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Installation and Operation of Hydraulic Pumping Systems on Cook Inlet

By

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ABSTRACT

Hydraulic pumping systems have been installed on three Cook Inlet self-contained drilling and producing offshore platforms. The design, installation, and operation of these systems, which utilize high pressure crude oil as power oil, have presented some unique problems:

1. Location of pumps and prime movers on the platforms.
2. Routing of high pressure lines.
3. Selection of pipe, valves and fittings, and inspection of fabrication.
4. Instrumentation and control, and fire alarm and extinguishing systems.
5. Control of pulsation and vibration.
6. Design of special downhole equipment.

INTRODUCTION

Construction of permanent drilling-producing self-contained platforms in the Cook Inlet began in 1965. Middle Ground Shoal Platform Baker was the second platform to be erected in the Inlet, and was the first of four platforms to be erected by the Chakachatna Group, which consists of Pan American Petroleum Corporation, Skelly Oil Company, Phillips Petroleum Company, and Atlantic Richfield Company, with Pan American as operator for the Group. Following construction of Middle Ground Shoal Platform Baker in mid-1965, two other platforms, Granite Point Platforms Anna and Bruce, were erected. The fourth and final Chakachatna Group platform was South Middle Ground Shoal Platform Dillon, erected in 1967. All of the wells completed on these four platforms were initially flowing wells. Figure 1 shows the relative location of these Cook Inlet platforms.

Illustrations at end of paper.

A rapid decline in producing bottom hole pressures and associated decline in producing rate necessitated the installation of artificial lift facilities early in the life of the wells. Since several of the wells on Middle Ground Shoal Platform Baker were multiple completions and the producing GOR was about 400:1, a gas lift system was installed in mid-1967. The need for artificial lift became apparent on the other three platforms by the fall of 1967.

The operating conditions on Granite Point Platforms Anna and Bruce and South Middle Ground Shoal Platform Dillon were considerably different from the conditions that existed on Middle Ground Shoal Platform Baker, where gas lift had been installed. Drilling was still in progress on the Granite Point and South Middle Ground Shoal platforms, which limited the space available for installation of artificial lift equipment. Figure 2, Granite Point Platform Anna, is typical of the South Middle Ground Shoal and Granite Point platforms when drilling and production were in progress simultaneously. None of the wells on these three platforms were multiple completions. The GOR at Granite Point was considerably higher than at Middle Ground or South Middle Ground Shoal, averaging about 700:1. All of the wells drilled from each of the platforms had to be deviated, with some deviations quite extensive, in order to reach the desired bottom hole location. These high deviations caused many problems in performing the wireline work connected with the downhole gas lift equipment on Middle Ground Shoal Platform Baker. When all these factors were taken into account, gas lift was not considered to be the proper choice of artificial lift for the remaining three platforms. Rod pumping was not even considered since its use on the platforms would be impractical. The majority of the wells were capable of producing 4,000 to 4,500 bfpd from a depth of 8,000 to 9,000 ft., which was beyond the capability of electric submersible pumps. Subsurface hydraulic pumping, using the free-pump system, appeared to be the best selection. The major factors in favor of subsurface hydraulic pumping were:

1. The free pump could normally be retrieved by pumping it out of the well. This minimized both the need for wireline work, where success was questionable, and the need for pulling tubing, which is extremely costly. (The cost to mobilize a rig and round-trip tubing averages about \$30,000.)
2. Pump sizes could be changed very easily to coordinate with changes in producing capabilities.
3. Installation and operation of the hydraulic pumps would not be adversely affected by the deviated holes.
4. The power oil system could consist of several small pumps located throughout the platform where space was available. Also individual power oil pumps could be readily and economically transferred from one platform to another as power oil requirements changed.

Several problems had to be considered in the installation of the surface equipment on the platforms. The primary concern was to provide a system that would be safe, since high pressure power fluid would be required. The location of the prime movers and triplexes on the platform was given careful consideration. Also, isolation of the prime movers from the triplexes to prevent fire hazard was considered. Other items given special consideration were:

1. The design, selection, construction and location of high pressure pipe runs.
2. Provision for annunciation of operating conditions, safety shutdown instrumentation, and fire detection and control.
3. Control of pulsation and vibration.

The solutions to these problems, as well as a discussion of some special downhole equipment, are discussed in this paper.

DESIGN CRITERIA

Since the three platforms, South Middle Ground Shoal Dillon, Granite Point Anna, and Granite

Point Bruce, are located in two separate fields, as shown in Figure 1, and the fields have different producing characteristics, the same criteria could not be used to design the hydraulic pumping systems for all three platforms. The producing horizon in the South Middle Ground Shoal structure is the Hemlock, which is a Tertiary Age Conglomerate. The Middle Ground Shoal Member of the Tyonek Formation, which is a Tertiary Age Sandstone, is the producing horizon at Granite Point. The data shown in Table 1 was used in the design of the surface power oil pumping equipment, the high pressure piping, and the downhole hydraulic pumping equipment.

One of the first decisions to be made was the selection of the type of power fluid system; i.e., closed system or open system. South Middle Ground Shoal Platform Dillon has a producing GOR of about 300:1, which is low enough to permit producing all of the reservoir fluid, both liquid and gas, through the pump without adversely affecting the pump efficiency. Consequently, the closed system, as shown in Figure 3, was chosen for South Middle Ground Shoal. In this system, a packer is used below the pump which permits using the annulus to conduct the produced fluid to the surface and returning the power fluid back to the power fluid tank separate from the production. This separation of power fluid and produced fluid is desirable since the power fluid can be kept relatively clean of any contaminants that might be in the produced fluid - such as emulsions or sand.

