Instruction Memorandum No. 92-***
Expires: 9/30/93

To: All State Directors, District Offices, Resource Areas, PTC and SCD

From: Director

Subject: Establishment of Interim Manual/Handbook Guidance for Oil and Gas Drilling Operations - 3160

DD 10/31/92

DISTRIBUTION: All staffs involved with policy development, review, implementation and input for authorization and oversight of oil and gas drilling operations on Public and Indian Lands.

BACKGROUND/ISSUE: Attached are draft Manual Section 3160-1 (Attachment 1) and H-3160-1 (Attachment 2) concerning drilling operations. The Handbook has four chapters. Chapters I and II, addressing Administrative Processing and Environmental Reviews, respectively, are pending due to finalization of Onshore Oil and Gas Order No.1, Approval of operations. Chapters III and IV address Technical Reviews and Drilling Inspections.
The attachments provide interim policy on the intent of the minimum standards listed in Onshore Oil and Gas Order No. 2, Drilling operations, published final November 18, 1988. The Handbook also provides detailed guidance on the intent of the minimum standards listed in Onshore Oil and gas. Order No. 6, Hydrogen Sulfide operations, published final November 23, 1990.

POLICY: This release shall serve as the program policy for the subject listed above. Field offices shall incorporate this policy and provide comments based on experience garnered through this field season.

METHODS OF ACCOMPLISHMENT: The Manual/Handbook Sections are to be used as interim guidance until final documents are issued. As offices use these documents over the next few months, they are requested to submit any additional comments concerning content revision to UT-922. All comments received will be addressed prior to final release of the documents. Comments should be submitted by October 31, 1992.

BUDGET IMPLICATIONS: N/A

MANUAL/HANDBOOK: Once Chapters relative to Administrative Processing and Environmental Reviews are similarly drafted and commented upon, these documents will be made interim.

COORDINATION: Extensive coordination has occurred and the interim guidance, as drafted, has been circulated for initial review. This release needs to be incorporated into the appropriate Bureau training courses as well.

CONTACT PERSON: Questions may be addressed to Al McKee, Lead, Drilling Operations Handbook and Manual, UT-922, FTS-581-4045.

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Handbook.
H-3160-1 Drilling Operations

3160-1 DRILLING OPERATIONS

.01 Purpose. This Manual Section contains guidance and procedures for the administrative processing, the review of both the surface and subsurface portions of an Application for Permit to Drill (APD), remedial actions, evaluation of variances, drilling abandonments, and drilling inspections.

.02 Objectives. The objectives of these procedures are to ensure that drilling and drilling abandonment operations are uniformly approved and conducted in a manner consistent with statutory provisions, and regulatory and policy requirements; conform with current available technology and practice; afford adequate safeguards for the environment; assure that subsurface formations containing usable quality water or prospectively valuable deposit of minerals will not be endangered by drilling operations; and otherwise ensure the protection of public health and safety.

.03 Authority.

A. 43 CFR Group 3160

B. 25 CFR Group 211, 212, 213, and 227

C. Onshore Oil and Gas Order No. 1, Approval of Operations on Onshore Federal and Indian Oil and Gas Leases.

D. Onshore Oil and Gas Order No. 2, Drilling Operations on Federal and Indian oil and Gas Leases,

E. Onshore Oil and Gas order No. 6, Hydrogen Sulfide Operations on Federal and Indian Oil and Gas Leases.

.04 Responsibility.

A. State Director. The State Director is responsible for administratively processing; reviewing the Surface Use Plan of operations and the Drilling Plan portion of APD's for technical adequacy; making decisions on the applicability of the plan; requiring additional safeguards through the inclusion of *Conditions* of Approval (COA) when necessary; approving variances to the minimum standards; approving drilling abandonments; and conducting drilling inspections. Where these responsibilities are delegated to the District or Area Managers, The State Director is responsible for providing guidance and assistance, and ensures uniform implementation of the regulations, policy and procedures.

B. District Manager. If delegated, the District Manager may carry out any or all of the above responsibilities of the State Director.

C. Area Manager. If delegated, the Area Manager may carry out any or all of the above responsibilities of the State Director.

3160-1 DRILLING OPERATIONS

.05 References.

A. BLM Manual Handbook H-3160-1.

B. Standard Federal Lease Term. The standard lease term concerning drilling operations is set forth in Sections 5, 6 and 7 on the back of the Offer to Lease and Lease for Oil and Gas (Form 3100-11)

C. Application for Permit to Drill. Language and specifications relating to the administrative, surface and subsurface portions of the drilling operation contained on Form 3160-3.

D. Inspection Record Drilling, Form 3160-10. Inspection checklist utilized to document all drilling inspections.

E. Onshore Oil and Gas order No. 1, Approval of Operations on Onshore Federal and Indian Oil and Gas Leases, published final October 21, 1983.

F. Onshore Oil and Gas order No. 2, Drilling operations an Federal and Indian oil and Gas Leases, published final November 18, 1988.

G. Onshore Oil and Gas order No. 6, Hydrogen Sulfide operations on Federal and Indian oil and Gas Leases, published final November 23, 1990.

.06 Policy. Drilling and drilling abandonment operations, including all associated surface construction activities, on a Federal or Indian oil and gas lease shall not be initiated without prior approval from the AO. All drilling operations must conform to the minimum standards of Onshore oil and Gas order No. 1, No. 2 and No. 6 unless a variance has been approved. Upgrading from the minimum standards where appropriate is at the discretion of the AO. Recommendations on surface construction and drilling methodologies shall be made when necessary to provide adequate safeguards to ensure the intended results are obtained. Inspections of drilling operations shall be conducted by certified Petroleum Engineering Technicians (PETs) in accordance with the provisions of the Inspection and Enforcement Strategy. Because industry conducts drilling operations 24 hours a day, drilling inspections and abandonments can occur at any time of the day. Flexible PET duty hours and overtime is imperative for inspections to occur.

.07 File and Records Maintenance. The records, case files, and the Automated Inspection Recordation System (AIRS) for all oil and gas operational activities shall be accurately and timely maintained to ensure that the BLM can properly supervise drilling operations.

3160-1 DRILLING OPERATIONS

.1 Administrative Process
(To Be Developed)

.2 Surface Approval
(To Be Developed)

.3 Technical Approval

.31 Technical Considerations. Due to the timeframes required under Onshore Oil and Gas Order No. 1 (OOGO 1), the technical review must be conducted in as timely manner as possible. Written documentation of this review should be a permanent part of the official well file. A documentation sheet should be filled out for the geologic, hydrologic, and engineering portions of the review.

A. Geologic Review. A geologic review must take place prior to the engineering review. Certain portions of the APD Drilling Plan need to be independently reviewed for completeness, reasonableness and accuracy. Any significant discrepancies between the operator's submittal and the independent review by the BLM specialist must be resolved at this time. Usable quality water should either be addressed in a separate hydrologic review or contained within the geologic review itself.

B. Engineering Review. After the geologic and hydrologic reviews have been concluded, an engineering evaluation is conducted to determine if the technical aspects of the drilling plan are adequate. The engineering review must take into account any discrepancy or identified unresolved problem that the aforementioned geologic review uncovered. in addition, certain Drilling Plan items need to be independently verified to ensure that the plan is technically feasible, and that the minimum standards of OOGO 2, and if applicable OOGO, 6, have been met.

C. Conditions of Approval. After the engineering review has concluded, Conditions of Approval (COA's) are developed for inclusion in the approval of an APD, and as discussed elsewhere, may address surface issues. CCA's either modify the proposal and/or supplement the requirements as specified by the operator, but are not synonymous with lease stipulations. These COA's specifically address either those elements of the drilling plan that need to be upgraded and are in addition to OOGO 2 and OOGO 6 minimum standards, or are based upon an operators written and justifiable variance (see Variance Section .33). Typical COA's may also include notifications, reports or any other pertinent drilling information.

.32 Minimum Standards. OOGO 2 specifies minimum standards for most typical drilling procedures. Most of these standards are predicated upon American Petroleum Institute (API) Specifications, Recommended Practices, and/or Bulletins. Where applicable, API references are included (see Appendix 1) Many instances will necessitate the AO to upgrade some aspect of the requirements to address a particular set of circumstances for which the minimum standards are not deemed to be sufficient. The AO must ensure the drilling plan adheres to both the minimum standards and to any additional requirements placed upon the operator through the COAs. Some procedures are of a critical nature and the only way to ensure the operator is conducting operations prudently is through witnessing or an inspection. For a detailed discussion of all OOGO 2 and OOGO 6 minimum standards see H-3160-1, Chapter III Technical Reviews and Chapter IV - Drilling Inspections.

A. Well Control Requirements. This standard ensures that adequate Blowout Prevention Equipment (BOPE) is properly installed, pressure tested, and utilized while initial drilling and completion operations are conducted. The AO shall ensure that the intended working pressure of BOPE to be utilized will be adequate and that the minimum bore of the BOP to be utilized is not smaller than the internal diameter of the casing string to which it will be attached. Any significant pressure discrepancy should be rectified with the operator prior to approval of the APD. Should the operator’s proposed BOPE not exceed the anticipated surface pressure, the AO shall require a higher rated BOPE System. Any BOPE variances should be considered with considerable caution. The BOPE
performs a vital safety precaution and every effort should be made to witness critical pressure tests.

B. Casing and Cementing Requirements. Casing programs must be reviewed 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 by OOGO 1.

1. Casing Strings. Most wells are drilled utilizing multiple casing strings which perform various functions. Casing strings along with the cementing program provide the framework for pressure maintenance and for isolation and protection of usable quality water zones and prospectively valuable mineral deposits. casing strings may include the conductor, surface, intermediate, production or liners. See H-3160-1 Technical Reviews and Illustration 6, Typical Casing Terminology.

2. Casing Design. Various aspects of the proposed casing program shall be reviewed to ensure adequacy. These include: ensuring that the proposed casing and cementing program shall protect and or isolate all usable quality water zones or prospectively valuable mineral deposits anticipated to be encountered while drilling the wellbore; ensuring that each casing string will be set across competent formations; ensuring that the operators casing design rationale is logical and acceptable for the area; ensuring that equipment such as centralizers and scratchers are utilized; and that all casing, except the conductor casing, shall be new casing that meets or exceeds API standards.

3. Cement. The engineer review shall ensure that the proposed cement volumes are adequate to provide sufficient coverage of the critical resources identified in the geologic and hydrologic reports. The level of the cement behind the casing may need to be verified through specifying logging requirements in the CoAs. If a cement job is unsuccessful, remedial operations shall be requited after prior approval. witnessing any critical cementing operations to ensure proper procedures should be a key consideration.

4. Casing String Pressure Test. The casing string pressure test is to ensure that the casing run into the hole has pressure integrity. In addition to the required initial test, the AO may require additional tests should lengthy rotating hours incur before setting the next casing string. Any significant casing leak should be located and repaired by means such as AO deems necessary. Witnessing these tests should be a priority. A successful pressure test must be obtained prior to proceeding to the next phase of the drilling program.

5. Casing Shoe Pressure Integrity Test. OOGO 2 requires on all exploratory wells and on that portion of any well approved for a 5M BOPE system or greater, a pressure integrity test of each casing shoe shall be performed. This test shall be performed before drilling more than 20 feet of new hole. To aid in enforcement of this minimum standard, the AO should require the operator to record all casing shoe pressure integrity tests in the drillers log through a COA. Formation at the shoe shall be tested to a minimum of the mud weight equivalent anticipated to control the formation pressure to the next casing depth or at total depth of the well. This test is not a formation breakdown nor bleedoff test. It is to establish a minimum value which the operator and drilling contractor will know the shoe can handle for use in emergency well control operations. This will also indicate that the casing is set across a competent enough formation to handle the maximum mud weight anticipated necessary to drill the next portion of hole.

6. Miscellaneous. Any other aspect of the casing or cementing procedures the AO is concerned with shall be addressed with additional COA's and may require witnessing the operations.

C. Mud Program. The Drilling Plan shall be reviewed to ensure that the drilling fluid system and additives will be compatible and not detrimental to all usable quality water and prospectively valuable mineral zones anticipated to be encountered as identified by the geologic review. OOGO 2 requires that a mud test shall be performed at least every 24 hours after mudding up to determine at a minimum: density, viscosity, gel strength, filtration loss, and pH. Sufficient quantities of mud materials shall maintained an location in the event the mud system would have to be weighted up to effectively handle a kick situation. The AO shall ensure that kick detection and control equipment, and flare systems are utilized when appropriate.

D. Drill Stem-Test Requirements. OOGO 2 specifically requires three basic minimum standards: proper circulation techniques of hydrocarbons i.e. reverse circulation or displacement into the formation; adequate separation equipment; and spark arresters or water cooled exhaust on all internal combustion engines within 100 feet of the wellbore. If a review of the Drilling Plan indicates extensive DST operations or if open chamber DST operations are anticipated, the AO should also address special safety concerns via additional COA's. See H-3160-X Drilling Inspections.

E. Special Drilling Operations. Some specialized drilling techniques pose additional concerns are addressed either by specific minimum standards or COAs.

1. Air/Gas Drilling. OOGO 1 requires the operator to submit specific information regarding the utilization of air/gas as a drilling medium. OOGO 2 lists ten air/gas minimum standards with which the operator shall comply. All this specialty equipment is primarily for safety and protection of the environment, and is in addition to the common mud equipment. Substitutions, e.g. replacing an annular preventer with a rotating head, is not the *intent of* the order. The AO shall inform the SMA that a minimum well pad size will be required to safely accommodate the required distances -for the compressor *and b*looey line and pit.

2. Hydrogen Sulfide Operations. The APD shall address all potential safety and public health hazards and plans for their mitigation. OOGO 2 requires that hydrogen sulfide safety and monitoring equipment shall be available and in use where atmospheric concentrations of hydrogen sulfide of 10 ppm or greater are anticipated. Other specific minimum standards are addressed in OOGO 6, Hydrogen Sulfide Operations.

3. Deviated and Horizontal - Wellbores. The Drilling Plan should be reviewed to determine if any deviated or horizontal portions of the wellbore are proposed by the operator. Significant deviation of the completed well requires prior approval as provided in the regulations at 43 CFR S3162.5-2 (b) . All wellbore paths, i.e. different orientations, require prior approval. If a deviated drilling operation has occurred without approval, a directional survey shall be required.

F. Surface Use. Surface use is specifically addressed in OOGO 1 and the Surface Use Plan of Operation (SUPO) contained in the approved APD. Even though the Drilling Plan and SUPO are two different parts of the approval, they are interrelated and should be coordinated between specialists. During the engineer review, the SUPO should be scanned to determine if any anomaly is apparent and brought to the attention of the Surface Management Agency (SMA).

G. Plugging Operations. Any usable quality water; prospectively valuable mineral zone; or any formation fluid with a potential to migrate shall be protected. This applies to open hole, interior casing, as well as open hole/casing annuli. Protection or isolation of all critical zones must be required during the approval process and accomplished during the plugging operations. It is imperative that all critical plugging phases be witnessed to ensure that optimum practices are utilized at that time. From a practical and regulatory standpoint, it is far easier to avoid or correct problems as they occur than to require and substantiate remedial operations at a later date.

1. Approval Considerations. Approval may be granted orally by the AO prior to initiation of abandonment operations. Because approvals may be granted during off-duty hours, coordination between the engineer and PET must occur. This oral request and approval shall be followed by a written notice of intent (NOI) to abandon filed not later than the fifth business day following oral approval. All aspects of the plugging procedure should be reviewed to ensure no degradation will occur.

2. Minimum Standards. OOGO 2 details specific minimum standards for abandonment of newly drilled wells. An operator may choose various methods of achieving the minimum standards. However, it is incumbent upon the AO to ensure the methodology will not jeopardize the plugs durability nor placement accuracy. The SMA is responsible for cellar fill material as well as any surface rehabilitation concerns.

.33 Variances. The operator shall specify in writing the minimum standards for which a variance is requested along with the circumstances which warrant approval of the variance(s) requested and the proposed alternative methods by which that minimum standard will be achieved. The APD is a contract between the operator and the Bureau. As such it shall conform to all the minimum standards of OOGO 2, unless specific variances are requested by the operator and approved by the AO. If the proposed drilling plan does not conform with the minimum standards of OOGO 2 and the operator has not requested variances, the seven day notification letter shall require all discrepancies to be corrected prior to APD approval.

A. Bureau's Standards. OOGO 2 represents the Bureau's true minimum standards for drilling operations. For the most part, variances should be an exception and not the rule. Failure of having the necessary equipment to preform required operations shall NOT constitute justifiable reason for variances. Equipment limitations the operators part is also inexcusable. The AO shall use discretion when considering any request to vary from the standards and shall document each variance.

B. Approval Process. Variances may be granted on a well-by-well basis via the APD approval and reiterated in the COA’s or on a field wide basis if significant applicable concerns are present via a NTL. If occurring during the approval process, documentation should be provided via the engineer review. For emergency situations, oral approvals may be granted for variances with written documentation via a sundry notice within 5 days.

.4 Drilling Inspections. Drilling and other related operations are inspected to ensure that equipment, practices, and procedures are in accordance with the appropriate lease terms and conditions, regulations, Notice to Lessees (NTLs), minimum standards of OOGO 2, OOGO 6 and written instructions or conditions which are part of the approved APD. Bureau personnel shall inspect, take enforcement action if necessary, and document and report on drilling activity on Federal and Indian leases. All required inspections are to be carried out in accordance with the priority and the frequency established in the annual Inspection and Enforcement Strategy. The strategy as it applies to drilling inspections is based upon national criteria but is developed to address specific situations found in particular District or Resource Area. Local examples could be witnessing all cement operations across an aquifer, troublesome high pressure zones, etc. Drilling inspection priorities are generally assigned by the petroleum engineer who reviews the APD.

.41 Inspection Preparation. The following is a guide to prepare for an inspection of a drilling or workover operation.

A. Select Inspection Item. An inspection item (drilling well) may be located on a lease, communitization agreement (CA), a unit, or a participating area (PA) within a unit. The selection of the inspection item is based an the district inspection plan. Every effort must be made to inspect all high priority drilling operations when they occur.

B. Obtain a Copy of the Approved APD. The inspector should review the APD for the well to be inspected to determine the approved technical and environmental requirements. Generally, the APD consists of a completed Form 3160-3, the drilling plan, and the surface use plan of operations. If applicable, a Drilling Operations Plan (DOP) and Public Protection Plan (PPP) as required by OOGO 6 may also be part of the APD package. The inspector should review the well and lease file, and the APD package for conditions of approval to determine all the inspection requirements.

.42 Inspection Guidelines. The handbook section discusses in detail all the steps for a drilling inspection. It includes a discussion of what a drilling inspection is and how to conduct and document the inspection. While inspecting, the inspector only witnesses the tests and operations; the inspector must not operate equipment. A proper mix of various inspection activities is essential for an effective and efficient inspection program.

.43 Inspection Procedures. The following procedures are utilized.

A. Corrective Actions Involving Shut Downs. In many inspection situations, the required correction action will be performed while the PET is still on location. However, in other situations, circumstances, such as obtaining necessary equipment or performing a required test, will prevent immediate correction. In these situations, it may be necessary to shut down the drilling operation until the corrective action is performed. The PET must consider the drilling situation and what detrimental affects the shut down could cause. Discussions with the AO are strongly encouraged prior to initiating shut down operations. Some of the paramount concerns to take into account could be the health and safety of the rig crew, the condition of the wellbore or special operations being conducted at the time. In all shut down operations, the operator shall be given the onus of determining how the condition the hole should be placed in. Some possible scenarios may be pulling the bit a few feet off bottom and circulating, pulling the bit up into the last. casing string, setting temporary cement plugs or packers, etc.

B. Instructions for Completing Inspection Record - Drilling, Form 3160-10. Inspection records should be documented as instructed in the Inspection and Enforcement Strategy and in the AIRS Handbook H-3160-C. During each inspection the inspector must fill out the Inspection Record - Drilling, Form 3160-10.

C. Checklist Categories. The items in the inspection record are categorized under the following titles: General, Surface Use, Blowout Preventer and Associated Equipment, Casing and Cementing, Mud Program, Special Operations - Air/Gas Drilling, Hydrogen Sulfide Operations and Other. See Chapter IV - Drilling Inspections for a detailed discussion.

---------- END OF MANUAL ----------

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A. INTRODUCTION.

This handbook chapter provides detailed guidance on the intent of the minimum standards listed in Onshore Oil and Gas Order No. 2, Drilling Operations (Order No. 2), procedures for technical review and approval of the Drilling Plan contained in the Application for Permit to Drill or Deepen (APD) package, appropriate remedial actions, guidance on the evaluation of variances, and the approval of drilling abandonments.

This handbook chapter also provides detailed guidance on the intent of the minimum standards listed in Onshore Oil and Gas Order No. 6, Hydrogen Sulfide Operations (Order No. 6). The primary purpose of Order No. 6 is to protect public health and safety and those personnel essential to maintaining control of the well. This handbook chapter is not intended to address all situations that will be encountered in the approval and inspection of Hydrogen Sulfide (H_2S) operations. However, if the objective of the minimum requirement is being met by the proposed methodology, that criteria coupled with good judgement should be used in considering proposals for approval.

Order No. 2 only constitutes minimum standards. Upgrading from the minimum standards for situations where more protective measures are appropriate as deemed by the authorized officer is encouraged. While reviewing an APD, the authorized officer should utilize more restrictive conditions of approval as are necessary to provide adequate measures.

The rationale and application of the minimum standards, forms, example scenarios, and sample calculations have been included to assist in the technical review of an APD's drilling and/or abandonment plan.

The forms and checklists found as illustrations at the end of this handbook chapter are not mandatory in form nor content, rather as a basic standard format which can be modified to better suit the needs and circumstances of the various field offices. The illustrations are designed to facilitate the technical review of an application, and their utilization is strongly encouraged to aid in documentation of facts leading to approval or denial of an APD.

It is not the prerogative of the authorized officer to instruct operators on methodologies utilized to obtain required results. However, the operator's techniques should be reviewed to determine if they will provide adequate safeguards to ensure the intended results. It may be appropriate for the authorized officer to provide recommendations which have proven successful. Where applicable, examples of common, acceptable remedial procedures are included for various situations which may arise when the specific minimum standard were not met either due to wellbore conditions or timing problems.

It is typical to authorize remedial actions or changes to drilling operations via oral approvals due to tight time constraints. As prescribed by 43 CFR §3161.2 any oral approvals or orders shall be confirmed in writing by the authorized officer within 10 working days from issuance. Office procedures must exist which ensure the inspection staff is always informed of any changes to the APD or oral approvals.

The violation and corrective action portions of the order are unique in that minor violations may still necessitate immediate corrective timeframes much the same as major violations. Prompt corrective actions are necessary to defuse trivial violations, which if left uncorrected, may substantially increase in severity. A determination of violation severity and associated enforcement can only be made at the time of inspection. The specific situation, e.g. hole conditions, depths to potential high pressure zones, etc., will determine whether the existence or the continuation of that violation will cause or threaten immediate, substantial, and adverse impacts on public health and safety, the environment, production accountability, or royalty income (see 43 CFR §3160.0-5 definition of major violation). Likewise, the application of immediate assessments per 43 CFR §3163.1(b)(1) must be based upon a review of the drilling situation occurring at that time.

The BLM's responsibility in the approval of the downhole portion of the drilling and abandonment of oil and gas wells is manyfold. The regulations, orders and especially the approval document shall provide for the health and safety of the well site personnel (see API RP 54, Recommended Practices for Occupational Safety for possible safety issues); to protect usable quality water and other prospectively valuable minerals; and to ensure that the well is drilled using current technologies which provide the most durable wellbore as practical. Finally, the abandonment of newly drilled wells shall ensure that the well is left in a condition which isolates usable quality water,

prospectively valuable mineral zones and other zones containing any fluids with a potential to migrate.

Most of the minimum standards of Order No. 2 are predicated upon American Petroleum Institute (API) Specifications, Recommended Practices, and/or Bulletins. Be advised, however, that the API standards are not to be enforced as Minimum Standards, but rather are to be utilized as reference only. Where applicable, API references are included (see Appendix 3). Standards applicable to Order No. 6 are found in API, National Association of Corrosion Engineers (NACE), and American National Standards Institute (ANSI) (see Appendix 4).

B. TECHNICAL CONSIDERATIONS.

The following provides a list of major technical factors to be considered in reviewing a proposed drilling program. Due to the timeframes required under Onshore Oil and Gas Order No. 1 (Order No. 1), the review must be conducted in as timely manner as possible. The review may find information on the APD face page, Form 3160-3 (Illustration 1) or in the pertinent portion of the Drilling Plan. Written documentation of this review should be a permanent part of the official well file. The illustrations provide examples of appropriate review documentation. A documentation sheet should be filled out for the geologic and engineering portions of the review. Upon completion of each item, appropriate boxes of the documentation should be checked, dated, or initiated.

1. Geologic Review.

A geologic review (see Illustration 2) should take place prior to the engineering review. Drilling Plan Items 1,2,6,7 and possibly 8 need to be independently reviewed for completeness, reasonableness and accuracy. Any significant discrepancies between the operator's submittal and the independent review by the BLM specialist must be resolved at this time.

In review of the drilling plan, attention should be given to the competency of those formations opposite proposed casing setting depths and whether more appropriate formations exist. Also indication should be given for any fluid hydrocarbon, prospectively valuable resource, or usable quality water zone the proposed wellbore is expected to encounter and at what estimated depth. See Appendix 2 for a discussion on one possible method to determine usable quality water. The necessity and rationale for any additional logs or tests should also be a part of this review as well as any information available on expected pressures, potential hazards, etc.

Identification of those zones requiring protection, such as usable quality water, should either be addressed in a separate hydrologic review (see Illustration 3) or contained within the geologic review itself.

2. Engineering Review.

After the geologic and hydrologic reviews have been concluded, an engineering evaluation is conducted to determine if the technical aspects of the drilling plan are adequate. The engineering review (see Illustration 4 and, if appropriate, Illustration 5) must take into account any discrepancy or identified unresolved problem that the aforementioned geologic review identified, such as protection of usable quality water. In addition, Drilling Plan Items 3, 4, 5, 6, 7 and possibly 8 need to be independently verified to ensure that the plan is technically feasible, and that the minimum standards of Order No. 2, and if applicable Order No. 6, have been met. Detailed concerns are addressed in the following Minimum Standards Section.

In all situations where issues or concerns arise which are outside the experience of the reviewing individual, discussions with both internal and external sources of information is highly advisable. Sources would include engineers in other offices, other states, operator counterparts, or industry experts.

The approval of an APD will usually be to a specific total depth (TD). It is not uncommon for formations to be encountered deeper than anticipated. In these situations, or any other situations where the operator wishes to drill further than approved, it is typical to grant oral approval allowing further drilling to the target formation. While considering the request, a few issues need to be considered: will the new deeper TD penetrate a H_2S formation; require higher rated BOPE; and will the further drilling necessitate adjustments to the proposed casing and cementing programs to adequately isolate or protect usable quality water zones and/or other mineral zones.

Also while not currently required but if included, the intended completion program should be reviewed to ensure that the completion and downhole equipment 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), unless downhole commingling is approved (or is anticipated in the future).

3. Conditions of Approval.

After the engineering review has concluded, necessary Conditions of Approval (COA's) are developed for inclusion in the approval of an APD. These COA's specifically address those elements of the drilling plan which may need to be upgraded, are in addition to Order No. 2 Minimum Standards, or are based upon an operator's written and justifiable variance (see Variance Section, IV of this Handbook). Typical COA's may also include notifications, reports or any other pertinent drilling information. Illustration 6 is an example of possible drilling plan COA's.

C. MINIMUM STANDARDS.

1. Well Control Requirements.

The intent of this section is to ensure that adequate Blowout Prevention Equipment (BOPE) is properly installed, pressure tested, and utilized while initial drilling and completion operations are conducted. API RP 53, Recommended Practices for Blow-Out Prevention Equipment Systems for Drilling Wells, and API RP 59, Recommended Practices for Well Control Operations, provide invaluable well control information.

Drilling Plan Item 3, shall be reviewed by the authorized officer to ensure that the intended working pressure of BOPE to be utilized shall be adequate. BOPE equipment selection shall be predicated upon an adopted pressure gradient which assumes a partially evacuated hole whereby the hydrostatic pressure gradient is approximately one-half that of water and approximately double that of a pure gas column. BOPE shall be rated at a working pressure which exceeds the highest anticipated surface pressures (ASP) assuming a partially gas-cut mud column which exerts a force of 0.22 psi/foot.

As specified in Order No. 2, Definition Section, the review shall also ensure that the minimum bore of the drilling spool and related BOP to be utilized is not smaller than the internal diameter of the casing string to which it will be attached.

Drilling Plan Item 3 should also be scrutinized to determine if the BOPE narrative agrees with the BOPE schematic, or if either conflict with the minimum standards of Order No. 2. Any discrepancies should be addressed in the seven day letter and rectified before APD approval occurs.

The maximum anticipated bottom hole pressure (ABHP) as provided by the operator is stated in Drilling Plan Item 7 of the APD. A review of drilling histories, mud weights, formation gradients, etc from surrounding wells is necessary so that the reviewer is assured that the operator's submitted ABHP is reasonable. Drilling Plan Item 5, Mud weights, should correspond with the operator's ABHP. Any significant discrepancy should be rectified with the operator prior to approval of the APD. However, numerous conditions exist where the maximum mud weight may not occur at TD, but at a shallower, overpressured zone. BOPE should always be based upon the highest pressure gradient zone to be encountered, not always necessarily the deepest formation. Once a credible ABHP is established, the following formula can be used to determine the surface pressures:

$$ASP = ABHP - (0.22 * TVD)$$

Where: ASP = Anticipated Surface Pressure
ABHP = Anticipated Bottom Hole Pressure
and TVD = True Vertical Depth

Illustration 4 provides an example of this calculation.

Should the operator's proposed BOPE not exceed the ASP, the authorized officer shall require a higher rated BOPE System. As required by Order No. 2, III.A.1, "*The working pressure of all BOPE shall exceed the ASP to which it may be subjected...*" Any requested variances for lower rated BOPE components should be approached by the authorized officer with extreme caution.

Order No. 2 specifies the addition of pressure control or kick detection equipment for special subsurface pressure situations, as italicized below, which requires further engineering consideration. For 5M systems, Order No. 2 requires the addition of a second pipe ram "*if conditions warrant*" and/or a remote kill line "*when the expected pressures approach working pressure*". As a rule of thumb, whenever the ASP approaches 10% of the rated working pressure of a 5M system, the authorized officer should review local issues such as: is the proposal for an exploratory well, is the presence of H_2S a possibility, do layered high pressure formations exist, what do offset well pressures indicate, etc. to determine if additional pressure control or kick detection equipment is prudent. To further assist the authorized officer is the utilization of an evacuated hole gradient calculation. In this procedure, if the pressure at the surface, assuming an

evacuated hole gradient (0.13 psi/foot) exceeds the working pressure of the approved BOPE, then a condition exists which may warrant additional pressure control or kick detection equipment. Illustration 5 provides further discussion on this procedure.

Section III.C., *Mud Program Requirements* of Order No. 2 requires the addition of electronic/mechanical mud monitoring equipment, gas detecting equipment, and a mud-gas separator (gas buster) for "*abnormal pressure*" situations. Abnormal pressure situations can be determined in the similar manner as discussed for upgrading 5M systems. Additionally, a trip tank is required on "*upgraded*" 5M systems. An "upgraded" 5M system is one which has any equipment in addition to the minimum requirements as discussed above.

The BOPE test pressures are specified in Order No. 2. It should be pointed out that test pressures should never exceed 100% of stack working pressure in any event. The COA's should specify any additional BOPE tests required prior to drilling into known high pressure zones. If a BOPE pressure test is not going to be witnessed or it can be determined that the drilling contractor rig's mud pumps are not capable of safely attaining the required test pressure, the authorized officer should consider requiring independent BOPE testers and copies of the results submitted to the authorized officer via additional COA's.

Although well heads are not specifically addressed in Order No. 2, it is the intent that well heads are categorized as "related equipment (BOPE)" as discussed in Order No. 2, Section III.A.1. and as such shall have a pressure rating no lower than the approved BOPE. This is necessitated because the wellhead is the bottom pressure seal for the BOPE. The authorized officer should also ensure that wellheads are properly attached to the casing in accordance with the provisions of API Spec 6A, Specifications for Wellhead and Christmas Tree Equipment . It may be necessary to address wellhead working pressures and attachment procedures via the COA's.

Specific provisions of Order No. 2 require utilizing targeted tee's, see Section II. Definitions, to handle redirecting fluids through the BOPE and choke system. Bull plugs utilized for targeted tee situations shall be manufactured for resistance to impulse and erosion and shall be installed directly opposite fluid flow from the wellbore (in the running position). Coflexip hose or Tee-Blocks may be utilized in BOPE installations if the equipment meets or exceeds the requirements of Order No. 2.

2. Casing and Cementing Requirements.

a. General.

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 by Order No. 1; Drilling Plan Item 4.

b. Casing Strings. Most wells are drilled utilizing multiple casing strings each of which performs various functions. See Illustration 7, Typical Casing Terminology.

(1) Conductor Casing. This casing maintains hole integrity in shallow, unconsolidated sediments. Essentially it provides a conduit for drilling returns while spudding the well. This eliminates the possibility of washouts directly under the rig substructure.

(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 near surface usable quality water or prospectively valuable mineral zones. This casing is set in a competent bed and cemented with sufficient cement to fill all the annular space to surface. For development wells, the length of the surface string and the cementing program are typically determined by known field conditions. The competence of the formation at the casing seat, formation fracture gradient, and casing setting depth are all interrelated and critical to adequate pressure control.

(3) Intermediate Casing. One or more strings of intermediate casing must be set when required for protection of oil, gas, usable quality water zones, and prospectively valuable 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; contain any fluid with a potential to migrate and/or isolate brackish water from usable quality water. 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. This casing string also must be cemented so that all exposed usable quality water zones, oil and gas zones, other prospectively valuable mineral deposits, and anomalous pressure intervals below the previous string are covered or isolated.

(5) Liners. API defines a liner as an abbreviated casing string. When any casing string does not extend to the surface,

at least a 100 foot overlap between the outer and inner strings is required. 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.

Liner laps are tested to ensure that the lap has both pressure integrity and prevents fluid migration. The seal mechanism may either be integral part of liner hanger or simply the cement sheath through the liner lap. Should the liner lap fail the test, remedial action shall be required. This remedial action will be commensurate with the particular problem, but will usually involve remedial cementing operations. Some liner situations do not require seal mechanisms. These situations may be, but not limited to: slotted liners, gravel pack completions, horizontal completions, or other situations where zonal isolation or pressure control is not a concern.

c. Casing Design.

(1) Isolation/Protection. The authorized officer shall make a determination as to what constitutes the presence of either prospectively valuable mineral deposit or usable quality water to be encountered while drilling the wellbore proposed by each APD. Even in the presence of an operator's good intentions to perform his duties in a prudent manner, the authorized officer still has the responsibility to ensure adequate protection of aquifers and other minerals regardless of the expense to the operator for these optimum procedures.

Coal, oil shale, or any other mineral perceived by the authorized officer as economic in the reasonably foreseeable future and requiring protection should have minimum parameters as to amount, depth and quality as established by an in-house expert. Any zone containing water with a Total Dissolved Solids (TDS) content of 10,000 or less ppm water shall also require protection. Also any zone with any fluid with a potential to migrate should be isolated. While not specifically under the BLM's purview, 40 CFR requires protection for community water development which should also be taken into consideration.

For established and developed areas, key aquifers containing usable quality waters or formations containing prospectively valuable mineral deposits minerals should already have established casing and cementing programs. However, in exploratory wells where unknown formations will be encountered, the geologic and hydrologic reviews should identify potential zones requiring protection. The drilling permit COA's must require the operator to pay heed to specific intervals of concern and that should drilling confirm the presence of water or minerals that protection or isolation via the cementing program will be required. The establishment of field protection/isolation practices should

consider the deterioration of tubular goods as well as cement life.

In areas where coal or other prospectively valuable minerals coexist with oil and gas resources, consideration should be given to techniques whereby both resources may be produced concurrently. For example, in an underground mining situation utilizing room and pillar technique, such a possibility exists where the wellbore can be situated through the pillar portion of the mine and continue to produce oil and gas from a deeper formation. However in many situations, the preferential right to extract one commodity before another will be evident from the provisions granted in the respective leases. In these situations, the operation extracting the non-preferential commodity must be halted. A common technique in preferential right surface mining would be a casing and cementing program that would allow for the casing to be cut off and the well plugged below mining depth, and subsequent to completion of mining operations, the well may be reentered, a tie back liner set, and placed back on production.

The authorized officer should use discretion when requiring water quality tests to determine if the well should be obtained for water well purposes. Further guidance on water quality and this process is contained in Manual 3160-4, Conversion to Water Well.

(2) Competent Formations. Of utmost consideration in establishing the depth of any casing string, once the issue of protection of usable water and other resources has been addressed, is to assure that the casing shoe is set across a competent formation. The geologic review should ensure that each casing string will be set across competent formations by a review of adjacent wells, historic problems and discuss the inherent strengths or weakness of a particular formation matrix.

A competent formation is one in which the wellbore is approximately at gauge diameter and will withstand the pressure that it may be expected to encounter assuming normal drilling operations. Depending upon well configuration, completion operations such as fracturing pressures, should also be taken into consideration.

Determining what constitutes a competent formation is usually based upon known or inferred geologic data. Previous drilling and testing history can establish that a formation such as a thick shale is competent and acceptable for placing the casing shoe. For example, throughout the Rocky Mountain area, a common practice is to set surface casing in a thick shale formation that lies below usable water zones or other near surface resources requiring protection. Experience will typically override theoretical design assumptions such as assumed

formation pressure and fracture gradients or the historical rule of thumb of setting a minimum of 10% of total depth.

(3) Design Factors. Order No. 2 requires that operator's supply all design factors for all exploratory wells. In addition to the design factors, the authorized officer could also request the operator's assumptions and calculations leading to the factors. These design factors shall be evaluated during the engineering review.

As an initial criteria for evaluating exploratory wells, the engineer should ensure that the proposed casing program meets or exceeds the design criteria historically utilized in the general area. Design criteria varies from field to field taking into account casing quality, well life, subsurface hazards, production techniques, and most notably economics. Very few companies nor notable authors will agree on acceptable design factors. Historical trends have indicated values of Burst 1.125, Joint 1.8 (dry) or 1.6 (buoyant) and Collapse 1.0, however local knowledge and practice may dictate different design factors. If the submitted casing program varies significantly from the typical field factors, the operator shall be required to submit rationale justifying their design factors. The authorized officer must determine if the operator's rationale is logical and acceptable for the area. API Bull 5C2, Performance Properties of Casing, Tubing and Drill Pipe, and API Spec 5L, Specifications for Line Pipe, are excellent sources for most tubular parameters. Illustration 8 provides an example worksheet to calculate design factors.

The authorized office could also consider a cursory review, and on a random basis, a detailed analysis, of the design factors for development wells to ensure the proposed casing is acceptable for local conditions.

Casing design should take into consideration the worst case scenario for a particular design factor, i.e. the situation which places the highest differential pressure between the interior and exterior of the pipe. Post drilling completion operations, such as hydraulic fracturing, should always be considered when analyzing worst case scenarios.

Formation pressure gradients and fracture gradients must be taken into account when reviewing casing design. Lacking better data in exploratory well situations, it shall be assumed that formation pressure gradients will be 0.44 - 0.50 psi/ft and that fracture gradients will be 0.70 - 1.00 psi/ft. The geologic review shall indicate if the well will encounter abnormal situations which the engineer should consider.

In most cases better data will be available than these design assumptions, either from internal files or from data supplied by the operator. Only in those cases where this information is not on file and when the operator does not have or refuses to supply data would the "assumed" formation pressure gradients and fracture gradients be primary design criteria. This is because theoretical design criteria was based upon uniform and continuous depositional environment such as what exists in the Gulf Coast but which may be totally unrealistic in the Rocky Mountain region as well as other regions.

Some operators will point out the apparent conflict between the criteria for well control equipment and that for casing design parameters. Be advised that the 0.22 psi/foot standard for minimum BOPE working pressure criteria applies ONLY to surface stack components and shall not be utilized for casing design. This distinction in assumptions concerning the design of BOPE and casing was arrived at in Order No. 2 as a compromise with industry during the initial rulemaking. Design criteria for the BOPE assumes a partially evacuated hole with a gradient of 0.22 psi/ft of hydrostatic pressure whereas the casing design assumes "normal drilling operations". Again these standards are minimum design criteria and depending upon specific circumstances the authorized officer may choose to upgrade the criteria.

(4) Centralizers. Casing centralizers are a necessary tool which helps promote a cementing environment which minimizes channeling in an effort to yield a uniform sheath of cement surrounding the casing. Some centralizers are designed so as to cause the cement to spiral around the pipe which helps to displace the drilling mud and are commonly called turbulators. Centralizers utilized should meet the criteria in API Spec 10D, Specifications for Casing Centralizers. The engineer should become familiar with both the benefits and disadvantages of the spring-type and positive standoff centralizers.

As a minimum standard, centralizers are required only on the bottom three joints of the surface casing. There will also exist situations where adequate standoff, such as horizontal wells, must be provided for casing strings other than just the surface casing. The reviewing official must determine if casing eccentricity and the increase in quality cement bonding require the addition of COA's for centralizers on the intermediate and production strings at predetermined strategic points. A review of usable quality water aquifer depths, prospectively valuable deposits of minerals, zonal isolation or hole deviation must be considered in determining the necessity and location of

centralizers. Witnessing surface casing (or any other protection string) to ensure required centralizers are utilized avoids subsequent problems and costly and possibly unsuccessful remedial work.

(5) Scratchers. Although not a minimum standard, scratchers, in conjunction with centralizers, are often run on casing strings to further promote the development of the cement sheath, and the authorized officer can consider requiring their utilization. An example of this situation might be across a fresh water aquifer or other situations necessitating adequate cement bonding, and the authorized officer does not consider it prudent to leave scratcher utilization up to the operator's discretion. Caution should be taken when requiring too many peripherals which could cause hanging up or sticking of the casing string. Scratchers are designed for either reciprocation or rotation of the casing. Hole conditions or the operator's preference will dictate which is used. To get the best cement bond possible the preflush fluid should be pumped in turbulent flow and the casing should be either reciprocated or rotated while the cement is being pumped up the annulus. The scouring action of the preflush and the action of the scratchers will help remove the mud cake and increase the probability obtaining a good cement formation bond.

(6) Casing Condition. Order No. 2 requires that all casing, except the conductor casing, shall be new or reconditioned and tested casing that meets or exceeds API standards for new casing. API Spec 5CT, Specifications for Casing and Tubing; and API RP 5A5, Recommended Practice for Field Inspection of New Casing, Tubing and Plain End Drill Pipe, provides discussions on pipe condition, tubular inspections, and wall thickness determinations. Used casing shall only be approved by the authorized officer under circumstances where appropriate and when the wall thickness of the proposed casing is verified to be at least 87.5% of the nominal wall thickness of new casing.

The determination of what constitutes "appropriate" shall be based upon local field knowledge and anticipated downhole conditions such as pressure gradients, drilling hazards, formation depths, presence of corrosive fluids, etc. If the operator does not provide evidence of the wall thickness when requesting the approval of used casing with the APD package, the authorized officer shall require it via the seven day letter. Acceptable verification methods include those procedures typically utilized by pipe inspection service companies. In those instances when the casing is not available for verification, i.e. not yet purchased, at the time of APD approval, it may be necessary to condition the APD such that running of the casing shall not occur until tubular condition and wall thickness has been addressed and approved. The COA's should also address where wall thickness documentation shall be maintained. For example a copy in the BLM official file and a copy

with the driller's log.

When pipe threads are connected, a metallurgical change occurs due to torque and friction. This process will affect, at a minimum, joint and pipe body strength. If the pipe markings fade or become illegible, that pipe should be considered used pipe until traceability of mill of origin can be provided as prescribed by API Spec 5CT. The authorized officer must realize that traceability of mill origin may take considerable time and effort, and that during this time, the intended casing operation may not proceed.

d. Cement.

(1) General. Order No. 2 requires that surface casing shall be cemented back to surface either during the primary cement job or during remedial cementing. This is to ensure all near surface usable quality waters are isolated and a competent anchor is provided for pressure control. Cement along with the casing program provide the framework for pressure maintenance and for isolation and protection of resources. It is critical the cement sheath provide adequate formation to pipe bond. Cement blending and field mixing conditions should ensure consistent cement properties throughout the pumping operation.

In instances where rotary string and casing contact is likely, as a large rotary string inside a small diameter casing, for example a 4 1/2 inch kelly and drill pipe in 8 5/8 inch, 24 #/foot casing, the continual contact of the rotary string with the casing will eventually shatter the cement sheath through induced vibration. Because drill string size is rarely known at the approval stage and to eliminate any shattering possibility, the authorized officer could consider utilizing neat cement for the surface casing cementing program. Neat cement exhibits a much higher compressive strength than light weight pozzolan cements and therefore will better withstand the vibration.

To eliminate the potential of damaging an otherwise adequate cement job, a minimum of 500 psi compressive strength shall be exhibited by the cement prior to drilling out the shoe. This compressive strength is based on the cement at bottom hole temperatures and pressures - not on surface conditions. Cementing companies may be able to provide the authorized officer with estimated WOC times.

(2) Volume Calculations. The engineer review shall ensure the proposed cement program contained in Drilling Plan Items 2 and 4 is acceptable. This review will include a volume determination ensuring that cement volumes are adequate to provide sufficient coverage of the critical resources identified in the geologic and hydrologic reports. Illustration 9 provides an example worksheet and absolute volume factors to aid in calculating cement slurry densities. Illustrations 4 and 8 provide documentation for cement volume calculations.

The cement additives should also be reviewed to ensure they are appropriate for the location and depth of the well. As an example, to avoid cement degradation in wells with bottom hole static temperatures in excess of 230^{0}F, the cementing program should include at a minimum of 30% of silica sand or silica flour depending upon density requirements.

(3) Placement Techniques. Various placement techniques exist which have proven themselves for different cementing applications. Cement may be placed via plug method, inner-string method, multiple stage jobs, energized cement, etc. Order No. 2 requires top plugs to be utilized to reduce contamination of the cement by the displacement fluid. Bottom plugs or other isolation techniques may be employed to avoid contamination of the cement by the fluid displaced ahead of the cement slurry (preflush). These isolation techniques may include inner-string displacement or a suitable preflush.

The ideal cement displacement situation should be at a pump rate necessary to achieve turbulent flow regime in the annulus. If this is not possible due to horsepower constraints or other reasons such as weak formations, at the very least plug flow conditions should be achieved while cement is displaced in the annulus. Laminar flow conditions are the least desirable flow rate, and should only be utilized as a last resort.

Witnessing cementing operations to ensure utilization of the top plug and other proper procedures should be a key consideration. If witnessing of the operation cannot occur, cement placement procedures can be partially established by job reports from the cement service company. Expensive and possible ineffective remedial work will not always rectify improper or inadequate cementing procedures.

(4) Verification. Cement tops (TOC) and bond quality may be determined from numerous methods. TOC may be determined by monitoring returns at the surface or by temperature logs. More advanced logging techniques such as cement bond logs (CBL) and cement evaluation tools (CET) are also capable of indicting bond quality in addition to TOC. These various methods all have inherent limitations as well as cost versus effectiveness aspects which should be considered by the authorized officer. In addition, possible micro annulus masking effects from pressure applied at the surface to the casing should also be considered. Logging companies should be consulted to determine adequate WOC time prior to running the logs.

Because cement bond logs are not typically run to verify the quality of the surface casing cement job, it is recommended that all high-priority surface casing cementing operations should be witnessed to verify that cement is brought back to ground level.

