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This report describes the current methods of design, construction, and development of wells for in situ leaching of uranium. The discussion includes the alternatives for well design drilling equipment and fluids, grout formulation and emplacement, well integrity testing and repair, and well development and stimulation. Current practice in these areas was determined through interviews and discussions with eight operators of commercial-scale in situ facilities. Based on this information and previous experience, recommendations are made regarding well design, construction, and development for in situ leaching.

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DESIGN, CONSTRUCTION, AND DEVELOPMENT OF IN SITU MINING WELLS

by

D. L. Shuck and J. N. Brooke

ABSTRACT

This report was prepared for the Bureau of Mines to describe the current methods of design, construction, and development of wells for in situ leaching of sedimentary uranium deposits. The discussion includes the alternatives for well design drilling equipment and fluids, grout formulation and emplacement, well integrity testing and repair, and well development and stimulation. Current practice in these areas was determined through interviews with eight operators of commercial scale in situ facilities and is also discussed. Based on this information, plus the authors' experience, recommendations are made regarding well design, construction, and development for in situ leaching.

INTRODUCTION

In situ leaching involves circulating a suitable chemical solution through an undisturbed mineralized strata to mobilize the contained metal values. Circulating leach solution is done by constructing and operating wells throughout the ore body to inject and recover the leach solution. Wells are also placed surrounding the ore body to monitor leach solution confinement. Characteristically in situ leaching of uranium has a relatively lower capital cost and shorter lead time to operation than conventional mining and milling. These characteristics coupled with a rising demand for uranium led to the rapid development of in situ leaching for uranium production from sedimentary deposits. As a result considerable knowledge and experience has been gained regarding both the development and operation of in situ leaching facilities during the past ten years.

The design, construction, and development of wells is a vital part of an in situ leaching project. To obtain economic production, it is generally necessary to install and operate a large number of wells. Because of this it is essential to minimize the cost of construction of each well. However, it is also essential that the quality of each well be maintained to comply with environmental regulations, to minimize impact on surrounding ground waters, and to optimize leach solution contact with the ore. Inappropriate well design, construction, and development methods were a principal cause of unnecessary environmental impacts and unsatisfactory production performance during the development of in situ leaching.

The lessons learned coupled with the maturity of the industry and the potential for additional growth prompted the preparation of this manual. The material is presented in the following order: First, current methods for well design, drilling, grouting, and development/stimulation are discussed. Following this is a summary and discussion of the current practice of eight major operators with regard to these aspects of well construction. The final section gives some comments and recommendations regarding well construction and operation which are based on the personal experience of the authors, the reviewers of this manual and the in situ mining operators which were surveyed.

DESIGN CONSIDERATIONS

There are several texts dealing with the design of shallow water wells. Perhaps the best known and most readily available of these is "Ground Water and Wells" published by the Johnson Division of Universal Oil Products, Inc. (30).[1] Another equally comprehensive reference on the subject is "Water Well Technology" by M. D. Campbell and J. H. Lehr, published by McGraw Hill Book Co. (20). Other less comprehensive references, which deal only with limited aspects of well design for ground water development, are also available (11, 38,59). However to date, much less information has been published with regard to well design, construction, and development for in situ mining (1,56). Therefore, this chapter discusses two aspects of well design: 1) the principal differences in well design for ground water development and for in situ mining, and 2) the principal components of well design for in situ mining.

The following table compares the principal differences in well design for ground water development versus in situ mining.

	Ground Water Development	In Situ Mining
1) Well Function	Water production only	Injection and production of the chemical leach solution.
2) Available Data Base	Generally obtained from outside sources of information rather than developed during the project.	Developed for the ore body and host formation during the project.
3) Well Location	Fixed by use or user	Fixed by the limits of the ore body (ref. Note).
4) Well Depth	As required to obtain the needed water quality and flow.	Fixed by ore distribution within the host formation (ref. Note).
5) Completion Interval	Generally 100% of the water bearing formation.	Generally limited to the ore grade portion of the mineralized host sand (ref. Note).
6) Number of Wells	Typically 1 to less than 100 depending on whether a domestic or municipal water supply is involved.	Typically 10 to several thousand depending on whether a pilot or commercial scale operation is involved.
7) Yield per Well	From a few gpm to several thousand gpm depending on the nature of the water supply.	From a few gpm up to a hundred gpm depending on the host formation characteristics.

Note: location, depth, and completion interval of associated monitor wells are typically established on the basis of both regulatory and geologic considerations relative to the ore body.

[1]Underlined numbers in parentheses refer to items in the list of references at the end of this report.

As a result of the differences seen above, it is not practical to utilize for in situ mining some of the well design, construction, and development methods used for ground water development. In addition as both operators and regulatory agencies gain more experience with in situ mining, a consistent approach to well design and development seems to be evolving. The balance of this chapter discusses of the principal components of well design for in situ mining.

Required Data Base

Three types of data must be developed as prerequisites for specifying a well design for in situ mining. These are: 1) the characteristics of the host aquifer, 2) the characteristics of the mineralized portion of that aquifer, and and 3) preliminary cost guidelines. The specific data required and methods of obtaining the data are discussed in the following paragraphs.

Geologic and Hydrologic Characteristics

Both geologic and hydrologic data must be developed for the host aquifer. The geologic data of interest include: (1) the type, extent, depth, and thickness of the aquifer, (2) the nature and extent of major structural features (e.g., confinement, dip, boundaries, fractures, etc.), and (3) the physical characteristics of the host and interbedded materials (e.g., degree of consolidation/cementation, grain size distribution, etc.). The hydrologic data include: (1) type and extent of the aquifer, (2) the nature of local aquifer confinement, ground water flow, and water quality, and (3) the expected range of static water levels, formation porosities, permeabilities, fracture pressures, and maximum water yields.

Data similar to the above must also be developed for the mineralized zone. The geologic data include, (1) the nature, extent, and competence of aquicludes for isolation of the ore zone, (2) the physical and structural characteristics of the mineralized zone relative to the remainder of the host aquifer, (3) the nature and extent of interbedded material in the mineralized zone, (4) the extremes as well as the mean depth and nominal thickess of the ore to be developed. The hydrologic data cover both the ore zone and adjacent areas of fluid contact, and include: (1) the range of expected injection/production rates for wells completed over typical ore grade intercepts, and (2) the degree of leach solution confinement to the ore grade portion(s) of the mineralized zone.

Data Acquisition Methods

Development of the detailed geologic and hydrologic data required for an in situ mining project requires integrating the data obtained from: examination of drill cuttings, wireline logging, selective coring, and hydrologic testing. Each method is discussed briefly in the following paragraphs.

Drill Cuttings

Drill cuttings can provide a continuous inexpensive record of the formations drilled. However, the sorting and delay associated with their transport to the surface, coupled with the drilling methods and sampling techniques employed, confound their description and correlation with depth. Nevertheless, when developed by an experienced geologist and correlated with geophysical logs this information can provide a qualitative understanding of formation characteristics. When the results from a number of drill holes are combined, a generalized picture can be developed of the formation characteristics over the area drilled.

Wire-Line Logging

The bulk of the information regarding formation characteristics, and ore delineation is developed by wire-line logging techniques (31,45). Typically such logs measure either a natural characteristic or a stimulated response of the drilling fluid or formation. Geologic information from drill cuttings and cores are used to confirm and refine the interpretation of the log. A brief description of the most commonly used wire-line logs follows.

Resistance Log

At a given current flow, the potential difference between two electrodes depends on the resistance, measured in ohms, of the intervening materials. The latter is a function of the electrical resistivity of the fluid and solid phases present and the average distance and area through which the current flows. Thus to the extent that the current path length and/or pore fluid composition are either constant or reproducible, the lithologic characteristics of a formation can be inferred from its resistance characteristics. The measured resistance of a saturated porous material generally decreases with increasing: (1) conductivity of the solid phase, (2) surface area per unit volume of material, (3) salinity of the pore fluid, and (4) fluid mobility within the material. Thus uniform-coarse grained, and cemented sediments tend to exhibit significantly higher resistances than fine grained porous sediments such as clay or shale.

Resistivity Log

Resistivity or specific resistance, measured in ohm·meters, is determined by measuring the resistance of a sample under conditions of known and reproducible current path length. Since the solids fraction of sedimentary materials are typically non-conductive, the material resistivity depends primarily on: (1) the composition of the pore fluid(s), and (2) the surface area and pore structure characteristics of the material as described in the previous paragraph. Thus within the limits of constant/reproducible fluid characteristics, the observed resistivity characteristics can be related to formation structural characteristics. The resistivity characteristics of various sediments are essentially the same as those described previously for the resistance log. The principal advantage over the resistance log is that a specific reproducible volume of material established by the probe design, is examined regardless of probe location in the bore hole.

Spontaneous Potential Log

Spontaneous potential is a measure of the drilling fluid potential at a given location relative to a constant reference potential. The observed potential is a function of the relative ionic concentrations in the drilling and formation fluids and relative ionic mobility through the formation strata at that location. Of its three components, namely redox, streaming, and electro-chemical potentials, the most significant is the electro-chemical potential produced at the junction of dissimilar materials. The latter is greatest in the vicinity of clay or shale/sand contacts. The polarity is governed by the relative ionic concentrations in the drilling and formation fluids. Thus within the limits of reproducible fluid characteristics, self potential can be used to refine the interpretation of formation characteristics developed from resistance/resistivity logging.

Natural Gamma Log

Naturally occurring gamma radiation is due principally to the presence of K^{40} and the products of uranium/thorium decay, principally Bi^{214} and Pb^{214}. Its primary use is for estimating uranium content based on an assumed proportionality between uranium, which is not a gamma emitter, and its gamma emitting decay products. In addition, gamma emitters such as K^{40} are more strongly sorbed by smaller-grained high-surface-area materials exhibiting natural ion exchange characteristics. Thus the relative gamma characteristics of various strata can be used to refine lithologic identification. Specifically, clays and shales exhibit higher natural gamma readings than sands in the absence of decay products from uranium/thorium mineralization.