In the open system, also shown in Figure 3, a packer is not used and the power fluid is mixed with the produced fluid at the downhole hydraulic pump and returns to the surface through a tubing string, along with the production. This system permits downhole separation of liquid and gas before the fluid enters the pump, which is desirable for high GOR wells. Since the GOR at Granite Point was 700:1, the open power fluid system was selected for Granite Point Platforms Anna and Bruce.

The next decision to be made was the selection of what type fluid to be used as power fluid. Since high pressure crude oil would present a hazard,

power water with a friction-reducing additive was considered. The manufacturer of the hydraulic equipment did not recommend the use of water in this isolated location. Therefore, the decision was made to use crude oil as the power fluid, with extra precautions taken to make the systems as safe as possible.

SELECTION AND LOCATION OF SURFACE EQUIPMENT

Probably the most critical decision to be made in the selection of surface equipment concerned the power oil pumps and their corresponding prime movers. Consideration was given to using either a central power oil pump, or several smaller pumps.

Each type of system has advantages; however, installation of several smaller power oil pumps was more advantageous for a Cook Inlet platform because (1) the entire platform production would not have to depend upon a single pump in case of equipment failure; (2) the output volumes and pressures could be readily and economically adjusted to meet changing demands; and (3) the smaller pumps were more readily available than large central units. Also, the smaller pump and prime mover can be skid-mounted as a unit providing further flexibility since the units can be transferred between platforms as the needs dictate. Consequently, several triplex pumping units, powered by individual natural gas internal combustion engines, were installed on each platform. Natural gas engines were selected, primarily because of the availability of surplus natural gas for fuel and also due to the availability of that type of engine. Electric motors were considered; however, their use would have necessitated expanding the existing AC generator system on each platform to meet the higher electrical demand, which was not as economically favorable as the purchase and installation of natural gas engines.

Two sizes of triplexes and prime movers were installed on the platforms. The larger, Size 4 J, units have an output range from 1,768 bpd at 5,000 psi to 4,437 bpd at 2,170 psi, and are rated at 180 horsepower. The smaller, Size 4 H, units are capable of delivering from 1,380 bpd at 5,000

psi to 3,450 bpd at 2,040 psi, with a rating of 125 horsepower. The plunger and liner size has been changed several times in the triplexes, in order to meet different power oil volume and pressure requirements. This is a desirable feature of hydraulic pumping which permits maximum utilization of the equipment. The smaller units were installed during the initial construction of South Middle Ground Shoal Platform Dillon and Granite Point Platform Anna, because the larger units were not available at that time. As the systems were expanded, the larger triplexes became available and were purchased. South Middle Ground Shoal Platform Dillon has six larger triplexes and two smaller ones. Granite Point Platform Anna has three each of both size triplexes for a total of six, and Granite Point Platform Bruce has five large triplexes.

The triplex pumps and engines were installed on cantilevered landings at the outboard ends of the breezeways, as shown in Figures 4 and 5. Each landing can accommodate three triplexes and engines. This location was selected for several reasons, with the most important reason being for safety considerations. The cantilevered, or appendage, effect keeps the triplex pump and resulting high pressure discharge piping away from normal personnel working areas and passageways. The triplex areas are open to the outside providing free ventilation and unconfined accessibility, so that removal of equipment for repairs can be accomplished with a minimum of system downtime. Each triplex landing has a firewall separating the triplexes from the engines, minimizing fire hazards. In the event of a crude oil line rupture, the firewall prevents the oil from contacting hot engine exhausts or electrical controls in the prime mover area. Drain systems were installed on each triplex landing to prevent crude oil spills into Cook Inlet.

All high pressure discharge piping, valves and fittings were designed for 5,000 psig maximum operating pressures, which is the upper pressure limit of the triplexes. The actual operating pressures thus far experienced have been between 2,500 to 3,200 psig, depending upon the size

of the downhole pump and the corresponding producing rates. The high pressure piping system was constructed of Schedule 160, Grade B seamless pipe and fittings, which provided the necessary 5,000 psi maximum pressure rating. Schedule 40, Grade B seamless pipe and fittings were used in the triplex suction system, where maximum pressures of only about 100 psig are experienced. The discharge piping consists of pipe sizes ranging from 2" to 6", depending upon the maximum flow rate anticipated through a particular pipe. Sizes were adjusted so that a maximum fluid velocity of 12 feet/second would never be exceeded for safety and friction loss considerations.

Initially, standard API 5000 ring joint flanges and ASA 150 raised faced flanges were used on the high and low pressure piping, respectively, on the South Middle Ground Shoal system and part of the Granite Point Platform Anna installation. When these two systems were being expanded, and during construction of the Granite Point Platform Bruce system, clamp-type seal ring connections were used in lieu of flanges. This type of connection is much smaller and considerably lighter than the standard flange type connection. Much of the piping was prefabricated in welding shops onshore and sent to the platforms to reduce costs and construction time. The clamp-type connections were more satisfactory for prefabrication, inasmuch as exact alignment of bolt holes was no longer necessary, thus saving a considerable amount of time. Valves were ordered from the manufacturer equipped with the special hub for the clamp-type connection.

Strict welding specifications as established by the American Welding Society were used in the fabrication of the high pressure piping. All welds were preheated and after a weld was completed, cooling was controlled at a rate of 6° F./minute. Each weld was stress relieved by a controlled heating and cooling process. All high pressure pipe welds were X-Ray inspected for penetration, porosity, etc., and then hydrostatically tested prior to putting the system in operation.

