Form 1221-
(June 1969)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

MANUAL TRANSMITTAL SHEET

Release
3-79
Date
2/2/84

Subject

H-3160-1 - TECHNICAL AND ENVIRONMENTAL CONSIDERATIONS

1. Explanation of Material Transmitted: This release updates R41-CDM 643.1 (formerly USGS Conservation Division Manual 643.1, incorporated into the BLM Manual system because of the merger, via Instruction Memorandum #83-649) and converts it to the BLM Manual system for the Oil and Gas Operations Program.

   The numbering system for this Manual Handbook, H-3160-1, and subsequent Manual Handbooks, to be numbered H-3160-2, -3, -4, etc., is an identification of the order of publication. This numbering system has been adopted as an interim numbering system pending final reorganization of material into the Code of Federal Regulations and the Paperwork Management System.

   Onshore Oil and Gas Order No. 1, Approval of Operations on Onshore Federal and Indian Oil and Gas Leases (published with corrections as Circular No. 2538), is to be used closely in conjunction with this Manual Handbook. Ensure that a copy of Circular No. 2538 is readily available for reference.

2. Reports Required: None.

3. Material Superseded: The pages to be removed are listed under "REMOVE" below. No other directives are superseded.

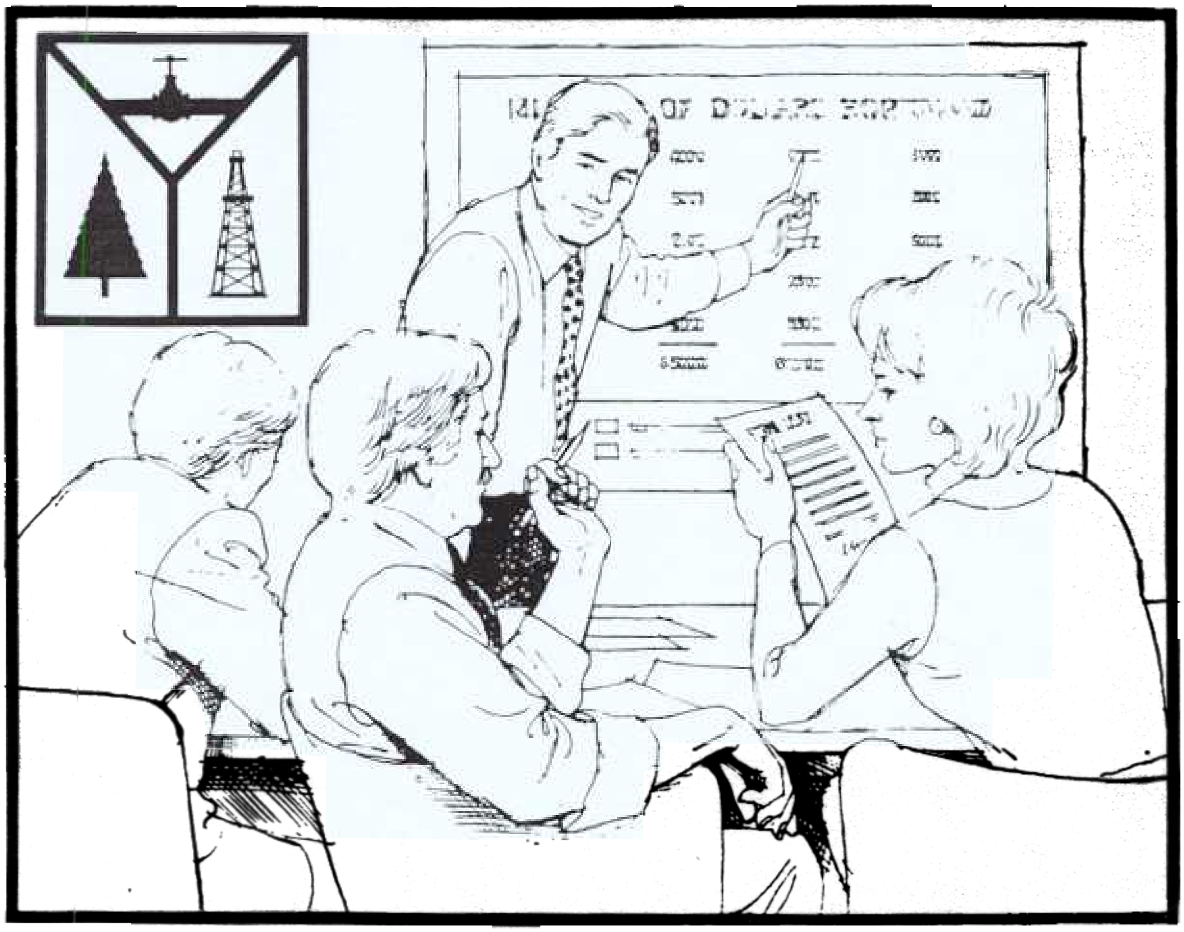
4. Filing Instructions: File as directed below

REMOVE:	INSERT:
None	All of H-3160-1
	(Total 19 sheets)

Deputy Director, Energy and Mineral Resources

TECHNICAL AND ENVIRONMENTAL CONSIDERATIONS

for Applications for Permit to Drill and Subsequent Operations



BLM Manual Handbook 3160-1

Table of Contents

I. Introduction.

This Handbook supplements the Manual Section on Application for Permit to Drill and Subsequent Operations by providing detailed guidance and useful forms and checklists for conducting the technical and environmental review of an Application for Permit to Drill or of a subsequent operation. The forms and checklists found as illustrations at the end of the Handbook are not mandatory in format or content. Although use of standardized forms is desirable, minor modification to the forms may be made to suit the needs and circumstances of the various Field Offices.

Illustration 1 is a recommended checklist for internal Field use to track important elements, such as time frames associated with processing the application, and to ensure that the application is administratively complete in accordance with Onshore Oil and Gas Order No. 1. Illustrations 2, 3, and 4 are designed to facilitate the technical and environmental reviews of the application. As the application is being reviewed for completeness, specialists may proceed to conduct these adequacy reviews, while identifying any deficiencies associated with the application.

Upon completion of the technical and environmental reviews, the reviewers present the findings along with recommended stipulations, if any, to the authorized officer, who approves or disapproves the application.

II. Technical Considerations.

The following provides a list of major technical factors to be considered in reviewing a proposed drilling program. Upon review of each item, appropriate boxes of Illustration 2 should be checked, dated, or initialed. Illustration 3 also contains elements that require technical appraisal. Technical completeness and the adequacy of the proposal are evaluated and shown on Illustrations 2 and 3.

A. Casing. The proposed casing program must be adequate to protect all fresh water zones, zones with oil and gas potential, and zones containing any other mineral deposits. The setting depth of each casing string must be such that the seat is opposite a rock stratum that will bear the weight of the casing string and that is competent (including the weight of the overburden) to contain any pressures to which the stratum at the seat will be exposed. Setting depths must also include consideration of other relevant factors, such as fracture gradients, fluid pressures indigenous to the formations, lost circulation zones, abnormally pressured zones, or other unusual characteristics.

In the absence of specific information for a geologic province, normal formation pressures are assumed to approximate 0.44-0.50 psi per foot of depth; a higher measurement is considered abnormally pressured.

Fracture gradients vary depending on the nature of rock, but are less than the overburden stress and generally range from 0.6 to 0.85 psi per foot of depth. Design parameters for casing programs, especially in a known normally pressured area, require casing/formation containment of bottom hole pressures (BHP's) assuming a gas/oil cut mud with a 0.33 psi per foot pressure gradient. However, in areas of known abnormal pressure or for wildcats, one should assume that gas will displace the mud in the casing and, further, that the gas column in the well exerts no more than 0.15 psi per foot of depth and that the gas specific gravity does not exceed 0.6.

Casing programs must be checked to ensure that the proposed weight and grade have sufficient strength to avoid collapse, burst, or tension failure. Information as to the size, grade, weight, type of thread and coupling setting depth of each string, and whether new or used is required.

1. Conductor Casing. This casing maintains hole integrity in shallow, unconsolidated sediments. It generally is set to a maximum depth of 120 feet and cemented to the surface where practical.

2. Surface Casing. This casing is designed to provide a competent anchor for blowout prevention equipment, which provides well control until the next string of casing is set; and to protect fresh water zones. This casing is set in a competent bed and cemented with sufficient cement to fill all the annular space. Generally, it is set to a depth that is at least 10 percent of the proposed total depth of an exploratory well or the next proposed casing string. For development wells, the length of the surface string and the cementing program are determined by known field conditions. The competence of the formation at the casing seat is generally more critical than the setting depth.

3. Intermediate Casing. One or more strings of intermediate casing must be set when required for protection of oil, gas, fresh water zones, and other mineral deposits; protection against abnormal pressure zones and lost circulation zones; or when otherwise required by expected well conditions. A sufficient volume of cement must be used to cover and/or isolate all hydrocarbon zones or other mineral deposits; isolate abnormal pressure intervals from normal pressure intervals; and/or isolate brackish water from fresh water. When any intermediate casing string does not extend to the surface, at least a 200-foot overlap between the outer and inner strings is desirable, but in no case may it be less than 100 feet. The interval of overlap must be made pressure competent, preferably by cementing but at least by pressure-competent hanger tools, and must be pressure tested after installation.

Generally, intermediate casing for wildcat wells is set to a depth of between 20 and 30 percent of the proposed total depth or next casing point. For development wells, the setting depth for this string cementing practice is determined on the basis of the conditions previously encountered in the area.

4. Production Casing. This string of casing must be set before completing the well for production. When the production string does not extend to the surface, at least a 200-foot overlap between the outer and inner strings is desirable, but in no case may it be less than 100 feet. The interval of overlap must be made pressure competent, preferably by cementing but at least by pressure-competent hanger tools, and must be pressure tested after installation. This casing string also must be cemented so that all exposed fresh water zones, oil and gas zones, other mineral deposits, and anomalous pressure intervals below the previous string are covered or isolated.

The proposed drilling program must provide that all casing strings (except the conductor casing) be pressure tested (0.2 psi/foot or 1,000 psi, whichever is greater) prior to drilling the plug after cementing; test pressures must not exceed the internal yield pressure of the casing. If the pressure declines more than 10 percent in 30 minutes, or if there is other indication of a leak, corrective measures must be taken. A successful pressure test must be obtained before proceeding to the next step of the drilling program.