(5) Remedial Operations. If the authorized officer determines a cement job is unsuccessful, remedial operations must be required. Typical remedial options may involve perforating the casing string, setting a cement retainer and squeezing cement up to an acceptable level. For surface casing where the cement has fallen back a minor amount, top jobs with 1 inch tubing may be appropriate. Placing pea gravel at surface is not the preferred remedial action. The pea gravel can not isolate nor protect any near surface usable quality waters or prospectively valuable minerals, and merely creates a reservoir around the casing in which liquid hydrocarbons or chemicals could collect.

On intermediate and production strings, some simple isolation, but not protection, problems may be remedied by bringing the cement level higher on subsequent casing strings. Other serious problems may necessitate the setting and cementing of an additional casing string or perforating and pumping sufficient cement to protect the zone of concern. Remedial operations are limited only by imagination and the resources available. However, operators will usually utilize the most cost effective and commonly accepted procedure to resolve the situation. In any event, the remedial procedures requires prior approval by the authorized officer.

e. Casing String Pressure Test.

The casing string pressure test is to ensure that the casing run into the hole has pressure integrity. In addition to the required initial test, the authorized officer may require additional tests should lengthy rotating hours incur before setting the next casing string, possibly wearing through the casing. To aid in enforcement of this minimum standard, the authorized officer could require the operator to record all casing string pressure tests in the drillers log through a COA.

The pressure applied at the surface is equal to the calculated test pressure minus the hydrostatic head of the fluid in the casing. However, pressure opposite the casing shoe must never exceed 70% of the internal yield strength of the casing. Internal yield values may be obtained from API Bull 5C2, Performance Properties of Casing, Tubing and Drill Pipe. To calculate the pressure to be applied at the surface, the following formula can be used:

$$P_{SFC} = P_{TEST}$$

$$\text{Condition: } P_{TEST} + P_{SHOE} < 0.7 * P_{YIELD}$$

Where: P_{SFC} = Pressure applied at the surface,
P_{TEST} = 0.22 psi per foot of casing length, or 1500 psi, (whichever is greater),
and, P_{SHOE} = Pressure applied at the casing shoe.

See Illustration 10 for a discussion and example of this determination.

If P_{SFC} does not stabilize and declines more than 10% in 30 minutes, the casing leak should be located and repaired by squeezing off, replacement, setting a scab string or by other means such as authorized officer deems necessary. Witnessing these tests should be a priority. A successful pressure test must be obtained prior to proceeding to the next phase of the drilling program.

f. Casing Shoe Pressure Integrity Test.

Order No. 2 requires on all exploratory wells and on that portion of any well approved for a 5M BOPE system or greater, a pressure integrity test of each casing shoe shall be performed. This test shall be performed before drilling more than 20 feet of new hole. To aid in enforcement of this minimum standard, the authorized officer could

require the operator to record all casing shoe pressure integrity tests in the drillers log through a COA.

Formation at the shoe shall be tested to a minimum of the mud weight equivalent anticipated to control the formation pressure to the next casing depth or at total depth of the well. The casing shoe pressure test shall be predicated upon the heaviest mud weight utilized to drill the portion of hole between the existing shoe and the next intended casing string. Illustration 11 provides an example of this determination in greater detail.

This test is not a formation breakdown nor bleedoff test. Casing shoe pressure integrity tests are required to ensure that casing is set across a competent enough formation to handle the maximum mud weight anticipated necessary to drill the next portion of hole. The intent of this requirement is to provide the operator and drilling contractor a known pressure value the shoe will withstand in the event of emergency well control operations. This test should be preformed with fluids which contain no fluid loss agents or lost circulation materials. This test is not a determination of the hydrostatic pressure at which the shoe will break down.

If the cement is not set or is "wet" while drilling out the casing shoe, it is a good indication that the casing shoe joint is not adequately cemented and remedial operations shall be required.

If casing shoe pressure integrity test requirements cannot be met, remedial operations are necessary before further drilling operations can continue. In situations where low pressure is expected and/or the geology of the area is well known, and the pressure loss is minimal, all that may be required is formally informing the company representative and driller that hard shut-ins cannot be accomplished. In situations where pressure control is vital, the only available procedure may be to squeeze the shoe and open portion of the wellbore with cement; drill out the cement; and retest. If the test still fails, the authorized officer may consider requiring additional casing strings prior to drilling with increased mud weights. Finally, in extremely situations, plugging the wellbore; skidding the rig; and redrilling with a more appropriate casing and mud program may be the only prudent alternative.

g. Miscellaneous.

Casing connections are a concern that are checked during casing string pressure test. Unfortunately, the fact that casing connections are improperly made will not manifest itself until the casing string pressure test fails; subsequent to running and cementing the pipe in the hole, and far to late to change any casing connection procedure which would have eliminated these leaks. Expensive remedial operations may not rectify the situation, and the only prudent alternative may be to skid the rig and redrill the hole. To avoid casing connection leaks, random casing running operations should be witnessed. The use of rope or a chain is acceptable to spin the casing and bury the threads, but casing tongs must be employed for the torquing portion. If improper casing connection techniques are utilized, the authorized officer could require the operator to torque the casing connections to the proper specifications supplied by the casing manufacturer. This requirement may best be addressed in a COA for future wells.

Drill pipe protectors, usually of hard rubber design, can be utilized to reduce friction between the drill string and either the casing or the wellbore. This method lowers both rotary torque as well as drill pipe and casing wear. API Spec 7J, Specifications for Drill Pipe/Casing Protectors (DP/CP), Appendix C provides recommended practices. A concern with DP/CP's is when drilled cuttings embed themselves into the protectors producing a very effective abrasive tool which may be more destructive than unprotected tool joints. For this reason, the use of DP/CP's may be limited to those situations when drilling through intermediate casing strings; in deviated/horizontal wellbores; or in severe dog leg/key seat situations.

3. Mud Programs.

Drilling Plan Item 5 shall be reviewed to ensure that the drilling fluid system will be compatible with, and not detrimental to, all usable quality water and prospectively valuable mineral zones anticipated to be encountered as identified by the geologic review. Relevant concerns may be: utilization of hazardous materials (see Order No. 1 for requirements); pH factor in H_2S environments (see Order No. 6 for specifics); oil-base muds, or salt saturated muds. Trivalent and hexavalent chromate muds are not typically acceptable (other chemical compositions involving chromium may not be chemically reactive and therefore acceptable). The use of any of these mud systems require proper handling, disposal and reclamation in accordance with BLM policy. API Spec 13A, Specifications for Oil Well Drilling Fluid Materials; API Bull D11, Glossary of Drilling Fluids and Associated

Terms; and API Bull 13D, The Rheology of Oil-Well Drilling Fluids, provides valuable information which may aid in this review.

Order No. 2 requires that a mud test shall be performed at least every 24 hours, after mudding up, to determine (at a minimum): density, viscosity, gel strength, filtration loss, and pH. These tests should be conducted in accordance with API RP 13B, Recommended Practice for Standard Procedure for Field Testing of Drilling Fluid Materials. Copies of the mud and corrosion recap could be required via a COA if there is a concern on what was actually utilized.

43 CFR §3162.5-2 (c) *High pressure or loss of circulation*, requires the operator to take immediate steps and utilize necessary resources to maintain or restore control of any well in which the pressure equilibrium has become unbalanced. To support this, Order No. 2 specifies that sufficient quantities of mud materials shall be maintained or readily accessible for the purpose of assuring well control. The term "readily accessible" recognizes that drilling relatively near a premix bulk mud supply is a sufficient and acceptable alternative to maintaining sufficient mud materials on the drilling site. A good rule of thumb to determine sufficient quantities of mud materials could minimally be that volume of basic viscosifiers (bentonite or similar) and necessary weighting additives (i.e. barite) equal to one hole volume and one circulating mud tank volume with a equivalent mud weight equal to the highest anticipated weight plus a one pound per gallon (1 PPG) safety margin.

Mud systems in abnormally high pressure areas or in exploratory wells are unique by their nature and require special equipment to aid in the detection and control of kicks. In accordance with Order No. 2 and 6, any APD approving an upgraded 5M, 10M or higher BOPE systems or any other situation where the authorized officer has a concern for kick detection should fall into this category. This specialized equipment usually includes: trip tanks; minimal electrical and or mechanical mud monitoring equipment i.e. pit volume totalizer (PVT); stroke counter; flow sensor, gas detection equipment, and mud/gas separators (gas busters), and, if conditions necessitate their utilization, shall be required by additional COA's. Any other additional equipment for these or other unusual situations may be appropriate as deemed necessary by the authorized officer. See Well Control Requirement Section of this Handbook for further discussion.

Flare systems are utilized on all exploratory wells, abnormally high pressure wells, or any situation where there exists a possibility of gas reaching the surface such as DST's. When utilized, the flare line should always extend to a separate pit other than the reserve pit. This avoids potential damage to any synthetic lining material through

erosion or melting as well as possible ignition of any flammable materials contained in the reserve pit.

4. Drill Stem Test Requirements.

Order No. 2 specifically requires three basic minimum standards: proper circulation techniques of hydrocarbons i.e. reverse circulation or displacement into the formation; adequate separation equipment; and spark arresters or water cooled exhaust on all internal combustion engines within 100 feet of the wellbore. Appropriate separation equipment should include separators and tanks to accommodate anticipated fluid recoveries. Spark arresters or water cooled exhaust are necessary to cool down exhaust emissions below the ignition temperatures of any liquid or gas which has the potential to circulate to the surface during the DST.
If a review of Drilling Plan Item 6 (anticipated testing, logging, and coring or logging procedures) indicates extensive DST operations or if open chamber DST operations are anticipated, the authorized officer should also address any special safety concerns via additional COA's. These additional concerns should include: performing DST's during daylight hours, vapor-proof lighting, tripping before daylight, or any other aspect the authorized officer deems necessary. See H-3160-1, Chapter IV - Drilling Inspection for further details.

5. Special Drilling Operations.

a. Air/Gas Drilling.

Order No. 1 requires the operator to submit specific information regarding the utilization of air/gas as a drilling medium (Drilling Plan Item 5). Order No. 2 lists ten air/gas minimum standards with which the operator shall comply. The majority of this specialty equipment is primarily for safety and protection of the environment, and is in addition to the required mud and well control equipment. Substitutions are not the intent of the order, for example, replacing an annular preventer with a rotating head. The intent of Order No. 2 is that the minimum standards for air/gas drilling operations shall be applicable to aerated, foamed, misted, or any system which utilizes a compressor. This rational is based on the fact that the safety concerns necessitating these minimum standards are consistent for all these drilling fluid medias. Primarily, when specialty equipment is utilized, the requirement(s) pertaining to that equipment will apply. As an example, if a compressor is in use, all applicable standards such as siting distance, water-cooled exhaust, etc will be enforced. API RP 46, Recommended Practices for Testing Foam Agents for Mist Drilling

provides some information pertinent to air/gas mud systems.

The authorized officer shall inform the SMA that a minimum well pad size will be required to safely accommodate the required distances for the compressor and blooey line and pit. Illustration 12 depicts minimum air/gas drilling equipment distances. Note that the compressors and blooey lines do not necessarily have to be in exactly opposite directions (i.e. 180 degrees apart).

b. Hydrogen Sulfide Operations.

The APD shall address all potential safety and public health hazards and plans for their mitigation. Order No. 2 refers and defers to Order No. 6 for specific hydrogen sulfide safety and monitoring equipment minimum standards. Also see API RP 49, Recommended Practices for Safe Drilling of Wells Containing Hydrogen Sulfide for further discussion.

(1) General. Receipt of a drilling plan that proposes to penetrate a formation(s) which has zones known to contain or which could reasonably be expected to contain concentrations of H_2S of 100 ppm or more in the gas stream must be reviewed and analyzed against Order No. 6. Be advised that "gas stream" includes any H_2S gas which can break out at the surface regardless of the source, i.e. from a hydrocarbon or sour water zone.

Various parts of the APD will contain the requirements outlined in Order No. 6. This is a change from past practices where the operator attached a "contingency plan" to the APD which specified all special H_2S operations including public protection. H_2S requirements fall under two separate and distinct categories. (One) the Drilling Operations Plan (DOP), the part that will most likely be incorporated within the body of the APD, and, (two) if the applicability criteria is met, a public protection plan (PPP). Certain portions of the PPP not contained in the body of the APD, such as telephone lists and duties of key personnel, will normally be lumped together and made an attachment to the APD. Therefore, the reviewer may find the DOP and PPP components in the applicable portions of the drilling plan or as a separate plan all together. The DOP, and if required PPP, submitted as part of the APD package shall be approved, not merely accepted. Illustration 13 provides a list of APD requirements for H_2S operations and example checklists for the review of the DOP and the PPP.

Since most DOP's are only in effect for the relatively short drilling period, no annual review is typical. Exceptions to this are when field-wide plans are submitted, the duration of drilling operation lasts well over one year, or actual drilling operations are not commenced soon after APD approval. It should be noted that field-wide operations plans must be supplemented for the site specific operation and can not merely be attached to the APD as originally approved.

Any variances from the minimum requirements outlined in Order No. 6 should strongly consider the protection of public health and safety, the environment and effective and efficient control of the well. Reasonable professional judgement, with emphasis on the intent, must be used in the application of Order No. 6 requirements to field operations.

(2) Technical.

(a) Drilling Program. Review of the stratigraphic section (geology report) will normally provide an indication about the H_2S potential. If the operator does not expect to encounter H_2S, geologic analysis must then particularly consider the possibility. Any conclusions about H_2S presence must reference data from fields within the same geologic basin and extrapolate the potential for encountering H_2S in concentrations of 100 ppm or more in the gas stream. In cases where the BLM, not the operator, anticipates H_2S and the 100 ppm or 500 ppm radius of exposure (ROE) may include the locations outlined in the applicability criteria (III B.1.), an anticipated concentration and flow rate should be determined to adequately assess the necessity for a public protection plan. The operator shall be required, via the seven day letter, to submit the DOP and PPP, or submit justification explaining why the information is unnecessary. If the concentration and flow rate cannot be anticipated, a 3000' ROE is to be assumed. Illustration 14 contains Nomographs based upon the Pasquill-Gifford equation which can be utilized to determine the 100 ppm or the 500 ppm ROE.

When determining whether or not the ROE will include locations identified under the applicability criteria, the term "where the public could reasonably be expected to frequent" is used. Some examples of this include: places of normal and routine visits by the public for recreational purposes (i.e. fishing holes, motorcycle tracks, picnicking areas, etc.) and parking lots. These would be areas of common knowledge in the local community. The use of discretion is

absolutely necessary when determining the necessity of a PPP.

(b) Metallurgical Equipment. The components of the casing and pressure control equipment that will or have the potential for exposure to H_2S shall be suitable for H_2S service. Statements in the APD should reflect such suitability by indicating conformance to NACE Standard MR0175-90, Material Requirements - Sulfide Stress Cracking Resistant Metallic Materials for Oilfield Equipment, or manufacturers verification for suitable H_2S service.

If the suitability is questioned, additional manufacturer's documentation from the operator should be requested. Equipment that shall conform to these standards include:

1. Drill string
2. Casing
3. Wellhead
4. BOPE
5. Casing head and spool
6. Rotating head
7. Kill lines
8. Chokes, choke manifold and choke lines
9. Valves
10. Mud-gas separators
11. DST tools
12. Test units
13. Wire line lubricators and logging equipment
14. Tubing, flanges and other related equipment

The metallurgical properties to consider include:

1. Hardness of steel - Rockwell < 22
2. Grade of steel
3. Processing method
4. Strength properties - Tensile less < 55,000 PSI.

Working environment considerations include:

1. H_2S concentration
2. Well fluid Ph and the use of scavengers
3. Wellbore pressures and temperatures

Some working environments such as high temperatures may mitigate, to some degree, the effects of H_2S on equipment but should not be relied upon as the sole protective measure. The effects of H_2S on elastomers, packing, and similar internal equipment parts must also be considered. Illustration 15 is a cross reference for steel hardness scales, and Illustration 16 is a partial list of H_2S service BOPE designations.

(c) Mud Program. Quantities of mud additives to scavenge and/or neutralize H_2S, sufficient to treat the active mud system, shall be on location where formation pressures are unknown (i.e. beyond the known producing limits of a field). The surface volume in the active mud system for an average well depth will usually consist of two hole volumes. Deeper wells may fall below this amount due to equipment, cost, and location constraints.

A scavenger is a chemical that reacts with H_2S or a sulfide salt rendering the sulfide inert. To mitigate corrosion, sulfide stress cracking (SSC), and hydrogen embrittlement (HE), Order No. 6 requires maintaining the mud a minimum pH of 10. However, it is highly advisable that a mud pH of 10.5 be utilized giving a pH safety margin of 0.5. Alkalinity is an effective method in combating H_2S returns to the surface. H_2S, an acid, reacts with an alkaline mud creating sulfide salts (i.e. HS^-, $S^=$ and water) which then can react with the scavengers. A drop in mud pH is considered an indicator of H_2S influx and care should be taken to maintain the mud pH of 10.5. For example, a mud pH of approximately 9 gives a relative percentage of H_2S (versus HS^- and $S^=$) of less than 1%, whereas near a pH of 8 the relative percentage vastly increases to over 10%.

Some types of mud systems (i.e. certain polymers and low-pH, nondispersed inhibitive water-based muds), will be affected by high pH. Most of these systems lose effectiveness at high pH. However, discretion should be exercised when an operator indicates that maintaining a pH of 10 may be detrimental to mud effectiveness. In these cases, supporting documentation including alternative mud systems that accomplish similar benefits given the anticipated downhole environment, should be requested and analyzed against the benefits pH offers in H_2S control. In any event, H_2S control will be the determining factor in mud system approval.

SSC, HE and corrosion are the most serious effects when H_2S enters the mud. Higher temperatures (>200° F) have a beneficial effect by decreasing the rate of SSC/HE. Chloride ions, found in many inhibitive mud systems, promotes SSC. Oil based muds are beneficial in preventing SSC/HE and corrosion. However, H_2S is more soluble in oil than water which increases the risk of H_2S breakout at the surface.

(d) Flare System. The flare system is extremely critical in protection of essential personnel. Placement of flare lines in relation to the location/rig layout should be carefully reviewed considering all factors. The ignition system shall be capable of igniting the gas under all conditions. "Diesel buckets" should not be allowed, but rather flare systems utilizing continuous pilot, spark or electronic type ignitors. In the review of the APD, past drilling experience and local knowledge of the formations to be drilled should be utilized to determine if the gas will be noncombustible, some suitable means to sustain a flare must be supplied, possibly an auxiliary gas supply.

Involvement of staff with a background in H_2S operations in certain surface related considerations is essential. It may be advisable that the engineer attend the onsite to get a better understanding of the location and the effects H_2S mitigating measures would provide. A larger location may be necessary to properly place the flare pit in areas that allow adequate dispersion of flared/vented effluent. Refer to the environmental section for more details.

(e) H_2S Detection and Monitoring Equipment. Order No. 6 contains minimum standards for H_2S and SO_2 detection and monitoring equipment. In addition to the required three H_2S detectors, it is highly advisable to have a fourth sensor located at the mud hopper, especially if enclosed. The sensor at the bell nipple should be strategically placed to avoid its susceptibility to "mud-off" and to better detect H_2S that "falls" lower in the cellar.

The calibration, testing, and maintenance of H_2S and SO_2 detection systems shall be in accordance with manufacturers specifications and recorded in the drillers log. At a minimum, an operator's statement that compliance with manufacturers calibration standards/procedures will occur shall be acceptable. To facilitate subsequent inspection of the operation, requests to the operator should be made to obtain these specifications. Detection equipment for SO_2 may consist of, at a minimum, a portable sensing device. The device shall be positioned such that a concentration reading can be obtained at any area potentially impacted by SO_2. Because SO_2 is lighter than air, the issue of pluming needs to be considered. Illustration 17 contains some examples of different SO_2 plume conditions.

(f) Drill Stem Testing (DST). The DST of any zones that contain or may contain H_2S shall occur with only the personnel necessary to safely conduct the test and operate the rig in its current status. Changes will occur in essential personnel from those personnel considered essential during drilling operations. In these cases, additional company personnel such as a geologist or reservoir engineer and service company personnel may also be considered essential personnel.

(g) Well Control Equipment. For the purposes of H_2S operations, drilling operations for exploratory wells shall employ a mud-gas separator and rotating head. Mud-gas separators are erroneously synonymous with a gas buster. The difference is that a mud-gas separator is equipped with a liquid level control valve (automatic dump valve), whereas a gas buster merely operates at atmospheric conditions. Both are used to safely control trip gas and gas from gas-cut-mud. This gas occurs mainly as free gas or as gas slugs and should not be confused with dissolved gas at standard surface pressure. The major concern is recirculating gas-lightened mud which lowers the hydrostatic head and may affect well control. Other problems may be surging of mud pits, which would blast mud out of the tanks causing potential equipment damage, creation of a fire hazard when gas slugs reach the surface and direct exposure of essential personnel to the effects of H_2S. Separated gas shall be piped into the flare system if possible.

Degassing in Order No. 6 refers to the equipment installed on and in the mud tanks to eliminate dissolved gasses in the mud. Degassers are specifically utilized to eliminate the entrained gas (H_2S) which will not break out. There are two types of degassers: the centripetal or agitation type and the vacuum type. The centripetal pulls fluid off the bottom and utilizes a cyclone effect to break out the gas. The vacuum type pumps the fluid into a vessel and pulls the gas out of the mud by a vacuum pump. When a gas buster is utilized, degassing will occur after the mud has passed through the gas buster. These gasses should be piped into the flare system. The operator should be questioned if an agitation type degassing system is proposed for a well where entrained H_2S gas may be a problem. Refer to API RP-49 Section 5.14 for locating this equipment.

(h) Training. Order No. 6 requires operator assurance that all personnel are properly trained in H_2S drilling and contingency procedures as outlined in API RP 49, Section 2. The training shall be completed 500 feet above or three days (whichever is earlier) before penetrating the first formation containing or reasonable expected to contain H_2S. To assist in compliance determinations made by PETs for operator chosen training methods, the DOP should address how the operator intends to accomplish this training and the operator should be required to notify the authorized officer when these criteria has been mat via a COA.

(i) Protective Equipment for Essential Personnel. Order No. 6 contains many specific standards for protective equipment for essential personnel. See ANSI Standard Z.88.2-1980 (or current edition), American National Standard Practices for Respiratory Protection, concerning Order No. 6 requirements for a proper respiratory protection equipment program.

Identification of the type of equipment to be used to fulfill Order No. 6 requirements shall be included in the APD. The operator will usually identify this equipment by manufacturer name and type. Any doubts about the type of equipment specified shall be satisfied prior to APD approval and if necessary, the clarification obtained from the operator should be specifically included as a COA.

The DOP shall specify on the layout diagram type and locations of protective equipment considered to be "readily accessible" to essential personnel.

(j) Explosion Proof Ventilation Fans. In addition to the minimum requirements of Order No. 6 and for the necessary safety and protection of essential personnel, it is highly advisable that the authorized officer consider requiring the utilization of explosion proof ventilation fans in enclosed areas which might be exposed to concentrations of H_2S. Particularly important is the ventilation of the cellar area under the substructure where H_2S might accumulate undetected. This requirement should always be included in all H_2S DOP approvals as a COA.

(k) External Communication. The mouth piece(s) of the required electronic communication equipment, i.e. telephones, radios, and mobile phones, shall be in a safe area strategically located utilizing the prevailing winds to an advantage and capable of

communicating with offsite entities. This equipment shall be identified on the layout diagram.

(l) Effective Communication. Once protective breathing apparatus is donned, effective communication is considered to include chalkboards, pads and pencils, a system of hand signals, or built-in microphones or voice activated equipment in the masks. The DOP should include mention of the type(s) of effective communication procedures to be used by the crew. All equipment necessary for the chosen communication procedures shall be in place at the time Order No. 6 is implemented.

(m) Wind Direction Indicators. The location and drill rig layout diagrams and/or DOP text should identify the locations and height of wind direction indicators.

(n) Production Facilities. Operator's should be encouraged to submit production plans at the time of facility construction not at the APD stage. However, if production facilities are proposed at the APD approval stage, the APD shall be conditioned to require submittal and prior approval of the production facilities (at that future time) to ensure compliance with Order No. 6.

(o) Radius of Exposure. Illustration 14 contains Nomographs based upon the Pasquill-Gifford equation to assist in determining either the 100 ppm or the 500 ppm ROE. In the case where a more elaborate model or calculation than the Pasquill-Gifford equation is required, a BLM State Office Air Resources Specialist should be consulted on the adequacy of any proposed model or calculation scheme. If the State Office does not have and Air Resources Specialist, the State Office Air Quality Coordinator should contact the Model Review Team (MRT) at the Environmental Science and Technology Center (ESTA). To assist the Air Specialist/ESTA in determining the adequacy of the proposed model, the local office shall require the operator to provide the following information:

1. The name of the model, who developed it and who supports the model.

2. When, where, and by whom the model has been accepted for this use on BLM managed land/minerals or by other governmental bodies and what specific provisions, if any, were applied to its use.

3. Whether the model has been reviewed as part of the UNAMAP series of models by the Environmental Protection Agency and/or contacts made with any air regulatory agencies concerning the use of this model for hydrogen sulfide dispersion analysis.

4. Copies of referenced journal articles describing the model, if available and as necessary.

5. Type of hardware/software required to run the model (personal computer, mini, mainframe or special software).

6. All information required to run the model (meteorological data, location(s) where meteorological data was collected, source strength calculations, receptor descriptions, model options used, etc.).

7. Source code and user manual, if available, to evaluate this model or is it proprietary?

8. Model accountability for effect of terrain on wind flow.

9. Topographic map(s) of the area which will be analyzed using the model with the sources and sensitive receptors (i.e., sites of potential public or resource risk) shown.

The operator should be advised via the seven day letter that delays in APD processing may occur due to BLM evaluation of the alternative method proposed to calculate ROE and subsequent technical input by the operator may be necessary to fully justify use of the model in specific situations. Field personnel should be aware that the acceptance of a model for use in one situation may not mean that it is appropriate and approved for other geographic locations or field applications.

(3) Environmental.

(a) Surface Use Program. Review of the surface use plan should be done in conjunction with review of the drilling plan. The office and field review should both consider the aspects of the well site diagram with respect to H_2S safety and operations. Refer to Order No. 6, Section III.A.1.b. for the specific requirements for the well site diagram to ensure it is complete.

The overriding consideration in the siting and orientation of the well pad should be the primary wind direction. In mountainous areas, the affect of valley winds must also be addressed in the planning of specific well location and rig orientation. Every attempt should be made to provide for an uphill/upwind location for the primary access road and downwind location for the reserve and flare pits.

Special consideration should be given to ensuring adequate room to locate flare pit(s) and safe briefing areas at least 150' from the wellbore and providing for a secondary means of egress from the site. The secondary means of egress is only to move personnel to a safe area. It is highly desirable but not required to tie back to the primary access road and is not necessarily an improved road and may be a marked footpath. In any case, it must be passable for its intended use as a medical evacuation route.

The secondary means of egress and a second flare pit, if used, should be at an angle of no less than 90 degrees from the primary road or pit with reference to cardinal wind direction at the site. If a crew camp is requested for remote locations, every effort must be made to locate the camp off the well pad, uphill and upwind from the well. Consideration should also be given to locating the access road(s) to maximize the opportunity to control access to the well site (e.g. bridge, stream crossings, cattle guards, etc.) in case the public protection plan is implemented.

Some consideration should also be given to the placement of caution/danger signs so that they will be visible to vehicles approaching the location in light of vegetation types, time of year, etc. In addition, consideration for vehicles being able to turn around prior to entering the location (i.e. near the warning signs 200 to 300 feet from the location) should be considered in the surface use plan and discussed at the field review. This may involve a turn around area or simply some assurance that vehicles could back up to a point to turn around.

Order No. 6 contains minimum standards for the color requirements for operational danger or caution signs. In some locations, consideration must also be given to the sighting of transmitters (e.g. satellite dishes) for communication purposes. These issues must be discussed at the preliminary onsite drilling inspection with the operator and surface management agency personnel. The information for the office review will normally be found on a diagram attached to the drilling operations plan or on the location layout diagram as part of the surface use plan of operations (SUPO) submitted in accordance with Order No. 1.

The BLM employee conducting the onsite predrill inspection should also review the radius of exposure calculations for the 100 and 500 ppm radii and check the location of residences, roads, campgrounds, etc. in the area. If a public protection plan was submitted with the APD, a field verification of the vicinity map is appropriate. If a review of the area within the calculated radii of exposure areas indicate that a public protection plan should be required (i.e. the applicability criteria found in section of Order No. 6 apply), it should be requested from the operator.

(b) NEPA. The potential for or known existence of H_2S must be considered in the NEPA analysis process. The risk for loss of well control and subsequent effects to the public health and safety must be analyzed in light of the mitigation presented (e.g. technical drilling considerations and public protection plan) in the event of a potentially hazardous release of H_2S. Those residences, etc within the 100 ppm radius of exposure and public highways, roads, etc. within the 500 ppm radius of exposure should be the areas considered in the analysis.

(4) Public Protection Plan.

The PPP is required when the applicability criteria are met and provides the details of actions to alert and protect the public in the event of a release of a potentially hazardous volume of H_2S. The PPP shall be onsite at all times the requirements of Order No. 6 are in effect. The requirements in Order No. 6 are considered minimum standards and therefore, the plan typically will contain more information.

Submittal of a single PPP covering a unit or field shall be approved with a condition that any site specific information necessary to comply

with the requirements of Order No. 6 shall be submitted with each APD. Individual approval of APD's should be conditioned such that the previous field-wide or unit PPP is made a part of the APD.

For the required parts of a public protection plan that are not contained in the body of the APD, a separate attachment should be included in the APD package. This attachment probably will contain the list of names and telephone numbers of various parties and telephone call list for emergency personnel.

The public protection plan shall contain the information identified in section III.B.2.b. The following explanations are provided for certain portions of the PPP.

1. Key personnel are considered personnel under the authority of the operator.

2. The person(s) designated by title or position as having authority to ignite the well shall include at least one direct employee of the operator.

3. The monitoring of releases of H_2S or SO_2 levels in affected areas may be done through the use of portable detection equipment if they meet the requirements of Order No. 6 for minimum detection concentrations and response times.

4. Access control and site security during times of active H_2S or SO_2 release should be in the form of physical or human barriers and not signs, informative literature, or verbal warnings (i.e. flyers, bull horns, etc.)

(5) <u>Subsequent Operations</u>.

The submission of any requests for change of plans, whether related to the drilling (change of casing, cementing, etc.) or surface use operations plan (additional reserve pits, change of access, etc.), should be reviewed against the same criteria as the original APD with respect to H_2S operations.

Order No. 6 requires that if H_2S was not anticipated but subsequently encountered in concentration of 100 PPM in the gas stream, the operator shall immediately ensure control of the well. Since actual concentrations are difficult to determine during drilling operations without actually conducting tests, the BLM shall assume that <u>any</u> H_2S encountered will necessitate compliance with Order No. 6 unless

substantial evidence exists to the contrary.

Control of the well means the elimination of H_2S returns to the surface and compliance with the requirements of Order No. 6. All H_2S equipment necessary for essential personnel protection and well operation, the circulating medium conditioned to mitigate H_2S effects, possible realignment of the well pad/drill rig configuration, etc., shall be in place prior to resumption of actual drilling operations.

On a case-by-case basis, such as low H_2S volumes, the authorized officer may not require replacement of non-H_2S trimmed equipment i.e. BOPE, drill string, wellhead etc. However, in high concentrations, all possible equipment should be replaced. In some instances, even cemented casing may need isolation by another severe service string. Diligent attempts must be made by the operator to ensure a safe operation given this equipment and operating condition. A premium will then be placed on ensuring elimination of H_2S at the source to minimize H_2S effects on the operation. Therefore, close adherence by the operator to the requirements concerning the mud system and drilling parameters, and essential personnel protection must occur.

Any modifications to the original drilling program necessary to mitigate the unexpected effects of H_2S should be initiated at this time. For example, revisions to the casing and cementing programs may be necessary.

c. Deviated and Horizontal Wellbores.

The drilling plan should be reviewed to determine if any deviated or horizontal portions of the wellbore are proposed by the operator. If a deviated or horizontal well bore is proposed, the drilling plan must identify the proposed azimuth, kick-off point, inclination rate (angle build rate), and the estimated closure or horizontal length to be drilled. This information is essential to properly evaluate the drilling plan. Significant deviation from the approved plan requires prior approval as provided for in the regulations at 43 CFR §3162.5-2(b). All wellbore paths, i.e. different orientations of bottom hole locations, require prior approval.

In evaluating the drilling plan, the proposed azimuth and horizontal length must be reviewed to ensure the wellbore meets all spacing requirements for setback or drilling windows. When reviewing the bottom hole location, the well path must also allow for possible wellbore drift and the inherent inaccuracies, i.e. degree of error, in the measurement while drilling (MWD) tools. Casing design criteria must take bending and biaxial stress into consideration. The cementing program needs to be balanced between proposed completion program and zone isolation. Additional information may be needed in evaluating the cementing program to ensure the spacer and displacement fluid weights are equivalent. The mud program may propose the use of friction reducing agents which may be harmful to surface and subsurface resources.

Additional attention must be given to survey requirements during all stages of the drilling program. Consideration should be given for requesting a survey of the last casing string above the kick-off point. Operators may assume that the vertical section of the wellbore is truly vertical. Depending on the depth of the last casing string, the deviation from true vertical can move the wellbore outside the spacing unit or across lease lines. All bottomhole locations (including wellbores of different orientations in the same horizontal plane) must be directionally surveyed to determine the exact location of the wellbore(s). API BUL D20, Directional Drilling Survey Calculations Methods and Terminology; and API BUL D8, A Tabular Method of Determining Build Up Rate and Dog Leg Severity, provides acceptable methods of determining bottom hole locations. All directional surveys which indicate both azimuth and inclination are critical in determining bottomhole location as well as producing intervals (critical for correlative rights issues and reservoir studies).

The authorized officer should specify the approved direction of the deviated wellbore, including the approved azimuth and inclination, when approving the drilling plan. Requirements specifying the results necessary for acceptable surveys and the frequency of directional surveys should be included in the COA's. The operator should be reminded that only the deviation proposed, within acceptable limits, is approved for the APD and all other deviations will require prior approval.

6. Surface Use.

Surface use is specifically addressed in Order No. 1 and the Surface Use Plan of Operation (SUPO) contained in the approved APD. Even though the Drilling Plan and SUPO are two different parts of the proposal, they are interrelated and approval considerations should be coordinated between downhole and surface specialists. During the engineer review, the SUPO should be scanned to determine if any anomaly is apparent and brought to the attention of the Surface Management Agency (SMA). For example, if air/gas drilling is anticipated, the drilling plan layout should be reviewed to ensure blooey lines and compressors, etc. are taken into account for pad size. Any safety concerns, such as egress for H_2S areas, are paramount points of discussion. Also, any post-drilling operational constraints, such as adequate well pad size for safe completion procedures (massive hydraulic fracturing) should be discussed. API RP 52, Recommended Land Drilling Operating Practices for Protection of the Environment and the Surface operating Standards for Oil and Gas Exploration and Development "Gold Book" are sources for common acceptable oilfield surface use practices.

7. Plugging of Drilling Operations.

a. General.

Any usable quality water; prospectively valuable mineral zone; or any formation fluid with a potential to migrate shall be protected. This minimum standard applies to open hole, casing interior, as well as open hole/casing annuli situations. These situations may exist whenever the primary or subsequent remedial cementing operation fail to achieve their intended level. Encountering a previously unknown aquifer or other geologic zone could be another possibility. Review of well logs may assist in detection of these zones. Regardless of the reason, protection or isolation of all critical zones must be required during the approval process and accomplished during the plugging operations.

In all situations, every effort should be made to provide a BLM representative to ensure that proper plugging procedures are utilized in accordance with the minimum standards and the specific approval requirements. It is imperative that all critical plugging phases be witnessed to ensure that optimum practices are utilized at that time. From a practical and regulatory standpoint, it is easier to avoid or

correct problems as they occur than to require and substantiate remedial operations at a later date.

b. Approval Considerations.
Approval may be granted orally by the authorized officer prior to initiation of abandonment operations. This oral request and approval shall be followed by a written notice of intent (NOI) to abandon filed not later than the fifth business day following oral approval. Illustration 18 provides a format and example to document oral approvals. Approvals shall always be based upon and require the well to be in a static condition, i.e. not either flowing nor taking fluid.

The approval shall ensure that the make-up water for both the spacer fluid and the cement should be nontoxic as well as compatible with the intended cement. Utilization of produced water which exhibit low total dissolved solids and low sodium levels may be acceptable providing the cement slurry design accounts for these parameters. All critical plugs should consider utilizing neat cement which exhibits higher compressive strength and durability as opposed to light weight pozzolan cements.

The plugging approval should take into consideration that current oilfield equipment and practices do not necessarily provide the capability for ensuring placement of 100 foot plugs, specifically in small diameter holes or tubulars. For example a 100 foot plug in 4 1/2 inch casing constitutes only 1.5 bbls of cement, a volume that is typically too small for pump trucks to place with any credibility. Small volume plugs also have a greater potential for contamination. In these instances, larger volume (i.e. longer) plugs could be considered.

Conversely, excessively large plugs, i.e. longer than 500 feet, due to their length and high density differential with spacer fluids have the potential to cause problems such as falling, separation, or breaking down weak formations. In most instances two shorter and separate plugs offer a type of redundancy, can be easier to place, and provide as much isolation as one long plug.

A typical plugging technique to isolate usable quality water or prospectively valuable minerals zones behind casing but above the TOC may be to perforating the casing below the zone; set a cement retainer; and squeeze a sufficient volume of cement to cover the zone achieving a sufficient pressure without breaking down the formation. Generally, the approval should specify how much pressure will be acceptable for a squeeze operation predicated on local knowledge, for example 1000 psi over pump pressure. For very thick zones this procedure may be performed above and below the intended zone. It is possible for multiple perforate and squeeze operations to occur. Shooting-off and recovering the casing below the protection zone, and then setting stub

and open hole plugs is another viable method which may afford better results than the perforate and squeeze technique.

All annulii at surface require a 50 foot cement plug. This plug may be placed by bullheading or pumping down 1 inch tubing as conditions allow. If the operator proposes slough filling via ready-mix, the authorized officer should consider the ramifications of potential bridging problems. Perforation and squeeze techniques (as discussed above) may also be viable for the surface casing shoe plug (50 feet in and 50 feet out) as well as any other casing shoe plugs (e.g. intermediate or production strings).

When plug back operations occur due to unretrievable fish, lost hole or junk, the addition of fracturing sand to the side-track or whip stock plug is a typical method to increase the compressive strength of the cement.

Plugs set in horizontal or highly deviated boreholes need to be properly blended and mixed to provide minimum freewater and avoid gravity segregation. The U-tube effect is practically eliminated in these wells. Therefore for placement purposes, both the cement and spacer fluid should be equivalent in density. Cement plugs set in horizontal sections are very difficult to place due to the increased volumes and slow pump speeds as well as the risk of cementing the work string inplace. Tagging a plug is equally as difficult due to the uncertainty of where the weight is being applied - on the plug or merely bending the pipe and setting down on the side (bottom) of the hole. It is best not to attempt to place a plug in the horizontal section, but rather in the radius portion and increase cement volumes. If a plug is necessary in the horizontal section, start placing the plug at the beginning of the horizontal section and work upward 200-300 feet.

As in primary cementing, to avoid cement degradation in wells with bottom hole static temperatures in excess of 230^{0}F, the plugging program shall provide for the utilization of either silica sand or silica flour depending upon cement slurry density requirements. This additive will usually be 30 percent by weight.

Contamination of cement plugs should be avoided to ensure durability and stability of the cement. Prudent oilfield practices should address proper plug setting techniques to minimize contamination. These techniques may include: requiring additional plug length; slow retrieval rates of the placement string; adequate volumes of preflush pumped in turbulent flow; or removal of all movable mud. The utilization of a bentonite pill placed directly below the bottom of the

plug could be considered to prevent plug migration and as an aid in placement.

c. Minimum Standards.

Order No. 2 details specific minimum standards for abandonment of newly drilled wells. An operator may choose various methods of achieving the minimum standards. However, it is incumbent upon the authorized officer to ensure the methodology will not jeopardize the plugs durability nor placement accuracy.

The SMA is responsible for cellar fill material as well as any surface rehabilitation concerns including dry hole marker specifications. If utilized, the dry hole marker shall be inscribed with the following information: Company; Well Number; Quarter/Quarter, Section, Township, Range, Meridian; County, State; and Lease Number.

D. VARIANCES.

Order No. 2 discusses variances in both Sections I.D.2 and in IV. The authorized officer should become familiar with both these sections. The operator shall specify in writing the minimum standards for which a variance is requested along with the circumstances which warrant approval of the variance(s) requested and the proposed alternative methods by which that minimum standard will be achieved, or why the minimum standard is not applicable for the instant situation. The APD is a contract between the operator and the BLM. As such it shall conform to all the minimum standards of Order No. 2, unless specific variances are requested by the operator and approved by the authorized officer. If the proposed drilling plan does not conform with the minimum standards of Order No. 2 and the operator has not requested variances, the seven day notification letter shall require all discrepancies to be corrected prior to APD approval.

Order No. 2 represents the BLM's true minimum standards for drilling operations. Variances should be an exception and not the rule. Failure of having the necessary equipment to preform required operations shall NOT constitute justifiable reason for variances. Equipment limitations on the operators part is also inexcusable. The authorized officer shall use discretion when considering any request to vary from the standards and shall document each variance.

Variances may be granted on a well-by-well basis via the APD approval and reiterated in the COA's or on a field wide basis if significant applicable concerns are present via a NTL. If occurring during the approval process, documentation should be provided via the engineer

review (Illustration 4). For emergency situations, oral approvals may be granted for variances with written documentation via a sundry notice within 5 days.

Glossary of Terms

-A-

Authorized Officer (AO): any employee of the Bureau of Land Management authorized to perform the duties described herein.

-C-

Conditions of Approval (COA): a site-specific requirement of operations incorporated into an approved APD or Sundry Notice.

-D-

Drilling Plan : documents submitted by an operator as part of an operations detailing the proposed drilling operations and containing such information as required by 43 CFR 3162.3-1(e).

Drilling Operations: for the purposes of this handbook, all operations conducted from the filing of an APD, through the running and cementing of the production casing/liner or a dry hole abandonment.

-E-

Exploratory Well: any well drilled in search of a new, and as yet undiscovered, field and/or pool of oil or gas. Drilling in a known area, but to a deeper undrilled formation would constitute exploratory drilling.

-P-

Prospectively Valuable Deposit of Minerals: any deposit of minerals that the AO determines to have characteristics of quantity and quality that warrant its protection.

-S-

Spudding: initiale hole making operations for a well. May involve dry-hole digger, cable tool spudding unit, air-rig or rotary rig capable of reaching total depth.

Surface Management Agency (SMA): any Federal or state agency having jurisdiction over the surface overlying federal or Indian owned minerals.

-S-
(Cont.)

Surface Use Plan of Operations (SUPO): a document submitted by the operator as part of an APD or a supplement to an approved plan of operations detailing proposed surface occupance and planned surface operations pursuant to a Federal or Indian oil and gas lease.

-U-

Usable Quality Water: generally those waters containing up to 10,000 ppm of total dissolved solids.

Illustration 1, Page 1

Form 3160-3
(December 1990)

SUBMIT IN TRIPLICATE*
(Other instructions on reverse side)

Form approved.
Budget Bureau No. 1004-01
Expires: December 31, 1991

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

APPLICATION FOR PERMIT TO DRILL OR DEEPEN

5. LEASE DESIGNATION AND SERIAL NO.: WY-01234

6. IF INDIAN, ALLOTTEE OR TRIBE NAME:

7. UNIT AGREEMENT NAME:

8. FARM OR LEASE NAME, WELL NO.:

9. WELL NO.: Gold Mine Fed #1

10. FIELD AND POOL, OR WILDCAT: Lost and Found

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA: Sec 17, T29N, R112W.

1a. TYPE OF WORK: DRILL [X] DEEPEN [ ]

b. TYPE OF WELL: OIL WELL [X] GAS WELL [ ] OTHER SINGLE ZONE [X] MULTIPLE ZONE [ ]

2. NAME OF OPERATOR: I.M. Good, Inc.

3. ADDRESS AND TELEPHONE NO.: 2625 Wakakara Lane; Denver, CO 80102

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.*)
At surface: 1980'FNL 1980'FEL; Sec.17, T.29N., R.112W.
At proposed prod. zone: Same

14. DISTANCE IN MILES AND DIRECTION FROM NEAREST TOWN OR POST OFFICE*: App. 20 Miles NW of Gettysburg, Wyoming

12. COUNTY OR PARISH: Lincoln 13. STATE: Wyoming

15. DISTANCE FROM PROPOSED* LOCATION TO NEAREST PROPERTY OR LEASE LINE, FT. (Also to nearest drlg. unit line, if any): 660'

16. NO. OF ACRES IN LEASE: 400

17. NO. OF ACRES ASSIGNED TO THIS WELL: 160

18. DISTANCE FROM PROPOSED LOCATION* TO NEAREST WELL, DRILLING, COMPLETED, OR APPLIED FOR, ON THIS LEASE, FT.:

19. PROPOSED DEPTH: 6500' TVD

20. ROTARY OR CABLE TOOLS: Rotary

21. ELEVATIONS (Show whether DF, RT, GR, etc.): 4860' GR

22. APPROX. DATE WORK WILL START*: Feb. 30, 1991

23. PROPOSED CASING AND CEMENTING PROGRAM

SIZE OF HOLE	GRADE, SIZE OF CASING	WEIGHT PER FOOT	SETTING DEPTH	QUANTITY OF CEMENT
12¼"	9 5/8"	36#/' K-55	1250'	To Surface
8¾"	7"	26#/' K-55	6500'	Above Jolly Fm. (4000')

SEE ATTACHED DRILLING PLAN AND SURFACE USE PLAN OF OPERATION.

24. ABOVE SPACE DESCRIBE PROPOSED PROGRAM: If proposal is to deepen, give data on present productive zone and proposed new productive zone. If proposal is to drill or deepen directionally, give pertinent data on subsurface locations and measured and true vertical depths. Give blowout preventer program, if any.

SIGNED Carolyn Mann TITLE Representative DATE Jan. 4, 1991

(This space for Federal or State office use)

PERMIT NO. _____ APPROVAL DATE _____

Application approval does not warrant or certify that the applicant holds legal or equitable title to those rights in the subject lease which would entitle the applicant to conduct operations thereon.
CONDITIONS OF APPROVAL, IF ANY:

APPROVED BY C. Kadiddlehopper TITLE Minerals Chief DATE 4-1-92

*See Instructions On Reverse Side

Title 18 U.S.C. Section 1001, makes it a crime for any person knowingly and willfully to make to any department or agency of the United States any false, fictitious or fraudulent statements or representations as to any matter within its jurisdiction.

INSTRUCTIONS

GENERAL: This form is designed for submitting proposals to perform certain well operations, as indicated, on all types of lands and leases for appropriate action by either a Federal or a State agency, or both, pursuant to applicable Federal and/or State laws and regulations. Any necessary special instructions concerning the use of this form and the number of copies to be submitted, particularly with regard to local, area, or regional procedures and practices, either are shown below or will be issued by, or may be obtained from, the local Federal and/or State office.

ITEM 1: If the proposal is to redrill to the same reservoir at a different subsurface location or to a new reservoir, use this form with appropriate notations. Consult applicable State or Federal regulations concerning subsequent work proposals or reports on the well.

ITEM 4: If there are no applicable State requirements, locations on Federal or Indian land should be described in accordance with Federal requirements. Consult local State or Federal office for specific instructions.