Gamma-Gamma Density Log

For a given radiation energy, the percentage of indicent gamma energy absorbed and/or scattered between a particular source and detector is approximately proportional to the bulk density of the irradiated material. Thus given some knowledge of the densities of the fluid and solid phases present, the detected gamma radiation is a measure of the formation porosity.

Neutron-Neutron Log

Fast neutrons emitted by a source lose energy via collision with the various constituents of the matrix material and pore fluid. The principal energy loss is by collision with hydrogen in the form of water or hydrocarbons and results in the conversion of fast neutrons to thermal neutrons. The intensity of the resultant thermal neutron activity can thus be correlated with the amount of hydrogen present between the neutron source and detector. Below the water table and in the absence of significant hydrogen bearing solids, the results can be reliably correlated to formation porosity.

Drift/Deviation Probe

Several methods can be used to determine the angular deviation of the hole from vertical and the bearing of the deviation as a function of depth.

Assuming the deviation is continuous between successive points of measurement, these data are used to calculate and display a plan view of hole deviation from vertical versus depth.

Caliper Tool

Typically a caliper tool has three spring-loaded arms extending from the probe body which maintain contact with the drill hole wall. Measurement of their combined deflection as the probe is pulled through the drill hole gives the variation in drill hole diameter versus depth. The data obtained are useful in determining the volume to be grouted.

Selective Coring

Because of the cost involved, coring is typically limited to a small fraction (less than 5 to 10%) of the total number of drill holes associated with an in situ mining project. It is also common practice to limit coring to either the mineralized formation or the mineralized portion of the host formation. The core is typically characterized for some or all of the following: (1) lithology, (2) porosity, permeability and grain size distribution of identified lithologic units, (3) ratio of chemical to equivalent (radiometric) uranium plus major chemical and mineral components of discrete core intervals, and (4) leach and restoration rates of the ore zone. The results of such characterization are then used to calibrate and/or supplement the results obtained by wire-line logging and hydrologic testing.

Hydrologic Testing

As with coring, the cost of hydrologic testing is such that relatively few tests (typically one per 2 to 10 acres of well field) are conducted. Hydrologic tests are done to develop three kinds of information: (1) flow characteristics and communication within the host formation, (2) fluid communication or confinement between the host and adjacent formations, and (3) limitations on the operation of individual wells. The most commonly used hydrologic test method is one of several types of pump test (33,43). Depending on the type of test employed, it is possible to determine: (1) the mean characteristic transmissivities (i.e., the product of aquifer thickness and fluid conductivity) and storage coefficient of the tested formation, (2) the mean leakance characteristics (i.e., square root of the quotient of fluid conductivity and thickness) of the confining aquicludes, and (3) the existence and nature of hydrologic boundaries within the test area. An important but frequently omitted compliment to the more commonly used types of pump test is the fracture/rupture test. From such tests the sensitivity of the host formation to hydraulic damage as a result of in situ operations can be determined. To minimize the possibiltiy of undesirable damage it is recommended that maximum down hole pressures assocaited with drilling operations and fluid injection be maintained at less than 80% of the characteristic fracture/rupture pressure. Two less commonly used test methods are: (1) tracer testing to determine interwell flow characteristics and (2) permeability/flow profiling to correlate local flow characteristics and wire-line log results in the immediate vicinity of the well bore. Combined with the results of selective coring, the results of hydrologic testing provide the technical data-base technical data-base necessary for both individual well and well field design.

Preliminary Cost Guidelines

In addition to the geologic and hydrologic data just described, some preliminary cost guidelines are essential for developing a practical well design. The principle cost guideline would be a specification for the minimum ore grade and thickness to be developed. This guideline can be developed in a number of different ways. The following equation is one example of such a guideline for minimum grade-thickness (GxT) value.

$$(GxT) > \frac{(W)(TF)}{20(A_{well})(RF)(NV)} \qquad (1)$$

where:

- W = expected total of all well related costs, \$,
- TF = ore zone tonnage factor, cu.ft./ton,
- RF = expected overall recovery factor, typically 0.5 to 0.8,
- NV = expected net product value, i.e. expected sale price less all non-well-related production costs, \$/lb, and
- A_{well} = average effective area of influence per well, sq ft.

Only one element in the preceding equation namely the tonnage factor (TF), is fixed in a given situation. The remaining terms are variable over a considerable range. However, each element influences the rate and cost of mineral production and therefore cannot be fixed arbitrarily. Accordingly, the guideline regarding well installation and completion cost cannot be rigorously established, but rather must be refined toward a minimum for each project as the project proceeds.

Given the data base described above, well design can proceed in a logical fashion. The three principal components of well design are considered in the following paragraphs. In the order of presentation they are pump selection, casing specification, and well completion.

Pump Selection

Current in situ mining practice utilizes submersible multi-stage centrifugal pumps exclusively. This results from the following factors: well depths are relatively shallow (typically less than one thousand feet), ready availability of pumps in the sizes and capacities required, plus high pumping efficiency relative to cost. While other pumping methods are employed in certain circumstances (such as mechanical bailing, swabbing, or air lifting for well stimulation), none of them are used as a primary pumping method. Accordingly, this section considers pump selection only for submersible centrifugal pumps. Intelligent selection of a pump requires that information be developed regarding: the nominal capacity, total head requirement, control/operating philosophy, and the operating environment. These items are fully explored in the following paragraphs.

Pump Capacity

As a general rule, the capacity of the pump should be matched to the expected yield of the well under steady state operation. The yield will vary from well to well depending on formation characteristics in a particular location, the length, effective diameter, and type of completion interval, its location within the aquifer, and the available draw down. An estimate of the injection/production flows obtainable under ideal steady state operation can be determined from the following equation due to Kozeny (41, p. 274):

$$q \simeq \frac{\pi T(\Delta s)\beta}{720\ln\left(\frac{r_e}{r_w}\right)}\left[1 + 7\sqrt{\frac{r_w}{2\beta b}}\cos\left(\frac{\beta\pi}{2}\right)\right]\gamma \qquad (2)$$

where:

- q = liquid flow rate, gpm,
- T = mean aquifer transmissivity, determined by means of one of several pump test methods (33,43) gpd/ft,
- s = maximum available drawdown, ft,
- r_e = effective recharge radius at which the hydrostatic head can be considered constant $\sim\sqrt{A_{well}/\pi}$, ft,
- r_w = effective well radius, ft,
- b = mean aquifer thickness, ft,
- β = fraction of the aquifer thickness over which the well is completed, dimensionless ≤ 1.0, and
- γ = well efficiency, dimensionless ≤ 1.0.

The well efficiency term accounts for the additional pressure drop occurring in the immediate vicinity of the well and can be expected to be strongly dependent on the particular well completion and development methods used. In the cited equation, it was assumed that the well was completed over a single interval extending from the top of the aquifer to some point within the aquifer, and that the confining aquicludes were completely impermeable. Since in many in situ mining applications neither assumption is valid, actual flows may be found to differ considerably from the estimates obtained with this expression. For a more thorough discussion of yields from partially penetrating wells, the reader should consult References 19,28,& 43.

Due to the large number of wells used for an in situ mining project, it is impractical to match pump capacity to individual well yield. Thus in general, the pump capacity is chosen at or near the average expected well yield for the ore zone, which is equivalent to establishing a maximum flow rate per well. In the case of wells having a lower than average yield under steady state operation, some type of control over pump performance must be incorporated in the well design. This control may be of two types: 1) a flow control or back pressure device to increase the total head and thus limit pump output or 2) an electrical control device capable of controlling pump output directly. While the initial cost of the first control method is significantly lower, the overall cost of pump operation and maintenance may be significantly higher and more than offset the initial cost advantage. Thus, the choice of control type should be governed by analysis of the relative total cost incurred. Regardless of the type of control selected, a check valve should be included either down hole or at the surface to prevent back flow into the well when the pump is not in operation.

Head Requirement

As with pump capacity, the required head will vary from one well to another, although the range of variation will be much less. The total dynamic head (h_T) required is the sum of the vertical lift (h_L), the friction head (h_F), the mainfold pressure (h_M), and the velocity head (h_V), as indicated in the following Equation (47, p. 9-14):

$$h_T = h_L + h_F + h_M + h_V \tag{3}$$

where:

h_F = friction head, feet = $(0.002594)\frac{fL}{\phi}\frac{q}{\phi 2}^2$

h_M = surface mainfold pressure, feet = $2.308\ P_M$

h_V = velocity head, feet = $0.002594\ \frac{q}{\phi 2}^2$

q = liquid flow rate, gpm,
ϕ = inside diameter of pump support piping, inches, and
f = friction factor for the pump production piping, dimensionless (Obtained from data presented in Appendix B).

In general, it is recommended that the submersible pump be located at least 5 ft above the well completion interval in order to minimize damage to the pump as a result of fine solids swept into the well bore. In the case of confined aquifers, it is further recommended that the pump be located at or above the upper confining clay or shale layer of the mineralized formation so as to prevent formation dewatering. Consequently, the vertical lift term (h_L) will be essentially independent of the completion interval location of a particular well. Thus, only the friction head (h_F) and velocity head (h_V) depend on the yield of a particular well, and the friction head (h_F) can be manipulated by means of a valve or regulator to achieve a specified total head requirement, regardless of the natural production characteristics of a particular well.

Pump Horsepower

The theoretical horsepower (P_T) of a pump in a given application is proportional to the product of the desired capacity (q) and the total dynamic head (h_T), as indicated in Equation 3 (47, p. 12):

$$P_T = \frac{q \cdot h_T}{3960} \tag{4}$$

The actual horsepower (P_A) required is the quotient obtained by dividing the theoretical horsepower (P_T) by the combined efficiency of a particular pump (e_p) and motor combination (e_m).