When appropriate, drill pipe protectors, usually of hard rubber design, can be required to protect both the drill pipe and the casing from wear, with particular consideration given to drilling through intermediate casing strings and/or in deviated wells or in "dog leg" situations.

B. Cement. Proposed cement volumes, type of cement and additives, and anticipated fill-up must be checked to ensure that sufficient cement will be used to protect all potentially productive zones, fresh water zones, zones containing other minerals, or other zones known to require protection. The setting depth of stage collars and the expected linear fill-up of each cemented string or stage must also be checked, when stage-cementing techniques are used.

For surface, intermediate, and production casing strings, if there are indications of improper cementing (such as lost returns, cement channeling, failure of cement to circulate to surface, when necessary, or mechanical failure of equipment), the authorized officer must require that the operator recement or make the necessary repairs. The authorized officer can require the operator to run a temperature or cement bond log to verify that the casing has been adequately cemented. Such logs also can be required by the authorized officer when it is important to verify that certain zones are protected.

In areas subject to surface mining, for oil and gas wells drilled through coal or other valuable mineral deposits that may be mined during the life of the well, consideration may be given to a casing and cementing program that would permit, if necessary, the well to be plugged below mining depth and cut off and, after mining is completed, the well to be reentered and put back on production.

C. Blowout Preventers. The well control system must be designed to meet the conditions likely to be encountered in the hole. The rated working pressure of the blowout preventer stack should approximate, but need not exceed, the least of the following: (1) The burst pressure rating of the casing to which it will be attached; (2) the formation breakdown pressure at the shoe of said casing string; or (3) the maximum anticipated surface pressure to which the equipment may be exposed. Illustration 5 provides detailed information on blowout prevention equipment.

The drilling application should have included a schematic drawing showing the following: Casinghead with connection; casing or drilling spool with kill line; blind rams; pipe rams; annular type or bag preventer; choke manifolds and header; manual control for valves; hydraulic controls (on rig floor and ground level remote); and accumulator system. The arrangement of the equipment on the stack may vary in accordance with API Bulletin RP 53 (Illustration 5) or its revisions, provided, however, that the kill line must be below those primary units (blind and pipe rams) that would be closed in an emergency and the kill line has one or more master valves and check valves. The arrangement of pipe rams above blind rams or vice versa is acceptable, but two sets of pipe rams should be required when a mixed-size drill string is to be utilized. A backup power source capable of closing the preventers must be required.

The proposed program also must provide for blowout prevention drills, periodic pressure tests (e.g., at the time of installation, prior to drilling out each casing shoe, and at least every 30 days), and regular maintenance. In addition, the pipe and blind rams must be activated at the midpoint of each round trip. The approval of the authorized officer must stipulate any additional special testing or other requirements needed to assure safe operations. Ram-type preventers and related control equipment must be tested to the rated working pressure of the stack assembly, or to 70 percent of the minimum internal yield pressure of the casing, whichever is less; or to such pressure as the authorized officer may otherwise prescribe. After installation, annular-type preventers must be tested to 50 percent of the rated working pressure; or to such pressure as the authorized officer may otherwise prescribe.

D. Drilling Fluid. The mud program submitted by the operator must include the expected weights and type of mud and weighting material (including hydrogen sulfide neutralizers when warranted) by depth intervals. The mud program must be adequate to contain expected pressures without causing formation breakdown and resultant lost circulation; its chemical composition in contact with fresh water zones must be nontoxic.

When air or natural gas is used as the drilling medium, the operator must include the compressor and other special equipment in a schematic diagram. The drilling program should include: Stand-by mud, already mixed, in the working pit; a blowout preventer stack; and staked-down blooie or exhaust lines ending at least 100 feet from the rig, with a constant-burning pilot light. If practicable, two lines in opposite directions, with control valves, should be installed as a protection against changing wind directions.

For exploratory wells, the operator must state in the APD the minimum quantities of mud material, including weighting material, to be maintained at the drill site for emergency use (generally, not less than that needed to make a mud volume equal to the calculated active downhole and surface capacity). The APD also must list type and location of both the mud monitoring or measurement equipment and the degasser.

E. Safety and Public Health Hazards. The drilling application must address all potential safety and public health hazards and plans for their mitigation. If hydrogen sulfide (H_2S) gas is expected to be encountered in dangerous quantities during drilling, the drilling application should include a contingency plan covering all proposed safeguards, the method and location of detection equipment and warning devices, public identification and alert plans, and employee education plans. This education covers the dangers of exposure to H_2S and procedures to be followed, if H_2S is encountered during drilling. The preventive measures and operating practices required must be provided to control the effects of the toxicity and corrosive characteristics of H_2S.

F. Completion Program. The completion program for a development well should be included as part of the application. For an exploratory well, the operator may submit his proposed completion program as a part of the application, or later on Form 3160-5, for the approval of the authorized officer, after a discovery has been made. The proposed program is checked to ensure that the completion type (open hole, liner, perforated casing) is adequate to isolate the target formation from other formations not considered a common source of supply during all phases of operations (testing, treating, producing, injecting, and abandonment). If the well is to be completed in more than one zone, then the downhole equipment must be checked to ensure the necessary separation of the formations, unless downhole commingling is also approved.

G. Hole Deviation. Unless otherwise approved by the authorized officer, all well holes must be drilled substantially vertically, i.e., within 10 degrees of the vertical, with a maximum deviation of 1 degree per 1000 feet, and with a maximum rate of change of 1 degree per 100 feet. If there are indications of excessive deviation, directional surveys can be required to determine the magnitude of the angle of drift and the direction in which the well hole is deviated.

III. Environmental Considerations.

Most proposed oil and gas actions are subject to a categorical exclusion review (CER). This process is undertaken to ensure that an action, as proposed, would involve no impacts that may be environmentally significant. Information provided in the Surface Use Program, as required by Order No. 1, is the basis for evaluation of environmental effects of the proposed action. These are tabulated with description, as shown in Illustration 3, which is designed to facilitate review for adequacy or acceptability from both engineering and environmental points of view. The result of the environmental review then can be recorded in Illustration 4 as a record of the CER.

The nine exception criteria used in the CER process to evaluate the potential impact of the categorically excluded action are that the proposed action may:

1. Have significant adverse effects on public health or safety.

2. Adversely affect such unique geographic characteristics as historic or cultural resources, park, recreation, or refuge lands, wilderness areas, wild/scenic rivers, sole or principal drinking water aquifers, prime farmlands, wetlands, floodplains, or ecologically significant or critical areas, including those listed on the Department's National Register of Natural Landmarks.

3. Have highly controversial environmental effects

4. Have highly uncertain environmental effects or involve unique or unknown environmental risks.

5. Establish a precedent for future action or represent a decision in principle about a future consideration with significant environmental effects.

6. Be related to other actions with individually insignificant but cumulatively significant environmental effects.

   Adversely affect properties listed or eligible for listing in the National Register of Historic Places.

8. Affect a species listed or proposed for listing on the list of Endangered or Threatened Species.

9. Threaten to violate a Federal, State, local, or tribal law or requirements imposed for the protection of the environment or which require compliance with Executive Order 11988 (Floodplains Management), Executive Order 11990 (Protection of Wetlands), or the Fish and Wildlife Coordination Act.

If none of the criteria is met, the action is excluded from further environmental documentation. However, if as a result of the CER the proposed action meets any of the nine exception criteria, an environmental assessment (EA) must be prepared. The EA should focus on the particular issue(s) identified in the CER. At the conclusion of an EA, it must be determined whether or not the proposed action is a major Federal action significantly affecting the quality of the human environment according to Section 102 (2)(C) of the National Environmental Policy Act. If the proposed action is determined to be such a major Federal action, then no decision on the project can be made until an environmental impact statement is completed.

An EA must be prepared automatically when an application is filed to drill the first Federal or Indian confirmation well in a newly discovered field. Thus, each new field involving Federal minerals should be analyzed at this point for the cumulative impacts of full field development and the findings and necessary mitigation measures documented in an EA. The operator(s) should be asked to provide a conceptual development plan for the field to assist in this analysis. The term "confirmation well" is loosely defined, but is construed usually as the second well drilled after a discovery. However, one or two additional wells after the discovery well is completed may be permitted with a CER, if these are needed to better define the extent of the discovery.

CHECKLIST FOR DRILLING APPROVAL

ADMINISTRATIVE REVIEW FORMAT

Authorized Operator			
Lease Name/Expiration Date		/	
Location (Section, Township, Range)/County		/	
Well Number/Type		/	
Surface Ownership*			
Bond Coverage/ Archeological Report.		/	
Communitization Agreement Required?/Agent Under Unit Agreement.		/	
Surface Management Agency Copy Sent/Received.	(date)	/	(date)
CER Conducted/EA Needed?		/	
Notice of Staking (NOS) Filed/Field Inspc. Held?	**(date)**	**/**	**(date)**
7-day Notification After Receipt of NOS/of APD.	**(date)**	**/**	**(date)**
APD Received/Approved	**(date)**	**/**	**(date)**

***Note:** When private surface is involved, lessee/operator must furnish name, address, and, if known, telephone number of private surface owner, prior to the onsite inspection either (a) on NOS form, or (b) in Surface Use Program, accompanying the Application for Permit to Drill (APD).

DRILLING PROGRAM

TECHNICAL REVIEW FORMAT

Information Required	Received with APD	Not with APD	Information Incomplete	Date Subsequent Information Received	OK for Approval
1. Surveyed Location Plat*					
2. Elevation*					
3. Type of Drilling Tool*					
4. Proposed Depth**					
5. Estimated Tops of Geologic Markers.***					
6. Estimated Tops and Bottoms of Water, Oil, Gas, or Other Minerals; Protection Plans.***					
7. Casing Program*					
8. Setting Depths of Casing and Cement Program.*					
9. Pressure Control Equipment-Diagram. Testing Procedures and Frequency.***					
10. Mud Program***					
11. Anticipated Type and Amount of Testing, Logging, Coring.***					
12. Expected Bottom Hole Pressure; any Anticipated Abnormal Pressures, Temperatures, or Hazards; Contingency Plans.***					
13. Starting Date, Duration**					
14. Any Additional Information Volunteered (Specify).***					

*Information required on, or attached to, Form 3160-3. (See Order No. 1.)
**Form 3160-3 only.
***See Order No. 1.