ITEM 14: Needed only when location of well cannot readily be found by road from the land or lease description. A plat, or plats, separate or on this reverse side, showing the roads to, and the surveyed location of, the well, and any other required information, should be furnished when required by Federal or State agency offices.

ITEMS 15 AND 18: If well is to be, or has been directionally drilled, give distances for subsurface location of hole in any present or objective production zone.

ITEM 22: Consult applicable Federal or State regulations, or appropriate officials, concerning approval of the proposal before operations are started.

NOTICE

The Privacy Act of 1974 and the regulation in 43 CFR 2.48(d) provide that you be furnished the following information in connection with information required by this application.

AUTHORITY: 30 U.S.C. 181 et seq., 25 U.S.C. 396; 43 CFR Part 3160.

PRINCIPAL PURPOSE: The information is to be used to process and evaluate your application for permit to drill or deepen an oil or gas well.

ROUTINE USES: (1) The analysis of the applicant's proposal to discover and extract the Federal or Indian resources encountered. (2) The review of procedures and equipment and the projected impact on the land involved. (3) The evaluation of the effects of proposed operation on surface and subsurface water and other environmental impacts. (4)(5) Information from the record and/or the record will be transferred to appropriate Federal, State, local or foreign agencies, when relevant to civil, criminal or regulatory investigations or prosecutions, as well as routine regulatory responsibility.

EFFECT OF NOT PROVIDING INFORMATION: Filing of this application and disclosure of the information is mandatory only if the operator elects to initiate drilling operation on an oil and gas lease.

BURDEN HOURS STATEMENT

Public reporting burden for this form is estimated to average 30 minutes per response, including the time for reviewing instructions, gathering and maintaining data, and completing and reviewing the form. Direct comments regarding the burden estimate or any other aspect of this form to U.S. Department of the Interior, Bureau of Land Management, (Alternate) Bureau Clearance Officer, (WO-771), 1849 C Street, N.W., Washington, D.C. 20240, and the Office of Management and Budget, Paperwork Reduction Project (1004-0136), Washington, D.C. 20503.

The Paperwork Reduction Act of 1980 (44 U.S.C. 3501 et seq) requires us to inform you that:

This information is being collected to allow evaluation of the technical, safety, and environmental factors involved with drilling for oil and/or gas on Federal and Indian oil and gas leases.

This information will be used to analyze and approve applications.

Response to this request is mandatory only if the operator elects to initiate drilling operations on an oil and gas lease.

*U.S. GPO: 1981-571-016/24050

GEOLOGIC EVALUATION REPORT ON

APPLICATION FOR PERMIT TO DRILL

OPERATOR:	SERIAL /LEASE #:
LOCATION:	WELL NUMBER:
GRD ELEV:	TOTAL DEPTH:
FIELD :	PROD FM(S):

1. STRATIGRAPHY (surface formation and estimated formation tops)

Formations as listed in APD: Inaccurate

FORMATION/MEMBER	TOP
	SURFACE

2. SUBSURFACE RESOURCES

	FORMATION	PROTECTION	PROJECTED BOREHOLEDEPTH
WATER-----SEE HYDROLOGIST'S REPORT			
NOTES			
OIL-------MULTIPLE, LENTICULAR RESERVOIRS MAY BE PRESENT			
GAS-------MULTIPLE, LENTICULAR RESERVOIRS MAY BE PRESENT			
OIL SHALE-			
TAR SAND--			
GILSONITE-			
PHOSPHATE-			
OTHER-----			

3A. CORING, LOGGING, AND TESTING REQUIREMENTS FOR MINERALS.

X: Proposed #: Additional Logs Required

SP	_____	Sonic	_____	Other logs
Resistivity	_____	Gamma	_____	_____
Neutron	_____	CBL/Temp	_____	
Density	_____	Caliper	_____	
Neutron/Den	_____	Mud	_____	

3B. OIL SHALE: GEOPHYSICAL LOGGING.

Is there potential for the borehole to penetrate an oil shale mineral resource? ____ yes/ ____ no. If so, has a Sonic Log been run within a 2 mile radius of the proposed borehole? ____ yes/ ____ no.

(well name, no., location, elevation)

4. GEOLOGIC HAZARDS.

If none are anticipated, check here: ____

	formation	projected borehole depth
H2S.....		
CO2.....		
High Pressure..		
Low Pressure...		
Other.....		

5. SUMMARY OF SUBSURFACE CONCERNS.

6. REFERENCES.

SIGNATURE: _____. DATE:_____/_____/_____.

GEOLOGIC EVALUATION REPORT ON

APPLICATION FOR PERMIT TO DRILL

OPERATOR:
LOCATION: N2SW, 26, T10S, R19E
GRD ELEV: 5,356'
FIELD : OLD SQUAWS CROSSING

SERIAL /LEASE #: U-3405
WELL NUMBER: WILD HORSE FED. 2-26
TOTAL DEPTH: 6,500
PROD FM(S): WASATCH (GAS)

1. STRATIGRAPHY (surface formation and estimated formation tops)

Formations as listed in APD: Accurate

FORMATION/MEMBER	TOP
UINTAH FORMATION	SURFACE
GREEN RIVER FORMATION	1,100'
MAHOGANY	1,800'
WASATCH	4,600'
CHAPITA WELLS	5,000'
BUCK CANYON	5,500'

2. SUBSURFACE RESOURCES

	FORMATION	PROTECTION	PROJECTED BOREHOLEDEPTH
WATER-----SEE HYDROLOGIST'S REPORT			
NOTES			
OIL-------MULTIPLE, LENTICULAR RESERVOIRS MAY BE PRESENT			
	WASATCH	YES	4,600'- 5,000'
	CHAPITA WELLS	YES	5,000'- 5,500'
	BUCK CANYON	YES	5,500'- TD
GAS-------MULTIPLE, LENTICULAR RESERVOIRS MAY BE PRESENT			
	WASATCH	YES	4,600'- 5,000'
	CHAPITA WELLS	YES	5,000'- 5,500'
	BUCK CANYON	YES	5,500'- TD

OIL SHALE- YES MAHOGANY: 1,800-1,850'
L1: 1,920-1,980'
TAR SAND--
GILSONITE-
PHOSPHATE-
OTHER-----

3A. CORING, LOGGING, AND TESTING REQUIREMENTS FOR MINERALS.

X: Proposed #: Additional Logs Required

SP		Sonic		Other logs
Resistivity	X	Gamma	X	
Neutron	X	CBL/Temp	#	
Density	X	Caliper	X	
Neutron/Den		Mud		

3B. OIL SHALE: GEOPHYSICAL LOGGING.

Is there potential for the borehole to penetrate an oil shale mineral resource? __X_ yes/ ____ no. If so, has a Sonic Log been run within a 2 mile radius of the proposed borehole? __x_ yes/ ____ no.

COTTON PETROLEUM CORP., BARTON FEDERAL 1-26, NWSE, 26, T10S, R19E, GR: 5,317', TD: 8,200'.

4. GEOLOGIC HAZARDS.

If none are anticipated, check here: _X__

	formation	projected borehole depth
H2S.....		
CO2.....		
High Pressure..		
Low Pressure...		
Other.....		

5. SUMMARY OF SUBSURFACE CONCERNS.

GEOPHYSICAL LOGS SHOULD BE RUN FROM SURFACE CASING TO TD.
A CEMENT BOND OR TEMPERATURE LOG SHALL BE RUN.
THE OIL SHALE ZONES (MAHOGANY, L1) SHOULD BE ISOLATED AND PROTECTED.
ANY FRESH WATER ENCOUNTERED DURING DRILLING SHOULD BE REPORTED TO TIM INGWELL AT THE BLM DISTRICT OFFICE IN VERNAL AND ISOLATED AND PROTECTED (SEE HYDROLOGIST'S REPORT).

6. REFERENCES.

Dwight's Completion Cards.
COTTON PETROLEUM CORP. BARTON FEDERAL 1-26, NWSE, T10S, R19E, GR: 5,317', TD: 8,200'.
Picard, D.M., 1957, Green River and Lower Uinta Formations-Subsurface Stratigraphic Changes in Central and Eastern Uinta Basin, Utah: Intermtn. Assoc. Petrol. Geol. Guidebook, 8th Ann. Field Conf, p. 116-130.
Smith, M.C., 1981, Structure contours and overburden of the top of of the Mahogany Bed, Green River Formation, Eastern part of the Uinta Basin, Uintah, Duchesne, and Carbon Counties, Utah, and Rio Blanco County, Colorado, USGS Misc. Field Studies Map, MF-1311.
Untermann, G.E., and Untermann, B.R., 1964, Geology of Uintah County: Utah Geol. and Min. Survey Bull. No. 72, 98 p.

SIGNATURE: _____. DATE:_____/_____/_____.

HYDROLOGIC REPORT ON

APPLICATION FOR PERMIT TO DRILL

OPERATOR:
LOCATION:
GRD ELEV:
FIELD :
MUD SYST:

SERIAL /LEASE #:
WELL NUMBER:
TOTAL DEPTH:
PROD FM(S):

1. SUBSURFACE GROUNDWATER RESOURCES.

FM TOP	AQUIFER (FM)	DEPTH	QUALITY (TDS)	AQUIFER ZONES

2. SURFACE HYDROLOGY CONCERNS. NONE.

3. RECOMMENDATIONS.

4. REFERENCES:

SIGNATURE_____ DATE___/___/___

HYDROLOGIC REPORT ON

APPLICATION FOR PERMIT TO DRILL

OPERATOR:
LOCATION: N2SW, 26, T10S, R19E
GRD ELEV: 5,356'
FIELD : OLD SQUAWS CROSSING
MUD SYST: FRESH WATER

SERIAL /LEASE #: U-3405
WELL NUMBER: WILD HORSE FED. 2-26
TOTAL DEPTH: 6,500
PROD FM(S): WASATCH (GAS)

1. SUBSURFACE GROUNDWATER RESOURCES.

FM TOP	AQUIFER (FM)	DEPTH	QUALITY (TDS)	AQUIFER ZONES
SURFACE	UINTA FM	0'	FRESH *U	0- 300'
1,100'	GREEN RIVER FM			
	BIRD'S NEST	1,300'	FRESH-SALINE *U	1,300-1,600'
	DOUGLAS CRK	3,000'	FRESH-SALINE *U	3,000-4,100'

*U= USABLE WATER (TDS≤10,000 PPM)

2. SURFACE HYDROLOGY CONCERNS. NONE.

3. RECOMMENDATIONS.

THE FOLLOWING DOWNHOLE PROCEDURES SHOULD BE FOLLOWED:

1) ISOLATE AND PROTECT ALL USABLE WATER ZONES (TDS≤ 10,000 PPM). BASE OF USABLE WATER ABOUT 5,360' (HOWELLS,1987).
2) REPORT ALL WATER SHOWS AND WATER SANDS ENCOUNTERED DURING DRILLING TO TIM INGWELL AT THE VERNAL DISTRICT OFFICE OF THE BLM.
3) ANY DETECTABLE WATER FLOW WILL BE SAMPLED AND THE ANALYSIS WILL BE SUBMITTED TO THE BLM VERNAL DISTRICT OFFICE.

THE TOPS OF THE FRESH WATER AQUIFERS WERE CHOSEN FROM GEOPHYSICAL LOGS AND THE BASE OF MODERATELY SALINE WATER FROM HOWELLS (1987).

4. REFERENCES:

Dwight's Completion Cards
Geophysical Logs:
COTTON PET. CO. 1-26,NWSE 26 T10S, R19E, GR: 5,317', TD: 8,200'.
Howells, L., Longson, M.S., and Hunt, G.L., 1987, Base of Moderately Saline Ground Water in the Uinta Basin, Utah: State of Utah Dept. of Natural Resources, Technical Publication No. 92, 46 p.
Hood, J.W., Mundorff, J.C., Price, D., 1976, Selected hydrologic data, Uinta Basin Area, Utah and Colorado, U.S. Geological Survey, Utah, Basic Data Release, 321 p.

SIGNATURE_____ DATE___/___/___

ENGINEERING EVALUATION
APPLICATION FOR PERMIT TO DRILL

Operator: _____ : Well Number: _____

_____ Exploratory : _____1/4_____1/4 Section _____

_____ Development : Township _____ Range _____, __M

(As defined by OOGO 2) : _____ County, _____

Lease No. _____ CA/Unit Name/No. _____

BLOWOUT PREVENTION EQUIPMENT (BOPE)(Item 3)

ABHP (Item 8) = _____ PSI; TVD = _____ Feet

Operators Gradient (ABHP/TVD) = _____ PSI/FT *is, is not* appropriate and *does, does not* coincide with the Anticipated Mud Weight (Item 6) for each drilled interval. The most credible ABHP is _____ PSI/FT.

Rationale: _____

ASP = ABHP - (0.22 * TVD)

ASP = _____ - (0.22 * _____)

ASP = _____ PSI

Operators proposed BOPE of _____M (Item 3) *exceeds, does not exceed* the ASP and is therefore *adequate, not adequate.*

Concerns: _____

CASING PROGRAM (Item 4)

Casing setting depths *are, are not* across competent formations (See Items #1 & #2 and Geologic Report) and therefore *are, are not* appropriate. See attached Design Factor Worksheet. Casing design *is, is not* adequate.

Concerns: _____

CEMENTING PROGRAM (Item 5)

All usably quality water; prospectively valuable mineral and/or hydrocarbon zone as specified on the Geologic Report *is, is not* adequately isolated and/or protected. See attached Cement Slurry and Calculated Fillup Worksheets.

Concerns: _____

DRILLING FLUID (MUD PROGRAM) (Item 6)

Proposed drilling fluid additives *are, are not* nontoxic and compatible with formations likely to be encountered.

Concerns: _____

TESTING, LOGGING, and CORING PROCEDURES (Item 7)

Adequate logs *are, are not* proposed (See Geologic Report). Cement bond evaluation tools *are, are not* proposed across critical zones. Special Drill Stem Test operations *are, are not* proposed.

Concerns: _____

CORRELATIVE RIGHTS

This well *is, is not* drilled inconformance with a spacing pattern acceptable to the AO. Spacing Order _____.
Concerns: _____

SPECIAL DRILLING OPERATIONS

Air/Gas drilling - Hydrogen Sulfide - Directional/Horizontal.
Concerns: _____

MISCELLANEOUS

Any other facets of the proposed operation (Item 9).
Concerns: _____

VARIENCES

All variences granted meet or exceed the minimum standards of OOGO 2.
Concerns: _____

RECOMMENDATION

: is recommended to include the following conditions into this APD's approval (COA's):

_____

viewed by _____ Date _____

ENGINEERING EVALUATION
APPLICATION FOR PERMIT TO DRILL

Operator: I.M. Good, Inc. : Well Number: Good Mine Fed #1
___ Exploratory : SW 1/4 NE 1/4 Section 17
X Development : Township 29N Range 112W, 6th
(As defined by OOGO 2) : Lincoln County, Wyo
Lease No. WY-01234 CA/Unit Name/No. ___

BLOWOUT PREVENTION EQUIPMENT (BOPE)(Item 3)

ABHP (Item 8) = 3000 PSI; TVD = 6500 Feet.
Operators Gradient (ABHP/TVD) = 0.46 PSI/FT (is.) is not appropriate and (does.) does not coincide with the Anticipated Mud Weight (Item 6) for each drilled interval. The most credible ABHP is 0.46 PSI/FT.
Rationale: All offset wells drilled with ≈ 9.0 ppg mud

ASP = ABHP - (0.22 * TVD)
ASP = 3000 - (0.22 * 6500)
ASP = 1570 PSI

Operators proposed BOPE of 3 M (Item 3) (exceeds.) does not exceed the ASP and is therefore (adequate.) not adequate.
Concerns: Operators BOPE Diagram does not reflect an annular preventer.

CASING PROGRAM (Item 4)

Casing setting depths (are.) are not across competent formations (See Items #1 & #2 and Geologic Report) and therefore are. are not appropriate. See attached Design Factor Worksheet. Casing design (is.) is not adequate.
Concerns: None

CEMENTING PROGRAM (Item 5)

All usably quality water; prospectively valuable mineral and/or hydrocarbon zone as specified on the Geologic Report is. (is not) adequately isolated and/or protected. See attached Cement Slurry and Calculated Fillup Worksheets.
Concerns: Usable Quality Water Above Proposed Cement top on 7 inch Production Casing.

DRILLING FLUID (MUD PROGRAM) (Item 6)

Proposed drilling fluid additives are. (are not) nontoxic and compatible with formations likely to be encountered.
Concerns: Need to specify no chromates.

TESTING, LOGGING, and CORING PROCEDURES (Item 7)

Adequate logs (are.) are not proposed (See Geologic Report). Cement bond evaluation tools are. (are not) proposed across critical zones. Special Drill Stem Test operations are. (are not) proposed.
Concerns: Require CBL/CET on 7 inch Production Casing

CORRELATIVE RIGHTS

This well (is) is not drilled inconformance with a spacing pattern acceptable to the AO. Spacing Order GENERAL.
Concerns:

SPECIAL DRILLING OPERATIONS

Air/Gas drilling - Hydrogen Sulfide - Directional/Horizontal.
Concerns:

NONE.

MISCELLANEOUS

Any other facets of the proposed operation (Item 9).
Concerns:

NONE.

VARIENCES

All variences granted meet or exceed the minimum standards of OOGO 2.
Concerns:

NONE.

RECOMMENDATION

t is recommended to include the following conditions into this APD's approval (COA's):

1. AN ANNULAR PREVENTOR SHALL BE UTILIZED IN CONJUNCTION WITH THE APPROVED 3M BOPE.

2. GEOLOGIC ANALYSIS INDICATES THAT USABLE QUALITY WATER MAY BE IN THE JOLLY FORMATION AT A PROJECTED DEPTH OF ± 4000 FEET. IF ENCOUNTERED WHILE DRILLING, THIS ZONE SHALL BE PROTECTED BY BRINGING THE CEMENT LEVEL BEHIND THE 7 INCH PRODUCTION CASING TO AT LEAST 100 FEET ABOVE THE FORMATION.

3. NO TRIVALENT OR HEXAVALENT CHROMATE ADDITIVES SHALL BE USED IN THE MUD SYSTEM IN ORDER TO PROTECT USABLE QUALITY AQUIFERS.

4. TO DETERMINE CEMENT TOP AND BOND QUALITY, CEMENT BOND LOG (CBL) OR CEMENT EVALUATION TOOL (CET) SHALL BE RUN AFTER THE 7 INCH PRODUCTION CASING IS RUN AND CEMENTED IN PLACE.

Reviewed by Fred Kautzick Date February 31, 1988

CONDITIONS OF APPROVAL

Company: I.M. Good Inc.
Location: SW/NE, Sec.17, T.29N., R.112W.
Well No. Fed #1
Lease No. WY-01234

I. NOTICES

Approval of this application does not warrant or certify that the applicant holds legal or equitable title to those rights in the subject lease which would entitle the applicant to conduct operations thereon.

All lease and/or unit operations will be conducted in such a manner that full compliance is made with applicable laws, regulations (43 CFR Parts 3100, 3160 and 3180), lease/agreement terms, Onshore Oil and Gas Orders, Notice to Lessee's and this approved plan of operation.

The operator is fully responsible for the actions of his subcontractors.

A copy of the approved application and these conditions shall be maintained on location during all construction and drilling operations. Deviation from the approved plan without prior approval is not allowed.

Operators have the responsibility to assure that activities authorized by this permit are conducted in a manner that complies with other applicable Federal, State and local laws and regulations.

If fill materials are needed to construct roads or well sites, proper permits must be obtained from the Surface Management Agency, unless materials are obtained from a private source. On BLM administered lands, the use of materials shall conform with 43 CFR 3610.2-3.

Be advised that I.M. Good, Inc. is considered to be the operator of well No. 1, SW/NE, Sec.17, T.29N., R.112W. 6th Mer., Lincoln County, Wyoming, Lease WY-01234, and is responsible for the operations conducted on the leased lands.

Bond Coverage for this well is provided by BLM Bond No. MC-0089 (principle: I.M. Good, Inc.) via surety consent as provided for in 43 CFR 3104.2.

This office will hold the aforementioned operator and bond liable until the provisions of 43 CFR 3106.7-2, Continuing Responsibility, are met.

This APD is valid for one year from the date of approval, provided lease expiration does not occur. If activities have not commenced by the end of this one year period, the APD will be returned to the operator without prejudice. Should the operator still desire to drill the well, a new APD must be submitted. Upon written request by the operator, a one-time 90 day extension to this time period may be granted by the AO with the concurrence of the appropriate SMA.

A temporary water use permit for this operation is required from the State Engineer.

If at any time the facilities located on public lands authorized by the terms of the lease are no longer included in the lease (due to a contraction on the unit or other lease or unit boundary change) the BLM will process a change in authorization to the appropriate statute. The authorization will be subject to appropriate rental, or other financial obligation determined by the AO.

Review and appeal rights are contained in 43 CFR 3165.5 and 3165.4. Contact the Motor City District Office for further information.

Failure to comply with the provisions of this permit, including applicable regulations, stipulations and/or approval conditions will be considered a violation subject to the enforcement provisions of 43 CFR Subpart 3163.

II. CONDITIONS OF APPROVAL

A. REQUIRED NOTIFICATIONS

1. The operator or contractor shall contact the BLM (Attn: Coleman Young) at (303) 567-8910 at least 48 hours prior to commencement of access and site construction or reclamation activities.

2. The operator shall contact the Motor City District Office (Attn: John Spanner) at (303) 567-8910 at least 24 hours prior to the following operations:
   - spudding (including dry hole digger or rat hole rigs);
   - running and cementing all casing strings; and,
   - pressure testing of BOPE or any casing string.

3. In the case of newly drilled dry holes, and in any emergency situation, after hour authorization may be obtained by contacting the following individuals, in the order listed:

Cleve Fondle, Petroleum Engineer	(303) BR-549.
Fred Kaputnik, Petroleum Engineer	(303) FONE-HOME.

If unable to reach the any of the above individuals, contact:

Clem Kadiddlehopper, Minerals Chief (303) 123-4567.

The Motor City District BLM FAX Number is (303) 567-8900.

B. DRILLING PLAN

The Drilling Program shall be supplemented with the following conditions of approval:

1. An Annular preventor shall be utilized inconjunction with the approved 3M BOPE system.

2. Usable quality water and prospectively valuable minerals shall be isolated and/or protected. Geologic analysis indicates that usable quality water may be encountered in the Jolly formation at a projected wellbore depth of 4100 feet. If encountered while drilling, this zone shall be protected by bringing the cement level behind the 7 inch production casing to at least 100 feet above the formation (approximately 4000 feet).

3. Surface casing shall have a centralizer on each of the bottom three joints.

4. In order to protect usable quality water aquifers, no trivalent nor hexavalent chromate additives shall be used in the mud system.

5. Daily drilling and completion progress reports shall be submitted to the Motor City District office on a weekly basis.

6. To determine the top of cement (TOC) and bond quality, a cement bond log (CBL) or a cement evaluation tool (CET) shall be run after the 7 inch production casing string has been run and cemented in place.

7. Two copies of all logs, and a single copy of core descriptions, core analyses, drill stem tests, well-test data, geologic summaries, sample descriptions, and all other surveys or data obtained and compiled during the drilling and/or completion operations shall be submitted to the Motor City District, BLM.

8. Gas produced from this well may not be vented or flared beyond an initial authorized test period of 30 days or 50MMCF following its completion, whichever comes first, without the prior written approval of the authorized officer. Should gas be vented or flared without approval beyond the authorized test period, the operator may be directed to shut-in the well until the

gas can be captured or approval to continue venting or flaring as uneconomic is granted and the operator shall be required to compensate the lessor for that portion of the gas vented or flared without approval which is determined to have been avoidably lost.

9. Operations authorized by this permit shall not be suspended for more than 30 days without prior approval of the Authorized Officer. All conditions of this approval shall be applicable during any operations conducted with a replacement rig.

10. Section 102(b)(3) of the Federal Oil and Gas Royalty Management Act of 1982, as implemented by the applicable provisions of the operating regulations at Title 43 CFR 3162.4-1(c), requires that "not later than the 5th business day after any well begins production on which royalty is due anywhere on a lease site or allocated to a lease site, or resumes production in the case of a well which has been off production for more than 90 days, the operator shall notify the authorized officer by letter or sundry notice, Form 3160- 5, or orally to be followed by a letter or sundry notice, of the date on which such production has begun or resumed."

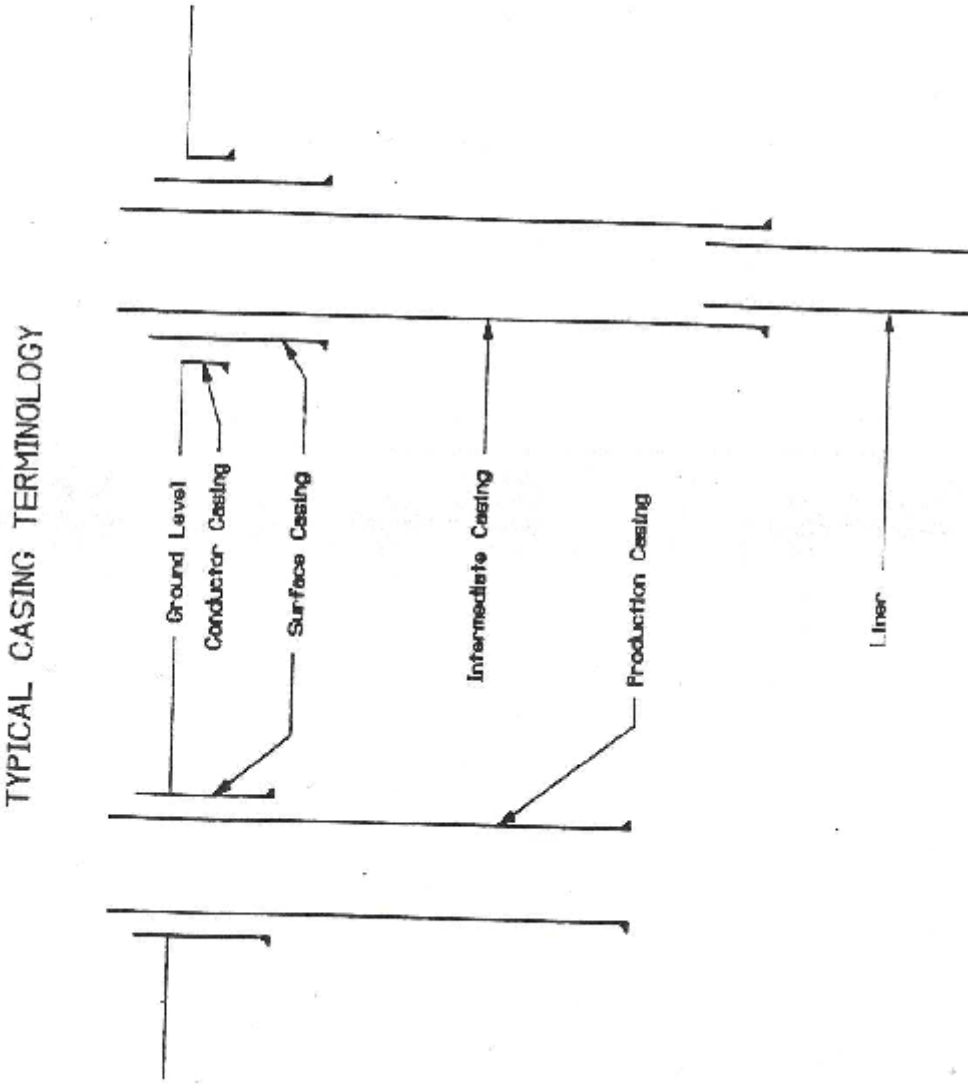
The date on which production is commenced or resumed will be construed for oil wells as the date on which liquid hydrocarbons are first sold or shopped from a temporary storage facility, such as a test tank, and for which a run ticket is required to be generated or, the date on which liquid hydrocarbons are first produced into a permanent storage facility, whichever first occurs; and, for gas wells as the date on which associated liquid hydrocarbons are first sold or shipped from a temporary storage facility, such as a test tank, and for which a run ticket is required to be generated or, the date on which gas is first measured through permanent metering facilities, whichever first occurs.

If you fail to comply with this requirement in the manner and time allowed, you shall be liable for a civil penalty of up to $10,000 per violation for each day such violation continues, not to exceed a maximum of 20 days. See Section 109(c)(3) of the Federal Oil and Gas Royalty Management Act of 1982 and the implementing regulations at Title 43 CFR 3162.4-1(b)(5)(ii).

C. SURFACE USE PLAN OF OPERATIONS

To be developed by the appropriate Surface Management Agency.

Illustration 6



SURFACE CASING

Size	Grade	#/ft.	Coupling	Fj	Pc	Pi	Length	Weight

INTERMEDIATE CASING

Size	Grade	#/ft.	Coupling	Fj	Pc	Pi	Length	Weight
							Total Weight	

PRODUCTION CASING

Size	Grade	#/ft.	Coupling	Fj	Pc	Pi	Length	Weight
							Total Weight	

CASING PARAMETERS

JOINT

SFt = Fj / Wt. ; SFt => 1.6(dry) or 1.8(bouyant)

___1. Surface _____ = (_____) / (_____)
___2. Intermediate _____ = (_____) / (_____)
___3. Production _____ = (_____) / (_____)

COLLAPSE

SFc = Pc / (MW * .052 * Le) : SFc => 1.125

___1. Surface _____ = (_____) / (_____ * .052 * _____)
___2. Intermediate _____ = (_____) / (_____ * .052 * _____)
___3. Production _____ = (_____) / (_____ * .052 * _____)

BURST

SFb = Pi / BHP ; SFb => 1.0

___1. Surface _____ = (_____) / (_____ * .052 * _____)
___2. Intermediate _____ = (_____) / (_____ * .052 * _____)
___3. Production _____ = (_____) / (_____ * .052 * _____)

CEMENT VOLUMES

STG	Hole Size	Casing Size	Ann. Vol.	Sx. Cmt.	Cmt. Yield	Vol. Cmt.	Max. Cmt. Fill up	Expected Fillup	O.K.
Sfc									
Int									
Prod									

SURFACE CASING

Size	Grade	#/ft.	Coupling	Fj	Pc	Pi	Length	Weight
9 5/8	K-55	36	STC	423K	2020	3520	500	18K

INTERMEDIATE CASING

Size	Grade	#/ft.	Coupling	Fj	Pc	Pi	Length	Weight
							Total Weight	

PRODUCTION CASING

Size	Grade	#/ft.	Coupling	Fj	Pc	Pi	Length	Weight
7	K-55	26	LTC	401K	4320	4980		169K
							Total Weight	169K

CASING PARAMETERS

JOINT

SFt = Fj / Wt. ; SFt => 1.6(dry) or 1.8(bouyant)

OK 1. Surface 23.5 = (423K) / (18K)
__ 2. Intermediate ____ = (____) / (____)
OK 3. Production 3.4 = (401K) / (169K)

COLLAPSE

SFc = Pc / (MW * .052 * Ls) ; SFc => 1.125

OK 1. Surface 8.6 = (2020) / (9 * .052 * 500)
__ 2. Intermediate ____ = (____) / (____ * .052 * ____)
OK 3. Production 1.4 = (4320) / (9 * .052 * 6500)

BURST

SFb = Pi / BHP ; SFb => 1.0

OK 1. Surface 1.2 = (3520) / (9 * .052 * 6500)
__ 2. Intermediate ____ = (____) / (____ * .052 * ____)
OK 3. Production 1.6 = (4980) / (9 * .052 * 6500)

CEMENT VOLUMES

STG	Hole Size	Casing Size	Ann. Vol.	Sx. Cmt.	Cmt. Yield	Vol. Cmt.	Max. Cmt. Fill up	Expected Fillup	O.K.
Sfc	12 1/4	9 5/8	.3132 Ft³/Ft	225	1.15	259 Ft³	826 Ft.	165% Dev. To Sfc	Yes
Int									
Prod	8 1/2	7	.1268 Ft³/Ft	150	1.20	180 Ft³	1420 Ft	±5080 Ft	No*

CEMENT SLURRY WORKSHEET

Cement Composition: _____

Dry Ingredients				Water Requirements	
Material	Weight (Lbs)	Absolute Volume (Gal)	Volume (Gal)	Gal of Water	Lbs. of Water
Totals:	A		B	C	D

$$\text{DENSITY} = \frac{A + D}{B + C} = \frac{\quad}{\quad} = \frac{\text{Lbs}}{\text{Gal}}$$

$$\text{YIELD} = \frac{B + C}{7.48} = \frac{\quad}{\quad} = \frac{\text{Cu Ft}}{\text{Sack}}$$

From Joe Goodwin, Mobil Oil

CEMENT SLURRY CALCULATIONS

Rules To Remember:

1. Salt (NaCl) and KCl percentages are always based upon the weight of the mix water.

2. All other admix materials added to a cement system are always based upon the weight of the cement or cementateous material.

3. Cement additives such as retarders, fluid loss additives, dispersants, and de-foamers are ignored in the calculations.

4. Water always weighs 8.33 lb/gal.

5. There are 7.48 gallons in a cubic foot.

ABSOLUTE VOLUME FACTORS FOR DISSOLVED NaCl and KCl

PERCENT (BWOW)	ABSOLUTE VOLUME FACTOR NaCL	KCl
2	0.0456	0.0547
4	0.0418	0.0500
6	0.0408	0.0490
8	0.0406	0.0488
10	0.0407	0.0486
12	0.0409	
14	0.0411	
16	0.0414	
18	0.0417	
20	0.0422	
25	0.0423	
30	0.04237	
35	0.04240	
37.2	0.04245	

From Joe Goodwin, Mobil Oil

ABSOLUTE VOLUME FACTORS

MATERIAL MATERIAL)	BULK WEIGHT (LB/CU FT)	ABSOLUTE VOLUME (GAL/LB)	WATER REQUIREMENTS (GAL/LB OF
A Cement	94	0.0382	0.055
B Cement	94	0.0382	0.0552
C Cement	94	0.0382	0.0672
G Cement	94	0.0382	0.0528
H Cement	94	0.0382	0.0456
Gyp-Seal	100	0.0444	0.0480
Trinity LW(or TXI)	75	0.0429	Variable
Attapulgite Clay	40	0.0415	0.6350
Barite	135	0.0284	0.1730
Bentonite	60	0.0453	0.6360
Bentonite (Prehydrated)	60	0.0453	2.5440
Calcium Chloride	50	0.6120	0.0000
Diacel D	16.7	0.0572	0.4555
Gilsonite	50	0.1122	0.0540
Hi-Seal	50	0.1000	0.0120
Kolite	50	0.0925	0.0400
Hematite	187	0.0239	0.0060
Ilmenite	150	0.0265	0.0060
Silica Sand	70	0.0456	0.0060
Silica Flour	70	0.0456	0.0420
Perlite (regular)	8	0.0564	0.0238
Pozzolan	74	0.0487	0.0774
Hydrated Lime	31	0.0545	0.1530
Sodium Metasilicate	87	0.0859	3.5000

CEMENT SLURRY WORKSHEET

Cement Composition: Class "H" + 8% Gel + 1/8 #/sx Cellophane 18% Salt

Dry Ingredients				Water Requirements	
Material	Weight (Lbs)	Absolute Volume (Gal) #	Volume (Gal)	Gal of Water	Lbs. of Water
"H"	94	.0383	3.591	4.2864*	35.7057**
8% Gel	7.52	.0453	.3407	4.7827*	39.8400**
18% Salt	6.0437	.0417 (.0412)	.2502		
Totals:	A 107.5637		B 4.1819	C 9.0691	D 75.5457

$$\text{DENSITY} = \frac{A + D}{B + C} = \frac{107.5637 + 75.5457}{4.1819 + 9.0691} = 13.8 \ \frac{\text{Lbs}}{\text{Gal}}$$

$$\text{YIELD} = \frac{B + C}{7.48} = \frac{4.1819 + 9.0691}{7.48} = 1.77 \ \frac{\text{Cu Ft}}{\text{Sack}}$$

* Obtained from: Lbs of material x .0456 from water requirements on page 3

** Gallons of water x 8.33 gal/lb
#/gal

From Joe Goodwin, Mobil Oil

CASING STRING PRESSURE TEST

The major concern in casing string pressure tests is not to exceed 70% of the internal yield (burst) pressure (P_{YIELD}) of the casing while achieving the test pressure (P_{TEST}). The point of concern usually occurs at the casing shoe because the mud column exerts its maximum pressure at that depth. However, in tapered strings each section should be checked.

Pressure at the shoe (P_{SHOE}) is the pressure exerted on the casing shoe during the test and includes the test pressure plus the hydrostatic pressure of the mud column, and may be calculated the following equation: P_{TEST} + (0.052 * Mud Weight * Depth) or by utilizing the nomographs. Nomographs 1, 1A, and 2 were developed to quickly determine P_{SHOE}. The point which P_{TEST} changes from 1500 psi to 0.22 psi/ft occurs at 6818 feet. Nomograph 1 adds 1500 psi to the mud column for wells less than 6818 feet deep, Nomograph 1A is an expanded version of Nomograph 1 for casing depthe to 2000 feet, and Nomograph 2 adds 0.22 psi/ft to the mud column for wells deeper than 6818 feet.

To determine the proper pressure for the casing string pressure test, the following process may be used: Obtain P_{YIELD} from API Bull 5C2, Performance Properties of Casing, Tubing and Drill Pipe, Table 1 and multiply this value by 0.7 to determine the maximum pressure to be placed on the casing shoe ($0.7*P_{YIELD}$). (Or wherever the critical casing point exists). Next, determine P_{SHOE} from either a calculation or from the appropriate nomograph using those values for mud weight and casing setting depth which exist at the time of the test.

The nomograph values are not the last step in this determination. Should $0.7*P_{YIELD}$ exceed the nomograph value, P_{TEST} may be applied directly at the surface (P_{SFC}). However, if P_{SHOE} exceeds $0.7*P_{YIELD}$, P_{SFC} should be lowered so the pressure opposite the shoe does not exceed the $0.7*P_{YIELD}$ value. This can be done by subtracting the difference between the two (P_{SHOE} - $0.7*P_{YIELD}$) from P_{TEST}.

Examples are on the next page.

CASING STRING PRESSURE TEST

EXAMPLES:

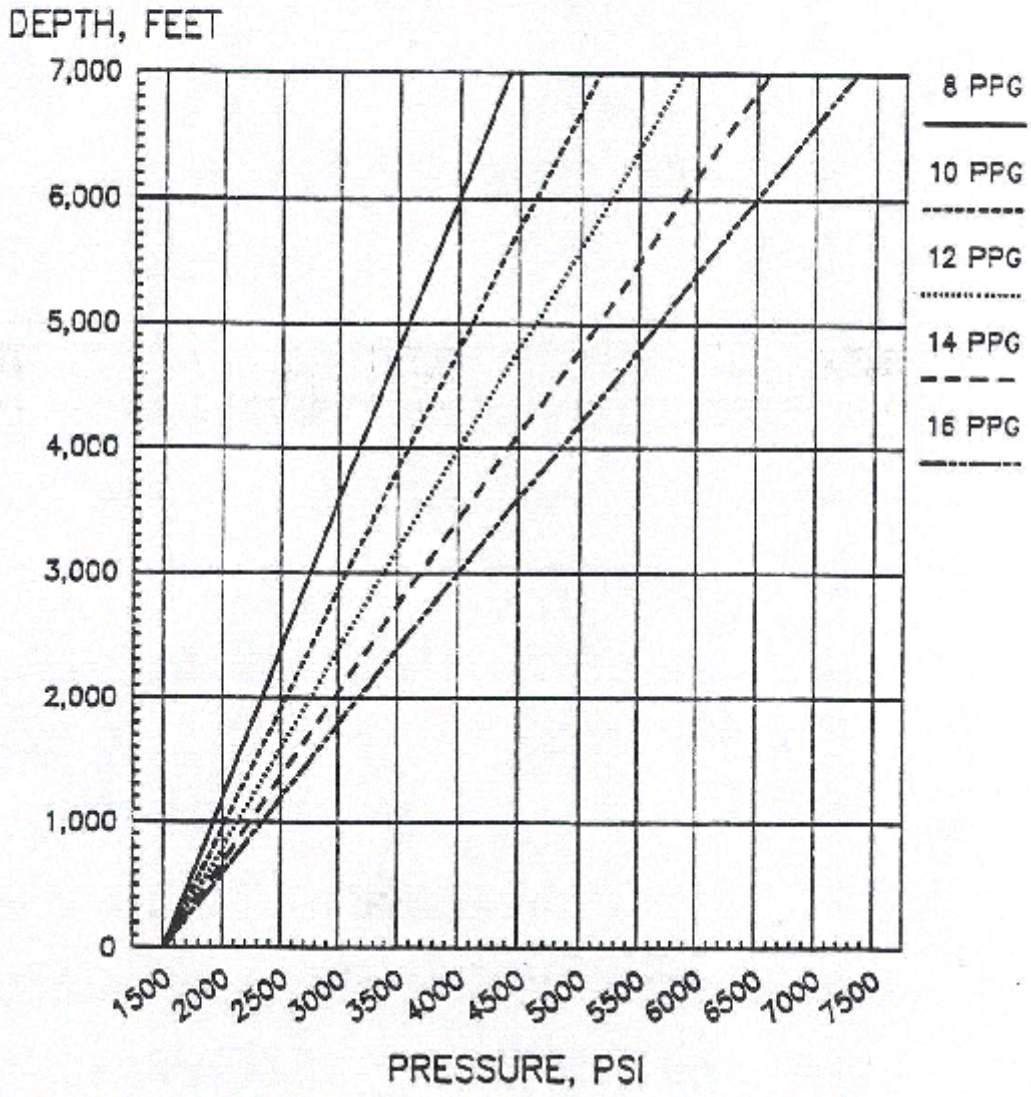
1. Assume: 9 5/8 inch, K-55, 40 lb/ft casing set at 1400 feet with 9 ppg mud in the hole.
   From API Bull 5C2, P_{YIELD} = 3950 psi; $0.7*P_{YIELD}$ = 2765 psi.
   From Nomograph 1, P_{SHOE} = 2175 psi (calculates to 2155 psi).

   Because $0.7*P_{YIELD}$ exceeds P_{SHOE},
   $P_{SFC} = P_{TEST} = \underline{1500}$ psi.

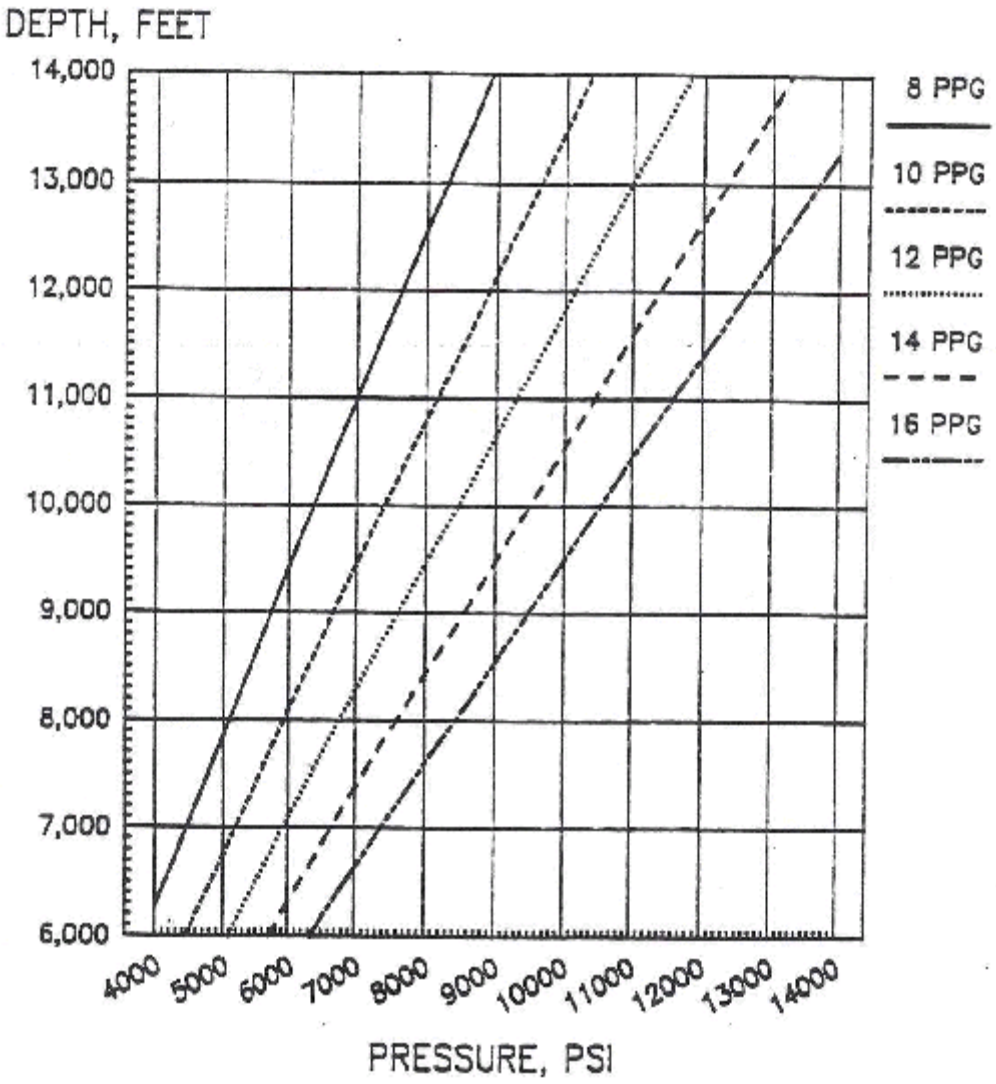
2. Assume: 7 inch, N-80, 29 lb/ft casing set at 10,000 feet with 10 ppg mud in the hole.
   From API Bull 5C2, P_{YIELD} = 8160 psi; $0.7*P_{YIELD}$ = 5712 psi.
   From Nomograph 2, P_{SHOE} = 7350 psi (calculates to 7400 psi).

   Because P_{SHOE} exceeds $0.7*P_{YIELD}$,
   $P_{SFC} = P_{TEST} - (P_{SHOE} - 0.7*P_{YIELD})$
   $P_{SFC} = 2200 - (7400 - 5712) = \underline{512}$ psi.

NOMOGRAPH 1
PRESSURE AT CASING SHOE
WELLS < 6818 FEET



NOMOGRAPH 2
PRESSURE AT CASING SHOE
WELLS > 6818 FEET



CASING SHOE PRESSURE INTEGRITY TEST

This test is a determination that the formation directly below the casing setting depth is capable of maintaining the pressure exerted by the mud weight necessary to drill down to the next casing setting point. This in reality is a mud weight equivalence test. To determine the pressure to be added to the mud column at the surface (P_{SFC}), the following equation may be used:

$$P_{SFC} = 0.052*TVD*(MW_2 - MW_1)$$

Where: TVD = True Vertical Depth, feet
MW_2 = Mud Weight at the Next Casing Point, ppg
and, MW_1 = Mud Weight at the Current Casing Point, ppg.

EXAMPLES:

1. Assume: Surface Casing set at 1300 feet with 9 ppg mud in the hole. It is anticipated that 11 ppg mud will be necessary to drill to the next casing setting point of 8000 feet.

   Utilizing the equation: $P_{SFC} = 0.052*TVD*(MW_2 - MW_1)$

   $P_{SFC} = 0.052*1300*(11 - 9)$

   $P_{SFC} = 135$ psi

   Add 135 psi at the surface to the existing mud column to achieve a mud weight equivalence test.

2. Assume: Intermediate Casing set at 7000 feet with 10 ppg mud in the hole. It is anticipated that 13 ppg mud will be necessary to drill to the next casing setting point of 11500 feet.