Additional Considerations

Several additional factors must be considered before specifying and selecting a pump for a particular application. These factors include the physical and chemical environments and the flow control device used. With all in situ mining applications the potential exists for erosion, corrosion, and precipitation. The two principal causes of erosion are entrainment of fine particles or gas bubbles in the fluid being pumped. While entrainment of fine particles may not be preventable, it can be minimized by: (1) proper well screen selection in terms of slot size and diameter, (2) effective well development following completion, (3) maintaining fluid velocities through the screen at recommended levels, and (4) locating the pump above rather than in the completion interval. Similarly, entrainment of gas bubbles may not be preventable but can be minimized by means of suitable liquid level control or reduction of the pumping rate so as to minimize pump cavitation and exolution of dissolved gasses.

Suitable materials of construction for the wetted parts of the pump and motor will minimize the potential for corrosion. Many of the available submersible pumps are not available in corrosion resistant materials. Particular care must be exercised in specifying pumps for use with either ammoniacal or acidic leach solutions. Where corrosion is suspected or has proven to be a problem, it is now common practice to specify stainless steel (Grundfos) pumps.

While it is not possible generally to eliminate precipitation in the production well bore, three things can be done to mitigate its impact. The first is use of a leach chemistry which minimizes the potential for supersaturation and thereby precipitation. The second is adoption of a flow or liquid level control method which is effective in further minimizing the potential for supersaturation. Third is adoption of a well and pump maintenance schedule which alleviates the impact of precipitates on both well and pump performance.

The Pump Specification

Combined into a concise format, the factors discussed in the foregoing paragraphs become the pump specification. A typical specification would consist of the following components:

Pump Type ______________________________
Nominal Capacity ______________________ gpm.
Nominal Head Requirement _______________ ft.
Anticipated Operating range in terms of flow capacity and
total head __________ to __________ gpm x ft.
Nominal Horsepower requirement ____________ Hp.
Type of Power Supply _______ volts at __________ phase
Materials of construction ______________
Type of motor and pump controls ____________
Critical dimensions ______________________
Other Considerations _____________________
____

Once this specification is complete, pump selection can proceed. The various pump vendors can be contacted for assistance in matching pump requirements to the performance of a particular pump.

Casing Selection

As previously noted, commercial scale in situ mining involves the installation and operation of large numbers of wells, ranging in number from several hundred to several thousand. Also, the majority of commercial operations have well depths of less than 1,000 feet. While consideration is being given to developing ore bodies at depths from 1,000 to 3,000 feet, no significant development of these ore bodies by in situ mining methods has occurred to date. Therefore, the following discussion of well casing materials and design considerations concentrates on practice at moderate depths. Well casing design practice for depths greater than 1,000 feet is covered in several texts (3,22, 49), which discuss the subject relative to oil and gas production. Such practices may have to be modified to reflect in situ mining practices and economics.

Casing Materials

The leach solutions employed in solution mining may be either acidic or basic with reagent concentrations as high as 0.33 Molar and may contain chemical oxidants at concentrations as high as 0.05 Molar. In addition to the primary constituents, other corrosive species, such as chloride ion may be introduced into the leach solution as a result of well cleaning or stimulation and the uranium recovery process. Thus, it is essential that the casing material be resistant to chemical and electrolytic attack. This requirement coupled with the modest depth at which most in situ mining is currently being practiced (1,000 feet) has led to the nearly exclusive use of plastic casing materials. Three types of plastic casing are in general use, namely, polyvinyl chloride (PVC), acrylonitrile butadiene-styrene (ABS), and glass-fiber-reinforced plastics (FRP). The first two materials, PVC and ABS, are homogeneous polymer formulations from which well casing is produced by continuous hot extrusion of the material. In contrast to this, the third material (FRP), is a composite material consisting of glass fiber filaments bonded together with a compatible polymer such as epoxy resin. Well casing is typically produced by spiral winding resin coated glass filaments over a hot mandrel, which causes polymerization of the resin. By virtue of its composite structure, fiber reinforced plastic casing typically has better structural characteristics than either PVC or ABS casing. The cost of FRP casing is typically two to three times that of PVC casing, but only slightly greater than that of ABS casing. The combination of its structural characteristics relative to its cost have largely eliminated ABS as a practical casing material at present. Finally, the selection of PVC versus FRP casing reduces to balancing the costs against the mechanical/structural requirements of a particular application.

Casing Diameter

The minimum possible casing diameter for a particular application is set by the need to accommodate the selected pump. In practice, extra clearance is necessary so that casing distortion and deflection will not interfere with placement of downhole equipment (Figure 1). Distortion may occur as the result of poor quality control during casing manufacture or as the result of stresses on the casing during storage, placement, or grouting. Casing deflection is typically caused by: (1) rapid drill hole deviation or sloughing of the wall, or (2) axial compressive loading of the casing during placement or grouting. Deflection and distortion may be further aggravated by any loss of casing strength due to the release of heat with setting of the grout slurry. Recommendations vary as to what clearance should be provided between the pump and casing diameters. From the standpoint of minimizing interference during the placement of downhole equipment, the clearance should be as large as practical. However, from the standpoint of effective cooling of the downhole pump motor as well as overall cost, the clearance should be as small as practical, consistent with the nominal flow rate for the well. Thus, the clearance provided and the casing diameter selected for a particular application will be the practical minimum based on field experience. In the absence of such experience, a casing diameter from 1/2 inch to 1 inch greater than the pump diameter is usually adequate.

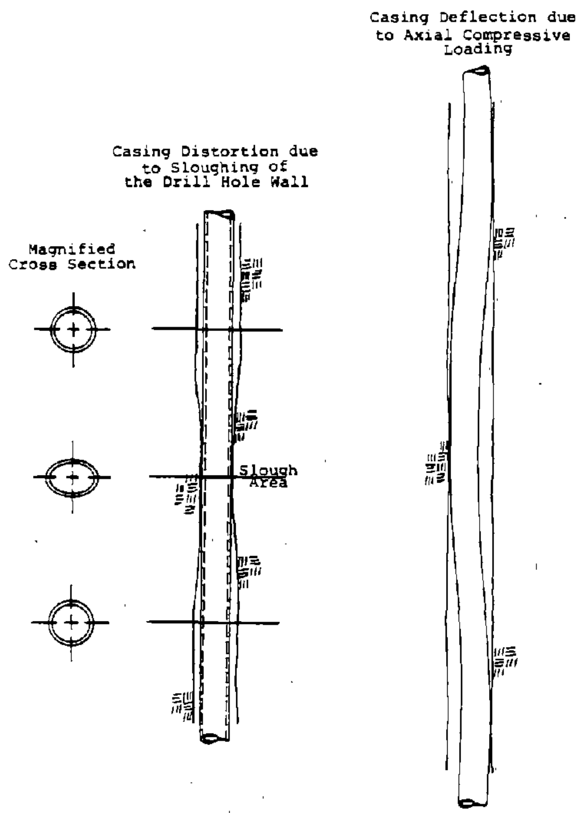


FIGURE 1 - Examples of casing distortion and deflection.

Wall Thickness

The casing wall thickness required for a given application is a function of four types of stress and the structural characteristics of the casing. The first type of stress to which the casing is subjected is a tensile hoop stress (burst pressure). This stress is related to either the combined effect of injection pressure and water hammer surge during operation (Figure 2), or the hydrostatic pressures necessary to achieve and maintain grout emplacement

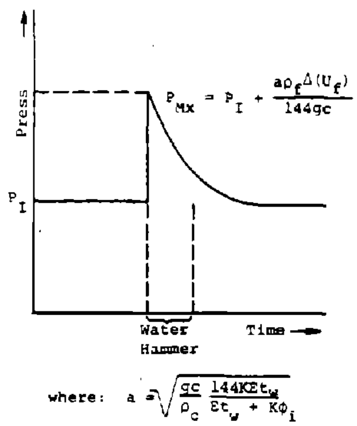


FIGURE 2 - Water hammer surge during operation.

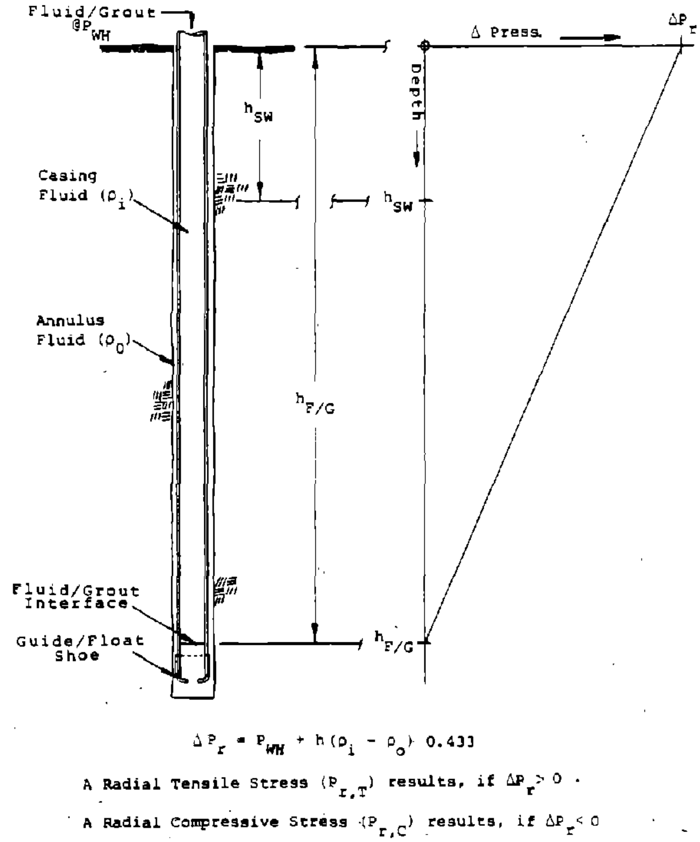


FIGURE 3 - Differential radial pressure due to grout emplacement.