All piping, both suction and discharge, was routed around the periphery

of the platform, away from working areas and heavily used walkways and passages, to minimize hazards to platform personnel in the event of a line break. These areas are also remote with respect to electrical lines and engine exhausts to reduce the possibility of fire. Both the main suction and discharge piping loops around the platform, so that each triplex landing can be isolated from the rest of the system without interrupting flow to the other landings, or to the flow control headers in the wellhead rooms. This is shown on Figure 4.

FIRE PROTECTION

The use of crude oil as high pressure power fluid created considerable concern with respect to fire hazard. The occurrence of a fire around the high pressure system could result in the loss of lives as well as possibly the loss of the entire platform. Consequently, considerable planning went into the design and installation of gas detection, fire detection and fire extinguishing systems for the hydraulic pumping systems on each platform. Prior to the installation of the hydraulic pumping systems, gas and fire detection systems, as well as dry chemical and water deluge extinguishing systems, were already installed to cover the existing hazardous areas on each of the platforms.

The gas detection system was expanded for the hydraulic pumping system, to provide detectors in both the triplex area and the prime mover area on each landing. These detectors were connected into the triplex shut-down system to shut the triplexes down in the event of either a fuel gas leak, or a high pressure crude oil leak. The system also sounds an alarm and provides a signal on an annunciator panel showing on which triplex landing the leak was detected.

Temperature-rise type fire detectors were installed in the triplex area and prime mover area on each landing. These detectors operate on a supervisory-type circuit from a 24 VDC-powered alarm panel. The panel automatically actuates a fire alarm, shuts down the hydraulic pumping system, and actuates signal lights on annunciator panels to show where the fire is located. The 24 VDC power for both the gas detectors and

fire detectors is independent of the platform electrical power system. The supervisory feature in the circuit provides an automatic indication, by turning off a light on the panel, if the circuit is disabled and could not provide automatic detection. This assures having a fail-safe system at all times.

A centralized dry chemical fire extinguishing system was installed on each platform for the hydraulic pumping system. This system is completely separate from the other dry chemical systems on the platform, and is designed to automatically route the dry chemical from the one source tank to whichever landing detects a fire. The dry chemical is provided to only the triplex area, since that would be the most probable source of fuel for a fire, should one occur. Automatic water deluge valves were also installed for each triplex landing. Sea water is directed into the triplex area about 45 seconds after the dry chemical starts. This water is provided by the platform fire-water system, which is powered by a diesel-driven, automatic-start fire pump. The dry chemical and/or water deluge systems can be actuated by either a local manual fire alarm switch at each landing, or by manual valves at the centralized dry chemical tank, in addition to the automatic actuation by the fire detectors. Although these fire extinguishing systems have not been required by an actual fire, tests have indicated they will be more than adequate to automatically extinguish and control a fire.

INSTRUMENTATION AND CONTROL

The hydraulic pumping systems were designed for semi-attended operation. Operating personnel are in attendance on the platforms at all times; however, they do not keep constant surveillance over the equipment. Control over the system is accomplished by a combination of manual and automatic-manual operation. Safety shutdowns have been provided to shutdown the entire system, or portions of the system, in the event of malfunction of the equipment or undesirable changes in operating conditions.

An annunciator panel located in the control room on each platform

serves as the main source of control and surveillance for the hydraulic pumping system. This panel contains the shutdown relays and malfunction indicator lights, as well as the hand-off-automatic (H-O-A) control switches for the charge pump and the triplexes. Safety shutdowns are provided for the individual components of the system as follows:

Power Oil Tank - High or low fluid level, high or low gas blanket pressure.

Charge Pump - Low suction pressure, high discharge pressure, high discharge temperature.

Triplex Pumps - Low suction pressure, high or low discharge pressure, low pump lube pressure.

Triplex Prime Mover - Low lube pressure, high jacket water temperature.

Use of mercury type pressure or temperature switches has been unsatisfactory, due to the shock to the platform which results when ice flows against the platform in the winter or when a supply boat bumps into the legs. Consequently, bourdon-tube type pressure switches are used on the high pressure and low pressure power oil systems and bi-metal temperature switches provide the charge pump and engine high temperature shutdown signals. Diaphragm operated micro-switches provide the signal for the engine and triplex oil pressure protection.

The system is started by manually setting the H-O-A switches on the annunciator panel in the automatic position, then each engine is started manually using 440 VAC electric starters. Pressure controllers, located on the high pressure power oil piping at each triplex landing, bypass any excess power oil back to the power oil tank. The high pressure power oil feed to each well is manually regulated by flow controllers on the headers in each wellhead room. Figure 6 shows a typical header and flow control system in a wellhead room. The system is balanced out by manually regulating the speed of the triplexes to eliminate bypassing an excessive

amount of power oil back to the power oil tank. This is necessary to prevent handling excess power oil through the tank, thereby providing as much settling time as possible to keep the power oil clean. A recycle pump on the power oil tank is used periodically to pull the bottoms from the tank. Chemical is added to the power oil in an effort to maintain the grind-out below 0.5 percent BS&W, in order to minimize wear on the downhole hydraulic pumps.

CONTROL OF PULSATION AND VIBRATION

Hydraulic hammer or pulsation is an inherent feature of positive displacement reciprocating plunger pumps. The triplexes at each landing on the Cook Inlet platforms take fluid from a common suction header and discharge into a common discharge header, which tends to multiply the pulsation problem. This problem is further magnified if engine and triplex speeds are not synchronized, which results in adverse harmonic fluid vibrations. Mechanical vibrations from the reciprocating machinery also adds to the problem.

