEMATIC DIAGRAM OF
TYPICAL LNG STORAGE TANK

FIGURE 3.1–F9

To minimize pressure fluctuations caused by ship loading operations, the tanks will be individually pressure controlled. These controls will be maintained on an absolute pressure scale to avoid boil-off fluctuations with changing atmospheric conditions. However, gauge pressure control can override the absolute pressure at the upper and lower pressure limits, for tank protection.

Safety pressure and vacuum valves, sized to handle the full emergency requirements, will protect the tanks under extreme conditions. Redundant monitoring, automatic shutdown and prealarming devices will be installed to prevent emergency conditions from occurring. An internal shutoff valve at the tank bottom outlet connection will be provided to minimize the size of an LNG spill caused by line breakage between the tank and the loading pump.

Tank level monitoring will be accomplished by two float-type level transmitters (one operating, one spare) and one differential pressure type level transmitter, all with recording readout in the central control room. In addition, a multi-point temperature probe with incremental read-out capability will allow early detection if stratification of tank contents occurs.

The tank rundown line and the LNG carrier loading line shutdown systems can be manually or automatically activated in case of abnormal operating conditions. Automatic activation signals will include high or low tank level and high or low tank pressure.

Handling

The LNG loading system will be designed to handle the simultaneous loading of two LNG carriers.

Cooldown of the loading arms and the LNG ship tanks will be accomplished by two 50% capacity cooldown pumps. These pumps will be designed to deliver a combined flow of 1,051 gpm at a pressure of 60 psig measured at the ship's flange. An automatic minimum flow bypass control around the pumps will allow a turndown from 100% to 0%, to accommodate all foreseeable cooldown rates. This system will also be used to purge the ship's tanks of inert gas following return from dry dock.

The loading operation will be started at low rates by gravity flow through the pump bypass valve. After the initially heavy boil-off vapor release has stabilized, the loading pumps will be started sequentially to satisfy the flow demand.

The LNG loading pumps will take suction from the bottom of the LNG storage tanks and will have the capacity to supply the product at an average rate of 58,000 gpm to each of two LNG carriers at a pressure of 40 psig measured at the vessel's flange. Eight parallel LNG pumps will be provided for the full loading rate and will serve all four storage tanks. These pumps will be locally started, but can be stopped from each berth control tower, the carrier, the central control room, the shutdown system, or locally.

An automatic pressure control system on the pump discharge header will open a bypass valve to protect the LNG loading pump at low carrier loading rates. This will also allow the loading operator to throttle the valves to the ship tanks without stopping the pump. Automatic shutdown controls are provided for additional pump protection.

The loading operation at each berth will use five 16-inch arcticulated loading arms, four liquid-handling and one vapor-handling. Each arm will be provided with an automatic shutoff valve to prevent LNG spillage during emergency conditions.

The loading operation will be controlled from a fully instrumented control panel in a loading control tower overlooking each berth. Product samples will be taken during the loading operation and will be analyzed for composition.

Displacement and boil-off vapors will be returned to the tank system by two electric motor-driven centrifugal blowers. Vapor flash caused by pump energy input and pipeline heat leak will be minimized during the normal loading process by maintaining the carrier tank pressure 0.4 psi above the storage tank pressure. Though only one blower will be used under normal loading operation, a second, parallel blower will be required during the cool-down operation.

The vapor will be returned to the storage tanks during loading operation on demand control. The returned vapors will replace liquid pumped out of the tank. Excess vapors will be returned via the storage blowers to the liquefaction units.

An emergency vent stack will be provided on shore and sized to exhaust the maximum possible flow during an unexpected emergency and an unexpected trip-out of the tankage vapor blower. This stack will also be used to vent the nitrogen vapors from the carrier tanks after return from drydock.

After completion of the loading operation, the loading arms will be isolated and drained into the LNG drain collecting drum. The LNG will then be pumped back to the storage tanks. The LNG loading line will not be drained during interim periods; vapors caused by heat leakage will be returned to the LNG plant, where they will be reliquefied.

A shutdown system will be provided for emergencies. It will activate manually or automatically to stop the loading operation and close the loading arm isolation valves. Automatic activation will be triggered by excessive ship movement, or high pressure in one of the carrier tanks. Activation of the shutdown system, whether manually or automatically initiated, will follow a predetermined sequence to protect personnel and equipment and to avoid pressure surges in the loading line.

Utility Systems

Desalinated Water

Desalinated seawater will be used to meet the fresh water requirements of the plant. Five packaged multiple-flash type desalination units will be provided (one unit will be a spare). Desalination feed water will be taken from the discharge of the sea cooling water supply pumps.

Each desalination unit will produce 345 gpm of desalinated water (with a maximum salinity of 5 ppmw and total dissolved solids content of 15 ppmw) from 3,035 gpm of seawater. The remaining 2,690 gpm of brine from each operating unit will be returned through the sea cooling water discharge system.

The maximum desalinated water requirement will be 1,245 gpm. The desalinated water will be stored in a 43,000 barrel epoxy-lined, cone roof tank and will be pumped to the potable water, fresh cooling water make-up and demineralizer feed water systems.

Steam and Condensate

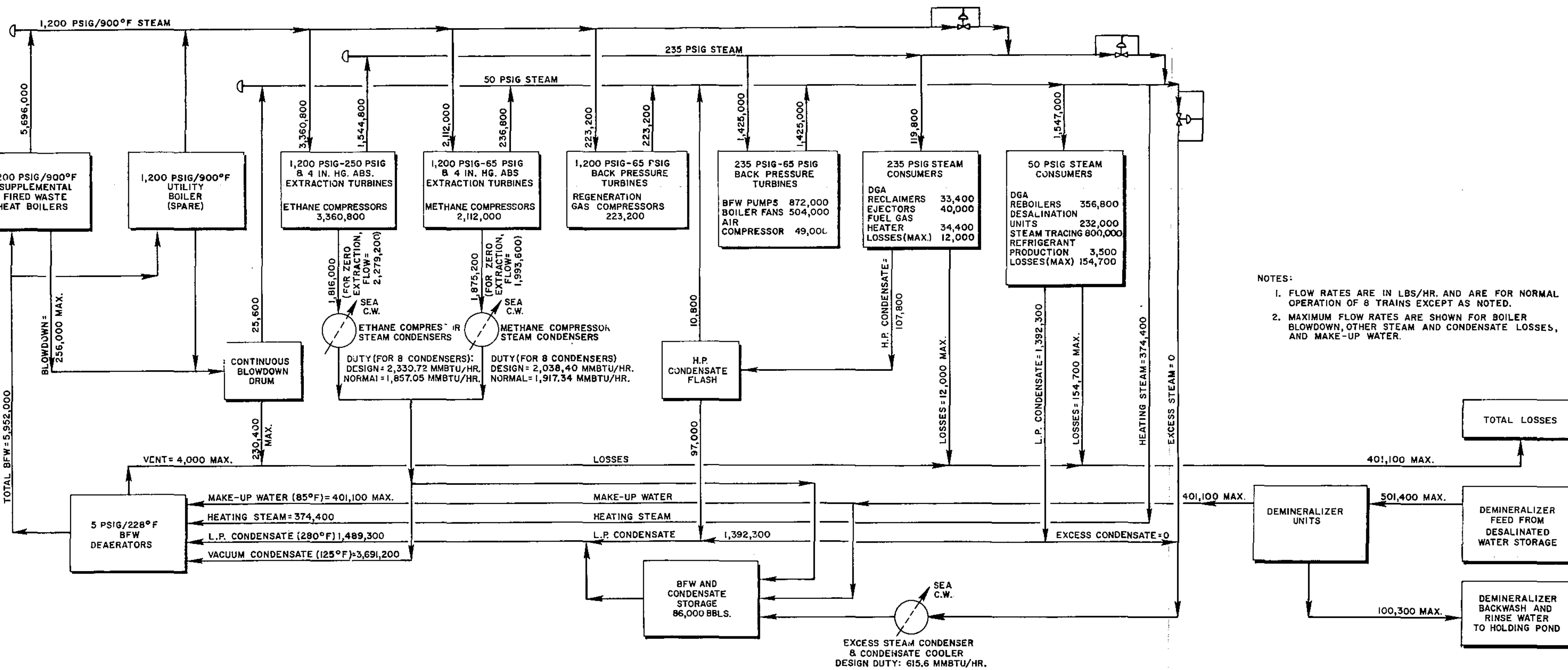
Steam at three different pressure levels will be required: (1) high pressure steam at 1200 psig (900°F); (2) intermediate pressure steam at 235 psig (saturated); and (3) low pressure steam at 50 psig (saturated).

High pressure steam at 1200 psig, 900°F, will be generated in eight supplementary gas-fired waste heat boilers, one for each train. Exhaust gas from the propane compressor gas turbine driver will supply hot gas as a heat source to the waste heat boilers. Each boiler will be designed to generate 800,000 pounds per hour of high pressure steam. An additional gas-fired utility boiler of the same capacity will be provided as a spare and for start-up purposes.

The block flow diagram on the following page, Figure 3.1-F10, titled Steam and Condensate System, shows the steam and condensate distribution for the entire complex during normal operation. At design conditions, the quantity of steam generated in eight boilers will be 5,696,000 pounds per hour at 1200 psig and 900°F.

High pressure steam will be used to drive the eight ethane compressor extraction turbines and the eight methane compressor extraction turbines. The exhaust steam from these turbines will be condensed by seawater at four inches if mercury absolute pressure and will be returned to the boiler feedwater deaerators.

Ethane compressor turbine steam will be extracted at 250 psig to drive back-pressure turbines for the boiler feedwater pumps, the boiler fans and one air compressor. Steam will be exhausted from the back-pressure turbines at a nominal pressure of 65 psig to supply most



NOTES:

1. FLOW RATES ARE IN LBS/HR. AND ARE FOR NORMAL OPERATION OF 8 TRAINS EXCEPT AS NOTED.
2. MAXIMUM FLOW RATES ARE SHOWN FOR BOILER BLOWDOWN, OTHER STEAM AND CONDENSATE LOSSES, AND MAKE-UP WATER.

TRANS-ALASKA GAS PROJECT

LNG PLANT STEAM & CONDENSATE SYSTEM

FIGURE 3.1–F10

of the heat required for the deaerators, DGA gas treating units, desalination units and steam tracing.

Methane compressor turbine steam will be extracted at a nominal 65 psig to balance low pressure steam requirements. Low pressure steam will also be produced through condensate flashing and boiler blow-down flashing.

Cascade controls will be used for the steam system. The 1200 psig steam system will be balanced by a pressure control valve which will depressurize steam to the intermediate pressure system at 235 psig. The intermediate pressure steam, in turn, will be balanced by a pressure control valve which will depressurize steam to a nominal pressure of 50 psig. A desuperheater will be provided at each of these two depressurizing stations, with boiler feedwater serving as the saturating fluid.

If the pressure rises 3 psi above the nominal pressure of 50 psig in the low pressure steam header, the excess steam will be condensed by seawater and stored in the boiler feedwater and condensate storage tank. If the header pressure exceeds the nominal value by 10 psi, steam will be vented to the atmosphere from the low pressure header through a steam vent valve and silencer.

Each steam pressure system will be further protected against overpressure by safety relief valves.

Boiler Feedwater

Condensate will be recovered for reuse as boiler feedwater. Make-up water will be supplied from the desalinated water storage tank. This water will be demineralized and then fed to the deaerators. Four boiler feedwater deaerators rated at 1,600,000 pounds per hour capacity each and two mixed bed polishing type demineralizer units rated 830 gpm capacity each will be provided.

Each demineralizer will be designed to produce a net of 830 gpm of demineralized water with a total dissolved solids content of 0.5 ppmw from 1040 gpm of desalinated feedwater; 210 gpm will be used for backwashing and rinsing one unit and then will be discharged to a waste water holding pond. The demineralizers will be designed to handle 50 ppmw solids from the desalination unit; normal feedwater to the demineralizers will contain 15 ppmw total dissolved solids. The resin mixture in each demineralizer unit will consist of a strong acid cation resin which will be regenerated with sulfuric acid and a strong base anion resin which will be regenerated with sodium hydroxide. One unit will be operating while the other is being regenerated.

The deaerators normally operate at 5 psig and 228°F and reduce the dissolved oxygen content in the boiler feedwater to 5 ppmv. Hydrazine solution will be injected into the suctions of the boiler feedwater pumps to scavenge the oxygen remaining in the feedwater after deaeration. Trisodium polyphosphate solution will be injected either into the suction of the boiler feedwater pumps or the boiler drums, to settle the solids in the steam drums and allow removal of these solids in the boiler blowdown stream.

During normal operation, the feed streams to each deaerator will include the following: Condensate from low pressure steam consumers and high pressure condensate flash drum; vacuum condensate pumped from the ethane and methane compressor turbine steam condensers; heating steam from the low pressure steam header; and make-up water from the demineralizer.

A boiler feedwater and condensate storage tank will be provided to collect low pressure and vacuum condensate, and demineralized water not fed directly to the deaerators. The low pressure condensate will be cooled and excess low pressure steam will be condensed by seawater.

Seawater Cooling

Once through seawater cooling will be used as the main heat exchange medium. Seawater will flow through an intake pipe to trash racks and moving screens in the pumping basin, and will then be filtered through automatic strainers at the pump discharges. Fourteen operating pumps and two stand-by pumps will be provided. Each pump will have an individual suction basin, permitting maintenance shut-down of the basin, the moving screen and the pump. These pumps will be designed to supply the total sea cooling water, screen wash water and desalination unit feed water requirements.

A chlorine system, consisting of a booster pump, chlorinators, vaporizers and liquid storage cylinders, will inject chlorine into the seawater at the seawater intake, the pump suction and the automatic strainers.

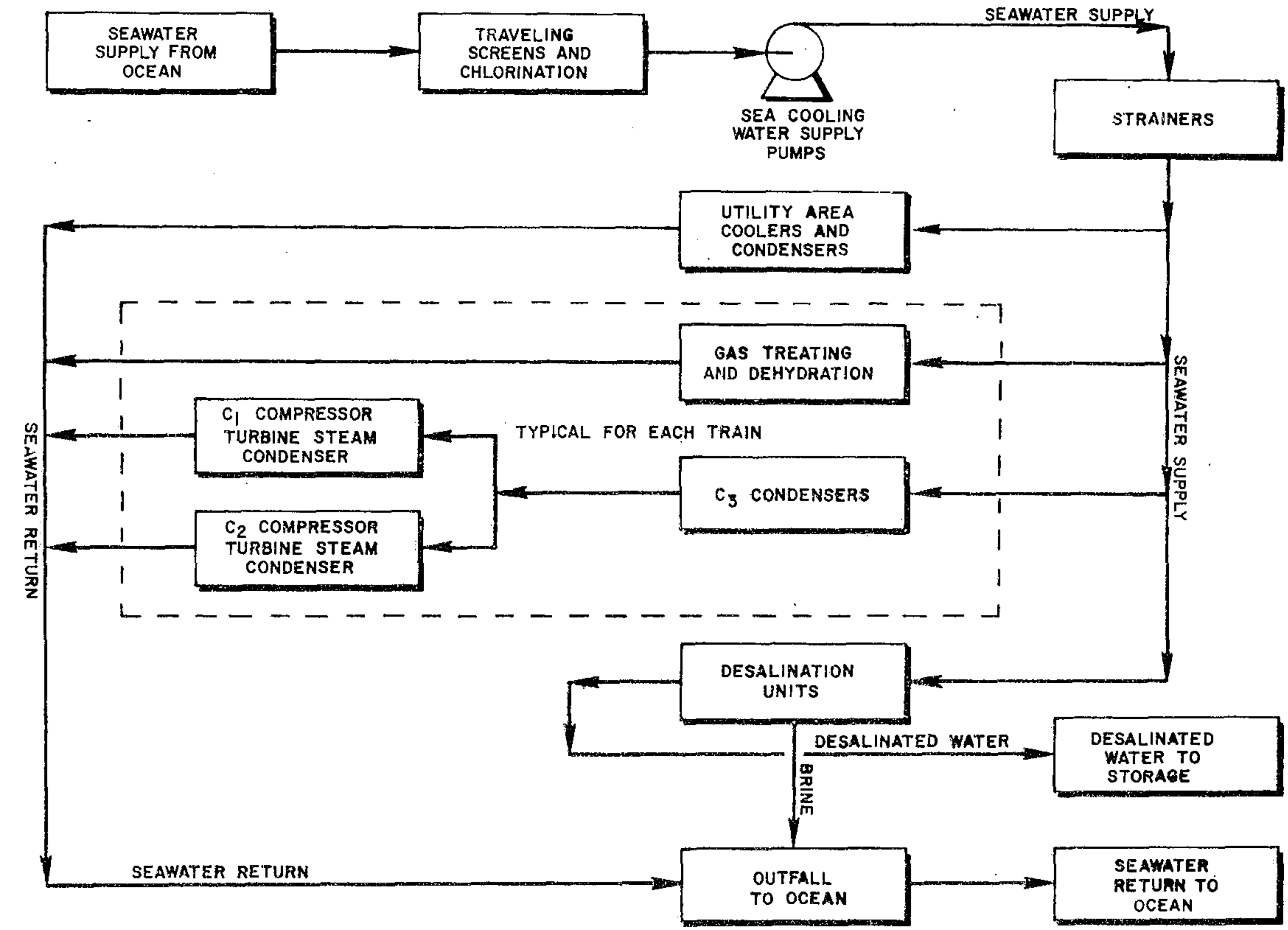
The block flow diagram, Figure 3.1-F11 on the following page, shows the cooling water distribution for the entire plant.

Cooling water will be piped and distributed to the eight liquefaction units and the utility plant. A shut-off valve will be installed on the seawater supply header to each liquefaction unit. Each seawater exchanger will be equipped with a mussel trap. The major sea cooling water users will be the propane condensers and the steam condensors for the methane and ethane compressor turbines. Seawater from the exchangers and brine from the desalination units will be returned to Orca Bay through an outfall system. The total design flow for the seawater cooling system will be 1,147,370 gpm.

Table No. 3.1-T1 on page 3.1-30 shows a summary of the cooling water requirements.

Fresh Water Cooling

A closed fresh cooling water system will be required for the lube oil coolers of the propane, ethane and methane compressors and



TRANS-ALASKA GAS PROJECT

LNG PLANT SEAWATER COOLING BLOCK FLOW DIAGRAM

FIGURE 3.1–F11

Table No. 3.1-T1

LNG PLANT

SEAWATER COOLING SUMMARY

Service	Design Flow Gpm	Cooling Water Temperature Rise, °F
Propane Condensers and Turbine Steam Condensers for Methane and Ethane Compressors(1)	1,048,700	15.3
DGA Treating Coolers and Condensers	18,780	20.0
Utilities Coolers and Condensers	79,890	20.0
TOTAL (for 8 trains)	1,147,370(2)	15.7 (avg.)(3)

(1) Series flow through propane condensers and turbine steam condensers.

(2) The sea cooling water pumps will be designed to supply an additional 23,620 gpm for the total screen wash and desalination feed requirements.

(3) The total average temperature rise, including the brine discharged from the desalination units to the seawater outfill system, will be 16.1°F.

compressor drivers. Make-up water will be supplied from the desalinated water storage tank.

Fresh cooling water at 100°F will be pumped to the lube oil coolers from a fresh cooling water storage tank of 5,200 barrels capacity. The hot water returning from the lube oil coolers at a maximum temperature of 120°F will be cooled to 100°F by seawater in the fresh water-seawater exchanger. The corrosion inhibitors required will be added to the fresh cooling water storage tank. A summary of flows and temperatures is shown below:

Area	Design Flow Gpm	Cooling Water Temperature Rise, °F
Propane, Ethane and Methane Compression (Lube Oil Cooling)	14,200	20
Utilities	2,000	20
Total (for 8 trains)	16,200	20 (avg.)

Potable Water

Potable water for the plant process units, offsites and administration building will be supplied from the desalinated water storage tank and pumped through carbon filters and an automatic hypochlorinator to the drinking water surge drum. This drum will be pressured with clean plant air.

Fire Fighting Systems

Fresh water will normally be used for fire protection. The primary supply will be furnished by either of two fresh water gravity feed tanks with sufficient elevation to provide a minimum of 100 psig at the most remote hydrant. Fire hydrants and monitor nozzles will be strategically located throughout the plant. Fire fighting water will be distributed to hydrants, hose stations and monitor nozzles by a looped underground system of fire mains.

One fresh water storage tank will provide a 12-hour supply of fresh water to the LNG storage and process areas at a flow rate of 7,500 gpm. Another tank will provide a 6-hour supply of fresh water to the LNG loading berths and marine fire fighting system at a flow rate of 3,000 gpm.

A back-up fire fighting water source will be provided by three diesel engine driven vertical water pumps which will supply seawater to the fire fighting system. Each pump will have a capacity of 2,500 gpm at 150 psig discharge pressure. The pumps will be located in a separate suction basin at the seawater pump station.

The fire fighting water piping will be normally filled with fresh water. The pressure will be maintained in the piping by static head from the elevated fresh water storage tank. If the water level in the tank drops below a level of five feet, an alarm will sound in the central control room. The diesel engine-driven pumps will then be manually started to supply seawater to the fire fighting water piping.

After each use of the back-up seawater supply source, the pipes will be drained of seawater and flushed and pressurized with fresh water. The seawater pumps will be normally tested using a bypass around the fire fighting water piping to avoid unnecessarily contaminating the piping with seawater.

Dry chemical or Halon fire extinguishing equipment will be provided by five portable trailer units: two for the LNG loading area; one for the pumping station; one for the process area; and one for the LNG storage area. Additionally, fixed nozzle, self-contained dry chemical or Halon extinguishing systems will be located at each LNG loading platform, each building containing gas compressors and the LNG pumps.

The fire fighting system on each loading berth will be compatible with the system on the LNG carrier to provide mutual assistance in case of failure of one system.

In addition to fire hydrants, monitor nozzles and dry chemical or Halon systems, a mechanical foam system will be provided to blanket the LNG storage tank for protection. The foam will not extinguish an LNG fire, but will provide an effective cooling medium for absorbing radiated heat from such a fire.

The foam system will consist of a portable foam generating truck and fixed piping and distribution nozzles for each LNG storage tank. To utilize the foam system on any tank, the foam generating truck will take suction from a convenient fire hydrant and proportion an appropriate amount of foam concentrate into the fire fighting system branch piping serving that tank. The foam solution will then be directed to the tank to be protected through the fixed piping and will exit as foam at the tank top through distribution nozzles.

The capacity of the system will be designed to cover one LNG tank top with a 3% foam solution at a density of 0.10 gpm per square foot for one hour.

Numerous hand-operated CO_2 extinguishers and breathing apparatus will be located throughout the plant. All fire fighting systems will be designed in strict accordance with NFPA regulations.

Fire prevention and detection systems will be discussed under "Safety Considerations."

Electric Power Generation

Eight electric power generators, rated 23.7 megawatt output each, will be provided. One generator will be a spare. Each generator will be driven by a regenerative cycle gas turbine. Power is generated at 13.8 kilovolts (kv), three phase, 60 Hertz.

One emergency diesel engine-driven power generator with 600 kilowatt output will also be provided. The emergency power generator starts automatically on total power failure in the plant and will supply power for emergency lighting, battery chargers for instruments and electric motor-operated shutdown valves.

Control systems and shutdown/interlock systems will be direct current operated and will not be affected by AC power fluctuations.

Electric power requirements will be shown in Table No. 3.1-T2, on page 3.1-34.

Electric Power Distribution

The primary distribution voltage will be 13.8 kv, with secondary distribution at 4,160 volts and 480 volts.

The 13.8 kv distribution system will consist of dual feeders to each of several major 13.8 - 4.16 kv substations. All 13.8 - 4.16 kv and 4160 - 480 volt substations supplying process or critical loads will be double-ended to achieve the highest degree of power reliability and continuity.

Distribution equipment such as switchgear and motor controllers will be indoor type, located in non-hazardous weather-tight buildings adequately heated, lighted and ventilated.

System protective devices will be selected and coordinated to insure that the interrupter nearest the point of short circuit or high overload will open first and minimize disturbances on the rest of the electrical system.

Fuel Gas and Losses

The LNG Plant will consume approximately 290 MMBtu per day due to fuel gas requirements and process losses.

Fuel gas will be used for the propane compressor turbine, electric power generator drivers, the regeneration gas heater and to fire boilers. The exhaust gases from the propane compressor turbines will be sent to the waste heat boilers to provide part of the boiler heat requirements. The remaining heat will be provided by supplementary gas firing.

Approximately 65% of the average fuel gas requirements will be produced in the fuel flash drums of the liquefaction trains. Flash gas from

Table No. 3.1-T2

LNG PLANT

ELECTRIC POWER SUMMARY[1]

Area	Connected Load kw	Normal Operating Load kw	Operating Load When Loading Tanker kw
Gas Treating	4,570	2,500	2,500
Liquefaction	14,120	7,980	7,980
Refrigerant Production, LNG Storage and Handling	12,440	1,720	8,980
Utilities and Off-Sites[2]	114,080	93,740	93,740
Lighting	1,000	1,000	1,000
Total kw (8 trains)	146,210	106,940	114,200
Average kw (8 trains)		109,840[3]	

(1) Motor efficiency = 92%.

(2) Seawater cooling supply pumps will be the major electric power users in the utilities and offsites area. Total connected load for these pumps will be 104,960 kw, and the normal operating load will be 91,840 kw.

(3) Average = 0.6 (normal) + 0.4 (tanker loading).

the DGA gas treating units will provide less than one percent of fuel gas used. Pipeline gas will provide the remaining fuel requirements.

The fuel gas from the liquefaction flash drums and from pipeline gas will be heated to 100°F. All fuel gas streams will be fed to a knockout drum and then will be piped to the users.

Process losses are due to refrigerant losses and the venting of waste gases in the DGA regeneration section.

Requirements for average operations are summarized below:

User	Gas Required[1] For Average Operations Billion Btu/d
Propane Compressor Gas Turbine Drivers	106.85
Supplemental Fired Waste Heat Boilers[2]	139.28
Electric Power Generator Gas Turbine Drivers	29.94
Process Losses	2.64
Miscellaneous	11.54
Total (LNG Plant)	289.25

(1) Fuel gas requirements are on an average calendar day basis. All eight trains are operating only 205 days of the year, on the average; on the remaining 160 days, only seven trains are in service.

(2) Supplemental fuel gas required for the waste heat boilers.

Instrument and Utility Air

Two centrifugal air compressors will be provided for instrument and utility air service. Each compressor will have a capacity of 3,000 cfm at a discharge pressure of 140 psia and will be capable of providing 100% of the required instrument and utility air. The operating compressor will be steam turbine driven. The spare compressor will have an electric motor drive.

Atmospheric air will be filtered before it is compressed. Each compressor will have individual fresh water interstage and aftercoolers. The two compressors will have a common air receiver with a hold-up time of two minutes at 3,000 cfm. The compressed instrument and utility air will be prefiltered and dried in a dual column desiccant dryer to a dew point of -45°F at 100 psig.

Afterfilters will be provided to prevent any powdered desiccant from carrying over into the instrument and utility air header. Normal header pressure will be 100 psig. Utility air requirements are automatically cut back to preferentially supply instrument air requirements when the supply air pressure is low.

Nitrogen

Two packaged nitrogen generation units will be provided. One unit will be a spare.

Each unit will include a compressor, exchangers, a nitrogen separation column, a five metric ton liquid nitrogen storage tank and a nitrogen vaporizer. Each nitrogen unit will produce 30,000 Scf/hr of nitrogen vapor at 150 psig and 120 pounds per hour of liquid nitrogen. The liquid nitrogen will be stored and used to provide for short duration peak demands of nitrogen.

A liquid nitrogen line will connect this facility with the LNG loading berths to allow transfer of up to five metric tons of liquid N_2 to the LNG carriers. Transfer of liquid nitrogen to the carrier will be required only under unusual conditions and will not be a part of normal operations.

During normal operations, the plant will use an estimated average of 12,630 Scf/hr of nitrogen vapor. Nitrogen will be used for purging liquefaction cold boxes, the stem seals of electric motor operators for control valves and emergency shut-down valves, and miscellaneous electrical equipment.

After the loading of an LNG carrier, nitrogen vapor will be required to purge the loading arms. Nitrogen vapor for use in purging the loading arms and other berth facilities will be stored in a nitrogen vapor surge drum.

Additional nitrogen storage tank trucks and vaporization facilities will be rented to provide nitrogen vapor for purging process equipment and LNG storage tanks during the initial plant start-up and during scheduled plant shutdowns. A summary of nitrogen vapor usage follows:

Area	Nitrogen for Average Operations, Scf/hr
LNG Storage and Handling	1,530
Liquefaction	11,100
TOTAL (for 8 trains)	12,630

Offsites

Relief System

Pressure relief gases will be burned in elevated, smokeless flare stacks. Two separate flare stacks are provided: One for relief of high pressure pipeline gases and one for relief of process plant gases.

The process plant pressure relief header will collect gas from the sub-headers from all trains and will be sloped toward a common knock-out drum to facilitate draining condensate from the header. Cold gases such as refrigerants will pass through a cold knockout drum and will be heated prior to entering the common knockout drum. Gases from the common knockout drum will flow to the flare stack.

The waste gases from the DGA gas treating units, consisting principally of CO_2, will be discharged to the atmosphere through a vent stack.

An emergency vent stack will be provided at the storage area. This stack will be designed to handle low pressure, slightly above atmospheric, emergency venting requirements from the LNG tankage and loading facility.

DGA Storage

Aqueous 65% DGA solution for all of the trains will be pumped from one 8,000 gallon DGA solution make-up tank to the DGA surge tank in each train. A 12,000 gallon DGA sump will be provided with a capacity to hold the DGA solution content of one complete train.

DGA will be added to the sump by gravity flow from individual drums in a heated building adjacent to the sump. Solution concentrations will be manually monitored. The DGA solution will be filtered before being sent to the DGA makeup tank to remove any particulates picked up in the sump.

Diesel Fuel Storage

Arctic grade diesel fuel for the use of personnel and work boats will be stored in a tank at the Alaskan Marine Terminal small boat harbor. Fuel will be shipped in by barge. Fueling facilities at the plant garage and other miscellaneous requirements will be served by a tank truck hauling diesel from the small boat harbor.

Small arctic diesel fuel storage containers will be located as an integral part of emergency equipment, such as at the emergency diesel-driven fire fighting water pump and at the emergency power generator. All storage containers will be equipped with level indicating and low level alarming devices and will be protected by relief valves against overpressure.

Auxiliary Facilities

Administration Buildings

A single-story steel and concrete building with approximately 30,000 square feet of floor space will house administrative and technical offices and conference rooms. A laboratory, pipeline Dispatching and Control Center and a communication room will also be included as a part of this building. The building will be suitably heated. The Dispatching and Control Center will be air conditioned.

Maintenance Shop and Warehouse Building

A building of steel and transite with a floor space of 55,000 square feet will be provided for warehousing plant supplies, spare parts and maintenance materials. Maintenance shops for the various crafts will be provided in a portion of this building. Shops and offices in this building will be heated. Low-level heating will be provided in the warehouse.

Control Building

The control building will contain all main control panels for all process trains and utility plants. The building will have approximately 18,000 square feet of floor space. It will also include operating offices, a kitchen, a locker room, a control laboratory for use by operators, a supply room and a mechanical equipment room. This building will be of concrete and steel construction and will be heated. The control room will be air conditioned.

Cafeteria, Change House, Fire and Safety Building

A single building will be provided near the main plant entrance to house change and locker facilities with 270 lockers, a cafeteria which will seat 50 people, offices for fire and safety personnel, fire and safety equipment storage, first aid facilities and offices for the security personnel. This 6,000 square foot building will be of concrete and steel construction and will be heated.

Garage

A garage will be provided for servicing maintenance vehicles and other plant rolling stock. The fire truck and ambulance will also be housed in this heated building. Facilities will include hydraulic lifts, a dynamometer and fueling facilities for diesel and gasoline. Approximately 4,500 square feet of floor space will be provided in this steel and transite building.

Compressor Building

Each of the eight LNG trains will contain a group of compressors and drivers which will be housed in a transite and steel compressor building equipped with bridge cranes for maintenance use. Each building will have concrete floors and will contain 25,000 square feet of floor space. The buildings will be insulated and heated.

Utility Building

A single utility building containing approximately 5,000 square feet of floor space will be required to house utility facilities such as demineralization and desalination equipment, instrument and utility air compressors and the operating faces of boilers. A switchgear room will be included. Construction of this building will be similar to that of the compressor houses.

DGA Sump Building

A building with 600 square feet of floor space will be provided to enclose one end of the DGA mixing sump and to house 25 drums of DGA. The sump will be 17' x 17' x 10' deep, and will hold sufficient DGA for a single train. The building will be suitably heated.

Switchgear Buildings

One switchgear building will be provided for each liquefaction train to house motor controls and switchgear. The buildings will be similar in construction to the compressor buildings. Each building will have 1,000 square feet of floor space and will be suitably heated and insulated.

Power Plant Building

A two-level power plant building having 60,000 square feet of floor space will be provided in the power generation area to house the generators and drivers, switchgear, the stand-by generator, a control room, battery room and supply room. A bridge crane will be included over the turbine generator. The building will be suitably heated.

Personnel Housing

Sixty-five permanent homes, each containing 2,500 square feet of floor space and located on a 1/4 acre site, will be provided at the housing complex 3/4 miles west of the plant. This housing will provide residences for key operating personnel. Others will reside in the Cordova area.

Guest House

A guest house with 7,500 square feet of floor space will provide accommodations for approximately fifteen people. Included will be a kitchen, dining and a recreation room. This building will be of wood frame and masonry construction.

Recreation Building

A recreation building having 12,000 square feet of floor space will be provided at the housing complex. It will include a small store, kitchen and dining facilities, a game room, an auditorium and stage, bowling alleys and a swimming pool and sauna.

Operator Shelter Buildings

Two shelter buildings will be provided--one each at the LNG loading pumps and the seawater intake structure. Each will have 200 square feet of floor space.

Personnel Boats

Two personnel boats will be required for travel between the LNG Plant site and Cordova, Alaska. At the present time, the only methods of transportation to the site are water craft and helicopter. The personnel boats will provide the flexibility required in the operation of the plant and will ferry plant personnel residing on Gravina Peninsula.

Each personnel boat will be capable of carrying approximately 40 passengers at speeds of approximately 25 miles per hour and will have a deck cargo carrying capacity of 20,000 pounds. The boats will be licensed and certified by the U. S. Coast Guard and will be equipped with navigation and life saving equipment.

Safety Considerations

Safety will be a major consideration in the design of the entire LNG Plant. Safety elements to be considered in the design will include detection of fire or presence of combustible vapors, high pressure relief and emergency venting, containment and control of LNG spillage and leaks, shutdown systems, seismic considerations, noise control, adherence to applicable design codes and personnel training. These safety considerations will be discussed in more detail in the following paragraphs.

Fire Prevention

To protect the LNG Plant from fire, automatic ultraviolet flame detectors and combustible vapor detectors will be strategically located throughout the plant facilities. Detection of either fire or combustible vapors at any of these locations will automatically send an alarm to the central control room. These automatic detectors will be periodically checked for reliability.

Combustible vapor detection at less critical locations will be done periodically with portable equipment. In this manner, minor leaks will be detected and repaired before they can cause an emergency condition.

Fire fighting systems in the LNG Plant site will consist of water spray, mechanical foam, dry chemical or Halon, and hand extinguishers. A detailed description of these facilities was presented on page 3.1-31 of the Utility Systems section.

The water spray systems will include monitor nozzles and fire hydrants located throughout the processing, berth and storage facilities. Automatic sprinklers will be provided in offices, warehouses and other buildings. The water spray will extinguish non-hydrocarbon fires and will provide a cooling medium for exposed equipment. Monitor nozzles at the loading berth will also be used to provide a water spray for promoting the dispersion of vapors in the event of an LNG spill. The fire water system on the loading platform will be compatible with the system on the LNG carrier.

All plant piping will be grounded to protect against lightning and to prevent flowing LNG from building up static charges. Insulated flanges, bonding cables and ground rods will be used for tanks supported on non-conducting foundations.

Piping, valves and fittings will be of materials having required impact resistance at LNG temperatures. Provisions will also be made for thermal expansion and contraction by installation of bellows, expansion joints and expansion loops.

Block valves will be situated so that major areas of piping and equipment can be isolated in case of leaks. Relief valves will be provided between block valves to protect from possible over-pressure resulting from thermal expansion. Process fluid, high pressure steam, fire protection and other critical piping will be identified by color coding, painting or labeling.

Vehicular traffic will be restricted within the facility. Vehicles will operate only at low speeds and will be equipped with spark arrestors.

The control building will be constructed of fire resistant material. The building will be kept under positive pressure, which will be continuously monitored. No combustible process gases will be brought into the control room.

Venting

High pressure relief and emergency venting will be included in the design of the plant safety systems.

During unusual or emergency situations such as power failure or fire, it will be possible for the pressure of processing streams to increase above the normal working pressure. Accordingly, all pressure vessels will be provided with safety relief valves designed to operate at or below the maximum allowable working pressure of the vessel.

In general, the hydrocarbon relief valves will exhaust to a closed relief header system and will then be discharged to an elevated flare stack, or they will be vented, without burning, at a safe height above the plant. The gases that are vented to the atmosphere without burning will come primarily from the LNG storage and loading facilities, which will operate at a pressure too low for discharging vent gases to the flare stack.

The vent stack diameter and height will be sized to ensure safe dispersion in the atmosphere. Lightning protection and location of the vent stack will minimize the possibility of vapor ignition by lightning discharge. Nitrogen snuffing will also be provided.

The LNG Plant design will incorporate a means of safely shutting down vital operations within the plant in the event of an emergency or upset conditions. The DGA gas treating facility will include automatic feed gas diversion to the flare system in the event circulation should be interrupted. A flare header vent valve will be included in the dehydration facility on the gas header leading to the liquefaction section. The gas stream will be manually diverted to the flare header in the event feed gas to the cryogenic section does not meet inlet specifications.

To protect the regeneration gas heaters in the dehydration facility during this venting operation, the heaters will be provided with necessary monitoring equipment and control instruments to stop burner fuel flow in the event of high temperatures or low regeneration gas flow. Additionally, automatic shutdown will occur in case of flame failure or low fuel gas pressure.

Spills and Leaks

Containment and control of LNG spillage and leaks will be a major safety consideration in the design and operation of an LNG facility.

Operational experience in existing LNG facilities has shown that no failures have occurred in large storage tanks containing LNG when they are constructed of materials that will withstand cryogenic conditions. The LNG storage tanks will be designed to withstand severe winds, rain, snow and earthquakes.

Provisions will also be made for dikes to contain LNG spills. The proposed bi-level diked area will contain the contents of more than one tank as required by NFPA standards. An LNG spill will flow through a trapezoidal channel from the diked area surrounding the tanks to the lower level diked area. The lower diked area will have a sump at the low point designed to hold the LNG volume of a ten-minute duration spill from an assumed ruptured tank loading line. Spilled LNG within the dike will be dissipated by boil-off to the atmosphere. An automatic drainage valve will be used to keep the diked area free of rain water and snow melt.

LNG storage tank safety considerations must also provide for the possibility of stratification and subsequent "rollover." This is a term used to describe the sudden evolution of a large quantity of vapor within a storage tank. This phenomenon can occur in an LNG storage tank when two layers of LNG of different densities are not adequately mixed.

To avoid stratification, the fill connection will be piped to the bottom of the tank in order to mix the contents. Operations will be monitored by comparing temperature and density of the LNG already in the tank with the LNG being sent to the tank.

To protect the storage tanks from possible overpressure caused by fire exposure or blocked discharge conditions, the tanks will be equipped with pressure relief valves set at the maximum allowable working pressure for the tank. The relief valves will handle all the vapor produced during these emergency conditions. The relief valves will discharge directly to the atmosphere.

In addition to relief valves, vacuum safety valves will be installed to protect the tank from a possible underpressure condition. Activation of these safety valves will be extremely unlikely. An absolute pressure control system will maintain constant tank pressure even with changes in atmospheric pressure conditions. Gauge pressure instruments will override the absolute pressure instruments during periods of extreme atmospheric pressure variation. High and low pressure switches will close the shut-off valves in the tank fill or emptying lines in case of failure of both pressure control systems, thus adding another dimension of safety to the pressure safety systems.

Shutdown Systems

An LNG Plant shutdown system will be provided to protect plant and personnel in the event of an LNG spill, fire or other emergency. Shutdown systems for both the ship and the loading facility will be interlocked and can be manually activated from the carrier, the LNG Plant control building or from the loading control tower at the berth. Automatic activation of the loading shutdown system will be triggered by excessive LNG carrier movement during the loading operation, or by high pressure in the LNG carrier tanks.

All vital locations within the LNG product storage and loading facilities can be isolated in an emergency by means of remote controlled valves. These valves will be located in the product line from each LNG storage tank, at each LNG loading pump, each cool-down pump, each vapor return blower, and on the loading line at the approach to both loading berths. To prevent potentially dangerous pressure surges during shutdowns, valves will be programmed for sequential closure at controlled rates. In the event of a complete power failure, the valves normally operated by motors can be operated by hand.

Automatic control systems will be provided with manual override so that control valves and process equipment can be operated from the control house and appropriate local control panels. Instrumentation will be designed so that, in the event of a power or instrument air failure, the system will go into a fail safe condition maintained until plant personnel take corrective action. Electrically interlocking relays, shutdown systems, solenoid valves and other systems vital to safe and uninterrupted plant operation will be powered from a reliable 48V DC battery system isolated from effects of any possible AC power dip or power outage.

Communication to the control building by telephone or two-way radios will be provided throughout the plant. This will enable operating personnel to activate fire fighting equipment, stop the flow of liquid and gas and sound emergency alarms from within the plant without having to return to the control room. Communications will be provided from the LNG loading berth to the control building, pumping station and carrier.

Seismic

Design of the facility to withstand seismic forces will require consideration of the direct and indirect effects of earthquakes and local geology. The direct effect will be vibratory ground motion, while indirect effects will include landslides, subsidence, soil liquefaction and tsunami wave generation.

Careful location of the facility and adequate site preparation will minimize the risks of vibratory ground motion, landslide, subsidence and soil liquefaction. Location of the onshore facility at a 150 foot elevation will eliminate the risk of tsunami damage.

The preliminary seismic design has assumed an effective bed-rock acceleration of 0.60g for the maximum ground motion to which the storage or other processing equipment in the facility can be exposed without loss of fluids from storage tanks or processing equipment. An acceleration factor of 0.3g has been applied in the preliminary design of other facilities not processing or containing LNG.

The final seismic design of the LNG storage tanks and containment walls will be based on an elastic modal response spectrum analysis, using the maximum expected earthquake for the plant area. Other facilities not processing or containing LNG will be built to a less severe criteria.

Training

All operating personnel will be fully instructed concerning any potentially dangerous situations associated with the LNG Plant and methods of handling such hazards. A formal training program will consist of both classroom and field training. Fundamentals such as properties of LNG, potential hazards, safety aspects and fire fighting techniques will be taught in the classroom, followed by practical drill application at the plant site. Manufacturer's representatives will conduct classes on specific pieces of equipment such as marine terminal loading arms, control systems, LNG pumps, LNG storage tanks, fire fighting equipment and other special equipment.