(Figure 3). When during grout emplacement the maximum pressure occurs depends on the specific characteristics of the displaced fluid, grout slurry, and displacing fluids and the rate of grout emplacement. Its principal components are indicated in Figure 3. Regardless of origin the maximum tensile hoop stress occurs at the top of the casing string and is concentrated in the area of the casing-to-well-head joint. Utilizing the largest of these calculated pressure differentials and the physical characteristics of the selected casing material, the minimum practical wall thickness can be calculated by means of the following equation (3):

$$t_w = \frac{\phi_O P_{r,T}}{(P_{r,T} + 2\sigma_T)} \tag{5}$$

where:

t_w = minimum practical wall thickness, inches,
ϕ_O = average outside casing diameter, inches,
$P_{r,T}$ = differential radial pressure causing tension, psi, and
σ_T = design tensile stress, psi (refer to Appendix C).

It should be noted that the effect of water hammer on casing design can be minimized by using slow-acting flow control devices.

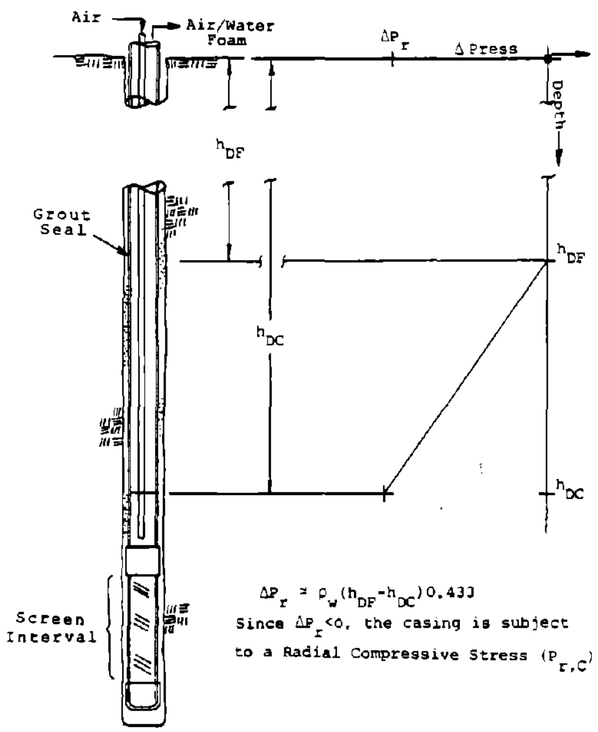


FIGURE 4 - Differential radial pressure due to air lift development.

The second principal type of stress to which the casing is subjected is a compressive hoop stress (collapse pressure). This stress may arise due to a two point compressive load or a uniform compressive load on the casing wall. It is not possible to reliably predict the magnitude of two-point compressive loads, since they typically result from unusual and unexpected conditions during well completion (Figure 1). Therefore, this discussion is limited to uniform compressive loads and the casing wall thickness necessary to resist them. The maximum load of this type occurs at the bottom of the casing and is associated with grout emplacement through a float shoe (Figure 3) and/or air lift stimulation of the completed well (Figure 4). In the former case the load is due to the differential pressure which develops across the casing after grout emplacement as a result of releasing well-head pressure. In the latter case the load is due to the differential pressure acting on the casing while inducing flow through the well completion interval. This stress is normally small, but may become large enough to cause casing damage during the initial phase of well development, particularly if a competent grout seal has not been obtained. Based on the maximum anticipated pressure differential, and the physical characteristics of the selected casing material, the minimum practical wall thickness can be calculated by means of the following equation (3):

$$P_{r,c} = \frac{2E}{(1 - \nu^2)}\left[\frac{t_w^3}{\phi_c(\phi_c - t_w)^2}\right]\left[\sqrt{1 - \frac{3}{4}\left(\frac{S_z}{\sigma_T}\right)^2} - \frac{1}{2}\left(\frac{S_z}{\sigma_T}\right)\right] \tag{6}$$

where:

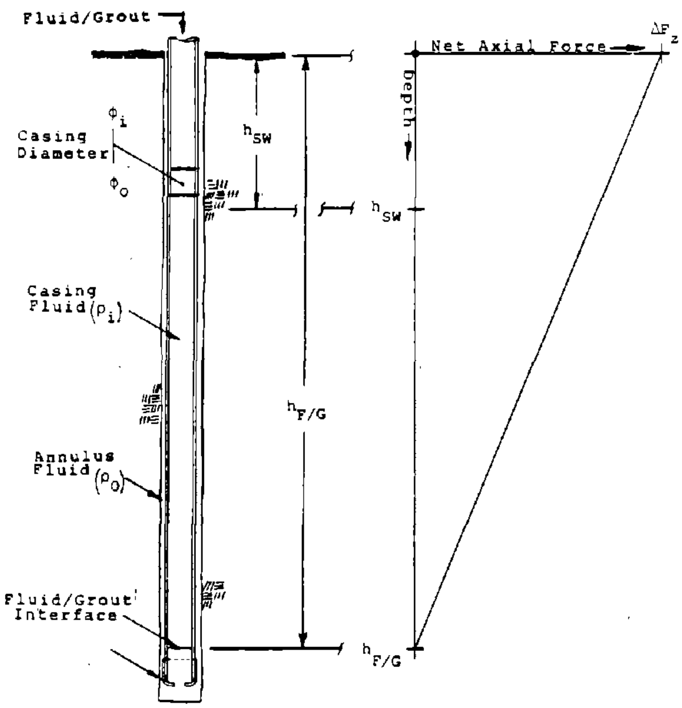
$P_{r,c}$ = differential radial pressure acting on the casing, psi,
t_w = minimum practical wall thickness, inches,
ϕ_c = maximum outside casing diameter, inches,
E = modulus of elasticity, psi, (refer to Appendix C),
ν = Poisson's ratio, dimensionless (refer to Appendix C),

S_z = axial tensile stress in casing, psi, = $\dfrac{4\Delta F_z}{\pi(\phi_o^2 - \phi_i^2)}$ (Figure 6)

σ_T = design tensile stress, psi, (refer to Appendix C).

It can be expected that the casing wall thickness required to withstand a given hoop stress in compression will be approximately three times that required to withstand the same hoop stress in tension. Accordingly, every effort should be made to minimize the magnitude of compressive hoop stresses to which the casing string is subject during installation and operation.

The third principal type of stress is an axial tensile stress. It arises due to the net axial force acting on the casing and contents during grout emplacement or the combined effect of injection pressure and water hammer surge during operation. The axial tensile load developed during grout emplacement occurs when the casing is suspended off the bottom of the drill hole and is full of grout, while the annulus is full of clean-up fluid, as illustrated in Figure 5. The tensile load under these conditions is greater than that associated with the shut-in pressure required to maintain grout displacement (Figure 3) by the net weight of the casing string suspended in the clean-up fluid. The maximum combined pressure acting on the well head due to fluid injection and water hammer (Figure 2) produces an axial tensile stress as well as a tensile hoop stress in the casing. Based on the larger of these tensile forces and the physical characateristics of the selected casing material, the minimum practical wall thickness necessary to withstand axial tension can be calculated by means of the following equation (3):



$$\Delta F_z = \frac{\pi}{576}\left[\phi_o^2(\rho_c - \rho_o) - \phi_i^2(\rho_c - \rho_i)\right]h + P_{WH}\left(\frac{\pi}{4}\phi_i^2\right)$$

an Axial Tensile Force ($F_{z,T}$) exists, if $\Delta F_z > 0$

an Axial Compressive Force ($F_{z,c}$) exists, if $\Delta F_z < 0$

FIGURE 5 - Net axial force on casing due to grout emplacement with surface restraint.

$$t_w = \sqrt{\frac{F_{z,T}}{\pi\sigma_T} + \left(\frac{\phi_i}{2}\right)^2} - \left(\frac{\phi_i}{2}\right) \qquad (7)$$

where:

$F_{z,T}$ = net axial force acting on the casing, lbs,
t_w = minimum practical wall thickness, inches,
ϕ_i = average inside casing diameter, inches, and
σ_T = design tensile stress, psi (refer to Appendix C)

Regardless of its origin, the maximum axial tensile stress occurs at the top of the casing string, and will typically be concentrated in the vicinity of the uppermost casing joint.

The fourth principal type of stress is an axial compressive stress, due to the net buoyant force acting on the casing during grout emplacement, as illustrated in Figure 5. The magnitude of this force is equal to the difference between the weight of cement displaced by the casing string and the weight of that string, including the casing, accessories, and contained displacement fluid. The critical axial load at which the casing will begin to buckle is related to its dimensions and material characteristics by the following equation (54, p. 268-273):

$$|F_{z,C}| < F_{Mx} = \frac{\pi^2 EI}{144(h_{F/G})^2} \tag{8}$$

where:

$F_{z,C}$ = magnitude of the axial compressive force on the casing, lbs,
F_{Mx} = maximum axial compressive load which can be supported without column buckling, lbs,
E = modulus of elasticity of the casing material, psi,
$h_{F/G}$ = depth to the fluid/grout interface, ft., and
I = moment of inertia of the casing, $(\text{inches})^4$, (refer to Appendix C).

In general buckling can not be prevented via adjustment of the casing wall thickness except at low length to diameter ratios and low axial compressive loads. Thus at the length to diameter ratios typical for well casing, it is necessary to either reduce the axial compressive load or design the casing string to resist buckling. The axial compressive load can be reduced by increasing the displacement fluid density thus making the casing string either neutrally buoyant or under slight tension. The tendency to buckle can be reduced by locating centralizers at sufficiently frequent intervals along the casing to reduce the unsupported free casing length and maintain casing alignment within the drill hole.