Additional Requirements or Revisions Before Approval May Be Granted.

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Petroleum Engineer

SURFACE USE PROGRAM

TECHNICAL/ENVIRONMENTAL REVIEW FORMAT

Information Required	Received with APD	Not with APD	Information Incomplete	Date Subsequent Information Received	OK for Approval
1. Existing Roads (Map)					
2. Planned Access Roads (Map or Plat).					
3. Location of Existing Wells (Map or Plat).					
4. Existing and/or Proposed Location of Production Equipment on/off Well Pad (Map or Plat).					
5. Location and Type of Water Supply (Map, Plat, and/or Written).					
6. Construction Materials--Source, Type (Map, Plat, or Written).					
7. Methods and Location of Waste Disposal (Written).					
8. Ancillary Facilities (Map or Plat).					
9. Wellsite Layout Plat (not less than 1 inch = 50 feet).					
10. Plans for Surface Reclamation					
11. Surface Ownership					
12. Additional Information Volunteered.					
13. Representatives (Lessee's or Operator's) & Certification.					

Additional Requirements or Revisions Before Approval may be Granted.

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Reviewer

CHECKLIST DESCRIPTION FOR SURFACE USE PROGRAM

1. Existing Roads--a legible map, labeled and showing:

   A. Access route to location (including distances from point where access route exits established roads).

   B. Location of proposed well site in relation to a town (village) or other locatable point such as a highway or county road that handles majority of through traffic to general area.

   C. Access road(s) labeled.

   D. Plans for improvement and/or statement that existing roads will be maintained in the same or better condition.

2. Planned Access Roads--map or plat identifying all permanent and temporary access roads to be constructed or reconstructed, showing:

   A. Width.

   B. Maximum grades.

   C. Turnouts.

   D. Drainage design.

   E. Location and size of culverts and/or bridges, fence cuts and/or cattleguards, and type of surfacing material (if any).

   F. Major cuts and fills.

   G. Information indicating where existing facilities may be altered or modified.

   H. Any access roads crossing Federal or Indian lands needed to haul water for drilling.

   I. Methods for protecting permafrost from thawing (where appropriate)

3. Location of Existing Wells--a map or plat showing location of all wells within a 1-mile radius of proposed location:

   A. Water wells.

   B. Disposal wells.

   C. Drilling wells.

   D. Producing wells.

   F. Injection wells.

4. Location of Existing and/or Proposed Facilities, if Well is Productive:

   A. On Well Pad--map or plat showing location of production facilities and lines to be installed, if well is completed for production.

   B. Off Well Pad--map or plat showing existing or new production facilities to be utilized and lines to be installed if well is completed for production. Include dimensions of facility layout, if new construction.

Note: Operator has option of submitting information under 4.A and B, after well is completed for production, by applying for approval of subsequent operations.

5. Location and Type of Water Supply (by quarter-quarter section on map or plat, or written description):

   A. Source and transportation method for all water to be used in drilling, if source is on Federal or Indian land.

   B. Same as 5.A if water is from a Federal or Indian project.

   C. If water well is to be drilled on lease, so state

Note: Operator only needs to show location of source, if water is from other than Federal or Indian land.

6. Source of Construction Materials:

   A. Character and use of all mineral materials, if proposed source is owned by the Federal Government or by an Indian tribe or allottee.

   B. If materials are from other than Federal or Indian lands, so state.

7. Methods for Handling Waste Disposal:

   A. Describe methods and locations of proposed safe containment and disposal of each type of waste material, including:

      Cuttings.

      Garbage.

      Salts

      Sewage

      Chemicals

   B. Plans for eventual disposal of drilling fluids and any produced oil or water recovered during testing operations.

8. Ancillary Facilities--map or plat showing all proposed camps and airstrips as to their location, land area required, and construction methods and standards. (Approximate camp center and airstrip centerlines to be staked on the ground.)

9. Well Site Layout--a plat (not less than 1" = 50') showing:

   A. Cross sections of proposed drill pad showing any cuts and fills and relation to topography.

   B. Proposed location of reserve and burn pits, living facilities, and soil material stockpiles.

   C. Rig orientation, parking areas, and turnaround areas.

   D. Statement as to whether reserve pit is to be lined or unlined. If lined, detail plans.

10. Plans for Restoration of Surface:

A. Statement of surface reclamation program upon completion of operations, including:

Configuration of reshaped topography, drainage system, surface manipulations.

Segregation of spoil piles.

Waste disposal.

Revegetation methods and soil treatments.

Other practices necessary to reclaim all disturbed areas, including access roads or portions of well pads no longer needed.

Estimated timetable for commencement and completion of reclamation operations dependent on weather and other local uses.

Identification Number ____________

UNITED STATES DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

Originating Office Address

RECORD OF (CATEGORICAL EXCLUSION) REVIEW FORMAT

Project Identification

Operator/project Name ________________________________

Project Type ________________________________

Project Location ________________________________

Date Proposal Submitted ________________________________

____

Field Inspection(s)

Date(s) ________________________________

Participants ________________________________

I have reviewed the proposal in accordance with the categorical exclusion review guidelines and criteria. Based on my analysis of the proposal's impacts, it is my opinion that none of the exclusion review criteria would be met.

____________________	____________________
Date	Analyst

I concur with the reviewer's opinion and determine that the proposal would not involve any significant effects. Therefore, the proposal is exempted from further NEPA documentation.

____________________	____________________
Date	Approving Official

CATEGORICAL EXCLUSION REVIEW INFORMATION SOURCES FORMAT

Criteria 516 DM 2.3.A.	Federal/State Agency			Local and Private Corre-spondence (date)	Previous NEPA Document	Other Studies and Reports	Staff Expertise	Other
	Corre-spondence (date)	Phone Check (date)	Meeting (date)					
1. Public Health and Safety.								
2. Unique Characteristics.								
3. Environmentally Controversial.								
4. Uncertain and Unknown Risks.								
5. Establishes Precedent.								
6. Cumulatively Significant.								
7. National Register Historic Places.								
8. Endangered/ Threatened Species								
9. Violate Federal, State, Local, Tribal Law.								

SECTION 2-C
BLOWOUT PREVENTER STACK ARRANGEMENTS — SURFACE INSTALLATIONS

CLASSIFICATION OF BLOWOUT PREVENTERS

2.C.1 API classification of typical arrangements for blowout preventer equipment is based on working pressure ratings. Stack arrangements shown in Figs. 2.C.1 to 2.C.10 should prove adequate, in normal environments, for API Classes 2M, 3M, 5M, 10M, and 15M. Arrangements other than those illustrated may be equally adequate in meeting well requirements and promoting safety and efficiency.

STACK COMPONENT CODES

2.C.2 The recommended component codes for designation of blowout preventer stack arrangements are as follows:

A = annular type blowout preventer.
G = rotating head.
R = single ram type preventer with one set of rams, either blank or for pipe, as operator prefers.
R_d = double ram type preventer with two sets of rams, positioned in accordance with operator's choice.
R_t = triple ram type preventer with three sets of rams, positioned in accordance with operator's choice.
S = drilling spool with side outlet connections for choke and kill lines.
M = 1000 psi rated working pressure.

Components are listed reading upward from the uppermost piece of permanent wellhead equipment, or from bottom of the preventer stack. A blowout preventer stack may be fully identified by a very simple designation, such as:

5M - 13-5/8 - SRRA

This preventer stack would be rated 5000 psi working pressure, would have a throughbore of 13-5/8 inches, and would be arranged as in Fig. 2.C.5.

RAM LOCKS

2.C.3 Ram type preventers should be equipped with extension hand wheels or hydraulic locks.

SPARE PARTS

2.C.4 The following recommended minimum blowout preventer spare parts approved for the service intended should be available at each rig:

a. a complete set of drill pipe rams and ram rubbers for each size of drill pipe being used,

b. a complete set of bonnet or door seals for each size and type of ram preventer being used,

c. plastic packing for blowout preventer secondary seals, and

d. ring gaskets to fit flange connections.

PARTS STORAGE

2.C.5 When storing blowout preventer metal parts and related equipment, they should be coated with a protective coating to prevent rust. Storage of elastomer parts is covered in Par. 7.A.13.

DRILLING SPOOLS

2.C.6 While choke and kill lines may be connected to side outlets of the blowout preventers, many operators prefer that these lines be connected to a drilling spool installed below at least one preventer capable of closing on pipe. Utilization of the blowout preventer side outlets reduces the number of stack connections by eliminating the drilling spool and shortens the overall preventer stack height. The reasons for using a drilling spool are to localize possible erosion in the less expensive spool and to allow additional space between rams to facilitate stripping operations.

2.C.7 Drilling spools for blowout preventer stacks should meet the following minimum specifications:

a. Have side outlets no smaller than 2" nominal diameter and be flanged, studded, or clamped for API Class 2M, 3M, and 5M. API Class 10M and 15M installations should have a minimum of two side outlets, one 3" and one 2" nominal diameter.

b. Have a vertical bore diameter at least equal to the maximum bore of the uppermost casinghead as specified in Table 6.1 of *API Spec 6A: Specification for Wellhead Equipment.**

c. Have a working pressure rating equal to the rated working pressure of the attached blowout preventer and the upper portion of the casinghead (or tubing head).

2.C.8 For drilling operations, wellhead outlets should not be employed for choke or kill lines. Such outlets may be employed for auxiliary or back-up connections to be used only if a failure of the primary control system is experienced.

Available from American Petroleum Institute, Production Department, 211 North Ervay, Suite 1700, Dallas T 201

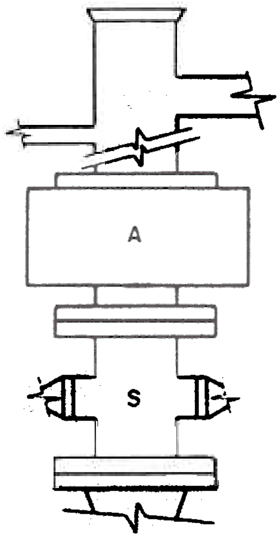

FIG. 2.C.1
ARRANGEMENT SA

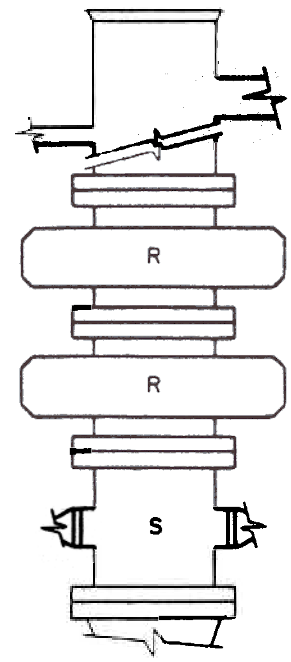

FIG. 2.C.2
ARRANGEMENT SRR
Double Ram Type Preventers, R_d, Optional.