Particular emphasis will be given to training in fire fighting techniques. All operators will be given fire drill ground training in the use of hose lines fitted with spray nozzles. This equipment will be used against small fires, LNG spills and for protecting fire fighters while they are closing valves, making rescues and similar activities. Refresher training will be given routinely and new employees will be oriented and trained with the regular crews after special preparation.

Control of Plant Effluents and Emissions

Effluents

The proposed waste water system is shown in Figure 3.1-F12, following. A summary of waste water flows, compositions and temperatures is presented in Table No. 3.1-T3 on page 3.1-47. The values shown are for average conditions unless otherwise stated.

Raw sewage will be collected in an equalization tank to smooth out surges in flow and will then be sent to an activated sludge unit to reduce biological oxygen demand (BOD). Activated sludge treatment is followed by chlorination for disinfection.

After treatment, the effluent will be tested, and if in compliance with Federal and state standards, will be transferred to the holding pond for discharge into Orca Bay. Material not meeting these standards will be recycled back through the activated sludge unit or the chlorination unit, according to the treatment level required. The equalization tank and activated sludge unit are included in the block labeled "Sanitary Effluent Treating" on the waste water system diagram.

Compressor house drainage systems will be provided to collect oily drips and drains from the normal operation and maintenance of the compressors. The drainage system effluent will be routed through a coalescing medium for oil removal before being blended with the raw sewage upstream of the sewage treating facilities.

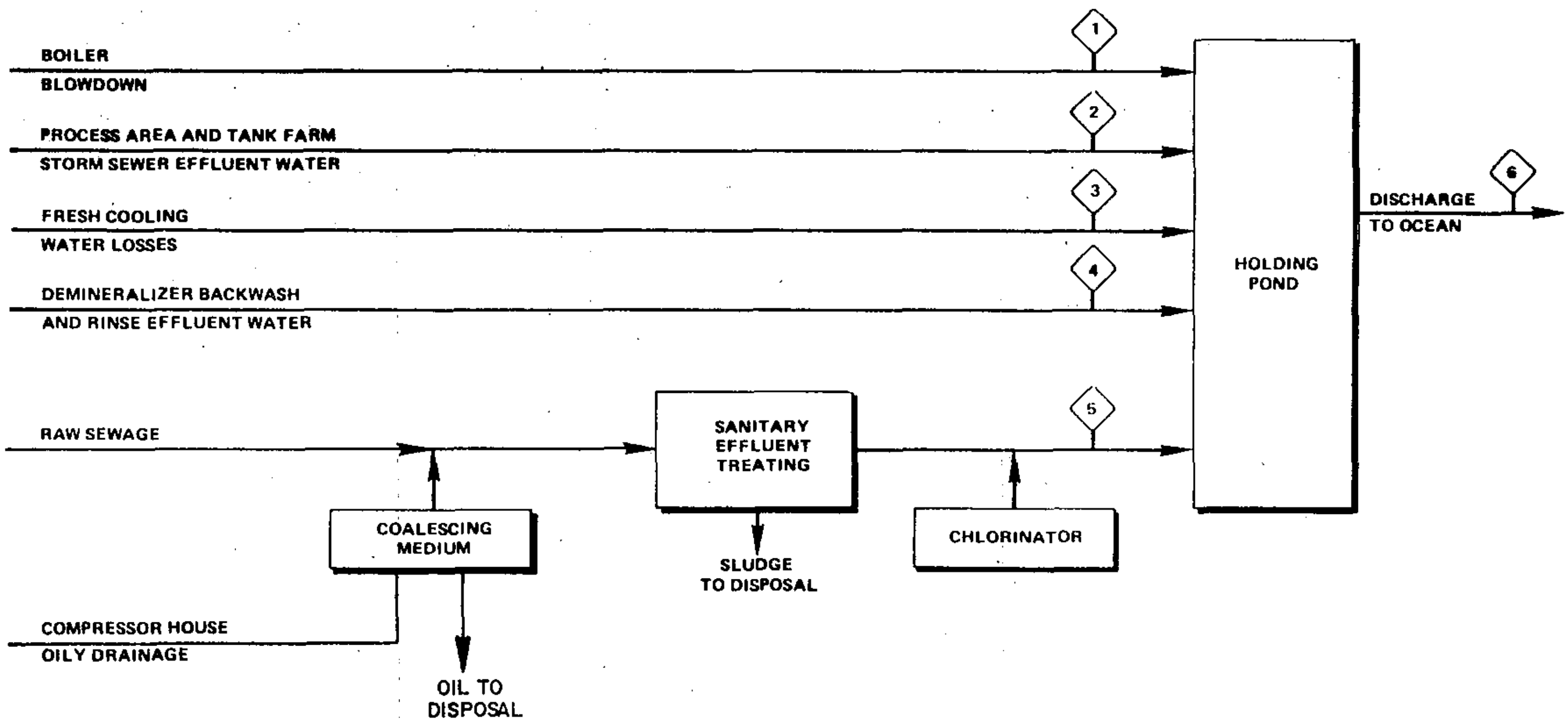
A storage sump immediately downstream of the coalescer will contain the effluent for testing of the oil content. In the event there is a break-through of oil, the material will be recycled through the oil removal system.

Equipment maintenance and proper operation of oily water drainage systems will ensure that water drained to the holding sump is not contaminated with oil. Oil skimmers will be provided at the sump as an additional safeguard, but they are not expected to be used during normal operation.

In addition to the combined effluent stream from the sewage treating facilities, the following non-oily effluent water streams will be discharged directly to the holding pond: (1) boiler blowdown; (2) process area and tank farm storm drain effluent water; (3) fresh cooling water losses; and (4) demineralizer backwash and rinse effluent water.

The first, third and fourth streams will inherently be oil-free. The storm sewer effluent from the process area and tank farm will be essentially oil-free, since no heavy oils are stored or used in these areas.

The waste water streams will be collected in a holding pond measuring 60 feet wide by 320 feet long by 10 feet deep. Waste water will be analyzed, treated if necessary, and discharged to Orca Bay.



TRANS-ALASKA GAS PROJECT

WASTE WATER SYSTEM
LNG PLANT

FIGURE 3.1–F12

Table No. 3.1-T3

LNG PLANT

WASTE WATER SUMMARY

Component	Stream Number 1	2	3	4	5	6
Flow, gpm						
Average	120	1000	0	30	19.5	1169.5
Normal	100	600	0	25	13.0	738.0
Design	512	8000	80	210	65.0	8867.0
Temperature, °F	100	50		70	70	56
pH	7.0	7.0		7.0	7.0	7.0
BOD, ppmw					25	0.4
Phosphate ($PO_4^{\equiv}$), ppmw	15					1.5
Chloride (Cl^-), ppmw	20	10		25	25	12
Oil and Grease, ppmw		<1				<1
Suspended Solids, ppmw	15	100			20	5*
Total Dissolved Solids, ppmw	200	25		100	450	52

* Most of the suspended solids settle out in the holding pond.

The holding pond will dampen surges in effluent water flow and will allow settling of suspended solids. The pond will be designed to provide a retention time of approximately 2-1/2 hours at the maximum design waste water flow rate of 8,867 gpm. Ninety percent of this flow would be from runoff during a rainfall having a rate of one inch in one hour. During normal weather, the effluent retention time in the holding pond will be much longer than 2-1/2 hours.

The holding pond will be provided with an automatic pH recorder-controller to maintain the pond effluent water pH between 6.8 and 7.2. This water will be further analyzed for BOD, dissolved oxygen, oil and grease, suspended solids, color and odor before being discharged to Orca Bay.

Storm water runoff from areas outside the tank farm and process areas will be discharged directly to Orca Bay through concrete-lined channels.

Emissions

All equipment that might emit pollutants to the atmosphere will be designed to meet applicable emission standards. Fuel gas from the LNG Plant and the pipeline will be used as the sole energy source to drive the gas turbines for the propane compressors and electric power generators.

The exhaust gases from the propane compressor turbine drivers will be discharged to the waste heat boilers to provide part of the boiler heat requirements. The additional heat necessary for boiler steam requirements will be provided by supplementary gas-firing. Fuel gas will also be used for all fired process heaters. The electric power generator turbine exhaust gases and the waste heat boiler and process heater flue gases will be discharged to the atmosphere from elevated stacks.

Emissions from the plant may result from four sources:

1) Particulates, nitrogen oxides and sulfur dioxide in the flue gases from the gas-fired equipment;

2) Hydrocarbon vapors (mostly methane) from the LNG tankage area emergency vent stack;

3) Waste gases (mostly carbon dioxide) from vent stacks in the DGA units; and

4) Oxygen-enriched waste gas from the nitrogen production facilities.

Particulates, Nitrogen Oxides and Sulfur Dioxide

Particulate emissions for the LNG Plant will be well below the emission level allowed by applicable regulations. Continuously operating equipment will be fired by fuel gas, for which particulate emissions are essentially zero. Diesel fuel will be used for certain minor functions, such as operating the standby generator, the backup fire pump and the personnel boats. These will provide only minor contributions of particulates to the atmosphere.

The only significant nitrogen oxides (NO_x) emissions will be in the flue gases from the process heaters, boilers and power generator gas turbines. The best available emission reduction techniques will be used in the design of this equipment to minimize NO_x emissions to the atmosphere and assure compliance with applicable regulations.

The fuel gas burned will have a sulfur content of less than one grain per 100 scf. Sulfur dioxide (SO_2) emissions in the flue gases from the process heaters, waste heat boilers and electric power generator gas turbines will be minimal and well below the emission level allowed by applicable regulations.

A summary of the estimated stack emissions from the gas-fired equipment is shown in Table No. 3.1-T4 on the next page.

Hydrocarbons

The process units will be designed to avoid emitting hydrocarbon vapors to the atmosphere. During upsets, however, hydrocarbon vapors may be discharged through the process plant pressure relief header to an elevated smokeless flare stack for burning. A separate flare stack will be provided for burning of pipeline relief gases.

A potential source of hydrocarbon emissions will be from the tank farm. However, the storage facilities for propane, ethane, LNG and for aqueous DGA solution will be designed according to EPA guidelines to minimize these emissions.

LNG will be stored in above ground double wall storage tanks. Vapors (mostly methane) from LNG storage vessels will be normally compressed and returned to the suction of the methane compressors in the liquefaction trains. During an upset, such as the shutdown of the methane compressors, the vapors may be vented to the atmosphere through the emergency vent stack at the LNG tank farm.

The low vapor pressure DGA solution (less than 0.5 psia at storage conditions) will be stored in a cone roof nitrogen blanketed tank. The DGA system will have its own closed sewer system for collecting drips and drains. These provisions will minimize DGA emissions to the atmosphere.

Mechanical seals will be used on pumps and compressors, and valve packing and gasketing materials are to be carefully selected. LNG pumps will be of the submerged, seal-less suction pot mounted type.

Table No. 3.1-T4

LNG PLANT

STACK EMISSION SUMMARY FOR AVERAGE OPERATIONS OF EIGHT TRAINS[1]

Service	Total Units Operating	Excess Air % wt.	Stack Height, ft.	Total Heat Input MMBtu/hr (HHV)	Total Flue Gas Rate, MM lb/hr	NO_x (as NO_2)		
						lb/hr (each unit)	lb/hr (Total)	lb/MMBtu
Gas Turbines for Propane Compressors	8	287	(2)	(2)	(2)	(2)	(2)	(2)
Supplemental Fired Waste Heat Boilers	8	120	150	10,850[3]	13.76	271	2168	0.20[4]
Gas Turbines For Electric Power Generators	6	287	100	1304.1	3.738	150	900	0.69
Regeneration Gas Heaters	8	20	100	111.3	0.106	2.8	22.4	0.20[4]

(1) Stream-day basis (345-day on-stream factor for each train). Operations when loading an LNG tanker make up 40% of the operating time. The fuel gas has a total sulfur content less than 1 grain/100 scf.

(2) Propane compressor turbine exhaust gases are discharged to the supplemental fired waste heat boilers.

(3) The total heat input of 10,850 MMBtu/hr includes a heat input of 4710 MMBtu/hr to the propane compressor gas turbines and a heat input of 6140 MMBtu/hr from supplemental gas firing in the boilers.

(4) Based on waste heat boiler and process heater manufacturers meeting the EPA "New Source Performance Guidelines" of 0.20 lb. NO_x/MMBtu for gaseous fuel burning equipment.

Waste Gases

The primary source of carbon dioxide emissions, other than from the exhaust stacks of gas fired equipment, will be from the DGA units. Waste gases from the regenerator overhead accumulators in these units will be vented directly to the atmosphere; they will have a composition of 92.12 volume percent carbon dioxide, 6.8 percent water vapor, and 1.08 percent hydrocarbons. The venting rate of these waste gases will be 182,800 lbs/hr for all DGA units.

Oxygen-Enriched Waste Gas

The packaged nitrogen generation units will separate the N_2 gas required for the LNG Plant and the Marine Terminal from the atmosphere, resulting in super oxygenated air as a byproduct. This oxygen-enriched waste gas will be returned to the atmosphere from the nitrogen production units. The normal venting rate will be approximately 1030 lbs/hr total.

Odors

Odor-producing materials, such as asphalt, aromatics and phenols will not be present in any of the streams processed in this plant. The hydrocarbon emissions previously discussed will all be essentially odor-free.

Solid Wastes

Sludge from the DGA and the activiated sludge treating units will be disposed of by land fill or biological land enrichment. Since the amounts involved will be small, the land area requirements will be minor and will be controlled within the plant boundary.

Refuse from plant operating personnel will be disposed of by local contractors using approved land fill sites.

Solids from packaging materials required for plant operation will be recycled when possible, or disposed of with the refuse from plant operating personnel.

Spent desiccant will be disposed of by land fill on the plant site. Replacement will occur at three to five year intervals and will not be a significant problem.

Estimated quantities of solid wastes follow:

Material	Quantity, lbs/year
Sludge from DGA and activated sludge treating units	40,000
Solid refuse from plant operating personnel and materials packaging	338,000
Spent desiccant	336,000

Noise Control

Noise levels are maintained within required limits by means of mechanical controls which reduce the sound intensity at the source of the noise and in the work areas. Where this is not feasible, administrative controls will be developed to limit the worker's time of exposure to noise. Where neither mechanical nor administrative controls can bring noise levels down to acceptable limits, personnel protective devices such as earmuffs or earplugs will be used.

When final equipment selections are made, additional steps to control noise will be incorporated as required. These steps will include: using mufflers on vents, jets, compressor inlets and outlets and control valves; reducing air-fan noise by using multiple blades and low speeds; using totally enclosed motors or insulated wraps on motor cases; inlet mufflers and/or insulated ducts for boiler burners; and sound-insulated operating stations for full-time working exposure in areas with noise levels above 90 dBA. During and after start-up of the complex, noise levels will be monitored to determine if and where additional noise control will be required.

The following table outlines the noise level design limits:

Facility	Continuous Noise Limit (in dBA)
Control Rooms and Offices	55
Boundary of Complex	65
Within Five Feet of Regular Working Area	85 - 90
Occasional Working Area	95
Infrequently Occupied Areas Within Plant	105

Instrumentation and Controls

The natural gas LNG Plant will be designed for remote control from one centrally located control building. The control panel will have a removable graphic process display. Local control panels will be provided for the compressors, utilities and at the marine terminal loading berth stations. Essential control information on the local panels will be duplicated on the central main panel.

The control instrumentation will be standard miniature electronic type with signal ranges of either 4-20 ma or 10-50 ma direct current. A complete, battery powered DC back-up system will be provided in case the main power supply systems fail.

Continuous analytical instruments will be used, where necessary, to provide for process monitoring. Compressors and turbine drivers will be equipped with electronic vibration, axial position and bearing temperature monitoring equipment.

Control valves will be pneumatically operated. Bypass and block valves will be supplied for control valves in severe and critical service.

The instrument air will be supplied at a header pressure of 100 psig from two centrifugal compressors. The air will be dried in a desiccant dryer to a dew point of -45°F at 100 psig.

All emergency shut-off valves and operating valves in cryogenic service sizes eight inches and larger, will be equipped with power operators. Maintenance valves will be manually operated. All emergency shut-off valves and vital normal operating valves can be remotely operated from the central control room and also from local pushbutton stations. Valve position indicating lights in the control room will indicate the closed, open or in-transit condition.

Power operators for all emergency shutoff valves will be connected to the emergency power supply system as back-up. In addition, a handwheel will be supplied for all motor operated valves to stroke the valves manually in case of total power outage.

Electrically interlocking relays, shutdown systems, solenoid valves and other systems vital to safe and uninterrupted plant operation will be powered from a reliable 48 V DC battery system to ensure continuous operation during an AC power dip or power outage.

Field mounted instruments and control components will be protected against the weather. Electric heat tracing will be used when required.

Telecommunications Facilities

The plant will be equipped with a 500 station, Private Automatic Branch Exchange (P.A.B.X.) which will service the voice communications originating within the plant; one marine radio-telephone system with two of its channels connected to the P.A.B.X.; and voice communication from the pipeline system. Outside connections will be provided via a microwave radio system from the plant to the public network central office at Cordova. The P.A.B.X. system will be installed early to be used during construction.

Provisions have been made for using leased channel Alternate Voice Data (AVD) service between the LNG Plant and the receiving terminal in California. The actual leased AVD channels from Cordova to Point Reyes, California will be provided by RCA Alaska at the prevailing FCC regulated rates and conditions.

There will be a hand-held radio communication system for in-plant use, with a transceiver located in the control room of the control building.

A Remote Job Entry (RJE) computer terminal and ancillary equipment will be provided. During the construction phase, the RJE terminal will be used for construction management systems, and will be connected to a data communications network via a leased AVD channel to Los Angeles.

Process Supply Requirements

The Liquefaction Plant will be self-sufficient with respect to utilities. Operating supplies which must be brought in are shown in Table No. 3.1-T5, following. Additionally, the plant will require spare parts and lubricants for the mechanical equipment.

DGA will be delivered in barrels to the plant and stored in a heated building adjacent to the DGA sump. For startup, propane will be shipped to the plant and stored in conventional LPG storage vessels. The catalyst and chemicals will be delivered to the plant by ship and barge and stored in the warehouse.

Natural gas from the feed stream will be used for fuel to generate electric power and steam. The plant will also produce liquid and vapor nitrogen requirements.

Arctic diesel fuel will be required for the operation of the personnel boats, plant rolling stock and intermittently for various in-plant standby equipment. The diesel fuel will be delivered by barge and stored near the small boat harbor.

Maintenance Requirements

Spares are provided for equipment essential to LNG production. The design will stress reliability of operation for continuity of LNG deliveries. This will include an allowance of twenty days per year per train for downtime. Scheduled shutdown is planned for fifteen days. The remaining five days are allowed for unscheduled downtime. Since each of the trains will be able to operate independently, scheduled maintenance will be performed on only one train at a time.

No unusual maintenance problems are anticipated for the Liquefaction Unit. The cryogenic equipment will operate under clean and corrosion-free conditions at the low operating temperatures involved. Provisions will be included for thawing of cryogenic equipment.

The equipment items expected to require the most maintenance are the steam turbines, steam supply system and the hot section of the

Table No. 3.1-T5

LNG PLANT

CATALYSTS, CHEMICALS AND UTILITY REQUIREMENTS

Initial Charge

Molecular Sieve Desiccant	1,008,000 lbs
Inert Support (1/4" - 3/4")	8,800 cf
Alumina	2,880 cf
DGA (100%)	66,900 gal
Propane	600,000 gal (1)
Corrosion Inhibitor (*e.g.*, Drewgard 100)	360 gal
Fire Fighting Chemicals:	
Mechanical Foam Concentrate	10,000 gal
Sodium or Potassium Bicarbonate	25,000 lbs
Fresh Water (2)	7,770,000 gal
Nitrogen (3)	3,210,000 lbs

Consumption (4)

Molecular Sieve Desiccant	336,000 lbs/yr (5)
DGA (100%)	261,400 gal/yr
Corrosion Inhibitor	1,250 gal/yr
Anti-Foaming Agent	4,200 lbs/yr
Trisodium Polyphosphate	29,800 lbs/yr
Hydrazine (35 wt %)	1,970 lbs/yr
Sodium Hydroxide (25 wt %)	89,840 lbs/yr
Sulfuric Acid (93.2 wt %)	270,550 lbs/yr
Chlorine	4,746,470 lbs/yr
Arctic Diesel	460,000 gal/yr
Fire Fighting Chemicals:	
Mechanical Foam Concentrate	As Needed
Sodium or Potassium Bicarbonate	As Needed

(1) Estimate eight 75,000 gallon shipments.

(2) Fresh water required to fill up the two fresh water storage tanks. This will be made by the desalination plant.

(3) Nitrogen required for three volume displacements of the four LNG storage tanks and the process equipment prior to the initial startup.

(4) Based on a 345-day on-stream factor for each train.

(5) Based on three year life.

gas turbines. The equipment manufacturers' recommended inspection intervals will be followed to avoid unscheduled interruption of LNG Plant operation. Scheduled maintenance on these items will be performed during the annual shutdown period.

Maintenance procedures will be introduced to minimize corrosion. The parts of the plant which would be most susceptible to corrosion will be the DGA gas treating facilities and the seawater cooling system. This corrosion will be minimized by the use of proper materials and linings. Corrosion inhibitors will be added to the DGA system.

The LNG storage tanks will be relatively free from maintenance because the contents will be essentially non-corrosive. Maintenance on associated equipment, such as testing of relief valves and foundation heater adjustments, will be accomplished without taking the tanks out of service.

Accessibility to equipment will be an important consideration in the design of an easily-maintained plant. All equipment will be designed, constructed and installed in such a way that it will be readily accessible for maintenance or can be easily removed to the maintenance shop.

To ensure against extended downtime for maintenance, long delivery spare parts for machinery will be warehoused at the facility.

One complete spare gas turbine rotor (compressor and turbine rotor) will be available for use in any of the eight identical LNG trains. Spare blades will also be maintained on site to allow a gas turbine rotor to be rebuilt after it has been replaced by the spare. Other spare gas turbine parts will be available, including the first-stage nozzle and burner can assemblies and bearing assemblies.

A complete rotor will be stored in the plant warehouse for each group of steam turbines serving the main process compressors. Maintenance of steam turbines will be further supported by spare parts consisting of bearing assemblies, nozzle block assemblies, nozzle control valves and turbine blades.

A complete spare rotor for each type of main process compressor will be stocked, as well as associated compressor parts, such as bearings, shaft seals, rotor impellers and seal oil and lube oil system parts with pump and exchanger spares. A spare gas turbine electric generator will be installed, and common maintenance spares for the gas turbine will also be carried.

Maintenance will be a consideration in the design and procurement of all equipment. Interchangability of parts between equipment, specification of common sizes of exchanger tubes; interchangability of instrumentation components, etc., will all be considerations which will reduce the quantity of spare parts stocked and the corresponding investment in inventories.

A well-trained plant maintenance force and well-equipped shops will be provided for conducting maintenance on plant equipment. All major maintenance can be performed at the plant site.

SECTION 3.2

CONSTRUCTION

Table of Contents

Index to Figures

SECTION 3.2

CONSTRUCTION

Schedule

The construction schedule for the LNG Plant will require seven years to complete. The plant will operate at full capacity at the end of the seven-year construction period. This schedule contemplates that should all requisite authorizations and permits be granted by the end of the first project year, first LNG could be produced 57 months later. This will correspond with the date the Alaskan Gas Pipeline is first capable of delivering gas.

A bar chart, representing the schedule for the construction of the LNG Plant, is shown on Figure 3.2-F1. The schedule is divided into three major catagories: engineering, procurement and construction. Engineering will begin at project initiation; procurement activities are scheduled to begin the second year; and construction, which begins with the clearing of the site, is scheduled to begin in the middle of the second year.

The scheduled delivery of equipment and materials and the time required for fabrication are based on the market conditions for the last quarter of 1973. Two months will be allowed for shipping time to the job site.

It has been assumed that a 60-hour work week will be used, and that sufficient skilled labor will be available to support the construction program as planned.

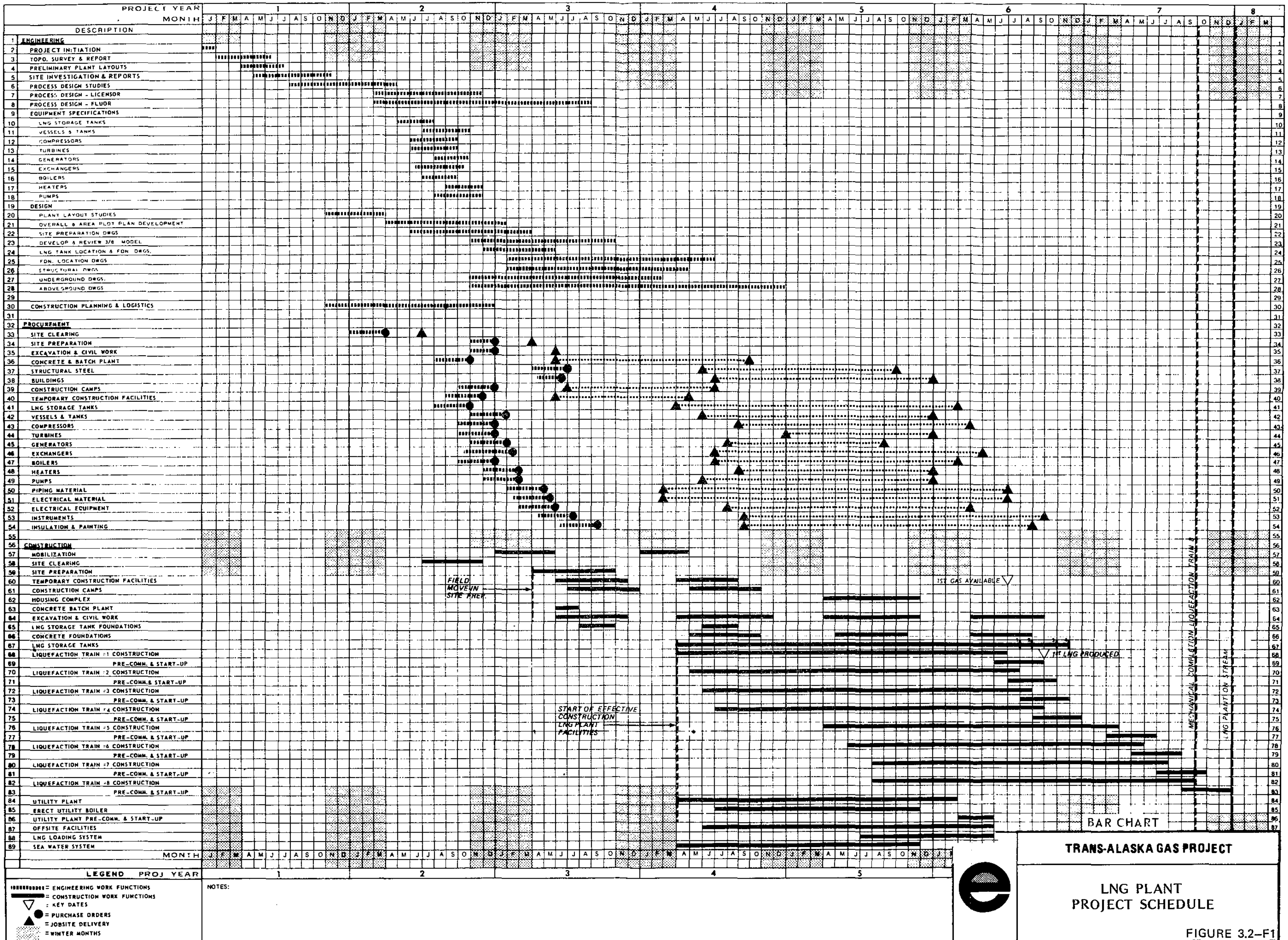
Field move-in will depend on the timely construction of the ferry and barge docks that will be required to move materials, equipment and personnel to the job site and on scheduled site clearing. Field move-in for site preparation is scheduled for April 1 of the third year.

The erection of LNG Storage Tank No. 1 will start April 1 of the third year. The last tank will be completed by June 1 of the sixth year. The erection of each storage tank will take seventeen months, four which will be allocated for testing and insulation.

Critical Path

The construction activities that will form the critical path for the LNG Plant have been identified and are shown in sequence below:

- LNG Plant Project Mobilization
- Site Data Gathering and Reports
- Process Design Studies
- LNG Storage Tank Design and Specifications
- Procurement of LNG Storage Tank Material
- Fabrication and Delivery of LNG Storage Tank Material



TRANS-ALASKA GAS PROJECT

LNG PLANT
PROJECT SCHEDULE

FIGURE 3.2–F1

- LNG Storage Tank Erections
- Insulation of LNG Storage Tanks
- LNG Tank No. 1 Ready to Receive LNG
- Liquefaction Train No. 1 Start-Up
- First LNG Available (October of sixth year)
- Liquefaction Train No. 8 Start-Up

Procurement and fabrication of the following items will require special attention to assure that their long delivery lead times do not upset the proposed schedule.

Item	Delivery
LNG Tank Material	17 months
Compressors	20 months
Turbines	24 months
Generators	18 months
Exchangers	16-1/2 months
Utility Boilers	18 months

The starting dates, construction durations and mechanical completion dates for each liquefaction train are listed below:

Liquefaction Train No.	Start Date	Mechanical Completion Date	Duration of Construction
1	April 1, Year 4	July 1, Year 6	27 months
2	May 1, Year 4	August 1, Year 6	27 months
3	June 1, Year 4	Sept. 1, Year 6	27 months
4	July 1, Year 4	Oct. 1, Year 6	27 months
5	April 1, Year 5	April 1, Year 7	24 months
6	June 1, Year 5	June 1, Year 7	24 months
7	August 1, Year 5	August 1, Year 7	24 months
8	August 1, Year 5	Oct. 1, Year 7	26 months

Section 3.3
Capital and Operating Costs

SECTION 3.3

CAPITAL AND OPERATING COSTS

Table of Contents

Index to Figures and Tables

SECTION 3.3

CAPITAL AND OPERATING COSTS

General

The estimated capital cost for the LNG Plant includes all facilities which will constitute the complete operating plant. The estimated operating and maintenance expense includes all costs necessary to operate and maintain the complete facility for a year.

Capital Cost Estimate

A summary of the estimated capital cost for the Alaskan LNG Plant is shown in Table No. 3.3-T1 on the following page. As shown on the table, the capital cost of the system is estimated at $1,602,417,000. Table No. 3.3-T2 on page 3.3-3 presents a breakdown of the estimated capital expenditures by quarter-year for the seven-year period. The estimates are based on 1973 prices for materials, equipment, services and supplies.

Description of Capital Cost Elements

Following is a definition of cost elements included in the Capital Cost Estimate with an identification of related costs included in each element:

Direct Job Costs

Equipment - The cost of all plant equipment and machinery used in the completed plant, including tanks, vessels, rotating machinery (such as generators, compressors and pumps), boilers, exchangers, cooling towers, etc.

Materials - The cost of all physical materials used in constructing the completed plant, such as cement, aggregate, sand, building materials, pipe and fittings, valves, fabricated steel and rebar, wire and conduit, instruments, insulation, paint, etc.

Direct Labor and Subcontract Labor - The cost of all craft, direct labor and subcontract labor for the construction of the plant. Benefits, burdens, insurance, etc. are not included as direct labor. These labor requirements are shown on Figure 3.3-F1 on page 3.3-4. Requirements will peak at 5,600 men during the fifth summer after project initiation.

Spare Parts and Maintenance Equipment - The cost of all equipment and materials purchased and stored for future use during start-up

Table No. 3.3-T1

LNG PLANT

CAPITAL COST
(Dollars Stated in Thousands)

Direct Job Cost:	
Equipment	$ 248,539
Materials	152,642
Direct Labor	203,243
Subcontract Labor	32,175
Spare Parts and Maintenance Equipment	6,462
Sales Taxes	2,837
Freight	45,213
Consumables	1,651
Royalties	15,851
Start-up Costs	9,100
Subcontracts:	
Site Preparation	$ 37,162
Housing	4,714
Buildings	2,574
Total Direct Job Costs	$ 762,163
Indirect Job Costs:	
Fee	$ 43,647
Temporary Construction Facilities	88,798
Construction Services and Expense	24,804
Field Staff and Expense	80,014
Benefits, Burdens, Insurance	89,824
Construction Tools and Equipment	30,745
Total Indirect Job Cost	$ 357,832
Office Costs:	
Engineering	$ 16,958
Purchasing	1,236
Expediting	536
Business Services	852
Office Expense	3,645
Payroll Burdens	5,874
Indirect Office Expense	21,637
Owner's Overhead	15,235
Total Office Cost	$ 65,973
Contingency	$ 59,298
Contract Project Management Fee	33,397
Intangible Plant	5,604
Allowance for Funds Used During Construction	442,792
Partial Year Costs Less Revenues	(145,092)
Total Depreciable Capital	$ 1,581,967
Land Cost	5,400
Working Capital	15,050
ESTIMATED TOTAL CAPITAL	$ 1,602,417

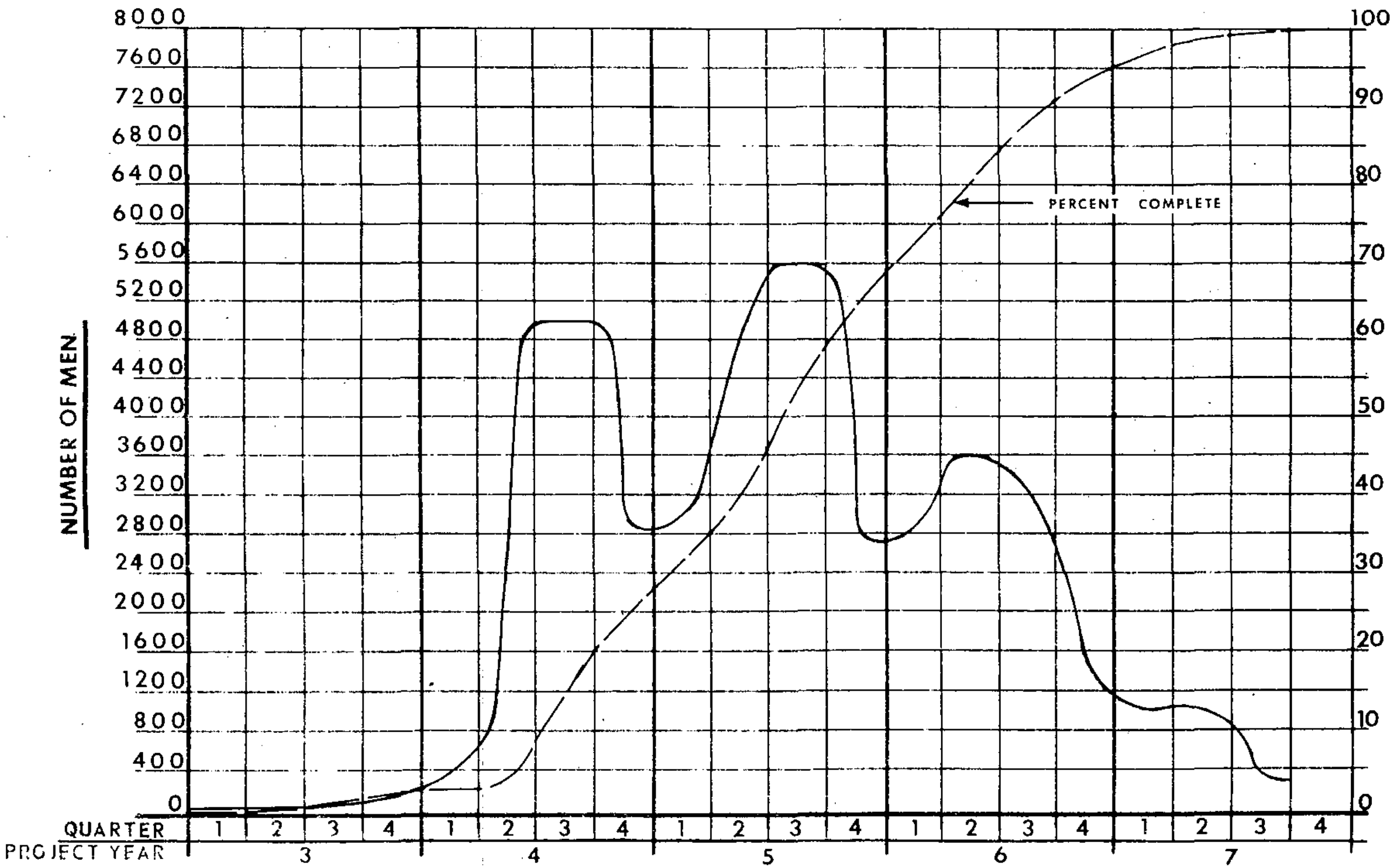
Table No. 3.3-T2

LNG PLANT

SCHEDULE OF ESTIMATED CAPITAL EXPENDITURES
(Dollars Stated in Thousands)

Year/Quarter	Labor	Materials	Other	Allowance for Funds Used During Construction	Start-up Costs or (Credits)	Working Capital	Total by Quarter
Year 1, Q 1	$	$	$ 10,027[1]	$ 492[2]	$	$	$ 10,519
Q 2			2,192	311			2,503
Q 3			2,544	374			2,918
Q 4			2,661	440			3,101
Year 2, Q 1			2,987	514			3,501
Q 2			2,545	581			3,126
Q 3			7,175	771			7,946
Q 4			7,695	954			8,649
Year 3, Q 1	651	6,911	27,063	2,004			36,629
Q 2	816	35,537	18,919	3,234			58,506
Q 3	1,410	40,252	39,647	5,728			87,037
Q 4	2,669	29,074	23,854	7,069			62,666
Year 4, Q 1	2,689	19,260	23,562	8,226			53,737
Q 2	17,989	17,124	40,169	11,120			86,402
Q 3	34,411	25,959	34,701	13,457			108,528
Q 4	25,370	28,224	32,034	15,646			101,274
Year 5, Q 1	22,041	27,302	32,519	17,805			99,667
Q 2	33,644	28,065	34,437	20,317			116,463
Q 3	39,908	35,289	36,406	24,471			136,074
Q 4	29,684	36,606	30,872	27,197			124,359
Year 6, Q 1	21,438	29,340	27,435	29,583			107,796
Q 2	25,250	19,000	25,289	31,840			101,379
Q 3	22,664	13,655	23,727	34,207	12,106	3,010	109,369
Q 4	11,205	9,906	19,710	35,742	(10,456)	1,505	67,612
Year 7, Q 1	6,522	4,971	15,794	36,670	(27,260)	1,505	38,202
Q 2	6,245	1,836	14,042	37,534	(26,344)	1,505	34,818
Q 3	2,725	761	19,761	38,153	(40,143)	1,505	22,762
Q 4	562	222	14,713	38,352	(52,995)	6,020	6,874
TOTALS	$ 307,893	$ 409,294	$572,480	$442,792	($ 145,092)	$ 15,050	$1,602,417

(1) Includes expenditures made prior to Project Year 1.
(2) Accumulated allowance for expenditures made prior to Project Year 1.



TRANS-ALASKA GAS PROJECT

LNG PLANT CONSTRUCTION MANPOWER CURVE

FIGURE 3.3–F1

operation of the plant and to replace items which fail or wear out. This item also includes the cost of all maintenance and safety equipment required for plant operations. This includes rolling stock, such as trucks, pickups, mobile cranes, fire trucks, ambulance, snow plows, forklifts, automobiles, tractors and trailers. The cost also provides for maintenance equipment in the garage and in the instrument, electric, machine, pipe and paint craft shops.

Sales Taxes - The cost of gross receipt taxes assessed for the plant.

Freight - This includes the cost to move materials and equipment from the marshalling yard to the job site. This also includes barge rentals or aircraft charters. It includes heavy lift charges, terminal charges, air or ocean freight charges, brokerage or agent fees, demurrage, storage and wharfage handling charges. The cost of marine insurance is also included here. (The cost of any rail or truck charges to deliver the material or equipment from the place of purchase to the marshalling yard is included with the material or equipment costs.)

Consumables - The cost of initial plant charges of catalysts, chemicals, lubricants and other consumables and similar items required for start-up and initial operation is included. <u>Construction</u> consumable supplies are <u>not</u> included here.

Royalties - The cost of paid-up royalties to licensors of the liquefaction process used is included in this entry.

Start-up Costs - The cost of start-up service by contractors, vendors and licensors, and for the training of applicant's operating personnel is included in this item.

<u>Subcontracts</u>

Site Preparation - The cost of preparing the site for the erection of equipment and installation of materials, including clearing, excavating, filling, leveling, grading and construction of dikes, basins, tank berms, drainage system and roadway bases is included in this item.

Housing - The cost of constructing permanent houses and facilities to be used as residences for key operating personnel is included in this item.

Buildings - The cost to construct all buildings for the LNG Plant except operator residences.

<u>Indirect Job Costs</u>

Fee - The Engineering and Construction Fee paid to contractors or firms furnishing services.

Temporary Construction Facilities - The cost of temporary buildings, roads, utilities, shops, furnishings, yards, fencing, labor camp facilities, catering, purchased utilities and services used during construction is included here.

Construction Services and Expense - The cost includes incidental subcontracts during construction, such as X-ray, janitorial, medical aid and laboratory services, and any professional services for tax consultants, labor relations attorneys or employee organizations. The cost of moving construction equipment and small tools to and from the job site and the cost of fuels and lubricants for construction equipment and its maintenance. The cost of expendable supplies, such as welding rod, fluxes and gases are also included.

Field Staff and Expense - The cost of salaries, benefits, travel expense and allowances paid to the field staff.

Benefits, Burdens and Insurance - The cost of direct labor payroll benefits, burdens and insurance and taxes is included in this section.

Construction Tools and Equipment - The cost includes small tools purchased for the construction of the plant and the cost of purchasing construction equipment. Rental costs are also included in this category.

Office Costs

Engineering - This is the cost of producing specifications, drawings and other engineering requirements necessary for the purchase of equipment and materials.

Purchasing - The costs to obtain quotations, to select supplies and to prepare purchase documents are included here. Traffic office costs are also a part of purchasing costs.

Expediting - The cost incurred to expedite the delivery of materials purchase is included in this entry.

Business Services - Costs for accounting, payroll taxes, consultation, legal matters, insurance and other business matters are included in this item.

Office Expense - The cost of reproduction, duplicating, printing, postage, telephone, telegraph, preparation of models, computer programming and use, travel expenses and other direct office expenses are included here.

Payroll Burdens - This is the cost of all payroll burdens and benefits paid to office employees. These are estimated as a percentage of salaries and wages.

Indirect Office Expense - This covers the cost of facilities, furniture and fixtures, utilities, corporate management and department services not directly associated with the project.

Owner's Overhead - This is the overhead cost of applicant.

Contingency

Contingency costs are 5% of the total of Direct Job Costs plus Indirect Job Costs plus Office Costs.