The physical characteristics of various casing materials necessary for the indicated stress analyses are contained in Appendix C. The minimum wall thickness specified should be the maximum wall thickness determined by analysis using the previous equations plus a suitable safety factor. If this wall thickness is too great due to other considerations, then safeguards must be employed to prevent casing failure during emplacement and grouting.

Joint Type

Four types of joint: the glued bell and spigot, threaded, fusion welded, and spline connected, are commonly available with the casing materials described above. The glued bell and spigot joint (Figure 6) is limited primarily to PVC and ABS casing, which can be solvent welded. While extensively used, this joint has been found to have a number of draw backs. Principle among these is that the solvent welded joint does not develop adequate early strength to insure casing integrity under variable field conditions (7). This may be further aggravated, if the joint is stressed soon after making by the pressure used for grout emplacement. As a result of this and the increased use of FRP casing, the threaded joint is coming into wider use. It can be

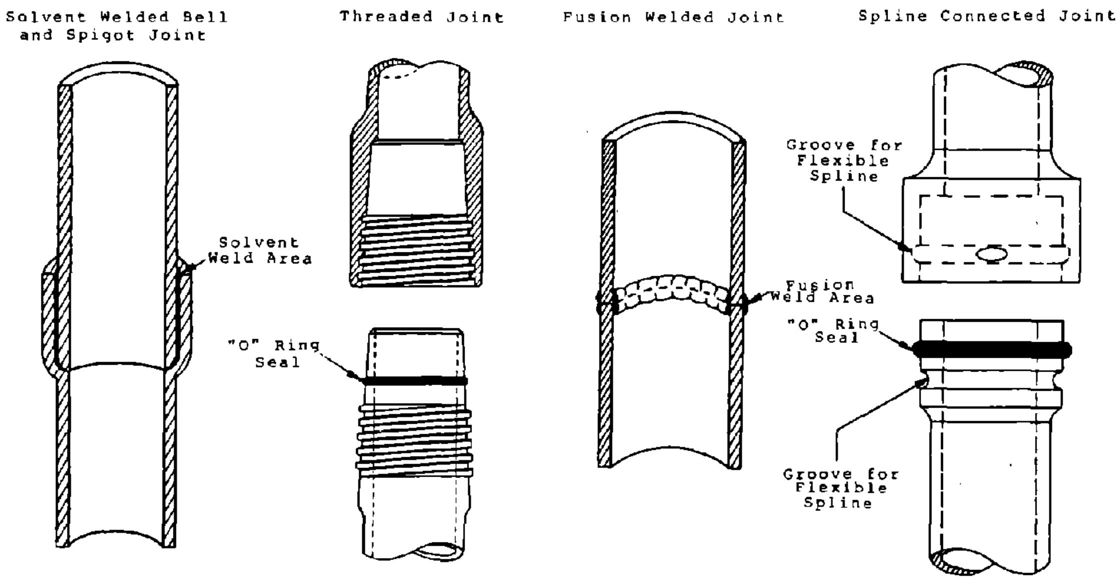


FIGURE 6 - Various types of casing joints.

used with any of the casing materials described, and may utilize either the standard tapered pipe thread or an Acme thread with one or more "O" ring seals (Figure 6). Although compatible with all three types of casing material, the spline connected joint has found only limited use to date, and that has been primarily for small scale in situ mining tests. This is due to its higher cost and larger outside diameter, which can increase interference between the casing and drill hole wall during placement of the casing string. A fourth type of joint, the fusion welded joint, is used extensively with a variety of ABS plastics, for surface piping installations. However to date, it has not received much application as a method for joining well casing.

The Casing Specification

Combining the factors considered in the preceding paragraph in a concise format gives the casing specification. A typical specification would be:

Casing material ____________________

Inside diameter _____ in. $\pm$ (allowable tolerance)

Wall thickness _____ in. $\pm$ (allowable tolerance)

Type of joint ____________________

Maximum OD of joint _____ in. $\pm$ (allowable tolerance)

Minimum structural characteristics:

Expected Service Life _____ yrs., and conditions ____________

Minimum tensile strength of: pipe ________ psi, and joints ________ psi

Minimum long term burst strength _____ psi, as measured by ____________

Minimum collapse strength _____ psi, as measured by ____________

Lengths to be supplied ____________________

Other features ____________________

An essential complement to this specification is use of proper quality assurance (QA) procedures. The importance of QA procedures cannot be overemphasized especially for selection and installation of well casing. Several instances have occurred where the customer received substandard material, which later caused operating or regulatory difficulties that could have been avoided by effective QA procedures. In general such procedures should be structured to verify statistically that the material received meets specification prior to its being released for use.

Well Completion

The completion interval(s) of the installed well serves three functions. First, it must provide any necessary support for the exposed portion of the formation. Second, it permits the injection of solution into or, the production of solution, from the exposed formation interval. Third, it should be designed to provide the desired flow rate of leach solution while confining flow to the mineralized portion(s) of the host formation.

Note that two of these three functions are not common to conventional water well design. The requirements for solution injection and solution confinement are unique to well design for in situ mining. Thus, the objective of the selected well completion technique is not to maximize total water production but, rather, to maximize leach solution flow through the mineralized portion of the host formation. Furthermore due to the large number of wells involved in an in situ mining project, it is generally desirable to use one common well completion technique for Injection, Production, and Monitor wells, even though the criteria for establishing the completion interval may differ. As important as proper selection and design of the well completion, is assuring its proper implementation. The most frequently encountered problem in this regard is assuring that the correct interval is completed.

The following discussion of well completion techniques considers first the impact of formation characteristics on the available completion alternatives. Next is a discussion of the principal methods of well completion. Last is a discussion of the essential components of a well completion specification. Assuring completion of the correct interval(s) is discussed in the broader context of drilling quality assurance in the next chapter.

Formation Characteristics

In addition to providing solution access to the selected formation interval(s), the well completion method must also provide support for the exposed portion of the formation. Thus, the physical characteristics of the formation, namely compressive strength, competence or degree of cementation, and grain size distribution establish what methods of well completion are practical in a given situation. Table 1 summarizes the general relationships between the formation characteristics and the methods of well completion.

TABLE 1

Relationship of Well Completion to Formation Characteristics

Characteristic	Level or Method			
Compressive Strength	---High---		----Low----	
Competence: Natural	----Good----		----Poor----	
Under Leach Conditions	Good	Poor	Good	Poor
Recommended Completion	Open hole or Under-reamed	Perforated or Screened	Perforated or Screened	Screened w/Sand or Gravel Pack

The third physical characteristic of the formation, the grain size distribution, is important in sizing the perforation or well screen for sand control.

Screened Completions

In addition to allowing water to enter or leave the well bore freely, a well designed screen prevents sand from entering the well bore and structurally supports the surrounding formation. The most commonly used well screen is the continuous slot type depicted in Figure 7. This well screen is made by simultaneously wrapping and welding a wire of essentially trapezoidal cross section (wedge bar wire) around a structural support. The support may be either a circular array of longitudinal rods or a perforated pipe. The latter method of fabrication produces a screen with greater structural strength at the expense of somewhat poorer hydraulic characteristics, because the support decreases the open area. This disadvantage can be partially overcome by using an underbar support of thin vertical rods installed between the wedge bar wrap and the perforated pipe. Because the well screen is invariably the weakest structural element in the well, one of the styles of perforated pipe support is almost always used in the manufacture

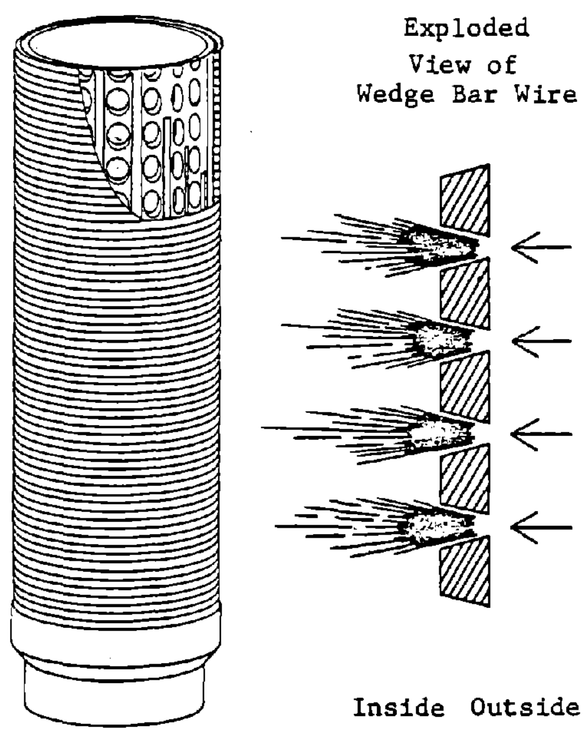


FIGURE 7 - Continuous slot wedge bar well screen (Courtesy of Johnson Well Equipment, Inc.)

of plastic well screen. The wedge bar cross section of the continuous wrap yields an opening configuration which minimizes clogging by sand particles swept through the screen during production (Figure 7). However, quite the opposite is true during injection. Thus, it is important that tramp solids be removed from the injection solution by filtration.

The method for developing a well with a screened completion depends on the grain size distribution of the portion of the formation to be developed. When this zone consists of a well-graded medium-coarse sand, i.e., one with a uniformity index $\geq$ 5.0 and an effective grain size $\geq$ 0.02 inches, the well is "naturally" developed. In this case, the gap between successive wraps of wedge bar is specified to retain 50 wt. % of the sand grains within the developed formation interval (30, p. 190). During well development, the sand adjacent to the screen is agitated and the fines fraction removed through the screen. The result is a "natural pack" of material surrounding the screen, which is graded from coarser to finer material with distance from the screen (Figure 8).