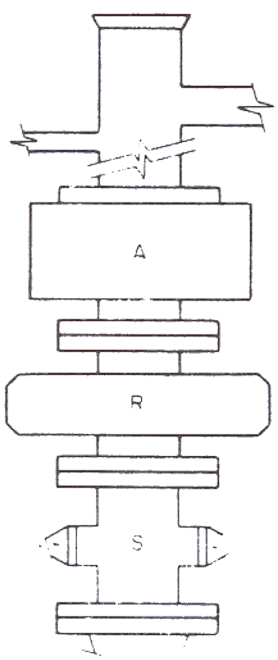

FIG. 2.C.3
ARRANGEMENT SRA

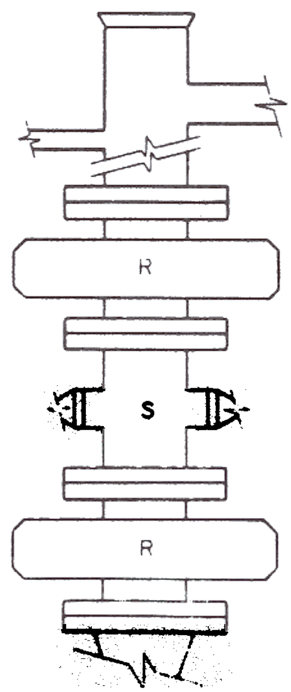

FIG. 2.C.4
ARRANGEMENT RSR

TYPICAL BLOWOUT PREVENTER
ARRANGEMENTS FOR 2M RATED WORKING
PRESSURE SERVICE – SURFACE INSTALLATION

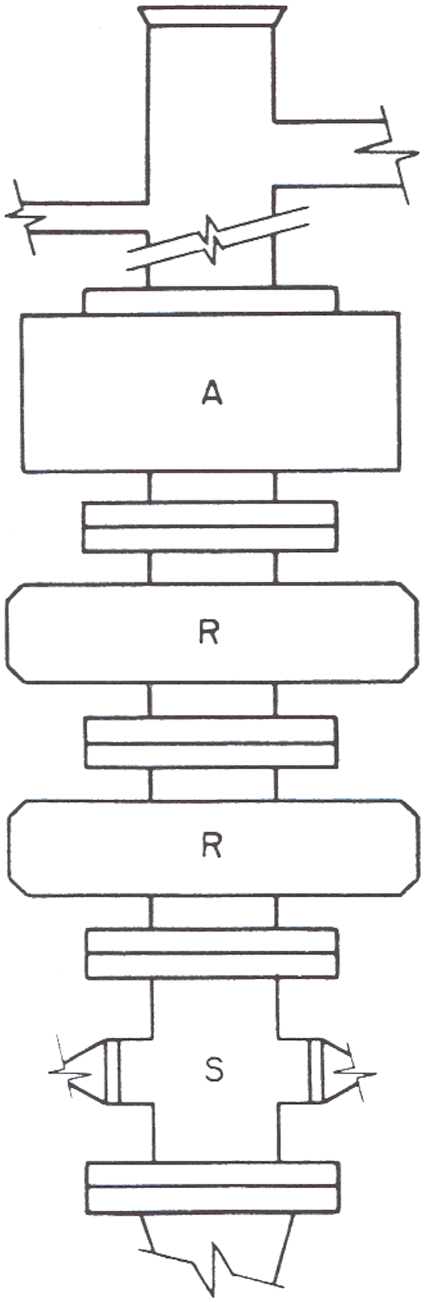

FIG. 2.C.5

ARRANGEMENT SRRA

Double Ram Type Preventers, R_d, Optional.

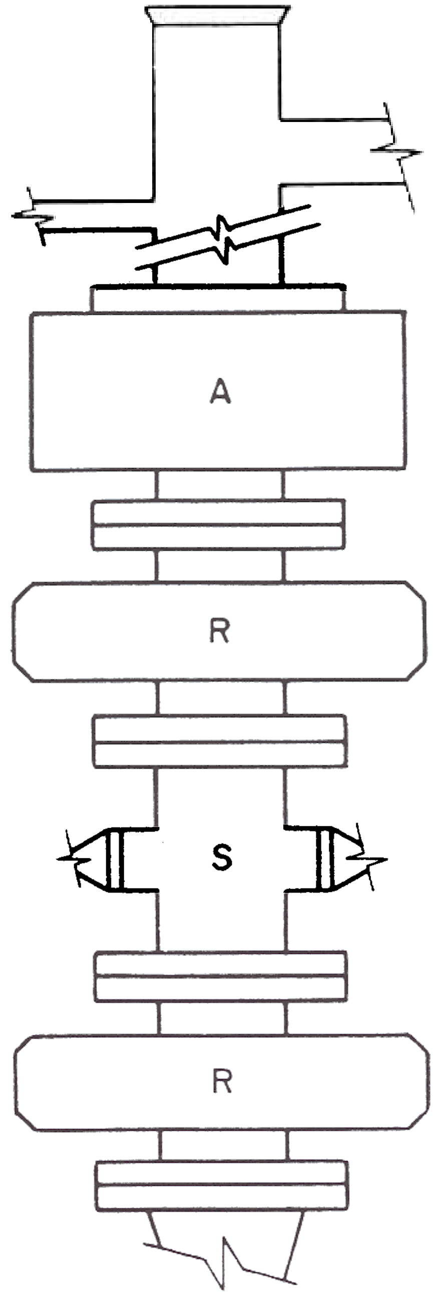

FIG. 2.C.6

ARRANGEMENT RSRA

TYPICAL BLOWOUT PREVENTER ARRANGEMENTS FOR 3M AND 5M RATED WORKING PRESSURE SERVICE— SURFACE INSTALLATION

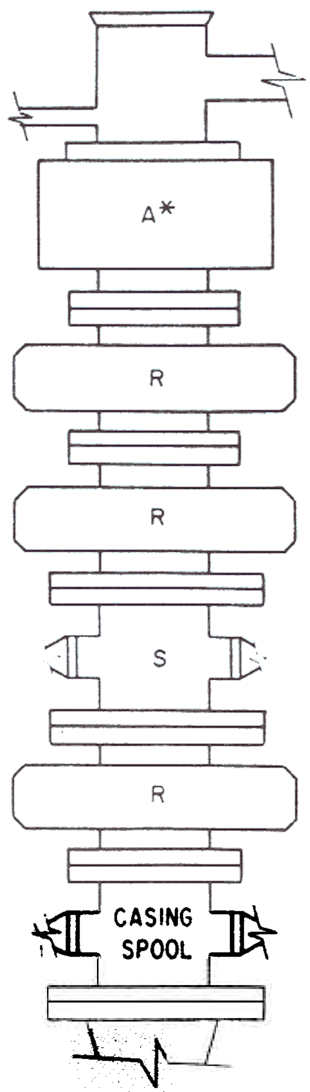

FIG. 2.C.7

ARRANGEMENT RSRRA*
Double Ram Type Preventers.
R_d. Optional.

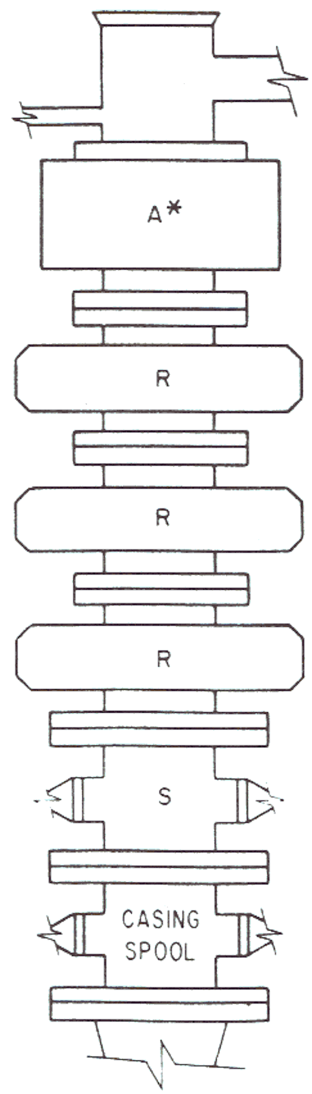

FIG. 2.C.8

ARRANGEMENT SRRRA*
Double Ram Type Preventers.
R_d. Optional.

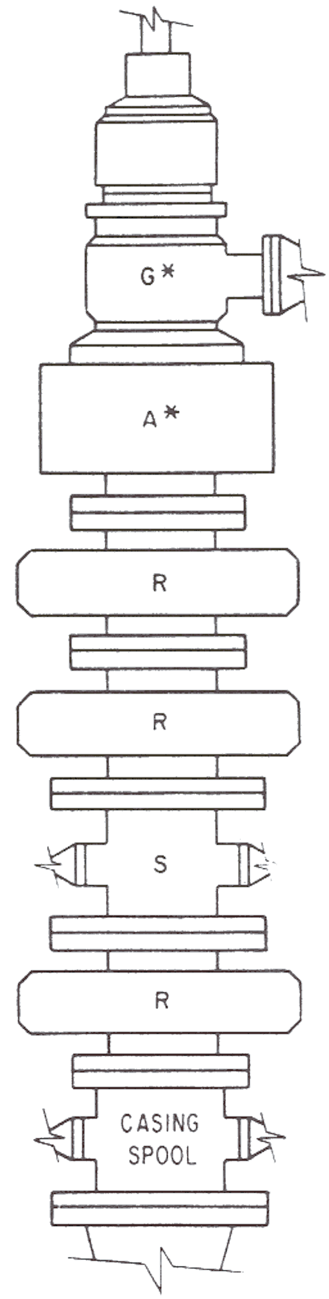

FIG. 2.C.9

ARRANGEMENT RSRRA*G*
Double Ram Type Preventers.
R_d. Optional.