   Utilizing the equation: $P_{SFC} = 0.052*TVD*(MW_2 - MW_1)$

   $P_{SFC} = 0.052*7000*(13 - 10)$

   $P_{SFC} = 1092$ psi

   Add 1092 psi at the surface to the existing mud column to achieve a mud weight equivalence test.

REQUIRED AIR/GAS EQUIPMENT DISTANCES

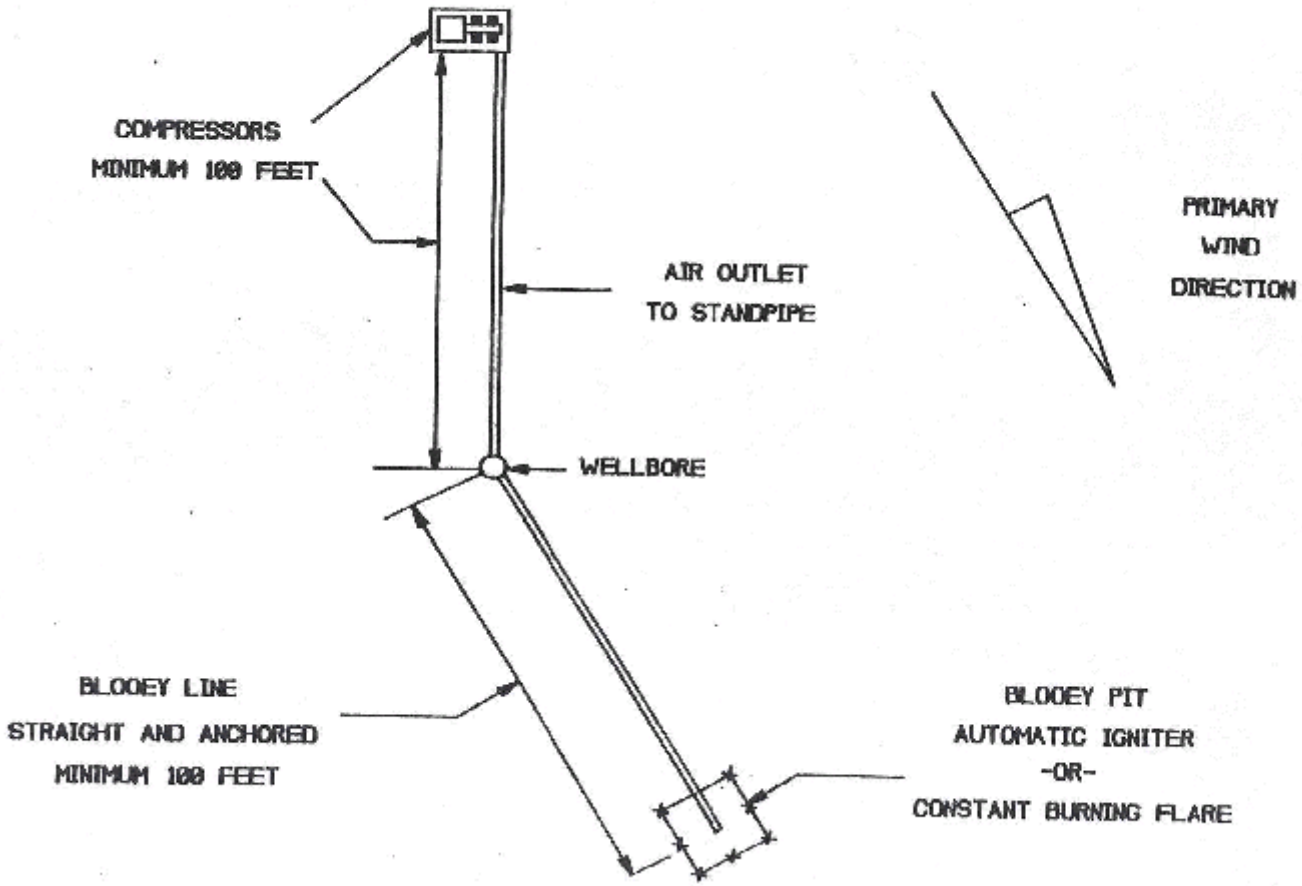


Illustration 11

APD REQUIREMENTS FOR H_2S

1. The authorized officer shall be notified when operations are 500 feet above or 3 days before (whichever is earlier) drilling the first formation expected to contain H_2S.

2. A copy of the Drilling Operations Plan (DOP) shall be available during operations at the wellsite beginning 500 feet above or 3 days before (whichever is earlier) drilling the first formation expected to contain H_2S.

3. A Public Protection Plan (PPP) providing details of actions necessary to alert and protect the public in the event of a release of a potentially harmful volume of H_2S shall be submitted to the authorized officer for drilling or producing operations when applicability criteria of Order No. 6 are met.

4. A copy of the PPP shall be available at the drilling and/or completion site.

5. H_2S DOP and PPP shall be reviewed by the operator on an annual basis and copy of any necessary revisions shall be submitted to the authorized officer upon request.

6. If unanticipated H_2S in excess of 100 ppm in the gas stream is encountered, the operator shall immediately ensure control of the well, suspend drilling operations (unless detrimental to well control), and obtain materials and safety equipment to bring the operations into compliance with the applicable provisions of Order No. 6. In addition, the operator shall notify the authorized officer of the event and the mitigating steps that have or are being taken, as soon as possible, but no later than the next business day. If said notifications are subsequent to actual resumption of drilling operations, the operator shall notify the authorized officer of the date that drilling was actually resumed. It is the operator's responsibility to provide, if necessary, a H_2S DOP and a PPP to the authorized officer for approval within five business days following resumption of drilling ahead operations.

H_2S DRILLING OPERATIONS PLAN (DOP) LIST

a. Training of personnel in H_2S.

b. Well site diagram, depicting:
   i. Drill rig orientation.
   ii. Prevailing winds.
   iii. Terrain of surrounding areas.
   iv. Location of briefing areas.
   v. Location of access roads (including secondary egress).
   vi. Location of flare lines and pits.
   vii. Location of caution/danger signs.
   viii. Location of wind indicators.

c. Description of H_2S safety equipment/system, including:
   i. Well control equipment:
      - Flare lines - ignition means.
      - Remote controlled choke.
      - Flare gun/flares.
      - Mud gas separator and rotating head (if exploratory).

   ii. Protective equipment for essential personnel:
      - Location, type, storage and maintenance of escape breathing apparatus.
      - Means of communication.

   iii. H_2S detection and monitoring equipment:
      - H_2S sensors and audible/visual alarms.
      - Portable H_2S and SO_2 monitors.

   iv. Visual warning systems.
      - Wind direction indicator.
      - Caution/danger signs and flags.

   v. Mud program.
      - Mud system and additives.
      - Mud degassing program.

   vi. Metallurgical properties of all tubular goods and well control equipment which could be exposed to H_2S.

   vii. Means of communication from wellsite.

d. Plans for well testing.

H_2S PUBLIC PROTECTION PLAN (PPP) LIST

a. Responsibilities and duties of key personnel and instructions for alerting public and requesting assistance.

b. List of names, telephone numbers of:
   i. Residents.
   ii. Individuals responsible for safety of pubic roadways.
   iii. Individuals responsible for safety of occupants of buildings within the 100 ppm ROE.

c. Telephone call list for:
   i. Requesting assistance from law enforcement.
   ii. Fire department.
   iii. Medical personnel.
   iv. Federal and State regulatory agencies.
   v. Necessary information and emergency responses list.

d. 100 ppm or 3000 feet ROE plat depicting all private or public dwellings, schools, roads, recreational areas, and other areas where the public might reasonably be expected to congregate.

e. Advance briefings of persons identified in Item b. addressing:
   i. Hazards of H_2S and SO_2.
   ii. Necessity for emergency action plan.
   iii. Possible sources of H_2S and SO_2.
   iv. Instructions of reporting a leak to operator.
   v. Manner in which the public will be notified of an emergency.
   vi. Steps to be taken in case of emergency including evacuation.

f. Guidelines for ignition of H_2S bearing gas.
   i. Designate the person who has the authority to ignite the escaping gas..
   ii. Define when,how and by whom the gas will be ignited.

g. Additional measures following the release of H_2S and SO_2:
   i. Monitoring of H_2S and SO_2 levels and wind direction.
   ii. Maintenance of site security and access control.
   iii. Communication of status of well control.
   iv. Other necessary measures as required by the authorized officer.

h. For production facilities, a description of the detection systems utilized to determine the concentration of H_2S released.

HYDROGEN SULFIDE NOMOGRAPHS

The following Nomographs may be utilized to determine the 100 PPM and 500 PPM Radius of Exposures (ROE). To use, simply draw a line from the H2S concentration to the gas flowrate. The point that the line crosses the middle collomn indicates the ROE in feet.

For example:

Using the 100 PPM Nomograph: The H2S concentration is 10,000 PPM (Point A) and the flowrate is 0.1 MMscf (Point B), the ROE is 100 feet (Point C).

Using the 500 PPM Nomograph: The H2S concentration is 10,000 PPM (Point A) and the flowrate is 0.1 MMSCF (Point B), the ROE is 46 feet (Point C).

PARTS PER MILLION TO PERCENTAGE CONVERSIONS (PPM TO %)

To convert from ppm to % move the decimal four (4) places to the left:

1. ppm = .0001 % which is 1/10,000 of 1%

10. ppm = .001 % which is 1/1,000 of 1%

100. ppm = .01 % which is 1/100 of 1 %

200. ppm = .02 % which is 2/100 of 1%

500. ppm = .05 % which is 5/100 of 1%

1000. ppm = .1 % which is 1/10 of 1%

10,000. ppm = 1 % which is 1%

10% = 100,000 ppm

20% = 200,000 ppm

30% = 300,000 ppm

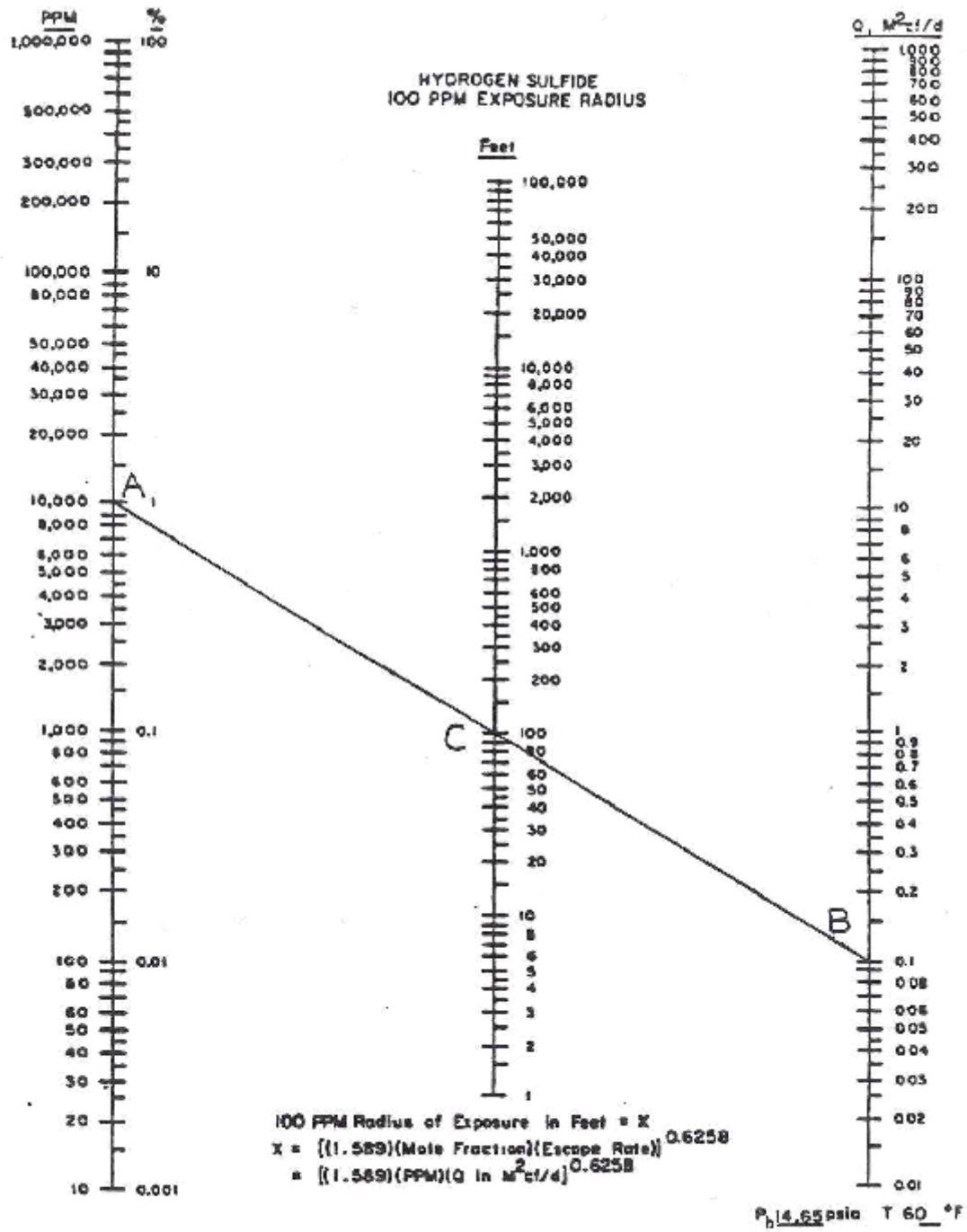


Fig. 3—Chart for determining radius of exposure (source: Railroad Commission of Texas).

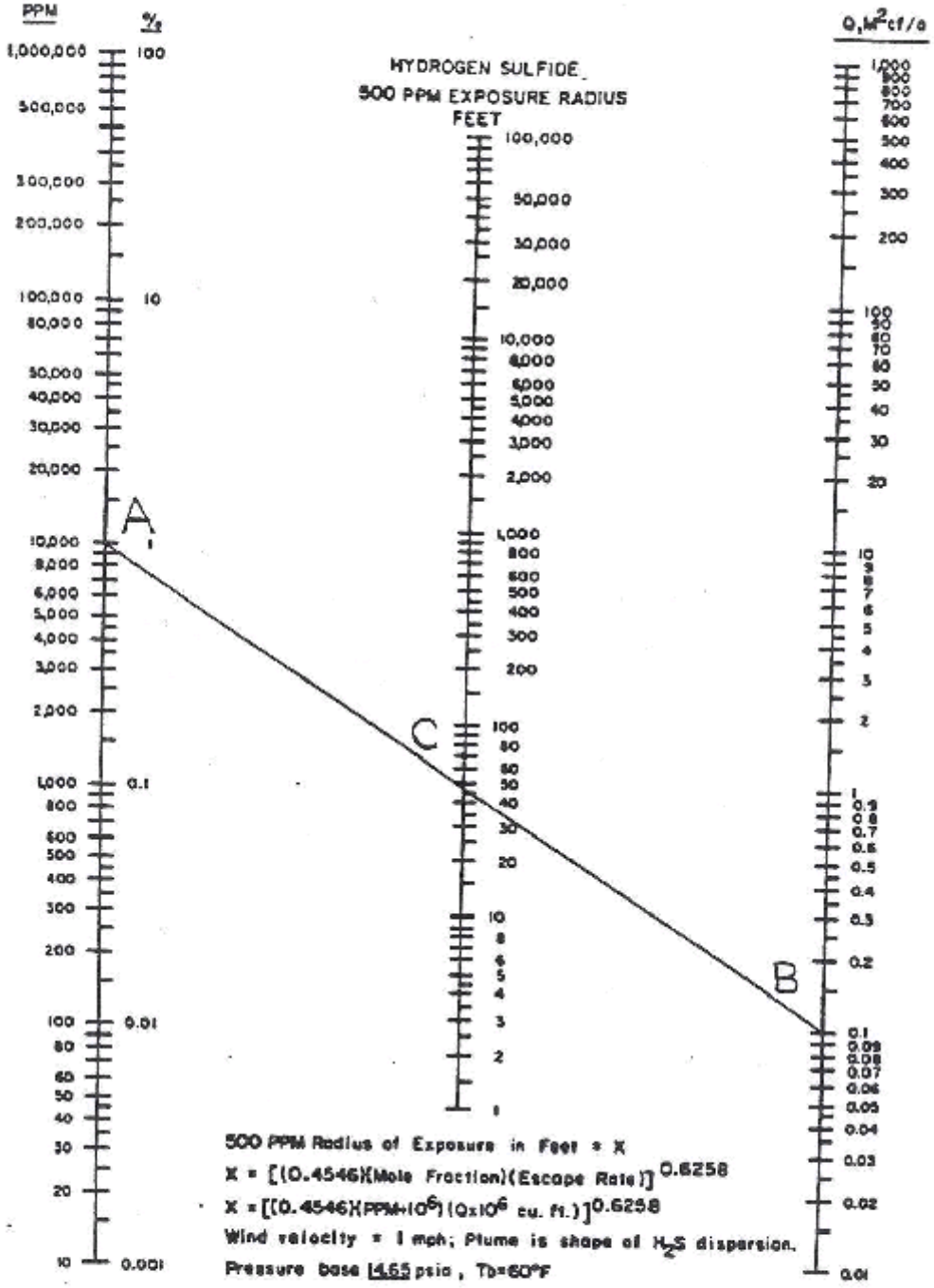


Fig. 4—Chart for determining radius of exposure (source: Railroad Commission of Texas).

TRI-STATE OIL TOOL INDUSTRIES, INC.

CONVERSION TABLE FOR HARDNESS TESTING
(APPROXIMATE VALUES)

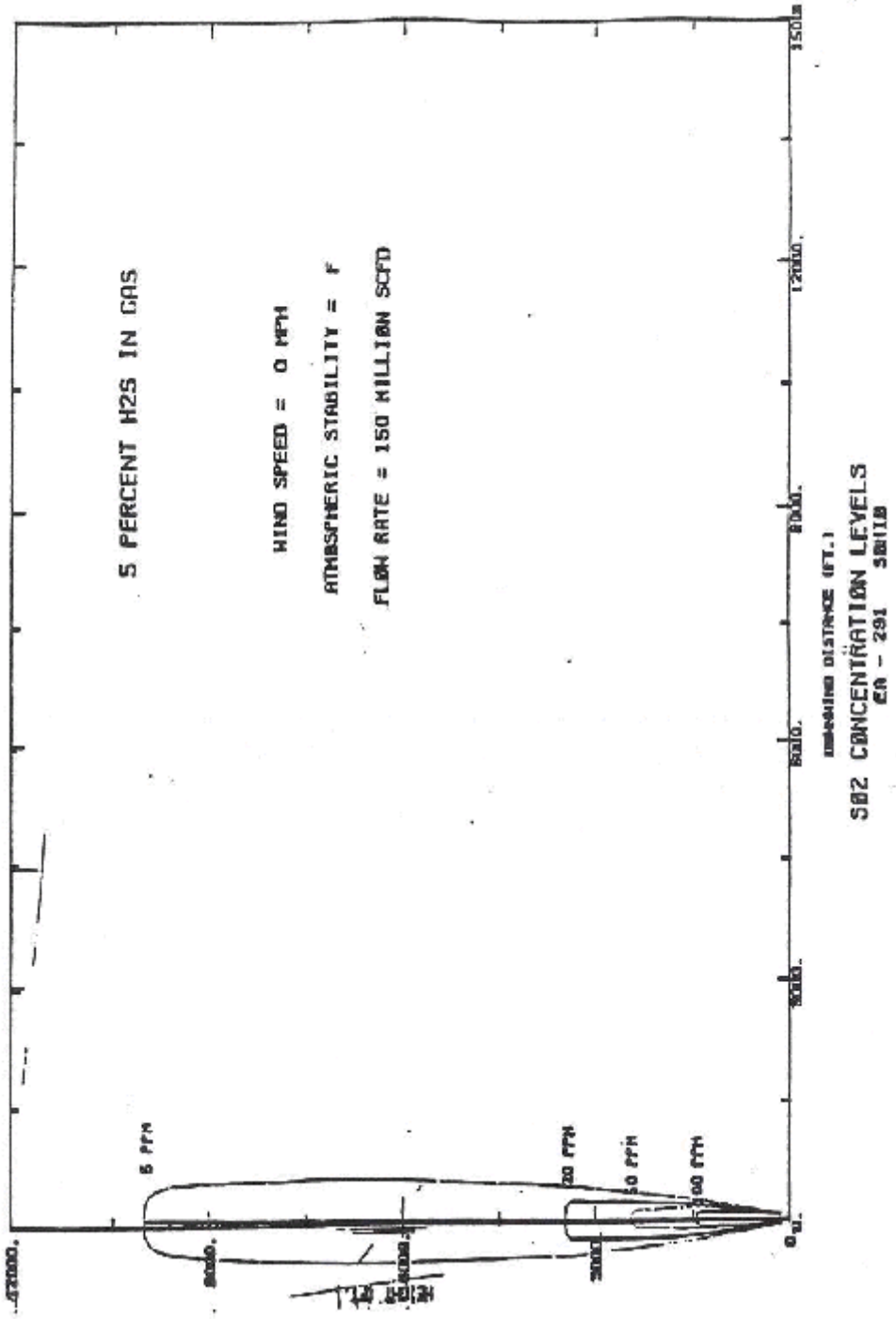
BRINELL		ROCKWELL		
Impression Diameter	Hardness Number	C Scale	B Scale	TENSILE STRENGTH
2.45	627	60		311
2.50	601	58		298
2.55	578	57		287
2.60	555	55		276
2.65	534	53		266
2.70	514	52		258
2.75	495	50		247
2.80	477	49		238
2.85	461	47		229
2.90	444	46		220
2.95	429	45		212
3.00	415	44		204
3.05	401	42		196
3.10	388	41		189
3.15	375	40	110	182
3.20	363	38	110	176
3.25	352	37	109	170
3.30	341	36	109	165
3.35	331	35	108	160
3.40	321	34	108	155
3.45	311	33	107	150
3.50	302	32	107	146
3.55	293	31	106	142
3.60	285	30	105	138
3.65	277	29	104	134
3.70	269	28	104	131
3.75	262	26	103	128

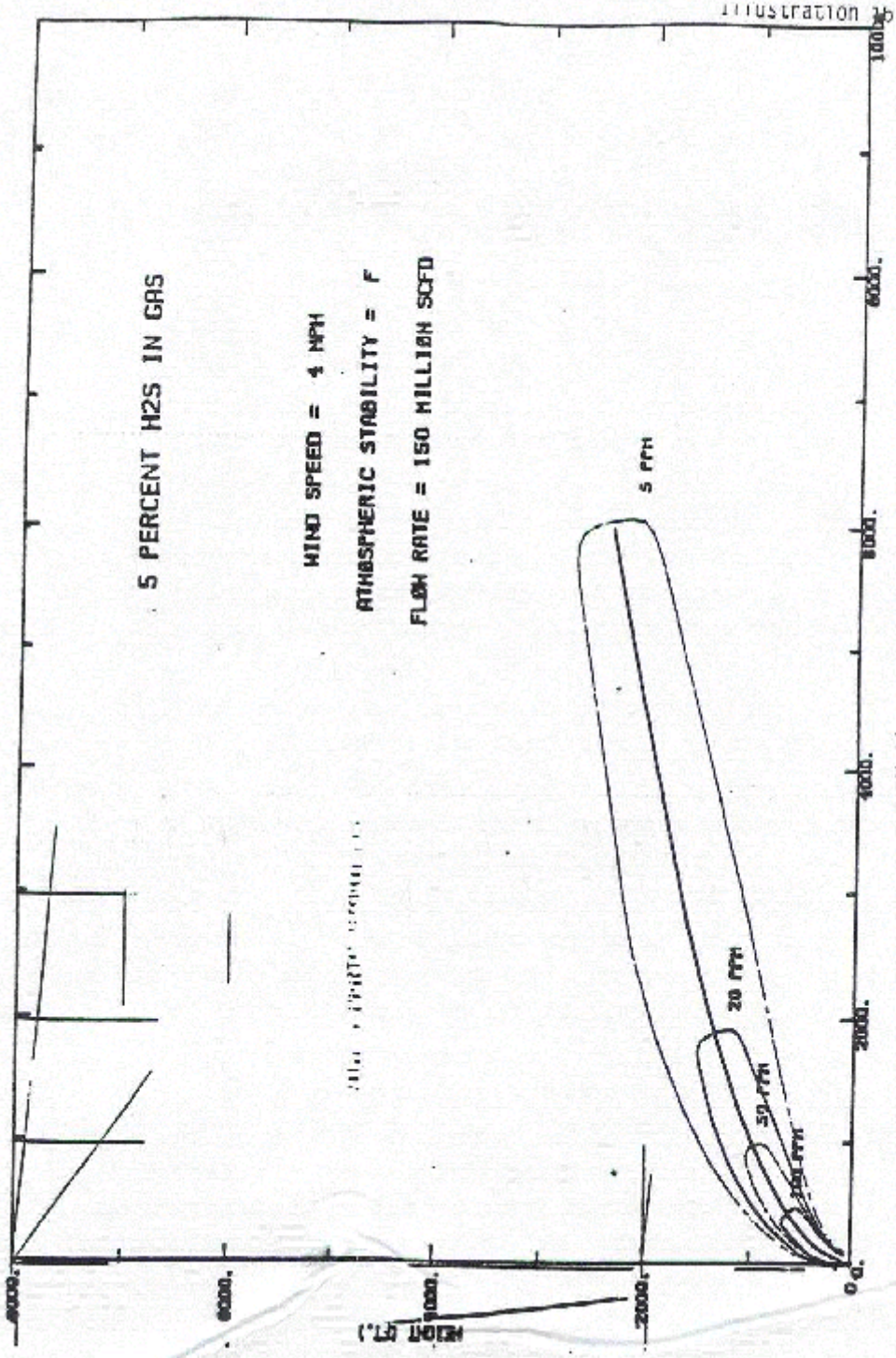
BRINELL		ROCKWELL		
Impression Diameter	Hardness Number	C Scale	B Scale	TENSILE STRENGTH
3.80	255	25	102	125
3.85	248	24	101	122
3.90	241	23	100	119
3.95	235	22	99	116
4.00	229	21	98	113
4.05	223	20	97	110
4.10	217	18	96	107
4.15	212	16	96	104
4.20	207	15	95	101
4.25	202	14	94	99
4.30	197	13	93	97
4.35	192	12	92	95
4.40	187	10	91	93
4.45	183	9	90	91
4.50	179	8	89	89
4.55	174	6	88	87
4.60	170	5	87	85
4.65	166	4	86	83
4.70	163	3	85	82
4.75	159		84	80
4.80	156		83	78
4.85	153		82	76
4.90	149		81	75
4.95	146		80	74
5.00	143		79	72
5.05	140		78	71
5.10	137		77	70

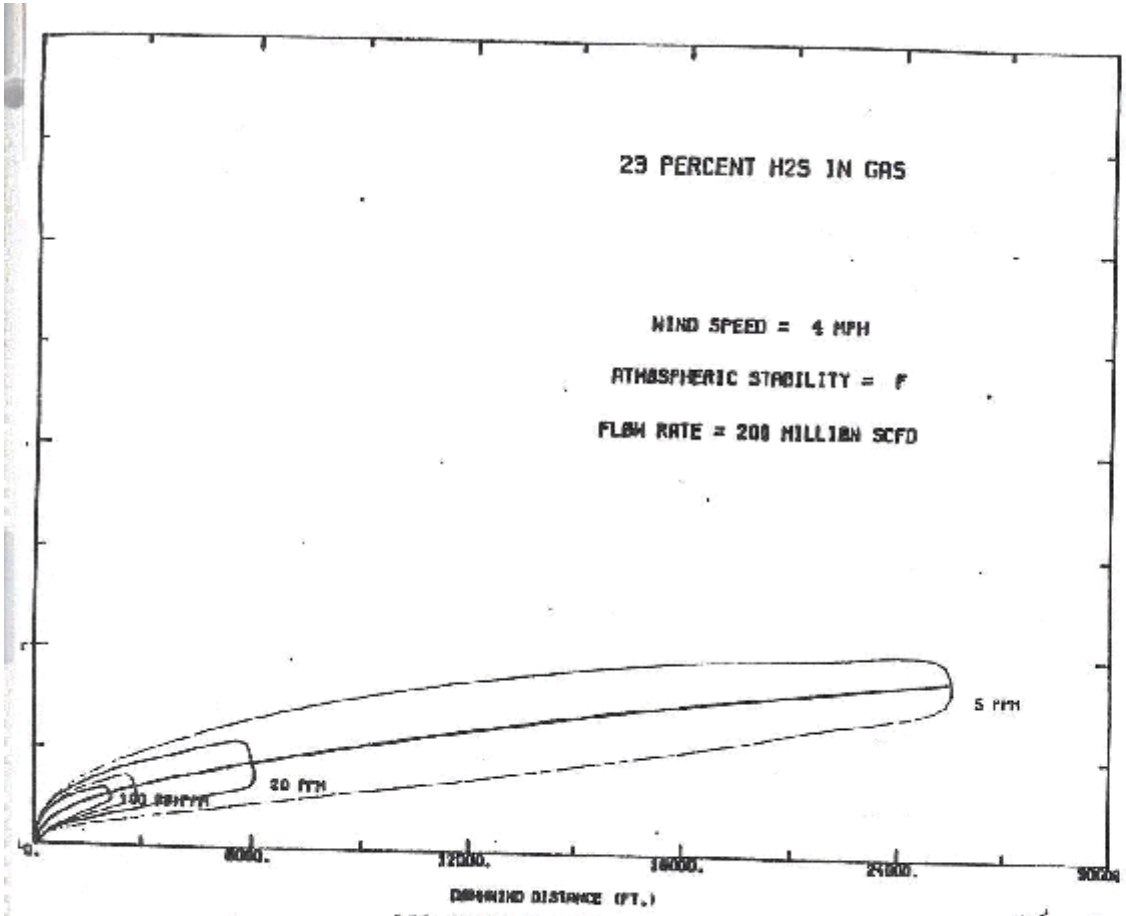
Diameter of Impression 3000 Kg. load - 10 MM. Steel Ball
Rockwell C-Scale 150 Kg. Load - 120° Diamond Cone
B-Scale 100 Kg. Load - .0625 in. Steel Ball
Tensile Strength 1000 pounds per square inch

H_2S modification for Blowout Preventers
(Courtesy of SPE-AIME)

Component	Standard service	H_2S service
Cameron type U		
Ram assembly		
(1) Ram	4340 Rc = 20-23	4340 Rc = 20-24
(2) Front packer	Specially compounded gas-resistant Hycor	Same
(3) Top seal	Rubber	Same
Bonnet bolts	4142 bolt class 354 (Rc = 35)	A 286
Operating piston	4140 Rc = 22-30	4140 Rc = 24
Connecting rod seal ring	Rubber	Specially compounded gas-resistant Hycor
Bonnet seal	Rubber-impregnated asbestos	Hycor-impregnated asbestos
Bonnet bolt retainer O-ring	Rubber	Hycor
Int. flange to bonnet cap screw	4142 bolt class 354 (Rc = 35)	4142 bolt class 354 (Rc = 22)
Shaffer type LWS		
Door cap screws	4140 BHN = 285-341	4140 BHN = 225-235
Cylinder cap screws	4340	4140 Rc 22
Cylinder head cap screws	4340	4140 Rc 22
Ram shaft	410 SS	4130 Rc 22
Hinge bracket cap screw	4340	4140 Rc 22
Secondary seal plug	Heat treated 4140	304 SS
Thread protector plug	Heat treated 4140	304 SS
Ram rubber retaining screws	Heat treated 4140 (BHN = 385)	4140 Rc 22
Ram block retaining screws	Heat treated 4140	K-Monel 500
Studs	4140 B-7	A-286 or soft B-7
Nuts	2H	2H Rc 22


5 PERCENT H2S IN GAS
WIND SPEED = 0 MPH
ATMOSPHERIC STABILITY = F
FLOW RATE = 150 MILLION SCFD
5 PPM
20 PPM
50 PPM
100 PPM
HEIGHT (FT.)
MAXIMUM DISTANCE (FT.)
SO2 CONCENTRATION LEVELS
EA - 291 SMITH


5 PERCENT H2S IN GAS
WIND SPEED = 4 MPH
ATMOSPHERIC STABILITY = F
FLOW RATE = 150 MILLION SCFD
5 PPM
20 PPM
50 PPM
100 PPM
HEIGHT (FT.)
DOWNWIND DISTANCE (FT.)
0.
2000.
4000.
6000.
8000.
10000.
SO2 CONCENTRATION LEVELS
EA - 291 SHHIO



SO2 CONCENTRATION LEVELS
EA - 291 SOHIO

Illustration 16, Page 3

APPROVAL TO PLUG AND ABANDON WELL

Operator_____ Representative_____

Phone_____

Well Number_____

Location: _____1/4_____1/4 Section _____ Township _____ Range _____

_____ County, _____ Lease No. _____

Field/CA/Unit Name or Number _____

See Attached Wellbore Diagram

Formation	Top	Base	Shows

Casing Size	Set At	Top of Cement	To be Pulled

T.D._____ Size Hole_____ Cubic Ft./Sack Cement_____

REMARKS/ADDITIONAL DATA

Type of Drilling Fluid/Mud in Hole_____

Adequate for Spacer Fluid (Minimum 9.0 PPG)?_____

Plans for Conditioning Hole Prior to Setting Plugs_____

Usable Quality Water Zones_____

Prospectively Valuable Mineral Zones_____

Drill Stem Tests_____

Lost Circulation Zones_____

Additional Information_____

PLUGGING REQUIREMENTS

Follow With Written Notice of Intent

Approved by_____ Date_____ Time_____

OPERATOR_____ WELL #_____ ___/___ SEC____ T____ R____

_____ COUNTY, _____ LEASE _____

NOTES:

Ground Level

___/___IN, ___-___, _____ #/ft.

SET @ _____ FT. W/_____ SX.

___/___IN, ___-___, _____ #/ft.

SET @ _____ FT. W/_____ SX.

___/___IN, ___-___, _____ #/ft.

SET @ _____ FT. W/_____ SX.

APPROVAL TO PLUG AND ABANDON WELL

Operator USA Oil & Gas Representative Jim Dandy

Phone (303) 345-6731

Well Number 1-29

Location: NW 1/4 SW 1/4 Section 29 Township 103S. Range 6E.

De Soto County, USA Lease No. M-0559-A

Field/CA/Unit Name or Number Wildcat

See Attached Wellbore Diagram

Formation	Top	Base	Shows
Mesaverde	11722'		
Hillcreek	13775'		
Frontier	15500'		Perm.
Mowry	15816'		
Dakota	16020'		Perm.
Morrison	16420		

Casing Size	Set At	Top of Cement	To be Pulled
13"; 72#/ft	2645'	Surface	None
9 5/8"; 53.5#/ft	11049'	±3500' 100% Bond @ 5000'	Dv @ 6025
7"; 29#/ft	10539-16503	Through Liner Lap	None.

T.D. 16525 Size Hole _____ Cubic Ft./Sack Cement _____

PB 16483'

REMARKS/ADDITIONAL DATA

Type of Drilling Fluid/Mud in Hole 9 ppg Bentonite

Adequate for Spacer Fluid (Minimum 9.0 PPG)? Yes

Plans for Conditioning Hole Prior to Setting Plugs Circ Hole w/ Fluid in Hole

Usable Quality Water Zones All zones cased & cemented

Prospectively Valuable Mineral Zones All zones cased & cemented

Drill Stem Tests Perfed zones were swabbed

Lost Circulation Zones All zones cased & cemented.

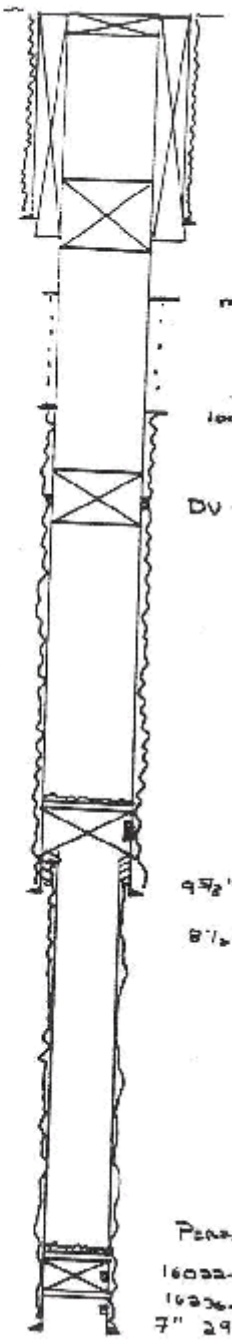
Additional Information Perfs @ 16022-34'; 16157-196'; 16226-338'
CICR @ 16200' squeezed w/ 100 sks; 60 ft on top.
No Haz Mat in Reserve Pit.

PLUGGING REQUIREMENTS

1. - CICR @ ± 15930'; squeeze w/ 100 sks; 60 ft on top
   - Circ. Hole w/ 9.0 ppg Drilling Mud
2. - Perf 9 5/8" @ ± 10360-382; Displace Reserve Pit
3. - CICR @ ± 10300'; squeeze w/ 100 sks; 60 ft on top
4. - Balance Plug across DV from ± 5900-6160'
5. - Balance SFC Shoe from ± 2500-2750' in 9 5/8"
6. - Top Job 13 3/8" x 9 5/8" Annulus w/ 400 sks
7. - Place 60' cement @ SFC inside 9 5/8"

Follow With Written Notice of Intent

Approved by Fred Kaputnik Date 9-31-89 Time 01:50



17½" Hole

(7) 60' @ SFC.

13⅜" 72#/. @ 3645 CMT TO SFC

12¼" Hole

(6) Top Job - 13⅜ & 9⅝" Annulus w/ 400 sx

max TOC @ 3500'

100% (CBL) @ 3000'

(5) Balance 2500 - 2766'

DV Tool @ 6025'

(4) Balance 5900 - 6160'

(3) CICR @ 10300' Squeeze 100 sx 60' on top

(2) Perf 9⅝" @ 10360-362 Disp Reserve Pit Fluids

9⅝" 53.5#/. @ 11049' w

8½" Hole

CIRC Hole w/ 9.0 Mud

(1) CICR @ 13950. Squeeze 100 sx 60' on top

Perfs Dakota

16022-24 ; 16157-196' (Potential)

16236-338 - Plugged CICR @ 16260 - Squ 100 sx 60' on top

7" 29#/. LNR 10539-16603 cmt Through Lnr Lap.

Appendix 1

ACRONYMS

ABHP	Anticipated Bottom Hole Pressure
AIRS	Automated Inspection Recordation System
AO	Authorized Officer
APD	Application for Permit to Drill
API	American Petroleum Institute
ASP	Anticipated Surface Pressure
BOP	Blow Out Preventers
BOPE	Blow Out Prevention Equipment
CBL	Cement Bond Log
CET	Cement Evaluation Tool
COA	Conditions of Approval
H_2S	Hydrogen Sulfide
M	1000 PSI (e.g. 2M = 2000 PSI)
MD	Measured Depth
NOI	Notice of Intent (to Abandon)
OOGO	Onshore Oil and Gas Order
PET	Petroleum Engineering Technician
PPG	Pounds Per Gallon
PPM	Parts Per Million
SUPO	Surface Use Plan of Operation
SMA	Surface Management Agency
TVD	True Vertical Depth

Estimating Aquifer Depth and Water Quality from Induction Logs

Abstract

When processing an Application for Permit to Drill (APD), the geologic section is required to identify the maximum depth of usable water as defined in 43 CFR 3162.5-2. the past, the Rock Springs District has used the deepest known water well in the vici of a proposed oil or gas well to estimate the depth of usable water. This method is thought to be erroneous for several reasons: (1) The depth of a water well invariabl reflects the shallowest aquifer which meets the needs of the party drilling the well; (2) In many cases few or no water wells exist proximal to the proposed oil or gas wel (3) The water quality of adjacent water wells is often unknown, and (4) The lithologi logs and associated data submitted by many water well drilling companies are often qu generic and insufficient for use in quantitative determinations.

Since freshwater is one of our most valuable and highly sought after resources, it is imperative that the Bureau take any and all steps necessary to protect this critical resource. The identification of subsurface aquifers is essential if we are to effectively review any drilling program, be it oil and gas, seismic shot holes, or water wells.

This paper outlines a method which allows aquifer depth and water quality to be estimated by using induction logs from nearby drill holes (usually oil and gas wells). This quantitative method is based on the well known Archie Equation which relates the resistivity recorded by an electric logging tool to the resistivity of a fluid contained in a given formation. Since resistivity can be related to the concentration of dissolved solids in a given solution, water quality can be determined. Aquifer depth can be easily determined by basic log interpretation in conjunction with the depth track printed on the log.

INTRODUCTION

Title 43, Part 3162.5-2 of the Code of Federal Regulations states: "The lessee shall isolate freshwater-bearing and other usable water containing 5,000 PPM or less of dissolved solids and other mineral-bearing formations and protect them from contamination". This regulation requires the geologist responsible for reviewing Applications For Permit to Drill (APD) to identify aquifers which meet the above criteria so that casing and cementing programs can be checked to determine their adequacy.

In the past the Rock Springs District has used the depth of water wells adjacent to the proposed oil and gas well to identify usable water zones. This method is thought to be erroneous because generally a water well is only drilled to the shallowest aquifer which meets a desired flow rate and water quality. In many cases water well depths essentially indicate the minimum depth to usable water and not the maximum depth. Also, water wells with good reliable data may not be present in an oil field even if an aquifer exists. Therefore, a better method is needed to identify aquifers which require mitigation techniques to protect them from interzonal flows within a well bore or annulus. The remainder of this paper sets forth a reasonably simple method which may be used to determine the depth and approximate water quality of aquifers which have been encountered and logged during oil and gas drilling operations.

QUALITATIVE INTERPRETATION

It is well established that electrical conductivity can be related to the amount of ionic solids in an aqueous solution. Since resistivity is simply the inverse of conductivity, electrical wireline logs readily lend themselves to water quality studies.

If an electrical induction log from a drill hole within a particular study area can be obtained, a quick qualitative interpretation of potential aquifers can be made. The logic is as follows: Since the ionic concentration of the mud filtrate can be determined and the short normal (or SFL) theoretically reads the flushed zone, the short normal (or SFL) curve on the log should give a resistivity reading representative of a fluid with a known concentration (mud filtrate) in a given rock matrix. Since the drilling mud is assumed to be homogeneous, this allows us to assume that the short normal (or SFL) is reading a rock matrix saturated with mud filtrate having a constant salinity. If it is assumed that the deep induction log reads the same rock matrix saturated with formation water (ground water), it may be interpreted that when the short normal or SFL curve is coincident with the deep induction curve, the formation water (ground water) has approximately the same ionic concentration as the mud filtrate. A formation factor is not needed because both fluids are in essentially the same rock matrix. While determination of the actual ionic concentration of formation waters in a given interval is somewhat more complex, this "zone of coincidence" as previously identified, may suggest a point to begin a more quantitative analysis.

Quantitative Analysis

Dissolved Ionic Solids (DIS)

Archie's (1942) experiments show that the resistivity of a water filled formation (R_o), filled with water having a resistivity of R_w can be related by means of a formation factor (F):

$$R_o = F \times R_w \qquad \text{(EQN. 1)}$$

If the drilling mud has flushed the formation, and if contamination of the drilling mud by ionic diffusion is negligible, the fluid resistivity of the flushed zone can be calculated using equation 1.

Manipulation of equation 1 allows us to calculate the formation factor if R_w is known:

$$F = \frac{R_o}{R_w} \qquad \text{(EQN. 2)}$$

When dealing with the SFL we may substitute R_{sfl} for R_o and R_{mf} for R_w. This gives us the following relationship:

$$F = \frac{R_{sfl}}{R_{mf}^{*}} \qquad \text{(EQN. 3)}$$

Note: $^{*}R_{mf}$ is generally taken from the log header and then corrected to formation temperature.

Once F is determined we can manipulate equation 1 to solve for the apparent resistivity of the formation water (R_{wa}) by substituting the deep induction Resistivity (R_{DEEP}) for R_o as follows:

$$R_{wa} = \frac{R_o}{F} = \frac{R_{DEEP}}{F} \qquad \text{(EQN. 4)}$$

Once R_{wa} has been determined, Figure 1, 2, or 3 (whichever is appropriate) may be used to determine the amount of dissolved ionic solids in the formation (Aquifer).

Total Dissolved Solids (TDS)

Total dissolved solids in a water sample includes all solid material in solution, whether ionized or not. It does not include suspended sediment, colloids, or dissolved gases. Theoretically, if all dissolved solids were determined accurately by chemical tests, total dissolved solids would be the numerical sum of these constituents.

A related measure is the residue left after evaporation followed by drying in an oven at 180°C, or less commonly at 110°C, for one hour. The solid material left after evaporation does not coincide completely with material originally in solution. Gases are driven off; bicarbonate is converted to carbonate; sulfate may be deposited as gypsum which traps some of the water; and small amounts of magnesium, chloride, and nitrate may be volatilized. Nevertheless, the residue after evaporation, along with electrical conductance, affords a rough check on the accuracy of the sum of TDS. The final classification of water in relation to potential use, however, should be based on concentrations of individual ions rather than on total dissolved solids. (Davis and DeWiest, 1966)

Since the regulation defines the usable cut-off as 5,000 PPM "Dissolved Solids" it is thought that this refers to total dissolved solids and not merely dissolved ionic solids. Therefore the concentration of dissolved ionic solids determined above must be "converted" to total dissolved solids.

Studies conducted by the Fluid Minerals Branch of the Rock Springs District Office indicate that total dissolved solids (TDS) are approximately one and one-half times the dissolved ionic solids (DIS) in Southwest Wyoming. That is:

$$TDS = 1.5^{*} \times DIS \qquad \text{(EQN. 5)}$$

*See Appendix 1 for the derivation of this factor.

Therefore, to determine the DIS cut-off for a given area the following equation may be used:

$$DIS = \frac{5000\ TDS}{K}$$

Where K is the ratio of TDS to DIS for a given area or formation.

Example

In a given water-bearing formation, the well log values are as follows:

*R_{sfl} = 50 ohm-meters
*R_{mf} = 1.25 ohm-meters
*R_{DEEP} = 80 ohm-meters

*after standard corrections

Using EQN. 3:

$$F = \frac{R_{sfl}}{R_{mf}} = \frac{50}{1.25} = 40$$

Using EQN. 4:

$$R_{wa} = \frac{R_{DEEP}}{F} = \frac{80}{40} = 2 \text{ ohm-meters at formation temperature}$$

Utilizing Figure 1, the DIS concentration is estimated to be 3000 PPM.

Using EQN. 5:

$$TDS = 1.5 \times DIS = 1.5 \times 3000 \text{ PPM} = 4500 \text{ PPM}$$

Based on 43 CFR 3162.5-2, this water is usable and should be protected.

Summary and Conclusions

It should be obvious that the foregoing methods assume certain conditions to exist at the time the well was logged. The most important assumptions are these:

1. The short normal (or SFL) tool reads mud filtrate in the flushed zone of the well bore and this filtrate has the same resistivity as the R_{mf} on the log header corrected to formation conditions.

2. The long normal (or Deep) tool reads formation water in the uninvaded zone.

3. The formation water is not contaminated with resistive fluids such as oil or gas.

4. The dissolved ionic solids concentration is representative of water quality, i.e., no organic contamination.

5. The aquifer is 100% water saturated and is capable of production.

6. The aquifer is relatively free of clay minerals. Clay minerals increase conductivity indicating poorer than actual water quality.

Using the criteria and procedures outlined above, it is possible to relate resistivity recorded on conventional downhole well logs to formation water quality. Further refinements to the techniques presented above may increase the accuracy of the calculations but for the purposes of the Application for Permit to Drill (APD) process, the foregoing analysis is probably adequate.

References

Archie, G.E., 1942, The Electrical Resistivity Log as an Aid in Determining some Reservoir Characteristics: Petrol Technology, V.5, p.54-62 in Asquith, G.B., 1982, Basic Well Log analysis for Geologists: AAPG Tulsa, Okla. 74101, p.2.