Natural development may prove impractical if: (1) the screen opening hydraulically limits solution flows due to an excessive pressure drop across or velocity through the screen, or (2) the formation proves insufficiently competent to prevent structural damage to the screen, or (3) the zone to be completed consists of poorly graded fine-medium sand, i.e., one with a uniformity index $\leq$ 3.0 and an effective grain size $\leq$ 0.01 inches. In such cases an "artificial pack" consisting of: clean coarse sand, a sized sand/gravel mixture, or a specially graded gravel mixture is placed between the well screen and drill hole during well development. This is done by placing a suitable quantity of the sand and/or gravel mixture to be used in the bottom of the drill hole and then washing the screen down through the mixture, (Figure 9). When a well is developed in this manner, and the screen

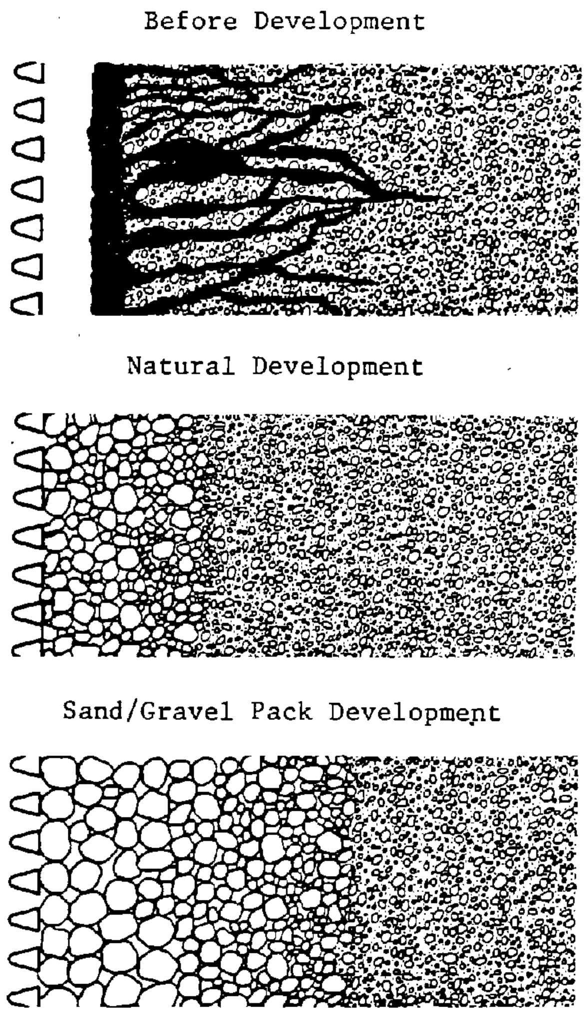


FIGURE 8 - Effect of development on sand gradation.

[2] $$\text{Uniformity Index} = \frac{\text{Sieve size, inches, which retains 40\% of the sand}}{\text{Sieve size, inches, which retains 90\% of the sand}}$$

Effective Grain Size = Sieve size, inches, which retains 90% of the sand is typically specified so as to retain 50 or more wt. % of the sand and 100 wt. % of the gravel used in the artificial pack (30, p. 199).

Because of the somewhat larger drill hole required and the cost of the additional materials and their placement, artificial pack completion is more expensive than natural pack completion. However, the difference in hydraulic performance and structural characteristics of the well may justify the extra cost involved. It is also more difficult to develop an artificial pack completion because of the greater distance and extra material located between the screen and sand face. Therefore, considerable care should be exercised in selecting the drilling fluid and drilling practice used for the completion interval so so as to minimize formation damage and facilitate well development.

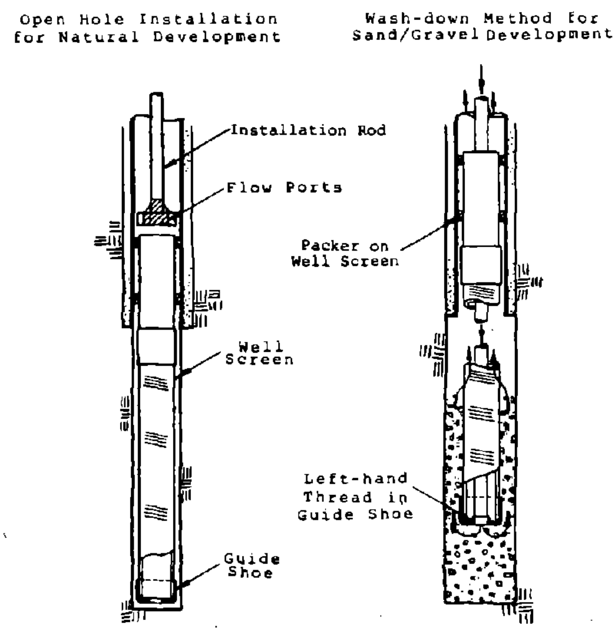


FIGURE 9 - Methods of installing a telescoped screen.

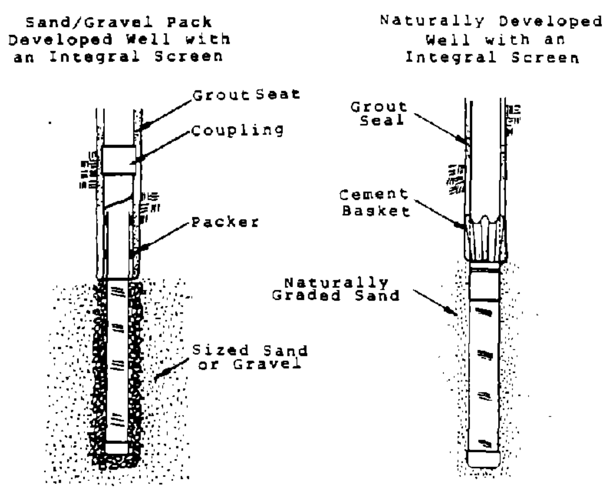


FIGURE 10 - Methods of installing and developing a screened well completion.

Two methods are commonly used to install the well screen and casing, as shown in Figure 10. In the first of these, the screen and casing are installed as an integral unit into the drill hole, and a cement basket is located above the screen to minimize fouling of either the screen or the adjacent sand face during grout emplacement. The second method is a two step procedure in which the casing alone is first installed either to the top of, or through the interval which is to be developed. In the first variation of the method, the interval of interest is exposed by drilling to the desired depth and diameter below the grouted casing. In the second variation, the interval of interest is exposed by either under reaming or perforating through the casing and grout seal. Lastly the screen is installed by telescoping through the casing and sealing it to the casing with a packer assembly. The essential features of the two methods are summarized in Table 2. The method chosen for a particular application will depend on site conditions, experience, and economic considerations.

TABLE 2

Integral Versus Telescoped Screen Installation

	Integral Screen and Casing	Telescoped Screen
No. of drill passes:		
with a pilot hole	3	3
without a pilot hole	2	2
Max. Screen Diameter:	Same as casing	At least 1" less than the casing ID.
Accessories Required:	Collar/Reducer Cement Basket Cement Diverter Plug Wiper Plug (optional)	Packer Assembly Casing Guide Shoe Wiper Plug (optional)
Difficulty of Well Development:	Moderate to High	Low to Moderate
Screen Replacement/ Retrieval Difficulty:	Difficult/Impossible	Moderate Difficulty

Perforated Completions

In those situations where sand control is less significant than providing structural support for the well bore, a perforated completion may be preferred to a screened completion due to its lower cost. If a prefabricated section of perforated or slotted casing is used, one of the two methods of well screen emplacement previously described can be used. Otherwise the well casing can be perforated after it has been grouted in place. Two methods are available for perforating the installed casing: namely by means of hydraulic jet or explosive jet.

Two types of hydraulic jet perforator are available, the first uses an extremely high velocity water jet while the second uses fine sand in combination with high velocty water to produce an abrasive jet (Figure 11). Both methods can penetrate a variety of plastic casing materials, the adjacent grout seal, and the host sandstone to a depth of 12 to 24 inches. With metal casing materials, only the combination jet of water and fine sand is an effective perforation method. Because of its more aggressive cutting action on plastic materials and higher cost, the combination or

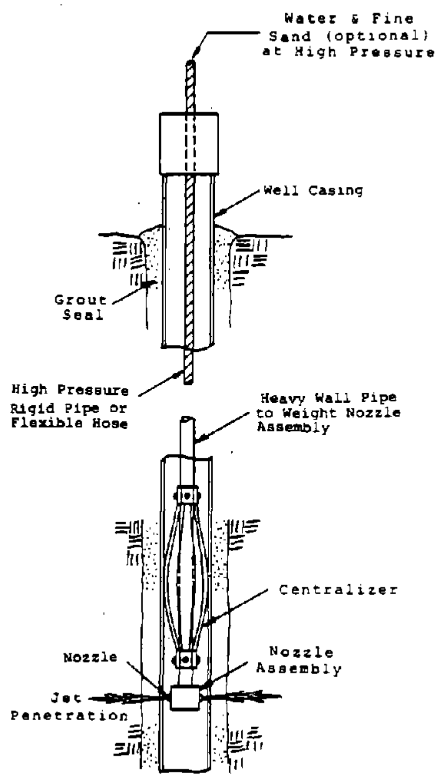


FIGURE 11 - Hydraulic jet perforator.

abrasive jet perforator has received little use to date as a perforation method. The water jet perforator has been evaluated and utilized to some extent where formation conditions are compatible with a perforated well completion. Although localized damage to the casing wall in the vicinity of the perforations has been noted with both PVC and FRP casing, the principal limitations to its broader application appear to be its higher cost relative to explosive jet perforation.