*Annular preventer, and rotating head, G, can be of a lower pressure rating

TYPICAL BLOWOUT PREVENTER ARRANGEMENTS FOR 10M AND 15M WORKING PRESSURE SERVICE— SURFACE INSTALLATION

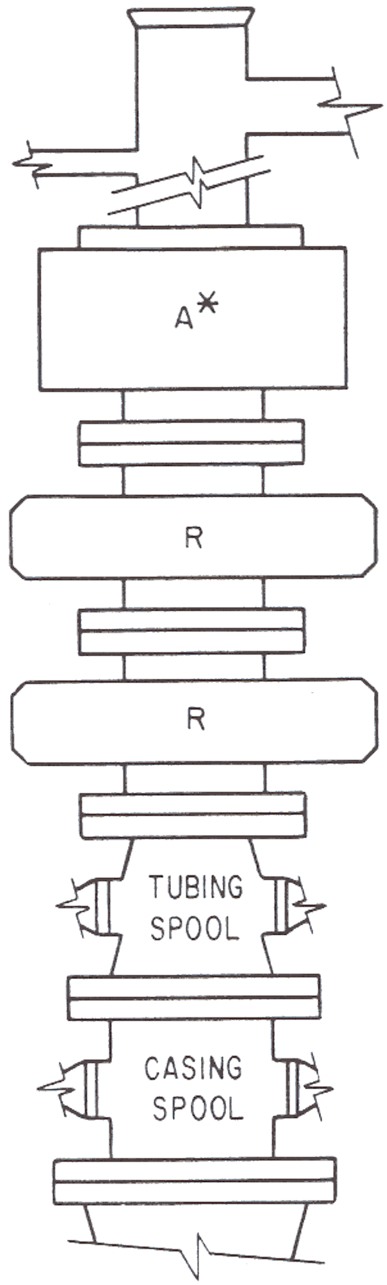

FIG. 2.C.10

ARRANGEMENT RRA*

Double Ram Type Preventers, R_d, Optional.

*Annular preventer, A, can be of a lower pr

TYPICAL COMPLETION BLOWOUT PREVENTER ARRANGEMENT FOR 3M, 5M, 10M, AND 15M RATED WORKING PRESSURE SERVICE – SURFACE INSTALLATION

SECTION 3-A
CHOKE MANIFOLDS – SURFACE INSTALLATIONS

PURPOSE

3.A.1 If the hydrostatic head of the drilling fluid is insufficient to control subsurface pressure, formation fluids will flow into the well. To maintain well control, back pressure is applied by routing the returns through adjustable chokes until the well flow condition is corrected. The chokes are connected to the blowout preventer stack through an arrangement of valves, fittings, and lines which provide alternative flow routes or permit the flow to be halted entirely. This equipment assemblage is designated the "choke manifold".

DESIGN CONSIDERATIONS

3.A.2 Choke manifold design should consider such factors as anticipated formation and surface pressures, method of well control to be employed, surrounding environment, corrosivity, volume, toxicity, and abrasiveness of fluids.

INSTALLATION GUIDELINES

3.A.3 Recommended practices for planning and installation of choke manifolds for surface installations include:

a. Manifold equipment subject to well and/or pump pressure (normally upstream of and including the chokes) should have a working pressure equal to the rated working pressure of the blowout preventers in use. This equipment should be tested when installed to pressures equal to the rated working pressure of the blowout preventer stack in use.

b. Components should comply with applicable API specifications to accommodate anticipated pressure, temperature, and corrosivity of the formation fluids and drilling fluids.

c. For working pressures of 3M and above, flanged, welded, or clamped connections should be employed on components subjected to well pressure.

d. The choke manifold should be placed in a readily accessible location, preferably outside of the rig substructure.

e. The choke line (which connects the blowout preventer stack to the choke manifold) and lines downstream of the choke should:

1) Be as straight as practicable; turns, if required, should be targeted.

2) Be firmly anchored to prevent excessive whip or vibration.

3) Have a bore of sufficient size to prevent excessive erosion or fluid friction:

a) Minimum recommended size for choke lines is 3-in. nominal diameter (2-in. nominal diameter is acceptable for Class 2M installations).

b) Minimum recommended size for vent lines downstream of the chokes is 2-in. nominal diameter.

c) For high volumes and air or gas drilling operations, 4-in. nominal diameter lines are recommended.

f. Alternate flow and flare routes downstream of the choke line should be provided so that eroded, plugged, or malfunctioning parts can be isolated for repair without interrupting flow control.

g. Consideration should be given to the low temperature properties of the materials used in installations to be exposed to unusually low temperatures.

h. The bleed line (the vent line which by-passes the chokes) should be at least equal in diameter to the choke line. This line allows circulation of the well with the preventers closed while maintaining a minimum of back pressure. It also permits high volume bleedoff of well fluids to relieve casing pressure with the preventers closed.

i. Although not shown in the typical equipment illustrations, buffer tanks are sometimes installed downstream of the choke assemblies for the purpose of manifolding the bleed lines together. When buffer tanks are employed, provision should be made to isolate a failure or malfunction without interrupting flow control.

j. Pressure gauges suitable for drilling fluid service should be installed so that drill pipe and annulus pressures may be accurately monitored and readily observed at the station where well control operations are to be conducted.

k. All choke manifold valves subject to erosion from well flow should be full-opening and designed to operate in high pressure gas and drilling fluid service. Double, full-opening valves between the blowout preventer stack and the choke line are recommended for installations with rated working pressures of 3M and above.

l. For installations with rated working pressures of 5M and above the following are recommended:

1) One of the valves in Par. 3.A.3.k should be remotely actuated.

2) Double valves should be installed immediately upstream of each choke.

3) At least one remotely operated choke should be installed. If prolonged use of this choke is anticipated, a second remotely operated choke should be used.

m. Spare parts for equipment subject to wear or damage should be readily available. A recommended inventory of choke manifold spare parts is included in Section 3-B.

n. Testing, inspection, and general maintenance of choke manifold components should be performed on the same schedule as employed for the blowout preventer stack in use (refer to Par. 7.A.7).

o. All components of the choke manifold system should be protected from freezing by heating, draining, or filling with proper fluid.

3.A.4 Figs. 3.A.1 through 3.A.3 illustrate typical choke manifolds for various working pressure service. Refinements or modifications such as additional hydraulic valves and choke runs, wear nipples downstream of chokes, redundant pressure gauges, and/or manifolding of vent lines will be dictated by the conditions anticipated for a particular well and the degree of protection desired. The guidelines discussed and illustrated represent typical industry practice.