Contract Project Management Fee

The Contract Project Management Fee is the management cost for project planning and execution.

Intangible Plant

Intangible Plant costs are the plant-related costs of initiating and mounting the project, and include consultant fees, legal fees, expenses for engineering, financial, operational and economic studies, and other developmental costs.

Allowance for Funds Used During Construction

The Allowance for Funds Used During Construction covers an allowance for financial charges incurred as interest during construction on the interim financing, plus an allowance for a return on the equity funds invested during the development, design and construction.

Partial Year Costs Less Revenues

Partial Year Costs Less Revenues are the net revenues or expenses during plant start-up.

Land Cost

Land Cost is the estimated expenditure for purchasing the plant site.

Working Capital

Working Capital is a provision for a continuous source of funds needed to meet short-term obligations for cash expenses and prepayments.

Operating Cost Estimate

A summary of the annual estimated operating costs for the LNG Plant is shown in Table 3.3-T3 on the following page. The total annual operating cost is estimated to be $85,568,790. The estimate is based upon last quarter 1973 prices unless otherwise indicated.

Description of Operating Cost Elements

Following is a definition of the cost elements included in the Operating Cost Estimate with an identification of the costs associated in each element:

Total Manpower (Staff)

This cost includes the wages and salaries, but does not include the payroll benefits, burdens and insurance for the Operating Staff of 272 employees. See Table 3.3-T4 on page 3.3-10 for a listing of LNG Plant employees by job classification. Figure 3.3-F2 on page 3.3-11 illustrates the organization and location of the operating manpower included in this cost item.

LNG Plant operations are based on having a full operating work force available 24 hours per day, seven days per week. The operating shift schedule will consist of three 8-hour shifts per day. Supervisory and technical personnel will work a regular 40-hour week. Of the total of 272 personnel included in the LNG Plant operating manpower, 172 are scheduled to work on a shift basis and 100 are scheduled to work on a weekly basis.

Maintenance (Contract)

This is the cost of maintenance charges paid to contractors to keep the LNG Plant operational and includes the cost of replacement equipment and materials.

Communications

The cost of operating the radio-telephone and microwave relay is included in this charge. A computer terminal line cost is also included.

Catering Services (Contract)

The charges for providing working personnel at the guesthouse, cafeteria and recreation hall is included in this cost. See Table 3.3-5 on page 3.3-12 for a list of the estimated contract manpower requirements included in this category. A total of 37 people will be employed to operate the guest house and cafeteria on a 24-hour per day schedule and the recreation hall on a 12-hour per day schedule.

Table No. 3.3-T3

LNG PLANT

ANNUAL OPERATING COSTS

Total Manpower (Staff)	$ 5,440,000
Maintenance (Contract)	38,410,000
Communications	202,800
Catering Services (Contract)	740,000
Catalysts and Chemicals*	
Molecular Sieves	369,600
Diglycolamine	731,900
Corrosion Inhibitor	15,640
Anti-foaming Agent	21,000
Trisocium Polyphosphate	3,830
Hydrazine	620
Sodium Hydroxide	1,930
Sulfuric Acid	4,770
Chlorine	360,700
Total Operation & Maintenance	$ 46,302,790
Utilities	
Arctic Diesel	$ 184,000
Administrative & General Expense	$ 4,214,000
Insurance	$ 5,850,000
Other Taxes	$ 29,018,000
Estimated Total Annual Operating Expenses	$ 85,568,790

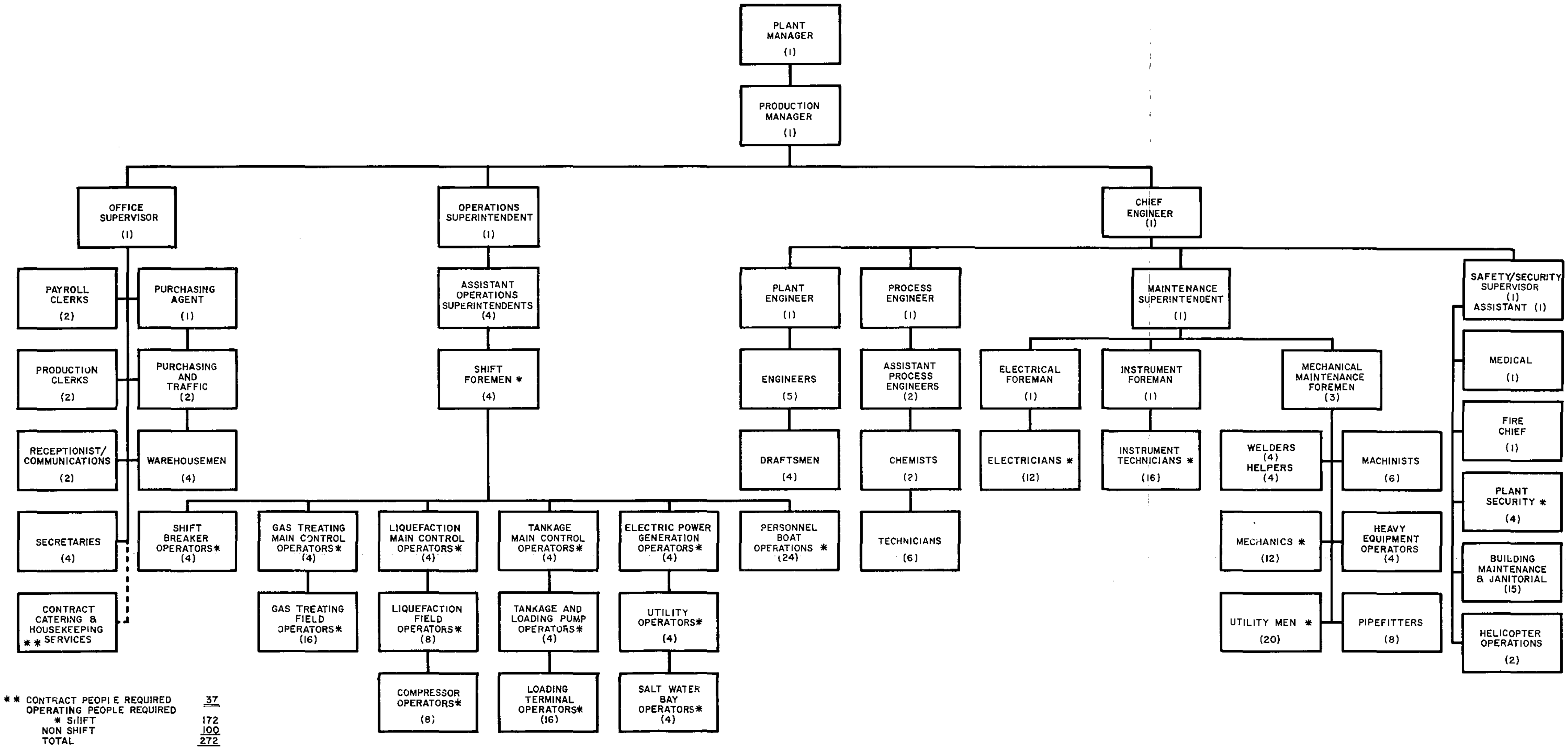
*Initial charge of catalysts and chemicals totaling $1,651,000 is included as consumables in the capital cost estimate.

Table No. 3.3-T4

ALASKAN LNG PLANT

PLANT OPERATING MANPOWER REQUIREMENTS

Position	Number of Employees	Position	Number of Employees
Plant Manager	1	Electricians	12
Production Manager	1	Instrument Foreman	1
Operations Superintendent	1	Instrument Technicians	16
Assistant Operations Superintendents	4	Mechanical Maintenance Foremen	3
Shift Formen	4	Welders	4
Shift Breaker Operators	4	Welders Helpers	4
Gas Treating Main Control Operators	4	Mechanics	12
Gas Treating Field Operators	16	Machinists	6
Liquefaction Main Control Operators	4	Heavy Equipment Operators	4
Liquefaction Field Operators	8	Pipefitters	8
Compressor Operators	8	Utility Men	20
Tankage Main Control Operators	4	Medical	1
Tankage and Loading Pump Operators	4	Fire Fighting	1
Loading Terminal Operators	16	Helicopter Pilot	1
Electric Power Generation Operators	4	Helicopter Mechanic	1
Utility Operators	4	Safety Security Supervisor	1
Personnel Boat Operators	12	Assistant Supervisor Plant Security	1
Personnel Boat Assistants	12	Guards	4
Salt Water Bay Operators	4	Janitors	5
Process Engineer	1	Building Maintenance	10
Assistant Process Engineer	2	Office Supervisor	1
Chemist	2	Payroll Clerks	2
Laboratory Technicians	6	Production Clerks	2
Chief Engineer	1	Receptionist/Communications	2
Plant Engineer	1	Secretaries	4
Engineers	5	Warehousemen	4
Draftsmen	4	Purchasing Agent	1
Maintenance Superintendent	1	Buyer	1
Electrical Foreman	1	Traffic Clerk	1
		TOTAL	272



TRANS-ALASKA GAS PROJECT

LNG PLANT
OPERATING MANPOWER

FIGURE 3.3–F2

Table No. 3.3-T5

ALASKAN LNG PLANT

CONTRACTED MANPOWER REQUIREMENTS

Position	Number of Personnel
Guest House	
Manager	1
Housekeeper	1
Cook	1
Maid	1
Cafeteria (24-hour Service)	
Manager	1
Clerk	1
Cook (Fry)	4
Cook (Pastry)	2
Serving	8
Dishwasher	8
Recreation Hall (Open 12 Hours)	
Manager	1
Assistants	8
TOTAL	37

Catalysts and Chemicals

This cost includes all catalysts and chemicals necessary to operate the LNG Plant for a year, excluding those quantities used in start-up.

LNG Plant operations will entail the consumption of certain catalysts and chemicals. The consumption rate for the molecular sieves is based on a three-year life expectancy. The consumption rate of diglycolamine (DGA) is due to gas treatment unit process losses during the removal of carbon dioxide such as the generation of oxidation products and side-reaction products of the DGA. Corosion inhibitors and anti-foaming agents are added to the cooling water streams on a regularly scheduled basis. Trisodium polyphosphate and hydrazine are used continuously in treatment of boiler feedwater as needed. Sodium hydroxide and sulfuric acid are used, as required, for pH adjustment of plant waste water outfall. The chlorine is consumed on a continuous basis in the treatment of the seawater intake. These consumption rates of chemicals are estimated upon experience with similar units.

Utilities

This cost item includes arctic diesel fuel used in the LNG Plant and associated support equipment. The cost of LNG Plant fuel gas and process losses will be absorbed by the owner of the gas.

Administrative and General Expense

This cost includes the home office cost during operation, and also payroll burdens and benefits for LNG Plant operating staff.

Administrative and General Expense was calculated at 70% of direct operating labor plus 10% of materials and supply expenses plus $865 per operating employee in Alaska.

Insurance

This includes the cost of premiums for casualty and earthquake insurance coverage for the LNG Plant.

Insurance costs were calculated at a rate of 0.78% of estimated insurable value including a $10,000,000 maximum earthquake coverage.

Other Taxes

Other taxes include Ad Valorem taxes and were calculated at 2.25% of estimated total investment not including any allowance for funds used during construction.

LNG Plant, LNG Terminal and LNG Carrier Fleet Interfacing Systems

The following is a description of the interfaces between the LNG Plant, the Alaskan Marine Terminal and the LNG Carrier Fleet. The portion of the cost of each interfacing facility attributed to the LNG Plant is identified.

Liquid Nitrogen

Liquid nitrogen will be stored onshore at Alaska. Storage facilities will be designed and costs are included in the plant estimate. Loading lines will be provided to transfer liquid nitrogen from storage to the LNG carriers. Costs for these lines have been included with the LNG Carrier Fleet estimate.

Communications

All communication facilities at the LNG Plant, and all communications between shore and ship have been included in the LNG Plant cost estimate.

Personnel Boats

Two boats will be supplied at the LNG Plant site. The cost for these boats and the cost for their operation is provided for as a part of the LNG facilities.

Cargo Functions

LNG will be pumped from the plant storage tanks and loaded on board the LNG carriers. The cost of all the piping, pumps and instrumentation required for this transfer has been included in the LNG Plant estimate. Also, the facilities inside the control tower buildings required for the monitoring of the LNG Carrier Fleet loading operations are included.

Diesel Fuel

Diesel fuel for the LNG Plant will be brought to the plant by barge and pumped to a storage tank located on shore at the small boat harbor. The costs for these facilities are included in the cost of the LNG Carrier Fleet.

Buildings for Marine Support

A small loading dock building at each berth will be provided for personnel shelter. The Marine Administration Building including the marine warehouse and shop facilities will be located at the water front adjacent to the construction dock to serve the small boat harbor. The costs for these buildings are included in the cost for the LNG Carrier Fleet.

SECTION 3.4

DESIGN CRITERIA

Table of Contents

Index to Tables

SECTION 3.4

DESIGN CRITERIA

Project Scope

The LNG Plant facilities are to be located at the terminus of the Alaskan Gas Pipeline east of Gravina Point. The plant will treat approximately 3375 MMcf/sd of gas received from the pipeline, and will convert all of the gas, except that consumed as fuel, and process losses, to LNG.

Designs will comply with accepted refinery practice and all applicable National Codes, such as API, ASME, NEMA, AWS, NFPA, IEEE, AISC, ISA, ANSI and TEMA; and other applicable Federal, state and local regulations.

Site Selection

The LNG Plant and Alaskan Marine Terminal is to be located on the southern coast of Alaska east of Gravina Point, and west of Harris Creek. The plant location was selected following evaluation of numerous sites along the southern coast of Alaska. Site data required for this study was derived primarily from public sources. Field investigation was limited to that necessary for the preparation of capital and operating cost estimates.

Process Selection

The Phillips "Optimized Cascade Cycle" process was selected on the basis of economics and the proven operating reliability of the process. Phillips Petroleum Company supplied the process design data for the liquefaction unit. Gas supply and composition are specified by applicant.

Feed Gas

Feed gas to the LNG Plant will be natural gas piped from the Alaskan North Slope fields. Design LNG output for the plant is the natural gas equivalent of 3030.44 MMcf/sd, net loaded on LNG carriers.

The design composition and range of feed gas compositions and conditions considered are shown in Table No. 3.4-T1 on the following page.

Table No. 3.4-T1

LNG PLANT

FEED GAS

Composition	Design Composition (Mol%)	Composition Range (Mol%)
Nitrogen	0.75	0.50 - 2.00
CO_2	1.02	0.50 - 2.00
Methane	85.91	83.74 - 87.00
Ethane	7.77	7.58 - 7.80
Propane	3.93	3.79 - 3.93
iC_4	0.26	0.19 - 0.36
nC_4	0.30	0.18 - 0.36
iC_5	0.03	0.02 - 0.05
nC_5	0.02	0.02 - 0.04
C_5+	0.01	Nil - 0.01
Total Sulfur	Less than 1 grain/100 SCF	
H_2S	Less than 1/4 grain/100 SCF	
Temperature	-2.6°F	
Pressure	650 psig minimum/750 psig maximum	

Design Parameters

Plant facilities will have the capability for recovering all vapors resulting from tanker cool-down, loading and storage boil-off. For design purposes, ambient conditions were considered to be:

Minimum dry bulb temperature	-25°F
Mean dry bulb temperature	40°F
Design dry bulb temperature	60°F
Maximum dry bulb temperature	82°F
Mean wet bulb temperature	38°F
Design wet bulb temperature	56°F
Maximum wet bulb temperature	68°F
Elevation above sea level	150 ft
Seawater temperature	52°F & 63°F

Maximum economical use will be made of air cooling. Other cooling will be by once-through sea water.

The plant will be self-sufficient for energy when supplied with feed gas. The only process inputs will be gas and minor quantities of catalysts and chemicals. Refrigerants will be produced from the feed gas stream. Fresh water, nitrogen and electricity will be generated within the plant.

Eight parallel independent process trains will be employed. A process train will treat the gas in a DGA unit and dehydrate the gas in a molecular sieve unit before the gas enters the liquefaction unit for conversion to LNG. Each train will operate 345 days per year, with an overall plant operating cycle of one year between shutdowns for train maintenance.

The liquefaction unit will not contain excess capacity; however, the gas treatment sections will include a 7% capacity overdesign.

Four 550,000-barrel LNG storage tanks will be provided. This is equal to about 2.1 tanker loads. Tanker loading facilities will be designed for an average loading rate of 58,000 gpm simultaneously to each of two carriers. LNG will be delivered at 40 psig pressure at the ship's rail.

Equipment

All major equipment proposed for the plant, with one exception, are proven designs with longer than one year's successful commercial operation. The General Electric Frame 7, 2-shaft, gas turbine is the exception. This model gas turbine is currently in production and will have several years of commercial operation before being placed in service at the LNG Plant.

Seismic and Tsunami Aspects

Two reference levels of ground acceleration will be considered in the structural design. The first and most severe (Level A) will be the maximum ground acceleration to which the facility can be exposed without loss of fluids from storage tanks or processing equipment, although certain structures could sustain structural damage. The second, less severe, level of ground acceleration (Level B) will be the maximum ground acceleration to which the facility can be exposed without sustaining any structural damage.

Based upon preliminary information, an effective bedrock design acceleration of 0.60g was used for Level A ground motion. Where the facility is founded on bedrock, amplification of the ground motion will be minimized and actual bedrock surface accelerations will be 0.60g or less. The design acceleration value for Level B ground motion was 0.30g.

Small amounts of displacement will be accomodated by designing the containment structures for plastic deformation. Careful location of structures and avoidance of highly fractured zones will greatly reduce risks associated with ground rupture. The risk of soil failures due to soil liquefaction will be minimized or eliminated by careful facility location and adequate site preparation.

Regulations and Codes Used for Design

The environmental regulations and codes to be followed in the design of this complex include:

Air Pollution Regulations

Federal secondary ambient air standards and the State of Alaska ambient air standards for sulfur dioxide, particulates, carbon monoxide, photochemical oxidants (as O_3), nitrogen oxides and hydrocarbons.

Federal and state requirements for NO_x, SO_2 and particulate emissions.

Federal New Source Performance Guidelines for hydrocarbon emissions from storage tanks and effluent oil water separators.

Waste Water Regulations

State of Alaska water quality criteria for disposal of waste water into surface waters, to the surface of the land, or into the ground.

Federal effluent water guidelines for thermal, sanitary and other effluent water streams.

Solid Disposal Regulations

State of Alaska solid waste criteria for incineration of solid effluents and for disposal of solid effluents on the land. (The State of Alaska has the primary role for the management of solid waste disposal. The role of the Federal Government is to provide technical and financial assistance in developing programs and guidelines in this area.)

Noise Regulation

Maximum noise limits for plant personnel exposure defined by the Federal Occupational Safety and Healty Act (OSHA) of 1970. (The State of Alaska OSHA of 1973 is essentially the same as the Federal OSHA.)

Section 4
Alaskan Marine Terminal

Section 4.1
Description of Facilities

SECTION 4.1

DESCRIPTION OF FACILITIES

Table of Contents

SECTION 4.1

DESCRIPTION OF FACILITIES

Index to Figures

SECTION 4.1

DESCRIPTION OF FACILITIES

General Description

The proposed Alaskan Marine Terminal will be located on the north shore of Orca Bay, east of Gravina Point on Prince William Sound. The berthing facilities are to be located approximately 1,200 feet offshore adjacent to the LNG Plant. The terminal will provide structural support for berthing and loading facilities, and will be used to transfer an equivalent of 2,864 million cubic feet per calendar day (MMcf/cd) of liquefied natural gas from the LNG Plant storage tanks to the LNG Carrier Fleet for transport to California. (See Figure 4.1-F1 on page 4.1-2.)

The marine terminal will be designed to simultaneously berth and load two LNG carriers with cargo capacities ranging in size from 125,000 to 165,000 cubic meters. The primary components of each of the two berths will include one loading platform and one service platform, four berthing dolphins and three mooring dolphins and personnel bridges for access to the various dolphins from the loading and service platforms. An additional mooring dolphin and trestle, common to both berths, will also be provided.

Support facilities for the marine terminal will also be included. A small boat harbor with a ferry landing and construction dock will be adjacent to the terminal. A marine administration building with a warehouse and shops will be located ashore.

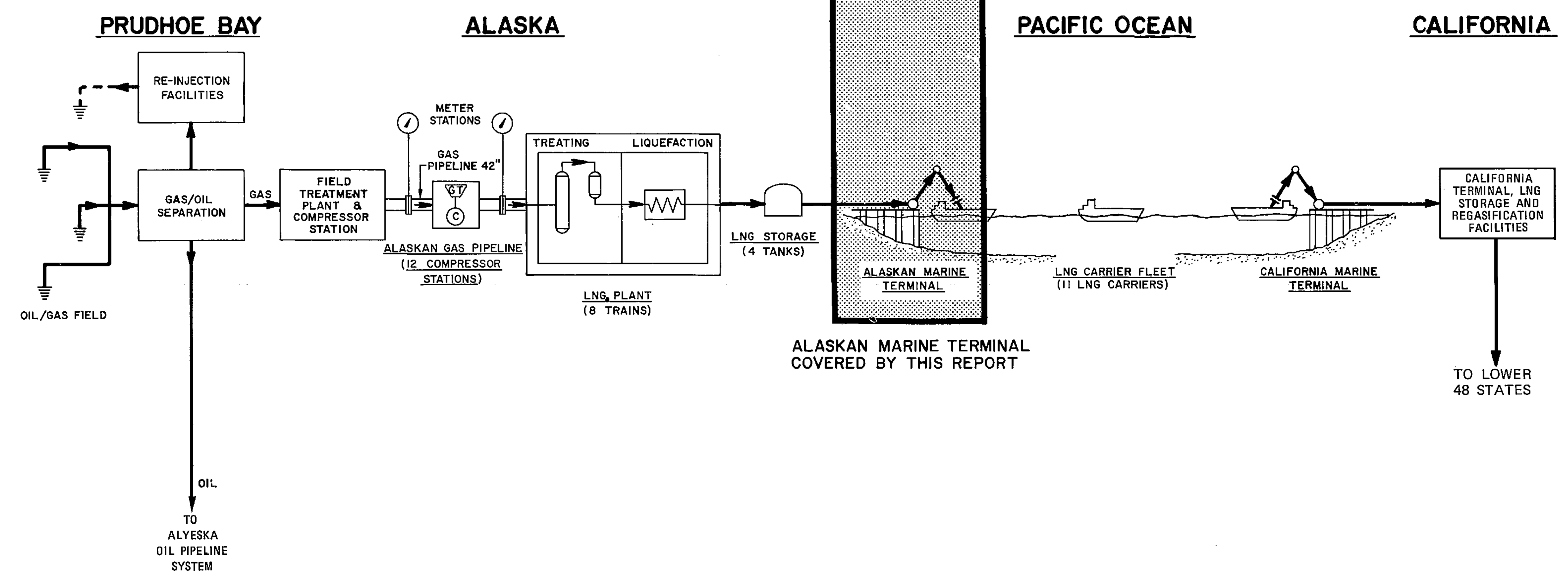
Process piping, instrumentation and controls, to be physically located at the marine terminal, are subsystems of the LNG Plant; however, these subsystems will also be described in this section for clarity.

Site Location

The site of the proposed Alaskan Marine Terminal is shown in Figure 4.1-F2 on page 4.1-3. The berthing and loading facility will be located on the southern shore of Gravina Peninsula approximately four miles east of Gravina Point. This location was selected following examination of numerous sites along the southern coast of Alaska from Cook Inlet to the mouth of the Copper River.

Site Description

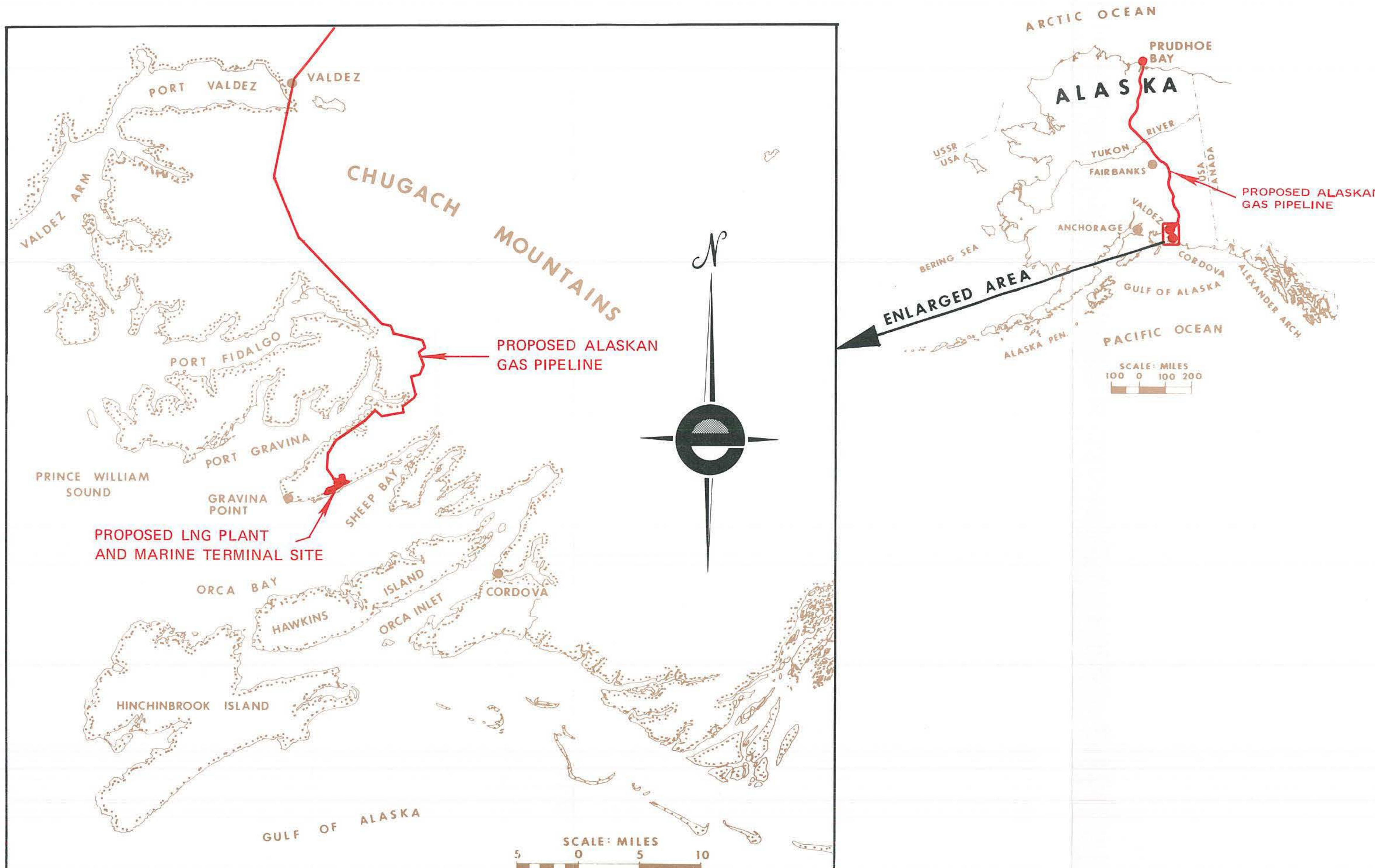
The marine terminal will be constructed along the southern beach of the peninsula as shown in Figure 4.1-F3 on page 4.1-4. The



TRANS-ALASKA GAS PROJECT

ALASKAN MARINE TERMINAL PROJECT ORIENTATION

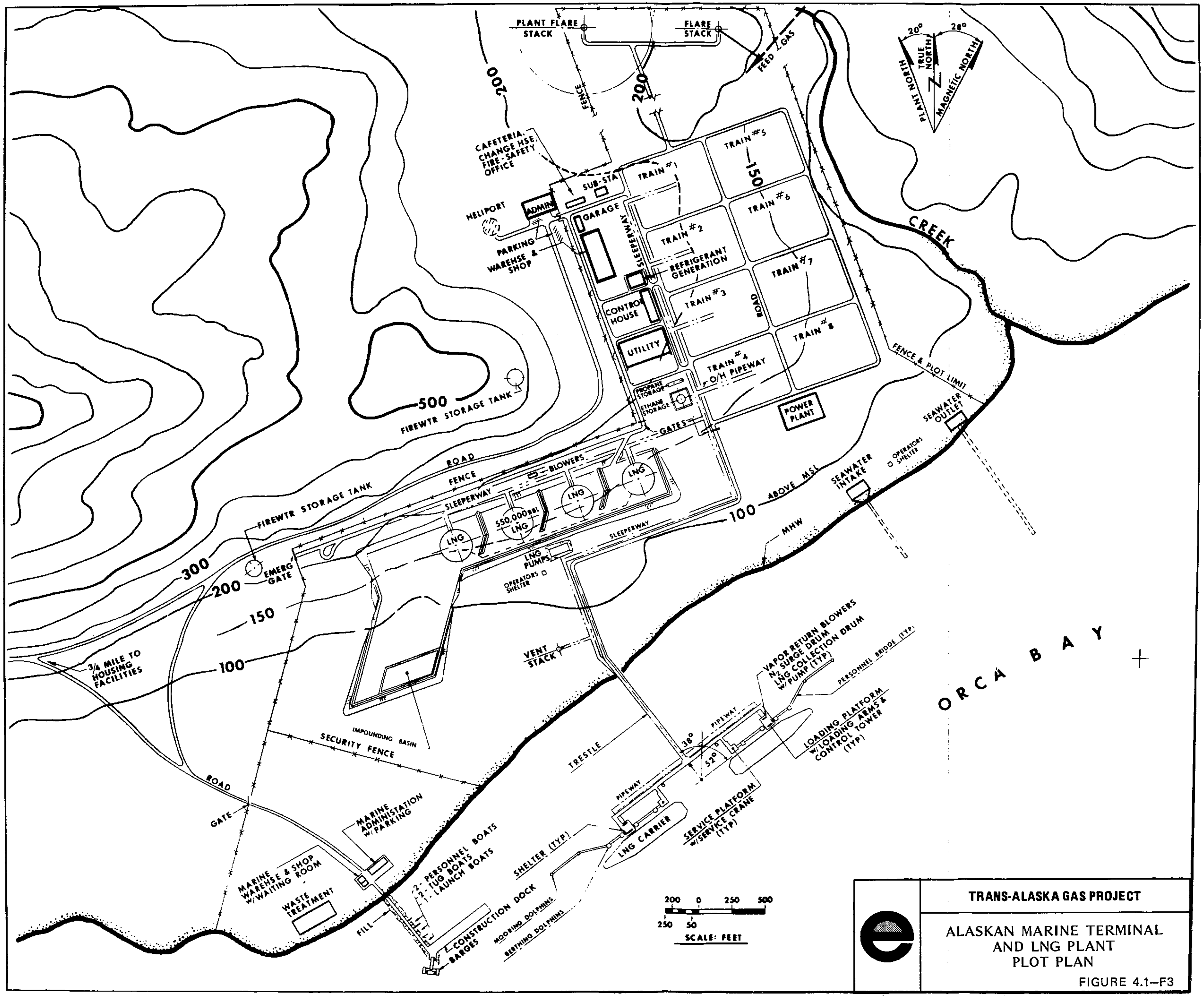
FIGURE 4.1–F1



TRANS-ALASKA GAS PROJECT

ALASKAN MARINE
TERMINAL AND LNG PLANT
SITE LOCATION

FIGURE 4.1–F2



TRANS-ALASKA GAS PROJECT

ALASKAN MARINE TERMINAL AND LNG PLANT PLOT PLAN

FIGURE 4.1–F3

facility will be constructed on an irregular terrace with an upward slope of approximately 15%. The soil cover consists of a narrow band of rocky sand gradually rising into a layer of organic silt and peat varying in depth from five to ten feet. Gravel is present under the organic silt on the terrace, and rests on a bedrock of jointed and fractured slate with occasional surface outcrops.

The mean lower low water depth is 51 feet at the face of the two proposed berths located approximately 1,200 feet from the shore line.

Foundations

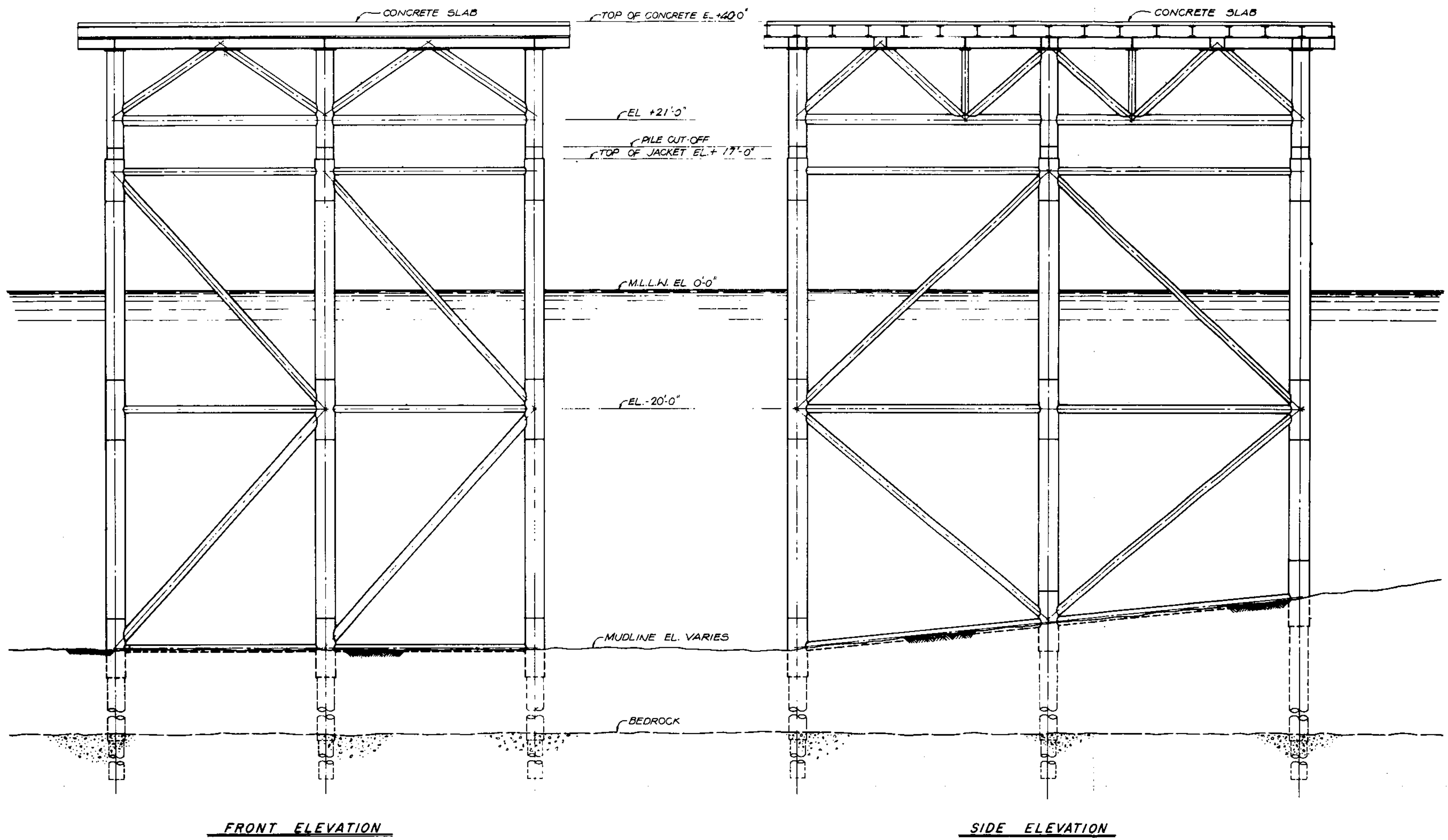
Arctic weather conditions will limit the work season at this site. Prefabricated jacket structures (see Figure 4.1-F4 on page 4.1-6) will be used for all offshore structural foundations at the terminal because these frames can be erected and installed in less time than the usual free-standing dock piles. The jacket's horizontal bracing will insure a stable work platform from which bores for pilings can be driven into the bedrock.

The field installation for all jacket structures at the terminal will be similar. The jacket structures will be fabricated and placed on barges for towing to the site. The installation can be accomplished with conventional equipment and standard construction practices. The jacket structures will be either launched or lifted from the barges and placed in position with a derrick barge crane. Piles will then be placed inside the jacket legs and driven through the overburden material and keyed into the bedrock. The driven pile will be welded to the top of the jacket. After the material inside the driven pile is removed, a hole will be drilled into the bedrock to accommodate the pin pile. The pin pile is necessary to provide lateral, compressive and tensile support. Flat or circular bars will be welded to the outside circumference of the pin pile and to the inside circumference of the driven pile to assure a good bond.

After the pin pile is inserted into the drilled hole, grout will be pumped into the pin pile under pressure and will circulate around the pin pile to provide a bond with the bedrock. The grout will also fill in the annular space between the pin pile and driven pile.

Marine Terminal Structures

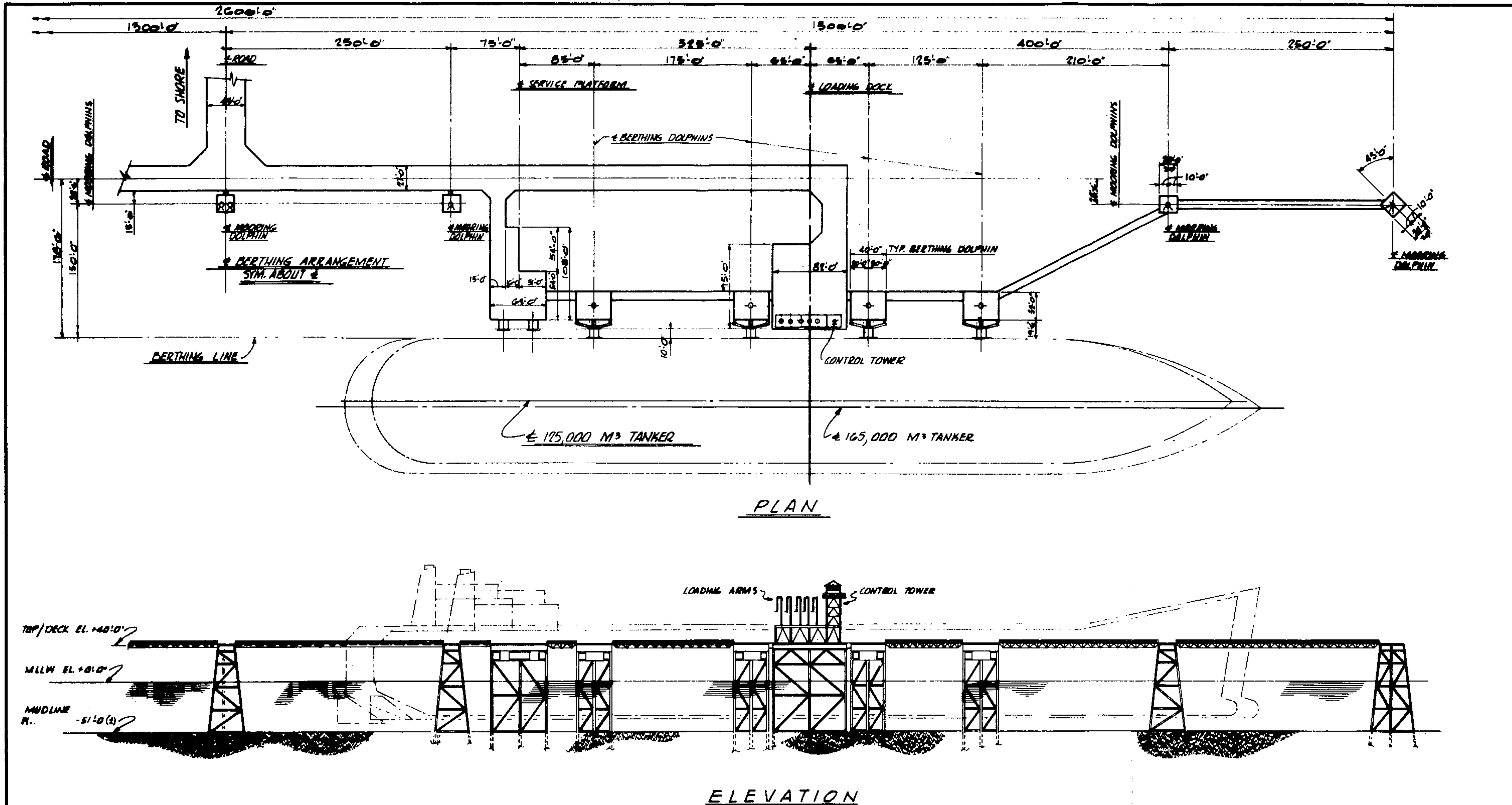
The terminal will consist of two berths for large LNG carriers with personnel bridges connecting loading and service platforms to the mooring and berthing dolphins. (See Figure 4.1-F5 on page 4.1-7.) A common approach trestle for piping and vehicular traffic will be constructed from the berths to the shore.



TRANS-ALASKA GAS PROJECT

ALASKAN MARINE TERMINAL
LOADING PLATFORM JACKET

FIGURE 4.1–F4



NOTE: ROADWAY JACKETS OMITTED FOR CLARITY

TRANS-ALASKA GAS PROJECT

ALASKAN MARINE TERMINAL
PLAN AND ELEVATION
SINGLE BERTH

FIGURE 4.1–F5

Deck Installation

The deck section of each marine terminal structure will be installed after the pile installation. The legs of the deck sections will be stabbed into the piling and welded in place with the final elevation of deck being 40 feet above mean lower low water depth.

Trestle

The trestle will be approximately 43 feet wide and will consist of one roadway and two pipe racks supported by jacket structures. Four-pile jacket structures will alternate with two-pile jackets for support of the trestle and will be spaced on 100-foot centers. (See Figure 4.1-F6 on page 4.1-9.)

Each pipe rack will be fabricated of two laterally braced wide flange girders with a maximum span of 100 feet. The pipe rack will support the LNG piping and vapor return lines. The rack will also support piping and lines for instrument air, fire fighting water, fresh water, diesel fuel, liquid nitrogen and communication and control.

A roadway twelve feet wide on the trestle will have a reinforced concrete slab with curbs. Support will be furnished by three 36-inch girders laterally braced at twenty-foot intervals with twelve-inch beams.