Davis, S.N., and R.J.M. DeWeist, 1966, Hydrogeology: John Wiley & sons, Inc., New York, pp. 298-309.

Todd, D.K., 1980, Groundwater Hydrology-Second Edition: John Wiley & Sons, New York, pp. 439-445.

Schlumberger Well Services, 1985, Log Interpretation Charts: Available from Schlumberger Well Service Offices.

Kent Hoffman

KSCO - BLM

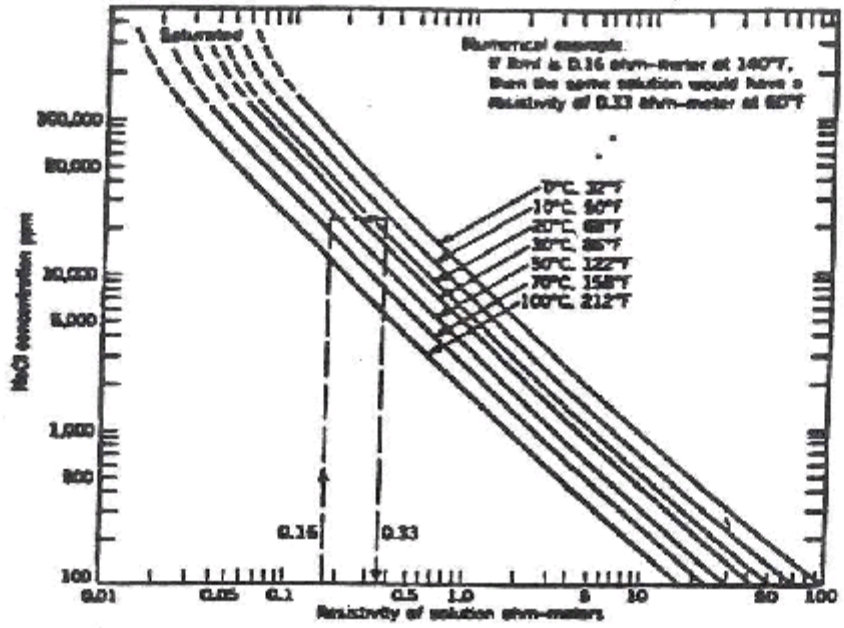


Figure 1 Relation of temperature and NaCl concentration to resistivity of the solution. (From Davis and DeWeist, 1966)

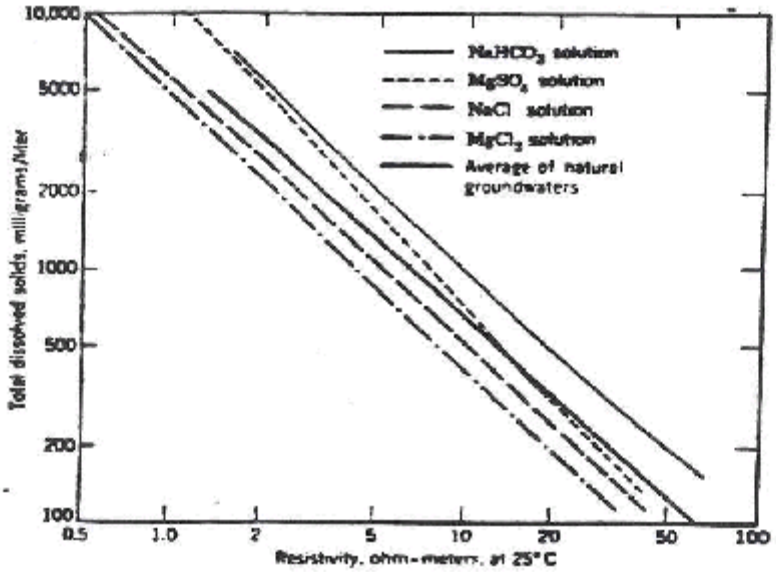


Fig. 2 Resistivity-concentration curves for various salt solutions and natural groundwaters (after *Agric. Handbook* 60, U.S. Dept. of Agriculture). (From Todd, 1980)

Resistivity of NaCl Solutions

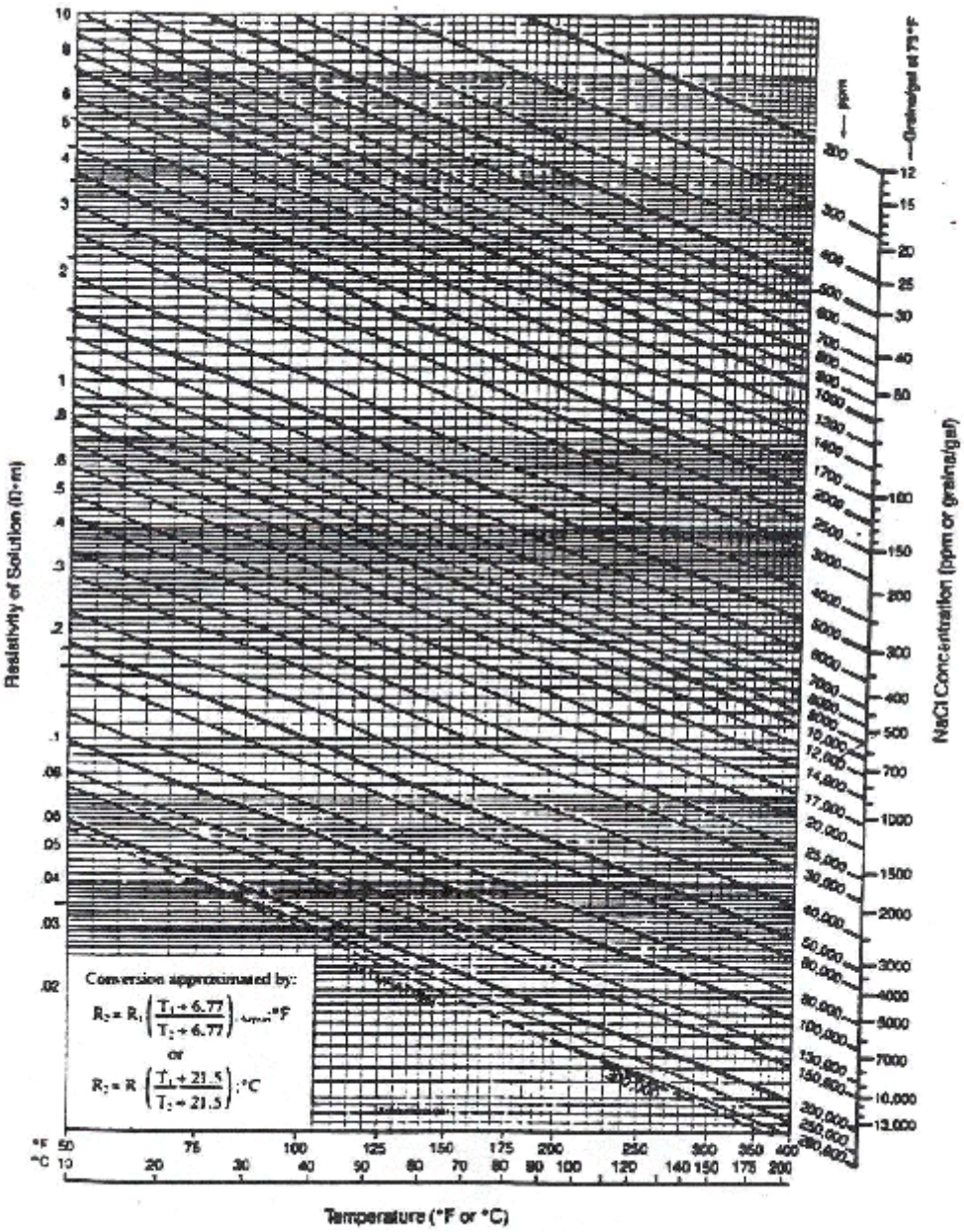


Figure 3 Gen-9 (From Schlumberger, 1985)

APPENDIX 1

Actual laboratory analyses were used to relate dissolved ionic solids (DIS) to total dissolved solids (TDS). The concentration of DIS for each sample was determined by converting the reported conductivity to resistivity and then utilizing Figure 1 to obtain DIS in parts per million (PPM). The DIS in PPM was then divided by the reported TDS (based on evaporation) to obtain a ratio. Table 1 presents the data used to obtain the TDS to DIS relationship. All analyses are from wells within the Rock Springs District.

Reported Conductivity (μ mho)	Resistivity	DIS in PPM	Reported TDS	TDS / DIS
1750	5.71	890	1055	1.2
245	40.82	120	220	1.8
17241	0.58	11,000	13792	1.3*
71429	0.14	43000	66694	1.6*
62500	0.16	40000	49415	1.2*
2000	5.00	990	1370	1.4
6200	1.61	3200	4630	1.4
5600	1.79	3100	4980	1.6
			Average	1.44

*WATER FROM HYDROCARBON PRODUCING ZONES

TABLE 1 - WATER ANALYSES USED TO RELATE DIS TO TDS.

List of API References applicable to Onshore Oil and Gas Order No. 2, Drilling Operations

1. API Bull 5C2, Performance Properties of Casing, Tubing and Drill Pipe.
2. API Bull 13D, The Rheology of Oil-Well Drilling Fluids.
3. API Bull D8, A Tabular Method of Determining Build Up Rate and Dog Leg Severity.
4. API Bull D11, Glossary of Drilling Fluids and Associated Terms.
5. API Bull D20, Directional Drilling Survey Calculation Methods and Terminology.
6. API RP 5A5, Recommended Practice for Field Inspection of New Casing, Tubing and Plain End Drill Pipe.
7. API RP 13B, Recommended Practice for Standard Procedure for Field Testing of Drilling Fluid Materials.
8. API RP 46, Recommended Practices for Testing Foam Agents for Mist Drilling.
9. API RP 49, Recommended Practices for Safe Drilling of Wells Containing Hydrogen Sulfide.
10. API RP 52, Recommended Land Drilling Operating Practices for Protection of the Environment.
11. API RP 53, Recommended Practices for Blow-Out Prevention Equipment Systems for Drilling Wells.
12. API RP 54, Recommended Practices for Occupational Safety.
13. API RP 59, Recommended Practices for Well Control Operations.
14. API Spec 5CT, Specification for Casing and Tubing.
15. API Spec 5L, Specification for Line Pipe.
16. API Spec 6A, Specification for Wellhead and Christmas Tree Equipment.
17. API Spec 7J, Specification for Drill Pipe/Casing Protectors.
18. API Spec 10D, Specification for Casing Centratizers.

List of References applicable to Onshore Oil and Gas Order No. 6, Hydrogen Sulfide Operations

1. API RP 49, Recommended Practices for Safe Drilling of Wells Containing Hydrogen Sulfide, Sections 2 and 5.14.

2. NACE Standard MR0175-90, Material Requirements - Sulfide Stress Cracking Resistant Metallic Materials for Oilfield Equipment.

3. ANSI Standard Z.88.2-1980, American National Practices for Respiratory Protection.

Rev. 04-20-93

A. Introduction.

This handbook chapter provides the inspector with a reference guide for preparing, conducting, and documenting inspection and enforcement activities on drilling operations that require prior approval of an APD.

The technical and environmental requirements for the conduct of drilling or workover operations are contained in the approved Application for Permit to Drill (APD) and Onshore Oil and Gas Order No. 1 (Order No. 1), Approval of Operations, Onshore Oil and Gas Order No. 2 (Order No. 2), Drilling Operations, and Onshore Oil and Gas Order No. 6 (Order No. 6), Hydrogen Sulfide Operations. Subsequent operations are addressed by other Onshore Oil and Gas Orders.

Drilling and other related operations are inspected to ensure that equipment, practices, and procedures are in accordance with the minimum standards of Order No. 2, Order No. 6 and the approved APD. BLM personnel shall inspect, take enforcement action if necessary, and document and report on drilling activity on Federal and Indian leases. All required inspections are to be carried out in accordance with the priority and the frequency established in the annual Inspection and Enforcement Strategy. The Strategy as it applies to drilling inspections is based upon national criteria but is developed to address specific situations found in particular local inspection offices. Examples could be witnessing all cement operations across an aquifer, troublesome high pressure zones, etc. Drilling inspection priorities are generally assigned by the petroleum engineer who reviews the APD.

B. Inspection Preparation.

The purpose of the inspection is to ensure that drilling operations are in compliance with the appropriate lease terms and conditions, regulations, Orders, Notice to Lessees (NTL's), and written instructions or conditions which are part of the approval of operations. The following is a guide to prepare for an inspection of a drilling or workover operation.

1. Select Inspection Item. An inspection item (drilling well) may be located on a lease, communitization agreement (CA), a

unit, or a participating area (PA) within a unit. The selection of the inspection item is based on the priority established by the Inspection and Enforcement Strategy for that particular inspection office. Every effort shall be made to inspect all high priority drilling operations when they occur.

2. Obtain a Copy of the Approved APD. The inspector should review the APD for the well to be inspected to determine the approved technical and environmental requirements. Generally, the APD consists of a completed Form 3160-3, the drilling plan, and the surface use plan of operations. If applicable, a Drilling Operations Plan (DOP) and Public Protection Plan (PPP) as required by Order No. 6 may also be part of the APD package. The inspector should review the well and lease file, the APD package, conditions of approval, and subsequent sundry notices to determine all the inspection requirements.

Special attention should be given to the following blocks of Form 3160- 3: Block No. 4 "Location of Well." This block describes the surface and subsurface location of the hole. The authorized officer may have approved a hole deviation. Block No. 19 "Proposed Depth." This information may alert the inspector that special requirements should be included in the approved plan. Block No. 23 "Proposed Casing and Cementing Program." This information should be verified with the approved plan. If there are differences, the inspector should look for a Sundry Notice - Notice of Change in Plans. If no change has been approved, the inspector should advise the authorized officer. Another source of important information are the Conditions of Approval (COA's) which are attached to the APD.

C. Inspection Guidelines.

This section presents the "what to do" for a drilling inspection. It includes a discussion of what a drilling inspection is and how to conduct and document the inspection. While inspecting, the inspector only witnesses the tests and operations; the inspector shall not operate equipment.

Under the Drilling (DW) inspection type there are several different drilling inspection activity codes as defined by the Inspection and Enforcement Strategy. A proper mix of various inspection activities is essential for an effective and efficient inspection program.

1. Detailed Inspections. A detailed inspection of all ongoing activities of a drilling well and the completion of all applicable sections of Form 3160-10, Drilling Inspection Record.

2. Non-detailed Inspection. At a minimum, inspection for and the completion of the first two sections of Form 3160-10, Drilling

Inspection Record. Also includes inspection of any drilling activity that has not progressed to the point where the applicable section can be completed in its entirety.

D. Inspection Procedures.

1. Corrective Actions Involving Shut Downs. In many inspection situations, the required correction action will be performed while the PET is still on location. However, in other situations, circumstances, such as obtaining necessary equipment or performing a required test, will prevent immediate correction. In these situations, it may be necessary to shut down the drilling operation until the corrective action is performed. The PET must consider the drilling situation and what detrimental affects the shut down could cause. Discussions with the authorized officer are strongly encouraged prior to initiating shut down operations. Some of the paramount concerns to take into account could be the health and safety of the rig crew, the condition of the wellbore or special operations being conducted at the time. In all shut down operations, it is the operator's responsibility to determining interim hole conditioning procedures. Some possible scenarios may be pulling the bit a few feet off bottom and circulating, pulling the bit up into the last casing string, or setting temporary cement plugs or packers.

2. Instructions for Completing Inspection Record - Drilling, Form 3160-10. Inspection records should be documented as instructed in the Inspection and Enforcement Strategy and in the AIRS Handbook H-3160-C. During each inspection the inspector shall fill out the Inspection Record - Drilling, Form 3160-10, shown in Illustration I, in accordance with the instructions. Inspection of a drilling operation may reveal incidents of noncompliance (INC's). Each potential INC is presented in the inspection form as a question. An INC exists if the question is applicable or required for the well and if the answer to the inspection question is "no", and the violation block is checked.

a. Header. The following is a list of the header items that need to be filled in. The APD and lease file must be reviewed so that the information is correct. See Figure IV-1 for the header portion of the Inspection Record - Drilling Form.

(Insert Header Here.)

Figure IV-1 - Drilling Inspection Record Header

(1) Lease No./Unit/CA: Enter the number or name of the inspection item.

(2) State: Enter State in which inspection item is located.

(3) District: Enter BLM District name.

(4) Field Area: Enter oil/gas field name.

(5) Detailed/Non-detailed: Enter inspection type code and inspection activity code.

(6) Well No.: Enter identification number of well.

(7) Location: Enter ¼ ¼, Section, Township, and Range location of well.

(8) Spud Date: Enter date well was spudded.

(9) Status: Enter activity taking place at time of inspection and depth at the time of inspection.

(10) Operator/Representative: Enter name of operator and designated representative.

(11) Rig/Contractor/Representative: Enter name of contractor and representative.

(12) Date: Enter date of inspection.

(13) Inspector: Enter name of BLM inspector.

b. Checklist Categories. The items in the inspection record are categorized under the following titles: General, Compliance with Approved Surface Use Plan of Operations, Blowout Preventer and Associated Equipment, Casing and Cementing, Mud Program, Special Operations - Air/Gas Drilling, Hydrogen Sulfide Operations and Other. When a checklist item under these headings is inspected, the blocks labeled "Inspected" and "Violation" are filled out as follows:

Inspected -Check box if item is inspected.
-Leave blank if item is not inspected.
-Check "NA" if item is not applicable.
-If an item requires clarification, enter an "R" in the inspection block and provide the information in the "Remarks" section at the bottom of the form.

Violation -Leave blank if inspected item is in compliance.
-Check box if inspected item is not in compliance.

3. The Inspection Record. The remainder of this section provides detailed explanation of the requirement, the authority citation(s) for the requirement, and the procedure of inspection for each of the checklist items on the Inspection Record. Special notes for attention are included. The items are listed in the numerical order they appear on the Inspection Record.

General

1. IS APPROVED DRILLING PERMIT AND PLAN ON WELL LOCATION?

a. Requirement. The operator shall have a copy of approved drilling permit and operation plan on location.

b. Authority:

(1) 43 CFR §3164.1, Order No. 1, Approval of Operations
(2) Application for Permit to Drill or Deepen, Form 3160-3.

c. Procedure.

(1) Determine availability and location of APD.

NOTE: During dirt construction operations, the APD should be in the contractors vehicle. If the well is spudded, the APD may be in doghouse, company man's trailer, or toolpusher's trailer. While rigging up, the toolpusher or company man could have the APD in a vehicle. On a small rig with no doghouse, the APD may be in weather-proof enclosure. The operator is in compliance if the approved APD is available on location.

(2) If APD is not on location an the operator does not correct, check "violation" and take enforcement action.

2. IS DRILL SITE PROPERLY IDENTIFIED?

a. Requirement. A sign shall be placed in a conspicuous place with the name of the operator, the lease serial number, the legal description, and the well number. When on Indian land, the name of the Indian tribe or allotted lessor shall precede the lease serial number. This requirement can be deleted or changed by the authorized officer. There is no stipulation as to size but the sign must be legible.

b. Authority: 43 CFR §3162.6 Well Identification.

c. Procedure.

(1) See if the sign is in a conspicuous place and if the required information is on the sign.

(2) If not and the operator does not correct, check "violation" and take enforcement action.

3. ARE OPERATIONS BEING CONDUCTED IN A WORKMANLIKE MANNER?

a. Requirement. The operator shall perform operations and maintain equipment in a safe and workmanlike manner.

b. Authority:

(1) 43 CFR §3162.5-2 Control of Wells.
(2) 43 CFR §3162.5-3 Safety Precautions.

c. Procedure.

(1) Observe the condition of wellpad, floor, and rig. Do the conditions fit the operation of the rig? Is rig floor safe to work on? (Free of drilling mud, subs, tools, etc.).

NOTE: The drilling location and the rig floor may be partially covered with drilling mud and equipment may be scattered about when drilling the surface hole and nippling up the blowout preventer equipment (BOPE). When surface pipe is set, the BOPE tested, and the rig is making new hole, it should be a different picture. The mud should be dried up and equipment put in its proper place. When making a trip, floor may be muddy and subs not in their proper place. During normal drilling, the floor should be washed and subs and tools picked up. Trash should be kept in a secured place so that it will not blow about. There are very few approved burn areas.

(2) Check all high pressure hoses and dresser sleeves for safety chains or cables at both ends.

NOTE: There have been a number of fatalities caused by hoses blowing loose and striking a person. This may happen at either end of the hose. The rotary hose is particularly vulnerable to breaking off and falling. If the rotary hose is steel and joined with chicsans (swivel joints), it also must be hobbled. When cementing, acidizing, fracturing, etc., the steel lines must be hobbled with safety chains or cables. If high pressure hoses and dresser sleeves are not secured, require the operator to secure the hoses and sleeves.

(3) Check to see if rig lighting is vapor-proof (explosion-proof).

NOTE: The light receptacles should be checked to make sure that the face plates and globes are intact. Conduit, armored cable, or heavy rubber covered wire must be in good condition. Generating units must be grounded and must be a safe distance away from the wellbore in accordance with State or Federal OSHA requirements. The inspector shall not climb the derrick to check light fixtures or other equipment as visual observation from the rig floor is usually sufficient to identify problems.

(4) Ensure fire extinguishers with full charges are available on location.

NOTE: Crew members may be assigned to man individual fire extinguishers and be trained on the use of the extinguishers for maximum effectiveness. Four 30 pound Ansul fire extinguishers directed at the base of a fire at the same time can stop a large fire.

(5) Observe to see if safe working practices are followed.

NOTE: Do all members of crew wear safety hats and shoes? Do workmen wear goggles when mixing caustic and know the correct procedure for mixing caustic? When mixing, caustic should always be added to water. Do crew members wear goggles when changing tong dies, repairing rotary chains, or cutting drilling lines? Are tools kept in safe working condition? Do personnel observe "NO SMOKING" signs? Do crew members use "derrick climber" when ascending and descending derricks and use safety belt when working in derricks? Is derrick man escape device, both the cart and the line (geronimo), installed and operable. If the

inspector observes a life threatening situation (i.e. geronimo not installed, no safety hobble on the rotary hose, etc.), the company man will be asked to correct the situation at that time.

(6) If operations are not being conducted in a workmanlike manner and if violations are not corrected after an oral warning, check "violation" and inform operator that OSHA will be notified. Document any findings in the remarks section.

4. DID OPERATOR REPORT ALL SPILLS?

a. Requirement. The operator is required to report all spills.

b. Authority:

(1) 43 CFR §3162.5-1(c) Environmental Obligations.
(2) NTL-3A, Reporting of Undesirable Events.

c. Procedures.

(1) Observe area around reserve pit and check to see how full the reserve pit is. An adequate freeboard should be maintained in accordance with the approved APD.

(2) Check location around rig and around fuel tank for signs of contamination.

NOTE: Check to see if there is evidence of a spill which has not been reported. The crew will ditch any mud to the sump around the pits or the reserve pit if low enough. Check the required freeboard in the reserve pit, because there is a chance of it breeching and allowing a large quantity of fluid to escape. If the reserve pit is breached and a spill occurs, notify the hazardous materials coordinator to determine if a release of a reportable quantity has occurred under the provisions of CERCLA. Fuel oil spills shall be reported according to the guidelines in NTL-3A. All spills shall be reported.

(3) If there is a possibility that a spill could occur, require the operator to correct the situation.

(4) If there is evidence of spills not reported, check "violation" and take enforcement action.

5. ARE DRILL-STEM TESTS CONDUCTED AS REQUIRED?

a. Requirement. Initial opening of drill stem test tools shall be restricted to daylight hours unless specific approval to start during other hours is obtained from the authorized officer. However, DST's may be allowed to continue at night if the test was initiated during daylight hours and the flow is stabilized and if adequate lighting is available (i.e. lighting which is adequate for visibility and vapor-proof for safe operations). Packers can be released, but tripping shall not begin before daylight, unless prior approval is obtained from the authorized officer. Closed chamber DST's may be accomplished day or night.

b. Authority:

(1) 43 CFR §3162.5-2(a) Well Control.
(2) 43 CFR §3162.5-3 Safety Precautions.
(3) 43 CFR §3164.1, Order No. 2, Drilling Operations
(4) 43 CFR §3164.1, Order No. 6, Hydrogen Sulfide Operations

c. Procedures.

(1) Review the approved APD to identify any special drill stem test requirements and for any variances approved. If specific drill stem test requirements are not addressed in the APD, then Order No. 2 and 6 minimum standards shall prevail.

NOTE: Well testing in an H_2S environment has restrictions in Order No. 6. The tests are to be performed with a minimum number of personnel in the immediate vicinity necessary to safely and adequately perform the test. The "immediate vicinity" is meant primarily as the rig floor or close proximity. The inspection of a drill stem test will be necessary at times, but the inspector does not need to be on the rig floor at all times. To assure that the tool is opened approximately at the proper depth, the inspector should count stands of pipe as the tool is lowered. This can be done from a safe distance.

Order No. 6 also requires that, except with prior approval, drill stem testing shall be conducted only in daylight hours. The intent of the "daylight" requirement is that the tool may not be opened or tripped out of the hole except during daylight. They may set up equipment and run the tool into the hole at any time of day or night. Also, only closed chamber testing is allowed so that formation fluids are not flowed to the surface. The inspector will have to confirm that a closed chamber tool is to be used before running into the hole. The inspector should not be on the floor when the tool is retrieved.

(2) A DST that flows to the surface with evidence of hydrocarbons shall be either reversed out of the testing string under controlled surface conditions, or displaced into the formation prior to pulling the test tool. This would involve providing some means for reverse circulation.

(3) Separation equipment required for the anticipated recovery shall be properly installed before the test starts. The time to inspect this equipment would be before the test starts.

(4) All engines within 100 feet of the wellbore that are required to "run" during the test shall have spark arresters or water cooled exhaust. See Air/Gas section for further discussion.

NOTE: It is a usual practice that circulating to condition mud, tripping out, making up test tools, and trip in hole will be timed so that the tool may be opened at daybreak. That way the test can usually be run in the daylight hours. It is safer to be able to turn off the generating unit when there is gas and/or oil surfacing. The no smoking rule must be strictly enforced. It is a good idea for all matches and cigarette lighters to be placed in a designated smoking area during the test. If conditions warrant, there is often a smoking

area designated 150' upwind of the test. The mud bucket must be used to direct fluids either to the pits or the sump. The driller must keep the hole full while pulling the test tools. The derrick escape line must be in good working order.

(5) Check location of usable fire extinguishers.

(6) Check pit level indicator to see if driller is keeping hole full.

(7) If operator is not conducting drill-stem test in a safe and workmanlike manner, or if operator does not have separation equipment, check "violation" and take enforcement action.

6. IS THE HOLE DEVIATION WITHIN APPROVED TOLERANCES?

a. Requirement. The operator shall conduct drilling operations in a manner so that the completed well does not deviate significantly from the vertical without the prior written approval of the authorized officer. Significant deviation means a projected deviation of the well bore from the vertical of 10 degrees or more, or a projected bottom hole location which could be less than 200 feet from the spacing unit or lease boundary. Any well which deviates more than 10 degrees from the vertical or could result in a bottom hole location less than 200 feet from the spacing unit or lease boundary without prior written approval shall be promptly reported to the authorized officer. In these cases, a directional survey may be required by the authorized officer.

b. Authority: 43 CFR §3162.5-2(b) Vertical Drilling.

c. Procedures.

(1) Check the APD for approved directional drilling.

NOTE: All wellbore paths, i.e. different orientations, require prior approval.

(2) The inspector should check the driller's log for deviation survey results. If the results are not recorded, require the operator to provide the survey data.

(3) If there is excessive deviation or deviation without approval and the operator has not obtained approval from the authorized officer, check "violation" and report the situation to the authorized officer for resolution.

SURFACE

7. IS SURFACE USE IN ACCORDANCE WITH APPROVED PLAN?

- WELL SITE LAYOUT?
- PITS, SUMPS, AND OTHER ANCILLARY FACILITIES?
- CONTAINMENT AND DISPOSAL OF SOLID, LIQUID, AND GASEOUS WASTES?
- FAILURE TO IMPLEMENT DUST CONTROL?
- FAILURE TO OBTAIN PRIOR APPROVAL FOR ADDITIONAL SURFACE DISTURBANCE?

a. Requirement. The operator shall comply with the approved surface use plan of operation. If modifications are to be made, the operator shall obtain prior approval from the surface management agency. The operator shall conduct operations in a manner which protects the mineral resources, other natural resources, and environmental quality.

b. Authority:

(1) 43 CFR §3164.1, Order No. 1, Approval of Operations
(2) 43 CFR §3162.5-1 Environmental Obligation.

c. Procedure.

(1) Determine if surface use is in accordance with the provisions of the Surface Use Plan of Operation (SUPO) as approved by the Surface Management Agency (SMA).

NOTE: The rig orientation should be compared to the approved well site diagram. If the diagram and the well site are reasonably the same, then it should be deemed acceptable. Minor variations in actual layout, given the site specific location, may not be considered a violation of H_2S requirements. The gravity of H_2S violations should be viewed against the safety requirements found in regulation.

(2) If surface use is not satisfactory, check "violation"; coordinate with the appropriate SMA for proper correction; and take enforcement action.

BLOWOUT PREVENTION (BOP) AND ASSOCIATED EQUIPMENT

This system is designed to prevent uncontrolled flow of fluid to the surface from the well bore. Specific blowout prevention equipment and arrangement are approved by the authorized officer. Inspection ensures that equipment specified in the approved plan has been properly installed and is operative. The system shall be pressure tested before drilling out each casing string and functionally operated in accordance with Order No. 2. Results of the test and operations shall be recorded in the driller's log book, International Association of Drilling Contractor (IADC) Drilling Report.

Blowout prevention equipment is designed to close the top of the hole, control the release of fluids, permits pumping into the hole, and allow movement of the drill pipe. The basic components of the system may include: casing and casinghead; operating equipment (power source, accumulator, master control panel, and remote control panel); flow and choke fittings; kill connections; fill-up connections; and auxiliary equipment (kelly cock, floor safety valves etc.)

8. IS BOP PRESSURE RATING AND ARRANGEMENT AT LEAST THAT APPROVED?

a. Requirement. Blowout preventer (BOP) and related equipment (BOPE) shall be installed, used, maintained, and tested in a manner necessary to assure well control and shall be in place and operational prior to drilling the surface casing shoe unless otherwise approved by the APD. The operator shall use pressure control equipment that is rated to at least what is approved by the authorized officer.

b. Authority:

(1) 43 CFR §3162.5-2a Drilling Wells.
(2) 43 CFR §3164.1, Order No. 1, Approval of Operations
(3) 43 CFR §3164.1, Order No. 2, Drilling Operations

c. Procedure:

(1) Review the approved APD to identify the BOPE required and for any variances approved. If specific BOPE requirements are not addressed in the APD, then Order No.

2 minimum standards shall prevail.

(2) Check the actual installation of equipment to determine if the BOP type, pressure rating, and arrangement are satisfactory.

NOTE: Catalogs on BOP's, valves, unions, etc. should be available at the office. If not, the manufacturer will usually supply them free of charge. World Oil puts out Composite Catalogs which provides valuable information. The inspector may have to verify the pressure rating of the BOP by locating the data plate on the equipment, or the company representative may be required verify the rating.

(3) Verify that ram rubbers are in the preventer for each size of drill pipe if a tapered string is in use. This can be verified at the time of BOP test. Variable ram rubbers are acceptable.

(4) Visually check to see if all bolts or studs are in place and tightened adequately on flanges, stacks, choke, and kill lines.

(5) If BOP installation is not satisfactory, check "violation" and take enforcement action.

9. ARE CHOKE LINES AND MANIFOLD, KILL LINES AND FILL LINES PROPERLY INSTALLED AND OPERABLE?

a. Requirement. Blowout preventer (BOP) and related equipment (BOPE) shall be installed, used, maintained, and tested in a manner necessary to assure well control and shall be in place and operational prior to drilling the surface casing shoe unless otherwise approved by the APD.

b. Authority:

(1) 43 CFR §3162.5-2a Drilling Wells.
(2) 43 CFR §3164.1, Order No. 1, Approval of Operations
(3) 43 CFR §3164.1, Order No. 2, Drilling Operations

c. Procedure.

(1) Review the approved APD to identify the BOPE required and for any variances approved. If variances have not been approved, Order No. 2 minimum standards shall

prevail. See Illustration 2 & 3 for choke and kill line installation diagrams.

NOTE: The operation of various components will be checked during the actual testing of the BOP, which is performed before drilling the cement and shoe, after setting surface pipe, and setting each successive casing string.

The choke line between the BOP stack and the manifold should be straight. Any necessary turns should be made on tee-blocks or targeted on running tees, see Order No. 2, Definition W. High pressure flex line that is flanged, bolted and tested to approved working pressure is an acceptable substitute provided the requirements of Order No. 2 are met. Targeted turns (Y's) made at angles greater or less than 90 degrees are not acceptable.

The choke line and manifold, kill line and fill lines shall be tested each time the BOP is tested. The equipment shall be tested at least once every 30 days.

On 2M rating working systems:
-Threaded connections are optional if the pressure specifications are met.
-A check valve is not required and only one choke line valve and one kill line valve is required.
-The choke line may be 2 inches in diameter.
-There shall be two adjustable chokes in the choke manifold.

On 3M rated working systems;
-There shall be two adjustable chokes in the choke manifold.
-There shall be two flanged choke line valves in the cellar and one flanged valve in the kill line as well as a check valve.
-The choke line shall be a minimum of 3 inches in diameter.

On 5M rated working system and higher, or 3M systems if required by approval:
-One of the adjustable chokes is replaced with a hydraulic or pneumatic controlled choke.
-The remote control is on the rig floor.
-One of the choke line valves in the cellar is replaced with a hydraulic or pneumatic controlled valve. This valve is usually activated by accumulator pressure.

(4) The fill up line shall be connected above the uppermost blow out preventer, i.e. drilling nipple or rotating head.

(5) The kill line shall be hooked up to a mud source.

NOTE: During winter time operations this line should be hooked up but a drain plug may be removed so that the line can be drained to prevent freezing. A hammer union left undone on the low-end of the kill line would be another acceptable alternative. In either of these situations, the line can quickly be returned to service.

(6) If choke line, and manifold, fill line, and kill lines are not properly installed or not operable and the operator fails to repair, check "violation" and take enforcement action.

10. ARE CONTROLS INSTALLED AND FUNCTIONAL?

- REMOTE CONTROL ON FLOOR?
- MASTER CONTROLS?
- HAND WHEELS OR AUTOMATIC LOCKING DEVICES?
- VALVE INSTALLED IN CLOSING LINE OF ANNULAR PREVENTER?

a. Requirement. Blowout preventer (BOP) and related equipment (BOPE) shall be installed, used, maintained, and tested in a manner necessary to assure well control and shall be in place and operational prior to drilling the surface casing shoe unless otherwise approved by the APD. The operator shall use pressure control equipment that is

rated to at least what is approved by the authorized officer.

b. Authority:

(1) 43 CFR §3162.5-2(c) High Pressure or Loss of Circulation
(2) 43 CFR §3164.1, Order No. 1, Approval of Operations
(3) 43 CFR §3164.1, Order No. 2, Drilling Operations

c. Procedure.

(1) Review the approved APD to identify the BOPE controls required and for any variances approved. If specific BOPE control requirements are not addressed in the APD, then Order No. 2 minimum standards shall prevail.

(2) Check to see if the remote controls will close all preventers.

(3) Do the master controls open and close all preventers?

(4) Do the master controls open and close the choke line valve on 5M systems or higher?

(5) Are hand wheels or autolock installed and operable?

NOTE: Remote controls shall be readily accessible to the driller and shall be capable of closing all preventers. Master controls are at the accumulator and are capable of closing and opening all preventers and the choke line valve used on the systems rated at 3M, 5M, and higher. There shall be hand wheels on preventers so equipped. This will be waived if the preventer is equipped with automatic locking devices. The valve installed in the closing line of the annular preventer should be as close as possible to the annular preventer to act as a locking device when the annular is closed. This valve should be maintained in the open position at all other times. When testing BOP, make sure that driller can close the preventers from both the remote panel and the master controls at the accumulator. On most systems the preventers can also be opened at the driller's remote panel, but as long as the

preventer can be closed at the station, that is all that is required. The master controls will perform both operations.

(6) If required controls are not installed, check "violation" and take enforcement action.

(7) If controls are installed but not operable and the operator fails to repair, check "violation" and take enforcement action.

11. IS PRESSURE ACCUMULATOR SYSTEM ADEQUATE TO ACTIVATE BOP?

- NITROGEN PRECHARGE PRESSURE?
- RESERVOIR CAPACITY TWO TIMES USABLE FLUID VOLUME?

a. Requirement. Blowout preventer (BOP) and related equipment (BOPE) shall be installed, used, maintained, and tested in a manner necessary to assure well control and shall be in place and operational prior to drilling the surface casing shoe unless otherwise approved by the APD.

b. Authority:

(1) 43 CFR §3162.5-3 Safety Precautions.
(2) 43 CFR §3164.1, Order No. 1, Approval of Operations
(3) 43 CFR §3164.1, Order No. 2, Drilling Operations

c. Procedure.

(1) Review the approved APD to identify the BOPE and associated accumulator system required. If specific accumulator system requirements are not addressed in the APD, then Order No. 2 minimum standards shall prevail.

(2) Check the reservoir to see if it is at the correct level.

NOTE: For 2M BOP Systems The accumulator shall have sufficient capacity to close all BOP's and maintain a minimum pressure of 200 psi above precharge on the closing manifold without the use of the closing unit pumps. Nitrogen bottles that meet manufacturer's specification may be used as the backup to the required power

source.

NOTE: For 3M BOP Systems The accumulators shall have sufficient capacity to open the hydraulically controlled gate valve, if so equipped, close all rams plus the annular preventer, and maintain a minimum pressure of 200 psi above precharge on the closing manifold without the use of the closing unit pumps. This is a minimum requirement. The fluid reservoir capacity shall be double the usable fluid volume of the accumulator system capacity and shall be maintained at the manufacturer's recommendations. There is usually a petcock, sight glass, or a mark indicating the desired reservoir level. The accumulator system installed for 3M BOP systems is required to have two independent power sources to close the preventers. Nitrogen bottles may be substituted (three minimum) as a back up source and shall be replaced when the pressure falls below 1500 psi. Each bottle is inspected individually; full charge is 2500 psi or 2650 psi depending on size of bottle and manufacturer's specifications.

NOTE: For 5M and higher BOP Systems The accumulator shall have sufficient capacity to open the hydraulically-controlled gate valve, if so equipped, and close all rams plus the annular preventer and maintain a minimum pressure of 200 psi on the closing manifold without the use of the closing unit pumps. The reservoir capacity is figured the same as the 3M system, and it should be kept at the level recommended by the manufacturer. For three ram systems, add a fifty percent safety factor to compensate for any fluid loss in the control system or preventers. See Illustration 4 for an example of calculating volumes. Two independent sources of power are required for powering the closing unit pumps and although nitrogen bottles may be used for redundancy they are not suitable as one of these sources of power.

(3) Check the accumulator gauges to see if the accumulator, manifold, and annular gauges indicate their appropriate pressures.

3000 psi Accumulator Systems - The gauges on the accumulator indicate three important functions. The accumulator gauge indicates the pressure of the fluid stored in the cylinders. The manifold gauge specifies the accumulator operating pressure. The annular gauge indicates the pressure to operate the hydraulic system used to close the annular BOP. The accumulator pressure gauge should be maintained at 3000 psi to ensure that the maximum amount of usable fluid will be available to operate the BOP system (Manufacturer's Recommendation). The manifold pressure gauge should be maintained at 1500 psi or one-half (1/2) of the accumulator pressure under normal drilling conditions. The manifold pressure is controlled by a regulator that can be bypassed by the use of a 4-way valve. This allows the availability of full accumulator pressure to the manifold in the event of an emergency. The annular pressure gauge should never exceed 1500 psi (manufacturer's recommendation). The pressure on this gauge can also be controlled by use of a regulator that allows the pressure to be adjusted for the appropriate function required of the annular preventer. During stripping or snubbing operations the pressure may be regulated back to 600 to 700 psi to allow drill pipe tool joints to pass through annular preventer.

1500 psi Accumulator System - The 1500 psi accumulator system only has one gauge. This gauge indicates the working pressure of the entire system. This system has limited use because the fluid stored in the spherical ball is only 1500 psi with a 750 psi nitrogen precharge, and this limits the amount of usable fluid available to operate the BOP stack. This system needs to be carefully sized and maintained due to the limited volume of usable fluid.

NOTE: Accumulator Precharge Pressure Test This test should be conducted at least once every six months and prior to connecting the closing unit to the blowout preventer stack. Measure the nitrogen precharge pressure on each accumulator bottle using an accurate pressure gauge attached to the precharge measuring port. If nitrogen precharge leak off exceeds Figure IV-2

ranges, the cylinder shall be recharged.

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* Accumulator working * Minimum acceptable * Desired precharge * Maximum acceptable  *
Minimum acceptable *
*  pressure rating    * operating pressure *     pressure      * precharge pressure  *
precharge pressure *
G44444444444444444444P44444444444444444444P44444444444444444444P44444444444444444444P44
4444444444444444444I
*     1,500 psi       *     1,500 psi      *      750 psi      *       800 psi       *
   700 psi       *
*     2,000 psi       *     2,000 psi      *    1,000 psi      *     1,100 psi       *
   900 psi       *
*     3,000 psi       *     3,000 psi      *    1,000 psi      *     1,100 psi       *
   900 psi       *
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Figure IV-2 - Accumulator Precharge Pressure Ranges

A quick check to determine an indication of the lowest accumulator bottle precharge is to ensure the system pressure is at 3000 psi, then turn off the accumulator pumps, open the bleed valve and slowly bleed-off the system pressure back into the reservoir. The pressure will stabilize for an instant and then drop to zero. This stable reading indicates the lowest bottle precharge pressure in the system. For example, if pressure reads 1000 psi before it drops to zero this would indicate the lowest bottle precharge is 1000 psi in the system. This procedure will work on 1500 psi systems as well as 3000 psi systems.

(4) Perform the nitrogen precharge pressure test as outlined in Order No. 2.

NOTE: If this requirement cannot be met, it indicates the possibility that the accumulator is undersized for the BOP stack in use or has a low nitrogen precharge, or it is an indication of bladder failure in one or more cylinders. This shall be remedied before proceeding.

(5) If test can not be completed, the rig shall not be

allowed to operate until equipment is repaired and test conducted. Drilling may resume if hole conditions indicate drilling would not pose a danger while the repairs are being done.

(6) If the accumulator system is inadequate and the operator fails to correct, check "violation" and take enforcement action.

12. ARE RAM TYPE PREVENTERS TESTED TO STACK WORKING PRESSURE IF ISOLATED BY TEST PLUG OR TO 70 PERCENT OF INTERNAL YIELD PRESSURE OF CASING IF BOP STACK IS NOT ISOLATED FROM CASING?

a. Requirement. Ram type preventers and associated equipment shall be tested to approved stack working pressure if isolated by test plug or to 70 percent of internal yield pressure of casing if BOP stack is not isolated from casing. Pressure shall be maintained for 10 minutes or until the provisions of the test are met, whichever is longer.

b. Authority:

(1) 43 CFR §3162.5-2 Control of Wells
(2) 43 CFR §3164.1, Order No. 1, Approval of Operation
(3) 43 CFR §3164.1, Order No. 2, Drilling Operations

c. Procedure.

1) Review the approved APD to identify the BOPE test pressures required and for any variances approved. If specific BOPE test pressure requirements are not addressed in the APD, then Order No. 2 minimum standards shall prevail. See Appendix 1 for step-by-step BOPE test procedures.

NOTE: Observe if ram type preventers are holding the required pressure as stipulated in the approved APD. Ram-type blowout preventers and related control equipment will be tested at the rated working pressure of the stack assembly when the stack is isolated from the casing by use of a test plug. When using a test plug, be sure that a valve on the casinghead is opened below the plug so that excess pressure will not be applied to the casing in the event that the plug leaks. In those rare instances where a packer (j-slot or cup type)is used to isolate the casing from the BOP stack, the casinghead valve cannot be opened (packer failure maybe indicated if more than 15 minutes is required for pressuring up). If pressure is being applied to the casing and stack simultaneously,

use the rated working pressure of the stack assembly not to exceed 70 percent of the internal yield pressure of the casing. Contractors, with portable high pressure pumping units, are often hired for testing BOPE.

(2) If using a portable testing unit, make sure they are using a chart recorder.

(3) Visually inspect BOP flanges, door covers, primary packing seals, choke and kill lines as well as valve flanges for leaks while pressure is held on components being tested. Pressure shall be maintained for at least 10 minutes.

NOTE: When pressure testing the BOPE components, a leak may take several minutes to bleed-off entrained compressed air before registering a fluid leak. If a leak develops in BOPE, the test should be stopped; the pressure released; and the problem corrected before further testing resumes.

(4) Make sure that there are no stem packing leaks on choke manifold valves and that all valves and flanges will hold the required pressure.

(5) Make sure that chokes have been installed and tested for integrity.

NOTE: Adjustable choke stems should be seated and pressure tested to 500 psi. A small amount of bleed-off may occur. Rapid bleed-off may indicate that the needle and/or seat are washed out and shall be replaced. Remote choke integrity can be determined in this same manner. Specific manufactures design remote chokes which provide complete shut off. Fixed orifice (positive) chokes are not acceptable and shall be replaced. Valves installed downstream of the chokes are not exposed to full working pressure of the system and are not utilized as isolation valves (isolation is provided by the wing valves upstream of the chokes), and only need to be pressure tested to 50% of working pressure.

(5) If the pressure test does not meet the requirement

and the operator fails to correct the problem, check "violation" and take enforcement action.

13. ARE ANNULAR TYPE PREVENTERS TESTED TO 50 PERCENT OF WORKING PRESSURES?

a. Requirement. Annular type preventers shall be tested to 50 percent of rated working pressure. Pressure shall be maintained for at least 10 minutes or until the provisions of the test are met, whichever is longer.

b. Authority:

(1) 43 CFR §3162.5-2 Control of Wells.
(2) 43 CFR §3164.1, Order No. 1, Approval of Operations
(3) 43 CFR §3164.1, Order No. 2, Drilling Operations

c. Procedure.

(1) Review the approved APD to identify the BOPE test pressures required and for any variances approved. If specific BOPE test pressure requirements are not addressed in the APD, then Order No. 2 minimum standards shall prevail.

(2) Observe if annular type preventer is holding the required pressure as stipulated.

NOTE: On 3M systems, annular preventers are required to be tested to 1500 psi (1/2 of 3000 psi), 5M to 2500 psi, and 10M to 5000 psi. If the annular preventer fails to seal, this may indicate that the annular regulator operating pressure is set too low. The accumulator is equipped with a regulator so that the closing pressure on the annular preventer may be turned down to 500-600 psi when "stripping" the drill pipe back in the hole to kill a well kick. The sealing element may leak a little at this pressure to help stop rubber erosion. If the pressure hasn't been regulated back up to at least 1000 psi after the stripping operation, an effective seal may not be obtained. The annular preventer should never be closed on an empty hole except in emergencies. Manufacturer specifications for pressure on annular preventer should not be exceeded.

If the preventer is being used only for flow diversion (diverter system), e.g. on conductor pipe, it is not normally nor necessary to test to 50% of working pressure. If required, a functional test may be performed on the diverter system. A function test for diverter systems ensures that when the annular is closed, the flow line valve is automatically opened. This prevents placing pressure on the conductor casing which could lead to underground blowouts.

(3) Visually check flange connections for leaks.