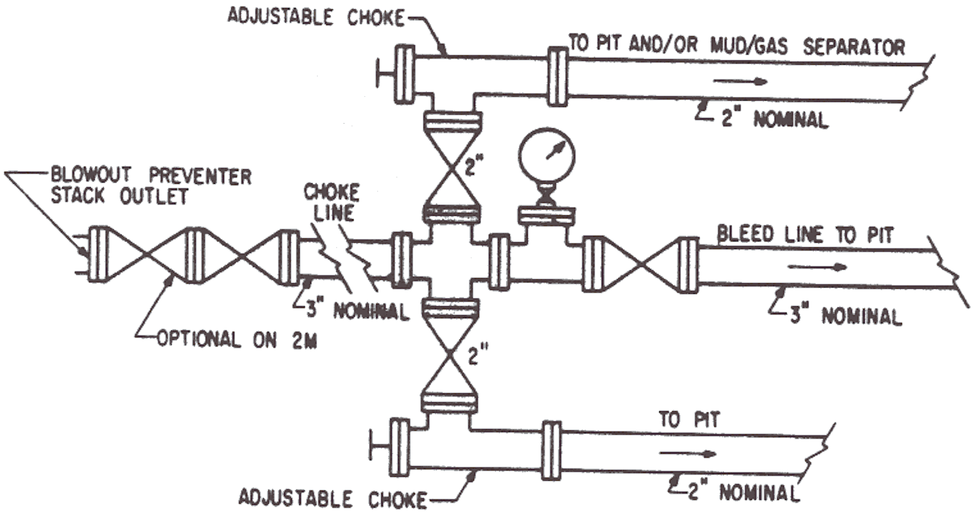

FIG. 3.A.1

TYPICAL CHOKE MANIFOLD ASSEMBLY FOR 2M AND 3M RATED WORKING PRESSURE SERVICE — SURFACE INSTALLATION

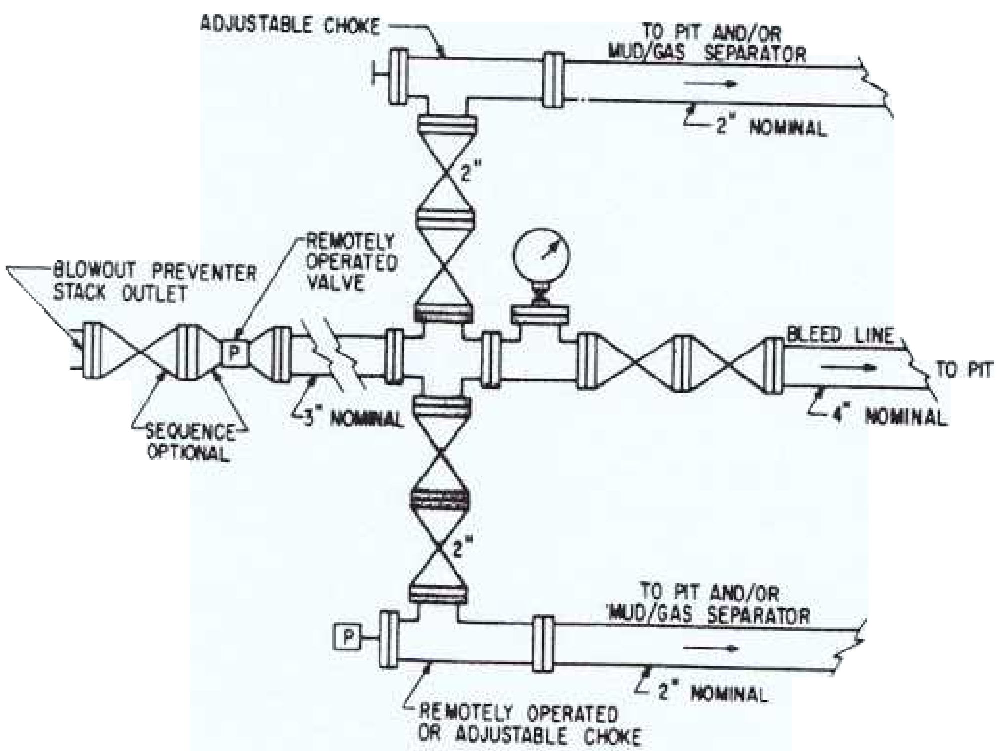

FIG. 3.A.2

TYPICAL CHOKE MANIFOLD ASSEMBLY FOR 5M RATED WORKING PRESSURE SERVICE — SURFACE INSTALLATION

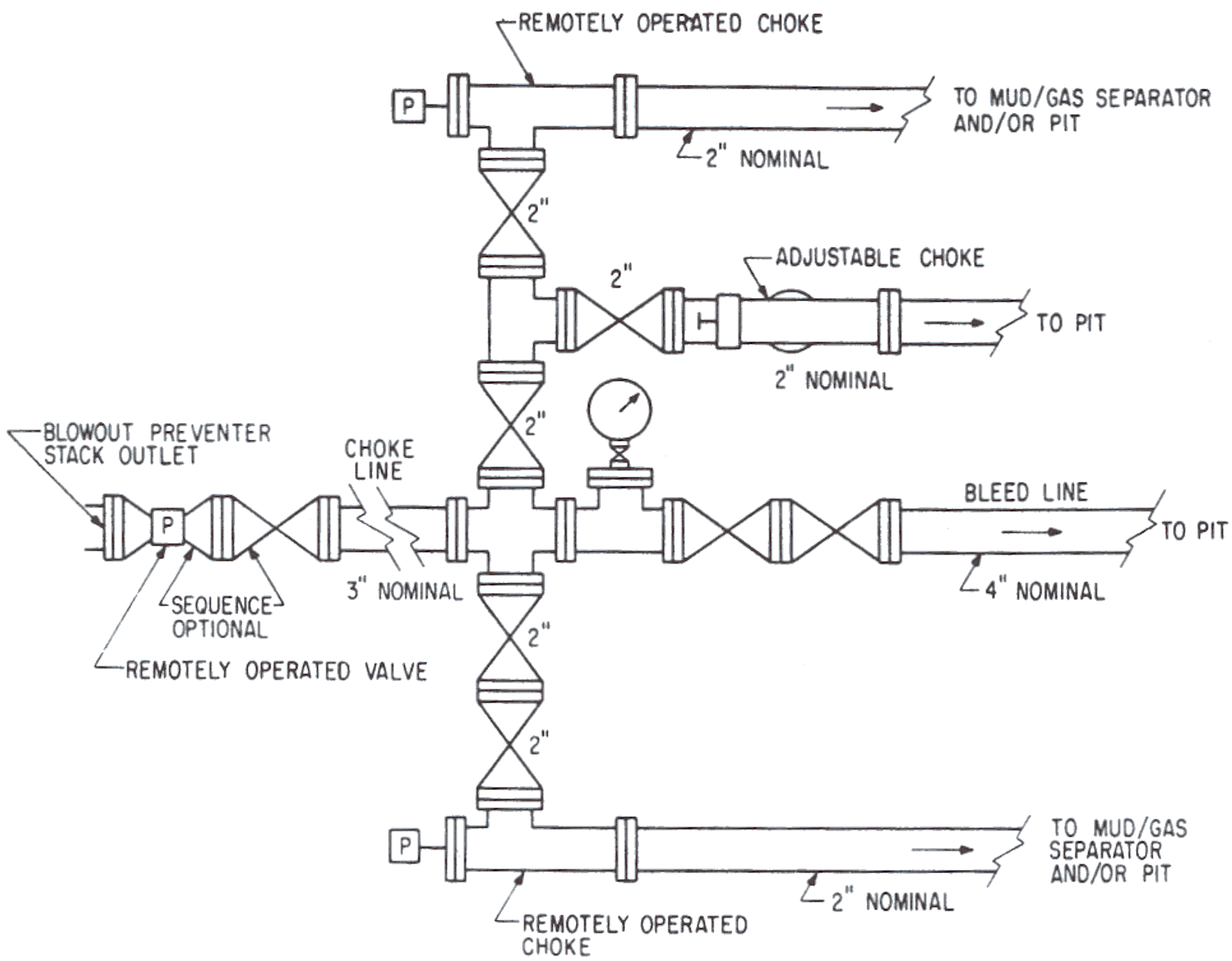

FIG. 3.A.3

TYPICAL CHOKE MANIFOLD ASSEMBLY FOR 10M AND 15M RATED WORKING PRESSURE SERVICE — SURFACE INSTALLATION

SECTION 4-A
KILL LINES — SURFACE INSTALLATIONS

PURPOSE

4.A.1 Kill lines are an integral part of the surface equipment required for drilling well control. The kill line system provides a means of pumping into the wellbore when the normal method of circulating down through the kelly or drill pipe cannot be employed. The kill line connects the drilling fluid pumps to a side outlet on the blowout preventer stack. The location of the kill line connection to the stack depends upon the particular configuration of preventers and spools employed; the connection should be below the ram type preventer most likely to be closed. Figs. 4.A.1 and 4.A.2 illustrate typical kill line installations for various working pressure service.

4.A.2 A "remote" kill line is commonly employed to permit use of an auxiliary high pressure pump if the rig pumps become inoperative or inaccessible. This line normally is tied into the kill line near the blowout preventer stack and extended to a site suitable for location of a pump or pump truck. This site should be selected to afford maximum safety and accessibility.

INSTALLATION GUIDELINES

4.A.3 The same guidelines which govern the installation of choke manifolds apply to kill line installations. The more important recommendations include:

a. All lines, valves, check valves, and flow fittings should have a working pressure rating and be tested following installation to pressures equal to or greater than the rated working pressure of the blowout preventer stack in use.

b. Flanged, welded, or clamped connections should be employed for fittings or valves with rated working pressures of 3M or above.

c. Components should be of sufficient diameter to permit reasonable pumping rates without excessive friction. The minimum recommended size is 2-in. nominal diameter.

d. Components which may be exposed to drilling fluids or formation fluids should comply with applicable API Specifications with particular consideration given to pressure, temperature, and corrosion resistance.

e. Double full-opening valves between the stack outlet and the kill line are recommended for installations with rated working pressures of 3M or above.

f. Periodic operation, inspection, testing, and maintenance should be performed on the same schedule as employed for the blowout preventer stack in use (refer to Par. 7.A.7).

g. All components of the kill line system should be protected from freezing by heating, draining, or filling with proper fluid.

h. Consideration should be given to the low temperature properties of the materials used in installations to be exposed to unusually low temperatures.

4.A.4 The kill line should not be used as a fill-up line. Routine use of the kill line could result in erosion of the lines and valves, thus reducing their usefulness in an emergency.