Pulsations and vibration can result in piping leaks which are a potential hazard to both personnel and equipment if the leak creates an explosion or fire on the platform. Also, cavitation, associated with fluid pulsation, can be very damaging to the pump itself. For these reasons, special attention was given to minimizing the pulsation and vibration of the hydraulic pumping equipment.

Recognizing that pulsations would exist, a specially designed inline pulsation dampener was installed initially on each triplex, between the vane-type suction booster pump and the suction flange on the triplex head. The dampeners were the rubber bladder type, charged with nitrogen to 90 percent of the normal operating suction pressure. The booster pump was an integral part of the triplex, driven off the triplex crankshaft. These booster pumps were, in turn, fed by centrifugal pumps located at the power oil storage tank.

Saddle type clamps were used to firmly secure all of the piping to structural members on the platform. The supports were very effective in

reducing mechanical vibration; however, the pulsation problem still existed. Recordings were made on both the suction and discharge ports of the triplex pumps, using an instrument that recorded the pulses. Severe pulsations, with variation ranging between 800 to 1,800 psi, were recorded on the discharge system operating at about 3,000 psig discharge pressure. Pulsations on the suction system varied between 10 to 30 psi when operating at about 80 psig.

In order to correct the discharge pulsation problem, a cartridge-bladder type pulsation dampener was then installed on the discharge immediately downstream of each triplex pump. The bladders, similar to the ones used in the suction pulsation dampeners, are charged with nitrogen, except to only about 10 percent of the normal operating discharge pressure. The dampeners were situated horizontally in line with the discharge port of the triplex, as recommended by the manufacturer, for the most effective flow stabilization. This installation is shown in Figure 5.

The pulsation survey on the triplex suctions indicated the vane-type suction booster pumps were creating pulsations, apparently due to the fact the vane-type pump is essentially a positive displacement pump. It was determined the centrifugal charge pumps at the power oil storage tank would adequately charge the triplex suctions; therefore, the booster pumps were subsequently removed from all triplexes. Removal of the vane booster pumps essentially eliminated the pulsations in the suction system. A marked reduction in vibration was also noted after the booster pumps were removed and the discharge pulsation dampeners installed. However, it is still necessary to closely observe the speed of the prime movers.

SPECIAL DOWNHOLE EQUIPMENT

The State of Alaska safety regulations require that all offshore wells with sufficient bottom hole pressure to cause natural flow must be equipped with a packer, to isolate the tubing-casing annulus, and with a subsurface safety valve in the tubing string to automatically shut in the well. Some of the first wells that were converted to hydraulic lift were still capable

of nominal flow; consequently, they were subject to this regulation. A special adaptation of the conventional hydraulically-operated ball safety valve was devised to provide shut-off between the downhole hydraulic pump and the packer. Hydraulic fluid for operation of the safety valve was obtained from the power oil feed tubing. A spring in the valve would close the valve anytime the power oil feed pressure dropped to within 250 psi of the bottom hole pressure. Therefore, anytime the well was shut in, the ball valve would close and would remain closed until the well was placed back on production by providing high pressure power oil to the pump. The safety ball valve could be inserted and retrieved by wireline to permit wireline work below the packer if desired. Figure 7 is a typical wellbore diagram showing the safety ball valve installation.

Attempts were made during the first hydraulic pump installations to use hydraulic-set retrievable packers, since rotating-set packers could not be used due to the high deviations. A flow-through dummy, which consisted of a tube with seals, was designed to be used with the closed power oil system bottom hole assemblies. By inserting the flow-through dummy into the bottom hole assembly, where the conventional downhole hydraulic pump would set, it would be possible to circulate fluid down through the power oil feed tubing and out the tailpipe below the packer to clean up the well prior to completion. The packer would then be set hydraulically, the dummy pump pulled by wireline, the downhole safety valve installed by wireline, the standing valve dropped, a hydraulic pump pumped down, and the well placed on production. The initial flow-through dummy was equipped with O-ring seals, but a satisfactory seal could not be obtained in the bottom hole assembly. Also, the O-rings peeled off during retrieval of the dummy and eventually plugged the suction of the downhole hydraulic pump. A bonded seal was tried, but results were still not satisfactory. Since the bottom hole pressure declined at a very high rate, it soon became possible to use lighter fluid to circulate the wells clean. Consequently, cleanup and control of the wells became easier and use of permanent packers became possible. With rig time running at

\$10,000 per day, further experimentation with the dummy pumps became impractical and uneconomical. As a result, the completion programs were revised to include wireline set permanent packers in lieu of the retrievable packers, and the attempted use of flow-through dummies was discontinued.

CONCLUSIONS

The hydraulic pumping systems on South Middle Ground Shoal Platform Dillon and Granite Point Platforms Anna and Bruce have been in operation for more than a year. During this

period of operation, the systems have performed efficiently and safely. This proves that hydraulic pumping, using crude oil as the high pressure power fluid, can be a safe method of artificial lift on self-contained offshore drilling-producing platforms in the Cook Inlet. Some of the major factors that must be considered in the design of such a system are, (1) design and location of equipment and piping to limit the exposure of personnel to the high pressure system, (2) provision of an annunciated control system for equipment and personnel protection, and (3) provision of an automatic fire fighting and alarm system.

Table 1 - Design criteria for hydraulic pumping systems, South Middle Ground shoal and Granite Point fields.