(4) Check regulator pressure on the annular preventer system at the accumulator to ensure the regulator is set not to exceed 1500 psi or minimum 1000 psi. During stripping or snubbing operations, the regulator pressure may be reduced to 600 or 700 psi so the annular preventer rubber can relax enough to allow passage of tool joints.

(5) If test does not meet the required pressure and the operator fails to correct the problem, take enforcement action.

14. ARE BOPE TESTS RUN AND RECORDED IN DRILLER'S LOG?

- WHEN INITIALLY INSTALLED?
- WHENEVER A SEAL SUBJECT TO TEST PRESSURE IS BROKEN?
- FOLLOWING RELATED REPAIRS?
- 30 DAY INTERVALS?

a. Requirement. All of the above described tests shall be recorded in the drilling log.

b. Authority:

(1) 43 CFR §3160.5-2(a) Drilling Wells.
(2) 43 CFR §3164.1, Order No. 1, Approval of Operations
(3) 43 CFR §3164.1, Order No. 2, Drilling Operations

c. Procedure.

NOTE: BOP tests are conducted at each of the above mentioned points. Exceptions could be that some operators test BOP's weekly or biweekly. Review the APD to determine if additional BOP tests are required prior to drilling a known high-pressure zone.

(1) Check the driller's log book to see if BOP tests have been performed and recorded as required by Order No. 2. Record date on form.

(2) If a contractor is used to conduct the BOP test, the contractor's report including pressure chart should be submitted to the authorized officer for review and made part of the inspection record.

NOTE: Check the pressure chart to see if the BOP tests meet minimum requirements.

(3) If an independent BOP test contractor is not used and the test is to be accomplished with rig equipment, every effort should be made to have an inspector present so verification of the test is possible. This verification is necessary because of the complexity of the test procedures and the difficulty in attaining and holding required test pressures with rig equipment.

(4) If BOPE tests were not run and/or recorded in the driller's log book, require the operator to perform the tests or verify that the tests were conducted.

(5) If the operator failed to test and/or record, check "violation" and take enforcement action.

15. ARE BOP DRILLS CONDUCTED WEEKLY AND RECORDED IN DRILLER'S LOG?

a. Requirement. A BOPE pit level drill shall be conducted weekly for each drilling crew. This drill shall be recorded in the drilling log.

b. Authority:

(1) 43 CFR §3162.5-2(a) Drilling Wells
(2) 43 CFR §3162.5-3 Safety Precautions
(3) 43 CFR §3164.1, Order No. 1, Approval of Operations
(4) 43 CFR §3164.1, Order No. 2, Drilling Operations

c. Procedure.

(1) Check the driller's log book to see if BOP drills have been held and how often.

NOTE: Crew members normally have preassigned duties and stations when it is necessary to circulate out a kick or preform a well control operation. This is vital to the success of stopping a blow out. There are certain procedures to follow and valves to open or close to successfully contain the influx of liquids and/or gases. The driller, toolpusher, or company man will call for tests and check that proper procedures are followed and that personnel are reporting their proper stations. A BOP drill is usually performed after the bit has been pulled up into the casing on a trip out of the hole. Only the rig personnel would initiate a BOP drill.

(2) Check to see if audible alarms, if applicable, are turned on and flowsensors and pit level indicators are functioning properly.

NOTE: Add a remark if visual monitoring equipment has been approved in lieu of audible alarms.

(3) If alarms and level indicators are not operational and the operator fails to repair, check "violation" and take enforcement action.

(4) If BOP drills are not conducted and recorded in the driller's log book, check "violation" and take enforcement action.

16. IS ANNULAR PREVENTER ACTIVATED WEEKLY AND RECORDED IN DRILLER'S LOG?

a. Requirement. Annular preventers shall be functionally operated at least weekly. This test shall be recorded in the drilling log.

b. Authority:

(1) 43 CFR §3162.5-2(a) Drilling Wells

(2) 43 CFR §3162.4-1 Well Records and Reports
(3) 43 CFR §3164.1, Order No. 2, Drilling Operations

c. Procedure.

(1) Inspector should check driller's log book when at rig and verify that the annular preventer has been activated at least weekly and recorded as required. Record most recent function test date on inspection record checklist.

(2) If the annular preventer has not been activated and recorded weekly, require a functional test, if appropriate. If the operator failed to test and record, check "violation" and take enforcement action.

17. ARE PIPE RAMS ACTIVATED EACH TRIP AND RECORDED IN THE DRILLER'S LOG?

a. Requirement. Pipe and blind rams shall be activated each trip, however this function need not be preformed more than once a day. This test shall be recorded in the drilling log.

b. Authority:

(1) 43 CFR §3162.5-2(c) High Pressure or Loss of Circulation
(2) 43 CFR §3164.1, Order No. 1, Approval of Operations
(3) 43 CFR §3162.4-1 Well Records and Reports
(4) 43 CFR §3164.1, Order No. 2, Drilling Operations

c. Procedure.

(1) Inspector should check driller's log book when at rig and verify that the crews activate the pipe rams each trip and record in tour book, as required. Record most recent function test date on inspection record checklist

(2) If pipe rams are not activated each trip and recorded in the driller's log book, check "violation" and take enforcement action.

18. ARE BLIND RAMS ACTIVATED EACH TRIP AND RECORDED IN THE DRILLER'S LOG?

a. Requirement. Blind rams shall be activated each trip, however this function need not be preformed more than once a day. This test shall be recorded in the drilling log.

b. Authority:

(1) 43 CFR §3162.5-2(a) Control of Wells
(2) 43 CFR §3164.1, Order No. 1, Approval of Operations
(3) 43 CFR §3162.4-1 Well Records and Reports
(4) 43 CFR §3164.1, Order No. 2, Drilling Operations

c. Procedure:

(1) Check driller's log book when inspecting the rig to make sure that the blind rams have been activated each trip and recorded as required. Record most recent function test date on inspection record checklist

NOTE: The following is a suggested method of operation, other variations could be acceptable: After the bit has cleared the rotary table, check to make sure that the hole is full and static, and then close the blind rams. Leave the rams closed until the new bit has been put on, any worn reamers have been changed, and any other necessary work has been performed. Then open the blind rams and trip back into the hole. Not only has it been demonstrated that the blind rams work, but also foreign objects have been kept out of the hole.

(2) If blind rams are not activated each trip and recorded in the driller's log book, check "violation" and take enforcement action.

19. IS THE SLOW PUMP SPEED RECORDED EACH TOUR AFTER WELL HAS BEEN MUDDED UP?

a. Requirement. Record slow pump speed on daily drilling report after mudding up.

b. Authority:

(1) 43 CFR §3162.5-2(a) Drilling Wells
(2) 43 CFR §3162.4-1 Well Records and Reports

(3) 43 CFR §3162.5-3 Safety Precautions
(4) 43 CFR §3164.1, Order No. 2, Drilling Operations

c. Procedure.

(1) The inspector should check the driller's log book to see if the slow pump speed has been recorded each tour, as required. Record most recent function test date on inspection record checklist.

NOTE: At the beginning of each tour, the driller should obtain the pump pressure at kill speed. This information is used in the event a kick is taken on that tour. The pump pressure at kill speed (ppks) is obtained by merely cutting the pump back to approximately one-half of the pump speed used to drill. With the pumps at a slower speed, there is less chance of damaging the surface equipment or fracturing the formation while circulating out a kick, and gives the operator a greater reaction time for operation of choke equipment.

(2) If slow pump speed has not been recorded as required, have crew determine slow pump speed and record pump speed and pressure. Check "violation" and take enforcement action.

20. ARE DRILL STRING SAFETY VALVES AND/OR INSIDE BOP VALVES MAINTAINED IN THE OPEN POSITION ON THE RIG FLOOR?

a. Requirement. All 2M and higher BOPE systems are required to have safety valves and subs to fit all drill strings in use. All 5M and higher BOPE systems also require an inside BOP or float sub available.

b. Authority:

(1) 43 CFR §3162.5-2(a) Drilling Wells
(2) 43 CFR §3162.5-3 Safety Precautions
(3) 43 CFR §3164.1, Order No. 1, Approval of Operations
(4) 43 CFR §3164.1, Order No. 2, Drilling Operations

c. Procedure.

(1) Check to see if there is a safety valve in the open position located near the rotary table as required.

NOTE: The safety valves shall be pressure tested each time the BOP is tested. The valves should open and close with an minimum of effort and shall hold the required test pressure. An inside BOP is acceptable for use but has limitations for wire line operations. The ideal situation is to have both a safety valve and inside BOP available.

(2) Check to see if the wrench for the safety valve is available on the rig floor.

NOTE: Not all safety valves use the same wrench. Make sure the correct size is available.

(3) If using a tapered string of drill pipe, make sure there is a safety valve for each thread size in the drill string, or appropriate cross over subs are available.

(4) If using an inside BOP for a safety valve, check to see if the poppet valve is held down and the thumb screw can be turned by hand.

NOTE: The poppet valve should work up and down freely and the thumb screw holding the valve open should be able to be turned by hand. Time is of the essence when preparing to "kill a kick".

(5) If the safety valves and/or inside BOP valves are not maintained in the open position on the rig floor and the correct wrench is not available, require the operator to correct the situation. If the operator fails to correct, check "violation" and take enforcement action.

21. IS UPPER KELLY COCK INSTALLED? IS LOWER KELLY COCK INSTALLED? ARE APPROPRIATE KELLY COCK WRENCHES AVAILABLE?

a. Requirement. All 2M and higher BOPE systems are required to have an upper kelly cock valve with handle available. All 5M and higher BOPE systems are required to also have a lower kelly cock valve with handle available.

b. Authority:

(1) 43 CFR §3162.5-2(a) Drilling Wells
(2) 43 CFR §3162.5-3 Safety Precautions
(3) 43 CFR §3164.1, Order No. 1, Approval of Operations
(4) 43 CFR §3164.1, Order No. 2, Drilling Operations

c. Procedure.

(1) Verify the use of the upper kelly cock valve and, if required, the lower kelly cock valve.

(2) Kelly cock valves shall be pressure tested to required BOPE pressure test requirements. This test shall be performed from the working pressure side.

(3) Check to see that the wrench or wrenches are close to the working area - usually on a tool board.

NOTE: The upper kelly cock and lower kelly cock usually take different size wrenches.

(4) If the required equipment is not installed, enter check under "violation" and take enforcement action.

CASING AND CEMENTING

The major purposes of the casing and cementing program are to: prevent caving of the hole, prevent migration of fluids from one zone to another, confine production to the well bore, permit installation of artificial lift or production equipment, and provide a means of controlling well pressure. Inspection ensures that the casing was run and cemented in accordance with the approved plan.

22. WAS CASING RUN IN ACCORDANCE WITH APPROVED APD (SIZE, WEIGHT, GRADE, DEPTH, NEW/USED)? CENTRALIZERS AS REQUIRED?

a. Requirement. The operator shall conduct operations in a manner which protects and isolates usable quality water and prospectively valuable mineral zones. Surface casing shall have centralizers on the bottom 3 joints of the casing. A minimum of 1

centralizers per joint, starting with the shoe joint.

b. Authority:

(1) 43 CFR §3162.5-1 Environmental Obligations
(2) 43 CFR §3162.5-2(a) Drilling Wells
(3) 43 CFR §3162.5-3 Safety Precautions
(4) 43 CFR §3164.1, Order No. 1, Approval of Operations
(5) 43 CFR §3164.1, Order No. 2, Drilling Operations
(6) 43 CFR §3164.1, Order No. 6, Hydrogen Sulfide Operations

c. Procedure.

(1) The inspector should check the approved APD and see what was specified as to size, weight, grade, and casing depth and required centralizers.

(2) Determine if the casing run was in accordance with the approved APD.

NOTE: If the inspector is present before the casing is run; the size, weight, grade, and tread type can be verified by looking at the joints of casing on the rack. General pipe condition can also be determined at this time. Used pipe shall have a minimum of 87½% of nominal wall thickness and can be verified by reviewing the pipe inspection company's report. If the casing has been run, the inspector may get this information off the driller's log book or by asking the company man or toolpusher to see their tally sheet. Occasionally, there will be one or more joints of casing left on the pipe racks and the inspector can get the size, weight, and grade from these joints. Casing strings may be designed to incorporate different grades and weights of casing, which in most cases will be either the long string or intermediate casing, but the leftover casing joints are a good indication of what was used. Upgraded casing strings may not necessarily constitute a violation, however the authorized officer shall be notified, and the operator required to obtain approval through a sundry notice.

Surface casing shall have centralizers on the bottom three joints of the casing. A minimum of one centralizer per joint, starting with the shoe joint. Additional centralizers may be required by the APD to adequately centralize casing across critical zones.

All deviations in casing setting depth shall be discussed with the authorized officer. Any casing setting depth change shall be reported on a sundry notice. The authorized officer will determine appropriate remedial actions and enforcement action required.

(3) If casing was not run in accordance with the approved APD, check "violation" and take enforcement.

23. WHEN SETTING SURFACE CASING, DID CEMENT CIRCULATE TO SURFACE? IF NOT, WAS REMEDIAL ACTION TAKEN?

a. Requirement. The operator shall conduct operations in a manner which protects and isolates usable quality water and prospectively valuable mineral zones.

b. Authority:

(1) 43 CFR §3162.5-1 Environmental Obligations
(2) 43 CFR §3162.5-2(a) Drilling Wells
(3) 43 CFR §3162.5-3 Safety Precautions
(4) 43 CFR §3164.1, Order No. 1, Approval of Operations
(5) 43 CFR §3164.1, Order No. 2, Drilling Operations

c. Procedure.

(1) If the inspector was not present while cementing the surface casing, determine if the cement was circulated to surface. The driller's log book should contain information relative to the cement job. An indication of proper cementing results can be obtained by asking the toolpusher or company man if returns were adequate throughout the cement job or if the cement fell back after pumping stopped.

NOTE: If the cement settled back, it is a acceptable practice to run 1" pipe down the annulus to the top of the cement and then pump cement until it surfaces. The hole will usually stay full at this time. It is a good idea when utilizing 1" pipe, to have the driller cut teeth on the bottom of 1" pipe. When the pipe stops, the crew can turn the pipe to the right. Pull the pipe to see if there is a cement core, assuring that the pipe has not just stopped on a collar or a bridge. Pea gravel around the casing at surface is not an acceptable isolation medium and merely creates a sump in which oil, chemicals and water could collect.

In a critical area where other resources are a concern, it may be necessary to determine the top of the cement by using a temperature survey and/or a Cement Bond Log (CBL) or Cement Evaluation Tool (CET). If an adequate fill up was not achieved, the operator is required to take corrective measures prescribed by the authorized officer, such as perforating the casing and squeezing cement through the perforations until it surfaces. A lack of cement or having contaminated cement around the shoe joint could lead to knocking off the casing shoe joint during drilling operations. This severe problem can be prevented by utilizing centralization and proper circulation techniques. In any situation when inadequate cementing has occurred, drilling shall not be allowed to proceed without proper remedial procedures.

If the cement placement is not adequate i.e., poor quality bonding or cement level not sufficient, or the design of the job is improper, there is a chance for damage to occur to the top joints of the surface casing string. This damage can be minimized by ensuring the BOP is properly centered with the rotary table and securely anchored with turnbuckles.

(3) Check to see if cement falls back in annulus.

(4) If the necessary remedial job is not taken or not adequate, check "violation" and take enforcement action.

24. WHEN SETTING (SUBSEQUENT) CASING WAS CEMENT JOB CONDUCTED AS APPROVED? IF NOT, WAS REMEDIAL ACTION TAKEN?

a. Requirement. The operator shall conduct operations in a manner which protects and isolates usable quality water and prospectively valuable mineral zones.

b. Authority:

(1) 43 CFR §3162.5-1 Environmental Obligations
(2) 43 CFR §3162.5-2(a) Drilling Wells
(3) 43 CFR §3162.5-3 Safety Precautions
(4) 43 CFR §3164.1, Order No. 1, Approval of Operations
(5) 43 CFR §3164.1, Order No. 2, Drilling Operations

c. Procedure.

(1) Determine if the cement job is conducted as approved for the intermediate, production strings and liners.

(2) Were stage collars used if approved and desired results achieved?

(3) While pumping cement, were returns lost?

NOTE: When circulation is lost during displacement or cement does not circulate, it may be necessary to run a cement bond log (CBL) cement evaluation tool (CET) or temperature survey after drilling down to the shoe. If the log reveals that cement level is too low, it will be necessary to perforate the casing and squeeze cement until the correct level is obtained.

If the inspector visits the drilling rig after a cement job has been performed, he should verify that the desired results were obtained; if not, what remedial action was taken.

Sources of information include cement companies job log and drillers log book. If CBL, CET or a temperature survey was run, the inspector should ask to see a copy of the log. The operator is required to furnish the BLM copies of all logs and surveys run.

Inadequate cement behind the production string would probably not be found until the production rig had moved in and would be remedied at that time.

(4) To ensure proper placement of cement slurry, the inspector must determine if the techniques used were adequate.

NOTE: To achieve a proper cement job, the cement should be pumped at either turbulent or plug flowrates. The use of scratchers and casing reciprocation or rotation is optional as hole conditions dictate.

25. WERE ALL CASING STRINGS PRESSURE TESTED PRIOR TO DRILL OUT?

- WAS REMEDIAL ACTION TAKEN IF TEST INDICATED NEED?
- WERE ALL PRESSURE TESTS RECORDED IN DRILLER'S LOG?

a. Requirement. The operator shall conduct operations in a manner which protects and isolates usable quality water and prospectively valuable mineral zones. All casing strings below the conductor shall be pressure tested to 0.22 psi per foot of casing length or 1500 psi, whichever is greater, but not to exceed 70 percent of the minimum internal yield. If pressure declines more than 10 percent in 30 minutes, corrective action shall be taken.

b. Authority:

(1) 43 CFR §3162.5-1 Environmental Obligations
(2) 43 CFR §3162.5-2(a) Drilling Wells
(3) 43 CFR §3162.5-3 Safety Precautions
(4) 43 CFR §3164.1, Order No. 1, Approval of Operations
(5) 43 CFR §3164.1, Order No. 2, Drilling Operations

c. Procedure.

(1) Review the approved APD to identify the casing string pressure test required. If specific casing string pressure test requirements are not addressed in the APD,

then Order No. 2 minimum standards shall prevail. See Illustration 5 for an example calculation.

NOTE: Proper procedure for casing test should be as follows: Float collar or baffle plate is usually placed in casing string from 30' to 80' above the casing shoe. The operator will be required to drill the top and bottom rubber wiper plugs, the float collar or baffle plate, and the cement to within 5' to 10' above the casing shoe. At this time, the casing pressure test can be performed. Casing shall be tested to 0.22 psi per foot of casing length or 1500 psi, whichever is greater, but not to exceed 70% of the internal yield of casing, including the hydrostatic pressure of fluid column inside the casing. After initial pressure is achieved, a slow bleed-off may be partly due to trapped compressed air and/or from pumping cold water into casing which is warm due to the curing cement behind the pipe. In this event, it would be appropriate to bump the pressure up again providing the 30 minute time frame starts again. If pressure declines more than 10% in 30 minutes or if there are other indications of a leak, corrective measures will be taken.

(2) Witness the casing pressure test.

(3) All casing strings shall be pressure tested before drilling out.

(4) If the operator has hired an independent contractor to perform the testing and a chart recorder is used, the inspector should request a copy of the chart.

(5) Was remedial action taken if test indicated need?

(6) Were all pressure tests recorded in driller's log book?

(7) If not tested as directed, check "violation" and take appropriate enforcement action.

26. WERE ALL WAITING ON CEMENT (WOC) TIMES ADEQUATE TO ACHIEVE A MINIMUM OF 500 PSI COMPRESSIVE STRENGTH?

a. Requirement. All waiting on cement times shall be adequate to achieve a minimum of 500 psi compressive strength at the casing shoe prior to drilling out.

b. Authority:

(1) 43 CFR §3162.5-1 Environmental Obligations
(2) 43 CFR §3162.5-2(a) Drilling Wells
(3) 43 CFR §3162.5-3 Safety Precautions
(4) 43 CFR §3164.1, Order No. 1, Approval of Operations
(5) 43 CFR §3164.1, Order No. 2, Drilling Operations

c. Procedure.

(1) Verify if WOC times are adequate as required by Order No. 2.

(2) Check for the type of cement used and the WOC time for that type.

NOTE: Setting time and compressive strength of various cement types can be verified using service company handbooks. Due to the time taken to cut off casing, weld on head, nipple up BOP, and install associated equipment, the WOC time is usually not a problem. For example, class "G" cement with 2% CaC1, at 80NF will reach a compressive strength of 1,035 psi in eight hours. The time used to test the blow out prevention equipment may be at least twelve hours, therefore WOC times are usually adequate.

(3) Look at the sample (usually 3) which were taken from the mixing tub at the time of cementing casing and check for hardness.

(4) Check the cement in place (CIP) time against the time of BOP test.

(5) If the WOC times are not adequate, check "violation"

and take enforcement action.

27. ARE CASING SHOE PRESSURE INTEGRITY TESTS (MUD WEIGHT EQUIVALENCY TEST) PERFORMED AND RECORDED IN LOG BOOK?

a. Requirement: On all exploratory wells, and on that portion of any well approved for a 5M BOPE system or greater, a pressure integrity test of each casing shoe shall be performed. Formation at the shoe shall be tested to a minimum of the mud weight equivalent anticipated to control the formation pressure to the next casing depth or at total depth of the well. This test shall be performed before drilling more than 20 feet of new hole.

b. Authority:

(1) 43 CFR §3162.5-1 Environmental Obligations
(2) 43 CFR §3162.5-2(a) Drilling Wells
(3) 43 CFR §3162.5-3 Safety Precautions
(4) 43 CFR §3164.1, Order No. 1, Approval of Operations
(5) 43 CFR §3164.1, Order No. 2, Drilling Operations

c. Procedure.

(1) Review the approved APD to identify casing shoe pressure integrity tests required. If specific casing shoe pressure integrity test requirements are not addressed in the APD, then Order No. 2 minimum standards shall prevail. See Illustration 6 for an example calculation.

NOTE: Pressure integrity test of the casing shoe, often called the equivalent mud weight test (EMWT), can be accomplished in several different ways. One method is to drill the casing shoe and up to ten feet of new hole in the formation below the shoe. Normally, after the cuttings are circulated to the surface, the bit is pulled up into the surface casing or appropriate casing string. If the test can be accomplished under 300 psi, the annular preventer is closed on the kelly. If test pressures exceed 300 psi, the pipe rams are closed on the first joint of drill pipe below the kelly. The kill line valve is then opened and pressure is applied on the hole by the rig pump (this pressure will be observed on the

stand pipe gauge). Test pressure shall be applied for thirty minutes.

If test pressure bleeds-off, bump it back up and hold for another thirty minutes. Should the test not hold, notify the authorized officer for further instructions. The test pressure used is based on calculations that determine the difference between the hydrostatic pressure of the fluid in the hole and the hydrostatic pressure of the anticipated mud weight at the next casing setting depth or the total depth of the well.

28. ALL INDICATIONS OF USABLE WATER REPORTED TO THE AUTHORIZED OFFICER?

a. Requirement. All indications of usable water shall be reported to the authorized officer prior to running the next string of casing or before plugging orders are requested, whichever occurs first.

b. Authority:

(1) 43 CFR §3162.5-1 Environmental Obligations
(2) 43 CFR §3162.5-2(a) Drilling Wells
(3) 43 CFR §3162.5-3 Safety Precautions
(4) 43 CFR §3164.1, Order No. 1, Approval of Operations
(5) 43 CFR §3164.1, Order No. 2, Drilling Operations

c. Procedure.

(1) Review the APD, drilling plan, and conditions of approval to determine if any usable quality water zones are anticipated to be encountered. If these zones are encountered, has the operator reported the encounter to the authorized operator.

(2) Check drillers log and ask tool pusher or company representative to determine if any water flows were encountered. The authorized officer shall determine if water flow samples should be analyzed.

(3) If usable quality water zones are not reported, check violation and require the operator to report on a sundry

notice.

29. ARE WIPER PLUGS USED AS REQUIRED?

a. Requirement. Top plugs shall be used to reduce contamination of cement by displacement fluid. A bottom plug or other acceptable technique, such as a suitable preflush fluid, inner string cement method, etc., shall be utilized to help isolate the cement from contamination by the mud fluid being displaced ahead of the cement slurry.

b. Authority:

(1) 43 CFR §3162.3-1(e) Drilling Applications and Plans
(2) 43 CFR §3162.5-2 Drilling Wells
(3) 43 CFR §3162.5-3 Safety Precautions
(4) 43 CFR §3164.1, Order No. 1, Approval of Operations
(5) 43 CFR §3164.1, Order No. 2, Drilling Operations

c. Procedure.

(1) Witness cementing operation to verify if wiper plugs are utilized. Review of driller's log may also provide this information.

NOTE: Top wiper plugs shall be used to help isolate the cement from contamination by the mud being displaced ahead of the cement slurry and to reduce contamination of cement by displacement fluid. If bottom wiper plugs are not utilized other approved alternative methods such as adequate preflush volumes or inner string cement methods, etc., shall be utilized.

(2) If wiper plugs or other approved methods are not properly used, check violation and contact the authorized officer for remedial action.

MUD PROGRAM

30. IS MUD SYSTEM IN ACCORDANCE WITH THE APPROVED APD?

a. Requirement. The characteristics, use, and testing of

drilling mud and the implementation of related drilling procedures shall be designed to prevent the loss of well control.

b. Authority:

(1) 43 CFR §3162.5-2 Control of Wells
(2) 43 CFR §3162.5-2(a) Drilling Wells
(3) 43 CFR §3162.5-3 Safety Precautions
(4) 43 CFR §3164.1, Order No. 1, Approval of Operations
(5) 43 CFR §3164.1, Order No. 2, Drilling Operations

c. Procedure.

(1) Determine if the mud system is in accordance with approved plan.

NOTE: The APD shall be reviewed to determine what the approved characteristics, use, and testing of the drilling mud and the implementation of related drilling procedures are adequate to prevent the loss of well control.

The APD may have special stipulations that require special equipment.

(2) If there is a deficiency and the operator fails to correct, check "violation" and take enforcement action.

31. ARE APPROPRIATE QUANTITIES OF MUD ON HAND?

a. Requirement. Sufficient quantities of mud materials shall be maintained or readily accessible for the purpose of assuring well control.

b. Authority:

(1) 43 CFR §3162.5-2 Control of Wells
(2) 43 CFR §3162.5-2(a) Drilling Wells
(3) 43 CFR §3162.5-3 Safety Precautions
(4) 43 CFR §3164.1, Order No. 1, Approval of Operations
(5) 43 CFR §3164.1, Order No. 2, Drilling Operations

c. Procedure.

(1) Check to see that sufficient quantities of mud are on hand.

NOTE: When the inspector is checking the rig, he should check to see that sufficient quantities of bentonite, weight mud, etc. are on hand to mix enough mud to fill the hole and circulate at the depth they are drilling at the time of inspection. This does not mean full pits of mud. In many areas premixed mud is available a short distance from the rig which the operator has the option of utilizing inplace of on hand mud.

(2) If the quantities of mud are inadequate and the operator fails to correct, check "violation" and take enforcement action.

32. MUD MONITORING EQUIPMENT IN ACCORDANCE WITH APPROVED APD?

a. Requirement. Visual mud monitoring equipment shall be in place to detect volume changes indicating loss or gain of circulating fluid volume. When abnormal pressures are anticipated electronic/mechanical mud monitoring equipment shall be required, which shall include as a minimum: pit volume totalizer (PVT); stroke counter; and flow sensor.

b. Authority:

(1) 43 CFR §3162.5-2 Control of Wells
(2) 43 CFR §3162.5-2(a) Drilling Wells
(3) 43 CFR §3162.5-3 Safety Precautions
(4) 43 CFR §3164.1, Order No. 1, Approval of Operations
(5) 43 CFR §3164.1, Order No. 2, Drilling Operations

c. Procedure.

(1) Check the approved APD to see what additional mud monitoring equipment is required.

NOTE: Mud monitoring equipment is designed to detect volume changes indicating loss or gain of circulating fluid volume. Inspection ensures that equipment specified or required in the approval plan has been properly installed and is operative. The pit level indicator in its simplest form is a piece of cord with a weight tied on one end and adjusted so that the weight just touches the level of the mud. A more sophisticated device consists of three different pits, calibrated so that a loss or gain will be recorded on a chart. It is usually set to give an audible alarm if there is a pit loss or gain. There may be a flow-no-flow indicator which records on a chart a loss of circulation, or an increase in returns and may give an audible signal. Pump speed indicators, also called stroke counters, warn if the pump speed has increased.

There may be more equipment than the approved APD required, but there should not be less.

(2) Check mud monitoring equipment console panel located on rig floor or in the doghouse to ensure it is operable and alarm system functional.

(3) If required equipment is not in place and properly functioning as required in the APD, check "violation" and enforcement action.

33. IS GAS DETECTION SYSTEM INSTALLED?

a. Requirement: Gas detecting equipment shall be installed in the mud return system for exploratory wells or wells where abnormal pressure is anticipated, and hydrocarbon gas shall be monitored for pore pressure changes.

b. Authority:

(1) 43 CFR §3162.5-2 Control of Wells
(2) 43 CFR §3162.5-2(a) Drilling Wells
(3) 43 CFR §3162.5-3 Safety Precautions
(4) 43 CFR §3164.1, Order No. 1, Approval of Operations
(5) 43 CFR §3164.1, Order No. 2, Drilling Operations

c. Procedure.

(1) Review the file to determine if the well is an exploratory well and if the APD requires gas detecting equipment.

NOTE: This capability is provided by numerous mud logging companies and are often referred to as a mud "sniffing" unit.

(2) If required gas detecting equipment is not in use and the operator fails to correct, check "violation" and take enforcement action.

34. IS ANNULUS FILLED IF MUD LEVEL DROPS BELOW 100 FEET WHILE TRIPPING?

a. Requirement. The operator shall take all necessary precautions to keep each well under control at all times and shall use and maintain material and equipment necessary to insure the safety of operations conditions and procedures.

b. Authority:

(1) 43 CFR §3162.5-2 Control of Wells
(2) 43 CFR §3162.5-2(a) Drilling Wells
(3) 43 CFR §3162.5-3 Safety Precautions
(4) 43 CFR §3164.1, Order No. 1, Approval of Operations

c. Procedure.

(1) The mud level should not be allowed to fall below 100' in the annulus while tripping drill pipe. Although not a specific requirement of Order No. No. 2, it is

considered a prudent precaution to maintain well control which is a provision of 43 CFR §3162.5-2.

NOTE: If the mud level falls too low, the hydrostatic head may be reduced enough to allow salt water or hydrocarbons, or both, to enter the bore hole and could result in a blowout. For example a 100' drop of 9.5 PPG mud reduces the bottom hole pressure by 49.4 psi (100 X 0.052 X 9.5 = 49.4). In many situations where drilling just slightly overbalanced, this pressure drop is sufficient to allow a kick.

The driller should keep the hole full while tripping out, and should fill the hole at least every ten stands or more often as the level dictates. Mud should not be allowed to fall below 100' in the annulus while tripping drill pipe.

When drill collars are being pulled from the hole, a greater amount of displacement occurs per stand because the size and density creates a greater displacement factor. In some instances one stand of drill collars will create a larger fluid level drop than five stands of drill pipe. See Illustration 7 for an example calculation and a comparison of fluid level drops between drill collars and drill pipe.

If the crew is pulling a wet string, the pump could be left engaged if it is powered by an independent prime mover. Some drilling rigs are equipped with a trip tank to automatically fill the hole as fluid level drops in the well bore. It will also measure the amount of mud required to fill hole. If the volume required to fill the hole is less than that calculated, according to the pipe pulled, it would indicate an influx of fluid into the well bore from the formation, which could lead to a blowout.

(2) Look at the chart recorder to see how often the driller filled the hole. The pit mud level recorder should have gone steadily down as the driller came out of

the hole.

(3) If the level of mud in the annulus drops below 100' and the operator does not correct by replacing mud, check "violation" and take enforcement action.

35. ARE MUD TESTS RECORDED IN DRILLER'S LOG?

a. Requirement. A mud test shall be performed every 24 hours, after mudding up, to determine as applicable: density, viscosity, gel strength, filtration, and pH.

b. Authority:

(1) 43 CFR §3162.5-2 Control of Wells
(2) 43 CFR §3162.5-2(a) Drilling Wells
(3) 43 CFR §3162.5-3 Safety Precautions
(4) 43 CFR §3164.1, Order No. 1, Approval of Operations
(5) 43 CFR §3164.1, Order No. 2, Drilling Operations

c. Procedure.

(1) Review the driller's log and the mud company's report to ensure that these mud tests are being conducted.

(2) If mud tests have not been performed within the last 24 hours and the operator does not conduct them, check "violation" and take enforcement action.

36. IS FLARE SYSTEM INSTALLED?

a. Requirement. All flare systems shall be designed to gather and burn all gas.

b. Authority:

(1) 43 CFR §3162.5-2 Control of Wells
(2) 43 CFR §3162.5-2(a) Drilling Wells
(3) 43 CFR §3162.5-3 Safety Precautions
(4) 43 CFR §3164.1, Order No. 1, Approval of Operations
(5) 43 CFR §3164.1, Order No. 2, Drilling Operations

c. Procedure.

(1) The flare line discharge shall be located not less than 100 feet from the well head, having straight lines unless turns are targeted with running tees.

(2) Flares shall be positioned downwind of the prevailing wind direction and anchored.

(3) The flare system shall have an effective method for ignition. Supplemental fuel shall be provided for ignition and continuous burning of noncombustible gases.

(4) If the flare system is not acceptable and the operator does not correct the situation, check "violation" and take enforcement action.

SPECIAL OPERATIONS - AIR/GAS DRILLING

As required by Order No. 2 Section III. 3., the following equipment, in addition to the equipment already specified elsewhere in Order No. 2, shall be in place and operational during all air/gas drilling operations:

37. IS ROTATING HEAD IN OPERATING CONDITION?

a. Requirement. A properly lubricated and maintained rotating head shall be in place and operational during air/gas drilling.

b. Authority:

(1) 43 CFR §3162.5-2(a) Drilling Wells
(2) 43 CFR §3162.5-3 Safety Precautions
(3) 43 CFR §3164.1, Order No. 1, Approval of Operations
(4) 43 CFR §3164.1, Order No. 2, Drilling Operations

c. Procedure.

(1) If air/gas drilling operations are occurring, a rotating head is required.

NOTE: Rotating head will be used when drilling with gas, air, or foam. It will also be used when circulating through the gas buster. Rotating heads are also a necessary safety precaution when drilling underbalanced.

(2) While inspecting rig, observe operation of the

rotating head.

NOTE: Rubber should be replaced if it is allowing fluids and/or gases to escape through the rubber sealing element.

(3) If required but not installed or if repairs are needed and operator does not make corrections, check "violation" and take enforcement action.

38. IS THE BLOOIE LINE INSTALLED AND THE PILOT LIGHT AND IGNITER INSTALLED AND OPERATING?

a. Requirement. A straight run, securely anchored blooie line shall discharge 100 feet from the well during air/gas drilling.

b. Authority:

(1) 43 CFR §3162.5-2(a) Control of Wells
(2) 43 CFR §3164.1, Order No. 1, Drilling Plan
(3) 43 CFR §3164.1, Order No. 2, Drilling Operations

c. Procedure.

(1) Check to see if the blooie line is securely anchored.

(2) Observe the blooie line while inspecting the rig to make sure there is a pilot light burning at the end of the blooie line.

NOTE: The pilot light shall be installed and burning at the end of the blooie line while air/gas drilling. This is usually accomplished by using butane/propane with an igniter.

(3) If the required blooie line and igniter are not installed and the operator does not correct, check "violation" and take enforcement action.

39. IS DEDUSTER EQUIPMENT INSTALLED?

a. Requirement. Deduster equipment shall be in place and operational during air/gas drilling.

b. Authority:

(1) 43 CFR §3162.5-1, Environmental Obligations

(2) 43 CFR §3162.5-3, Safety Precautions
(3) 43 CFR §3164.1, Order No. 1, Approval of Operations
(4) 43 CFR §3164.1, Order No. 2, Drilling Operations

c. Procedure.

(1) Deduster equipment is required at the well site during all air/gas drilling operations.

(2) Check if deduster equipment is installed and operational.

NOTE: Deduster equipment should always be used when air/gas drilling unless authorized officer waives requirement. Dedusting can be accomplished by injecting water into blooie line.

(3) If deduster equipment is required but not installed or not operable and operator does not correct, check "violation" and take enforcement action.

40. IS MUD CIRCULATION EQUIPMENT AVAILABLE FOR RAPID USE (INCLUDING RESERVE PITS AND STEEL TANKS)?

a. Requirement. Mud circulation equipment, water, and mud materials (does not have to be premixed) sufficient to maintain the capacity of the hole and circulating tanks or pits shall be in place and operational during air/gas drilling.

b. Authority:

(1) 43 CFR §3162.5(c) Control of Wells
(2) 43 CFR §3164.1, Order No. 1, Approval of Operations
(3) 43 CFR §3164.1, Order No. 2, Drilling Operations

c. Procedure.

(1) Mud circulation equipment is required for all air/gas drilling operations.

(2) Check the operation at the well site.

NOTE: Mud circulation equipment should be available for rapid use while air/gas drilling. There

should also be enough water and mud available to kill the well if necessary. The mud does not have to be premixed. In many areas premixed mud is available from a mud plant a short distance from the rig which the operator has the option of utilizing inplace of on hand mud.

There may be occasions where the operator can get permission to dig earthen pits, and if necessary, line the pits. If this permission has been granted, it should be in the approved APD.

(3) If the required mud circulation equipment is not available for rapid use and the operator does not correct, check "violation" and take enforcement action.

41. ARE ENGINES EQUIPPED WITH SPARK ARRESTERS OR WATER COOLED EXHAUST?

a. Requirement. Spark arresters on engines or water cooled exhaust shall be in place and operational during air/gas drilling.

b. Authority:
(1) 43 CFR §3162.5-1, Environmental Obligations
(2) 43 CFR §3162.5-3, Safety Precautions
(3) 43 CFR §3164.1, Order No. 1, Approval of Operations
(4) 43 CFR §3164.1, Order No. 2, Drilling Operations

c. Procedure.

(1) Spark arresters or water cooled exhaust shall be utilized on all air/gas drilling operations.

NOTE: Engine manufactures should be consulted when any modifications to the exhaust system are concerned. The objective of this minimum standard is to ensure that any particles being emitted from the exhaust are cooled down to a temperature beneath the ignition temperatures of any flammable gases which may occur during air/gas drilling.

(2) If the required spark arresters or water cooled exhaust equipment is not being utilized and the operator does not correct, check "violation" and take enforcement action.

HYDROGEN SULFIDE OPERATIONS

GENERAL

The inspection of hydrogen sulfide (H_2S) operations should be guided by the approved Application for Permit to Drill (APD). The requirements of Order No. 6 should have been built into the approved APD. Inspectors should review the Drilling Operations Plan (DOP) and the Public Protection Plan (PPP), if required, prior to an inspection. They need to be familiar with the approved site layout and specific requirements as they relate to the H_2S requirements. If the DOP and PPP were not previously reviewed then it would be a good idea is to take a copy of the DOP and PPP and ask the safety company person or drilling supervisor to go through the operations with the inspector. A good inspection approach to follow is shown on the Inspection Record-Drilling, Form 3160-10.

The inspector should report to the designated safety man upon arrival at the location. While we are not required to do so, it is good policy and will help with a cooperative atmosphere for the inspection. BLM inspectors must arrive on location with BLM supplied H_2S safety equipment and have been trained in H_2S safety in accordance with current BLM policy. Typically, each inspector needs to be equipped with a freshly calibrated monitor and an escape pack. We are responsible for our employees, not the drilling or safety company.

Inspections are to be conducted against the approved H_2S DOP and PPP, as required. If the inspector finds operations that are contrary to the requirements of Order No. 6, but approved in the APD, the inspector should only issue an INC to the company after consultation with the appropriate BLM personnel.

The gravity of violations, corrective actions and normal abatement periods listed in Order No. 6 are representative of those incidents most normally found. It is recognized that these will not fit all situations and should be modified within reason when applicable. When the question of major or minor violations exists, the overriding criteria should be the definitions as found in 43 CFR §3160.0-5.

[RESERVED SECTION]

[NOTE: When the BLM national H_2S personnel safety policy is developed, it should be summarized here.]

Items 42-56 shall be completed if required by the minimum standards of Order No. 6, and the approved APD.

42. ARE THE H_2S DRILLING OPERATIONS PLAN AND PUBLIC PROTECTION PLAN, IF REQUIRED, AVAILABLE AT THE WELLSITE?

a. Requirement: The operator shall take all precautions necessary to provide adequate protection for health, safety, and protection of property.

b. Authority:

(1) 43 CFR §3162.5-1 Environmental Obligations
(2) 43 CFR §3162.5-3 Safety Precautions
(3) 43 CFR §3164.1, Order No. 1, Approval of Operations
(4) 43 CFR §3164.1, Order No. 2, Drilling Operations
(5) 43 CFR §3164.1, Order No. 6, Hydrogen Sulfide Operations

c. Procedure.

(1) A copy of the DOP and PPP, if applicable, shall be at the well site beginning when the operation is subject to the terms of Order No. 6. Also check APD for requirements.

(2) Check PPP to identify when the plan will be in effect.

NOTE: The validity of data in the PPP needs to be confirmed during an inspection. For example, the inspector should ask to see a copy of the plan to ensure compliance with the requirement to have one available at the drilling site. Check a few phone numbers to be sure they are correct. On the way out, spot check whether the diagram includes buildings that may be occupied or roads that are maintained for direct public access. The purpose of checking is to ensure that the approved PPP, if required, accurately reflects the on-the-ground conditions.

If the information provided in the APD indicated that a PPP was not required, the inspector needs to spot check the field within the 100 ppm radius of exposure (ROE).

Illustration 8 contains Nomographs based upon the Pasquill-Gifford equation which can be utilized to determine the 100 ppm or the 500 ppm ROE.

The inspector should discuss several aspects of the plan with the safety company or drilling supervisor. The operator is to ensure that the public at greatest risk are notified first. The plan addresses "when and how" people are to be notified in case of an emergency. Also, the operator is required to have advance briefings to inform the residents and people responsible for the safety of occupants of buildings within the 100 ppm ROE. The briefings are to include discussions about the manner of informing people of an emergency and the means of for evacuation from the area. The inspector should discuss all these aspects of the PPP. The discussions will help confirm the validity of an approved PPP.

(3) Check to make sure that the H_2S safety instructions, DOP and PPP are posted at the well site, usually in the dog house.

(4) If there are no H_2S safety instructions, DOP and/or PPP posted, check "violation" and take enforcement action.

WARNING: When inspecting in areas with known H_2S presence, always carry an esacpe pack and know the operator's policies and procedures and follow them while inspecting.

43. ARE THE LOCATIONS OF SAFE BRIEFING AREAS AS APPROVED, ARE THEY DESIGNATED, AND IS SAFE ACCESS PROVIDED TO THEM?

a. Requirement: The operator shall take all precautions

necessary to provide adequate protection for health, safety, and protection of property.

b. Authority:

(1) 43 CFR §3162.5-1 Environmental Obligations
(2) 43 CFR §3162.5-3 Safety Precautions
(3) 43 CFR §3164.1, Order No. 1, Approval of Operations
(4) 43 CFR §3164.1, Order No. 2, Drilling Operations

(5) 43 CFR §3164.1, Order No. 6, Hydrogen Sulfide Operations

c. Procedure.

(1) If precautions are required, check the conditions at the well site to see if the number of locations and access to safe briefing areas are adequate.

NOTE: Determine whether the briefing areas, a minimum of two are required, are properly located, minimum of 150 feet from the well bore, and identified. Check whether the primary briefing area is designated and whether that area is typically upwind of the rig. Check whether the briefing areas have at least one wind direction indicator visible from each briefing area.

(2) If requirements are not met, check "violation" and take enforcement action.

WARNING: When inspecting in areas with known H_2S presence, always carry an escape pack and know the operator's policies and procedures and follow them while inspecting.

44. IS A SECONDARY MEANS OF EGRESS AVAILABLE AND PASSABLE?

a. Requirement: The operator shall take all precautions necessary to provide adequate protection for health, safety, and protection of property.

b. Authority:

(1) 43 CFR §3162.5-1 Environmental Obligations
(2) 43 CFR §3162.5-3 Safety Precautions

(3) 43 CFR §3164.1, Order No. 1, Approval of Operations
(4) 43 CFR §3164.1, Order No. 2, Drilling Operations
(5) 43 CFR §3164.1, Order No. 6, Hydrogen Sulfide Operations

c. Procedure.

(1) Verify that means of egress are acceptable.

NOTE: Check the access road approach on to the well pad relative to the well site diagram. Check the location and marking of the secondary means of egress. If a footpath is the secondary means of egress, check whether it is clearly marked and passable. Flagging is considered minimally necessary for clearly marking the path. To judge whether the path is considered passable, consider whether the route has been cleared enough for people to move freely. Also consider whether a path is so steep that ordinary people will not be able to escape.

(2) If requirements are not met, check "violation" and take enforcement action.

WARNING: When inspecting in areas with known H_2S presence, always carry an escape pack and know the operator's policies and procedures and follow them while inspecting.

45. IS REQUIRED SAFETY EQUIPMENT FOR ESSENTIAL PERSONNEL AVAILABLE AND OPERABLE?

- PORTABLE H_2S AND SO_2 detectors?
- SELF-CONTAINED BREATHING APPARATUS?
- EXPLOSION PROOF VENTILATION FANS?
- OTHER EQUIPMENT AS APPROVED IN THE DRILLING OPERATIONS PLAN?

a. Requirement: The operator shall take all precautions necessary to provide adequate protection for health, safety, and protection of property.

b. Authority:

(1) 43 CFR §3162.5-1 Environmental Obligations
(2) 43 CFR §3162.5-3 Safety Precautions
(3) 43 CFR §3164.1, Order No. 1, Approval of Operations
(4) 43 CFR §3164.1, Order No. 2, Drilling Operations

(5) 43 CFR §3164.1, Order No. 6, Hydrogen Sulfide Operations

c. Procedure.

(1) If the approved APD specifies personnel safety equipment for H_2S, check to see if all required equipment is provided.

NOTE: The number of 30-minute air packs, five minute packs, portable H_2S sensors, resuscitation and first aid kits should be specified in the approved DOP and PPP. This equipment shall be provided at the well site.

Determine if respirators are of an approved type (ANSI Standard Z88.2-1980 should be studied ahead of time) and are located where they are readily accessible. The inspector needs to determine whether there is at least one unit for each essential person on the rig. It's a good idea to discuss the protective breathing systems with the safety person. The inspector should determine which rig personnel (by position) are designated "essential" (a company decision) and minimally necessary to maintain control of the well.

Many respiratory protection systems are used in different configurations. If they have a cascade system, the face masks would usually be in protective boxes around the rig floor. If they use 30-minute self-contained breathing apparatuses, they are usually in protective cases and may be found at the safe briefing areas, the rig floor and various locations throughout the wellsite. Escape packs for the rig personnel are commonly located in the dog house, rig floor, mud trailers and mud pump rooms. If the inspector has the opportunity to witness a drill, it will be easy to decide whether the system they are using has equipment "accessible". If it appears that rig hands, including the derrick hand, have difficulty locating their equipment, discuss with the safety person the "accessibility" question. All respiratory equipment should be checked to ensure that it is clean and in good working order.

(2) Check to see if required communication systems are available.

NOTE: There are two requirements for communication systems when operating under Order No. 6 requirements. First, there is a requirement to have a means of communication for those essential personnel for times when they are working under mask. Typically, they will have chalkboards, pads and pencils, a system of hand signals, or built-in microphones or voice boxes in the masks. If they use something unusual, the inspector might ask for an explanation or demonstration to show that the communication method is effective.