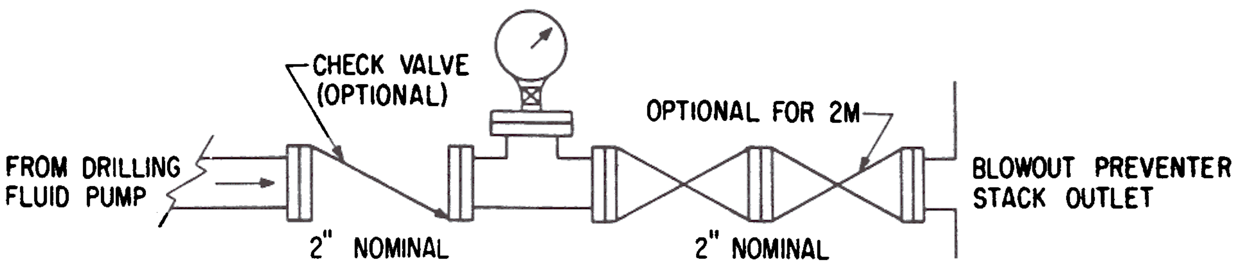

FIG. 4.A.1

TYPICAL KILL LINE ASSEMBLY FOR 2M AND 3M RATED WORKING PRESSURE SERVICE — SURFACE INSTALLATION

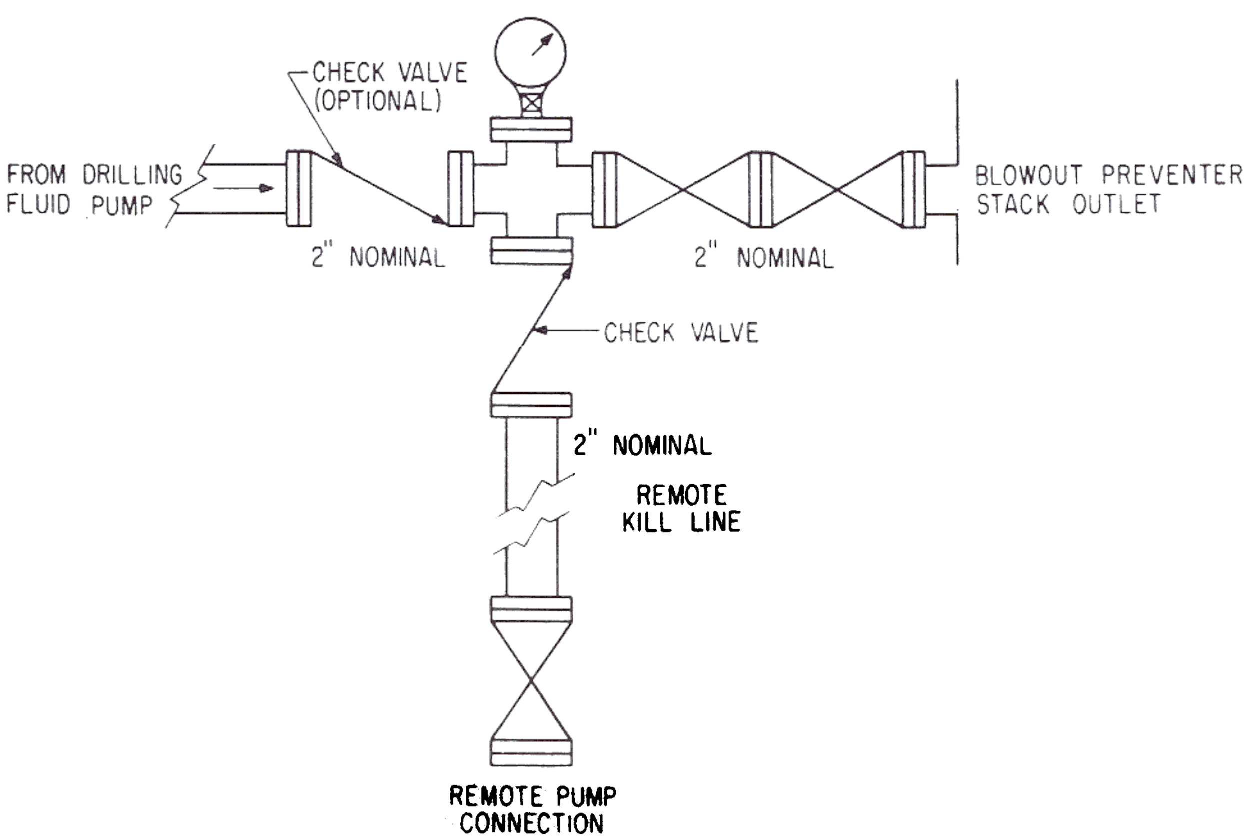

FIG. 4.A.2

TYPICAL KILL LINE ASSEMBLY FOR 5M, 10M, and 15M RATED WORKING PRESSURE SERVICE — SURFACE INSTALLATION

SECTION 5-A
CLOSING UNITS — SURFACE INSTALLATIONS

ACCUMULATOR REQUIREMENTS

General

5.A.1 Accumulator bottles are containers which store hydraulic fluid under pressure for use in effecting blowout preventer closure. Through use of compressed nitrogen gas, these containers store energy which can be used to effect rapid preventer closure. There are two types of accumulator bottles in common usage, separator and float types. The separator type uses a flexible diaphragm to effect positive separation of the nitrogen gas from the hydraulic fluid. The float type utilizes a floating piston to effect separation of the nitrogen gas from the hydraulic fluid.

Volumetric Capacity

5.A.2 As a minimum requirement, all blowout preventer closing units should be equipped with accumulator bottles with sufficient volumetric capacity to provide the usable fluid volume (with pumps inoperative) to close one pipe ram and the annular preventer in the stack plus the volume to open the hydraulic choke line valve.

5.A.3 Usable fluid volume is defined as the volume of fluid recoverable from an accumulator between the accumulator operating pressure and 200 psi above the precharge pressure. The accumulator operating pressure is the pressure to which accumulators are charged with hydraulic fluid.

5.A.4 The minimum recommended accumulator volume (nitrogen plus fluid) will be determined by multiplying the accumulator size factor (refer to Table 5-A) times the calculated volume to close the annular preventer and one pipe ram plus the volume to open the hydraulic choke line valve.

TABLE 5-A

Accumulator Operating Pressure, psi	Recommended Precharge Pressure, psi	Maximum Precharge Pressure, psi	Usable Fluid Volume (fraction of bottle size)	Accumulator Size Factor
1500	750	800	1/8*	8*
2000	1000	1100	1/3	3
3000	1000	1100	1/2	2

Notes:

*Based on minimum discharge pressure of 1200 psi.

Response Time

5.A.5 The closing system should be capable of closing each ram preventer within 30 seconds. Closing time should not exceed 30 seconds for annular preventers smaller than 20 inches and 45 seconds for annular preventers 20 inches and larger.

Operating Pressure and Precharge Requirements for Accumulators

5.A.6 No accumulator bottle should be operated at a pressure greater than its rated working pressure.

5.A.7 The precharge pressure on each accumulator bottle should be measured during the initial closing unit installation on each well and adjusted if necessary (refer to Par. 5.A.4). Only nitrogen gas should be used for accumulator precharge. The precharge pressure should be checked frequently during the drilling of the well.

Requirements for Accumulator Valves, Fittings, and Pressure Gauges

5.A.8 Multi-bottle accumulator banks should have valving for bank isolation. An isolation valve should have a rated working pressure at least equivalent to the designed working pressure of the system to which it is attached and must be in the open position except when accumulators are isolated for servicing, testing, or transporting (refer to Fig. 5.A.1). Accumulator bottles may be installed in banks of approximately 160 gallons capacity if desired, but with a minimum of two banks.

5.A.9 The necessary valves and fittings should be provided on each accumulator bank to allow a pressure gauge to be readily attached without having to remove all accumulator banks from service. An accurate pressure gauge for measuring the accumulator precharge pressure should be readily available for installation at any time.

CLOSING UNIT PUMP REQUIREMENTS

Pump Capacity Requirements

5.A.10 Each closing unit should be equipped with sufficient number and sizes of pumps to satisfactorily perform the operation described in this paragraph. With the accumulator system removed from service, the pumps should be capable of closing the annular preventer on the size drill pipe being used plus opening the hydraulically operated choke line valve and obtain a minimum of 200 psi pressure above accumulator precharge pressure on the closing unit manifold within two (2) minutes or less.

Pump Pressure Rating Requirements

5.A.11 Each closing unit must be equipped with pumps that will provide a discharge pressure equivalent to the rated working pressure of the closing unit.

Pump Power Requirements

5.A.12 Power for closing unit pumps must be available to the accumulator unit at all times, such that the pumps will automatically start when the closing unit manifold pressure has decreased to less than 90 percent of the accumulator operating pressure.

5.A.13 Two or three independent sources of power should be available on each closing unit. Each independent source should be capable of operating the pumps at a rate that will satisfy the requirement described in Par. 5.A.10. The dual source power system recommended is an air system plus an electrical system. Minimum recommendations for the dual air system and other acceptable but less preferred dual power source systems are as follows:

a. A dual air/electrical system may consist of the rig air system (provided at least one air compressor is driven independent of the rig compound) plus the rig generator (refer to Fig. 5.A.2).

b. A dual air system may consist of the rig air system (provided at least one air compressor is driven independent of the rig compound) plus an air storage tank that is separated from both the rig air compressors and the rig air storage tank by check valves. The minimum acceptable requirements for the separate air storage tank are volume and pressure which will permit use of only the air tank to operate the pumps at a rate that will satisfy the operation described in the pump capacity requirements (refer to Par. 5.A.10).

c. A dual electrical system may consist of the normal rig generating system and a separate generator (refer to Fig. 5.A.3).

d. A dual air/nitrogen system may consist of the rig air system plus bottled nitrogen gas (refer to Fig. 5.A.4).

e. A dual electrical nitrogen system may consist of the rig generating system and bottled nitrogen gas (refer to Fig. 5.A.5).

5.A.14 On shallow wells where the casing being drilled through is set at 500 feet or less and where surface pressures less than 200 psi are expected, a backup source of power for the closing unit is not essential.

REQUIREMENTS FOR CLOSING UNIT VALVES, FITTINGS, LINES, AND MANIFOLD

Required Pressure Rating

5.A.15 All valves, fittings, and lines between the closing unit and the blowout preventer stack should be of steel construction with a rated working pressure at least equal to the working pressure rating of the stack up to 5000 psi.

Valves, Fittings, and Other Components Required

5.A.16 Each installation should be equipped with the following:

a. Each closing unit manifold should be equipped with a full-opening valve into which a separate operating fluid pump can be easily connected (refer to Fig. 5.A.1).

b. Each closing unit should be equipped with sufficient check valves or shut-off valves to separate both the closing unit pumps and the accumulators from the closing unit manifold and to isolate the annular preventer regulator from the closing unit manifold.

c. Each closing unit should be equipped with accurate pressure gauges to indicate the operating pressure of the closing unit manifold, both upstream and downstream of the annular preventer pressure regulating valve.

d. Each closing unit should be equipped with a pressure regulating valve to permit manual control of the annular preventer operating pressure.

e. Each closing unit equipped with a regulating valve to control the operating pressure on the ram type preventers should be equipped with a by-pass line and valve to allow full accumulator pressure to be placed on the closing unit manifold, if desired.

f. Closing unit control valves must be clearly marked to indicate (1) which preventer or choke line valve each control valve operates, and (2) the position of the valves (i.e., open, closed, neutral). Each blowout preventer control valve should be turned to the open position (not the neutral position) during drilling operations. The choke line hydraulic valve should be turned to the closed position during normal operations. The control valve that operates the blind rams should be equipped with a cover over the manual handle to avoid unintentional operation.

g. Each annular preventer may be equipped with a full-opening plug valve on both the closing and opening lines. These valves should be installed immediately adjacent to the preventer and should be in the open position at all times except when testing the operating lines. This will permit testing of operating lines in excess of 1500 psi without damage to the annular preventer if desired by the user.

REQUIREMENTS FOR CLOSING UNIT FLUIDS AND CAPACITY

5.A.17 A suitable hydraulic fluid (hydraulic oil or fresh water containing a lubricant) should be used as the closing unit control operating fluid. Sufficient volume of glycol must be added to any closing unit fluid containing water if ambient temperatures below 32 F are anticipated. The use of diesel oil, kerosine, motor oil, chain oil, or any other similar fluid is not recommended due to the possibility of resilient seal damage.

5.A.18 Each closing unit should have a fluid reservoir with a capacity equal to at least twice the usable fluid capacity of the accumulator system.

CLOSING UNIT LOCATION AND REMOTE CONTROL REQUIREMENTS

5.A.19 The main pump accumulator unit should be located in a safe place which is easily accessible to rig personnel in an emergency. It should also be located to prevent excessive drainage or flow back from the operating lines to the reservoir. Should the main pump accumulator be located a substantial distance below the preventer stack, additional accumulator volume should be added to compensate for flow back in the closing lines.

5.A.20 Each installation should be equipped with a sufficient number of control panels such that the operation of each blowout preventer and control valve can be controlled from a position readily accessible to the driller and also from an accessible point at a safe distance from the rig floor.