<u>OPERATING DATA</u>	<u>SMGS</u>	<u>GRANITE POINT</u>
Avg. Depth of Wells, Ft.	10,687	10,452
Avg. Pump Depth (TVD), Ft.	8,935	7,990
Avg. Producing Fluid Level, Ft.	6,600	3,000
Producing BHP, PSIG	700	1,500
Producing BHT, °F	160	150
Design Producing Rates, BPD	6,000	6,000
Gas Oil Ratio	300	700

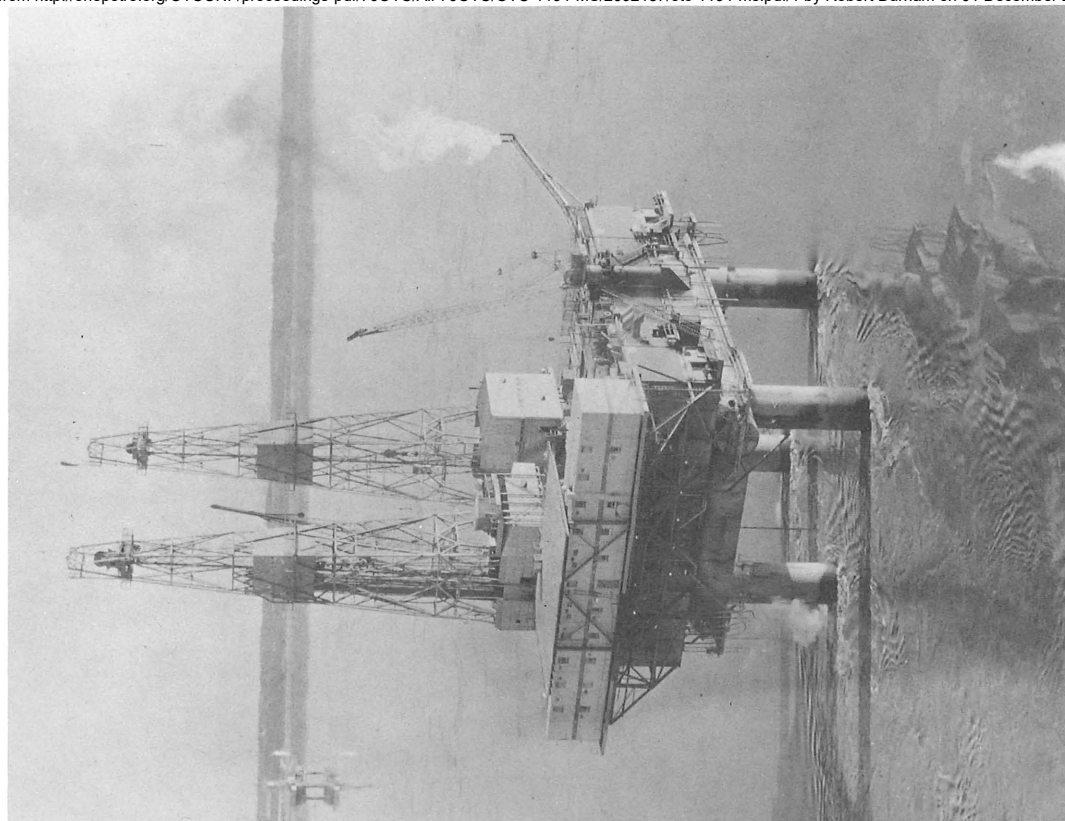


Fig. 2 - Granite Point Platform Anna during combined drilling and producing operations.