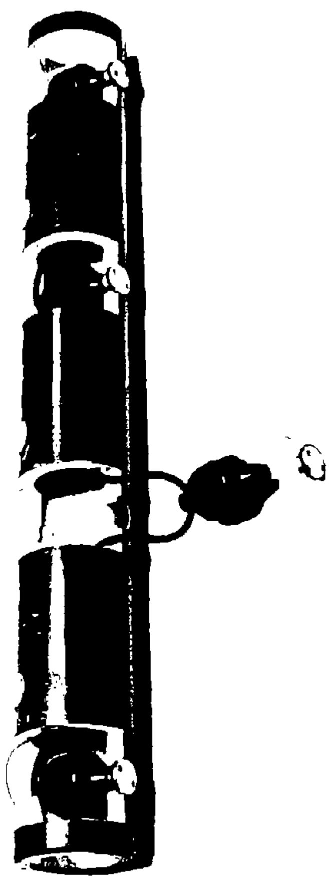


FIGURE 12 - Hollow carrier type explosive jet perforator (Courtesy of Gearhart, Inc.).

The second method of perforation, explosive jet perforation (Figure 12), is widely used in the completion of steel-cased wells. Generally this is the least expensive method of perforation since the carrier is wire-line deployable and the number and arrangement of individual charges can be readily adjusted to provide the perforation diameter, number, and interval required. Because of these advantages, explosive jet perforation has been evaluated and utilized by some firms for well completion. Somewhat greater caution must be exercised with this method of perforation to insure that unacceptable casing damage does not result. Generally the damage is greater with PVC than with FRP casing, but damage can be controlled within acceptable limits for both materials when a hollow carrier is properly used.

Both hydraulic and explosive jet perforation methods permit completion of one or more intervals. However, perforated completions expose much less area of the formation to solution flow than screened or open hole completions. Typically a perforated completion will expose less than 10% of the formation area that is exposed with a screened completion. In addition, the perforation diameters are invariably greater than the critical size necessary for effective sand control. Thus perforated well completions should only be considered where well efficiency and sand control are not significant considerations with regard to well design.

Open Hole and Under-Reamed Completions

Where neither sand control nor structural support of the formation are critical considerations, either open hole or under-reamed completion may be used. Which method is used depends on the hardness of the host formation and the desired completion diameter.

If the desired completion diameter is approximately the same as the casing or drill hole diameter, one of two variations of the open hole completion may be used (Figure 13). In method "A" a second drill pass is required to remove the wiper plug and/or residual cement from the casing and to drill on through the interval to be exposed. In method "B" the interval to be exposed is drilled on the first drill pass. A cement basket is then set at the top of the exposed interval to prevent grout from contacting this interval. If the cement basket leaks, savings in well completion costs may be more than offset by a need for more extensive or vigorous well development procedures. The risk of leakage past the cement basket can be partially offset by using a stronger or multiple baskets.

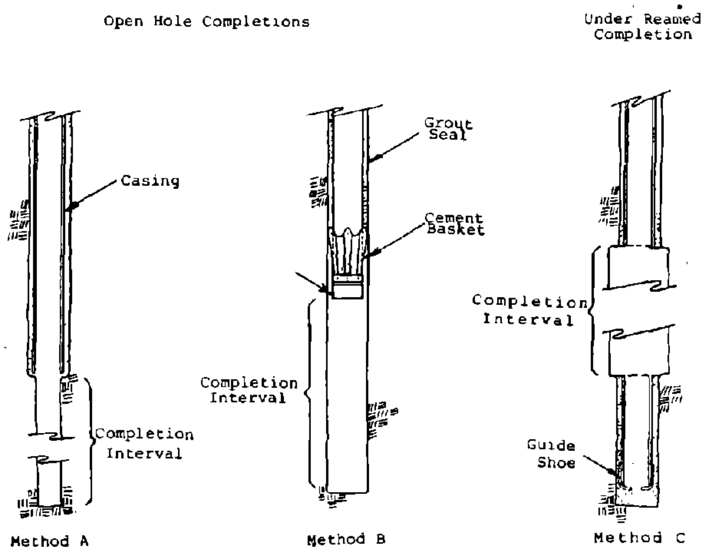


FIGURE 13 - Alternative open hole and under-reamed well completions.

If the desired completion diameter is greater than that obtainable with an open hole completion, an under-reamed completion (Figure 13) is used. The maximum practical diameter that can be obtained by this method is approximately three times the casing diameter. However, the maximum completed diameter and maximum drilling speed decrease as formation hardness increases due to the dimensional and structural limitations on the under-reamer bit. Because an additional drill pass is required and lower drilling speeds are used, the cost of an under-reamed completion is somewhat higher than an open hole completion. Importantly, there is a significant potential for damaging the well casing during the under-reaming drill pass. However, in the completion of relatively shallow or low permeability intervals the additional precautions required and the higher cost may be warranted by the improvement in well flows obtained.

The Well Completion Specification

Combined into a concise format, the factors discussed in the foregoing paragraphs become the well completion specification. A typical specification would consist of the following components:

Criteria for well completion:

Minimum ore grade _____ wt %
Minimum intercept thickness _____ ft.
Minimum Grade X Thickness Product _____ per intercept
Minimum Grade X Thickness Product _____ per hole

Type of Completion:

Screened:

Type of screen ________, Screen Diameter ________ in.
Gap width _______ in., Open area _______ sq.in./ft.
Type end connection ______________________________
Material of construction __________________________

Perforated:

Method of Perforation ___________________________________
Characteristic Dimension(s) _______, Perforation depth _______ inches
Perforation density________________, Perforation pattern___________
Critical operating parameters: (water flow rate and pressure; mesh size and quantity of abrasive; type, magnitude, and number of charges; etc., as appropriate)

Open Hole or Under-Reamed:

Nominal diameter __________ in.
Type of bit and equipment to be used ______________________________
Critical Operating Parameters (maximum drilling speed, type drilling fluid, nominal flow rate, and maximum pressure)

DRILLING CONSIDERATIONS

Drilling is done for two different purposes in conjunction with an in situ mining project. The first of these is for the purpose of mineral exploration and ore delineation, and the second is for the purpose of well installation. Both the cost and feasibility of subsequent in situ leaching can be significantly impacted by exploration drilling practice. In view of this and the economies to be realized by integrating ore delineation and well installation drilling, development of a set of standard practices which serve both purposes is generally desireable. The principal elements of drilling practice are: the type of drill rig, the drilling fluids, the type of bits, and the drilling parameters to be used. Each of these factors is considered in the subsequent sections of this chapter.

Drilling Equipment

There are three basic drilling methods available today. The first of these, Jet/Hydraulic drilling, consists of dislodging or abrading the material to be drilled by means of a moderate to high velocity fluid stream. The second, rotary drilling, consists of forcing a suitably designed bit against the material to be drilled and then rotating the bit to cut the material. The third, percussive drilling, consists of placing a suitably designed bit against the material to be drilled and striking it with a succession of sharp blows as the bit is slowly rotated. The three drilling methods are listed in ascending order of their ability to penetrate material of increasing hardness.

As indicated previously, most in situ mining operations are in sedimentary formations at depths generally greater than 150 feet but less than 1,000 feet. In addition as indicated previously, only one of the purposes for drilling is well installation. This combination of factors has led to the almost exclusive adoption of Hydraulic-Rotary drilling equipment and methods. Although a number of other drilling methods have been traditionally used for water wells (30, p. 209), they all have one or more disadvantages relative to Hydraulic-Rotary drilling. The three principle disadvantages of the other drilling methods are: slower drilling rates, inadequate depth capability, or the necessity of casing while drilling. The latter is a key consideration, since a large fraction of the drilling associated with any in situ mining project is for purposes of exploration and ore delineation rather than well installation.

Hydraulic-Rotary Drilling

In Hydraulic-Rotary drilling, the bore hole is cut by means of a rotating bit and the cuttings are removed by means of a drilling fluid as the bit penetrates the formation material. The bit operates on the lower end of the drill string which consists of three separate components. The first component is one or more drill collars, which are located immediately above the bit. Drill collars are extra-heavy walled large-diameter drill pipe (typically with an outside diameter 1 inch smaller than the bit). They serve to weight and stiffen the drill string immediately above the bit, thereby reducing the tendency for the drill to wander or drift off vertical. This portion of the drill string may also include one or more stabilizers. Stabilizers are oversize drill collars with an outside diameter comparable to the bit and either vertical or spiral flutes on the circumference to permit circulation of the drilling fluid. The second component of the drill string is one or more joints of standard weight seamless drill pipe, equipped with a standard tapered tool-joint pin on one end and tool-joint box on the other end. A commonly used rule of thumb is to choose the pipe such that the tool-joint is one-half to two-thirds of the drill hole diameter. The third and uppermost component of the drill string is the kelley, which has a cross section (square, hexagonal or grooved) such that it can be turned by the rotary table. The upper end of the kelley connects to the water swivel which is suspended from a traveling block on the derrick of the drill rig. The latter supports the entire drill string through the water swivel which permits its rotation via the kelley. A typical Hydraulic-Rotary drilling rig is depicted in Figure 14 with the major components identified.