CLOSING UNIT PUMP CAPABILITY TEST

5.A.21 Prior to conducting any tests, the closing unit reservoir should be inspected to be sure it does not contain any drilling fluid, foreign fluid, rocks, or other debris. The closing unit pump capability test should be conducted on each well before pressure testing the blowout preventer stack. This test can be conveniently scheduled either immediately before or after the accumulator closing time test. Test should be conducted according to the following procedure:

a. Position a joint of drill pipe in the blowout preventer stack.

b. Isolate the accumulators from the closing unit manifold by closing the required valves.

c. If the accumulator pumps are powered by air, isolate the rig air system from the pumps. A separate closing unit air storage tank or a bank of nitrogen bottles should be used to power the pumps during this test. When a dual power source system is used, both power supplies should be tested separately.

d. Simultaneously turn the control valve for the annular preventer to the closing position and turn the control valve for the hydraulically operated valve to the opening position.

e. Record the time (in seconds) required for the closing unit pumps to close the annular preventer plus open the hydraulically operated valve and obtain 200 psi above the precharge pressure on the closing unit manifold. It is recommended that the time required for the closing unit pumps to accomplish these operations not exceed two minutes.

f. Close the hydraulically operated valve and open the annular preventer. Open the accumulator system to the closing unit and charge the accumulator system to its designed operating pressure using the pumps.

ACCUMULATOR TESTS

Accumulator Precharge Pressure Test

5.A.22 This test should be conducted on each well prior to connecting the closing unit to the blowout preventer stack. Test should be conducted as follows:

a. Open the bottom valve on each accumulator bottle and drain the hydraulic fluid into the closing unit fluid reservoir.

b. Measure the nitrogen precharge pressure on each accumulator bottle using an accurate pressure gauge attached to the precharge measuring port and adjusted if necessary.

Accumulator Closing Test

5.A.23 This test should be conducted on each well prior to pressure testing the blowout preventer stack. Test should be conducted as follows:

a. Position a joint of drill pipe in the blowout preventer stack.

b. Close off the power supply to the accumulator pumps.

c. Record the initial accumulator pressure. This pressure should be the designed operating pressure of the accumulators. Adjust the regulator to provide 1500 psi operating pressure to the annular preventer.

d. Simultaneously turn the control valves for the annular preventer and for one pipe ram (having the same size ram as the pipe used for testing) to the closing position and turn the control valve for the hydraulically operated valve to the opening position.

e. Record the time required for the accumulators to close the preventers and open the hydraulically operated valve. Record the final accumulator pressure (closing unit pressure). This final pressure should be at least 200 psi above the

f. After the preventers have been opened, charge the accumulator system to its designed operating pressure using the accumulator pumps.

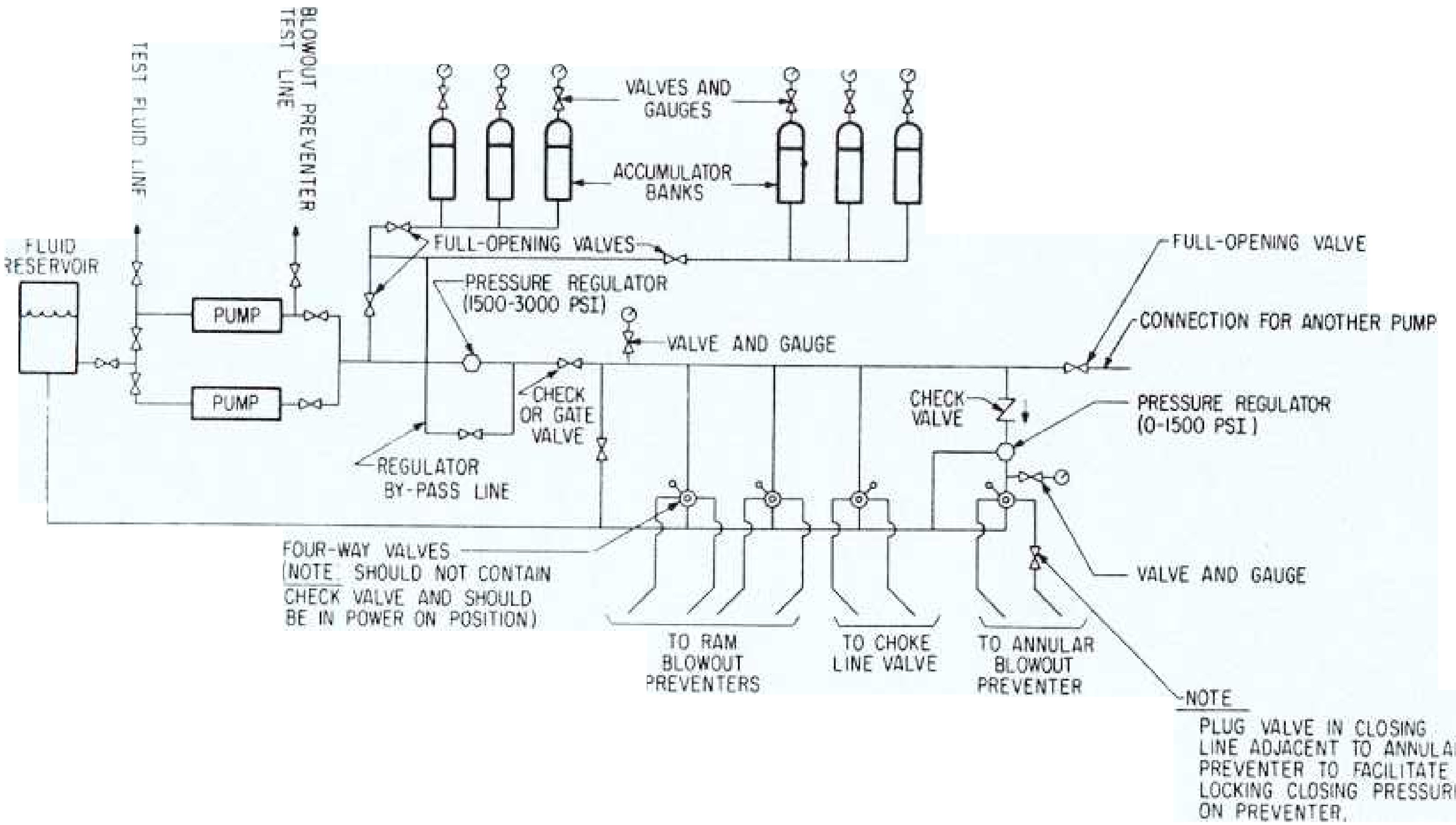

FIG. 5.A.1

TYPICAL BLOWOUT PREVENTER CLOSING UNIT ARRANGEMENT

SECTION 6-A
AUXILIARY EQUIPMENT — SURFACE INSTALLATIONS

6.A.1 Kelly Cock. A kelly cock shall be installed between the swivel and the kelly. The kelly cock should have a rated working pressure at least equal to the rated working pressure of the blowout preventer stack. A device is available to operate the kelly cock hydraulically from the rig floor in two to four seconds.

6.A.2 Lower Kelly Valve. A lower kelly valve should be used below the kelly. The lower kelly valve should have a working pressure rating at least equal to the rated working pressure of the blowout preventer stack.

6.A.3 Drill Pipe Safety Valve. A drill pipe safety valve should be available on the rig floor at all times. This valve or valves should be equipped to screw into any drill string member in use. The drill pipe safety valve should have a working pressure rating at least equal to the rated working pressure of the blowout preventer stack. The outside diameter of the drill pipe safety valve should be suitable for running into the hole.

6.A.4 Inside Blowout Preventer. An inside blowout preventer, drill pipe float valve, or drop-in check valve should be available for use when stripping the drill string into or out of the hole. The valve, sub, or profile nipple should be equipped to screw into any drill string member in use. The inside blowout preventer, float valve, or drop-in check valve should have a working pressure rating at least equal to the rated working pressure of the blowout preventer stack.

6.A.5 Trip Tank. A trip tank with a capacity of 10 to 40 barrels and built so that 42 gallons equals at least an inch of depth is an accurate device for measuring the influx or efflux of fluid from the wellbore.

6.A.6 Pit Volume Measuring and Recording Devices. Automatic pit volume measuring devices are available which transmit a pneumatic or electric signal from sensors on the drilling fluid pits to recorders and signaling devices on the rig floor. These are valuable in detecting fluid gain or loss when circulating.

6.A.7 Visual Pit Volume Measuring Device. A wood float attached to a counterweight above the rig floor by a small cable and rigged up to show pit volume on a board standing behind the counterweight is a useful sensing device when mounted on the drilling fluid pits or trip tank.

6.A.8 Flow Rate Sensor. A flow rate sensor mounted in the flow line is useful for early detection of formation fluid entering the wellbore or a loss of returns. When circulating through a surface system too large to permit accurate measurement of a pit gain, such as circulating through the reserve pit, a flow rate sensor mounted in the flow line is recommended.

6.A.9 Automatic Drilling Fluid Weighing Devices. Automatic drilling fluid weighing devices are available and can improve the measurement of fluid density in the surface system. It is possible to incorporate an automatic drilling fluid weighing device with an automatic weight material mixing system to control drilling fluid density automatically.

6.A.10 Manual Drilling Fluid Weighing Devices. A drilling fluid balance designed to weigh a compressed sample of drilling fluid can be used to read the density of gas cut drilling fluid without the necessity of diluting, degassing, weighing, and calculating so-called true drilling fluid weight.

6.A.11 Mud/Gas Separator. A mud/gas separator may be mounted on or near the surface pit system for convenience in handling gas cut drilling fluid. Such a device is useful in separating gas from drilling fluid and venting the gas safely away from the rig. This permits slightly gas cut drilling fluid to be returned to the pit system thus avoiding an excessive waste of fluid. Volume of liquids and gas to be handled should be considered in the design of the mud/gas separator.

6.A.12 Degasser. A degasser may be used to remove entrained gas from the drilling fluid. Removal of the gas improves pump efficiency and permits more efficient control of the fluid density. Adequate fluid handling capacity is very important since the input volume may be several times as large as the amount of fluid handled by the rig drilling fluid pumps.

6.A.13 Well Control Station. Remote adjustable chokes are available for use in choke manifold systems. These chokes improve well control operations by putting the choke control point at a convenient location where the choke operator can monitor and regulate drill pipe pressure, pump speed, and annulus pressure.

6.A.14 Stand Pipe Choke. An adjustable choke mounted on the rig stand pipe can be used to bleed pressure off the drill pipe under certain conditions, reduce the shock when breaking circulation in wells where loss of circulation is a problem, and bleed off pressure between blowout preventers during stripping operations. Refer to Fig. 10.A.1 for a typical stand pipe choke installation.

*Available from American Petroleum Institute, Production Department, 211 North Ervay, Suite 1700, Dallas TX 75201.