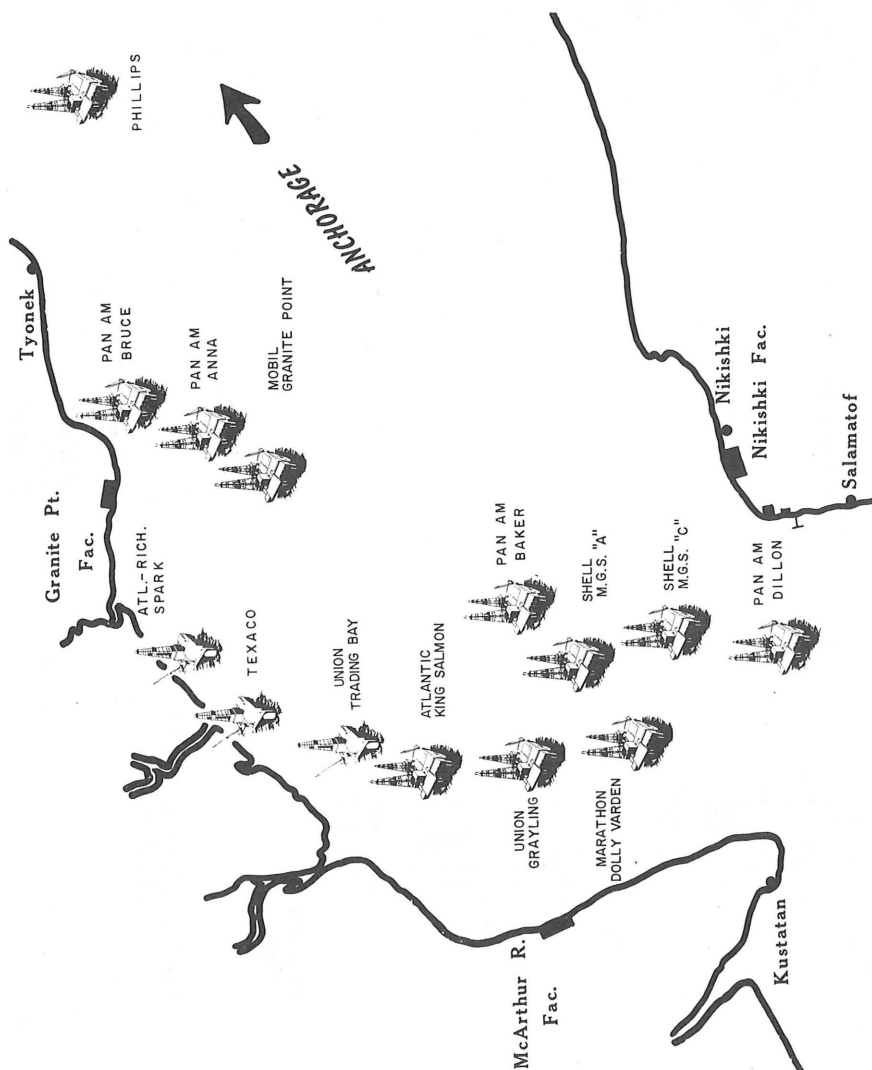


Fig. 1 - Platform locations, Cook Inlet, Alaska.

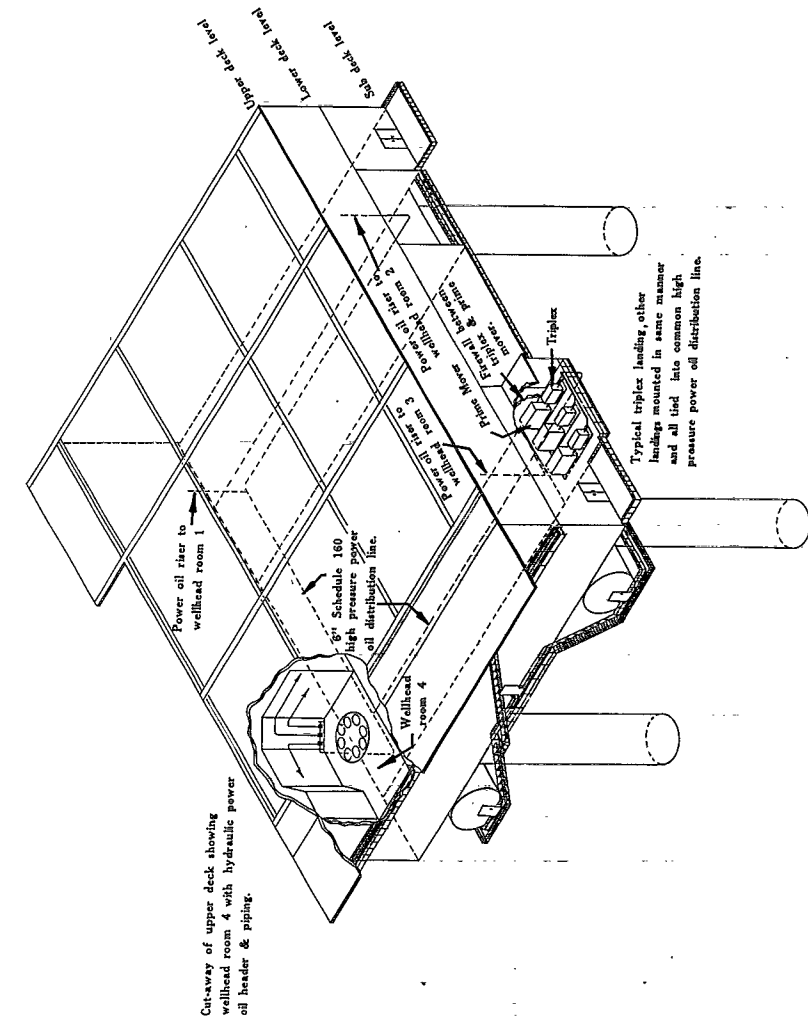


Fig. 4 - Isometric view of typical platform showing triplex landing and power oil distribution system.