Second, there shall be some effective means of communicating outside the operation from a safe area. Check to see what kind of system they have available and where it can be located. If an unusual system is being used, again, an explanation or demonstration may be requested to show effectiveness.

(3) Check the approved APD (DOP) to see if the H_2S safety measures require explosion proof ventilation fans.

NOTE: Explosion proof ventilation fans should be available to place under the rig floor and sweep across the cellar. H_2S will settle in the low places and positioning the fans in such a manner will help keep the cellar clear of H_2S. Precautions shall be taken even where fans are provided. Fans may be required in any enclosed area where H_2S could create a hazard.

(4) If any of the required equipment is not provided, check "violation" and take enforcement action.

WARNING: When inspecting in areas with known H_2S presence, always carry an escape pack and know the operator's policies and procedures and follow them while inspecting.

46. ARE INITIAL AND WEEKLY H_2S AND WELL CONTROL DRILLS HELD AND RECORDED ON THE DRILLER'S LOG?

a. Requirement: The operator shall take all precautions necessary to provide adequate protection for health, safety, and protection of property.

b. Authority:

(1) 43 CFR §3162.5-1 Environmental Obligations
(2) 43 CFR §3162.5-3 Safety Precautions
(3) 43 CFR §3164.1, Order No. 1, Approval of Operations
(4) 43 CFR §3164.1, Order No. 2, Drilling Operations
(5) 43 CFR §3164.1, Order No. 6, Hydrogen Sulfide Operations

c. Procedure.

(1) Check driller's log book to see if weekly drills were held.

NOTE: The inspector should check the drillers log, tour sheet, or its equivalent for notation of routine H_2S drills. If a drill has not been conducted in the past week, weekly drills are required, the inspector should ask that a drill be conducted in his/her presence. If the weekly H_2S safety drill has not been conducted, an INC should be written.

The inspector should ask the safety company or the drilling supervisor for a list of names of the essential personnel showing the dates of their H_2S training. Training shall conform to the requirements specified in API RP 49, Recommended Practices for Safe Drilling of Wells Containing Hydrogen Sulfide, Section 2. The list should include the essential personnel in each tour. If no such list exists, the inspector could ask one or two of the drilling crew about their most recent H_2S certification. The requirement is that initial H_2S training be completed when drilling reaches a depth of 500 feet above, or three days prior to penetrating

(whichever comes first) the first zone containing or reasonably expected to contain H_2S.

If training has not been conducted, the inspector should issue an INC. Consideration of whether the operation is unsafe and shutting-in the well is warranted will require good field judgement.

NOTE: Weekly H_2S drills may be conducted in conjunction with BOP drills.

(2) If the weekly H_2S drills were not conducted, check "violation" and take enforcement action.

WARNING: When inspecting in areas with known H_2S presence, always carry an escape pack and know the operator's policies and procedures and follow them while inspecting.

47. IS PERMANENT H_2S DETECTION AND MONITORING EQUIPMENT INSTALLED, TESTED AND OPERABLE?

- ARE LOCATIONS OF SENSING POINTS AS APPROVED?
- ARE H_2S DETECTOR/MONITOR TESTS RECORDED ON DRILLER'S LOG?

a. Requirement: The operator shall take all precautions necessary to provide adequate protection for health, safety, and protection of property.

b. Authority:

(1) 43 CFR §3162.5-1 Environmental Obligations
(2) 43 CFR §3162.5-3 Safety Precautions
(3) 43 CFR §3164.1, Order No. 1, Approval of Operations
(4) 43 CFR §3164.1, Order No. 2, Drilling Operations
(5) 43 CFR §3164.1, Order No. 6, Hydrogen Sulfide Operations

c. Procedure.

(1) Check the approved H_2S safety instructions and PPP to see if H_2S detection and monitoring equipment are required.

NOTE: The inspector should check the monitors with the designated safety person or rig supervisor (toolpusher). These people are familiar with sensor locations and calibration/maintenance procedures. There shall be a minimum of three sensors. The three sensors shall be located at the shale shaker, the bell nipple, and the rig floor. The alarm should be set to activate the visible warning system (flashing light for example) at 10 parts per million (ppm) H_2S in air. The audible alarm should activate at 15 ppm H_2S in air. They shall be calibrated and maintained in accordance with the manufacturers specifications. The person responsible for the alarm set and calibration methods used should be consulted since this equipment is not easy to test. If the inspector has the opportunity to witness an H_2S drill, have the safety person use H_2S to activate the alarms. If the alarms do not activate, ask for a demonstration of the calibration and alarm set procedure.

(2) If required detection and monitoring equipment is not installed, check "violation" and take enforcement action.

WARNING: When inspecting in areas with known H_2S presence, always carry an escape pack and know the operator's policies and procedures and follow them while inspecting.

48. IS WIND DIRECTION EQUIPMENT INSTALLED AND VISIBLE?

a. Requirement. The operator shall take all precautions necessary to provide adequate protection for health, safety, and protection of property.

b. Authority:

(1) 43 CFR §3162.5-1 Environmental Obligations
(2) 43 CFR §3162.5-3 Safety Precautions
(3) 43 CFR §3164.1, Order No. 1, Approval of Operations

(4) 43 CFR §3164.1, Order No. 2, Drilling Operations
(5) 43 CFR §3164.1, Order No. 6, Hydrogen Sulfide Operations

c. Procedure.

(1) Check approved APD to see what wind direction equipment is required.

(2) Check drill site for location of wind socks or streamers.

NOTE: Wind direction indicators are to be installed once the drilling reaches a depth of 500 feet above, or three days prior to penetrating (whichever comes first) the first zone containing or reasonably expected to contain H_2S. Any device that indicates wind direction such as wind socks, streamers, vanes, smoke, and pennants are acceptable. A minimum of two indicators are normally required. They should be at different elevations such as ground level and tree top height. One shall be visible from each principle working area. To check this, go to rig floor, mud mixing area, shale shaker area, pump house, safe briefing areas, and onsite trailers.

(3) If required wind direction equipment is not installed, check "violation" and take enforcement action.

WARNING: When inspecting in areas with known H_2S presence, always carry an escape pack and know the operator's policies and procedures and follow them while inspecting.

49. ARE CAUTION/DANGER SIGNS LEGIBLE, VISIBLE AND POSTED A SAFE DISTANCE FROM THE LOCATION?

a. Requirement. The operator shall take all precautions necessary to provide adequate protection for health, safety, and protection of property.

b. Authority:

(1) 43 CFR §3162.5-1 Environmental Obligations
(2) 43 CFR §3162.5-3 Safety Precautions

(3) 43 CFR §3164.1, Order No. 1, Approval of Operations
(4) 43 CFR §3164.1, Order No. 2, Drilling Operations
(5) 43 CFR §3164.1, Order No. 6, Hydrogen Sulfide Operations

c. Procedure.

(1) Check to see if Caution/Danger signs are required.

NOTE: The approved safety instructions and public protection plan describe the danger signs in detail (size, lettering, color and context).

Warning signs/flags shall be displayed when the drilling reaches a depth of 500 feet above, or three days prior to penetrating (whichever comes first) the first zone containing or reasonably expected to contain H_2S. When arriving at the drilling location, the inspector should note whether the signs are posted. If so, check to see whether the sign is approximately 200 to 500 feet from the edge of the location. Then, check all other "controlled" accesses for properly located warning signs/flags. The signs shall be legible and big enough so that they can be easily read as the inspector approaches the well site. No minimum or maximum size is mandated. The language is mandated in Order No. 6. Unless specifically approved otherwise, the language shall read:

DANGER - POISON GAS
HYDROGEN SULFIDE

and in smaller lettering:

Do Not Approach If Red Flag is Flying

If the signs do not have this exact language (but it seems to mean the same) and the language has not been specifically approved, do not immediately issue an INC. Contact the approving official and ask whether they would grant a verbal approval for the language actually on the signs.

There needs to be enough room for a vehicle (full size pickup truck or smaller) to turn around

before reaching the edge of the well pad. It is not necessary to have special turn around areas unless required in the approved APD.

Order No. 6 states that warning signs will be at all "controlled" accesses. This means all roads that lead to the well site. A good way to understand the intent is to consider that "uncontrolled" access would include any other means of approaching the location like on horseback, on foot across country, or the like.

OSHA standard colors for operational danger signs are red, white, and black. Caution signs are yellow and black. Either are acceptable for BLM minimum standards.

The signs shall be visible under all normal lighting conditions. To inspect against this requirement, check to see whether the signs are placed such that the vehicle headlights would illuminate the signs at night. If so, consider the requirement met.

(2) When approaching the drill site, check the warning signs posted along the access to the drill site and see if they shall meet the required standards as specified.

(3) If requirements are not met, check "violation" and take enforcement action.

WARNING: When inspecting in areas with known H_2S presence, always carry an escape pack and know the operator's policies and procedures and follow them while inspecting.

50. ARE WARNING FLAGS, FLARE GUN AND FLARES AVAILABLE?

a. Requirement. The operator shall take all precautions necessary to provide adequate protection for health, safety, and protection of property.

b. Authority:

(1) 43 CFR §3162.5-1 Environmental Obligations
(2) 43 CFR §3162.5-3 Safety Precautions

(3) 43 CFR §3164.1, Order No. 1, Approval of Operations
(4) 43 CFR §3164.1, Order No. 2, Drilling Operations
(5) 43 CFR §3164.1, Order No. 6, Hydrogen Sulfide Operations

c. Procedure.

(1) Check to see if Caution/Danger flags are required.

NOTE: The individual authorized to ignite the well, if there is a blowout, shall be identified in the PPP (a flare gun is needed to ignite the well).

If H_2S has been detected at any of the sensors in concentrations of 10 ppm or greater, a red flag shall be flying at the signs at the controlled accesses. Refer to the BLM's H_2S policy when approaching a wellsite displaying a red flag.

(2) The inspector needs to ask the safety person or drilling company supervisor about the person (position) responsible for deciding when to ignite an uncontrolled well.

NOTE: The inspector should ask what means would be used to ignite the well and decide whether it is a suitable means. Normally a flare gun, with at least two usable flares, or similar device is used. The reason for such a device is to be able to ensure ignition from a safe distance. If the device to be used is unusual, ask for information about how it is used. The inspector needs to judge the safety and effectiveness of the ignition technique.

If the produced gas contains high percentages of nitrogen, carbon dioxide, or other inert gases, the gas stream will not ignite. The DOP should address this situation.

(4) If requirements are not met, check "violation" and take enforcement action.

WARNING: When inspecting in areas with known H_2S presence, always carry an escape pack and know the operator's policies and procedures and follow them while inspecting.

51. IS EQUIPMENT H_2S TRIMMED AS REQUIRED?

a. Requirement. The operator shall take all precautions necessary to provide adequate protection for health, safety, and protection of property.

b. Authority:

(1) 43 CFR §3162.5-1 Environmental Obligations
(2) 43 CFR §3162.5-3 Safety Precautions
(3) 43 CFR §3164.1, Order No. 1, Approval of Operations
(4) 43 CFR §3164.1, Order No. 2, Drilling Operations
(5) 43 CFR §3164.1, Order No. 6, Hydrogen Sulfide Operations

c. Procedure.

(1) Order No. 6 requires that all equipment that has the potential for exposure to H_2S shall be suitable for H_2S service.

NOTE: The requirement is that the metallurgical properties of materials shall conform to NACE Standard MR0175-90, Material Requirement - Sulfide Stress Cracking Resistant Metallic Materials for Oilfield Equipment. Also, elastomers, packing, and similar parts that may be exposed to H_2S are to be resistant to the maximum anticipated temperatures of exposure. These are a very difficult requirements to inspect against if the approval is unclear. To inspect equipment, the inspector must first be familiar with the NACE Standard MR0175-90, the specific APD approval, and equipment manufacturer's ratings of many types of equipment. Discussing the requirements with the drilling supervisor is a good start. The inspector will, however, need to confirm that the equipment is the suitable grade and type for exposure to H_2S. Manufacturer supply catalogs and tubular books will be needed to compare

equipment models and steel grade markings. Illustration 9 is a cross reference for steel hardness scales. Illustration 10 is a partial list of H_2S service BOPE designations.

If the inspection reveals that only some of the required equipment is H_2S trimmed, the inspector needs to contact the authorized officer. Some types of equipment can be operated in an H_2S environment without specifically being "H_2S trimmed". Many aspects are considered when selecting equipment for an H_2S environment. APD review and analysis should have considered these aspects and approval granted based on other aspects. Therefore, discussions with the approving official is necessary prior to issuing an INC for equipment that is not H_2S trimmed.

(2) If requirements are not met, check "violation" and take enforcement action.

WARNING: When inspecting in areas with known H_2S presence, always carry an escape pack and know the operator's policies and procedures and follow them while inspecting.

52. IS REMOTE KILL LINE INSTALLED AND TESTED?

a. Requirement. The operator shall take all precautions necessary to provide adequate protection for health, safety, and protection of property.

b. Authority:

(1) 43 CFR §3162.5-1 Environmental Obligations
(2) 43 CFR §3162.5-3 Safety Precautions
(3) 43 CFR §3164.1, Order No. 1, Approval of Operations
(4) 43 CFR §3164.1, Order No. 2, Drilling Operations
(5) 43 CFR §3164.1, Order No. 6, Hydrogen Sulfide Operations

c. Procedure.

(1) Check the approved APD to see if H_2S safety requires a remote kill line.

NOTE: Order No. 6 and the DOP requires a remote kill line. It is common practice to run this line to the end of the catwalk. This will protect the line and result in a length of 60'-65'. They are constructed of 2" pipe and shall meet the pressure demands of the BOP stack.

(2) While at the well site, check to see if a remote kill has been installed and tested as required.

(3) If requirements are not met, check "violation" and take enforcement action.

WARNING: When inspecting in areas with known H_2S presence, always carry an escape pack and know the operator's policies and procedures and follow them while inspecting.

53. IS FLARE SYSTEM DESIGNED TO SAFELY GATHER AND BURN H_2S?

- IS THE FLARE SYSTEM EQUIPPED WITH A SAFE AND SUITABLE MEANS OF IGNITION?
- IS THE FLARELINE MOUTH AT LEAST 150' FROM THE WELLBORE?
- IF NONCOMBUSTIBLE GAS IS TO BE FLARED, IS SUPPLEMENTAL FUEL AVAILABLE?

a. Requirement. The operator shall take all precautions necessary to provide adequate protection for health, safety, and protection of property.

b. Authority:

(1) 43 CFR §3162.5-1 Environmental Obligations
(2) 43 CFR §3162.5-3 Safety Precautions
(3) 43 CFR §3164.1, Order No. 1, Approval of Operations
(4) 43 CFR §3164.1, Order No. 2, Drilling Operations
(5) 43 CFR §3164.1, Order No. 6, Hydrogen Sulfide

Operations

c. Procedure.

(1) Order No. 6 requires a flare system to safely gather and burn H_2S gas.

NOTE: The intent is that any volume/concentration of H_2S-bearing gas, if more than a single, low volume incident (puff), will be gathered and flared. Any low volume, single incident release of H_2S, however, could trigger (if a high enough concentration) implementation of the public protection plan. If H_2S gas is being flared, a sulfur dioxide detector -monitor shall be available to check impact area. Any type is acceptable as long as the concentration can be measured and is in good working order.

(2) Check the flare line to see if a flare pilot light was installed, and the igniter is operable.

NOTE: A flare pilot light with igniter should be installed on a flare line where there is a possibility of stacking H_2S.

(3) If a flare system with igniter is not installed and operable, check "violation" and take enforcement action.

WARNING: When inspecting in areas with known H_2S presence, always carry an escape pack and know the operator's policies and procedures and follow them while inspecting. When H_2S is flared, one of the combustion products is sulfur dioxide (SO_2). SO_2 is a toxic substance and should be avoided. A self-contained breathing apparatus is still necessary even after the H_2S is flared.

54. ARE MUD-GAS SEPARATOR AND ROTATING HEAD INSTALLED AND OPERATIONAL (EXPLORATION WELLS ONLY)? ARE DEGASSERS INSTALLED AND OPERABLE?

a. Requirement. The operator shall take all precautions necessary to provide adequate protection for health, safety, and protection of property.

b. Authority:

(1) 43 CFR §3162.5-1 Environmental Obligations
(2) 43 CFR §3162.5-3 Safety Precautions
(3) 43 CFR §3164.1, Order No. 1, Approval of Operations
(4) 43 CFR §3164.1, Order No. 2, Drilling Operations
(5) 43 CFR §3164.1, Order No. 6, Hydrogen Sulfide Operations

c. Procedure.

(1) Check the approved APD to see if the DOP requires a mud/gas separator.

NOTE: Degassing equipment shall conform to the specifications outlined in API RP 49, Recommended Practices for Safe Drilling of Wells Containing Hydrogen Sulfide, Section 5.14. The inspector must ensure equipment location is optimized and fully functional when drilling reaches a depth of 500 feet above, or three days prior to penetrating (whichever comes first) the first zone containing or reasonably expected to contain H_2S.

NOTE: The "gas buster" should be trimmed for H_2S service. The rotating head and all other associated equipment, if required, should be trimmed for H_2S service.

(2) Check to see if all requirements have been met.

(3) If required mud/gas separator and associated equipment are not installed and operable, check "violation" and take enforcement action.

WARNING: When inspecting in areas with known H_2S presence, always carry an escape pack and know the operator's policies and procedures and follow them while inspecting.

55. IS THE REMOTE CONTROLLED CHOKE INSTALLED, TESTED AND OPERABLE?

a. Requirement. The operator shall take all precautions necessary to provide adequate protection for health, safety, and protection of property.

b. Authority:

(1) 43 CFR §3162.5-1 Environmental Obligations
(2) 43 CFR §3162.5-3 Safety Precautions
(3) 43 CFR §3164.1, Order No. 1, Approval of Operations
(4) 43 CFR §3164.1, Order No. 2, Drilling Operations
(5) 43 CFR §3164.1, Order No. 6, Hydrogen Sulfide Operations

c. Procedure.

(1) Check the approved APD to see if the safety measures require remotely controlled choke valve(s).

NOTE: One of the chokes shall be remote controlled if there is a chance of encountering H_2S. This allows much closer coordination between the pump speed and the choke valve. A remotely controlled choke valve could make the difference between saving and losing the well and personnel. If the APD does not require a remotely controlled choke valve in an H_2S area, report this to the office engineering staff for clarification.

(2) Verify the presence of a remote controlled choke, if required.

(3) Verify that the control is installed and operable.

(4) If the remote control is not installed as required, check "violation" and take enforcement action.

WARNING: When inspecting in areas with known H_2S presence, always carry an escape pack and know the operator's policies and procedures and follow them while inspecting.

56. IS THE pH OF FRESHWATER MUD 10.0 OR ABOVE UNLESS OTHERWISE APPROVED?

- ARE SUFFICIENT QUANTITIES OF MUD ADDITIVES TO SCAVENGE H_2S AVAILABLE AT THE WELLSITE (EXPLORATORY WELLS ONLY)?

a. Requirement. The operator shall take all precautions necessary to provide adequate protection for health, safety, and protection of property.

b. Authority:

(1) 43 CFR §3162.5-1 Environmental Obligations
(2) 43 CFR §3162.5-3 Safety Precautions
(3) 43 CFR §3164.1, Order No. 1, Approval of Operations
(4) 43 CFR §3164.1, Order No. 2, Drilling Operations
(5) 43 CFR §3164.1, Order No. 6, Hydrogen Sulfide Operations

c. Procedure.

(1) The inspector should review the mud check sheets left by the contracted mud company to determine whether the requirements for mud properties are met.

NOTE: Unless otherwise approved, the mud shall be maintained with a pH of 10 or higher in a fresh water-based mud system. This may be done with the addition of caustic soda. Order No. 6 language also says that the pH requirement is not necessary if formation characteristics or mud types justify a lesser pH level. The intent of the requirement is that such systems need prior approval. The inspector needs to discuss the mud program with the approving official if lesser pH mud is in use. If the approving official cannot be contacted immediately, the inspector should let the drilling supervisor know of the concern. Collect available information on the mud program in use and tell the drilling supervisor that an answer on the suitability of the mud program will be forthcoming. The approving official may modify the approval if deemed appropriate.

(2) Check to see if scavengers are on hand if the pH is below 10.

NOTE: For wells where formation pressures are unknown (usually identified in the APD), H_2S scavengers and neutralizers shall be on location and in sufficient quantities to treat the active mud system. The inspector should observe the contents of mud additives in the mud trailer/house to determine if roughly enough scavengers and neutralizers exist. If the inspector cannot determine what is "roughly enough" then the approving official should be contacted.

(3) If requirements are not met and the operator fails to correct, check "violation" and take enforcement action.

WARNING: When inspecting in areas with known H_2S presence, always carry an escape pack and know the operator's policies and procedures and follow them while inspecting.

57. OTHER REQUIREMENTS PER APPROVED APD AND LEASE TERMS.

a.
b.
c.
d.

NOTE: There may be conditions of approval or special stipulations that are not covered by the check list items 1-55. These special requirements should be entered here for inspection purpose.

58. DESCRIPTION OF OPERATIONS WITNESSED?

- Describe all operations witnessed during the inspection.

Form 3160-10
(October 1991)

Illustration 1, Page 1

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

INSPECTION RECORD - DRILLING

Lease No./Unit/CA	State	District	Field Area	
WY-01234	Wyoming	Hard Rock	Lost and Found	☑ Detailed ☐ Non-Detailed

Well No./API No.	Location (1/4, 1/4, S-T-R)	Spud Date	Status
Gold Mine Fed #1	SW-NE 17-29N-112W	3-5-91	Drilling

Operator/Representative	Rig/Contractor/Representative	Date	Inspector	Travel Time	Inspection Time
I.M. Good Inc. C. Mann	Bobble & Bobble Rig #1	3-29-91	Tech Nician	3.5 Hrs.	2 Hrs.

GENERAL	INSPECTED	NA	VIOLATION
1. Is approved drilling permit and plan on location?	✓	✓	
2. Is drill site properly identified?	✓		
3. Are operations being conducted in a workmanlike manner? (Detailed list in handbook)	✓		
4. Did Operator report all spills?	✓		
5. Are drill-stem tests conducted as required?		✓	
6. Is hole deviation within approved tolerances?		✓	
	✓		
SURFACE USE			
7. Is surface use in accordance with approved plan?			
a. Well site lay-out;	✓		
b. Pits, sumps, and other ancillary facilities;	✓		
c. Containment and disposal of solid, liquid, and gaseous wastes;	✓ R		
d. Failure to implement dust control;	✓		
e. Failure to obtain prior approval for additional surface disturbance.	✓		
		✓	
BLOWOUT PREVENTER AND ASSOCIATED EQUIPMENT			
8. Is BOP pressure rating and arrangement at least that approved? Rating 5000 PSI			
9. Are choke lines and manifold, kill lines, and fill lines properly installed and operable?	✓		
9. Are controls installed and functional?	✓		
a. Remote control on floor?	✓		
b. Master controls?	✓		
c. Hand wheels or levers? (Circle appropriate item)	✓		
d. Valve installed in closing line of annular preventer?	✓		
11. Is pressure accumulator system adequate to activate BOP? psi rating 3000 Fluid volume 160 GAL	✓		
a. Nitrogen precharge pressure? Date last checked 3-10-91	✓		
b. Reservoir capacity two times usable fluid volume? 320 gal.	✓		
12. Are ram-type preventers tested to stack working pressure if isolated by test plug or 70 percent of internal yield pressure of casing if BOP stack is not isolated from casing? 5000 psi test pressure	✓		
13. Are annular-type preventers tested to 50 percent of working pressure? 2500 psi.			
14. Are BOPE tests run and recorded in driller's log? 5000 psi. DATE RECORDED			
a. When initially installed?	✓		
b. Whenever a seal subject to test pressure is broken? 3-10-91	✓		
c. Following related repairs?		✓	
d. 30-day intervals?		✓	
15. Are BOP drills conducted weekly and recorded in driller's log?		✓	
16. Is annular preventer activated weekly and recorded in driller's log? 3-27-91	✓		
17. Are pipe rams activated each trip and recorded in driller's log? 3-27-91	✓		
18. Are blind rams activated each trip and recorded in driller's log? 3-28-91	✓		
19. Is the slow pump speed recorded each tour after well has been manned up? 3-28-91	✓		
20. Are drill string safety valves and/or inside BOP valves maintained in the open position on the rig floor?	✓		
21. ☑ Is upper kelly cock installed? ☐ Is lower kelly cock installed? ☑ Are appropriate kelly cock wrenches available?	✓		
CASING AND CEMENTING			
22. Was casing run in accordance with approved APD (size 9 5/8 weight 36# grade K-55 depth 1260' ☑ New ☐ Used)?	✓		
Centralizers as required? 5 CENTRALIZERS 1280' 1180' 1140' 710' 668'	✓		
23. When setting surface casing, did cement circulate to surface? If not, was remedial action taken?	✓ R		

CASING AND CEMENTING (Continued)	INSPECTED M	NA M	VIOLATION M
24. When setting _____ casing, was cement job conducted as approved? If not, was remedial action taken?		✓	
25. Were all casing strings pressure tested prior to drill out? 1500 psi shoe			
a. Was remedial action taken if test indicated need? Action N.A.	✓		
b. Were all pressure tests recorded in driller's log? Date recorded 3-11-91	✓		
26. Were all waiting on cement (WOC) times adequate to achieve a minimum of 500 psi compressive strength?	✓		
27. Are casing shoe pressure integrity tests (mud weight equivalency test) performed and recorded in log book? Date recorded 3-11-91	✓		
28. All indications of usable water reported to the authorized officer?		✓	
29. Are wiper plugs used as required?	✓		
MUD PROGRAM			
30. Is mud system in accordance with approved APD?	✓		
31. Are appropriate quantities of mud on hand?	✓		
32. Is mud monitoring equipment in accordance with approved APD?	✓		
33. Is gas detection equipment installed?	✓		
34. Is annulus filled if mud level drops below 100 feet while tripping?	✓		
35. Are mud tests recorded in the driller's log? Date recorded _____	✓		
36. Is flare system installed?		✓	
SPECIAL OPERATIONS-AIR/GAS DRILLING			
37. Is rotating head in operating conditions?		✓	
38. Is the blooie line installed and the pilot light and igniter installed and operating?		✓	
39. Is deduster equipment installed?		✓	
40. Is mud circulation equipment available for rapid use *(including mud, reserve pits, and steel tanks)*?		✓	
41. Are engines equipped with spark arresters or water cooled exhaust?		✓	
HYDROGEN SULFIDE OPERATIONS (500' above or 3 days prior to expected H_2S)			
42. Are the H_2S Drilling Operations Plan and Public Protection Plan, if required, available at the wellsite?		✓	
43. Are the locations of safe briefing areas as approved, are they designated, and is safe access provided to them?			
44. Is a secondary means of egress available and passable?			
45. Is required safety equipment for essential personnel available and operable?			
a. Portable H_2S and SO_2 detectors?			
b. Self-contained breathing apparatus?			
c. Explosion proof ventilation fans?			
d. Other equipment as approved in drilling operations plan?			
46. Are initial and weekly training and H_2S/well control drills held and recorded on the driller's log?			
47. Is permanent H_2S detection and monitoring equipment installed, tested, operable?			
a. Are location of sensing points as approved?			
b. Are H_2S detector/monitor tests recorded on driller's log?			
48. Is the wind direction equipment installed and visible?			
49. Are the caution/danger signs legible, visible, and posted a safe distance from the location?			
50. Are the warning flags, flare gun and flares available?			
51. Is equipment H_2S trimmed as required?			
52. Is remote kill line installed and tested?			
53. Is the flare system designed to safely gather and burn H_2S?			
a. Is the flare system equipped with a safe and suitable means of ignition?			
b. Is the flareline mouth at least 150' from wellbore?			
c. If noncombustible gas is to be flared, is supplemental fuel available?			
54. Are the mud-gas separator and rotating head installed and operational *(exploratory wells only)*? Are degassers installed and operable?			
55. Is the remote controlled choke installed, tested, and operable?			
56. Is the pH of freshwater mud 10.0 or above unless otherwise approved?			
a. Are sufficient quantities of mud additives to scavenge H_2S available at the wellsite *(exploratory wells only)*?		✓	

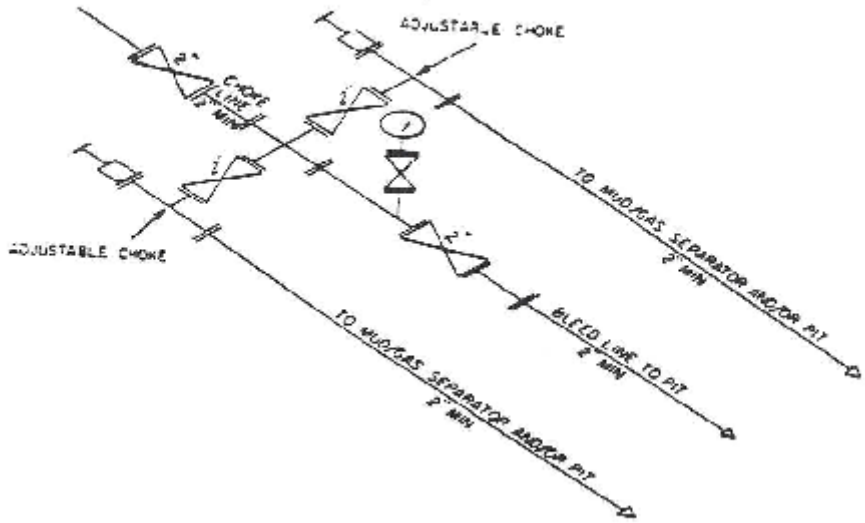
OTHER

57. Other special requirements per approved APD and lease terms. HT LINER WAS INSTALLED AS C.O.A

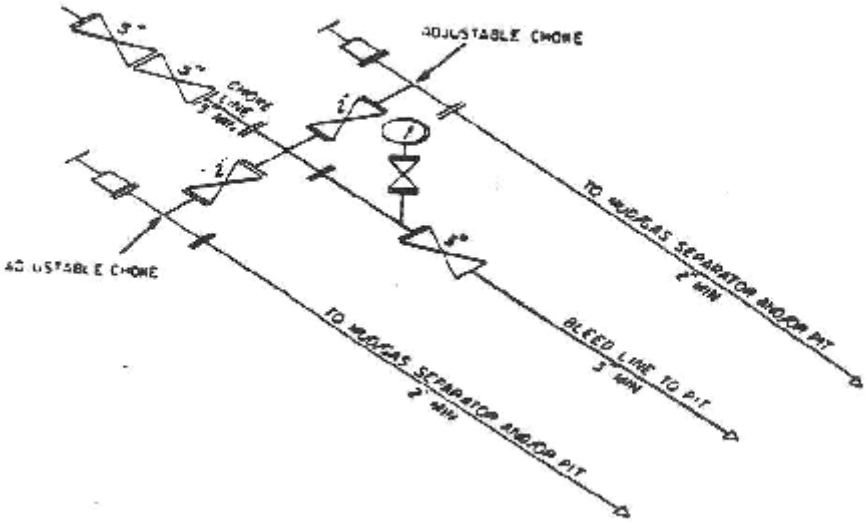
58. Description of operations witnessed CEMENT CIRCULATED THEN FELL BACK. TAGGED CEMENT @ 100' w/1" PIPE. RECEMENTED WITH 40 SKS CLASS H CEMENT. CIRCULATED 10 SKS TO PIT

I. Diagrams of Choke Manifold Equipment

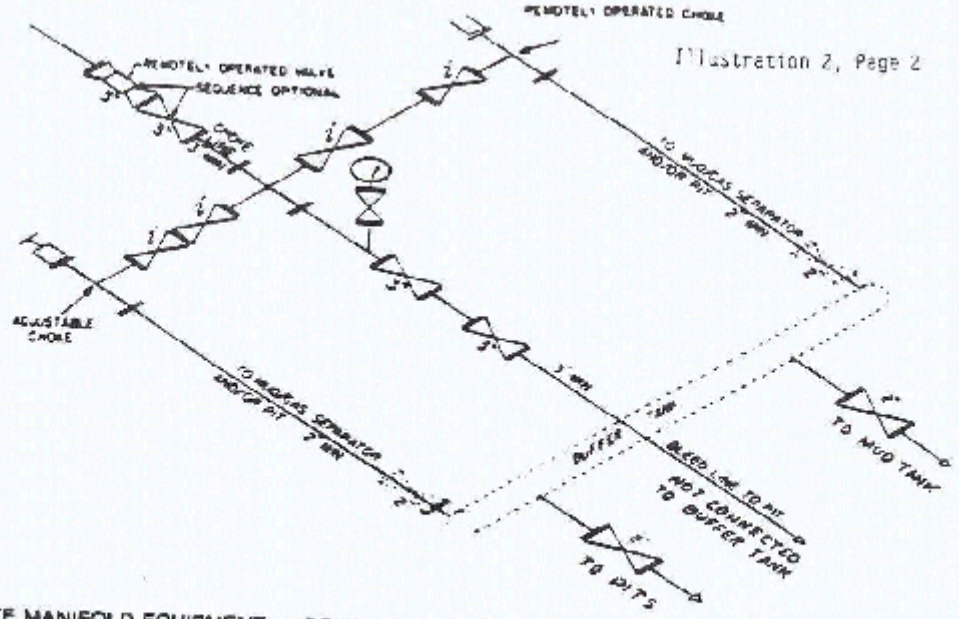
Illustration 2, Page 1



2M CHOKE MANIFOLD EQUIPMENT — CONFIGURATION MAY VARY

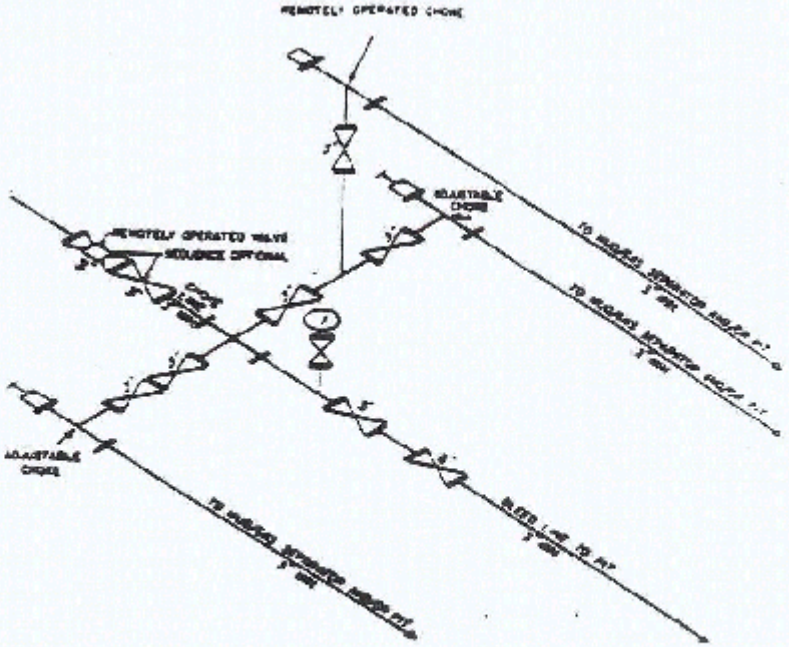


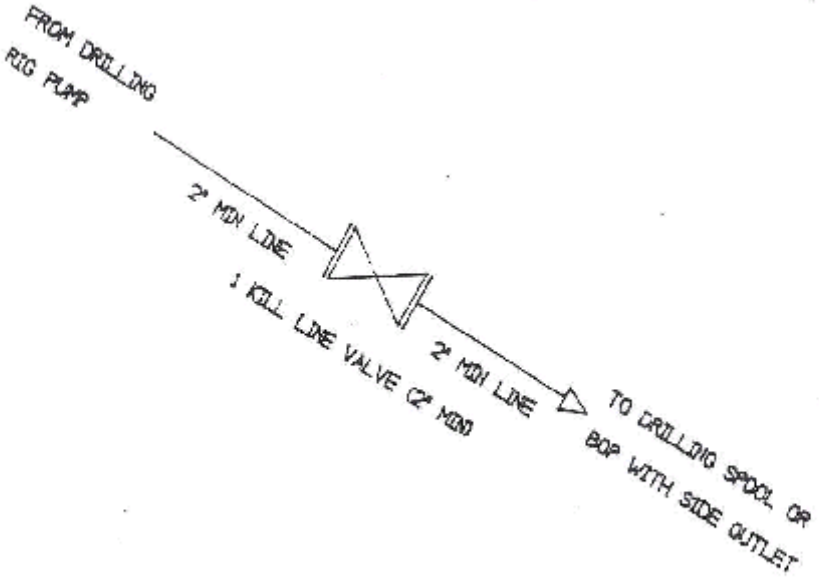
3M CHOKE MANIFOLD EQUIPMENT — CONFIGURATION MAY VARY



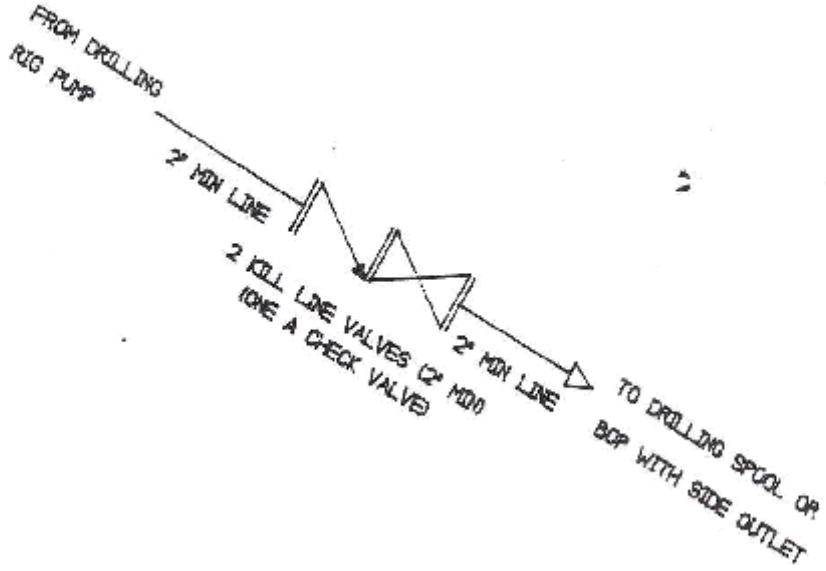
5M CHOKE MANIFOLD EQUIPMENT — CONFIGURATION MAY VARY

Although not required for any of the choke manifold systems, buffer tanks are sometimes installed downstream of the choke assemblies for the purpose of manifolding the bleed lines together. When buffer tanks are employed, valves shall be installed upstream to isolate a failure or malfunction without interrupting flow control. Though not shown on 2M, 3M, 10M, or 15M drawings, it would also be applicable to those situations.

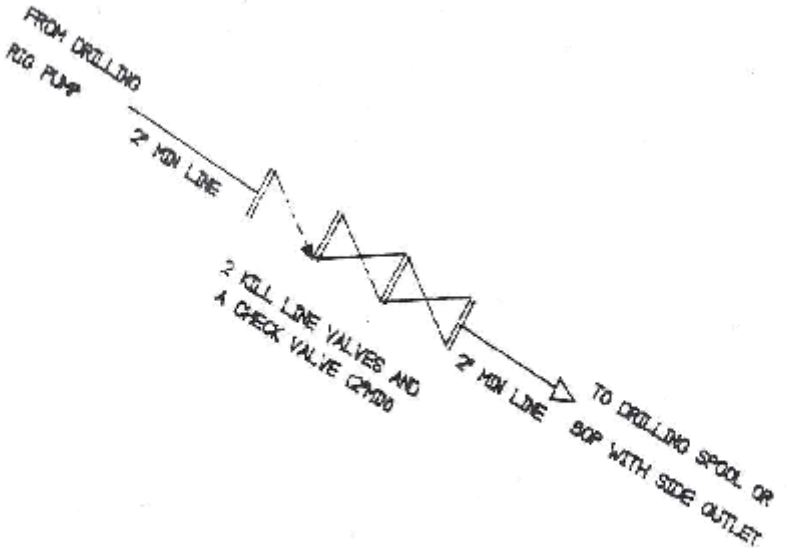




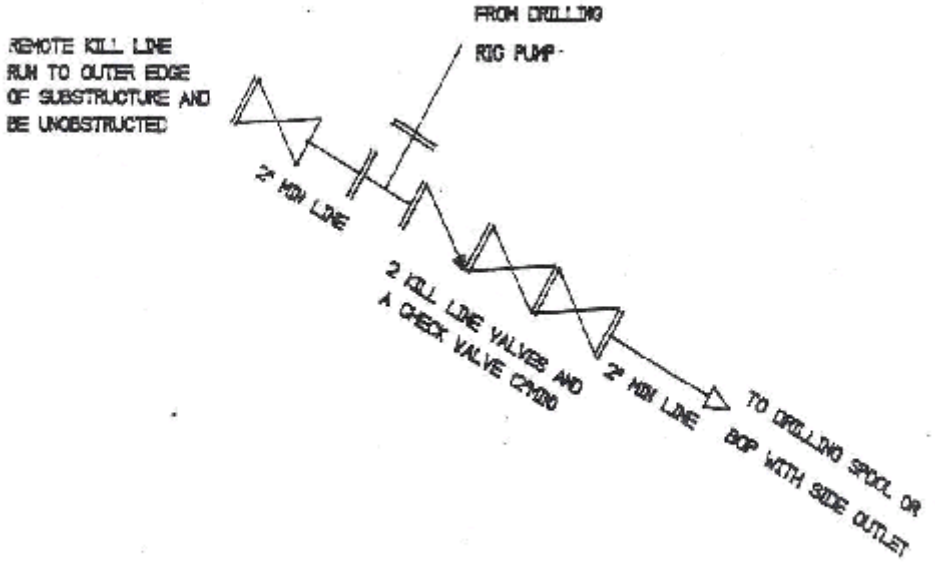
2M KILL LINE INSTALLATION - CONFIGURATION MAY VARY



3M KILL LINE INSTALLATION - CONFIGURATION MAY VARY



5M KILL LINE INSTALLATION - CONFIGURATION MAY VARY



10M & 15M KILL LINE INSTALLATION - CONFIGURATION MAY VARY
(ALSO 5M SYSTEMS UTILIZING 3 PREVENTERS)

ACCUMULATOR SIZING

The following method can be utilized to size accumulator systems:

1. Properly identify BOP equipment in use.

2. Determine the necessary gallons of hydraulic fluid to close each component.

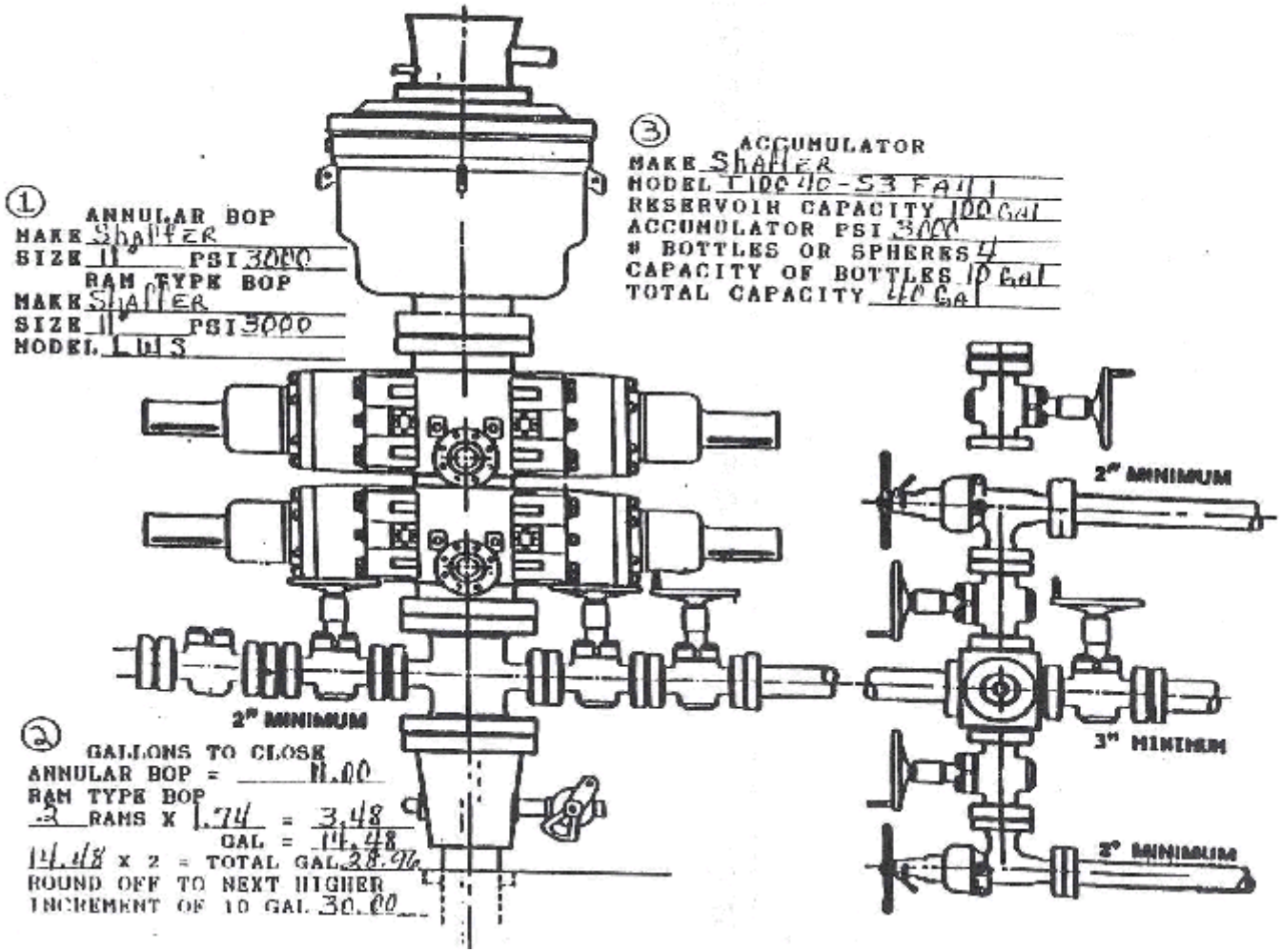
   NOTE: Two (2) ram BOP stack total volume is determined by multiplying the gallons by 2.

   Three (3) ram BOP stack total volume includes the required 50% safety factor and is multiplied by 3.

3. Calculate the volume of fluid the accumulator system can provide. This volume must exceed the closing gallons from step 2.

As demonstrated in the examples, the accumulator volume exceeds the gallons to close volume.