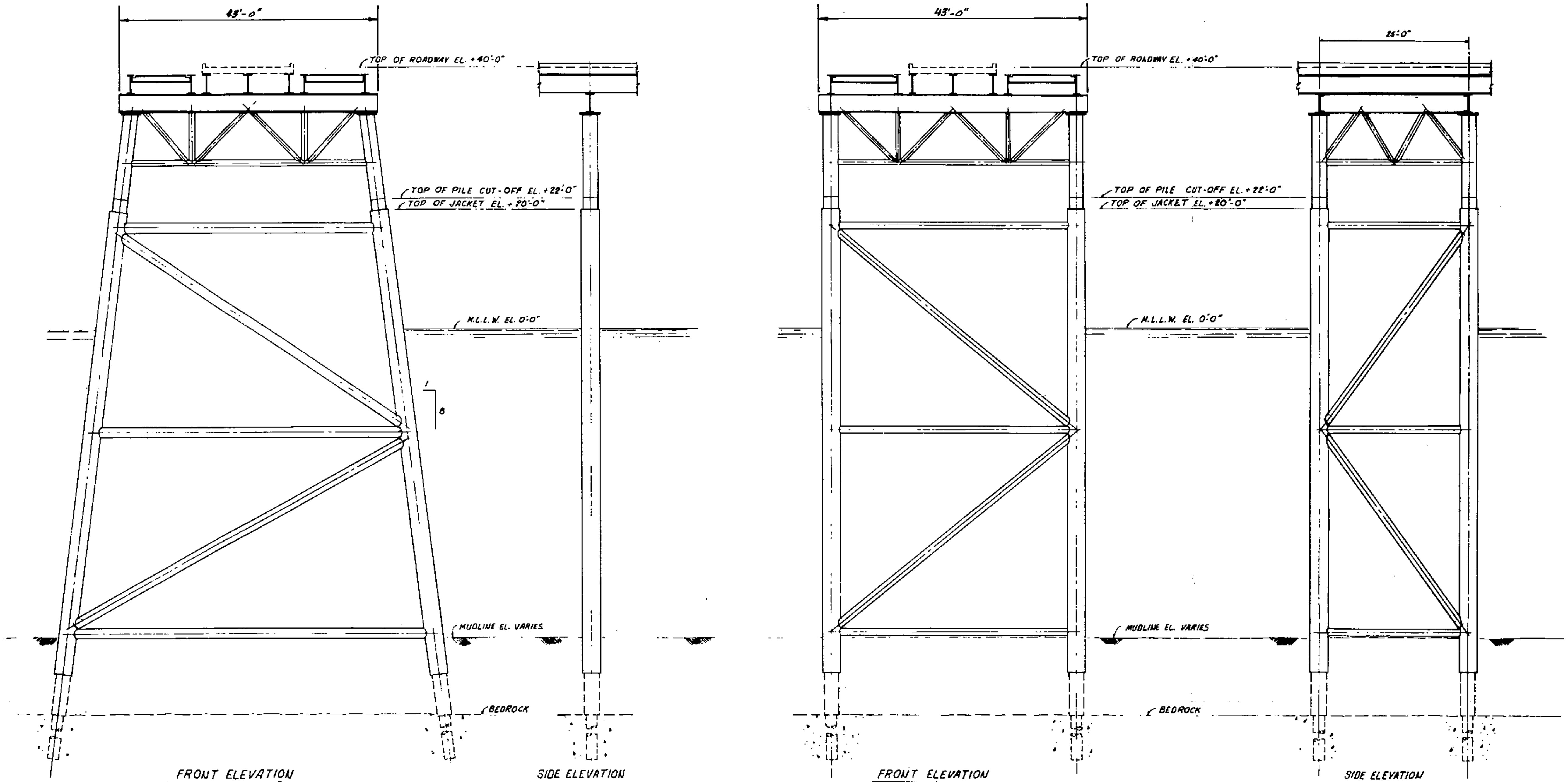
Loading Platform

One loading platform is to be constructed at each berth. The loading platform will provide space and structural support for the equipment necessary for loading LNG.

The loading platform structure will be connected to the trestle and will consist of a deck and a jacket section. The deck will be 82 feet long, paralleling the shoreline, and will be 95 feet wide. It will be elevated 40 feet above the mean lower low water depth. (See Figure 4.1-F7 on page 4.1-10.) The deck will consist of a reinforced concrete slab supported by steel deck beams and girders. The loading platform jacket is shown in Figure 4.1-F4 on page 4.1-6.

Loading Arms

Each loading platform will be equipped with a set of four 16" O.D. cryogenic loading arms and one 16" O.D. cryogenic vapor return arm. These five large arms will all have gaseous nitrogen purge connections. A sixth smaller cryogenic arm, nominally three inches in diameter, will be provided for loading liquid nitrogen onboard the carriers. Each cargo loading arm will consist of a base and a riser, an inboard arm and an outboard arm and related equipment necessary for operation and storage of the unit. The cargo loading arms are to be mounted on the loading platform with a centerline spacing of approximately nine feet between arms. Each arm will reach and remain connected to the carrier's manifold during loading while compensating for carrier motion at the berth.



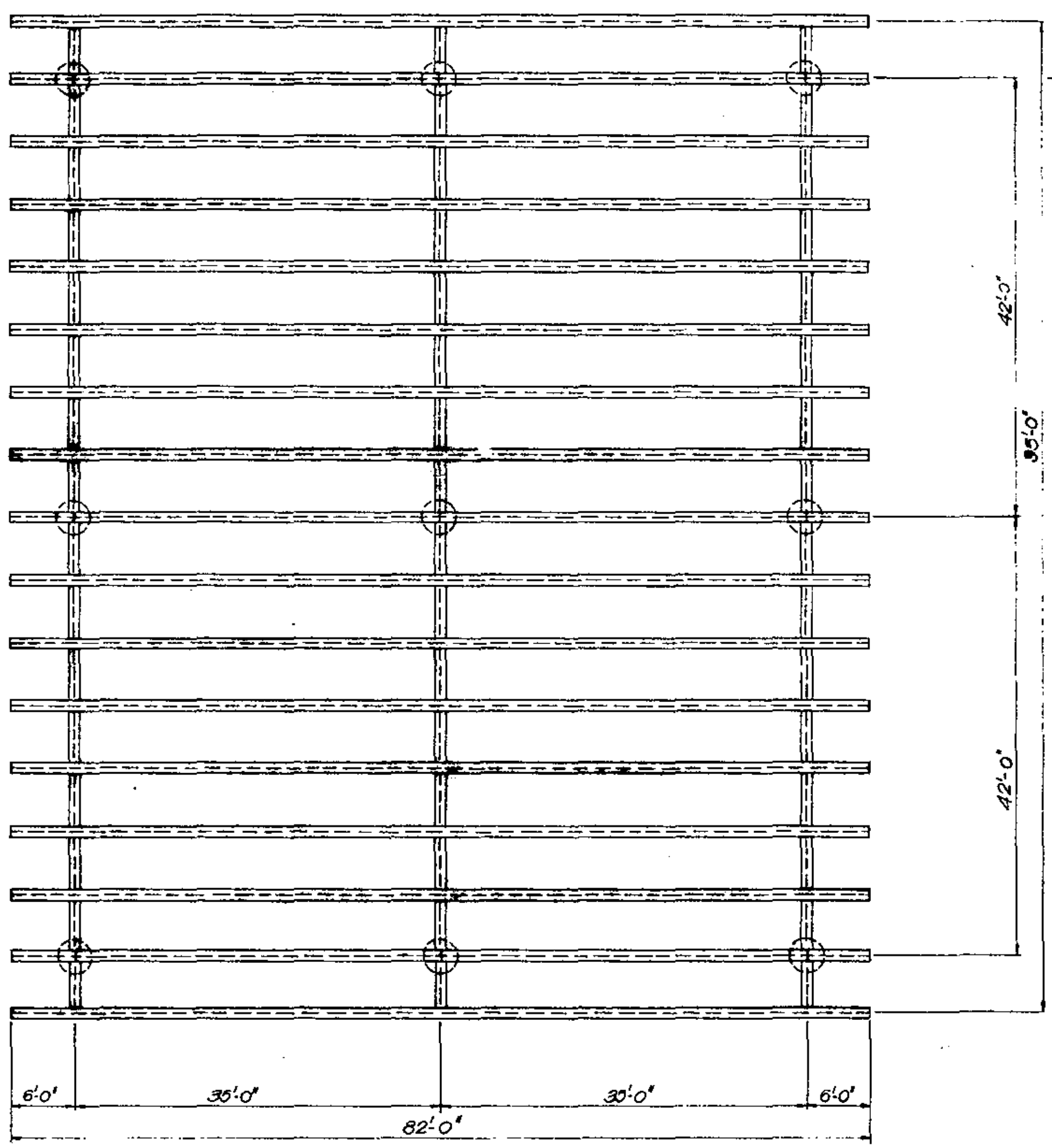
TWO PILE JACKET

FOUR PILE JACKET

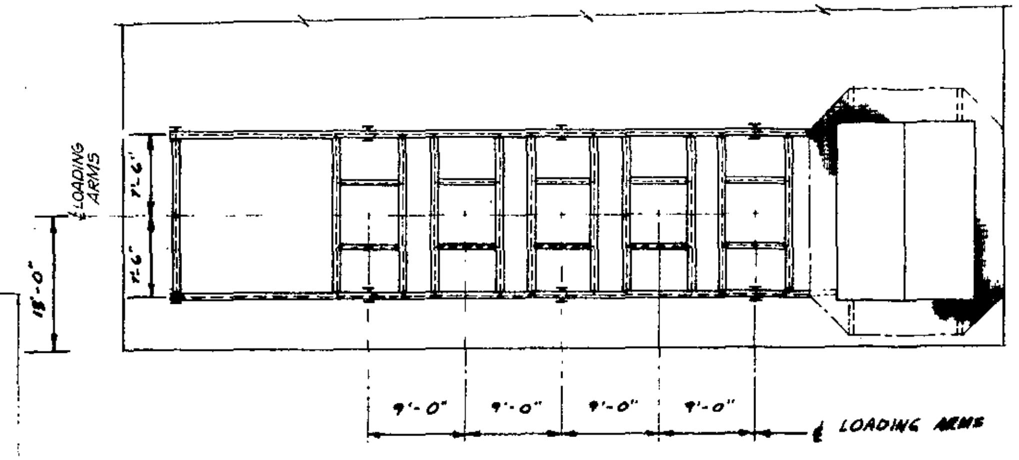
TRANS-ALASKA GAS PROJECT

ALASKAN MARINE TERMINAL
TRESTLE JACKET SUPPORTS

FIGURE 4.1–F6



MAIN DECK FRAMING PLAN



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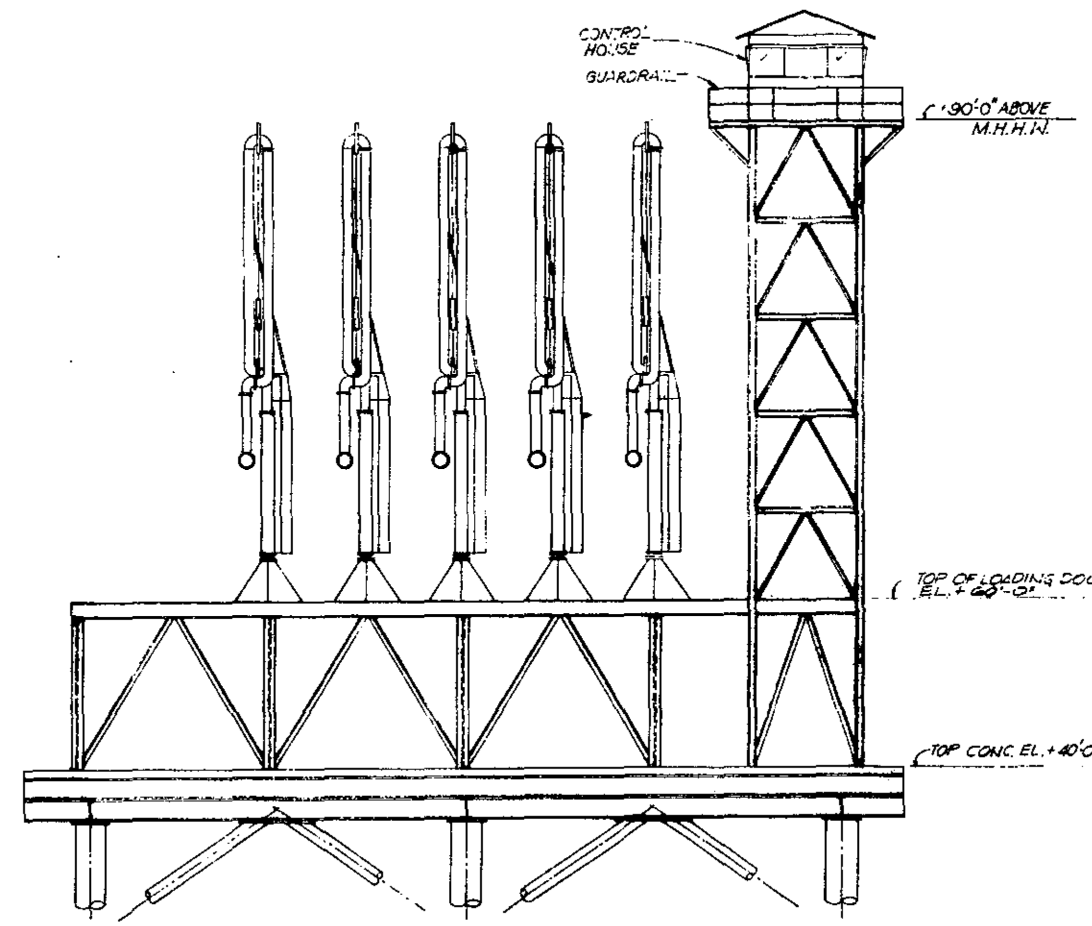
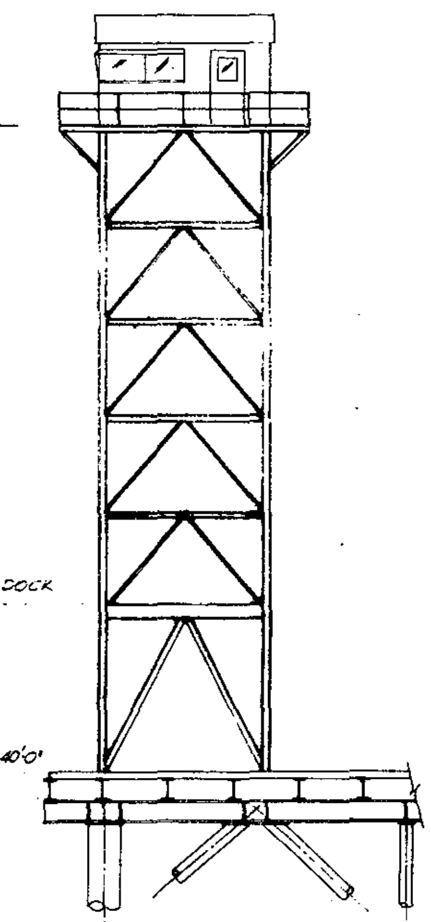


CONTROL TOWER & LOADING ARM STRUCTURE
FRONT ELEVATION



SIDE ELEVATION

NOTE: STAIRWAY AND SIDING ON CONTROL TOWER HAS BEEN OMITTED FOR CLARITY

TRANS-ALASKA GAS PROJECT

ALASKAN MARINE TERMINAL
LOADING PLATFORM DECK

FIGURE 4.1–F7

The cargo loading arms are to be fitted with limit switches to sound an alarm and initiate shutdown of the cargo transfer operation in case the arms exceed their motion envelope.

A vertical pipe riser will connect the platform piping with the cargo loading arm and will support the arm assembly. The inboard, lower section of the arm assembly will be connected to the riser and the outboard section of the arm assembly will be supported by swivel joints. The end of the outboard section terminates in a combination universal swivel unit which will be connected to the carrier manifold.

The loading arms will be hydraulically operated. Movement of the entire arm in the horizontal plane as well as individual movement of either section of the arm in the vertical plane will be accomplished by hydraulic cylinders. Once connected to the carrier's manifold, the arm's hydraulic control is to be bypassed to allow the entire cargo loading arm to move freely with the carrier's movements. The hydraulic unit can be operated locally, or from the control tower.

When not in use, loading arms will be stored in a vertical position and secured with tie-down latches.

LNG Loading and Return Systems

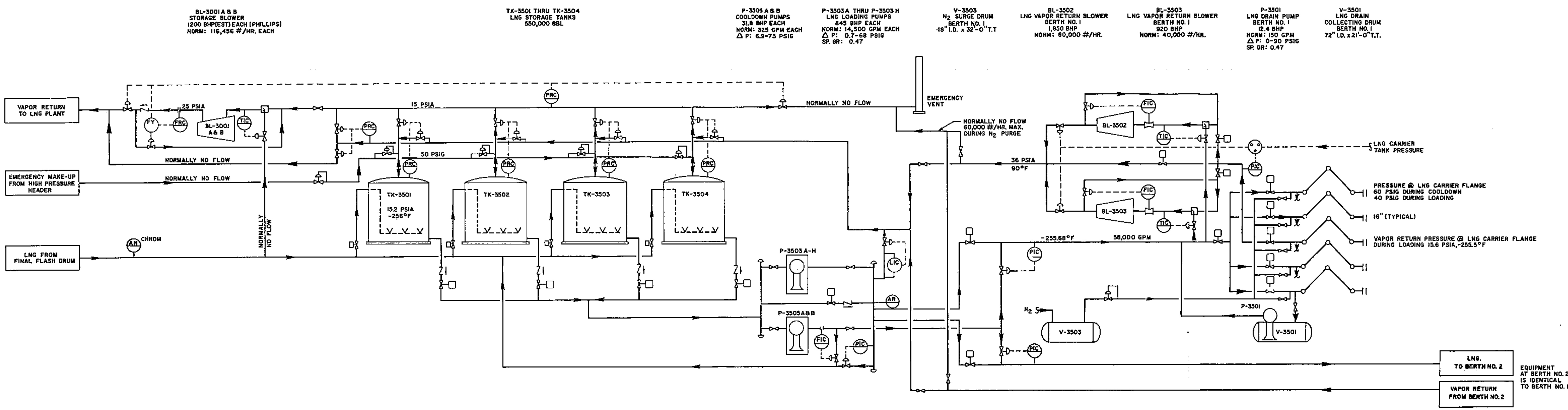
Loading

Loading will be accomplished through the interconnecting cryogenic LNG pipeline from the LNG Plant storage tanks. See Figure 4.1-F8 on the following page. Gravity feed through loading pump bypass valves will be used until the transient boil-off has diminished, and after vapor stabilization, the loading pumps will be sequentially started to increase product delivery. The eight loading pumps located at the LNG storage tanks will be able to achieve an average delivery rate of 58,000 gpm of LNG to each of two carriers simultaneously through the four 16-inch loading arms located on each loading platform. Each arm will be provided with an automatic butterfly shut-off valve as backup protection against LNG spillage.

The loading pumps will be started and stopped locally at the storage tanks in the LNG Plant, but will also be capable of shutdown from each berth control tower, each LNG carrier and the LNG Plant central control room. The loading operator will be able to throttle the loading valve to control the flow of LNG to the carrier without stopping the loading pumps. An automatic control system, sensing the pump discharge header pressure, will also be used to open a bypass valve for lower delivery rates to the carrier.

Return

The 16" O.D. vapor return arm and line will be used to transport displacement vapors and LNG boil-off from the carrier tanks back across the trestle to the LNG Plant storage tanks. The 16" O.D. vapor return arm on the loading platform will also be used to transport inert



TRANS-ALASKA GAS PROJECT

LNG PRODUCT STORAGE AND HANDLING PROCESS FLOW DIAGRAM

FIGURE 4.1-F8

gases from the LNG carrier cargo tanks, after arrival from drydock, through the return line to shore for venting. Two electric motor-driven centrifugal blowers will be located at each berth to move the boil-off and displacement vapors through the return line. The 1,850 horsepower blower will be capable of returning the estimated 80,000 pounds per hour of vapor to the tanks during normal loading operations. A supplemental 920 horsepower blower will be provided to increase the return capacity estimated at 40,000 pounds per hour during a preloading cool down. Since the storage tanks at the LNG Plant will be individually pressure regulated at 15.2 psia to minimize tank pressure fluctuations during loading, excess return vapors will bypass the tanks and be recycled directly to the LNG Plant.

An emergency vent stack for both the carrier tanks and the LNG storage tanks will be constructed near the shore line between the marine terminal and the LNG Plant.

Tower and Control House

A tower supporting a control house will be provided on each loading platform. The monitoring of the loading operations and the operation of the arms will be conducted from the control house. The tower supporting the control house will be fifteen feet by ten feet in cross-section and approximately sixty feet in height. An access stairway to the control house will be provided on the tower structure.

The control house will house analog instrumentation for process control and monitoring with standard ranges of 4-20 or 10-50 milliamps. Essential read-outs will be duplicated at the control house and at the LNG Plant central control room. Dry instrument air at 100 psig with a dew point of -45°F will be supplied in a header from the LNG Plant to activate pneumatic control valves. A shutdown station will be provided in each control house, at the LNG Plant central control room and on-board the LNG carriers to stop the loading operations. Normal operation of all actuated loading and bypass valves will be accomplished from the control house.

A reliable 48 volt DC power source will provide a fail-safe power source for valve actuators critical to loading operations.

Safety and Fire Equipment

Appropriate structures, including the loading platform, will be equipped with safety handrails as specified by the Occupational Safety and Health Act of 1970.

The marine terminal fire fighting systems will be designed for compatibility with the LNG carrier systems to provide for mutual fire fighting capability.

One 2-1/2" O.D. water hydrant for potable water and hydrants and monitor nozzles for fire fighting water will be provided on the loading platform. This water will be supplied from the LNG Plant.

A fire fighting water storage tank located at the LNG Plant will have the capacity to supply fresh water at a rate of 3,000 gpm for six hours to the LNG loading berths and marine fire system water hydrants. The pressure will be maintained in this system by the static head of the elevated storage tank.

A back-up fire fighting water system, located at the LNG Plant seawater pump station, will also be available for supplying salt water to the fire hydrants at the terminal. Three diesel-driven, vertical fire pumps for seawater will each have an output of 2,500 gpm.

Dry chemical or Halon fire fighting equipment will be located in two portable trailers near the berthing areas to supplement the fixed nozzle chemical fire system located on each loading platform.

Other equipment to be located on the platform includes one pneumatic connection to tie the shipboard shutdown system to the marine terminal shutdown system, one 4-line telephone cable, one control cable for pressure control of the vapor return system and one gangway.

Service Platform

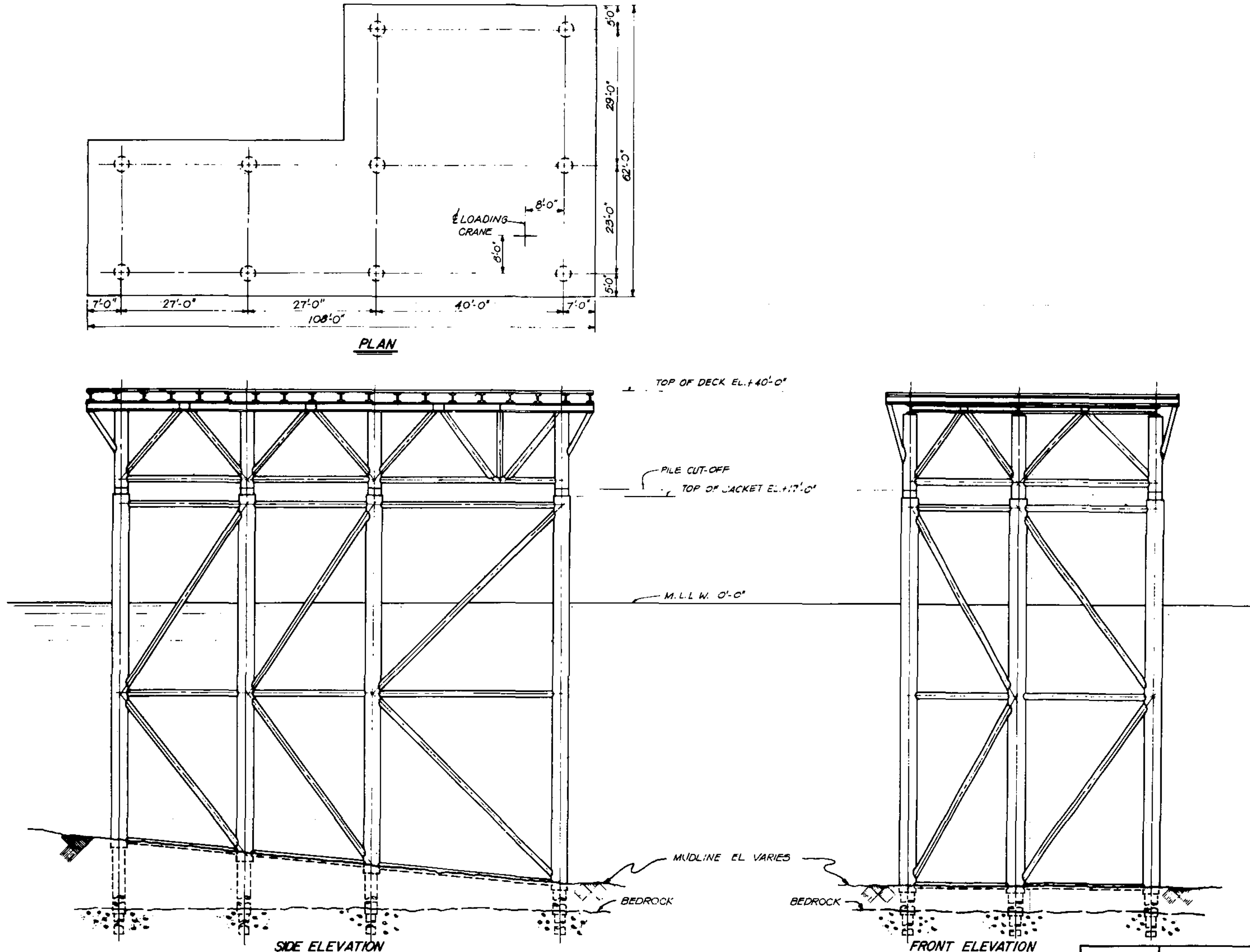
One service platform will be constructed for each berth. The service platform equipment will be used to transfer provisions and other supplies to and from LNG carriers while simultaneousing loading LNG cargo.

The "L" shaped platform will consist of a deck and a jacket structure. The jacket will be a ten-legged structure of all-welded tubular construction. See Figure 4.1-F9 on page 4.1-15.

Each platform is to be equipped with a fixed crane capable of transforming provisions between the service platform and a carrier at berth. The area in the vicinity of each service platform will be free from elevated obstructions which might interfere with operation of the crane.

The service platform will be equipped with a fendering system. Two fenders, constructed according to details outlined later under the heading "Fender Description," will be required to protect the service platform and the LNG carriers.

The fenders are to be attached directly to the platform since there will not be any piping or sensitive equipment that could be affected by the berthing impact. The normal approach of the LNG carrier will be at an angle of less than 10 degrees so that the service platform will not be contacted during berthing operation; however, the fenders will be provided on the structure to ensure protection of the carrier and service platform.



TRANS-ALASKA GAS PROJECT

ALASKAN MARINE TERMINAL
SERVICE PLATFORM

FIGURE 4.1–F9

Berthing Dolphins

Four berthing dolphins will be constructed at each berth. These dolphins, designed to absorb the berthing energy of the LNG carrier, will be essential in protecting both the terminal structures and the LNG carriers. The dolphins will also resist forces caused by the carrier motion due to wind or wind-generated waves.

The berthing dolphin structure (See Figure 4.1-F10 on page 4.1-17) will consist of a deck and a jacket section. The deck dimensions will be 40 feet in length along the shoreline by 32 feet wide. The deck will be constructed of metal grating supported by steel deck beams. The jacket will be a six-legged structure with the three seaward legs being vertical and the three shoreward legs battered on a 1 to 8 slope toward the shore. The jacket legs will be 52" O.D. and braced horizontally and diagonally with tubular members. The piling for the jacket will be 48" O.D. tubular steel driven piles connected to 36" O.D. pin piles inserted in the bedrock.

Each berthing dolphin will be equipped with a powered capstan and two quick-release hooks to accommodate spring lines from the carrier. The spring lines will be used to maintain the longitudinal position of the carrier relative to the loading platform. The powered capstan will be mounted on the dolphin directly behind the set of quick-release hooks and will haul in the spring lines from the carrier.

The capstan will consist of a vertical cylindrical drum driven by an explosion-proof electric motor. With the exception of electrical power leads, the entire unit will be in a self-contained, weather-proof housing designed for service in a marine environment.

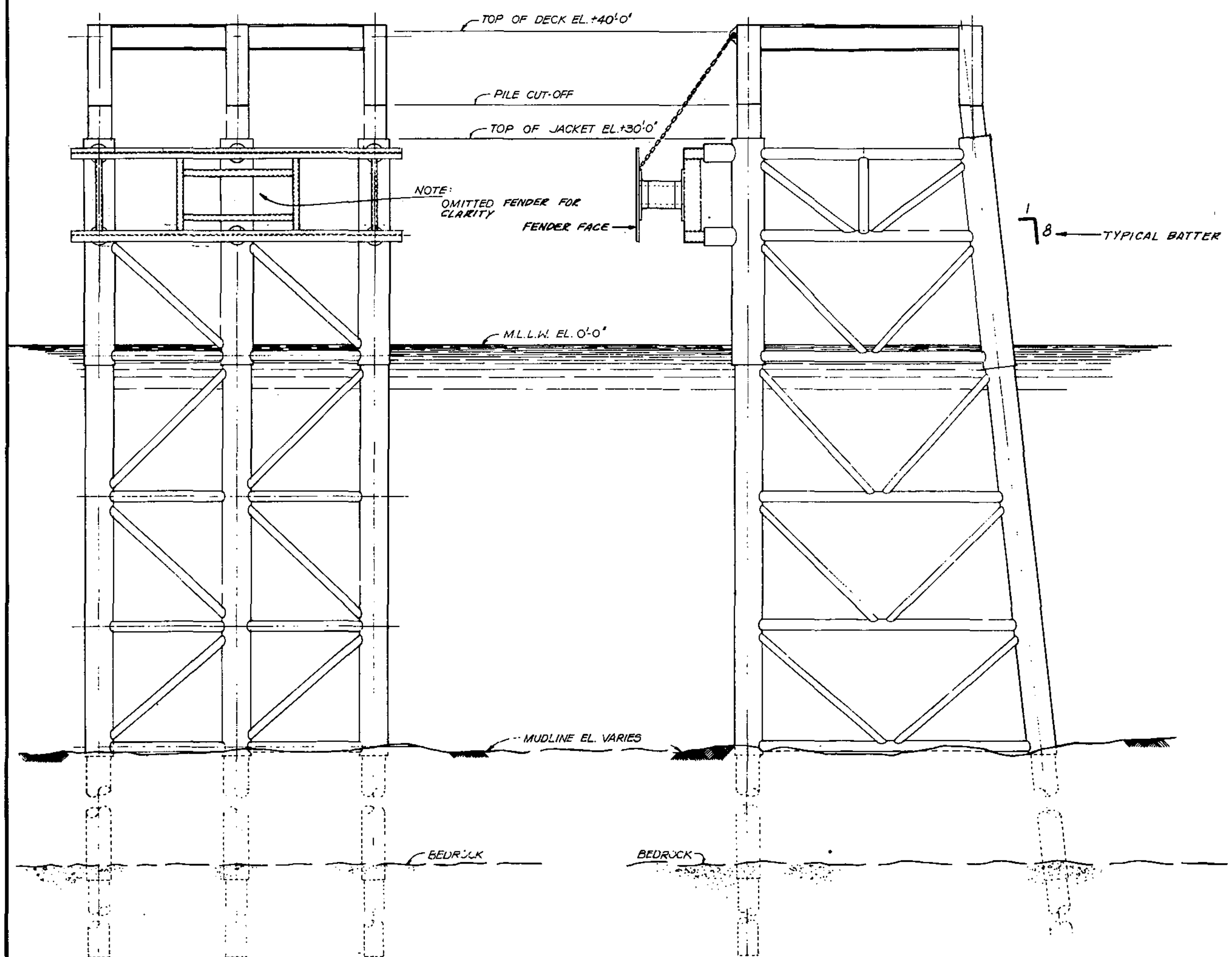
The two quick-release hooks will be in the center of the dolphin. The hooks are to be mounted opposite each other on a common circular base secured to the deck of the dolphin. They will rotate freely in the horizontal plane.

Fender Description

Each berthing dolphin fender will consist of one FT-19 Lord energy adsorbing unit and a fender face, supported by a gridwork of steel beams which will be welded to the jacket structure during field installation. The size of the fender face will be selected to insure that the allowable bearing pressure on the LNG carrier's hull of 4,000 pounds per square foot is not exceeded at maximum fender reaction.

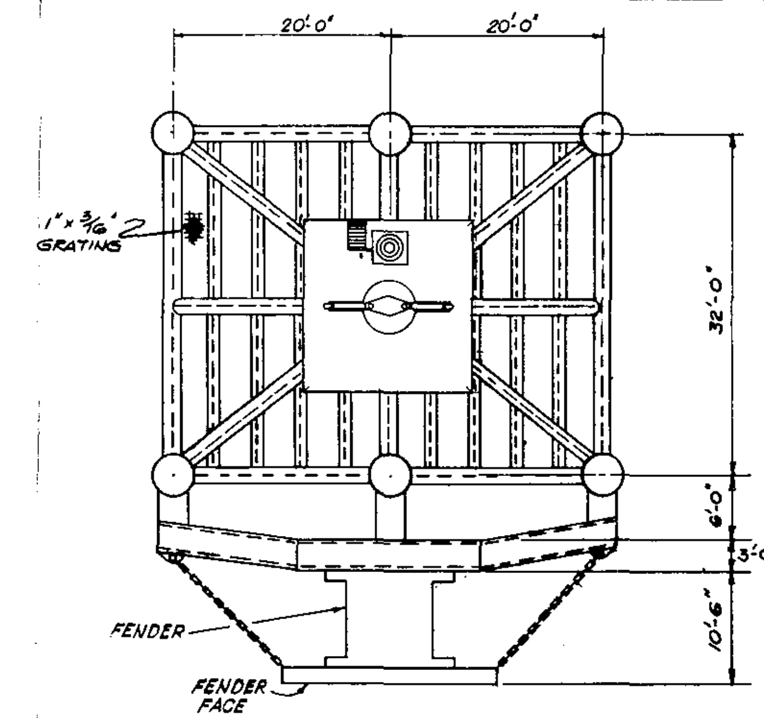
The FT-19 energy adsorbing unit is a cell fender which uses the controlled buckling column principle. This unit consists of a cylindrical, elastomeric section with steel mounting plate permanently bonded to the unit during vulcanization. Under axial loading, the contoured profile of the cylinder buckles radially.

The fender facing will be made of 1-3/4 inch thick, high-density polyethylene wear pads. The wear pads are to be supported by a steel frame bolted to the fender.



FRONT ELEVATION

SIDE ELEVATION



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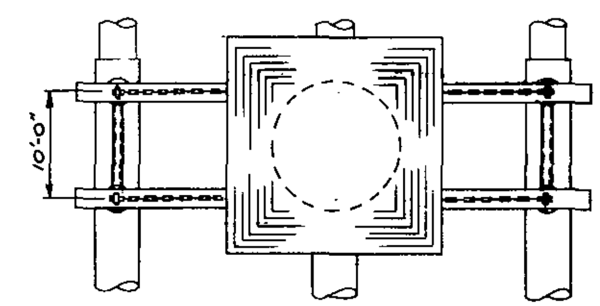


FENDER FRONT VIEW

TRANS-ALASKA GAS PROJECT

ALASKAN MARINE TERMINAL
BERTHING DOLPHIN

FIGURE 4.1–F10

The location of the berthing dolphins relative to the entire terminal layout will be based on carrier sizes the terminal is designed to accomodate and the requirement to protect any exposed structure. The two exterior dolphins will be spaced at the outside extremes of the parallel midbody of the smallest carrier. This is necessary to ensure that carriers, ranging in cargo capacities from 125,000 cubic meters to 165,000 cubic meters, will contact the exterior dolphins on their parallel midbody.

The fender system for the berthing dolphins will be installed last. Since it is important to have correct horizontal alignment for the fender faces of the four berthing dolphins, alignment columns will be used on each berthing dolphin to ensure that the required tolerance is held. The six alignment columns on each berthing dolphin can be adjusted in length to permit the horizontal alignment of the fender faces. Then the fender assembly, consisting of box beams, cell fenders and face, will be installed.

<u>Mooring Dolphins</u>

The mooring dolphins will be designed to secure a berthed LNG carrier and allow a minimum of movement caused by wind, waves and currents or a combination of the three. Mooring dolphins also will be used in the berthing operation by accepting and securing the mooring lines. Three mooring dolphins will be used for each berth with an additional mooring dolphin common to both berths. See Figure 4.1-F11 on page 4.1-19.

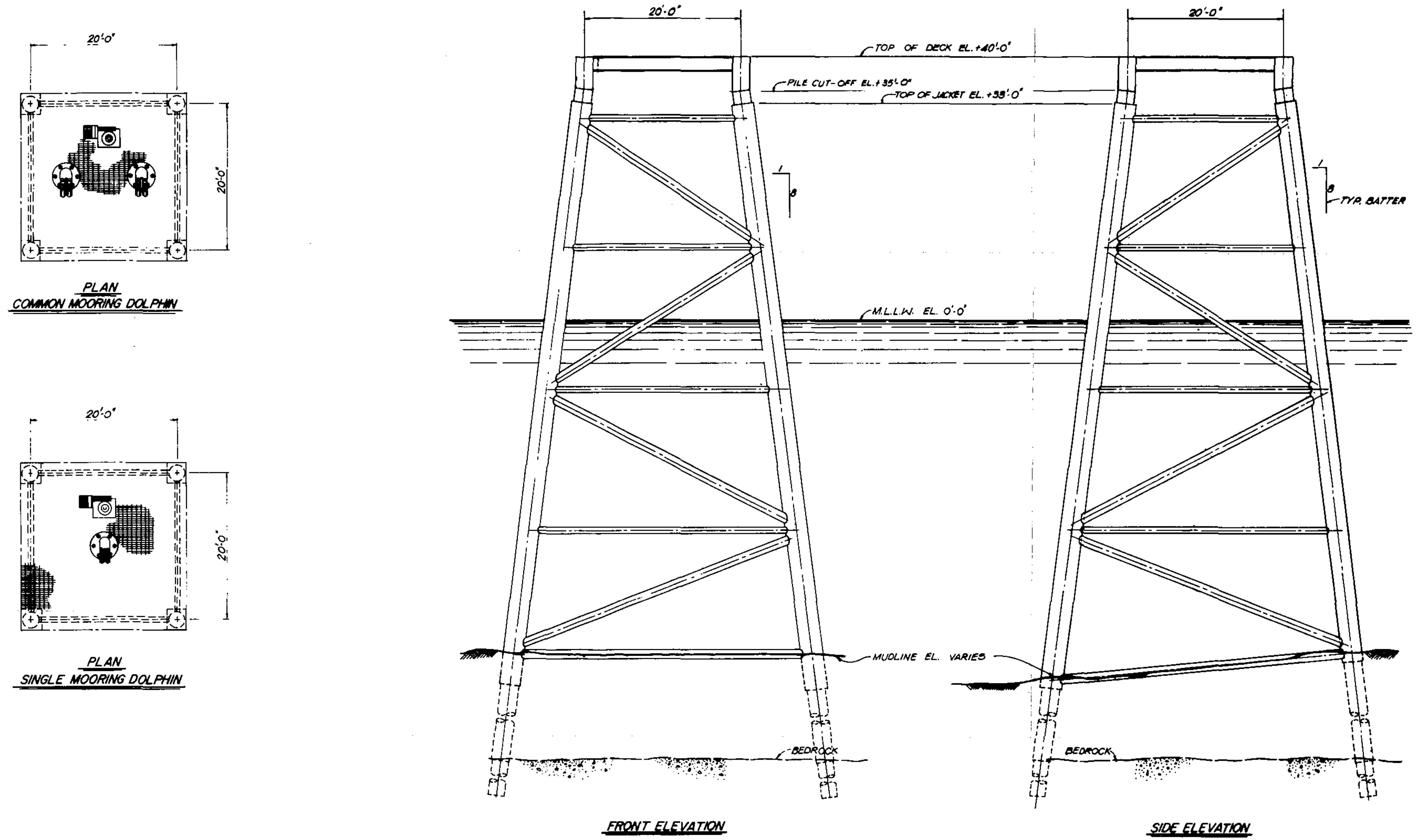
Each mooring dolphin will consist of a deck and a jacket structure. The deck will be built of metal grating supported by steel deck beams. The jacket consists of four legs on a 1 to 8 batter. Horizontal and diagonal bracing will be provided for added strength and stability.

Each mooring dolphin will be equipped with a powered capstan and one set of quick-release hooks similar to those described on the berthing dolphins. The two quick-release hooks on each mooring dolphin are to be oriented side by side on a common base and will be positioned perpendicular to the offshore edge of the dolphin.

<u>Personnel Bridges</u>

Each personnel bridge will consist of a truss and a walkway to provide access from the loading and service platforms to the berthing and mooring dolphins. The truss will have a triangular configuration composed of heavy chord members. The bracing member connecting the two top chords will provide the support for the walkway.

The personnel bridge will span between adjacent platforms and dolphins with the two top bridge chords to be supported by the jacket



TRANS-ALASKA GAS PROJECT

ALASKAN MARINE TERMINAL
MOORING DOLPHIN

FIGURE 4.1–F11

structures at each end. One end of the bridge will be fixed against translation while the other end is allowed to move parallel to the bridge. The walkway will include a grating and handrails.

Small Boat Harbor - Construction Dock - Ferry Landing

The small boat harbor and construction dock will consist of a dock, harbor, roadway and ferry landing. It will function as an unloading area for construction equipment, material and supplies, as well as a dock for tugs, crewboats and launches. The construction dock will be designed to support a crawler crane with a 100-ton load.

The small boat harbor will be protected by a breakwater, and is to be located on the southwestern end of the marine terminal. The exposed side will be used as a barge dock. A ferry landing is also to be incorporated into the design. The harbor will be large enough to accommodate all boats stationed at the marine terminal. Provision for refueling these boats will be included.

The construction dock will have surface dimensions of 70 feet by 532 feet, and will be supported by three concrete caissons. During construction, the supporting structure will be floated to the proposed location and sunk by filling the caissons with granular materials. The top surface of the dock will be crushed gravel compacted to provide a level surface. Concrete caissons will also provide breakwater protection on the shoreward side of the dock for the tugboats, crewboats and launches.

A walkway will be provided for access to each boat from the construction dock or roadway. The elevation of the construction dock will be 25 feet above mean lower low water.

A roadway will slope uniformly from the end of the construction dock to the shoreline. The roadway will be constructed on a rubble mound structure with a surface consisting of crushed rock and gravel.

The ferry landing will consist of two 10-foot by 30-foot floats flexibly connected to a 20-foot by 20-foot landing float. The landing float will be connected by a bridge to the roadway, pinned at each end. The flexible float connections will allow the float assembly to adjust for changes in water level. Two mooring dolphins will be installed to secure the float assembly and provide mooring for a ferry.

The small boat harbor will be designed to facilitate adequate water circulation to prevent ice formation in the winter.

Cathodic Protection System

Cathodic protection will be provided for all submerged structures in the form of a galvanic anode system utilizing sacrificial alloy. The system will be designed for the terminal operational lifetime and will require only a minimum amount of maintenance to the cables and power source. The anodes will be inspected periodically and will be replaced as necessary.