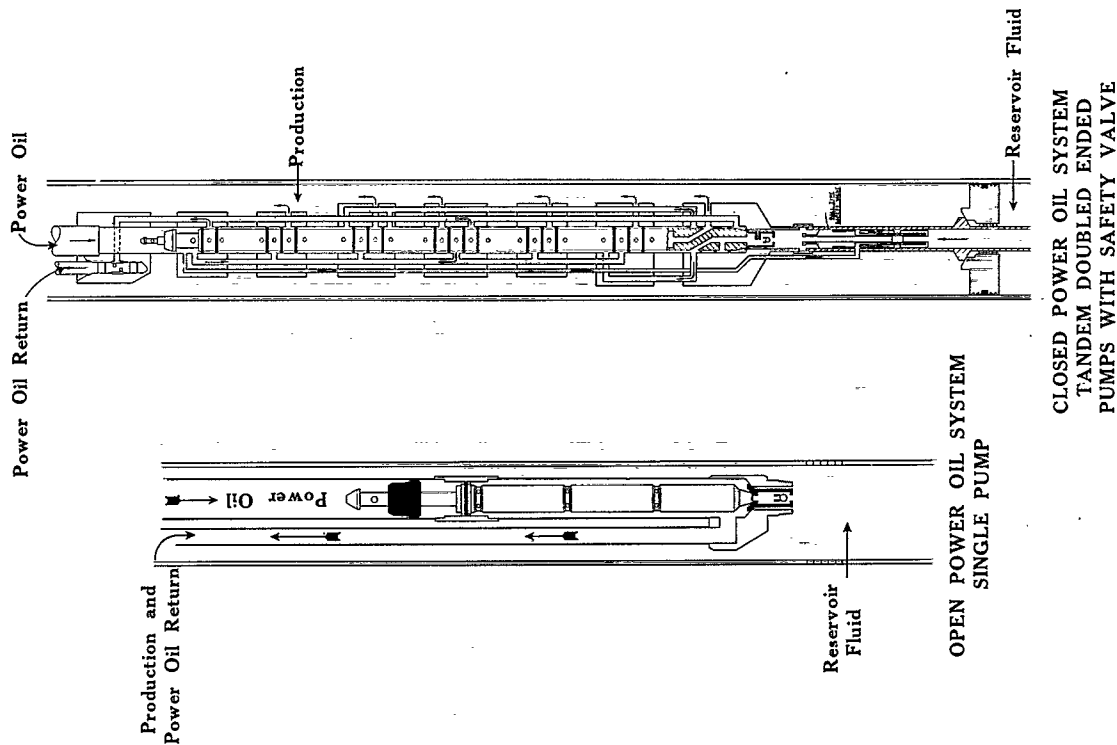


Fig. 3 - Open and closed power system with single and tandem bottomhole assemblies.

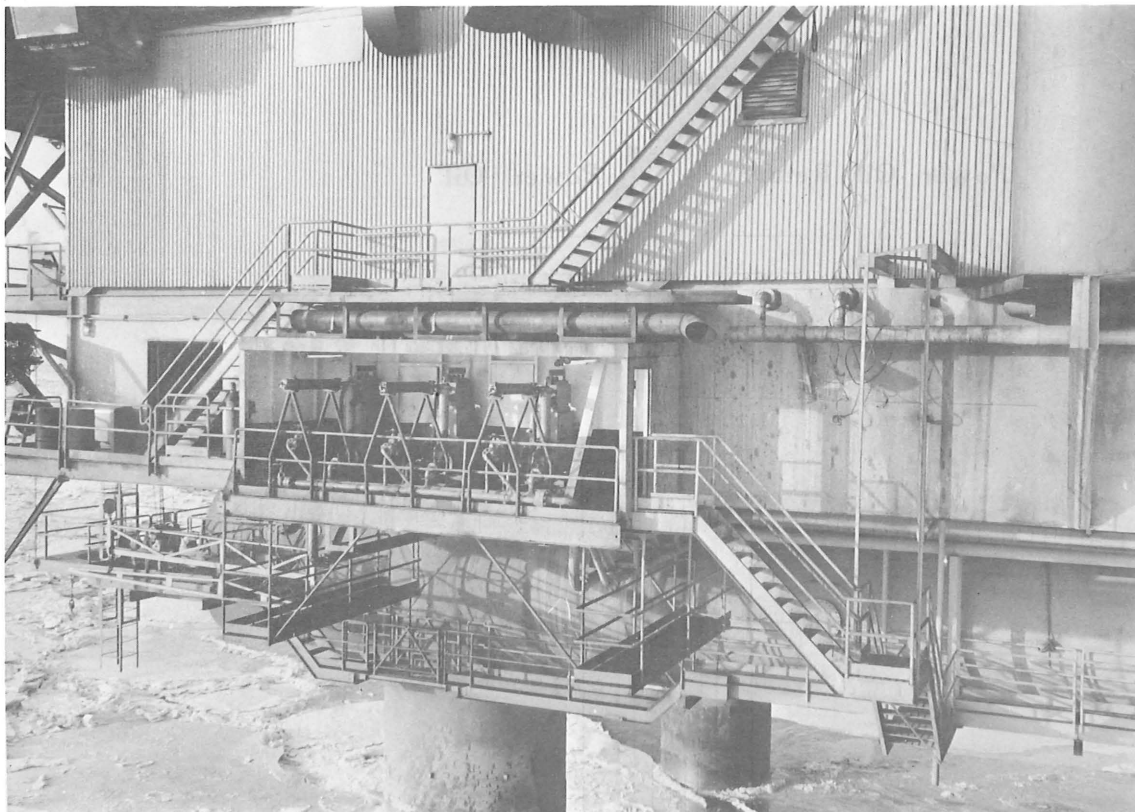


Fig. 5 - Typical triplex landing in lower breezeway of platform.