3M SY_TEM



① ANNULAR BOP
MAKE Shaffer
SIZE 11" PSI 3000
RAM TYPE BOP
MAKE Shaffer
SIZE 11" PSI 3000
MODEL LWS

③ ACCUMULATOR
MAKE Shaffer
MODEL T100 40-S3 FA11
RESERVOIR CAPACITY 100 Gal
ACCUMULATOR PSI 3000
BOTTLES OR SPHERES 4
CAPACITY OF BOTTLES 10 Gal
TOTAL CAPACITY 40 Gal

② GALLONS TO CLOSE
ANNULAR BOP = 11.00
RAM TYPE BOP
3 RAMS X 1.74 = 3.48
GAL = 14.48
14.48 x 2 = TOTAL GAL 28.96
ROUND OFF TO NEXT HIGHER
INCREMENT OF 10 GAL 30.00

Illustration 4, Page 2

SYSTEM

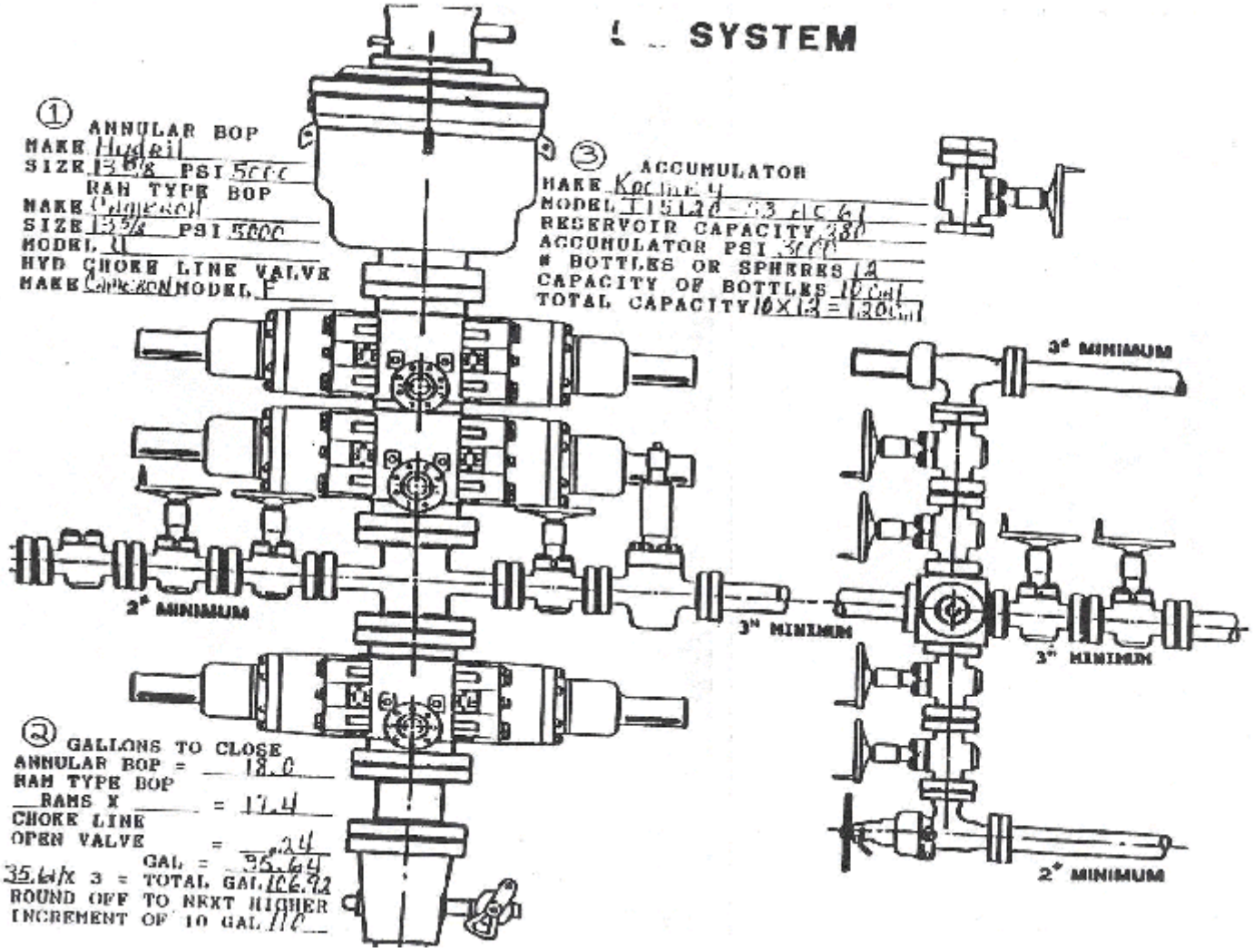


Illustration 4, Page 3

_M SY_ /EM

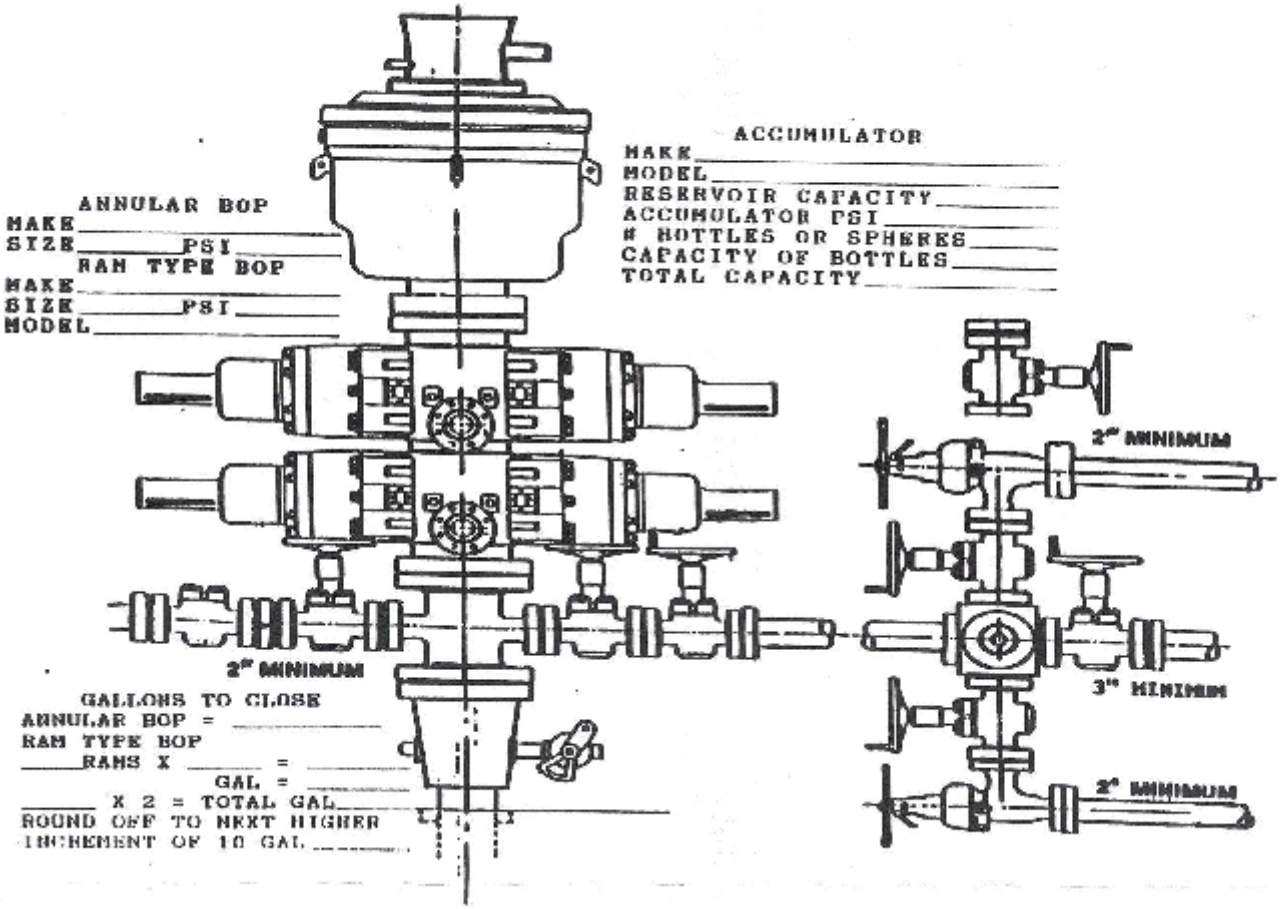
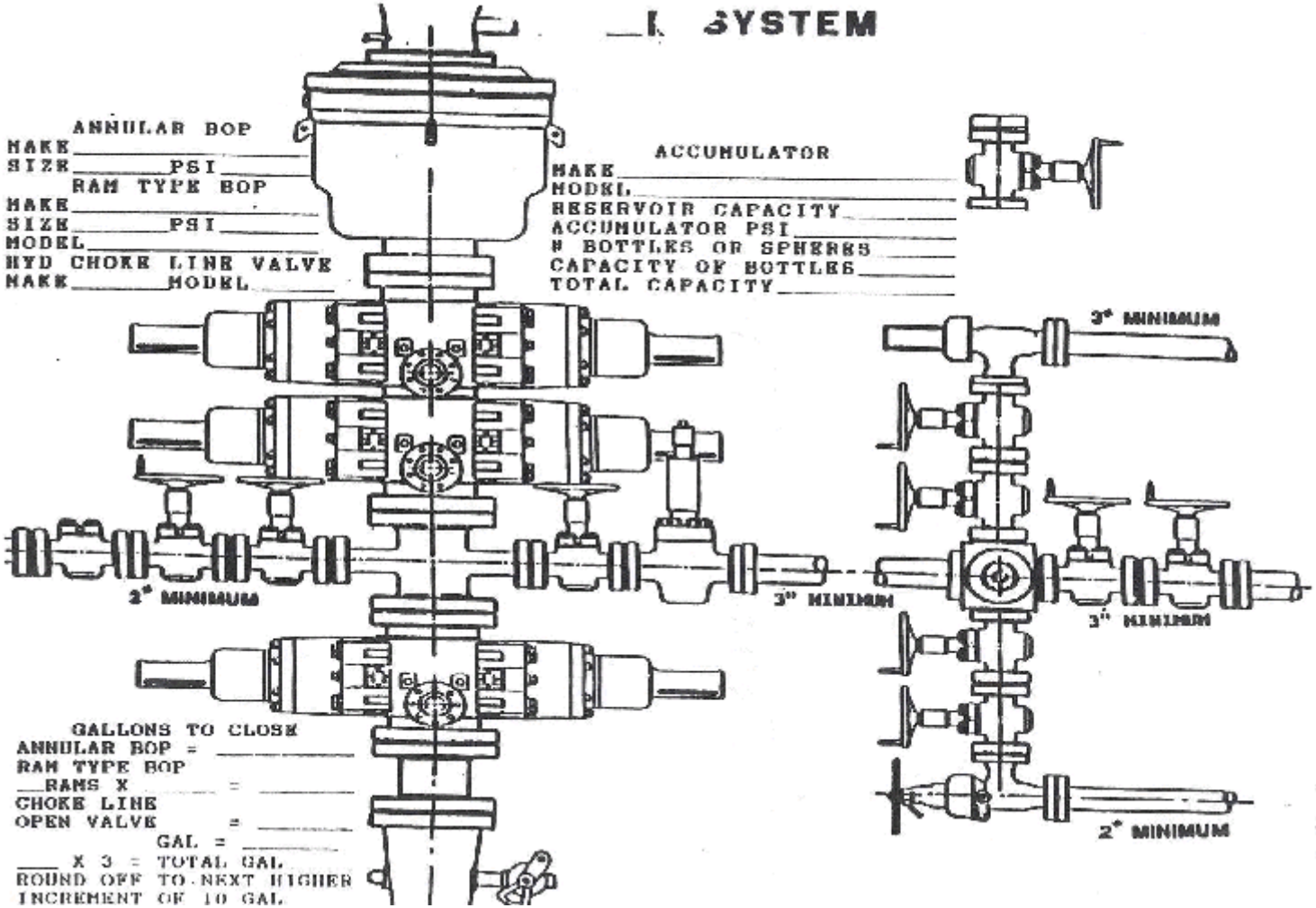


Illustration 4, Page 4

_I. SYSTEM


ANNULAR BOP
MAKE
SIZE PSI
RAM TYPE BOP
MAKE
SIZE PSI
MODEL
HYD CHOKE LINE VALVE
MAKE MODEL
ACCUMULATOR
MAKE
MODEL
RESERVOIR CAPACITY
ACCUMULATOR PSI
BOTTLES OR SPHERES
CAPACITY OF BOTTLES
TOTAL CAPACITY
3" MINIMUM
2" MINIMUM
3" MINIMUM
3" MINIMUM
2" MINIMUM
GALLONS TO CLOSE
ANNULAR BOP =
RAM TYPE BOP
__RAMS X =
CHOKE LINE
OPEN VALVE =
GAL =
___ X 3 = TOTAL GAL
ROUND OFF TO NEXT HIGHER
INCREMENT OF 10 GAL

CASING STRING PRESSURE TEST

The major concern in casing string pressure tests is not to exceed 70% of the internal yield (burst) pressure (P_{YIELD}) of the casing while achieving the test pressure (P_{TEST}). The point of concern usually occurs at the casing shoe because the mud column exerts its maximum pressure at that depth. However, in tapered strings each section should be checked.

Pressure at the shoe (P_{SHOE}) is the pressure exerted on the casing shoe during the test and includes the test pressure plus the hydrostatic pressure of the mud column, and may be calculated the following equation: P_{TEST} + (0.052 * Mud Weight * Depth) or by utilizing the nomographs. Nomographs 1, 1A, and 2 were developed to quickly determine P_{SHOE}. The point which P_{TEST} changes from 1500 psi to 0.22 psi/ft occurs at 6818 feet. Nomograph 1 adds 1500 psi to the mud column for wells less than 6818 feet deep, Nomograph 1A is an expanded version of Nomograph 1 for casing depthe to 2000 feet, and Nomograph 2 adds 0.22 psi/ft to the mud column for wells deeper than 6818 feet.

To determine the proper pressure for the casing string pressure test, the following process may be used: Obtain P_{YIELD} from API Bull 5C2, Performance Properties of Casing, Tubing and Drill Pipe, Table 1 and multiply this value by 0.7 to determine the maximum pressure to be placed on the casing shoe ($0.7*P_{YIELD}$). (Or wherever the critical casing point exists). Next, determine P_{SHOE} from either a calculation or from the appropriate nomograph using those values for mud weight and casing setting depth which exist at the time of the test.

The nomograph values are not the last step in this determination. Should $0.7*P_{YIELD}$ exceed the nomograph value, P_{TEST} may be applied directly at the surface (P_{SFC}). However, if P_{SHOE} exceeds $0.7*P_{YIELD}$, P_{SFC} should be lowered so the pressure opposite the shoe does not exceed the $0.7*P_{YIELD}$ value. This can be done by subtracting the difference between the two (P_{SHOE} - $0.7*P_{YIELD}$) from P_{TEST}.

Examples are on the next page.

CASING STRING PRESSURE TEST

EXAMPLES:

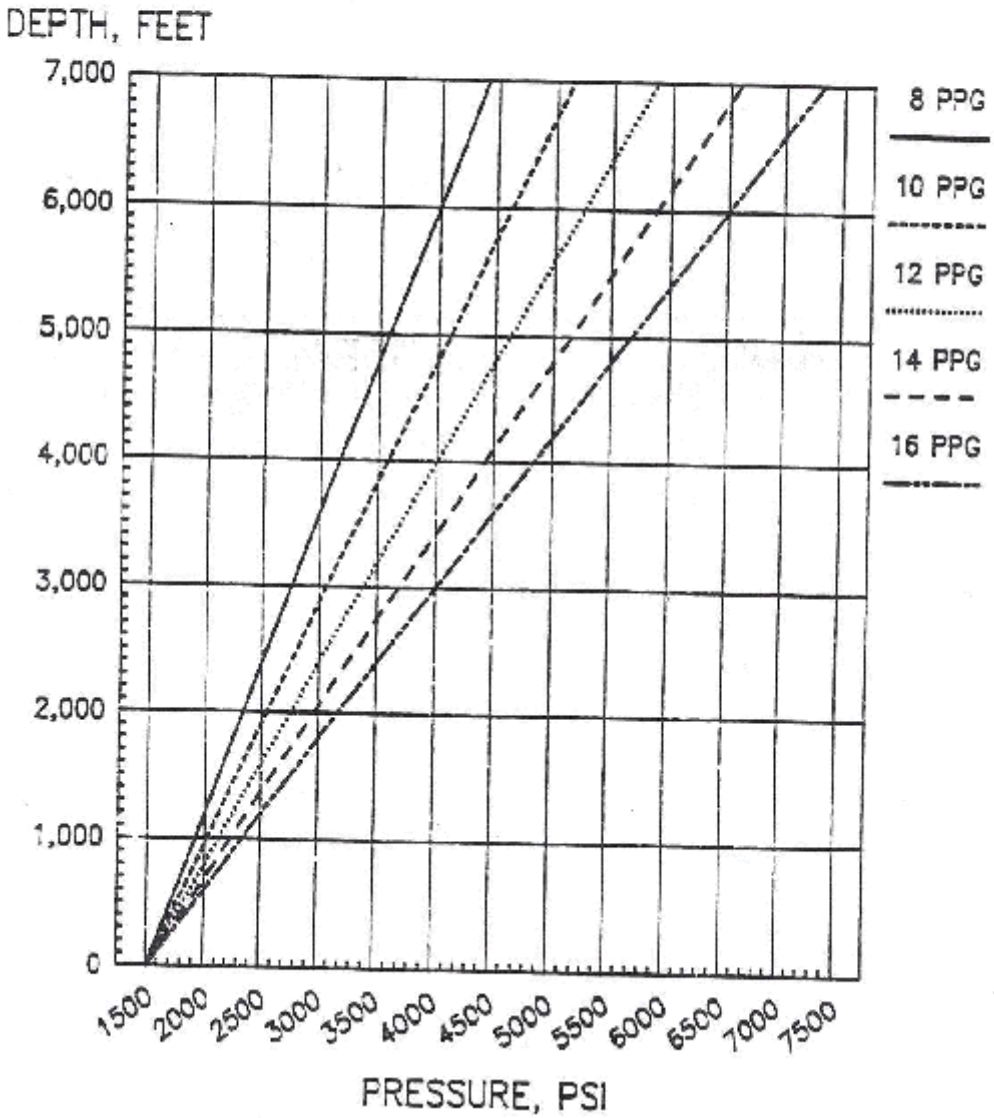
1. Assume: 9 5/8 inch, K-55, 40 lb/ft casing set at 1400 feet with 9 ppg mud in the hole.
   From API Bull 5C2, P_{YIELD} = 3950 psi; $0.7*P_{YIELD}$ = 2765 psi.
   From Nomograph 1, P_{SHOE} = 2175 psi (calculates to 2155 psi).

   Because $0.7*P_{YIELD}$ exceeds P_{SHOE},
   $P_{SFC} = P_{TEST} = \underline{1500}$ psi.

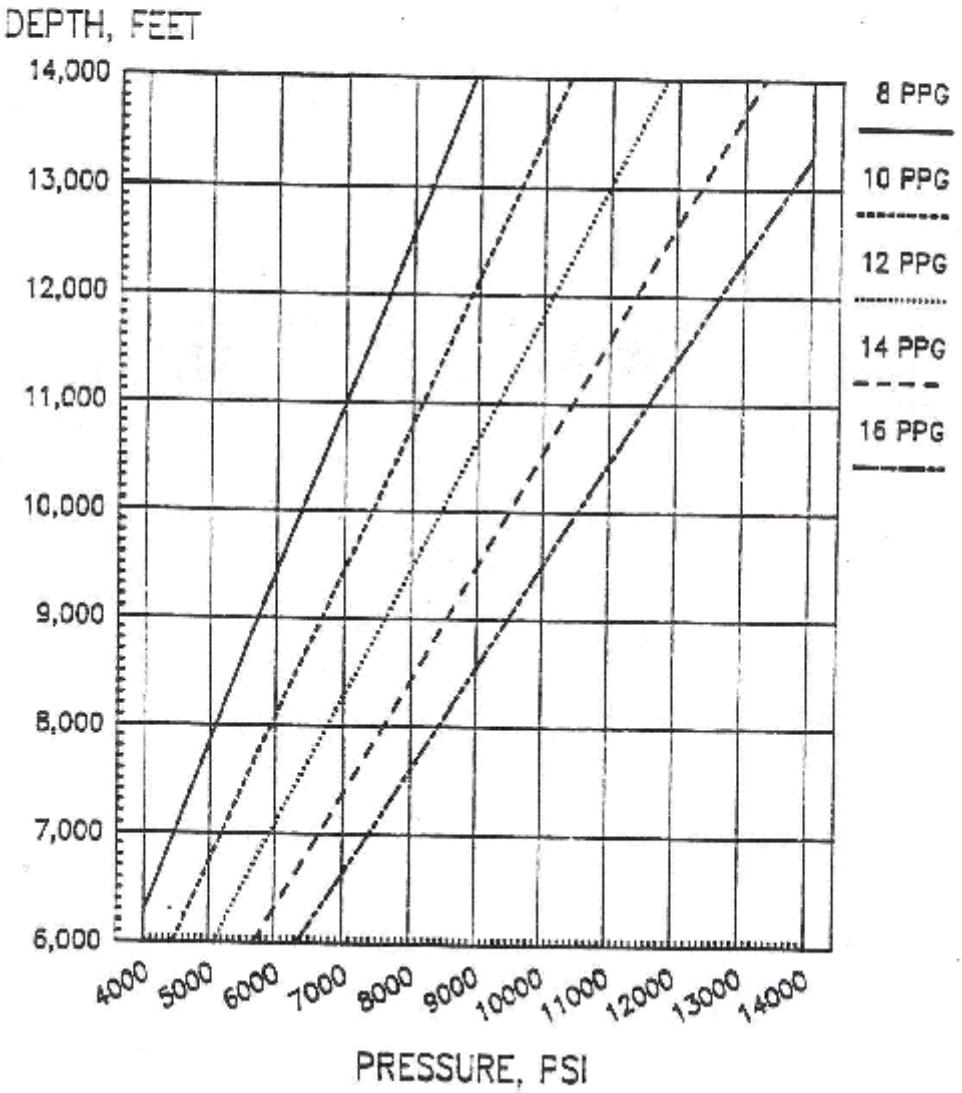
2. Assume: 7 inch, N-80, 29 lb/ft casing set at 10,000 feet with 10 ppg mud in the hole.
   From API Bull 5C2, P_{YIELD} = 8160 psi; $0.7*P_{YIELD}$ = 5712 psi.
   From Nomograph 2, P_{SHOE} = 7350 psi (calculates to 7400 psi).

   Because P_{SHOE} exceeds $0.7*P_{YIELD}$,
   $P_{SFC} = P_{TEST} - (P_{SHOE} - 0.7*P_{YIELD})$
   $P_{SFC} = 2200 - (7400 - 5712) = \underline{512}$ psi.

NOMOGRAPH 1
PRESSURE AT CASING SHOE
WELLS < 6818 FEET



NOMOGRAPH 2
PRESSURE AT CASING SHOE
WELLS > 6818 FEET



CASING SHOE PRESSURE INTEGRITY TEST

This test is a determination that the formation directly below the casing setting depth is capable of maintaining the pressure exerted by the mud weight necessary to drill down to the next casing setting point. This in reality is a mud weight equivalence test. To determine the pressure to be added to the mud column at the surface (P_{SFC}), the following equation may be used:

$$P_{SFC} = 0.052*TVD*(MW_2 - MW_1)$$

Where: TVD = True Vertical Depth, feet
MW_2 = Mud Weight at the Next Casing Point, ppg
and, MW_1 = Mud Weight at the Current Casing Point, ppg.

EXAMPLES:

1. Assume: Surface Casing set at 1300 feet with 9 ppg mud in the hole. It is anticipated that 11 ppg mud will be necessary to drill to the next casing setting point of 8000 feet.

   Utilizing the equation: $P_{SFC} = 0.052*TVD*(MW_2 - MW_1)$

   $P_{SFC} = 0.052*1300*(11 - 9)$

   $P_{SFC} = 135$ psi

   Add 135 psi at the surface to the existing mud column to achieve a mud weight equivalence test.

2. Assume: Intermediate Casing set at 7000 feet with 10 ppg mud in the hole. It is anticipated that 13 ppg mud will be necessary to drill to the next casing setting point of 11500 feet.

   Utilizing the equation: $P_{SFC} = 0.052*TVD*(MW_2 - MW_1)$

   $P_{SFC} = 0.052*7000*(13 - 10)$

   $P_{SFC} = 1092$ psi

   Add 1092 psi at the surface to the existing mud column to achieve a mud weight equivalence test.

HYDROSTATIC PRESSURE DROP
DRILL COLLARS VS. DRILL PIPE

To determine the feet of drill string which can be pulled equal to 100 ft. of fluid drop in the hole, the following equation may be used:

$$X = \frac{100\ (CC - DF)}{DF}$$

Where: X = Feet of Drill String Which Can Be Pulled, Feet
CC = Casing Capacity Factor, Barrels/Linear Foot (Bbls/LF)
and, DF = Steel Displacement Factor, Bbls/LF

NOTE: This formula assumes dry pipe is being pulled.

ASSUME: 9 5/8" 36 #/FT CASING;
4 1/2" 16.60 #/FT IF DRILL PIPE;
and 7"OD X 2 3/4"ID 111 #/FT DRILL COLLARS.

FROM THE TABLES ON PAGE 2 OF THIS ILLUSTRATION:

Casing Capacity Factor = 0.07730 Bbls/Linear Foot (Bbls/LF)
Drill Pipe Steel Displacement Factor = 0.00634 Bbls/LF
Drill Collar Steel Displacement Factor = 0.04025 Bbls/LF

Calculate the fluid drop from pulling Drill Pipe. Using the above formula:

$$X = \frac{100\ (0.07730 - 0.00634)}{0.00634}$$

X = <u>1119</u> FT of 4 1/2" DRILL PIPE.

Calculate the fluid drop from pulling Drill Collars. Using the above formula:

$$X = \frac{100\ (0.07730 - 0.04025)}{0.04025}$$

X = <u>92</u> FT 7" X 2 3/4" DRILL COLLARS.

Based on this example, pulling 1119 ft (slightly more than 37 joints or 12 stands and one joint) of 4 1/2" drill pipe would drop the fluid

level 100 ft, but pulling only 92 ft (one stand or 3 joints) of the 7" X 2 3/4" drill collars would drop the fluid level that same 100 ft. This example indicates the necessity of filling the hole much more frequently when pulling drill collars than when pulling drill pipe.

DIMENSION AND CAPACITY FACTORS OF CASING

Casing Size O.D. (Inches)	Weight Per Foot Complete	Inside Diameter (Inches)	Barrels Per Linear Foot	Linear Feet Per Barrel
4 1/2	9.50	4.090	.0162	61.54
	11.60	4.000	.0155	64.34
	13.50	3.920	.0149	66.99
	15.10	3.826	.0142	70.32
5 1/2	14.00	5.012	.0244	40.98
	15.50	4.950	.0238	42.02
	17.00	4.892	.0232	43.01
	20.00	4.778	.0221	45.09
	23.00	4.670	.0211	47.20
7	23.00	6.366	.0393	25.40
	26.00	6.276	.0382	26.14
	29.00	6.184	.0371	26.92
	32.00	6.094	.0360	27.72
	35.00	6.004	.0350	28.56
	38.00	5.920	.0340	29.37
7 5/8	26.40	6.969	.0471	21.20
	29.70	6.875	.0459	21.78
	33.70	6.765	.0444	22.49
	39.00	6.625	.0426	23.49
8 5/8	24.00	8.097	.0636	15.70
	32.00	7.921	.0609	16.41
	36.00	7.825	.0594	16.81
	40.00	7.725	.0579	17.25
9 5/8	36.00	8.921	.0773	12.93
	40.00	8.835	.0758	13.19
	43.50	8.755	.0744	13.43
	47.00	8.681	.0732	13.66
	53.50	8.535	.0707	14.13
10 3/4	40.50	10.050	.0981	10.19
	45.50	9.950	.0961	10.40
	51.00	9.850	.0942	10.61
	55.50	9.760	.0925	10.81
	60.70	9.660	.0906	11.03
13 3/8	54.50	12.615	.1545	6.47
	61.00	12.515	.1521	6.57
	68.00	12.415	.1497	6.68
	72.00	12.347	.1480	6.75

From Halliburton Cementing Tables

STEEL DISPLACEMENT FACTORS OF DRILL PIPE*

Size O.D. (in.)	Weight (lbs/ft)	API TOOL Joint	Barrels per ft.	Barrels per 3-Joint Stand (90')
2 7/8	10.4	IF	0.00391	0.3519
3 1/2	13.3	IF	0.00520	0.4680
4	14.0	IF	0.00551	0.4590
4 1/2	16.6	IF	0.00634	0.5704
4 1/2	16.6	XH	0.00648	0.5832
4 1/2	20	XH	0.00793	0.7137
5	19.5	XH	0.00754	0.6786

STEEL DISPLACEMENT FACTORS OF DRILL COLLARS*

	ID	Wt. (lb/ft)		
4 3/4	2 1/4	46.8	0.01880	1.1880
6	2 1/4	83.6	0.03005	2.7045
6 1/4	2 13/16	83.8	0.03026	2.7234
6 1/2	2 13/16	92.8	0.03335	3.0015
6 3/4	2 3/4	103	0.03681	3.3119
7	2 3/4	111	0.04025	3.6225
7 1/4	2 3/4	120	0.04371	3.9339
8	2 3/4	151	0.05482	4.9338
9	2 3/4	196	0.07133	6.4197
9	3	192	0.06993	6.2937
11	3	259	0.10878	9.7902

*Volume of steel in the wall of the pipe.

HYDROGEN SULFIDE NOMOGRAPHS

The following Nomographs may be utilized to determine the 100 PPM and 500 PPM Radius of Exposures (ROE). To use, simply draw a line from the H2S concentration to the gas flowrate. The point that the line crosses the middle collomn indicates the ROE in feet.

For example:

Using the 100 PPM Nomograph: The H2S concentration is 10,000 PPM (Point A) and the flowrate is 0.1 MMscf (Point B), the ROE is 100 feet (Point C).

Using the 500 PPM Nomograph: The H2S concentration is 10,000 PPM (Point A) and the flowrate is 0.1 MMSCF (Point B), the ROE is 46 feet (Point C).

PARTS PER MILLION TO PERCENTAGE CONVERSIONS (PPM TO %)

To convert from ppm to % move the decimal four (4) places to the left:

1. ppm = .0001 % which is 1/10,000 of 1%

10. ppm = .001 % which is 1/1,000 of 1%

100. ppm = .01 % which is 1/100 of 1 %

200. ppm = .02 % which is 2/100 of 1%

500. ppm = .05 % which is 5/100 of 1%

1000. ppm = .1 % which is 1/10 of 1%

10,000. ppm = 1 % which is 1%

10% = 100,000 ppm

20% = 200,000 ppm

30% = 300,000 ppm

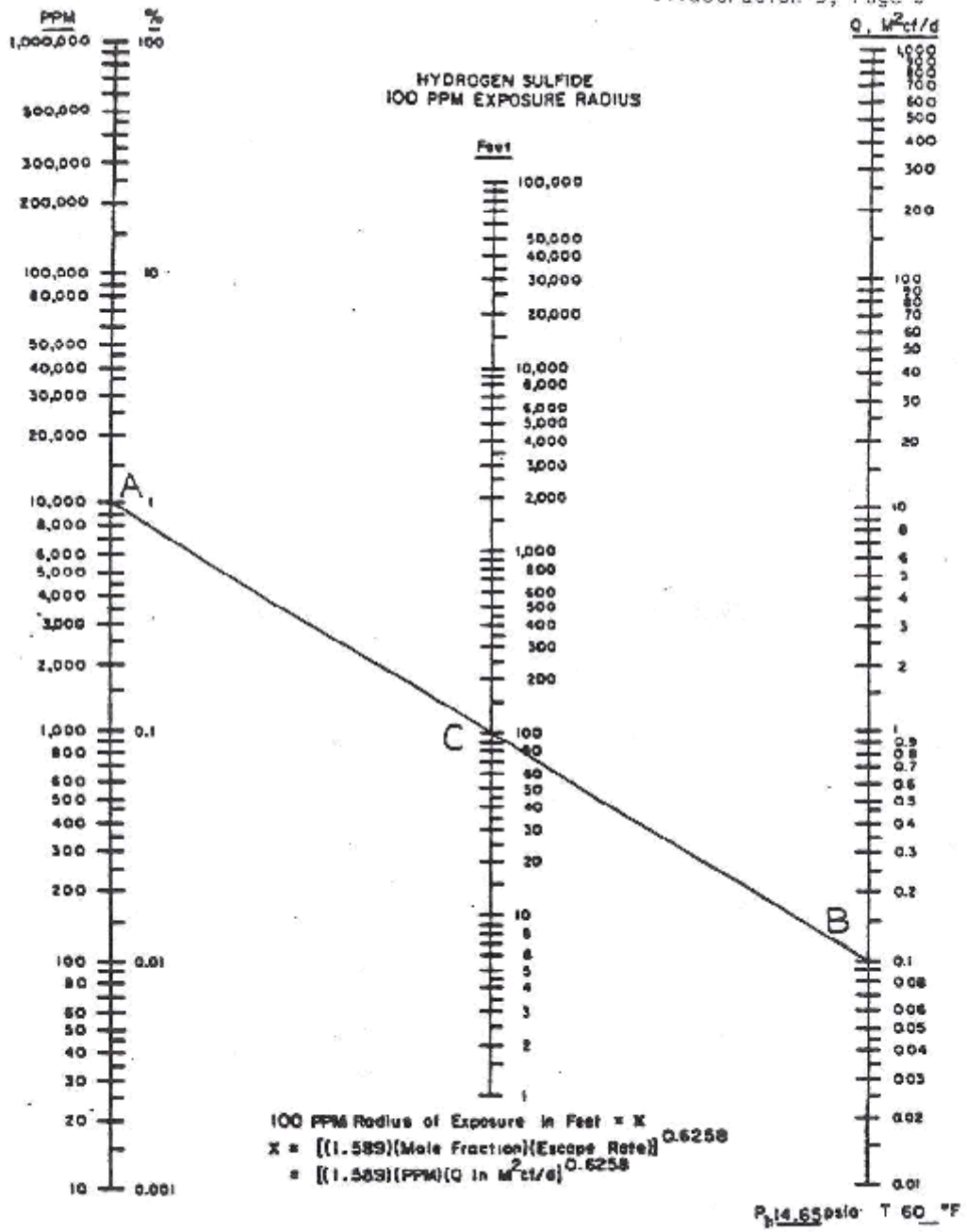


Fig. 3—Chart for determining radius of exposure (source: Railroad Commission of Texas).

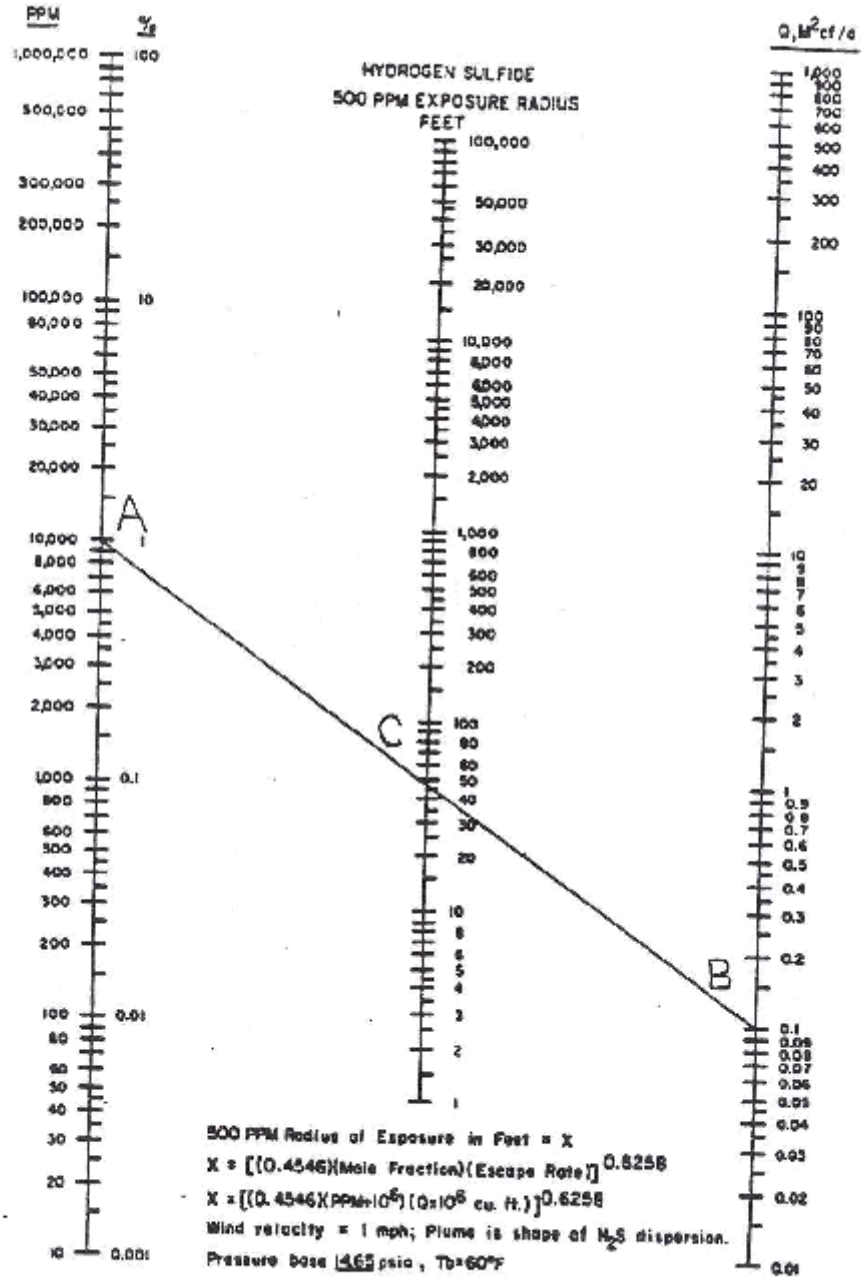


Fig. 4—Chart for determining radius of exposure (source: Railroad Commission of Texas)

TRI-STATE OIL TOOL INDUSTRIES, INC.

CONVERSION TABLE FOR HARDNESS TESTING
(APPROXIMATE VALUES)

BRINELL		ROCKWELL		
Impression Diameter	Hardness Number	C Scale	B Scale	TENSILE STRENGTH
2.45	627	60		311
2.50	601	58		298
2.55	578	57		287
2.60	555	55		276
2.65	534	53		266
2.70	514	52		256
2.75	495	50		247
2.80	477	49		238
2.85	461	47		229
2.90	444	46		220
2.95	429	45		212
3.00	415	44		204
3.05	401	42		196
3.10	388	41		189
3.15	375	40	110	182
3.20	363	38	110	176
3.25	352	37	109	170
3.30	341	36	109	165
3.35	331	35	108	160
3.40	321	34	108	155
3.45	311	33	107	150
3.50	302	32	107	146
3.55	293	31	106	142
3.60	285	30	105	138
3.65	277	29	104	134
3.70	269	28	104	131
3.75	262	26	103	128

BRINELL		ROCKWELL		
Impression Diameter	Hardness Number	C Scale	B Scale	TENSILE STRENGTH
3.80	255	25	102	125
3.85	248	24	101	122
3.90	241	23	100	119
3.95	235	22	99	116
4.00	229	21	98	113
4.05	223	20	97	110
4.10	217	18	96	107
4.15	212	16	96	104
4.20	207	15	95	101
4.25	202	14	94	99
4.30	197	13	93	97
4.35	192	12	92	95
4.40	187	10	91	93
4.45	183	9	90	91
4.50	179	8	89	89
4.55	174	6	88	87
4.60	170	5	87	85
4.65	166	4	86	83
4.70	163	3	85	82
4.75	159		84	80
4.80	156		83	78
4.85	153		82	76
4.90	149		81	75
4.95	146		80	74
5.00	143		79	72
5.05	140		78	71
5.10	137		77	70

Diameter of Impression 3000 Kg. load - 10 MM. Steel Ball
Rockwell C-Scale 150 Kg. Load - 120° Diamond Cone
B-Scale 100 Kg. Load - .0625 in. Steel Ball
Tensile Strength 1000 pounds per square inch

H_2S modification for Blowout Preventers
(Courtesy of SPE-AIME)

Component	Standard service	H_2S service
Cameron type U		
Ram assembly		
(1) Ram	4340 Rc = 20-23	4340 Rc = 20-24
(2) Front packer	Specially compounded gas-resistant Hycor	Same
(3) Top seal	Rubber	Same
Bonnet bolts	4142 bolt class 354 (Rc = 35)	A 286
Operating piston	4140 Rc = 22-30	4140 Rc = 24
Connecting rod seal ring	Rubber	Specially compounded gas-resistant Hycor
Bonnet seal	Rubber-impregnated asbestos	Hycor-impregnated asbestos
Bonnet bolt retainer O-ring	Rubber	Hycor
Int. flange to bonnet cap screw	4142 bolt class 354 (Rc = 35)	4142 bolt class 354 (Rc = 22)
Shaffer type LWS		
Door cap screws	4140 BHN = 285-341	4140 BHN = 225-235
Cylinder cap screws	4340	4140 Rc 22
Cylinder head cap screws	4340	4140 Rc 22
Ram shaft	410 SS	4130 Rc 22
Hinge bracket cap screw	4340	4140 Rc 22
Secondary seal plug	Heat treated 4140	304 SS
Thread protector plug	Heat treated 4140	304 SS
Ram rubber retaining screws	Heat treated 4140 (BHN = 385)	4140 Rc 22
Ram block retaining screws	Heat treated 4140	K-Monel 500
Studs	4140 B-7	A-286 or soft B-7
Nuts	2H	2H Rc 22

BLOWOUT PREVENTER EQUIPMENT TEST

I. INTRODUCTION

The regulations and Onshore Oil and Gas Order No. 2, Drilling Operations (Order No. 2) require that the BOP and related components (BOPE) shall be functionally operated and pressure tested at specified intervals throughout the drilling operations to insure their integrity. This discussion describes the procedures used to test BOPE.

II. BOPE TEST PREPARATION

The inspector prepares to witness the BOPE test by reviewing the approved APD, Drilling Plan, Conditions of Approval, and Order No. 2 for configuration of the BOP stack and pressure test specifications.

The well head is usually the weakest point on the BOP stack and the test is limited to its pressure rating. If the well head pressure rating is below the approved test pressure the test shall be suspended until the authorized officer is notified and the problem is resolved.

III. BOPE TEST PROCEDURE

The BOP tester or rig crew prepares the equipment to be tested by performing the following procedures: Remove the wear ring from the casing head if so equipped. Back out the lockdown studs which hold the wear ring in position. The jam nut on the lockdown studs must be retightened to prevent leakage. If the casing head is not equipped to accommodate a wear ring, eliminate this procedure and proceed to the next step.

The well head seat must be cleaned to receive the test plug. First, open valve on well head and drain fluid from BOP stack. Then clean the inside of BOP stack. This may be accomplished by washing with a water hose. Verify there is a circulating port in the test plug to allow pressure into the annular chamber.

Make sure the well bore is full of fluid up to the well head valves and ensure these valves are in the open position and remain open throughout the test.

The joint of drill pipe used for testing is placed into the mouse hole

and the full open ball valve, dart valve (floor stabbing valves), and the pressure source adapter sub are made up on the tool joint. The joint is removed from the mouse hole and made up on the test plug usually hand tight, so the joint can be unscrewed from the test plug after it is seated in the well head (the joint must be removed from the BOP stack to test the blind rams). The joint of drill pipe and test plug are lowered into the hole and the test plug seated in the well head.

The BOP stack is filled with water or a fluid with a viscosity no higher than water. Unscrew the drill pipe from test plug and remove drill pipe to allow closure of blind rams.

NOTE: At this time the blind rams, pipe rams, and the annular preventer can be opened and closed to ensure that the accumulator's hydraulic system operates correctly. All hydraulic lines from the accumulator to the BOP stack should be checked for external leaks.

The pressure source hose from the test truck is attached to the riser valve connection in the choke manifold. Usually the mud pressure gauge is removed and the source is attached at this connection.

NOTE: Depending on the design of the choke valve, it may, or may not, be able to provide a positive pressure seal. Chokes are primarily designed to restrict flow. If the chokes are not designed for a positive seal, they would not be required to hold approved test pressure. A test would be performed to verify the adequacy of the needle and seat by applying pressure to the valve and observing a slow bleed off of pressure. Hydraulic choke valves that are designed for a positive pressure seal would be required to hold the approved test pressure.

The blind rams are closed so pressure from the test unit can be applied against the blind rams and the appropriate valves to be tested in the choke manifold and kill line.

The initial test is performed with the blind rams closed and the outside valves closed (those valves furthest downstream in the choke manifold) and the kill line valve nearest to the BOP stack. The check valve in the kill line must be deactivated (held in an open position or disassemble) to pressure test the kill line valves. All other valves must be in the open position.

At this time the system is pressurized to the approved test pressure. A visual inspection of the system is performed with attention focussed on the:

- o Ring grooves and flanges.
- o Door gaskets.
- o Visual inspection (tattle-tale) holes for the primary packing seals of the ram type preventers.
- o Stem packings on the choke manifold valves.
- o Wear ring, lockdown studs, and jam nuts.

INSPECT FOR INTERNAL LEAKS

- Ram rubbers are visually inspected by looking into the wellbore. Turbulence in the fluid would indicate a leak.

- A test plug leak would be identified by fluid flow from the casing head valve.

- A choke manifold leak would be indicated by evidence of fluid in the manifold downstream of valves being tested.

NOTE: A visual inspection is required because a small leak will not show on the pressure gauge or pressure chart because of the large volume in the BOP stack and choke manifold. Valves are only tested from the working pressure side. Valves are never tested with a valve closed downstream from the valve being tested.

Witness operation of the choke manifold valves to ensure valves being tested are in the proper position. If valves are too stiff to operate, notify the company representative that the valves need maintenance.

Pressure is isolated and maintained for at least 10 minutes for the inspection of each set of components being tested. The pressure gauge or chart is monitored for a decline in test pressure. If a leak is detected during testing of the equipment, the test is suspended until proper repairs are made; after repairs, the test is resumed to retest failed components. After the initial test is completed, the pressure is bled off from the system and preparations are made for the next test.

The blind rams are opened and the test joint is installed back into the well bore and screwed into the test plug. At this time, the test can be resumed by closing the upper pipe rams and opening the valves previously tested and closing the next valves to be tested. The pressure source hose is attached to the test joint at the source

adapter sub and approved test pressure is again applied.

Inspect the pipe rams for leaks. Pipe ram and blind ram leaks can be caused by the following problems:

- The rubber that seals around the pipe or the rubber that seals against the bore of the BOP may be worn or damaged.

- The accumulator pressure may be set too low to seal the rams against the pipe.

- Leaking primary packing seals are indicated by fluid leaking from the tattle-tale holes.

If no leaks are detected following the 10 minute test interval on this set of valves, the pressure is released and the valves are positioned for the next test. The kill line check valve is returned to the normal operating condition.

Pipe rams will remain closed and the following valves tested to test pressure:

- o Choke line remote controlled (HCR) valve.
- o Kill line check valve.
- o Dart valve installed at the top of the test joint.

While the tester is continuing the test, the remaining pipe rams and valves will be isolated and tested in the same manner as previously discussed. The inspector will continue to inspect for leaks on the equipment being tested.

Ram type preventer and related equipment are all tested at the full approved test pressure. After these tests are completed, the annular preventer is tested at 50 percent of the working pressure to prevent excess stress on the sealing device.

After testing the annular preventer the test plug is unseated and the test joint and test plug are pulled from the well bore. The wear ring is seated (if so equipped) into the casing head and the lockdown studs are positioned and the jam nuts tightened.

The kelly is removed from the rat hole and the pressure source sub installed on the kelly to test the upper kelly cock valve and the lower kelly cock valve (if so equipped). The stand pipe valve should be maintained in the open position while this test is being performed. The pressure source hose is attached to the pressure source sub and the kelly pressurized to full test pressure and held for 10 minutes.

The BOP stack and related equipment tests must be recorded in the IADC Tour Book specifying the pressure rating and components tested. Obtain

copy of pressure chart and attach to inspection form.

In some cases, a contract tester is not used and the tests are performed by rig personnel and rig equipment. Tests conducted in this manner require verification by BLM personnel because test chart records are normally not provided. With some variations these tests are performed in the same manner as previously discussed. Test requirements will remain the same. If rig personnel and pumps are used for these tests witnessing the test is more critical. Most rig equipment is limited to perform tests under 3000 psi.