Section 4.2
Construction

SECTION 4.2

CONSTRUCTION

Table of Contents

List of Figures

SECTION 4.2

CONSTRUCTION

Schedule

The construction schedule for the Alaskan Marine Terminal will require five years. Installation of the process piping and instrumentation, part of the LNG Plant facilities, will require an additional half year. This schedule contemplates that should all requisite authorizations and permits be granted by the end of the first project year, the terminal could be operational 53 months later, or four months before the LNG Plant could produce first LNG.

A bar chart outlining three principal construction phases is shown in Figure 4.2-F1 on the next page.

The engineering phase is represented by line items numbered 1 through 6 on the chart. This initial phase, beginning with project approval, includes the preparation of bid proposals, design summaries, detailed drawings, specifications and the awarding of contracts. This activity will require a total of two years and two months.

The procurement phase, represented by line items 7 through 9, consists of placing orders and obtaining delivery of marine terminal components. This phase will begin in August of the second project year and will be completed by March of the third year.

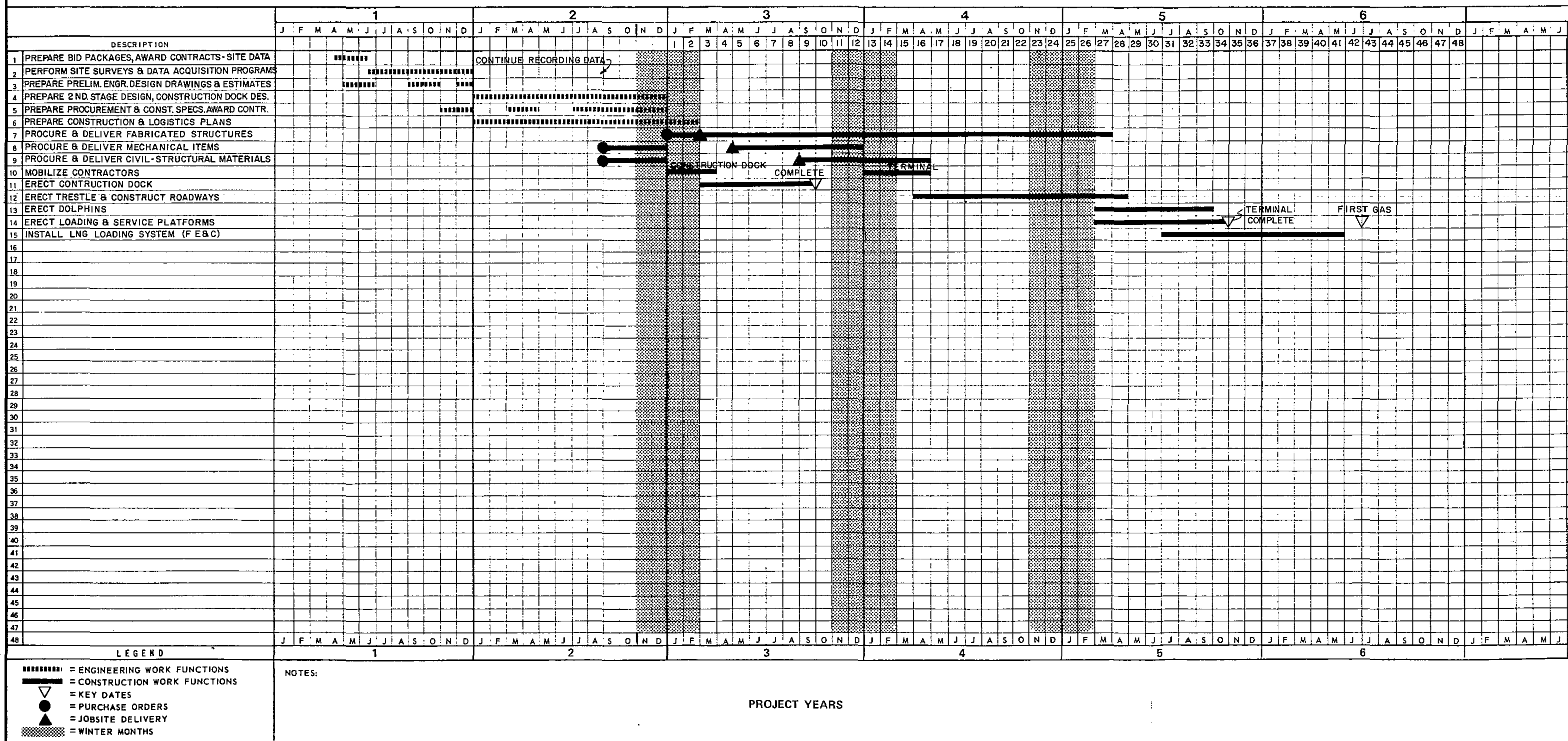
The construction phase, represented by line items 10 through 15 will include erection and construction of all necessary structures. This final phase will begin in January of the third project year and continue until completion of the interconnecting cryogenic piping to the LNG Plant in the middle of the sixth project year.

The bar chart is based on market conditions prevailing in the last quarter of 1973. A shipping delivery time of two months to the job site is allotted. It was assumed that sufficient skilled labor will be available to work a 60-hour construction week.

Critical Path

The construction activities that form a critical path for the marine terminal installation have been identified and are shown in sequence below:

- Project Mobilization
- Design
- Delivery of Prefabricated Construction Dock
- Contractor Mobilization
- Erection of Construction Dock
- Erection and Construction of the Berths



TRANS-ALASKA GAS PROJECT

ALASKAN MARINE TERMINAL CONSTRUCTION BAR CHART

FIGURE 4.2–F1

- Placement of Trestles and Roadways
- Erection of Dolphins and Platforms
- Installation of Cryogenic Piping

Completion of the construction dock in the third project year will be necessary to accept delivery of heavy structures and equipment for both the marine terminal and the LNG Plant. The construction dock is expected to be completed in six months. This will allow a three-month period between completion of the construction dock and the scheduled mobilization in January of the fourth project year of the principal contractor constructing the terminal platforms and berthing facility.

The construction schedule spans three arctic winter seasons, but on-site construction activities will only be necessary during the fourth and fifth project year winters. These activities will be reduced in scope from the summer schedule.

Section 4.3
Capital and Operating Costs

SECTION 4.3

CAPITAL AND OPERATING COSTS

Table of Contents

Index to Figures and Tables

Figures

Tables

SECTION 4.3

CAPITAL AND OPERATING COSTS

General

The estimated capital cost for the Alaskan Marine Terminal includes the loading and service platforms, the control house and tower, the berthing and mooring dolphins, the personnel bridges and the approach trestle. Also included are the small boat harbor with ferry landing and construction dock. The cost does not include shore-based fleet support equipment and facilities or cryogenic piping and controls. The estimated maintenance costs include all terminal expense necessary to function for a year. The operating costs associated with the terminal are included either in the LNG Plant or LNG Carrier Fleet costs.

Capital Cost Estimate

A summary of the estimated capital cost for the Alaskan Marine Terminal is shown in Table 4.3-T1 on the following page. As presented in the table, the capital cost of the marine terminal is estimated at $57,695,000. The estimate is based on last-quarter of 1973 prices. A schedule of estimated capital expenditures illustrating outlays each quarter for the project period is shown in Table 4.3-T2 on page 4.3-3.

Description of Capital Cost Elements

The following is a definition of cost elements used in the capital cost estimate with identification of related cost items:

Direct Job Cost

Equipment - This includes cost of all terminal machinery except controls. This cost figure includes the loading arms, pedestal cranes, capstans, quick-release hooks and fenders.

Materials - The cost of all physical materials used in constructing the completed marine terminal such as cement, aggregate, sand, prefabricated steel jackets, girders, insulation, paint and electrical wiring are included in this item.

Labor - The cost of employing all craftsmen, including primary and subcontractor labor are incorporated here. Benefits, burdens and insurance are not included as direct labor. The labor requirements for the terminal will peak at 120 men during the fourth and fifth project years of construction, as illustrated in Figure 4.3-F1 on page 4.3-4.

Table No. 4.3-T1

ALASKAN MARINE TERMINAL

CAPITAL COSTS

Direct Job Cost	
Equipment	$ 2,418,100
Materials	12,437,400
Labor	3,351,400
Spare Parts	60,000
Sales and/or Use Taxes	76,200
Freight	534,100
Start-up Costs	25,000
Total Direct Job Costs	$ 18,902,200
Indirect Job Costs	
Fee	$ 1,538,600
Temporary Construction Facilities	131,800
Construction Services, Supplies & Expenses	116,000
Field Staff & Expenses	1,214,500
Benefits, Payroll Burdens, Insurance and Taxes	1,055,300
Construction Tools & Equipment	5,111,700
Total Indirect Job Costs	$ 9,167,900
Office Costs	
Engineering	$ 1,635,000
Purchasing	100,000
Expediting	50,000
Business Services	50,000
Office Expenses	100,000
Payroll Burdens	100,000
Indirect Office Expenses	168,000
Owner's Overhead (2% of Direct Cost)	378,000
Total Office Costs	$ 2,581,000
Contract Project Management Fee	$ 7,924,000
Intangible Plant Costs	$ 503,000
Contingency	$ 1,533,000
Allowable for Funds Used During Construction	$ 20,604,000
Partial Year Costs Less Revenues	($ 3,826,000)
Total Depreciable Capital	$ 57,389,100
Working Capital	$ 306,000
ESTIMATED TOTAL CAPITAL COST	$ 57,695,100

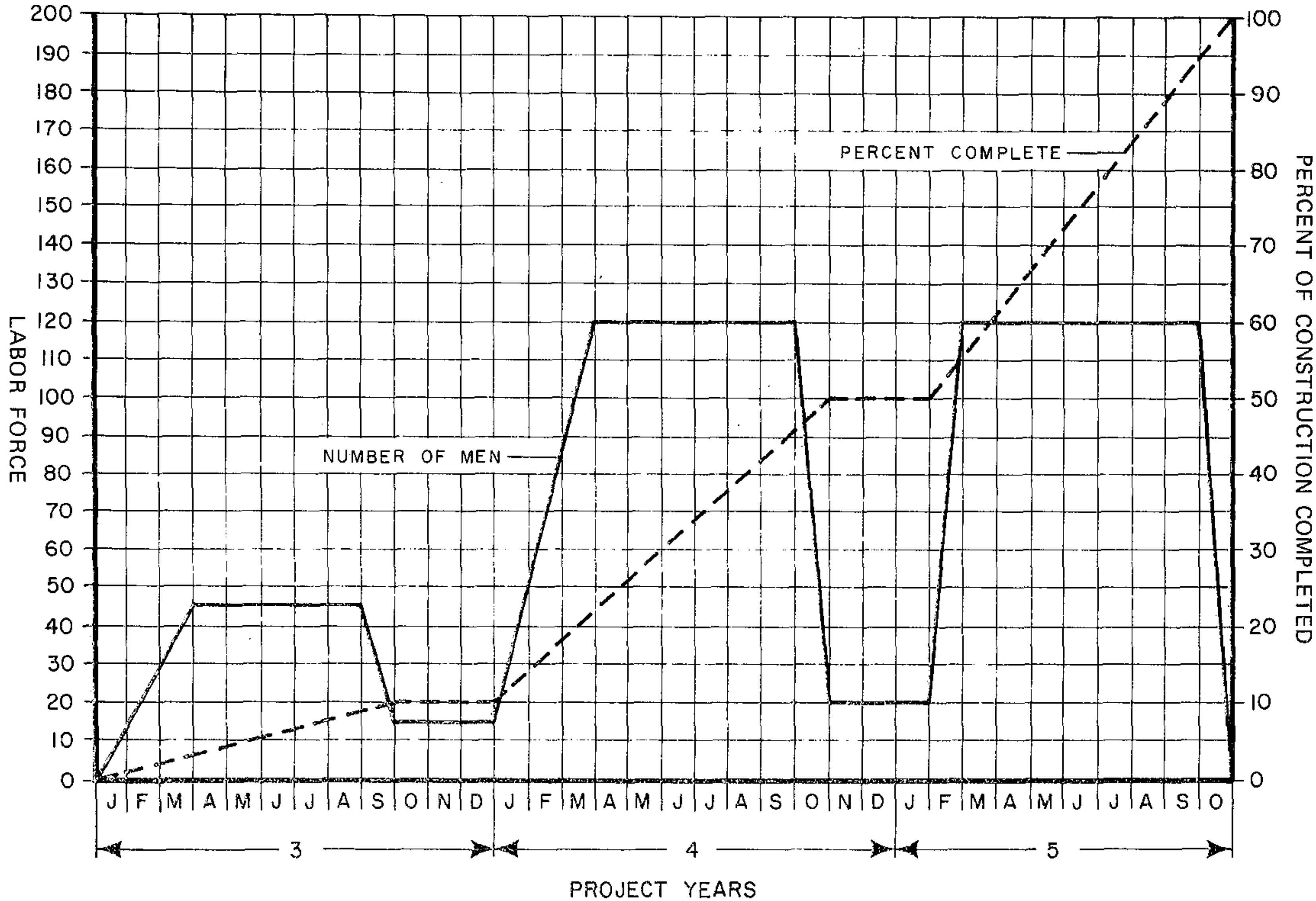
Table No. 4.3-T2

ALASKA MARINE TERMINAL

SCHEDULE OF ESTIMATED CAPITAL EXPENDITURES
(Dollars Stated in Thousands)

Year/Quarter	Labor	Materials	Other	Allowance for Funds Used During Construction	Partial Year Costs Less (Revenues)	Working Capital	Total by Quarter
Year 1, Q 1	$	$	$ 442 1/	$ 92 2/	$	$	$ 534
Q 2			487	36			523
Q 3			827	55			882
Q 4			854	75			929
Year 2, Q 1			477	87			564
Q 2			461	100			561
Q 3		1,489	477	155			2,121
Q 4		1,489	460	202			2,151
Year 3, Q 1	511	1,489	1,180	275			3,455
Q 2	511	1,489	1,178	367			3,545
Q 3	511	1,489	1,178	444			3,622
Q 4		1,489	1,178	550			3,217
Year 4, Q 1	511	1,489	1,178	663			3,811
Q 2	511	1,489	1,178	717			3,895
Q 3	511	1,489	1,178	827			4,005
Q 4	511	1,489	1,178	917			4,095
Year 5, Q 1	511	1,489	1,178	1,008			4,186
Q 2	511		1,178	1,071			2,760
Q 3	511		1,178	1,134			2,823
Q 4	511		1,166	1,199			2,876
Year 6, Q 1				1,230			1,230
Q 2				1,262			1,262
Q 3				1,308	671	61	2,040
Q 4				1,339	(159)	31	1,211
Year 7, Q 1				1,361	(607)	31	785
Q 2				1,381	(718)	31	694
Q 3				1,390	(1,264)	31	157
Q 4				1,389	(1,749)	121	(239)
TOTALS	$ 5,621	$ 16,379	$ 18,611	$ 20,604	($ 3,826)	$ 306	$ 57,695

1/ Includes expenditures made prior to Project Year 1.
2/ Accumulated allowance for expenditures made prior to Project Year 1.



TRANS-ALASKA GAS PROJECT

ALASKAN MARINE TERMINAL
CONSTRUCTION MANPOWER CURVE

FIGURE 4.3-F1

Spare Parts - The cost of all replacement parts and spares purchased and stored for use during start-up and initial operation of the terminal.

Sales and/or Use Taxes - The cost assessed to the marine terminal based on a percentage of the original cost of materials and equipment.

Freight - The cost to move materials and equipment from the marshalling yard to the job site. This includes barge rentals or aircraft charters. It includes heavy lift charges, terminal charges, air or ocean freight charges, brokerage or agent fees, demurrage, storage and wharfage handling charges. The cost of any rail or truck charges to deliver the material or equipment from the place of purchase to the marshalling yard is included in the material or equipment costs.

Start-up Costs - The cost of providing factory representatives from manufacturers of the loading arms, cranes and other terminal equipment to supervise installation and start-up.

Indirect Job Costs

Fee - This cost includes the contractor's cost for field supervision, home office expenses and profit.

Temporary Construction Facilities - The cost of temporary construction facilities includes the field offices, warehouses and a storage yard not considered part of the permanent facility. This cost also includes utilities and services purchased and used during the construction phase.

Construction Services, Supplies and Expenses - Construction services, supplies and expenses includes the cost of incidental third party services during construction, the cost of moving construction equipment and small tools to and from the job site, the cost of fuels and lubricants for construction and maintenance equipment and the cost of expendable supplies. Construction services, supplies and expenses are estimated for the field office, transportation services, survey crew, warehouse and storage yard.

Field Staff and Expenses - Field staff and expenses include salaries, travel expenses and allowances for the field staff.

Benefits, Payroll Burdens, Insurance and Taxes - These costs are incurred for tradesmen in addition to their base rate. They include fringe benefits, Workmen's Compensation insurance, Unemployment insurance and Social Security tax.

Construction Tools and Equipment - This cost includes the expense of renting and insuring the major pieces of construction equipment, mobilization and demobilization, leasing the various vehicles for the field staff, Builder's-Risk and Towing insurance and a small tool allowance.

Office Costs

Engineering - Engineering is the cost of engineering labor necessary to produce specifications, drawings and other engineering data required to purchase the equipment and materials and to direct their installation.

Purchasing - Purchasing is the cost of labor necessary to obtain quotations, to select suppliers and to prepare purchase documents. Traffic office costs are also a part of purchasing costs.

Expediting - Expediting is the cost of monitoring equipment and material delivery dates.

Business Services - Business services is the cost for the service staffs performing accounting, payroll tax calculations, consultation, legal services, insurance and other business services.

Office Expenses - Office expenses are the costs of reproduction, duplication, printing services, postage, telephone and telegraph communications, preparation of models, computer programming and use, travel expenses and other direct office expenses incurred.

Payroll Burdens - The cost of all payroll burdens and benefits paid to office employees.

Indirect Office Expenses - Indirect office expenses is the cost of facilities, furniture and fixtures, utilities, corporate management and department services not directly associated with the project, but indirectly necessary for the applicant to conduct business related to this project.

Owner's Overhead - Owner's overhead is the expense incurred by applicant in directing the engineering and construction for the project.

Contract Project Management Fee

Contract project management fee is the management cost for project planning and execution.

Intangible Plant Costs

Intangible plant costs are the costs of initiating and planning the terminal, and include consultant fees; expenses for engineering, financial, operational and economic studies; and other developmental costs.

Contingency

Contingency costs are estimated as a percentage of direct costs plus indirect costs plus office costs.

Allowance for Funds Used During Construction

The Allowance for Funds Used During Construction (AFC) covers an allowance for financial charges incurred as interest during construction on the interim financing plus an allowance for a return on the equity funds invested during the development, design and construction of the terminal. The AFC charges are calculated for all the capital expenditures listed in Table 4.3-T2 on page 4.3-3.

Partial Year Costs Less Revenues

Partial Year Costs Less Revenues are the estimated net revenues or expenses of the Alaskan Marine Terminal during the last two calendar quarters of the Trans-Alaska Gas Project year six and the entire four quarters of Project year seven.

Working Capital

Working capital provides a continuous source of funds needed to meet short-term obligations for cash expenses and prepayments.

Operating Cost

The estimated annual maintenance expenses for operating the Alaskan Marine Terminal are presented in Table 4.3-T3 on the following page. As shown in the table, the total cost is estimated at $1,490,000 per year.

The operating labor required for the fleet, terminal and plant interface is included in either the LNG Plant or the LNG Carrier Fleet reports.

Description of Operating Cost Elements

The following is a definition of cost elements used in the operating cost estimate with identification of related cost items:

Maintenance Labor and Materials

The costs of maintenance at the terminal will include minor above-water surveys of the structures each year, and major underwater surveys of the structures and the sea bottom every five years. Fenders and dock timbers will require occasional replacement; loading arms and pedestal cranes will need periodic inspection and replacement of worn parts; ice and snow

Table No. 4.3-T3

ALASKAN MARINE TERMINAL

Summary of Estimated Annual Operating Expenses

Description	
Maintenance Labor and Materials	$ 206,000
Utilities	27,000
Consumable Supplies	50,000
Administrative and General Expenses	26,000
Insurance	267,000
Other Taxes	914,000
Estimated Total Annual Operating Expenses	$ 1,490,000

will require removal; and sandblasting and painting will be continually in progress to preserve the structures. The rental of equipment to be used in maintenance operations, such as snow plows, service vehicles, compressors and lifting equipment is included in this section.

Utilities

Utilities will include the cost of electric power needed to operate the terminal.

Consumable Supplies

The cost of spare parts, chain, rags, small tools, nails, bolts, diving materials, welding material and paint estimated to be required is included in consumable supplies.

Administrative and General Expenses

The administrative and general expense is the cost estimated for managing the marine terminal system. An organization will be formed which will be responsible for handling administrative details of the project for the terminal segment.

Insurance

The insurance expense is the coverage carried on the terminal when it goes into operation. The cost of this insurance has been estimated on the basis of the coverage available during 1973. The insured value of the terminal is the cost to reconstruct and place the terminal in operation again. This estimate includes all material, labor and financing costs.

Other Taxes

The taxes estimated for the terminal facilities apply only to the original cost of the structures and equipment.

LNG Plant, LNG Terminal and LNG Carrier Fleet Interfacing Systems

The following is a description of the interfaces between the plant, terminal and fleet. The portion of the cost attributed to each facility is identified.

Cargo Functions

LNG will be pumped from the LNG Plant storage tanks and loaded on board the LNG carriers. The cost of all the piping, pumps and instrumentation required for this transfer have been included in the LNG Plant estimate. Also, the instrumentation inside the control house on the loading platform tower, which is necessary for monitoring of the LNG Carrier Fleet loading operations, is included in the LNG Plant estimate.

Liquid Nitrogen

Small quantities of liquid nitrogen will be stored onshore for use by the LNG carriers. Cost of the storage facilities for the nitrogen is included in the LNG Plant estimate. Costs for the transfer facilities are included in the LNG Carrier Fleet estimate.

Communications

All communication facilities at the LNG Plant, and all communication costs between shore and ship have been included in the LNG Plant cost estimate.

Personnel Boats

Two personnel boats will be provided. The cost for these boats and their operation is included as part of the LNG Plant estimate.

Buildings and Services for Operation

The LNG Plant estimate includes costs for land, site preparation and civil construction onshore, perimeter fencing, field fabricated tanks, permanent plant buildings except the Marine Administration Building, temporary construction buildings, the construction camp with mess hall and recreational facilities, mobile homes for field staff, staff accomodations and schools, hospital and church facilities for the staff, catering, the concrete batch plant, crewboats and helicopter service.

Buildings for Marine Support

The Marine Administration Building, including a warehouse and shops, will be located onshore near the small boat harbor. The cost of this building is included in the LNG Carrier Fleet estimate.

Diesel Fuel

Diesel fuel for the LNG Carrier Fleet will be brought by barge and pumped to a storage tank located onshore at the small boat harbor. The costs for these facilities are included in the cost of the LNG Carrier Fleet estimate.

Tugboats and Mooring Launch

The costs for the tugboats and mooring launch and for their operation is included as part of the LNG Carrier Fleet estimate.

SECTION 4.4

DESIGN CRITERIA

Table of Contents

SECTION 4.4

DESIGN CRITERIA

Project Scope

The Alaskan Marine Terminal will be designed to load simultaneously two 165,000 cubic meter capacity LNG carriers through cryogenic piping connected to LNG Plant storage tanks located north of the terminal. The terminal will service a fleet of eleven LNG carriers and will provide for the loading of an equivalent of 2,864 MMcf per calendar day of natural gas.

The terminal design will comply with all national codes of the API, ASME, AWS, NFPA, IEEE, AISC, ISA, INSI and TEMA, and other applicable Federal, state and local laws, regulations and orders.

Site Selection

The marine terminal is to be located on the southern coast of Alaska east of Gravina Point and west of Harris Creek. The location was selected following evaluation of numerous sites along the southern coast of Alaska. Site data required for this study was derived primarily from public sources. Field investigation was limited to that necessary for the preparation of capital and operating cost estimates.

The marine terminal site as located provides for an acceptable cryogenic piping length from the LNG Plant while insuring a deep unobstructed approach and berth for the LNG Carrier Fleet. The deep waters near the terminal eliminate the need for marked approach channels. Ample maneuvering room will be available in the wide expanses of water, precluding any need for a designated turning basin. Approaches and departures from the terminal by the carriers can be varied in response to weather conditions.

Meteorology

Meteorological parameters of the location will influence operation of the marine terminal. Exposure to prevailing winds is considered to be of primary importance in selecting a terminal design. Wind will be a major factor because the exposed portion of a carrier's hull and superstructure will constitute a large "sail area" upon which the wind can exert substantial force. Consequently, high velocity winds could make maneuvering at low speeds difficult and could require a ship to vacate a berth because of excessive loads imposed upon the berthing facilities.

The site is partially protected from winds out of the north and northwest by the peninsula. From the east and south, the maximum fetch ranges from five to seven miles. The greatest exposure to wind is from the southwesterly direction due to a lack of ground friction and the long fetch.

Winds exceeding 30 miles per hour may prevent docking or may result in suspension of cargo loading operations. Winds of this magnitude vary in duration and can be expected less than 15% of the time.

Prevailing winds have a velocity of less than 20 miles per hour at the site. The maximum design wind speed for a 100-year storm at the marine terminal is 145 miles per hour.

Annual precipitation at the location is expected to be 55 inches of rain, and over 140 inches of snow. Accumulation of snow upon structures will constitute a substantial load and will be considered in the design of the structures.

Air temperatures at the marine terminal location will range from an average low of about 23°F to an average high of approximately 53°F. Extreme temperatures are projected to range from -25°F to 83°F.

Visability at the site is reduced to less than 1 mile approximately 7% of the year due to fog.

Oceanography

The primary oceanographical concern is the exposure of the marine terminal location to waves. The configuration of the offshore site will allow orientation of the marine terminal berths along an axis nearly parallel to the direction of prevailing wave movement to minimize the potential effect due to wave action.

Data analysis indicates that the normal wave height in the area is three feet or less. Approximately one to two percent of the time, waves may exceed four to six feet in height, but these infrequent occurrences are not considered to represent any major operational difficulty.

The berth faces will be located on a line with a water depth of 51 feet at mean lower low water. The maximum tidal range extends from about 3.6 feet below to 15.2 feet above mean lower low water. Consequently, during the lowest astronomical tide, the water depth at the terminal will still be sufficient for the LNG carriers which have a maximum draft of 40 feet. A list of significant water fluctuations at the site are tabulated below:

Storm Surge	1.8 Feet
Highest Astronomical Tide	15.2 Feet
Mean Higher High Water	11.9 Feet

Mean High Water	10.9 Feet
Mean Tide Level	6.2 Feet
Mean Low Water	1.4 Feet
Mean Lower Low Water (Datum)	0.0 Feet
Lowest Astronomical Tide	-3.6 Feet

Currents at the marine terminal are not expected to exceed about 1.8 knots

Seiches, Earthquakes and Tsunami

Based on general knowledge of the area, it is anticipated that seiches will not be a problem.

Tsunami effects were investigated. A 12-foot tsunami wave was selected as the preliminary design wave, assuming two carriers in berth. With the berths unoccupied, a 20-foot tsunami wave was selected.

The possible recurrence intervals of tsunami in Prince William Sound are presented below.

Earthquake Magnitude on the Richter Scale	Recurrence Interval Years	Predicted Tsunami Heights Feet	Predicted Tsunami Periods Minutes
7.0	10	5	12
7.5	25	18	24
8.0	50	25	49
8.5	100	65	100

The recurrence interval is based upon a statistical analysis of sparse data and should be considered only as an approximation.

The tsunami heights and periods are based on empirical relations which do not include possible wave modification by local bathymetry.

In the preliminary design and layout of the Alaskan Marine Terminal, the recommendations of Basil W. Wilson in his work "The Tsunami of the Alaskan Earthquake, 1964: Engineering Evaluation" were followed. These recommendations will include the use of elastic shock-absorbing fenders, a deck elevation of sufficient height to prevent the carrier from being lifted onto the deck structures by the tsunami, and the use of constant tension mooring winches so that the carrier can ride with the wave.

The forces created by the 20-foot design tsunami with the berth unoccupied were calculated using the Solitary Wave Theory. This theory is based on a single propagating wave and is used in predicting wave particle velocities and accelerations in shallow water breaking waves. Since the tsunami is classified as a shallow water wave for berth design purposes, the wave profile is most nearly approximated by the solitary wave theory. Resulting wave forces on the structures were calculated based on this approximation. A discussion of the solitary wave theory is presented by Ippen, Estuary and Coastline Hydrodynamics, 1966, McGraw-Hill, Inc.

For the preliminary design, it has been projected that the 2,060 kip reaction resulting from berthing operations, will be a larger load than that caused by a tsunami with the carrier at berth.

Geology and Geotechnical Considerations

The seafloor near the proposed berth site consists of material ranging from the size of silt to that of cobbles. Median diameter particle size is fine or very fine sand. The cobbles are scattered on the seabed surface with large shells or shell fragments. This seafloor condition extends towards shore from the 60-foot water depth contour to a water depth of 25 feet. No boulders or outcrops exist within this range along the traverse.

For the preliminary design, it is estimated that up to 40 feet of sediment may be present at the 51-foot water depth contour. The design for the jackets and pin piles are based on this estimate of overburden depth.

No active fault zones are evident in the vicinity of the marine terminal site. In addition, there are no known offshore bathymetric features that could amplify a tsunami wave.

No previous occurrence of subsidence, uplift or soil liquefaction due to earthquake activity is evident nor has there been any reported for the area in which the marine terminal site is to be located.

For this application, the earthquake design has been based on criteria outlined in the Uniform Building Code for Zone 3. The use of the Uniform Building Code for earthquake analysis is approved by the American Petroleum Institute (API) publication RP2A of January, 1974, titled "Planning, Designing and Constructing Fixed Offshore Platforms." A final design will include a detailed dynamic response analysis of the marine terminal structure to possible earthquake effects.

Marine Terminal Structures

The marine terminal will be designed to simultaneously berth two LNG carriers with the following characteristics:

Cargo capacity	165,000 cubic meters
Overall length	1002.0 feet
Beam	150.0 feet
Draft (Loaded)	40.0 feet
Freeboard (Loaded)	61.0 feet
Displacement	122,000 long tons

The marine terminal berths will also be designed to accommodate LNG carriers of the 125,000 cubic meter cargo capacity which are presently under construction. This increased flexibility to respond to operational fleet changes will be accomplished by locating the platform and berthing dolphins in locations predetermined to provide secure mooring for either size carrier.

The decision to simultaneously accommodate two LNG carriers necessitated including in the terminal design numerous marine structures. Each berth must have a loading platform, a service platform, vehicular and pedestrian access from shore, adequate berthing and mooring dolphins and access walkways connecting the platforms and dolphins.

Each loading platform will have a control tower to be used in monitoring the LNG carrier loading.

Each service platform will have a 50-ton capacity fixed crane for loading stores onboard the LNG carriers.

A small boat harbor will be built for the tugboats, personnel boats and the mooring launch to be stationed at the terminal.

Structure Design Options

The basic options for the preliminary engineering design of the Alaskan Marine Terminal structures were limited to free-standing pile groups with steel or concrete superstructures, single free-standing pile structures with steel or concrete superstructures and jacketed-type structures with steel superstructures and concrete or steel decking.

Basic Design Selected

The jacketed-type structures with steel superstructures were selected as the most suitable preliminary design. Steel grating will cover the decks of the walkways and mooring and berthing dolphins while concrete slabs will cover the decks of the loading platforms, service platforms and roadways.

The selection of jacketed-type structures was based on the following considerations:

1) Jacketed structures which have been prefabricated can be installed in a shorter time than other commonly built dock structures utilizing free-standing pile groups. This is desirable because of the seasonal working conditions and project schedules.

2) Drilling into bedrock to install piling will be required since overburden is not of sufficient thickness to allow the proper installation of piles by other methods. This drilling is most easily accomplished with jacketed-type structures because the jacket will give lateral support to the piling during drilling operations.

3) The use of single pile structures would not be advisable, since this option would require large diameter piles making the necessary drilling operation both expensive and time consuming.

4) The use of jackets assures a stable platform for construction personnel to work on during the drilling and grouting operations for pile installation.

5) The jacket structures facilitate piling installation by providing a fixed guide for supporting and aligning the pile. This is preferable to working from floating marine equipment that constantly moves, making pile placement more difficult.

Utilizing jacketed structures, the elevations of the decks were set based on the maximum water elevation expected. At Gravina Point, the maximum tide level plus storm surge plus a twenty-foot tsunami assumed to be ninety percent above still water level was used as a basis.

Highest Astronomical Tide	= 15.2 Feet (MLLW)
Storm Surge	= 1.8 Feet
Height of Tsunami Above Still Water (0.9 x 20)	= 18.0 Feet
Maximum Wave Crest Elevation	= 35.0 Feet (MLLW)

Terminal Operation

The marine terminal structure design assumes that the LNG carriers will dock using one of two distinct methods.

The first method will use a combination of "first line ashore" equipment installed on the carrier, ship's power and tugboats to berth the LNG carrier.

The second and most commonly used method will require ship's power and tugboats to berth the LNG carrier.

Regardless of the method utilized, two important factors must be considered during the docking operations:

1) The velocity of the LNG carrier should not be excessive just prior to making contact with the fenders. The normal approach velocity will be less than 0.5 feet per second.

2) The approach angle relative to the fender faces should not exceed 10 degrees.

The dolphins and fenders are designed to withstand the impact of an LNG carrier berthing at a maximum velocity of 1.0 feet per second without sustaining damage.

The fenders are designed to compensate for an angular approach of up to 10 degrees. Though the first method of docking is ostensibly designed to pull the LNG carrier in parallel to the terminal, the carrier may be pulled in at a slight angle. In the second method of docking, the LNG carrier proceeds in the direction of the terminal at a slight angle relative to the fender faces.

Once the LNG carrier is alongside the terminal and has been positioned correctly with respect to the loading arms on the loading platform, it is tied up in place. Mooring lines from the LNG carrier are led out to quick-release hooks located on the berthing and mooring dolphins. During this operation, the tugboats stand by to assist if needed in maintaining the LNG carrier's position. When all the mooring lines are placed on the quick release hooks, the tugboats are no longer required to stand by and cargo loading operations may start.

Terminal Structure Design Loads

The loading conditions investigated in the design of the Alaskan Marine Terminal were made up of combinations of the following individual loads. These combinations were selected based on engineering judgment and experience gained from similar terminal designs.

Dead Load

Dead load is defined as the total weight of all empty vessels and equipment, structures, fixed cranes, fireproofing, insulation, piping, electrical conduit, ducts and all materials forming a permanent part of the structure.

Operating Load

Operating load is defined as the sum of the dead load plus the weight of any liquids or solids normally present within the vessels, equipment or piping during operation. Also included are the weights of all materials stored for operation and the operating loads of fixed cranes.

Live Load

Live load is defined as the weight of all movable loads including personnel, temporarily stored material and maintenance equipment. Live loads for the following structures are:

1) Loading Platform - A 250 psf load or a 36 ton truck, whichever is the larger load.
2) Service Platform - A 250 psf load or a 36 ton truck whichever is the larger load.
3) Trestle - A 200 psf load or a 36 ton truck, whichever is the larger load.
4) Berthing Dolphins - A 200 psf load.
5) Mooring Dolphins - A 100 psf load.

Wind Load

Wind load is the force resulting on a structure due to wind resistance. The design wind speed for the fixed structures is 145 miles per hour with a one minute duration, the maximum anticipated for a 100-year storm.

The structures are designed for this wind load in accordance with American Society of Civil Engineers Paper 3269, "Wind Forces on Structures", (Transactions Volume 126, Part II, 1961).

Earthquake Load

Earthquake load is the total horizontal static force equivalent, in design effect, to the dynamic loads created by ground motion during an earthquake.

For the purpose of this report, the earthquake design is based on the criteria outlined in the Uniform Building Code for Zone 3 earthquake analysis and is recognized by the American Petroleum Institute Publication RP2A (January, 1974), "Planning, Designing and Constructing Fixed Offshore Platforms" as being acceptable.

Berthing Load

Berthing load is the load caused by the berthing of a 165,000 m^3 capacity LNG carrier with a maximum approach velocity, perpendicular to the dock face, of 1.0 foot per second and an approach angle of 0 to 10 degrees. The berthing load is calculated using the following equation:

$$E = (1/2)\ (M_v + M_h)\ (C_c)\ (C_s)\ (C_e)\ (V_n^2)$$

Where:

M_v = Mass of the Vessel in $\frac{\text{kip - sec}^2}{\text{ft.}}$

M_h = Hydrodynamic Mass in $\frac{\text{kip - sec}^2}{\text{ft.}}$

C_c = Configuration Coefficient

C_s = Softness Coefficient

C_e Eccentricity Coefficient

V_n = Translational Velocity Normal to the Pier $\frac{ft}{sec}$

Based on the above formula, the design berthing energy is 3018 foot-kips.

A conservative approach velocity of 1.0 foot per second was selected because of the frequency of moderate 10 to 30 knot winds in the Gravina Point area and the large sail area peculiar to LNG carriers. In normal berthing, the velocity will be less than 1.0 foot per second. Winds in the 10 to 30 knot range occur annually 55 percent of the time.

The berthing dolphin deck is designed for a 200 psf live load and a 120 kip spring line mooring load.

Mooring Load

The design mooring load results from reactions of the moored LNG carrier to a 60-mile per hour wind from any direction, with the carrier at light draft. A total load of 880 kips results during these conditions and the maximum load on any one dolphin is 352 kips.

The mooring hooks selected for these dolphins have a nominal capacity of 400 kips. The maximum design load for the mooring dolphins is based on this capacity.

Wave forces are not calculated for this study but the additional load due to four-foot waves was assumed not to create forces greater than the 400 kip design load.

The mooring dolphin deck is designed for a 100 psf live load and a 400 kip mooring load. The common mooring dolphin deck is designed for a 100 psf live load and two 400 kip mooring loads.

Wave Load

Wave loads are as follows:

1) With Berth Occupied
   Wave height of 4.0 feet with a period of 6.0 seconds.

2) With Berth Unoccupied
   Wave height of 24.5 feet with a period of 8.0 seconds.

Design waves are assumed to occur at maximum tide level.

Tsunami Load

Tsunami loads are as follows:

1) With Berth Occupied
   Wave height of 12.0 feet with
   a period of 19.0 minutes.

2) With Berth Unoccupied
   Wave height of 20.0 feet with
   a period of 49.0 minutes.

Tsunami waves are assumed to occur at maximum tide level.

For the purpose of this design, it was assumed that the berthing load would be a larger load than that caused by a tsunami with the carrier at berth.

Structural Codes and Standards

All marine terminal structures will be designed to conform to the following laws, codes and regulations:

1) Occupational Safety and Health Act (OSHA).
2) American Institute of Steel Construction (AISC). "Specification for the Design, Fabrication and Erection of Structural Steel for Buildings," Latest Edition.
3) AISC Code of Standard Practice, Latest Edition.
4) American Association of State Highway Officials (AASHO) "Standard Specification for Highway Bridges," Latest Edition.
5) American Concrete Institute (ACI) 318 "Building Code Requirements for Reinforced Concrete," Latest Edition.
6) ACI 315 "Manual of Standard Practice for Detailing Reinforced Concrete Structures," Latest Edition.
7) American Institute of Timber Construction "Timber Construction Manual," Latest Edition.
8) American Welding Society Standard D1.1 "Structural Welding Code," Latest Edition.
9) The Metal Grating Institute Standard MG-1 "Metal Grating," Latest Edition.
10) American Petroleum Institute (API) RP 2A "Planning, Designing and Construction of Fixed Offshore Platforms," Latest Edition.
11) Applicable U. S. Coast Guard Regulations.

Codes and Regulations

The preparation, design, construction and operation phases of the Alaskan Marine Terminal will comply with all applicable Federal, state and local law regulations and orders. A nonexclusive listing follows:

Air Quality

The Clean Air Act.

Environmental Protection Agency (EPA) National Primary and Secondary Ambient Air Quality Standards.

Alaska Department of Environmental Conservation Act.

Alaska Air Pollution Control Regulations and Standards.

Water Quality

EPA Regulations on Oil Pollution Prevention.

EPA Regulations on Water Quality Standards Approved by the Federal Government.

U. S. Coast Guard Regulations.

EPA Regulations on Transportation for Dumping, and Dumping of Material into Ocean Waters.

Federal Water Pollution Control Act.

EPA General Provisions for Effluent Guidelines and Standards.

Alaska Water Quality Standards.

Alaska Wastewater Disposal Regulations.

Solid Waste Disposal Regulations

Alaska Department of Environmental Conservation Act.

Alaska Solid Waste Management Regulations.

Noise and Safety Regulations

Occupational Safety and Health Act (OSHA).

National Fire Codes.

Public Health Service Regulations on Drinking Water Standards.

Section 5
LNG Carrier Fleet

Section 5.1
Description of Facilities

SECTION 5.1

DESCRIPTION OF FACILITIES

Table of Contents

SECTION 5.1

DESCRIPTION OF FACILITIES

Index to Figures and Tables

Page

Figures

Tables

SECTION 5.1

DESCRIPTION OF FACILITIES

General Description

The proposed LNG Carrier Fleet will consist of eleven ships of 165,000 cubic meter capacity. Each carrier will have an average service speed of 18.5 knots and will be capable of completing the round trip voyage of 3,804 nautical miles between the Alaskan Marine Terminal and California in approximately eleven and one-half days. With each ship operating 330 days per year, the fleet will transport 308 shiploads of LNG annually to a regasification plant proposed to be located at Point Conception, approximately 120 miles north of Los Angeles, California.