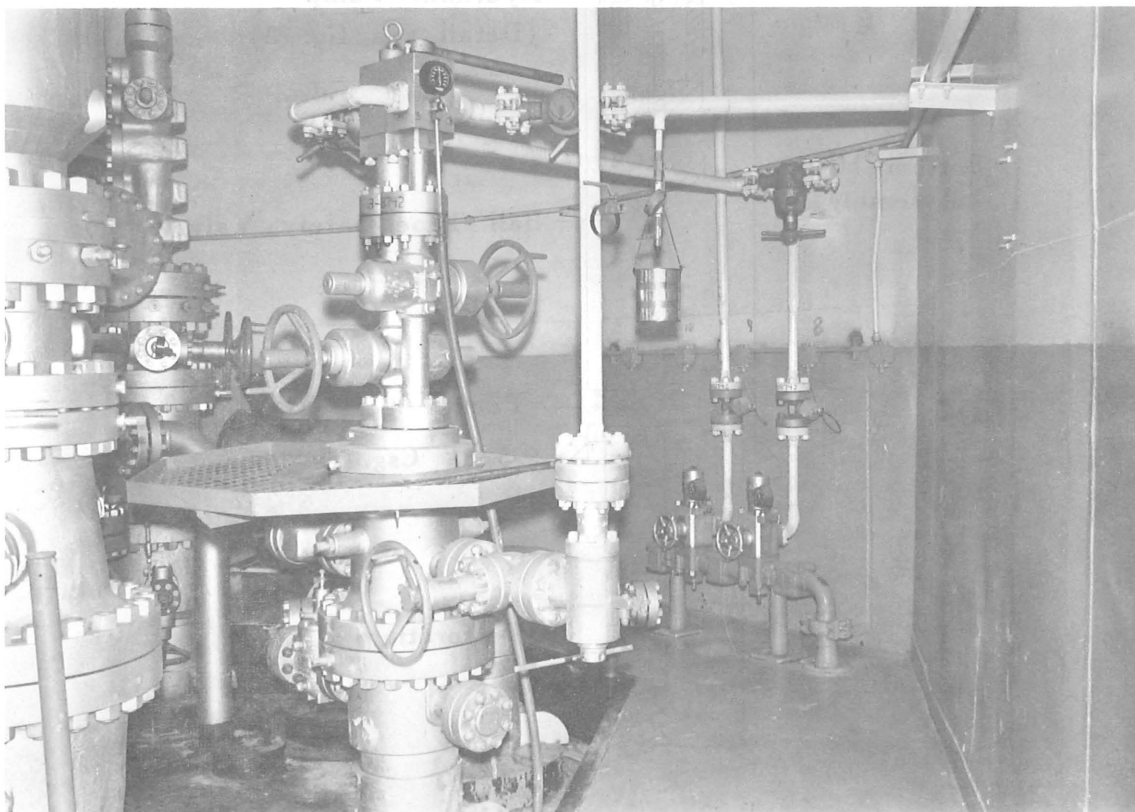


Fig. 6 - Typical wellhead room with high pressure power oil header and flow controllers.

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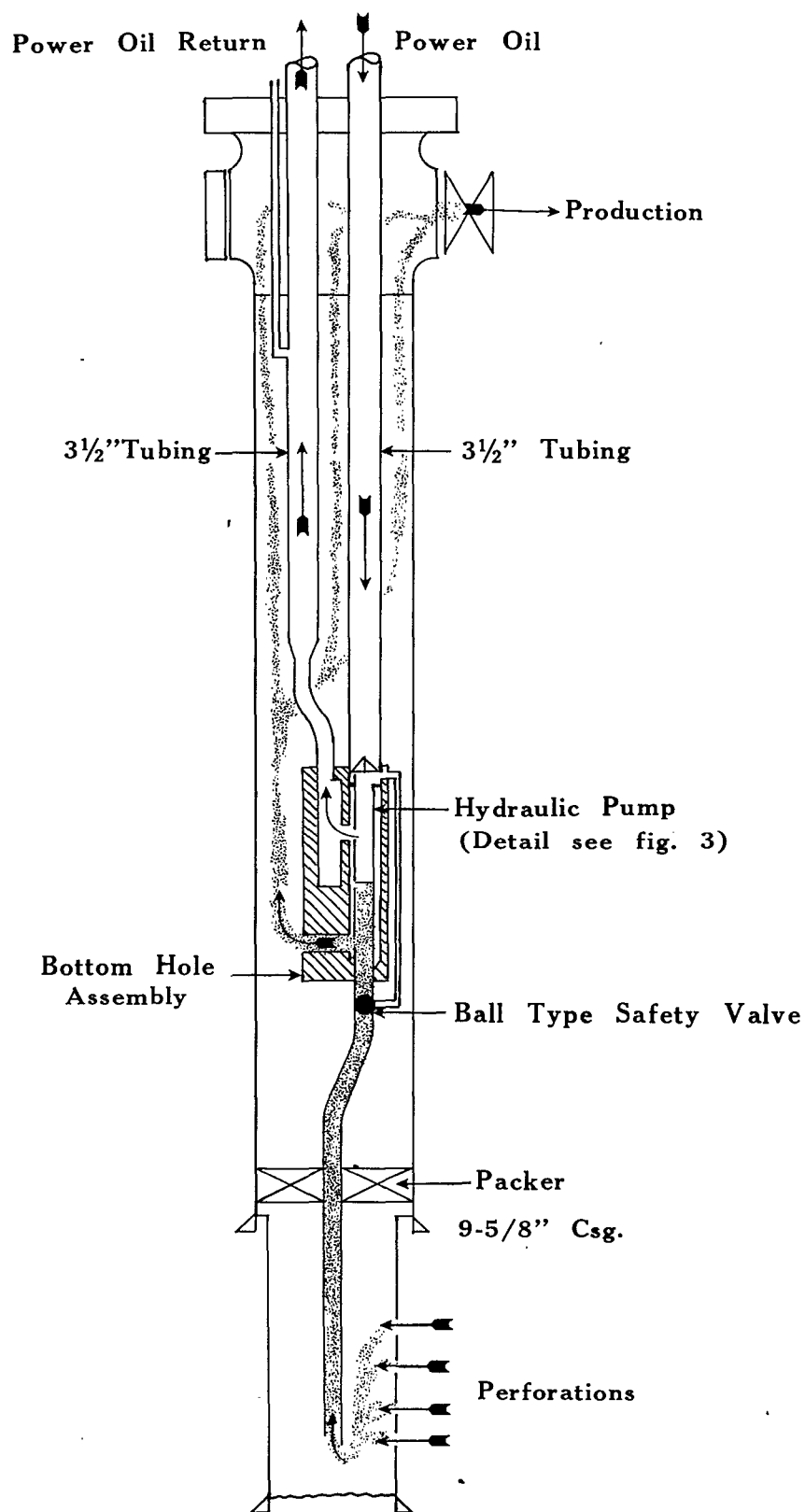


Fig. 7 - Typical wellbore diagram with downhole safety valve. Closed power oil system.