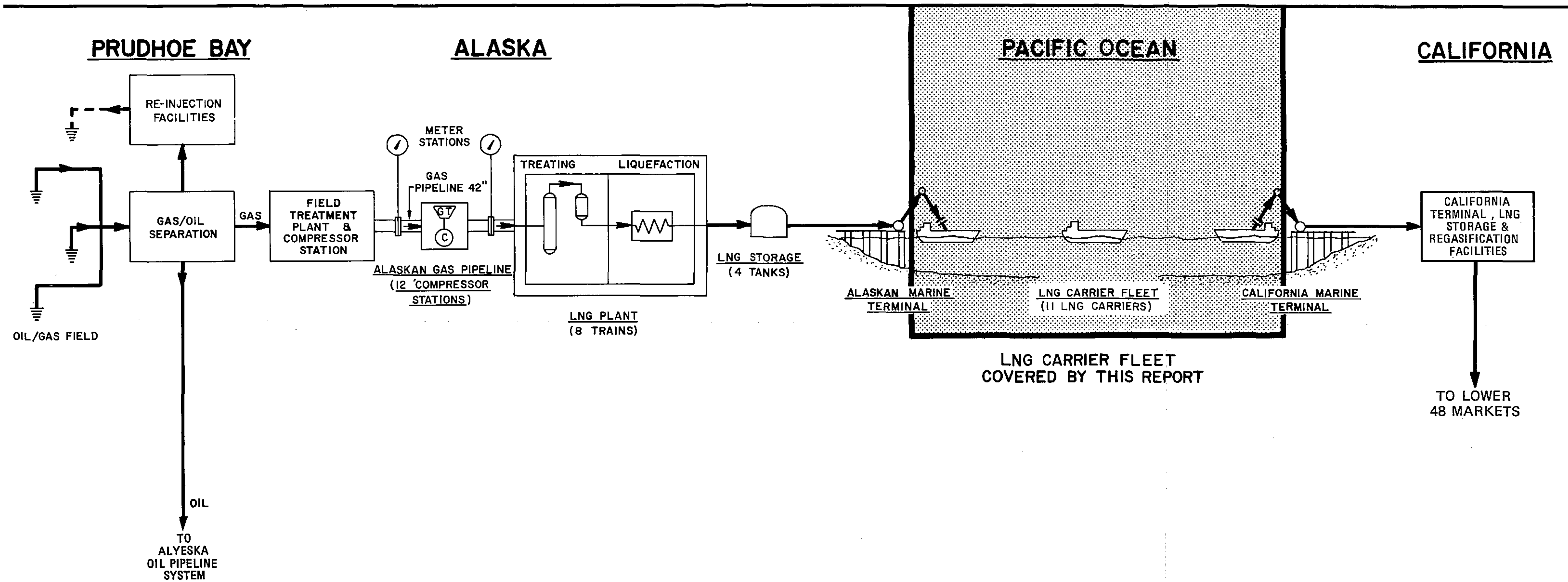
The fleet will be capable of delivering an average daily rate equivalent to 2,809 million cubic feet per calendar day (MMcf/cd) of natural gas with an energy content of 1160.2 Btu per standard cubic foot. The total energy delivered per year by the LNG Carrier Fleet for utilization in the lower 48 states will be 1,189,747,000 MMBtu. This energy delivery at the ship's rail to the regasification plant will be 87.85% of the natural gas energy delivered to the Alaskan Gas Pipeline from the producer's plant on the Alaskan North Slope. Figure 5.1-F1 on the following page portrays in graphic block form the facilities required to transport the natural gas from Alaska to California.

Marine Transportation Trade Route

The Alaskan Marine Terminal will be located at 60°38'N and 146°08'W, near Gravina Point on Prince William Sound, southeast of Valdez. The California terminal and regasification plant will be 1,902 nautical miles distant to the southeast, situated on the coastline at 34°27'N and 120°25'W, north of Los Angeles. LNG carriers will leave the Alaskan Marine Terminal at Orca Bay, proceed through Prince William Sound, then transit the northeast Pacific Ocean along the great circle route as shown on Figure 5.1-F2 on page 5.1-3. The carriers will approach the California Coast at the Santa Barbara Channel and berth at the marine terminal at Point Conception. The voyage will require approximately four and one-half days.

Carrier Description

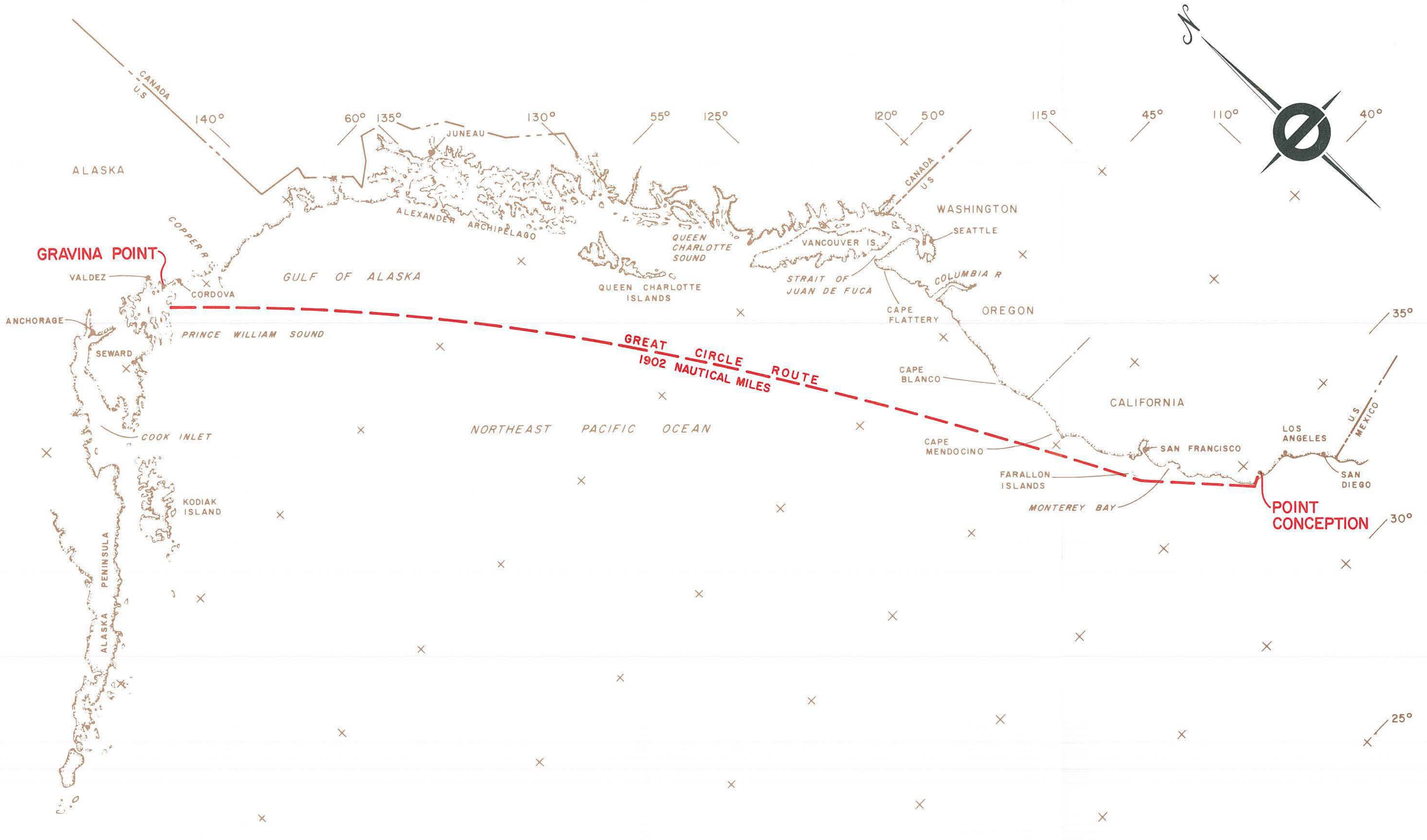
The proposed 165,000 cubic meter LNG carriers will be of the same general design as smaller LNG vessels presently in service and under construction. (See Figure 5.1-F3 on page 5.1-4.) Each carrier will be a self-contained transportation entity comprised of several interdependent systems. The principal characteristics of a 165,000 cubic meter LNG carrier are shown in Table 5.1-T1 on page 5.3-5.



TRANS-ALASKA GAS PROJECT

LNG CARRIER FLEET PROJECT ORIENTATION

FIGURE 5.1–F1



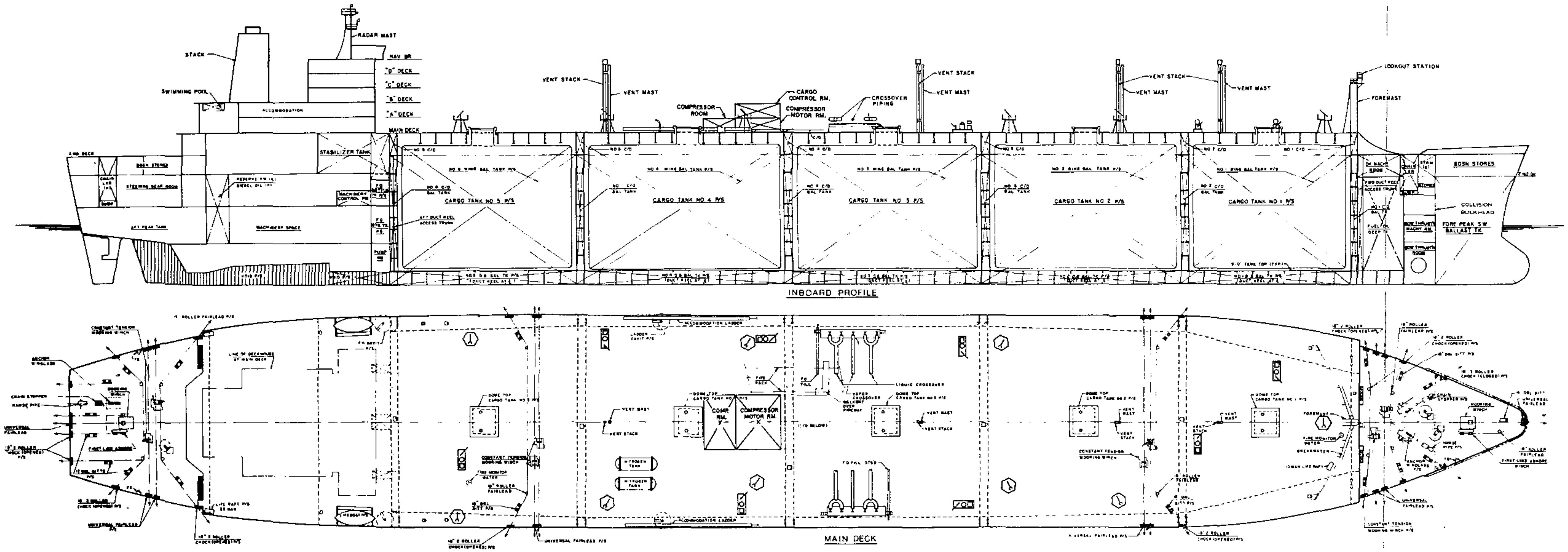
REFERENCE:

GREAT CIRCLE SAILING CHART OF THE NORTH PACIFIC OCEAN
N.O. 56
DEFENSE MAPPING AGENCY HYDROGRAPHIC CENTER

TRANS-ALASKA GAS PROJECT

LNG CARRIER FLEET
MARINE TRANSPORTATION
TRADE ROUTE

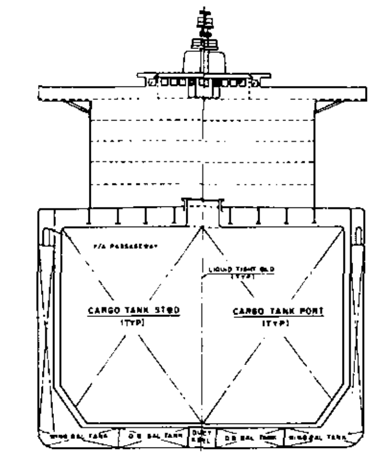
FIGURE 5.1—F2



INBOARD PROFILE

MAIN DECK

GENERAL ARRANGEMENT



MIDSHIP SECTION

LEGEND

P/S - PORT AND STARBOARD
S.W. - SALTWATER
F.W. - FRESH WATER
F.O. - FUEL OIL
DBL. - DOUBLE
C/D - COFFERDAM
F/A - FORE AND AFT
D.B. - DOUBLE BOTTOM
- FIRE MONITOR WATER
- FIRE MONITOR DRY CHEMICAL

TYPICAL PRINCIPAL CHARACTERISTICS

LENGTH OVERALL....1002 FEET
LENGTH BETWEEN PERPENDICULARS...952 FEET
BEAM....150 FEET
DEPTH OF HULL....101 FEET
DRAFT....40 FEET
BLOCK COEFFICIENT....0.75
DISPLACEMENT....122,000 LONG TONS

CLASSIFICATION

AMERICAN BUREAU OF SHIPPING ✠ AI Ⓔ

LIQUEFIED GAS CARRIER ✠AMS ✠ACC

TRANS-ALASKA GAS PROJECT

LNG CARRIER FLEET
TYPICAL 165,000 M^3 LNG TANKER
CONCH CARGO SYSTEM

FIGURE 5.1–F3

Table No. 5.1-T1

LNG CARRIER FLEET

Principal Characteristics of a 165,000 m^3 LNG Carrier

LNG Capacity, 100% Cold	165,000 m^3
Length Overall	1,002 Feet
Length Between Perpendiculars	952 Feet
Beam	150 Feet
Depth of Hull	101 Feet
Design Draft	40 Feet
Displacement	122,000 Long Tons
Block Coefficient	0.75
Propulsion Horsepower	55,000 HP
Number of Propellers	2
Type Propulsion	Geared Steam Turbine
Trial Speed (at 90% HP)	19.75 Knots
Service Speed (at 90% HP)	18.50 Knots
Ballast Capacity, 100%	66,000 Long Tons
Fuel Oil Capacity, 100%	8,200 Long Tons
Bow Thruster Horsepower	2,500 HP
Number of Cargo Tanks	5
Cargo Pump Capacity	14,000 m^3/hour
Cargo Boiloff	0.15% Cargo Volume/day
Number of Manifold Lines	5 Lines, 16-inch Diameter Each
Crew	11 Officers, 24 Crewmen

Hull System

The 165,000 cubic meter LNG carrier will be 1,002 feet in overall length, 150 feet in beam and 101 feet in hull depth. The displacement will be approximately 122,000 long tons and the loaded draft will be 40 feet. The ship will have a configuration similar to existing bulk commodity carriers, with the propulsion machinery and deckhouse located aft, and the cargo control room located amidship near the cargo loading manifold flange.

The LNG carrier will have a double hull design. This design will incorporate an inner reinforced steel hull approximately ten feet above the bottom of the ship's outer hull in conformance with current United States Coast Guard regulations. The same structural approach will be used for the sides of the vessel and for some of the decks. The space between the inner and outer hull of the ship will be used for shipboard services, inspection access and to store clean ballast water when the ship is not carrying LNG.

Propulsion Machinery System

Propulsion machinery onboard each ship will have 55,000 shaft horsepower transmitted through twin propellers. An average service speed of approximately 18.5 knots will be attained under most open sea conditions.

Maneuvering Systems

These LNG carriers will be designed to be highly maneuverable. The rudder system will have a rudder angle of 45 degrees, rather than the usual 35 degrees, to decrease the turning radius. A 2500-horsepower bow thruster system will be installed to aid in slow speed maneuvering and to assist docking tugs used at the marine terminals.

The bow thruster system will employ a propeller located in a transverse tunnel through the LNG carrier's forward underwater area. The propeller will produce a lateral force causing the LNG carrier to rotate around its vertical axis, and the propeller speed will be controlled from the bridge. The effectiveness of the bow thruster will be greatest at slow speeds. The bow thruster effectiveness will decrease markedly when the LNG carrier speed is one to two knots, but the effectiveness of the carrier steering rudder will increase with the carrier speed. Together, the two steering systems will provide positive steering control of the ship at all speeds.

Cargo Containment System

The cargo containment system to be used for each of the proposed LNG carriers has not been selected. Selection of the shipyard will be influenced by the type of cargo containment system proposed by the yard. Each of the systems presently under consideration, and the equipment necessary to utilize the various methods, will be described separately.

Cargo containment systems for LNG tankers are presently divided into two general categories: (1) "free-standing" self-supported tanks which have sufficient strength when properly mounted in the hull of the ship to support their own weight and the weight and dynamic force of the cargo, and (2) "membrane" tanks in which a thin metal barrier supported by insulation contains the liquid. The membrane barrier is supported by insulation that in turn transmits the weight and dynamic forces of the cargo to the inner hull structure of the ship. (See Figure 5.1-F4 on page 5.1-8.)

The most recent authoritative description of LNG tanker cargo containment systems appears in a paper prepared by William duBarry Thomas and Alfred H. Schwendtner, naval architects with the J. J. Henry Company, Inc. This paper was presented to the Society of Naval Architects and Marine Engineers in November, 1971. Of the systems described there, five are regarded as acceptable to applicant for use in the LNG fleet. Systems under consideration include spherical tank designs by either Kvaerner-Moss or Chicago Bridge and Iron; the Conch free-standing tank; and membrane tank designs by either Gaz Transport or Technigaz.

Kvaerner-Moss and Chicago Bridge and Iron Spherical Tanks Systems

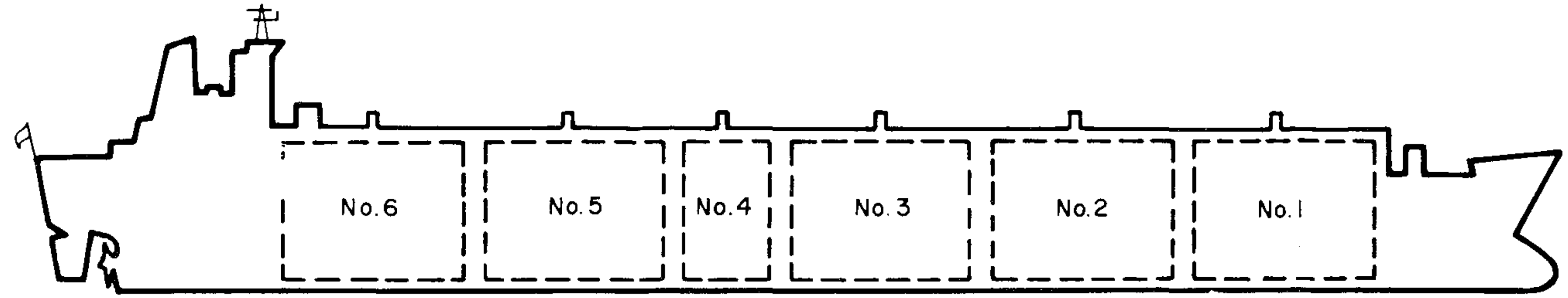
The use of large spherical tanks for the transportation of LNG was suggested some years ago. The development of this type of tank was stimulated by a United States Coast Guard statement that a secondary barrier would not be required for a pressurized vessel containment system. The Kvaerner-Moss group was first to put forth a design for such a ship, and first to contract for the construction of a large vessel of this type.

The Kvaerner-Moss tank consists of a sphere made of nine percent nickel steel or aluminum and supported by a cylindrical skirt. (See Figure 5.1-F5 on page 5.1-9.) The skirt is welded to a specially shaped section at the equator of the spherical tank and to the ship.

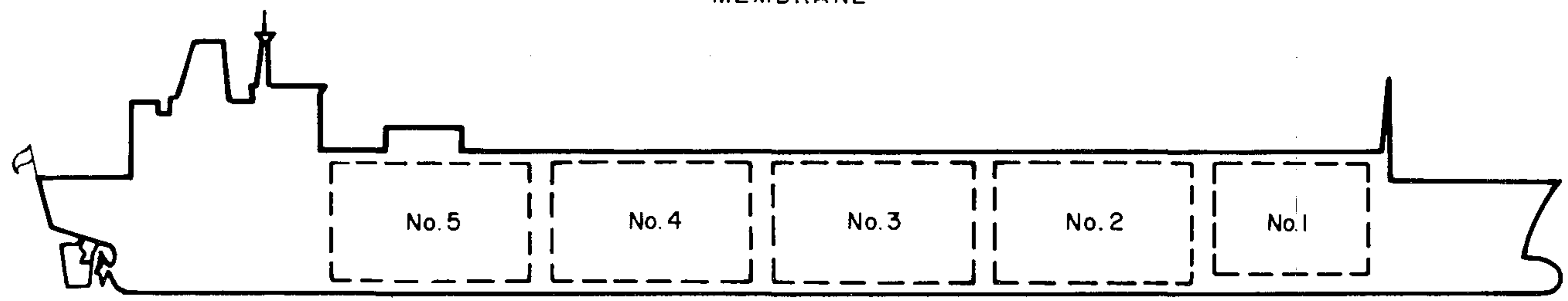
Insulation consists of polyurethane foam applied to the entire outer surface of the sphere, and to a portion of the skirt to control thermal stresses and to limit heat leak into the tank.

The distinguishing feature of the Kvaerner-Moss containment system is the fail-safe design concept. Using fracture mechanics and stress analysis, the tank is designed for such a high confidence level that the possibility of catastrophic failure of the tank is virtually eliminated.

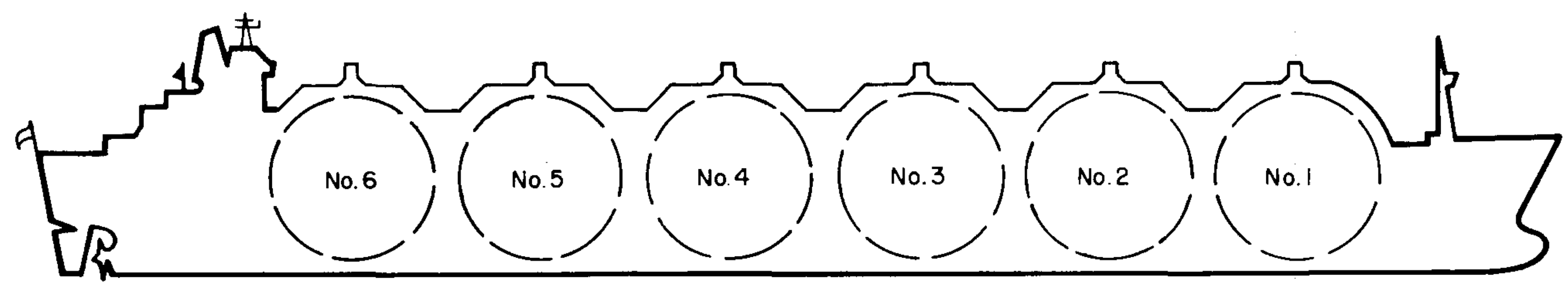
As a result of the high reliability inherent in the Kvaerner-Moss "leak before failure" design, only a small leak-protection system external to the tank is required. The external system consists of a drip tray catchment under the tank and a series of splash shields at the sides.



MEMBRANE



PRISMATIC FREE STANDING

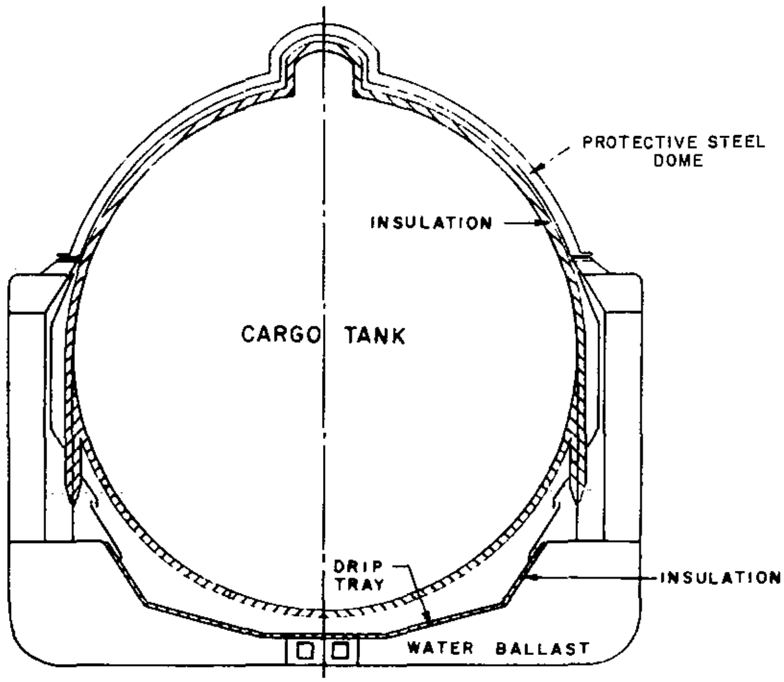


SPHERICAL FREE STANDING

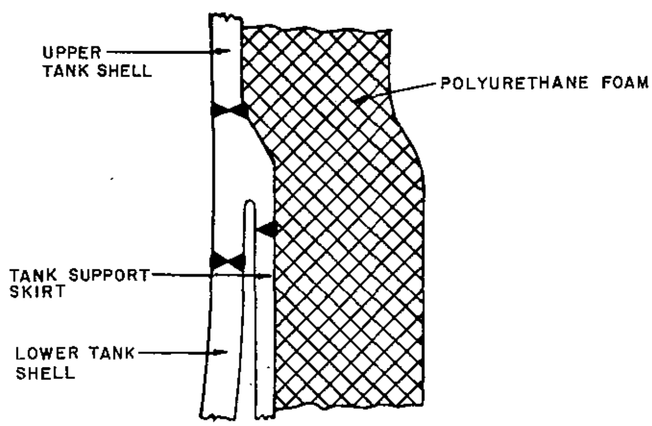
TRANS-ALASKA GAS PROJECT

LNG CARRIER FLEET
COMMON CARGO TANK
CONFIGURATIONS

FIGURE 5.1–F4



TYPICAL SECTION OF KVAERNER-MOSS SPHERICAL TANK DESIGN



DETAIL OF TANK SUPPORT SKIRT CONNECTION FOR KVAERNER-MOSS SPHERICAL TANK DESIGN

TRANS-ALASKA GAS PROJECT

LNG CARRIER FLEET
KVAERNER—MOSS
CONTAINMENT SYSTEM

FIGURE 5.1—F5

The cargo handling equipment associated with the Kvaerner-Moss system is conventional, with the exception of cool down spray nozzles and the emergency pumping equipment.

Two spray nozzle systems are used for the cool down. One system is located in the upper part of the tank to allow a general cool down before the vessel arrives at the loading terminal. The second array of nozzles is located at the tank's equator and is used during loading to prevent unacceptable thermal stresses in the concentrated mass of metal in the equator ring as the liquid level rises.

The Kvaerner-Moss system would use two submerged cargo pumps to unload the LNG. Tank pressurization will provide an additional back-up method for off-loading if both pumps fail.

The Chicago Bridge and Iron ("CB&I") system is similar to the Kvaerner-Moss system. The CB&I system is a spherical design utilizing the same tank materials and similar insulation. The distinguishing aspect of this system, compared to Kvaerner-Moss, is the use of a column support for the tank rather than a cylindrical skirt, and the use of a keyway system to anchor the tank to the support structure of the ship's hull.

Conch Free-Standing Tank System

The free-standing tank and balsa/polyurethane insulation system, employed by Conch International Methane Ltd., is the result of evaluation of a system developed for the *Methane Pioneer* (now *Aristotle*). This design was used in the *Methane Princess* and the *Methane Progress*, which became the first LNG tankers to go into base load service in 1964 and 1965.

Subsequent designs produced improvements to tank structure and insulation. Several years of study resulted in a cargo tank design of a conventional structure consisting of vertical stiffeners supported by deep horizontal webs with diagonal struts.

The insulation system used consists of reinforced polyurethane foam around the bottom and sides of the tank and fibrous glass on the top of the tank. The characteristics of the polyurethane produces a liquid-tight secondary barrier except at the top of the tank where a liquid-tight seal is not necessary.

The corners and upper boundaries of the insulated hold are fitted with balsa panels, forming a "picture frame" arrangement. The entire area surrounded by these boundary panels is covered with sprayed polyurethane, which bonds to the ship's structure and the tapered edges of the panels. Several layers of nylon mesh are embedded in the polyurethane, making the entire mass fracture resistant during thermal cycling.

The current midship section arrangement and insulation detail for a Conch Free-Standing Tank is shown in Figure 5.1-F6 on the following page. The Conch free-standing tank design represents the most proven method, having more ship-years of operation than any other design.

Gaz-Transport Membrane Tank System

The membrane tank containment system as developed by Gaz-Transport was used in the construction of the *Polar Alaska* and the *Arctic Tokyo*. A typical section view of this type of tank is shown in Figure 5.1-F7 on page 5.1-13.

From the ship's hull inwards towards the cargo, the tank consists of secondary insulation, a secondary barrier, primary insulation and a primary barrier. The two insulation layers are virtually identical, as are the two barriers. The arrangement for anchoring the primary insulation to the secondary barrier is different from the method used to anchor the primary insulation to the primary barrier.

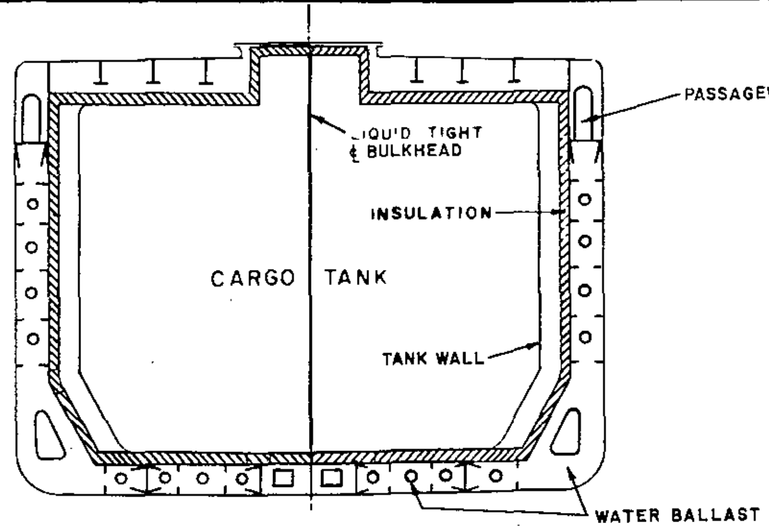
Each barrier in this proposed system will be constructed of 16-inch wide and 0.02 inch thick sheets with upturned edges, made of a 36 percent nickel-iron alloy called Invar. The primary and secondary insulation will consist of a multitude of plywood boxes filled with perlite. Expansion joints will not be needed because Invar has a small coefficient of thermal expansion.

The insulation and barriers will be installed in the following sequence. A framework of wood will first be attached to all surfaces of the cargo hold with studs and bolts. Next, the secondary insulation boxes will be placed inside the framework. A series of vertical channel members, made of nine percent nickel-steel will then be anchored to the wooden framework through the secondary barrier. Finally, the primary insulation boxes will be attached to these vertical channels.

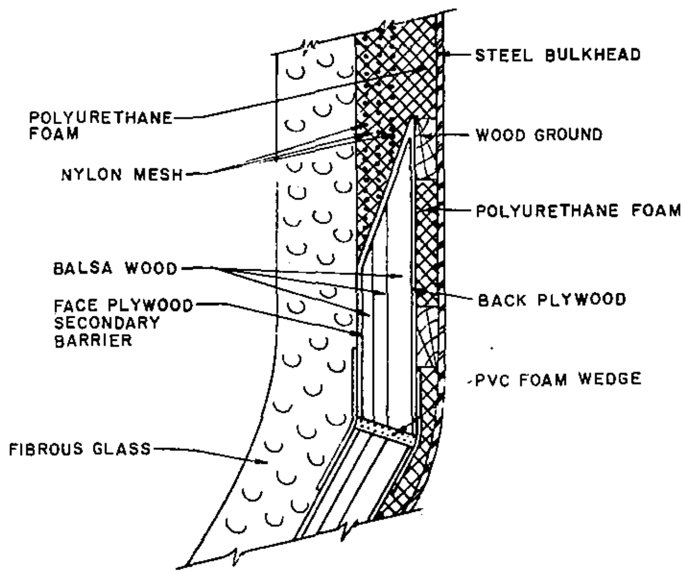
An Invar tongue will be welded halfway up the side of the secondary insulation boxes to support the secondary barrier, and special corner braces will be used. Each primary insulation box will also contain a tongue of Invar attached on one of the sides of the box. The upturned edges of the two adjacent primary barrier Invar sheets will be welded to this Invar tongue.

Special techniques must be provided to structurally support pumps, piping and equipment in membrane tank systems because direct attachment to the barrier may not be used. In the Gaz-Transport membrane system, the major equipment in the cargo holds will be supported by means of a tower framework suspended from the inside of the dome top and restrained from horizontal movement at the bottom.

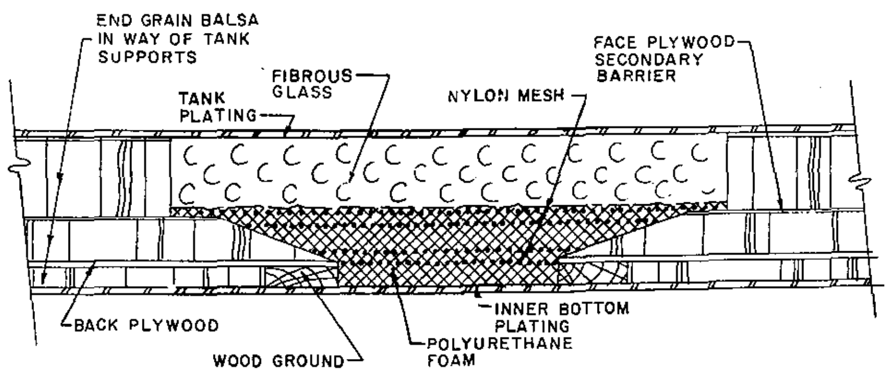
Provision will be made to ensure that the pressure between barriers does not exceed that inside the tank. In addition, gas



TYPICAL SECTION OF CONCH
FREE STANDING TANK DESIGN



(a) Sides



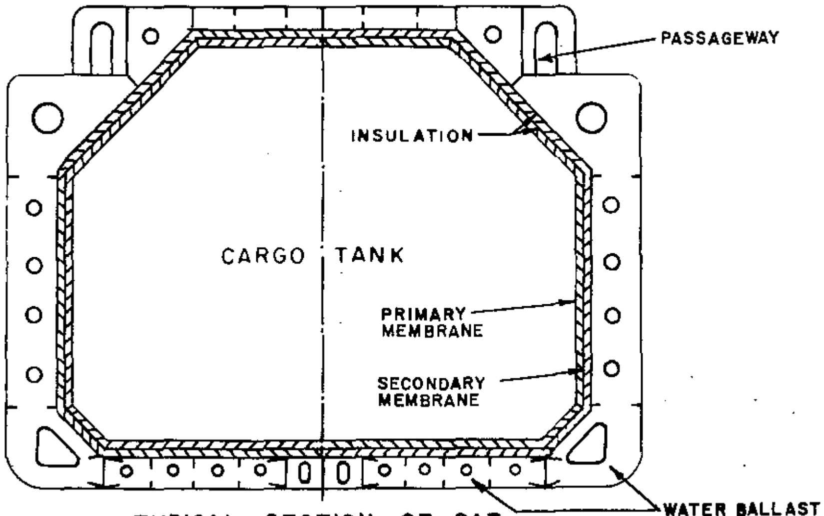
(b) Bottom

INSULATION DETAILS OF CONCH
FREE-STANDING TANK DESIGN

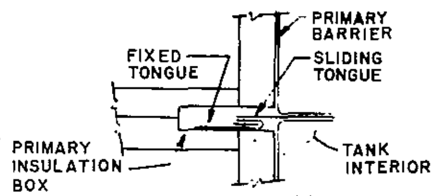
TRANS-ALASKA GAS PROJECT

LNG CARRIER FLEET
CONCH FREE–STANDING
CONTAINMENT SYSTEM

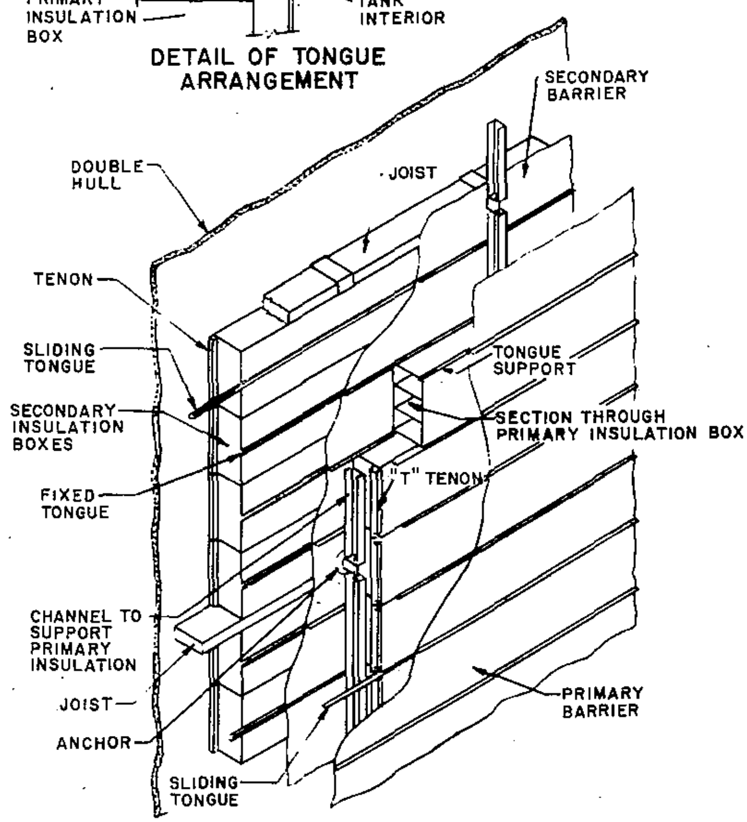
FIGURE 5.1–F6



TYPICAL SECTION OF GAZ TRANSPORT MEMBRANE TANK DESIGN



DETAIL OF TONGUE ARRANGEMENT



INSULATION DETAIL OF GAZ TRANSPORT MEMBRANE TANK DESIGN

TRANS-ALASKA GAS PROJECT

LNG CARRIER FLEET
GAZ TRANSPORT
CONTAINMENT SYSTEM

FIGURE 5.1–F7

detection points will be located between barriers, with provision for pumping LNG from this space in the event of major leakage through the primary barrier.

Technigaz Membrane Tank System

The present Technigaz (formerly Conch Ocean) membrane tank system consists of a stainless steel primary membrane barrier, balsa insulation and a plywood secondary barrier. This design was produced by Conch Ocean Ltd., formed in 1967 by Conch International Methane Ltd. and Gazocean S.A. The new Technigaz system was used successfully in the *Pythagore*, in conjunction with the Conch insulation and secondary barrier as described above, and used on the *Methane Princess* and the *Methane Progress*.

The Technigaz containment system is shown in section by Figure 5.1-F8 on the following page. The cargo hold would be constructed in the following manner. Wood grounds will be fastened to the inner hull structure to provide support for insulation panels and to smooth out irregular surfaces in the ship's steel. The spaces between these grounds will then be filled with mineral wool.

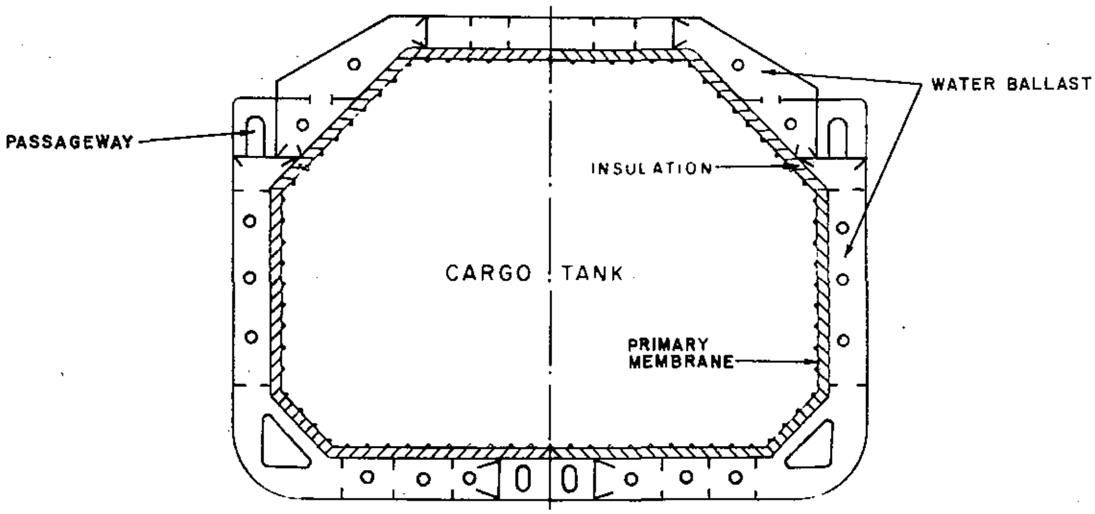
Insulation panels will be attached to the wood grounds. The joints between panels will be sealed with PVC wedges and plywood scab splices, the latter serving to complete the plywood secondary barrier. Balsa pads will then be attached to the inner face of the insulation panels to provide a flat surface upon which the membrane can be fastened. At all hold corners, hardwood keys of the same thickness as the pads will be provided to anchor the membrane through heavy stainless steel angle braces.

The primary membrane will be welded to the corner angle braces and attached in a regular pattern to the insulation panels. Welding of the membrane will employ the tungsten inert gas (TIG) process, without the addition of filler metal.

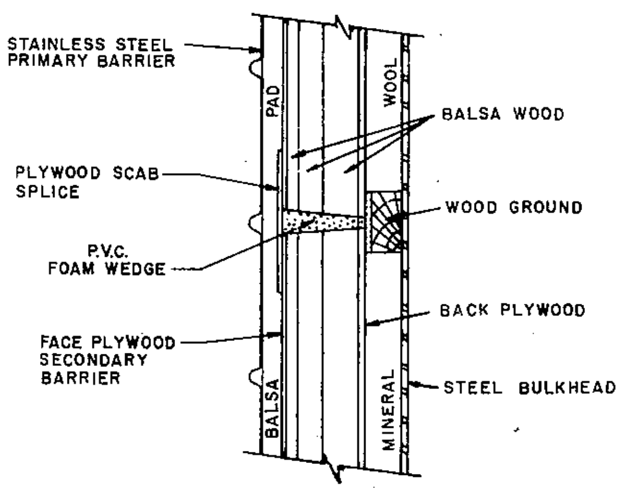
Major equipment in the cargo tanks will be carried on a trusswork tower suspended from the tank dome. The tower will be restrained at the bottom by keys attached through the membrane to hardwood blocks. The tower will be free to expand and contract vertically.

Instrumentation and Control Systems

Regardless of the cargo containment system used, the instrumentation and control systems will be located in the ship's accommodation area, engine room and cargo control room. These systems will not vary significantly from systems currently used on LNG tankers, and will include control equipment for operating boilers and propulsion machinery, navigation and communications systems, equipment for operating cargo and ballast control systems, inert gas systems, custody transfer systems, shutdown systems for emergencies and fire protection systems.



TYPICAL SECTION OF TECHNIGAZ MEMBRANE TANK DESIGN



INSULATION DETAIL OF TECHNIGAZ MEMBRANE TANK DESIGN

TRANS-ALASKA GAS PROJECT

LNG CARRIER FLEET
TECHNIGAZ
CONTAINMENT SYSTEM

FIGURE 5.1–F8

Control Equipment for Boilers and Propulsion Machinery

Control equipment for monitoring and operating boilers and propulsion machinery will be located both in the engine room and on the navigation bridge. The engine room equipment will be designed for a "one-man watch" operation.

Control Equipment for Cargo and Ballasting Systems

The cargo control room containing controls, instrumentation and alarm monitors for ballast and cargo handling will be located amidship.

Custody Transfer System

The custody transfer system will measure the LNG cargo level, density and temperature in the LNG carrier tanks.

The level will be measured by two different devices. The primary device will be a capacitance liquid level measuring instrument. The secondary or back-up measuring device will be a nitrogen "bubbler" instrument.

The capacitance device is an electronic instrument that provides for determining the height of liquid as a function of the change of electrical capacitance within a concentric probe extending from the top to the bottom of each tank.

The bubbler secondary device measures the difference in pressure resulting from a flow of nitrogen through a tube inserted in the tank. The differential pressure required to overcome the head of liquid with a bubble of gas is related to the height of liquid in the LNG tank. Because it is not always possible to keep the LNG carrier perfectly level, it will be necessary to compute the effect of different degrees of list and trim to properly determine the correct liquid volume in the tanks from height measurements.

The density of the LNG will be measured by an electronic device which utilizes a magnetically suspended sphere of the same approximate density as LNG. The force required to maintain the position of the sphere within the LNG is proportional to the LNG density.

Instruments will also be provided for accurately measuring the temperature of the LNG in the tanks.

Inert Gas Systems

On free-standing cargo tank designs, the insulation and void spaces between the cargo tanks and inner hull of the ship are slightly pressurized with nitrogen. On membrane cargo tank designs, the insulation and void spaces between the primary and secondary barriers and the secondary barrier and inner hull of the ship are likewise slightly pressurized with nitrogen. The nitrogen atmosphere is used to prevent the formation of a combustible mixture in the event of a cargo leak and to prevent ice formation in these spaces when the tanks are cold. Nitrogen is supplied to these spaces from two liquid nitrogen tanks carried onboard the ship.

It is impractical to carry enough liquid nitrogen onboard to fulfill all inert gas requirements. The additional inert gas requirements will be provided by a special, independently fired inert gas generator. It will produce the large quantities of inert gas required to gas free the cargo tanks prior to entry. Operationally, the inert gas will be used as a buffer to assure separation of air and LNG vapor (mostly methane), thus preventing formation of a combustible mixture. Before a vessel enters a shipyard for maintenance, repair and inspection, its tanks must be certified as gas free. Inert gas is used to purge the methane gas from the tanks. Finally, air is used to purge the inert gas from the tanks. Only then can the tanks be entered for inspection. In preparation for cooldown, the inert gas is used to purge air from the tanks before LNG is reintroduced.

Navigation and Communication Systems

The LNG tankers will be equipped with a three-centimeter radar system and ten-centimeter radar system, each having a separate display. Either radar may be connected to the computerized collision avoidance system to be installed in each tanker. The collision avoidance system will provide the LNG tanker with the capability to determine the location, speed and course of all other vessels within potential collison range. If a collision course is indicated, an advance warning will be immediately displayed on the system's screen. This system will allow the ship's officer to test different possible corrective actions by immediately displaying the results of the corrective action before actually executing a course change.

Additional navigational equipment will include a satellite navigation system with a LORAN C backup system, a gyrocompass with a standby compass, a depth sounder indicator and a radio direction finder.

The basic marine communications package will incorporate a low frequency, 500-watt main transmitter and a 40-watt reserve transmitter. The effective range of the low frequency transmitter is 300 to 500 miles, depending on the time of day, weather conditions and atmospheric factors.

A main high frequency 1000-watt transmitter will provide either voice or code communication capability. The unit will have a worldwide range. There will also be a standby 500-watt high frequency transmitter for code communication only, capable of contacting any place in the world.

A 52-channel VHF radiotelephone will also be provided, including the mandatory bridge-to-bridge channels required by marine regulations.

Shutdown System

A shutdown system interconnected with the marine terminals will be included onboard to stop cargo loading/unloading pumps and compressors and to activate all quick-close valves. The shutdown system will be automatically activated by causes such as excessively high cargo tank pressure, or excessive movement of the ship at the dock beyond the limits of the loading arms, fire within or near the loading system, loss of air supply and, in some cargo containment system designs, a low differential pressure between the cargo tanks and the insulation spaces. In addition, there will be five manually-activated shutdown stations located throughout the ship. The maximum shutdown time for the system will be approximately 15 seconds.

Fire Protection Systems

The entire cargo deck will be protected by three basic fire protection systems: dry powder units, water turrets and a water spray system. These will be located so that all critical areas will have overlap coverage to ensure maximum protection.

The dry powder units will use Purple "K" potassium bicarbonate which is compatible with foam systems. Similar powder units have been particularly effective in fighting LNG fires.

Water turrets will be located on deck along the sides of the ship to wash away accidental LNG spills and to cool the deck and topside equipment in case of fire. A system of spray nozzles will be installed along the longitudinal and crossover cargo piping so that the piping and the deck can be constantly sprayed with water in an emergency. Similar spray systems will be located so that all sides of the midship house and the front of the deckhouse can be sprayed with water. The shipboard spray systems will be activated from either the cargo control room or the wheelhouse.

A looped fire main system will run along both sides of the ship. The deck spray system will connect with the fire mains on each side, so that damage to one loop of the fire mains will not affect the water supply available to the spray system. The water monitors and the spray system will be served by the main fire pumps in the engine room and an emergency fire pump in the forward pump room. These fire protection systems for the proposed LNG tankers will exceed the requirements of the International Convention on Safety of Life at Sea, the United States Coast Guard and the American Bureau of Shipping.

Additional fire protection systems will be provided below deck for all accomodation spaces, machinery spaces, working areas and all other areas normally accessible to the crew. The systems will automatically sound the ship's fire alarm system when actuated. The alarm display boards will be installed in the wheel house and engine control room. Fire detection units protecting the gas compressor room and the cargo equipment motor room can actuate a visable and audible warning in the gas control room also. These fire detection systems will be powered from the emergency DC power circuits.

The accomodations, engine/boiler room, bow thruster room, port and starboard passageways and the enclosed areas will be protected by a salt water fire main system.

Portable fire extinguishers will also be provided, and the number, size, type and location will comply with United States Coast Guard regulations. The engine/boiler room will also be protected by a manually-released, CO_2 fire extinguishing system fixed in place.

In addition to the systems mentioned above, the burner hood containing the dual fuel burning equipment will be protected by a dry powder fire extinguishing system permanently installed. The system will be powered by nitrogen, and will automatically release when activated by a fusable line fire detector installed within the burner hood.

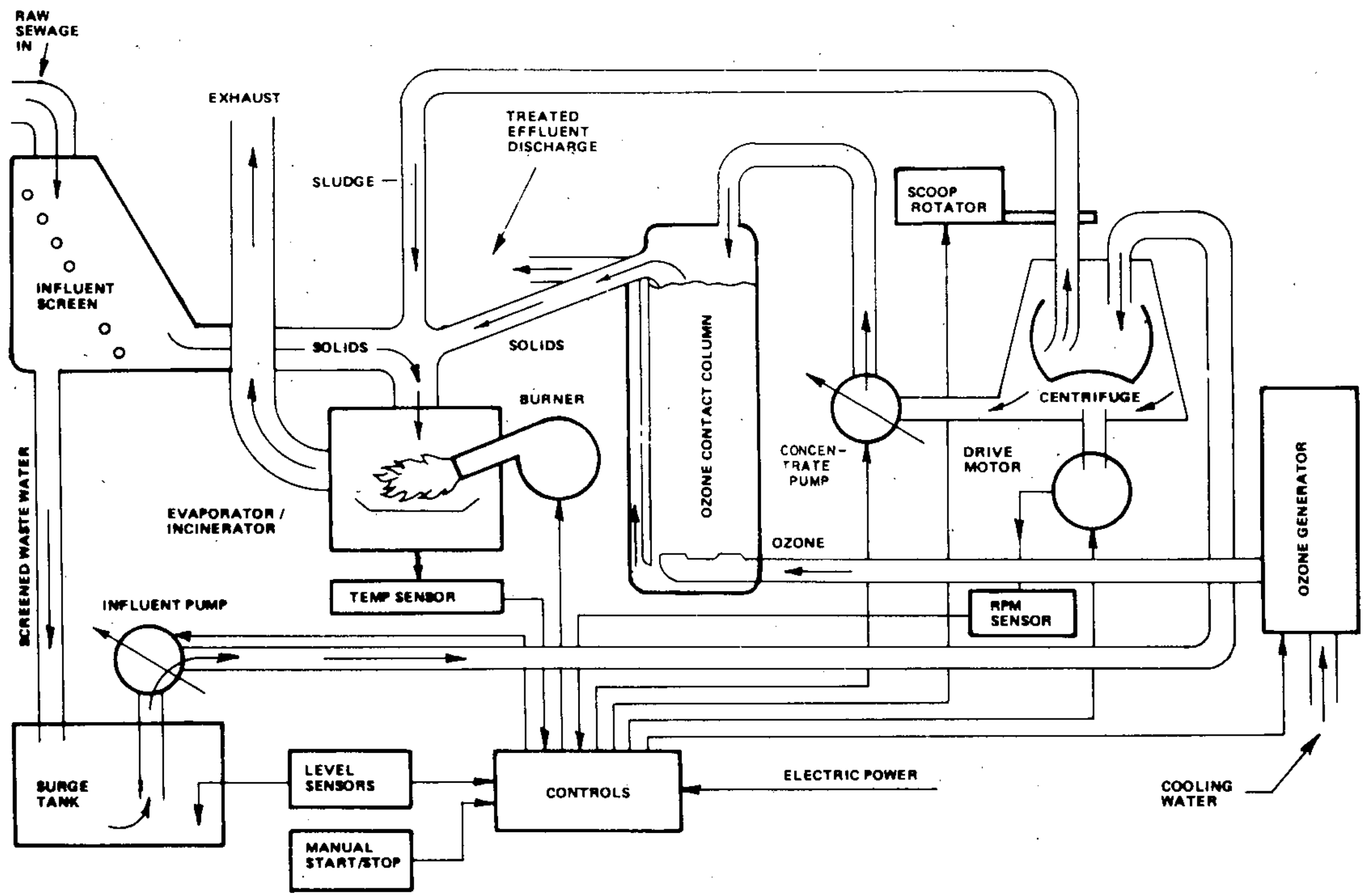
Provisions will be made for automatic shutdown of ventilating fans, fuel pumps and gas blowers when a fire hazard exists.

Sanitary Waste System

The sanitary system for the LNG tankers will incorporate the most advanced type of sewage treatment systems available. It will consist of a holding tank and a sewage treatment system. (See Figure 5.1-F9 on page 5.1-20.) While the LNG tanker is in port, all shipboard sanitary wastes will be treated, and the effluent, if any, will be retained in the holding tank. No effluent will be discharged in coastal waters. During normal operations at sea, all sanitary wastes will be treated by the sewage treatment system before discharge.

Typically, the ship will produce 35 gallons per capita per day ("gpcd") of sewage containing human wastes. Domestic waste quantities from showers, laundry and the galley will be approximately 35 gpcd for a total waste water generation of 70 gpcd. The size of the required holding tank will be determined when the United States Coast Guard establishes the final standards and regulations for shipboard sewage systems. At present, it is anticipated that a 15,000 gallon capacity tank will be used. This will be substantially greater than the required capacity of 70 gpcd for the crew over a five-day period.

The incinerator treatment plant will use both waste screening and centrifugation to remove the majority of solids, and will use ozonization for further disinfection. All solids and associated moisture will



TRANS-ALASKA GAS PROJECT

LNG CARRIER FLEET
TYPICAL SEWAGE
TREATMENT SYSTEM

FIGURE 5.1—F9

be eliminated by incineration and evaporation. The water effluent from the screening process will then be recycled for sanitary flushing, or discharged overboard when the LNG carrier is at sea.

Cooling Water System

A cooling water system will be required to remove the latent heat content of the exhaust steam in the condenser. Also, when the ship's energy needs are less than that provided by cargo boil-off, the excess boil-off will be burned in the boiler. Any surplus steam will be condensed in the main condenser to comply with the United States Coast Guard regulations. The shipboard condensers will discharge 60,000 gpm of cooling water at 6°F above intake conditions while under way. The discharge of the cooling water will spread and diminish to negligible temperature levels as a result of natural diffusion, wave action and the turbulence created by the vessel's displacement and propeller action. The condensers will discharge 60,000 gpm of cooling water at only 2°F above inlet conditions while the ship is berthed.

Pierside Loading Systems

The LNG cargo will be loaded into the shipboard cargo manifold by a set of five cargo handling arms located at the Alaskan Marine Terminal berths. Heated drip pans will be installed beneath the shipboard manifold to vaporize LNG leakage. The manifold and deck piping will be designed to drain automatically into the shipboard LNG cargo tanks when the LNG cargo loading pumps stop for any reason.

A smaller nitrogen loading arm will be capable of loading liquid nitrogen on board the LNG carrier, if required. Additional facilities will be located on board to allow the transfer of diesel fuel and Bunker "C" fuel. Potable water will be taken on board through interconnecting facilities.

Overboard Discharge Control Systems

Solid Wastes

Solid wastes will be compacted and then baled or ground for disposal when outside U. S. Coastal Zones and water ways.

Ballast Water

Normally, ballast water will neither be taken on nor discharged while the ship is at sea. Approximately 66,000 tons of ballast water will be taken on board in segregated ballast tanks while unloading LNG at the terminal in California. The ballast water will be discharged at the Alaskan Marine Terminal as LNG is loaded.

Bilge Water

Minor bilge water accumulations will occur during normal engine room operation, and minor quantities of lubricants from the ship's machinery may accumulate in the bilge water.

Bilge water accumulations at sea will be processed by an oil/water separator before being discharged to reduce the oil content to an acceptable level. The separator outlet will be equipped with an oily water detector which will stop the discharge of any effluent exceeding the appropriate regulatory standards. Effluent not meeting the discharge standards will be transferred to the holding tank for subsequent treatment.

LNG Carrier Manning

The LNG carrier will carry a 35-man crew. (See Table 5.1-T2 on the following page.)

The functions to be carried out by the ship's personnel are described by their classification. All stewards, cooks, messmen and galley boys will be assigned to the Steward's Section. The Deck Force will include the master, the mates, radio officer and the seamen. The engineering officer, engine room personnel, electricians and pump men will be assigned to the Engineering Section.

Crew Quarters

The LNG tankers will be at sea almost continuously so extensive crew quarters will be required onboard. Individual air-conditioned sleeping quarters will be provided for crewmen. There will be separate dining rooms and lounges for the officers and the crew. There will be provisions for recreation and hobby facilities. Included will be a hobby room; a swimming pool; a day room for the captain, chief engineer, first officer and first assistant engineer; an office for the captain and chief engineer; an engineer's office; a ship's office; an engineer's change room and a ship's laundry.

Shore Facility and Support Vessels

The LNG Carrier Fleet will include a Marine Administration Building located at Gravina Peninsula, containing offices, shops and warehouse space. The fleet will also provide two 4,400 horsepower tugboats and a 200 horsepower mooring launch at both the Alaskan Marine Terminal and the terminal located in California.

LNG CARRIER FLEET

LNG Carrier Crew

Rating	Number
Master	1
Chief Mate	1
2nd Mate	1
3rd Mate	1
Radio Officer	1
Bosun	1
Able Bodied Seaman	7
Ordinary Seaman	3
Total Deck Crew	16
Chief Engineer	1
1st Engineer	1
2nd Engineer	1
3rd Engineer	1
4th Engineer	1
Pumpman	3
Electrician	1
Repairer	1
Oiler	3
Total Engineering Personnel	13
Steward/Cook	1
Cook	1
Galleyboy	1
Messman	3
Total Stewards	6
TOTAL SHIP'S CREW	35

Note: The full complement of personnel (578) for the fleet is 50% greater than the number of crewmen (385) required to man eleven ships at any given time. The manning level arises from requirements for crew rotation, vacations, sick leave and personnel turnover.

SECTION 5.2

CONSTRUCTION

Table of Contents

Index to Figures and Tables

Figures

Tables

SECTION 5.2

CONSTRUCTION

The construction and delivery schedule for the LNG carriers is one which best interfaces the fleet buildup with the construction and start-up schedules for the LNG Plant and regasification plant storage and terminal facilities. Each of the four U. S. shipyards presently constructing LNG carriers has the capability to construct and deliver three "sister ships" within fifty-four months after the contracts are awarded. Normally, carriers can be delivered at six-month intervals, thereby providing a twelve-month buildup schedule.

Because the LNG Plant will be at full capacity fifteen months after the first natural gas processing train goes onstream, a twelve-month buildup schedule for the fleet is satisfactory.

The construction schedule (Figure 5.2-F1 on the following page) has been prepared on the basis of using four shipyards. Three yards will build three carriers each, and one will build two carriers.

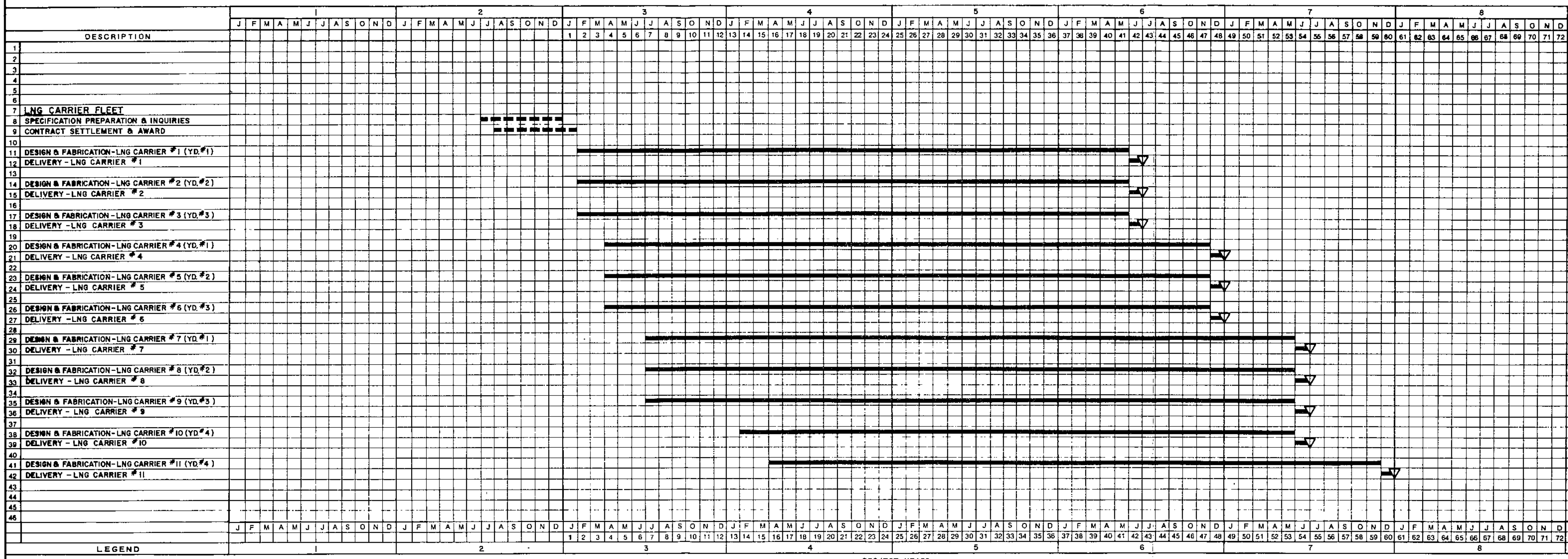
The major events which will take place during the construction of a carrier are the signing of the contract, laying the keel, launching, sea and gas trials and delivery. The delivery and in-service dates are noted on Figure 5.2-F1.

The shipyard will complete most of the design work and a sizable amount of the hull steel fabrication work before laying the keel. Once the steel arrives at the yard, it will be blasted and primed before the prefabrication of hull subassemblies begins. The piping, fittings and foundations will be under fabrication simultaneously with the subassemblies. After the keel laying, the main subassemblies and foundations will be erected.

Between the laying of the keel and the launching of the carrier, the yard will begin installing fittings, electrical cable, sheet metal hardware, machinery, structural insulation, main shafting and the propeller. After the carrier is launched, it will be taken to the outfitting dock, where the work already underway will be completed at the same time as the outfitting work.

The timing for installing the cargo tanks will depend on the cargo tank design. Normally, the membrane tanks and insulation are installed early in the construction schedule. Free-standing tanks, however, will generally be installed near the end of the construction program.

Prior to delivery, the carrier's cargo containment system, machinery and equipment will be tested at dockside and also at sea under



NOTE:

▽ - DATES WHEN LNG CARRIERS IN SERVICE

TRANS-ALASKA GAS PROJECT

LNG CARRIER FLEET
CONSTRUCTION SCHEDULE

FIGURE 5.2-F1

operating conditions. Tests will be conducted under the supervision of the representatives for the yard, the owners and the applicable regulatory agencies.

Sea trials will be conducted to assure that the carrier is fit for service and will perform according to the contract specifications regarding fuel consumptions, maneuvering, vibration, speed and other parameters. When the sea trials are completed, the performance of the cargo containment system will be tested by gas trials.

Testing the performance of the cargo containment system will be the last event before the ship is released by the yard for full service. The gas trials will be conducted by cooling and partially loading the tanks with LNG from a nearby source. During the trials, which are expected to last eight days, the overall cargo containment system performance will be tested; and the Coast Guard will verify that their regulations are satisfied.

Key dates for the construction schedule are shown in Table No. 5.2-T1 on the following page.

An average labor force of 10,700 shipyard employees will be required during the four-year construction period for the fleet. This number includes the employees of the cargo tank manufacturer, but not the employees of equipment vendors.

ALASKAN LNG FLEET

KEY TANKER CONSTRUCTION DATES

Ship No.	Yard No.	Contract	Keel	Launch	Gas Trials	Delivery	Full Service
1	1	January 31 (Year 3)	January 31 (Year 4)	January 31 (Year 5)	April 30 (Year 6)	May 31 (Year 6)	June 30 (Year 6)
2	2	January 31 (Year 3)	January 31 (Year 4)	January 31 (Year 5)	April 30 (Year 6)	May 31 (Year 6)	June 30 (Year 6)
3	3	January 31 (Year 3)	January 31 (Year 4)	January 31 (Year 5)	April 30 (Year 6)	May 31 (Year 6)	June 30 (Year 6)
4	1	January 31 (Year 3)	March 31 (Year 4)	March 31 (Year 5)	October 31 (Year 6)	November 30 (Year 6)	December 31 (Year 6)
5	2	January 31 (Year 3)	March 31 (Year 4)	March 31 (Year 5)	October 31 (Year 6)	November 30 (Year 6)	December 31 (Year 6)
6	3	January 31 (Year 3)	March 31 (Year 4)	March 31 (Year 5)	October 31 (Year 6)	November 30 (Year 6)	December 31 (Year 6)
7	1	January 31 (Year 3)	June 30 (Year 4)	June 30 (Year 5)	April 30 (Year 7)	May 31 (Year 7)	June 30 (Year 7)
8	2	January 31 (Year 3)	June 30 (Year 4)	June 30 (Year 5)	April 30 (Year 7)	May 31 (Year 7)	June 30 (Year 7)
9	3	January 31 (Year 3)	June 30 (Year 4)	June 30 (Year 5)	April 30 (Year 7)	May 31 (Year 7)	June 30 (Year 7)
10	4	January 31 (Year 3)	January 31 (Year 5)	January 31 (Year 6)	April 30 (Year 7)	May 31 (Year 7)	June 30 (Year 7)
11	4	January 31 (Year 3)	March 31 (Year 5)	March 31 (Year 6)	October 31 (Year 7)	November 30 (Year 7)	December 31 (Year 7)

SECTION 5.3

CAPITAL AND OPERATING COSTS

Table of Contents

Index to Tables

SECTION 5.3

CAPITAL AND OPERATING COSTS

Capital Cost Estimate

The estimated capital cost for designing, constructing and placing eleven 165,000 cubic meter tankers in service is $2,044,841,000, as shown in Table 5.3-T1 on the following page.

All costs shown in the table are based on information and data obtained during the last quarter of 1973. An exception was made, however, for the yard cost of the LNG tankers. This cost is actually a third quarter 1973 contract price for each of three 125,000 cubic meter tankers to be delivered in 1978 and 1979. While this procedure results in a mixture of time bases for cost estimation, it is nonetheless the best information available for shipyard costs as of late 1973.

Fleet Cost

The estimated capital cost of the LNG Carrier Fleet includes the yard costs of the eleven 165,000 cubic meter vessels at $138,600,000 each, plus the owner's burdens associated with constructing and preparing the ships for service.

Yard Cost

The estimated yard cost for the LNG carriers differs from other costs in the estimate because the yard cost is a "delivered cost" based upon the contract price of three 125,000 cubic meter LNG carriers which was negotiated in late 1973 for delivery in late 1978 and 1979. Added to that price are allowances for the increase in size to 165,000 cubic meters, ice strengthening and twin screw propulsion.

Estimates for all facilities included on Table 5.3-T1 other than the yard costs of the ships were based on economic conditions and information that existed in late 1973. Estimates of cost escalation have not been included.

Description		Cost
Delivered Price for a 125,000 cubic meter LNG Tanker		$107,500,000
ADD: Increased Capacity to 165,000 cubic meters	$26,200,000	
Ice Strengthening, Low Temperature Steel and Heating	1,200,000	
Additional Machinery, Twin Screws	3,700,000	
Subtotal		31,100,000
Total Cost for Each 165,000 Cubic Meter Vessel		$138,600,000

LNG CARRIER FLEET

Captial Cost Estimate
(In $1,000's)

Description	
Fleet Cost	
Yard Cost - 11 LNG Tankers	$ 1,524,600
Construction Supervision	19,437
Owner's Miscellaneous	4,576
Replacement Cost Insurance	6,644
Gas Trials	4,180
Subtotal	$ 1,559,437
Shore Facility and Support Cost	
Shore-based Structures and Equipment	
Buildings	$ 1,522
Service Vessels	11,900
Bunker "C", LN_2, and Diesel Facilities	4,186
Communications Equipment	30
Provisioning Containers	333
Spare Parts	4,551
Subtotal Shore-based Structures and Equipment	$ 22,522
Preoperating Expenses	
Crew Training and Indoctrination	$ 1,837
Initial Ship Voyage	4,928
Subtotal Pre-operating Expenses	$ 6,765
Intangible Plant, Capitalized Administrative and General, Engineering Expenses and Consultant Fees	
Intangible Plant	$ 1,500
Administrative Expenses	3,825
Engineering Expenses and Consultant Fees	11,224
Subtotal Intangible Plant, Capitalized Administrative and General, Engineering Expenses and Consultant Fees	$ 16,549
Provision for Working Capital	37,656
Subtotal Shore Facility and Support Cost	$ 83,492

LNG CARRIER FLEET

Capital Cost Estimate
(In $1,000's)

(Continued)

Description	
Capitalized Financing Cost	
Title XI Investigation Fee	$ 1,826
Allowance for Funds Used During Construction	
Interest on Borrowed Funds	$ 210,423
Allowance to Equity Funds	189,663
Subtotal AFC	$ 400,086
Subtotal Capitalized Financing Cost	$ 401,912
TOTAL CAPITAL REQUIREMENTS	$ 2,044,841

The extra cost for the capacity increase was based on a cost engineering analysis of the charges required to increase the capacity from 125,000 cubic meters to 165,000 cubic meters.

The provision for low temperature steel and ice strengthening is sufficient to meet the Class 1-B (medium ice conditions) design requirements established by the American Bureau of Shipping. The proposed location of the Alaskan Marine Terminal does not require additional strengthening for ice conditions.

The ships which will be used for the Alaskan trade will not be eligible for a Maritime Administration construction differential subsidy, even though they will be built in United States shipyards and financed under Title XI Provisions of the Merchant Marine Act of 1970.

Construction Supervision

The owners of LNG ships will incur costs during design and construction of the ships both at the yard and at the home office. These predelivery costs will include design studies, plan approval, construction inspections and other ancillary expenses related to the owner's supervision and inspection of the ship construction program.

Owner's Miscellaneous

This is the cost associated with initially stocking each ship with equipment and outfitting items not provided by the shipyard, but which are required for the vessel to function at sea. Included in this catagory are such items as hand tools, medicine and hospital supplies, galley equipment and maps; however, the inventory of the ship's spare parts are not included.

Replacement Cost Insurance

During the construction period, replacement cost insurance will be provided at the owner's expense to recover progress payments, accumulated interest paid on the progress payments, and escalation costs in case of loss during construction.

Gas Trials

The gas trials will be conducted by the shipyard before the ship is delivered to the owner. Approximately 6,800 cubic meters of LNG will be required to cool the tanks and to test the cargo system. The cost of gas trials includes all out-of-pocket operating expenses to the owner and the cost of the LNG.

Shore Facility and Support Cost

These capital costs include estimates for facilities required to provide support services to the fleet at both terminals plus the pre-operating and organizing expenses incurred by the fleet organization during the construction period.

Shore-Based Structures and Equipment

The shore-based structures and equipment are the facilities at each terminal which will support the LNG Carrier Fleet operations. A detailed breakdown of these costs are included in Table No. 5.3-T2 on the following page.

Accommodations will be provided for the supervisory administrative and operating personnel. Four tugboats and two mooring launches are included in this cost for fleet service vessels used at the terminals. Additional facilities will be provided for communications equipment, Bunker "C" and low sulfur diesel fuels and liquid nitrogen transfer. Also, equipment and space will be available for handling, storing and loading provision containers.

The spare parts for the carriers and tugboats are included in the cost of shore-based structures and equipment. Each carrier will normally carry a limited supply of spares onboard, but they will be replenished from ashore.

Pre-Operating Expenses

Pre-operating expenses include the cost of hiring and training the ship's crew plus the cost of the initial voyage for each carrier from the shipyard to the Alaskan Marine Terminal and for each tugboat to either the Alaskan Marine Terminal or the Point Conception terminal.

Intangible Plant, Capitalized Administrative and General, Engineering Expenses and Consultant Fees

These intangible costs are the marine-related costs of initiating and mounting the LNG project. Included are the administrative expenses which will be accumulated throughout the construction period and extending through the first full delivery of LNG. Also included are fees to consultants and expenses incurred by applicant for studies investigating the technical, financial, engineering, operational and economic aspects of the project.

Provision for Working Capital

Working capital provides a continuous source of funds needed to meet short-term obligations for cash expenses and other prepayments related to fleet operations.

1)	Provision for Minimum Bank Balance	$ 4,574,000
2)	Forty-five Days' Cash Operating Expenses	$ 5,161,000
3)	Prepayment of First Year's Ship Insurance Premium	$ 27,921,000
	Total Working Capital	$ 37,656,000

Table No. 5.3-T2

LNG CARRIER FLEET

Capital Cost of Shore-Based Structures and Equipment

Description	Liquefaction Terminal	Regasification Terminal	Total Cost
Direct Cost			
Buildings			
Administrative Offices and Laboratories	$ 398,000	$ 376,000	$ 774,000
Warehouse and Workshop Space	317,000	401,000	718,000
Total Buildings	$ 715,000	$ 777,000	$ 1,492,000
Service Vessels			
Four Tugboats	$ 5,748,000	$ 5,736,000	$ 11,484,000
Two Mooring Launches	125,000	125,000	250,000
Total Service Vessels	$ 5,873,000	$ 5,861,000	$ 11,734,000
Liquid Nitrogen Transfer	291,000	189,000	480,000
Bunker "C" Storage and Transfer	--	1,576,000	1,576,000
Diesel Storage and Transfer	180,600	211,000	391,600
Communications Equipment	16,500	12,500	29,000
Fleet Spare Parts	--	4,334,000	4,334,000
Provisioning Containers	--	327,156	327,156
Total Direct Cost	$ 7,076,100	$13,287,656	$ 20,363,756
Indirect Cost	529,500	1,628,744	2,158,244
Total Cost - Shore-Based Structures & Equipment	$ 7,605,600	$14,916,400	$ 22,522,000

Capitalized Financing Cost

Title XI Investigation Fee

The Marad Title XI Investigation Fee will be paid to the Maritime Administration to reimburse them for costs incurred to process the application for Title XI ship financing.

Allowance for Funds Used During Construction

In general terms, the allowance for funds used during construction includes the financial charges incurred from the time carrier progress payments and other construction drawdowns begin until each ship is delivered, or until the permanent fleet financing is initiated.

The shipyard requires that progress payments be made according to a predetermined schedule during the design and construction period of approximately four years. During this period, the owner will incur short-term financing charges which will become a part of the cost of the carrier when it is financed long-term.

The AFC charges are calculated for all capital costs shown in Table No. 5.3-T1 on page 5.3-2.

Capital Cost Cash Flow Schedule

The cash flow schedule for the total LNG Carrier Fleet capital requirements is shown in Table No. 5.3-T3 on the following page. The costs are divided into three primary groups: Fleet Cost, Shore Facility and Support Cost; and Capitalized Financing Costs.

Operating Costs

The total annual operating expenses for the fleet of LNG ships is projected to approximate $69.1 million. This estimate is summarized in Table No. 5.3-T4 on page 5.3-10. Costs were estimated for both carrier and shoreside expenses on the basis of information and economic conditions that existed in late 1973.

These expenses include the cost of the crews, vessel maintenance and repairs, consumables, insurance, port charges and miscellaneous administrative expenses. Shoreside expenses have been estimated for the service vessel crews, maintenance, fuel, insurance, shoreside administration and ad valorem taxes.

Carrier Expenses

Operating Labor

The annual payroll for the carrier's crew includes their basic wages, bonuses, vacation, overtime and benefits. Once a crew member is signed on, the carrier owner must also provide for his subsistence and repatriation.

LNG CARRIER FLEET

Estimated Capital Expenditures

Project Year Number	Quarter	Fleet Cost	Shore Facility & Support Cost	Capitalized Financing Cost	Total Capital Requirements
1	1		$ 574,000(1)	$ 15,000	$ 589,000
	2		556,000	35,000	591,000
	3		687,000	61,000	748,000
	4		918,000	95,000	1,013,000
2	1		661,000	131,000	792,000
	2		717,000	164,000	881,000
	3		773,000	200,000	973,000
	4	$ 1,812,000	791,000	784,000	3,387,000
3	1	2,653,000	885,000	932,000	4,470,000
	2	10,654,000	791,000	1,201,000	12,646,000
	3	44,215,000	770,000	1,496,000	46,481,000
	4	86,092,000	747,000	3,441,000	90,280,000
4	1	139,427,000	726,000	6,516,000	146,669,000
	2	156,226,000	3,685,000	10,474,000	170,385,000
	3	163,809,000	1,286,000	15,041,000	180,136,000
	4	174,617,000	1,275,000	19,932,000	195,824,000
5	1	171,248,000	3,874,000	25,116,000	200,238,000
	2	142,051,000	2,872,000	30,063,000	174,986,000
	3	110,188,000	2,884,000	34,345,000	147,417,000
	4	91,520,000	3,257,000	38,103,000	132,880,000
6	1	80,010,000	5,563,000	41,640,000	127,213,000
	2	61,950,000	13,335,000	44,910,000	120,195,000
	3	41,502,000	3,985,000	36,390,000	81,877,000
	4	33,970,000	11,955,000	33,668,000	79,593,000

LNG CARRIER FLEET

Estimated Capital Expenditures
(Continued)

Project Year Number	Quarter	Fleet Cost	Shore Facility & Support Cost	Capitalized Financing Cost	Total Capital Requirements
7	1	$ 21,055,000		$ 21,334,000	$ 42,389,000
	2	17,828,000	$11,955,000	22,442,000	52,225,000
	3	5,007,000	3,985,000	8,881,000	17,873,000
	4	3,603,000	3,985,000	4,502,000	12,090,000
TOTAL		$1,559,437,000	$83,492,000	$401,912,000	$2,044,841,000

(1) Includes estimated capital expenditures charged to "Intangible Plant" prior to project initiation.

Table No. 5.3-T4

LNG CARRIER FLEET

Annual Operating Expenses

Description	Amount (In $1,000's)
Carrier Expenses	
Operating Labor	
Crew (Includes Wages, Benefits)	$ 12,034
Crew Subsistence	550
Crew Repatriation	66
Total Operating Labor	$ 12,650
Maintenance and Repair Labor and Material	$ 4,623
Consumable Supplies	
Stores	$ 825
Fuel Oil	15,982
Liquid Nitrogen	620
Total Consumable Supplies	$ 17,427
Insurance	$ 27,801
Ship Miscellaneous Administration Expenses	$ 241
Port Charges	$ 1,658
Total Ship Operating Expenses	$ 64,400
Shoreside Expenses	
Operating Labor	
Crews for Service Vessels	$ 1,059
Labor for Pier Work and Service	702
Total Operating Labor	$ 1,761
Maintenance Labor and Materials	$ 401
Utilities	18
Tugboat and Launch Fuel	368
Insurance	181
Shoreside Administration	1,700
Ad Valorem Taxes	257
Total Shoreside Expenses	$ 4,686
TOTAL FLEET OPERATING EXPENSES	$ 69,086

The crew costs are based on the wage rates and benefits packages agreed upon by trade associations and unions from which the carrier owner acquires his crews.

Maintenance and Repair Labor and Material

To estimate the maintenance and repair expenses, a maintenance schedule was developed which will be in effect for the projected 25 year life of the fleet. This schedule (Table No. 5.3-T5 on the following page) provides for drydocking the carriers once every year, and provides for an American Bureau of Shipping survey of hull and machinery and United States Coast Guard inspections. The overall maintenance plan requires certain tasks to be performed each year with a check list of specific equipment and parts which should be replaced, repaired, or inspected at these times. A major maintenance survey of the carrier will be made every five years.

The type of cargo containment system employed may affect the cost of carrier maintenance repairs; however, available information does not indicate a difference in maintenance costs for the acceptable cargo containment systems. The hull and machinery are the parts of the carrier that normally require the greatest amount of maintenance.

Consumable Supplies

The supplies which the carrier will consume over the course of its voyage are fuel oil, LNG boil-off, liquid nitrogen and stores. The stores expense (Table No. 5.3-T6 on page 5.3-13) covers supplies used to run the carrier such as lubricating oils, cleaning supplies, paint, rope, etc.

The cost of the LNG boil-off to be used for fuel will be absorbed by the owner of the LNG. The quantity of LNG boil-off is the difference measured in Btu between LNG loaded at the LNG Plant and the LNG to be unloaded at the LNG terminal at Point Conception, California. The balance of the fuel requirements will be obtained by using 431,950 long tons of fuel oil per year and is included in the consumable supplies cost.

Nitrogen will be used to pressurize the voids and insulation spaces between the cargo tanks and the inner hulls of the carrier to prevent the accumulation of ice or combustible gas mixtures. The onboard supplies of liquid nitrogen must be replenished at regular intervals.

Insurance

The insurance expenses will include three categories of insurance for the LNG carriers while they are in operation. The cost of this total coverage has been estimated on the basis of the coverage available and the most recent rates for those coverages.

Table No. 5.3-T5

LNG CARRIER FLEET

Typical Annual LNG Tanker Maintenance and Repairs

General

- ABS Survey
- USCG Survey
- Dry Docking
- Engineering Services
- Port Charges
- Contractor Services
- Insurance Claims

Hull Systems

- Structural Survey
- Painting
- Deck Machinery
- Hull Piping Systems
- Bow Thruster System
- Lifesaving Equipment
- Navigation Equipment
- Accommodation Systems
- Communication Equipment
- Emergency Systems
- Steering Systems

Machinery Systems

- Prime Mover
- Steam Generators
- Shafting System
- Fire Protection System
- Condensers
- Auxiliary Systems
- Fuel Oil System
- Lube Oil System
- Electric Generators
- Electrical Distribution Systems
- Motors
- Control Systems
- Instrumentation
- Bilge and Ballast Systems

Cargo Systems

- Containment System
- Liquid Cargo Handling
- Warm Up and Cool Down Systems
- Instrumentation Systems
- Control Systems

Table No. 5.3-T6

LNG CARRIER FLEET

Annual LNG Tanker Stores and Equipment

DECK DEPARTMENT

Cleaning Supplies & Equipment
Lubricants, Oils & Greases
Paint & Painting Equipment
Tools
Hardware
Coast Guard Requirements
Cargo Equipment
Rope and Cordage
Stationery and Printing
Charts & Navigational Equipment
Medical Supplies & Equipment
Miscellaneous

STEWARD DEPARTMENT

Cleaning Supplies & Equipment
Expendable Equipment
Equipment Requirements for Union
Miscellaneous

ENGINE DEPARTMENT

Cleaning Supplies & Equipment
Lubricants, Oils & Greases
Paint and Painting Equipment
Tools
Hardware
Boiler Testing Equipment & Supplies
Electrical Supplies & Fittings
Refractory Supplies
Diesel Fuel for Misc. Equipment
Gaskets and Packing
Valves
Welding Gases & Equipment
Stationery and Printing
Miscellaneous

The basic insurance will cover the replacement cost of the hull and machinery including 100% coverage in the event of a collision, act of war or insurrection. The value placed upon the vessel is the cost to construct a replacement vessel and place it in operation, which includes the yard and financing costs plus the owner's burdens exclusive of gas trials.

Protection and Indemnity coverage, which is a marine liability coverage for both the vessel and crew, will also be provided.

The third coverage category is cargo insurance, which insures against the loss of cargo at the value assigned to the cargo at the delivery ports. This will normally be paid by the owner of the cargo.

Ship Miscellaneous Administrative Expenses

Miscellaneous administrative expenses are the overheads which are not readily identifiable with other expenses. These would include such things as medical examinations for the ship's personnel, equipment rentals, maintenance of petty cash funds, postage and telephone fees and other services which, from time to time, may be directly incurred by the tankers, yet not related to the shoreside administration expenses.

Port Charges

Normally, whenever a ship enters and leaves a port, a cost is incurred for pilots, tugs, berthing, casting off and other fees. The port charges published by the Los Angeles and San Francisco Port Authority were used as the basis for the California fees, inasmuch as they are the primary West Coast seaports. The limited amount of present traffic into the Gravina Point area made it difficult to provide an accurate fee for each entry and departure. The estimate for Alaska is based on current fees levied on ships calling at Cordova. Since tugboats and line handlers will be provided by the fleet, these charges were deleted from the estimated tariff.

Shoreside Expenses

The fleet will need support services from the various functions carried out on shore at each terminal. A certain amount of operating labor will be necessary for the service vessels, line handling and fleet-oriented terminal activities. Also, the service vessels will require maintenance and fuel supplies in conjunction with the administrative, maintenance, utility and insurance expenses for the other shore-based facilities.

Operating Labor

The tugboats will normally require a crew of five to eleven members, depending on how the vessels will be operated. The launches will be operated by one or two persons asssigned part-time from the plants.

A work force will be required for dock and cargo transfer supervision, line handling, container storing and transfer, and for loading Bunker "C" and liquid nitrogen.

Maintenance Labor and Materials

The tugboats will require routine maintenance as will the buildings and pumps and storage tanks for Bunker "C" and low sulfur diesel oil.

Utilities

This item covers the cost of required heating and lighting for the dock administration building, warehouses and workshops at both terminals.

Tugboat and Launch Fuel

This item covers the cost of 1,224,900 gallons of fuel which the tugboats and mooring launches will consume annually during routine operation.

Insurance

Normal plant insurance coverages for the buildings and equipment at each terminal are provided for in this cost. The insurance coverage for the service vessels, especially the tugboats will be similar to the coverage for conventional ships.

Shoreside Administration

The shoreside administration cost is incurred to manage the marine transportation system. An organization will be formed which will be responsible for handling administrative details of the project for the shipping segment.

The administrative organization will include a home office executive staff with underlying departmental managers and a secretarial staff, plus a port staff, consisting of managers and technicians. The procedures for invoicing, measurement, cost classification and accounting and other office tasks will also require a home office section of accountants, data processing specialists and clerks.

Ad Valorem Taxes

The ad valorem taxes estimated for the fleet terminal facilities apply only to the original cost of the buildings and equipment. The tugboats are taxed by weight under Alaskan law, and by a mil levy under California law. The estimate provides for the variations in the two states' taxation laws.

SECTION 5.4

DESIGN CRITERIA

Table of Contents

Index to Figures and Tables

Figures

Tables

SECTION 5.4

DESIGN CRITERIA

Project Scope

The LNG Carrier Fleet will transport an average equivalent of 2,864 million cubic feet per day of liquefied natural gas from Gravina Peninsula in Alaska to Point Conception in California, a distance of 1,902 nautical miles. The most desirable fleet design was determined to be eleven 165,000 cubic meter cargo tankers. Each ship will have an average service speed of 18.5 knots, and will be capable of completing a round trip in approximately eleven and one-half days.

Major Design Considerations

The design of the LNG Carrier Fleet was influenced by four interrelated major considerations. These factors are defined below, and will be discussed more fully in subsequent paragraphs.

Material Balance

The fleet was designed to transport all the LNG produced at the Alaskan LNG plant to California with a minimum of delay. The design was complicated by the necessity of coordinating an intermittent and variable flow process imposed by the LNG carrier transportation system with the constant flow process employed at the liquefaction and regasification plants.

Fleet Sizing

The number of carriers to be built, the cargo capacity of each carrier and the carrier service speed are all variables that affect the transportation capacity of the LNG Carrier Fleet. Other important parameters affecting the fleet size are the amount of time required for loading and unloading cargo, the time each vessel is out of service, the trade route followed, and the weather conditions that may be encountered by the ships while they are underway or in port. A simulation technique was employed to evaluate 400 different combinations of parameters before the proposed fleet configuration was selected.

Available Technology

The LNG Carrier Fleet will be designed to incorporate the most recent innovations presently used on the nineteen LNG tankers in operation. Proposed improvements considered for use in the 54 LNG tankers currently under construction have also been investigated. Five cargo containment systems, discussed in detail in the Description of Facilities section, are considered by applicant to be acceptable for use in the LNG Carrier Fleet.

Capital and Operating Cost

The LNG Carrier Fleet design will implicitly minimize the operating revenue requirements.

Material Balance

It was established that the LNG Carrier Fleet should be capable of transporting 100% of the Alaskan LNG Plant output each year.

Gas Composition

The transportation capacity of an LNG carrier which will carry a predetermined quantity of energy in the form of liquefied natural gas depends on the composition of the cargo. For the purpose of establishing a carrier design, it was presumed that the product pumped onboard at the Alaskan Marine Terminal would have a specific density ranging from 0.42 to 0.50 and a low temperature of -260°F. This presumption was derived from a typical gas analysis shown below:

Component		Mole %
Nitrogen	N_2	0.06
Methane	C_1	86.66
Ethane	C_2	8.37
Propane	C_3	4.25
Iso-Butane	iC_4	0.28
Normal Butane	nC_4	0.32
Pentanes Plus	C_5+	0.06
Molecular Weight		18.72
Gas/Liquid Volume Ratio		593:1
Gross Heating Value - Btu/cf		1157.8

The LNG Plant output will be the equivalent of 2,864 MMcf/cd of natural gas with an energy content of 1157.8 Btu/cf. The total energy output per year is estimated at 1,210,322,000 MMBtu. The LNG will be stored in four 550,000-barrel cryogenic storage tanks that will supply the LNG Carrier Fleet through the loading facilities located at the Alaskan Marine Terminal. It was presumed that the chemical composition of the LNG will not vary significantly during storage and loading.

The carrier vessel was assumed to be capable of loading only 98% of its rated cargo capacity in accordance with United States Coast Guard regulations. During transport to California, the LNG boil-off will change the chemical composition of the LNG delivered to Point Conception. These estimated changes are presented in Table 5.4-T1 on the following page. As a result of the boil-off, the heating value of the LNG increases slightly to 1160.2 Btu/cf.

Table No. 5.4-T1

LNG CARRIER FLEET

Composition and Properties of LNG Lifted at Gravina Peninsula and Delivered to Point Conception

Component	Loaded at Gravina Peninsula (Mole %)	Delivered to Point Conception (Mole %)
Nitrogen, N_2	0.06	0.05
Methane, C_1	86.66	86.47
Ethane, C_2	8.37	8.49
Propane, C_3	4.25	4.32
Iso-butane, iC_4	0.28	0.28
Normal Butane, nC_4	0.32	0.33
Pentanes Plus, C_5+	0.06	0.06
Other Properties		
Gas/Liquid Volume Ratio[1]	593:1	592.1
Molecular Weight	18.72	18.74
Gross Heat Value Btu/cf	1157.8	1160.2

[1] Gas volume at 14.73 psia and 60°F divided by liquid volume at 15.5 psia and LNG boiling temperature.

Energy Consumption

The LNG boil-off will be used to fuel the LNG carriers. The heel which remains in the tanks after unloading will be used to cool the cargo containment system on the return trip to Alaska. It was estimated that the total energy use for these purposes would be 20,575,000 MMBtu per year.

The energy balance is shown below:

Description	Energy in MMBtu/yr
LNG Lifted at Gravina Peninsula	1,210,322,000
Less: Boil-off	20,575,000
LNG Delivered to Regasification	1,189,747,000

Based on these estimates, the LNG Carrier Fleet will consume an average equivalent of 54.51 MMcf of natural gas per day, while delivering to California an equivalent of 2809.50 MMcf per day.

Fleet Sizing

Marine Transportation Trade Route and Passage Time

The fleet design is based on the assumption that the great circle route will define the trade route from the Alaskan Marine Terminal to California. This will result in a northwest by southeast course of 1,902 nautical miles from Gravina Peninsula to Point Conception.

It was further assumed that the carriers could steam in the open sea at an average speed of 18.5 knots. For simulation purposes, it was assumed that the ship's speed would be reduced to approximately 14 knots when the ship was within six miles of the Alaskan Marine Terminal and the speed would be reduced to approximately 10 knots within ten miles of the terminal at Point Conception.

Fleet Operation Simulation

In recent years, LNG carrier design has been restricted to the 125,000 cubic meter vessel size for reasons which included trade route restrictions, shallow terminal waters and the size of the various LNG projects.

The LNG Carrier Fleet design was based on several simulations in which an evaluation was made of all possible combinations of the following parameters: ten different carrier cargo capacities ranging from 130,000 to 200,000 cubic meters; five different service speeds ranging from 17.5 knots to 22.0 knots; and eight different fleet sizes ranging from five to twelve ships. This resulted in a total of 400 combinations being investigated. See Table 5.4-T2 on the following page.

Ship Service Time

It was also assumed during the fleet simulation that each carrier would be available for 330 days. Thirty-five days were allotted for drydocking, random repairs and delays. The projected out-of-service time is shown in Table 5.4-T3 on page 5.4-7.

It was anticipated that drydocking for annual surveys and repairs would require a total of twenty days. Fourteen days were scheduled for the actual drydocking. Two days were allowed to sail to the yard, and to gas free, warm up, inert and aerate the tanks so they can be entered safely for inspection. The four final days of the twenty-day period were scheduled for the carrier to return to its service route and to cool down its tanks in preparation for cargo loading.

It was estimated that unscheduled, out-of-service time will equal fifteen days. These days were allotted for repairs and maintenance not requiring drydocking and for other delays.

Scheduled LNG Plant maintenance was assumed to coincide with carrier drydockings during late spring, summer and early fall. This will minimize energy flow variations when maximum flow is demanded.

Port Events and Times

The activities of the marine transportation system were simulated using the sequence of events and interfaces shown in Table No. 5.4-T4 on page 5.4-8 and in Figure 5.4-F1 on page 5.4-9. The estimated duration of each event within the port routine is shown in Table No. 5.4-T5 on page 5.4-10.

These event durations were based on experience of other LNG vessels performing similar operations. The loading and discharge times were based on the estimated pumping rates for a 165,000 cubic meter vessel.

To simulate fleet operating conditions as closely as possible, the duration of each event time was randomly selected within the design limits established. Events with an uncertain time duration such as loading and unloading times, were stochastically selected by the fleet simulator within the maximum and minimum times.

Simulation Results

After possible fleet configurations were analyzed with the fleet simulator, it was determined that a fleet of eleven 165,000 cubic meter vessels with an average service speed of 18.5 knots would best serve the trade route between Point Conception and Gravina Peninsula.

LNG CARRIER FLEET

Fleet Configuration Combinations

Ship Size

Ten Capacities (Cubic Meters):	130,000; 140,000; 150,000; 155,000; 160,000; 165,000; 170,000; 175,000; 185,000; 200,000

Ship Speed

Five Speeds (Knots):	17.5; 18.5; 19.5; 21.0; 22.0

Fleet Size

Eight Sizes (Number of Vessels):	5; 6; 7; 8; 9; 10; 11; 12

Array = 10 Capacities x 5 Speeds x 8 Sizes

= 400 Possible Combinations

Table No. 5.4-T3

LNG CARRIER FLEET

Ship Out-of-Service Time

Description		Days/Year
Assumed Operating Year		365
Ship Out-of-Service Time		
Drydock Schedule		
Drydock Time	14	
Voyage to Yard and Gas Free	2	
Return to Service Route and Cool Down	4	
Total Scheduled Drydock Time	20	20
Random Repair and Delay		15
Total Ship Out-of-Service Time		35
Annual Ship Utilization Time		330

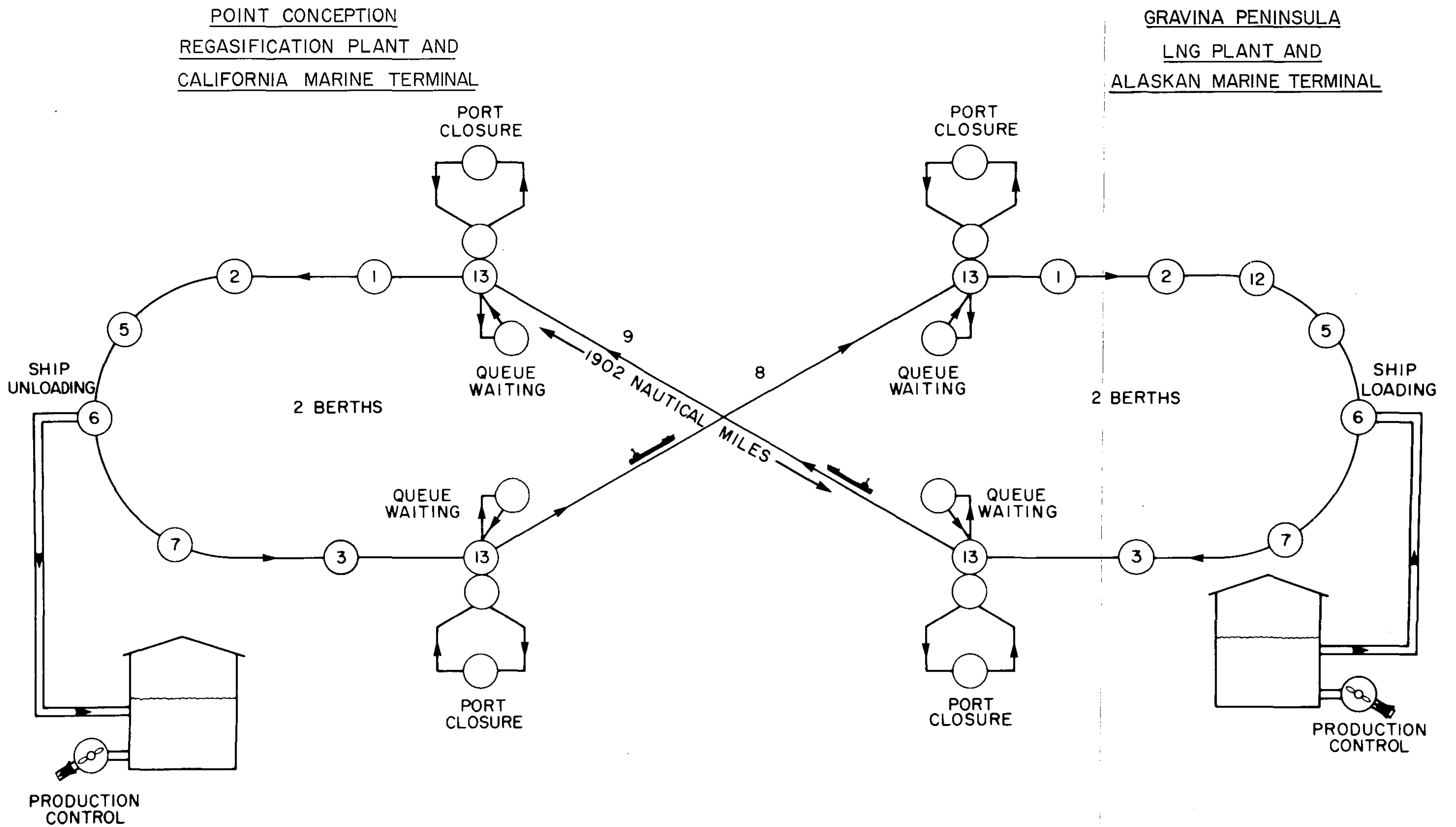
Table No. 5.4-T4

LNG CARRIER FLEET

Simulation Event Description

LNG Plant		Regasification Plant	
Event No.*	Description	Event No.	Description
11	Drydock	13	Port Closure (Storm Queue)
13	Port Closure (Storm Queue)	1	Berth Wait
1	Berth Wait	2	Tie-in
2	Tie-in	5	Unloading Line Wait
12	Cool Down	6	Unload
5	Loading Line Wait	7	Cast Off
6	Load	3	Random Repair and Delay
7	Cast Off	13	Port Closure (Storm Queue)
3	Random Repair and Delay	8	Unloaded Voyage
13	Port Closure (Storm Queue)		
9	Loaded Voyage		

*See pictorial representation of events by number in Figure 5.4-F1 on the following page.



NOTE:
REFER ALSO TO TABLE 9

TRANS-ALASKA GAS PROJECT

LNG CARRIER FLEET
MARINE TRANSPORTATION SYSTEM

FIGURE 5.4–F1

Table No. 5.4-T5

LNG CARRIER FLEET

Average Event Times for Port Routines Per Voyage

Event	Gravina Peninsula Alaska (Hours)	Gravina Peninsula Alaska (Days)	Point Conception California (Hours)	Point Conception California (Days)
Tie-In Time				
Pick Up Pilot at Pilot Station	1.5		0.5	
Delay in Pilotage Waters	1.0		1.0	
Mooring	1.5		1.5	
Connecting Lines and Cargo Gauging	2.0		2.0	
Average Total	6.0	0.250	5.0	0.208
Pumping Time				
Average	14.6	0.608	14.6	0.608
Cast-Off Time				
Disconnect Lines and Cargo Gauging	2.0		2.0	
Cast Off	1.5		1.5	
Delay in Pilotage Waters	1.0		1.0	
Drop Pilot	1.0		0.5	
Average Total	5.5	0.229	5.0	0.208

Note: The above average total times are maximum values. A reduction in the total time may be achieved by simultaneous occurrence of some of the scheduled events.

Available Technology

The LNG carrier design will be similar to the 125,000 cubic meter cargo capacity vessels presently under construction. See Figure 5.4-F2 on the following page and Table No. 5.4-T6 on page 5.4-13 for an illustration of the typical characteristics of the smaller vessel.

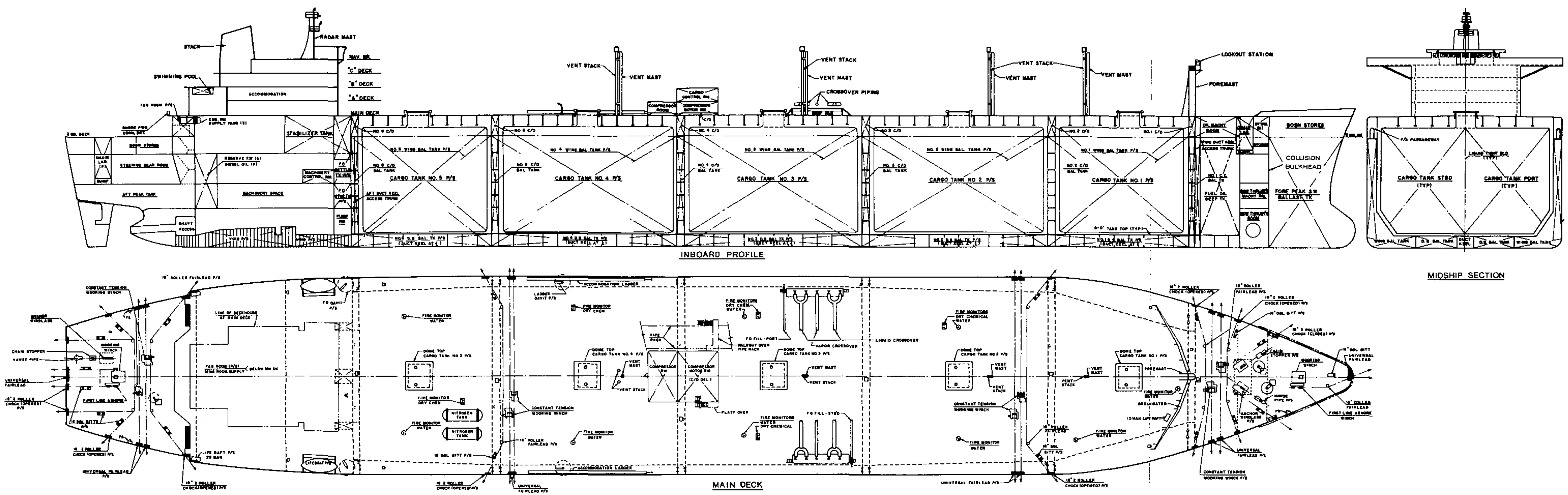
The double hull system, machinery and propulsion components and the instrumentation and control systems are typical for LNG carriers and incorporate accepted design concepts. A detailed description of these components may be found in the Description of Facilities section.

The cargo containment system for each carrier in the LNG Carrier Fleet will be either of the "free-standing" tank design or of the "membrane" design. Systems under consideration by the applicant include the spherical tank design offered by either Kvaerner-Moss or Chicago Bridge and Iron, the Conch free-standing tank and the Gaz-Transport and Technigaz membrane tanks. Detailed descriptions of these cargo containment systems and their comparative design features may be found in the Description of Facilities.

Regulations and Codes

The LNG Carrier Fleet design will meet or exceed all applicable Federal, state and local laws and regulations and orders, including those promulgated by the United States Coast Guard and the American Bureau of Shipping. In addition, the design will comply with the guidelines established by the International Conventions on Load Lines and on Safety of Life at Sea and other applicable conventions and agreements. The fleet design will be in accordance, whenever possible, with the recommendations of the Intergovernmental Maritime Consultive Organization. This specialized agency of the United Nations is currently drafting a code of international regulations that will recommend uniform standards for the construction and operation of various types of ocean-going vessels, including LNG tankers.

The American Bureau of Shipping and the United States Coast Guard have issued regulations which are specifically applicable to LNG tankers. The Coast Guard regulations for LNG tankers are contained in Title 46, Code of Federal Regulations and also in the "Tentative Guide for the Review of Liquefied Flammable Gas Carriers." These Coast Guard regulations concerned with the design and operation of LNG tankers are currently being revised. The revision was necessitated by advancing technology in the construction of LNG tankers and the increasing requirements for more and larger LNG tankers to meet the future energy requirements of the United States. The United States Coast Guard Chemical Transportation Industry Advisory Committee Task Force for LPG/LNG has been assisting the Coast Guard in formulating new United States regulations for liquefied flammable gas carriers.



GENERAL ARRANGEMENT

TYPICAL PRINCIPAL CHARACTERISTICS

LENGTH OVERALL.......935 FEET
LENGTH BETWEEN PERPENDICULARS......885 FEET
BEAM.......140 FEET
DEPTH OF HULL.......96 FEET
DRAFT.......36 FEET
BLOCK COEFF.......0.75
DISPLACEMENT.......95000 LONG TONS

CLASSIFICATION

AMERICAN BUREAU OF SHIPPING ✠ AI Ⓔ

LIQUEFIED GAS CARRIER ✠AMS ✠ACC

LEGEND

P/S - PORT AND STARBOARD
S.W. - SALTWATER
F.W. - FRESH WATER
F.O. - FUEL OIL
DBL - DOUBLE
C/D - COFFERDAM
F/A - FORE AND AFT
D.B. - DOUBLE BOTTOM

TRANS-ALASKA GAS PROJECT

LNG CARRIER FLEET
TYPICAL 125,000 M^3 LNG TANKER
CONCH CARGO SYSTEM
FIGURE 5.4–F2

Table No. 5.4-T6

LNG CARRIER FLEET

Principal Characteristics of a 125,000 m^3 LNG Tanker

LNG Capacity, 100% Cold	125,000 m^3
Length Overall	932 Feet
Length Between Perpendiculars	887 Feet
Beam	140 Feet
Depth of Hull	94 Feet
Design Draft	36 Feet
Displacement	95,200 Long Tons
Block Coefficient	0.73
Propulsion Horsepower	41,000 HP
Number of Propellers	1
Type Propulsion	Geared Steam Turbine
Trial Speed (at 90% HP)	19.75 Knots
Service Speed (at 90% HP)	18.50 Knots
Ballast Capacity, 100%	50,500 Long Tons
Fuel Oil Capacity, 100%	6,100 Long Tons
Bow Thruster Horsepower	2,000 HP
Number of Cargo Tanks	5
Cargo Pump Capacity	12,500 m^3/hour
Cargo Boiloff	0.15% Cargo Volume/day
Number of Manifold Lines	5 Lines, 16-inch Diameter Each
Crew	11 Officers, 24 Crewmen

The underlying philosophy of both the "Tentative Guide" and the proposed new United States regulations is to require a design and construction technique for LNG tankers that will prevent LNG spills to the maximum extent possible in the event of human error, accidents, groundings, strandings or minor collisions.

The United States Coast Guard presently has two important design requirements that enhance the safety and reliability of LNG tankers. The first regulation requires all LNG tankers to be constructed as double hulled vessels. The cargo tanks are located inside the inner hull, thus providing maximum protection for the tanks. The second requirement necessitates extremely high standards for calculations, tests and material qualifications to be used in the design of the cargo containment systems. The carriers are also carefully inspected during construction before Coast Guard certificates will be granted.

The safety and fire equipment for the LNG Carrier Fleet will meet or exceed all applicable Federal regulations. This includes specifically Title I of the Ports and Waterways Safety Act of 1972, that empowers the Secretary of Transportation to establish regulations to control vessel activities within inland waterways. The Coast Guard is also authorized to enforce regulations under this Act.

Z-2

Docket No. CP75–________

EXHIBIT Z-2

LOWER 48 STATES GAS TRANSPORTATION CONCEPT

Application of

EL PASO ALASKA COMPANY

EL PASO ALASKA COMPANY

Lower 48 States Gas Distribution Concept

Exhibit Z-2 contains two map-flow diagrams, Figures 1 and 2, which schematically illustrate El Paso Alaska's concept for making Alaskan gas available, by displacement and direct flow, from the Point Conception regasification facility to virtually any market area in the Lower 48 States. This transportation concept is based principally on the utilization of existing gas transmission systems.

Figure 1 of 2 is a map-flow diagram which illustrates:

1) The receipt, in 1980, from the outlet of Western Terminal's Point Conception Regasification Plant of an average daily volume of 2800 million cubic feet (MMcf/d);1/

2) The disposition of an illustrative one-half of the 2800 MMcf/d in the California, Northwest and El Paso Natural east-of-California market areas; and

3) The availability through displacement and reverse flow in the El Paso Natural system of an illustrative one-half of said 2800 MMcf/d to the Permian/Anadarko area for subsequent transportation to Midwestern and Eastern markets.

Specifically, Figure 1 of 2 shows the new pipeline facilities required by Western Terminal to transport 2800 MMcf/d from the regasification plant. The new pipeline facilities will connect the regasification plant to the existing California transmission pipelines of Pacific Gas and Electric Company ("PGandE") at Arvin and the load distribution center of Southern California Gas Company ("SoCal") at Cajon.2/ Figure 1 also

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1/ Annual average day volume resulting from the Trans-Alaska Gas Project transportation components extending from Prudhoe Bay to Point Conception.

2/ On September 17, 1974, at Docket No. CP75-83, Western Terminal filed an application with the Commission for conditional authorization to, among other things, construct and operate the new pipeline facility, shown on Figure 1, extending from the regasification plant to a point of connection with PGandE's transmission system at Arvin. The new pipeline facility, shown on Figure 1 as extending from Arvin to SoCal's load distribution center at Cajon, was not included in said application, but is based upon preliminary engineering studies by Western Terminal. As indicated in Western Terminal's application at Docket No. CP75-83, such facility, or similar facility, as required to receive and transport definitive volumes of gas derived from LNG, will be the subject of a timely supplemental filing by Western Terminal.

shows the current existing design gas flow direction and capacity of the PGandE and SoCal systems, and the required gas flow direction and flow volumes resulting from the receipt and disposition of the Alaskan gas as illustratively allocated.3/ Such resulting flows are less than existing capacities as determined by SoCal and PGandE engineering studies.

Figure 1 similarly shows the current design gas flow direction and capacity of the existing El Paso Natural mainline transmission system, and the required gas flow direction and flow volume resulting from the easterly flow of gas from the California/Arizona border toward the Permian and Anadarko Basin areas.3/ Such resulting flow direction and volumes, obtainable by minor compressor station piping modifications on the El Paso Natural system, are substantially less than total potential reverse flow capability of El Paso Natural's system. There exists in the El Paso Natural system the flexibility for operating at greater or lesser reverse flows than those shown on Figure 1. Moreover, there exists in the Transwestern Pipeline Company system shown on Figure 1 additional substantial reverse flow and displacement capability.

Figure 1 further shows the gas balance of 1400 MMcf/d made available in the Permian/Anadarko Basin supply area by the indicated reverse flow and displacement operations in the upstream pipelines. Under the illustrative assumptions previously made herein, such gas volume, because of the delivery of Alaskan gas at Point Conception, would be available for delivery from El Paso Natural's pipelines in the Permian/Anadarko Basin area into pipelines situated in that area having idle capacity.

It should be noted that the existing El Paso Natural net supplies projected on Figure 1 to be available in 1980, are based upon 1973 Form 15 data filed by El Paso Natural with the Commission. Further, the allocation of such existing gas supplies to the various market segments served by El Paso Natural are based upon the end use priorities prescribed by the Commission at Docket No. RP72-6.

Figure 2 demonstrates that in 1980 there will be idle capacity available in existing pipelines for moving gas to Midwest and Eastern markets from the Anadarko and Gulf Coast areas. Moreover, the projected idle capacity in such systems will be of such magnitude that quantities of Alaskan gas, much greater than those illustratively shown on Figure 1 could be transported.

Specifically, the map-flow diagram shows that existing major pipelines extending from the Anadarko Basin have a total transport capacity of some 6834 MMcf/d. Through projected deterioration of Anadarko gas supplies,4/ such pipelines in 1980 will only have supply availability

3/ See Illustrative California Gas Balance on Figure 1.

4/ As projected by Form 15 Reports filed with the Commission.

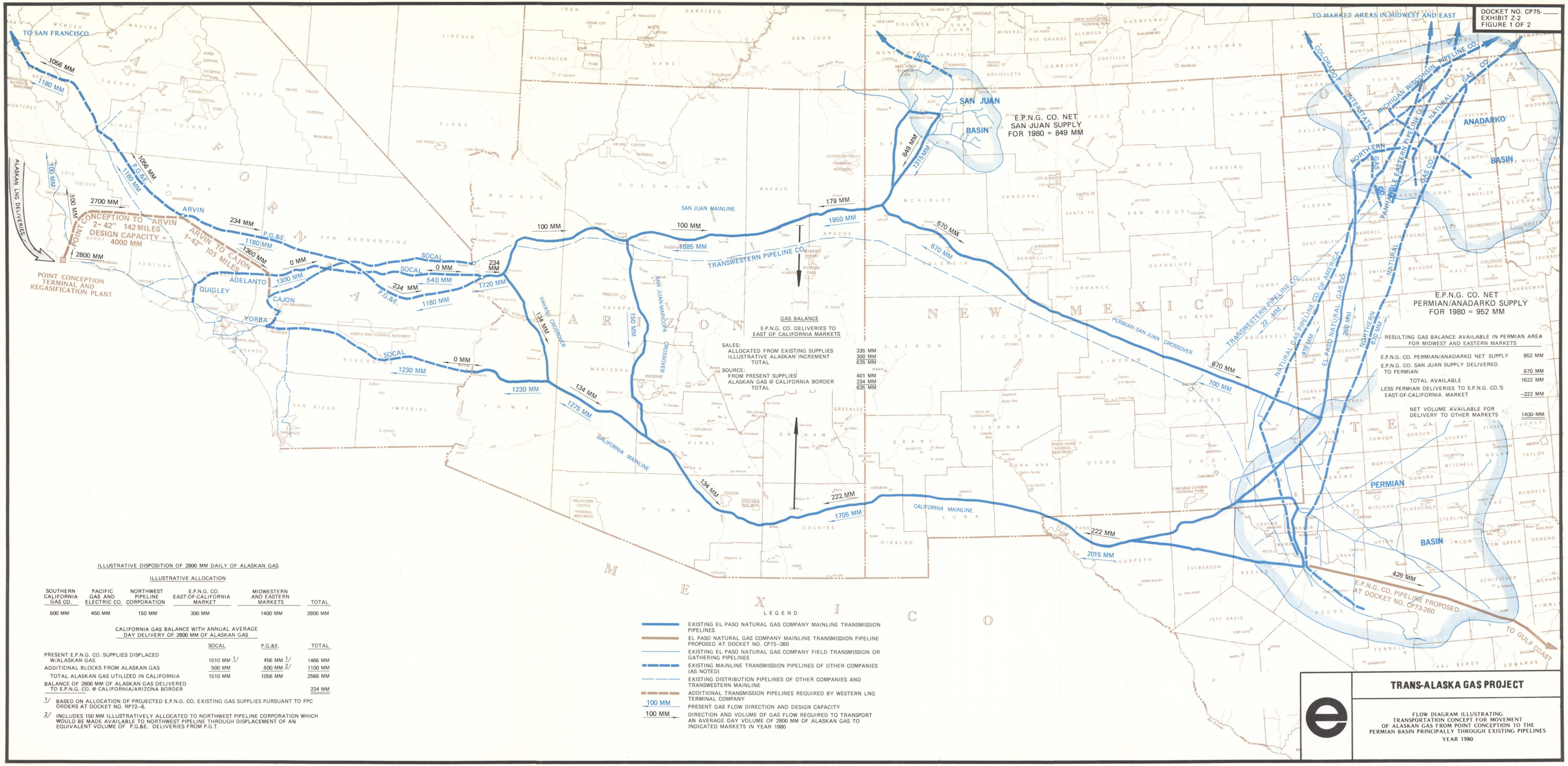
of some 3954 MMcf/d. This capacity/supply imbalance, as shown on Figure 2, will result in idle capacity in the pipelines of some 2880 MMcf/d. Further deterioration in Anadarko supplies is projected beyond 1980.

Similarly, Figure 2 shows that the existing major pipeline systems extending from the Gulf Coast supply area presently have a total transport capacity of some 16,028 MMcf/d. Through projected decline in deliverability of gas from the Gulf Coast sources,[5/] only some 8867 MMcf/d will be available to such pipelines in 1980. This will leave some 7161 MMcf/d of idle capacity in such pipelines in 1980. Further deterioration is projected in the Gulf Coast supplies beyond 1980.

By utilizing capacity in existing pipelines interconnecting the Permian-Anadarko supply areas and by the construction of relatively minor reinforcements and inter ties, as required, the volumes of Alaskan gas shown to be available in the Permian/Anadarko area on Figure 1 can be moved to existing systems extending from the Anadarko Basin. Through utilization of idle capacity in such systems, demonstrated on Figure 2, to be available in 1980, the gas can be moved to Midwestern and Eastern markets. With the construction of a facility from the Permian to the Gulf Coast area, such as that proposed by El Paso Natural at Docket No. CP73-260, the major, existing systems serving the entire Midwestern, Southeastern and Eastern portions of the Nation from the Gulf Coast would be given access to Alaskan gas.

5/ See Footnote 4 *supra*.

DOCKET NO. CP75- ____
EXHIBIT Z-2
FIGURE 1 OF 2



GAS BALANCE

E.P.N.G. CO. DELIVERIES TO EAST OF CALIFORNIA MARKETS

SALES:	
ALLOCATED FROM EXISTING SUPPLIES	335 MM
ILLUSTRATIVE ALASKAN INCREMENT	300 MM
TOTAL	635 MM
SOURCE:	
FROM PRESENT SUPPLIES	401 MM
ALASKAN GAS @ CALIFORNIA BORDER	234 MM
TOTAL	635 MM

E.P.N.G. CO. NET PERMIAN/ANADARKO SUPPLY FOR 1980 = 952 MM

RESULTING GAS BALANCE AVAILABLE IN PERMIAN AREA FOR MIDWEST AND EASTERN MARKETS

E.P.N.G. CO. PERMIAN/ANADARKO NET SUPPLY	952 MM
E.P.N.G. CO. SAN JUAN SUPPLY DELIVERED TO PERMIAN	670 MM
TOTAL AVAILABLE	1622 MM
LESS PERMIAN DELIVERIES TO E.P.N.G. CO.'S EAST-OF-CALIFORNIA MARKET	–222 MM
NET VOLUME AVAILABLE FOR DELIVERY TO OTHER MARKETS	1400 MM

ILLUSTRATIVE DISPOSITION OF 2800 MM DAILY OF ALASKAN GAS

ILLUSTRATIVE ALLOCATION

SOUTHERN CALIFORNIA GAS CO.	PACIFIC GAS AND ELECTRIC CO.	NORTHWEST PIPELINE CORPORATION	E.P.N.G. CO. EAST-OF-CALIFORNIA MARKET	MIDWESTERN AND EASTERN MARKETS	TOTAL
500 MM	450 MM	150 MM	300 MM	1400 MM	2800 MM

CALIFORNIA GAS BALANCE WITH ANNUAL AVERAGE DAY DELIVERY OF 2800 MM OF ALASKAN GAS

	SOCAL	P.G.&E.	TOTAL
PRESENT E.P.N.G. CO. SUPPLIES DISPLACED W/ALASKAN GAS	1010 MM 1/	456 MM 1/	1466 MM
ADDITIONAL BLOCKS FROM ALASKAN GAS	500 MM	600 MM 2/	1100 MM
TOTAL ALASKAN GAS UTILIZED IN CALIFORNIA	1510 MM	1056 MM	2566 MM
BALANCE OF 2800 MM OF ALASKAN GAS DELIVERED TO E.P.N.G. CO. @ CALIFORNIA/ARIZONA BORDER			234 MM

1/ BASED ON ALLOCATION OF PROJECTED E.P.N.G. CO. EXISTING GAS SUPPLIES PURSUANT TO FPC ORDERS AT DOCKET NO. RP72–6.

2/ INCLUDES 150 MM ILLUSTRATIVELY ALLOCATED TO NORTHWEST PIPELINE CORPORATION WHICH WOULD BE MADE AVAILABLE TO NORTHWEST PIPELINE THROUGH DISPLACEMENT OF AN EQUIVALENT VOLUME OF P.G.&E. DELIVERIES FROM P.G.T.

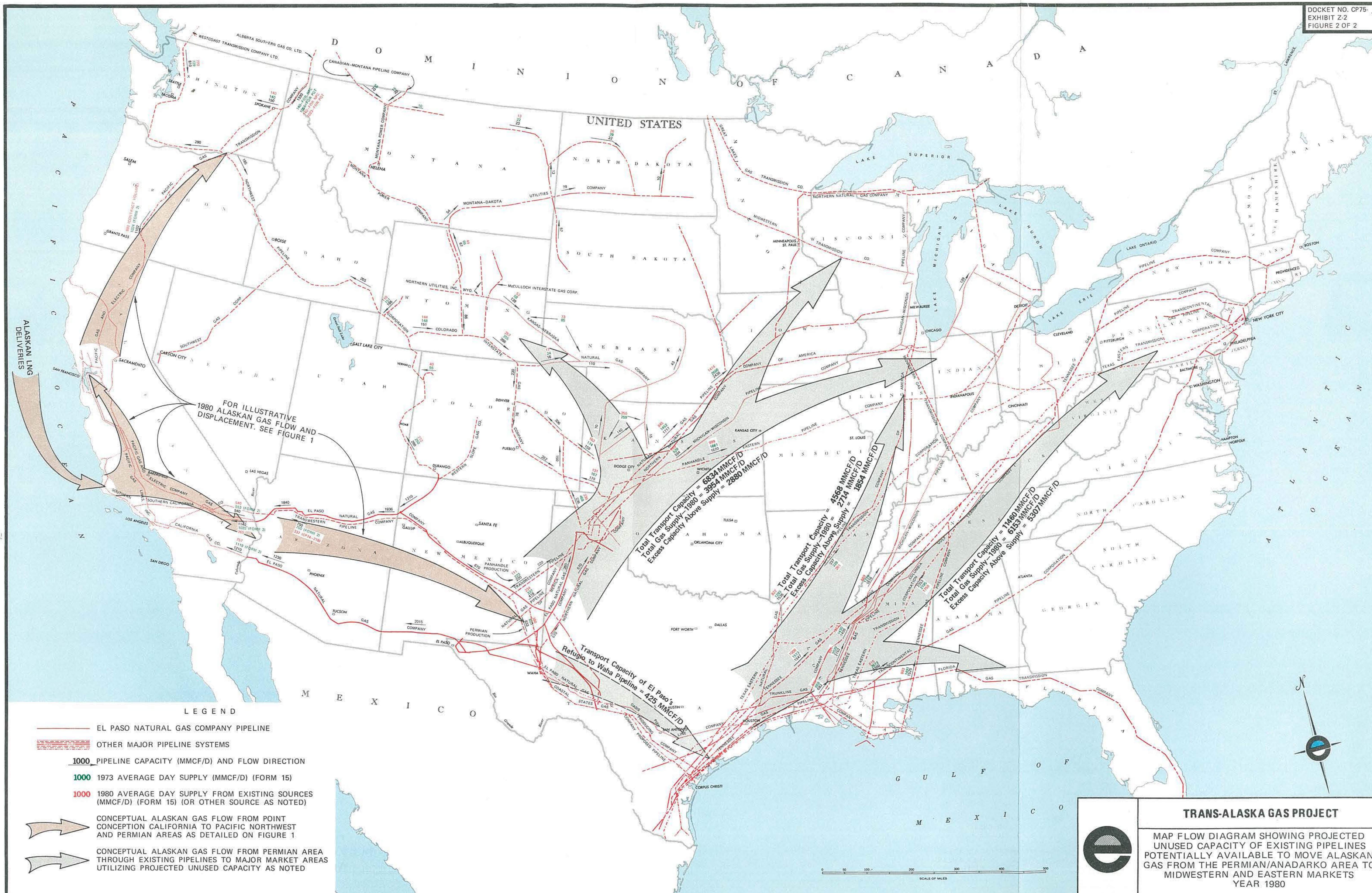
LEGEND

- EXISTING EL PASO NATURAL GAS COMPANY MAINLINE TRANSMISSION PIPELINES
- EL PASO NATURAL GAS COMPANY MAINLINE TRANSMISSION PIPELINE PROPOSED AT DOCKET NO. CP73–260
- EXISTING EL PASO NATURAL GAS COMPANY FIELD TRANSMISSION OR GATHERING PIPELINES
- EXISTING MAINLINE TRANSMISSION PIPELINES OF OTHER COMPANIES (AS NOTED)
- EXISTING DISTRIBUTION PIPELINES OF OTHER COMPANIES AND TRANSWESTERN MAINLINE
- ADDITIONAL TRANSMISSION PIPELINES REQUIRED BY WESTERN LNG TERMINAL COMPANY
- 100 MM — PRESENT GAS FLOW DIRECTION AND DESIGN CAPACITY
- 100 MM — DIRECTION AND VOLUME OF GAS FLOW REQUIRED TO TRANSPORT AN AVERAGE DAY VOLUME OF 2800 MM OF ALASKAN GAS TO INDICATED MARKETS IN YEAR 1980

TRANS-ALASKA GAS PROJECT

FLOW DIAGRAM ILLUSTRATING TRANSPORTATION CONCEPT FOR MOVEMENT OF ALASKAN GAS FROM POINT CONCEPTION TO THE PERMIAN BASIN PRINCIPALLY THROUGH EXISTING PIPELINES

YEAR 1980


DOCKET NO. CP75-
EXHIBIT Z-2
FIGURE 2 OF 2
DOMINION OF CANADA
UNITED STATES
PACIFIC OCEAN
ATLANTIC OCEAN
GULF OF MEXICO
MEXICO
ALASKAN LNG DELIVERIES
FOR ILLUSTRATIVE 1980 ALASKAN GAS FLOW AND DISPLACEMENT. SEE FIGURE 1
Total Transport Capacity = 6834 MMCF/D
Total Gas Supply-1980 = 3954 MMCF/D
Excess Capacity Above Supply = 2880 MMCF/D
Total Transport Capacity = 4568 MMCF/D
Total Gas Supply-1980 = 2714 MMCF/D
Excess Capacity Above Supply = 1854 MMCF/D
Total Transport Capacity = 11460 MMCF/D
Total Gas Supply-1980 = 6153 MMCF/D
Excess Capacity Above Supply = 5307 MMCF/D
Transport Capacity of El Paso's Refugio to Waha Pipeline = 425 MMCF/D
LEGEND
EL PASO NATURAL GAS COMPANY PIPELINE
OTHER MAJOR PIPELINE SYSTEMS
1000 PIPELINE CAPACITY (MMCF/D) AND FLOW DIRECTION
1000 1973 AVERAGE DAY SUPPLY (MMCF/D) (FORM 15)
1000 1980 AVERAGE DAY SUPPLY FROM EXISTING SOURCES (MMCF/D) (FORM 15) (OR OTHER SOURCE AS NOTED)
CONCEPTUAL ALASKAN GAS FLOW FROM POINT CONCEPTION CALIFORNIA TO PACIFIC NORTHWEST AND PERMIAN AREAS AS DETAILED ON FIGURE 1
CONCEPTUAL ALASKAN GAS FLOW FROM PERMIAN AREA THROUGH EXISTING PIPELINES TO MAJOR MARKET AREAS UTILIZING PROJECTED UNUSED CAPACITY AS NOTED
SCALE OF MILES
TRANS-ALASKA GAS PROJECT
MAP FLOW DIAGRAM SHOWING PROJECTED UNUSED CAPACITY OF EXISTING PIPELINES POTENTIALLY AVAILABLE TO MOVE ALASKAN GAS FROM THE PERMIAN/ANADARKO AREA TO MIDWESTERN AND EASTERN MARKETS YEAR 1980