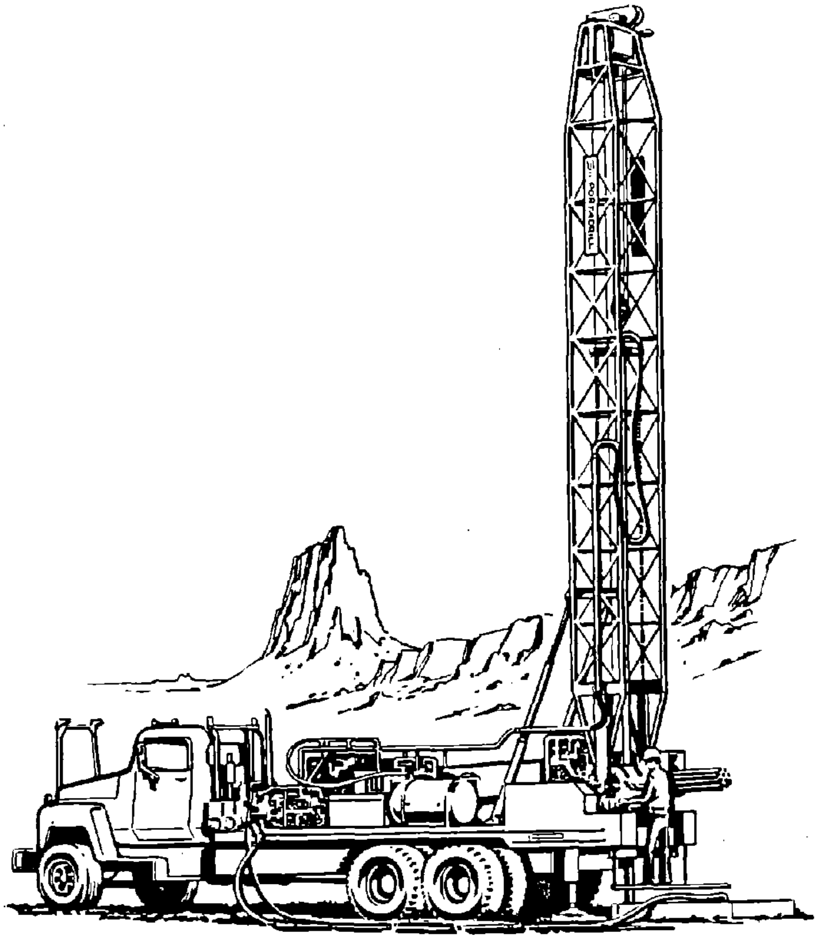


FIGURE 14 - Hydraulic-rotary drill rig.
(Courtesy of Portadrill Inc.)

Truck mounted Hydraulic-Rotary drill rigs are classified according to their maximum depth capability with a particular size, weight, and number of drill string components. However, the drill hole size required for well installation and mud pump requirements for drilling and grouting are typically greater than used in arriving at the clasification of most such equipment. Therefore, it is common practice to use a drill rig with a classification at least twice the maximum depth of the anticipated well installation. To effectively remove drill cuttings, the mud pump must have a capacity adequate to give annular velocities on the order to 60 to 100 ft./min. (20, p. 105) during the final drill pass before well casing is set. In addition the pump should produce the pressure required for grout emplacement at similar annular velocities.

To preclude having to move the drill rig off the hole when setting well casing and emplacing grout, it is essential that either the rotary table accommodate the intended casing size or that the table be retractable. Finally, in order to optimize the drilling parameters for each of the operations associated with well field development, it is generally preferable that the rotary table and the mud pump be independently driven.

Conventional Circulation Drilling

With conventional circulation (Figure 15) the drilling fluid is pumped by the mud pump, through the water swivel and drill string to the bit and then then returns to the surface via the annulus between the drill hole and the drill string. At the surface, the fluid is either directed into a pit or over a screen and through a cyclone to remove the entrained drill cuttings prior to its being recirculated. Typically, a water base drilling fluid circulating at a rate of 60 to 100 ft/min through the annulus is used to clean, cool, and lubricate the bit, and transport drill cuttings to the surface. Because of the significantly greater availability of drilling equipment and relatively low drilling costs for holes of less than ~ 1.0 ft. in diameter, conventional circulation drilling is used exclusively at present.

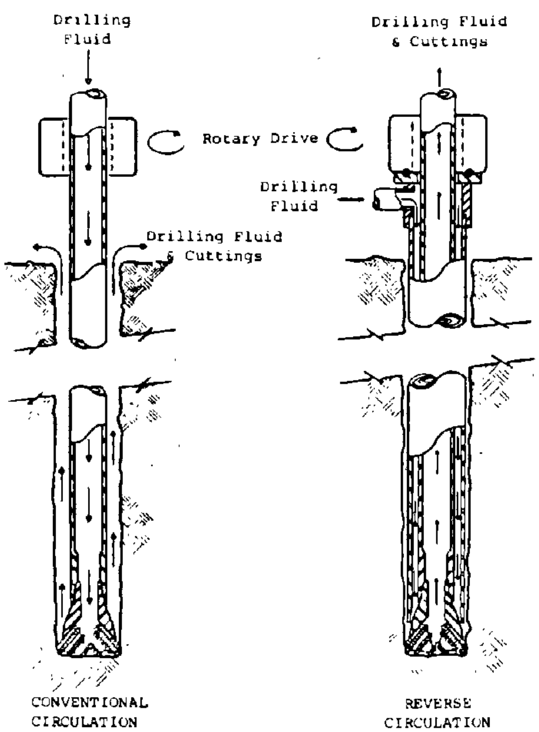


FIGURE 15 - Schematic of conventional versus reverse circulation drilling.

Reverse Circulation

With reverse circulation (Figure 15), the drilling fluid is typically conducted to the bit through the annulus of double walled drill pipe and is recovered through the center channel of the pipe and the water swivel. The drilling fluid may be circulated under pressure or gravity, depending on the requirements of the particular application and the location of the circulation pump. The recovered fluid is then circulated through a suitably designed solids separator before being recycled. Due to its higher costs and the absence of conditions either requiring or favoring its use over conventional circulation drilling, thus far reverse circulation drilling has found no application with regard to in situ mining. Its application to date has been limited to the recovery of high quality cuttings samples for purposes of ore body evaluation. In drilling either low permeability or sensitive strata for well completion, reverse circulation drilling may be preferable to conventional circulation drilling in terms of reduced formation damage and improved well performance. However, its significantly greater cost has prevented its evaluation and application in these cases.

Drilling Fluid

Regardless of the purpose for drilling a particular hole or the nature of the material being drilled, the drilling fluid must perform two essential functions. First, it must transport the drill cuttings from the bottom of the hole and keep them suspended during periods of interrupted circulation. Second, it must clean, cool, and lubricate the drill bit and pipe. In an in situ mining application it must also perform one or both of the following additional functions: provide support for the drill hole wall, and control fluid loss from the borehole. How a drilling fluid is formulated for a particular application will depend on the purpose of the drill hole, the characteristics of the formation, and the relative importance of the other factors just described.

Fluid Characteristics

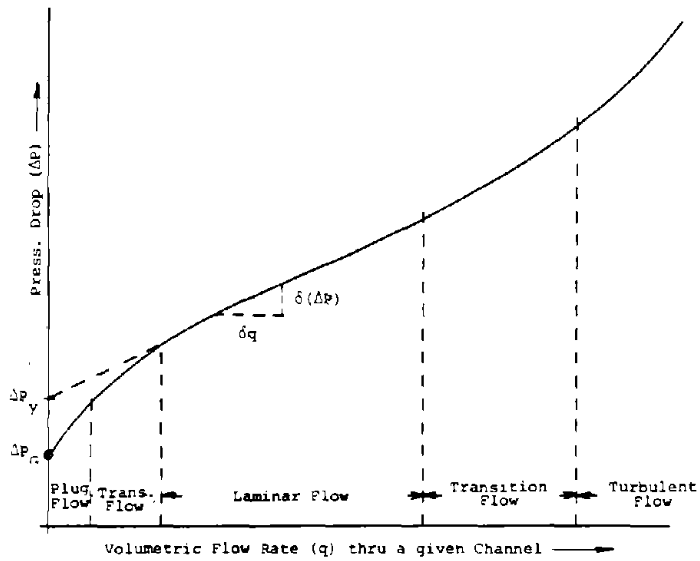
The properties of the drilling fluid which determine its ability to perform the functions described above are its density, viscosity, and filtration characteristics. Regardless of application, the optimal drilling fluid is the one providing the lowest practical combination of density, viscosity, and filtration characteristics at a particular cost.

Fluid Density:

The density of the fluid determines its ability to resist bottom hole pressures and support the drill hole wall as drilling proceeds. At the depths currently of interest, water generally has an adequate density but frequently lacks either the viscosity or filtration characteristics required. Depending on the type of fluid selected, an initial fluid density of 8.4 to 8.7 lbs/gal is adequate to obtain the additional fluid characteristics required. However, as drilling progresses non-settlable/nonseparable solids accumulate in the fluid causing an increase in fluid density. To maintain acceptable filtration and filter cake characteristics, it is recommended that the resultant change in fluid density be maintained less than 0.4 lbs/gal as measured by means of a hydrometer or mud balance. In addition it is recommended that the +200 mesh fraction of suspended solids (referred to as sand) be maintained at less than 2 volume percent (14). To maintain these limits and the desired fluid characteristics it may be necessary to modify mud pit design and/or the initial drilling fluid formulation.

Fluid Viscosity:

The viscosity characteristics of most drilling fluids are quite complex due to the electrostatic forces existing between the colloidal particles suspended in the fluid (Figure 16). In general the three parameters of gel strength, yield point, and plastic viscosity are used to characterize the behavior of a drilling fluid. The gel strength of the fluid is the minimum shear stress necessary to initiate fluid movement after some arbitrary period at rest. The yield point is an extrapolated value of stress, indicative of the residual electrostatic forces between colloidal particles, after initiation of plastic flow. Plastic viscosity measures the resistance to flow above the fluid's yield point.



Where:

ΔP_G = true yield point of the fluid = $G\left(\frac{A_{Surf}}{A_{Flow}}\right) + \rho_f L$

ΔP_y = equivalent yield point of a Bingham Plastic Fluid

μ_{eff} = effective viscosity = $c\frac{\delta(\Delta P)}{\delta q}$ in Laminar Flow region

μ_p = plastic viscosity = μ_{eff} for $\Delta P \; \Delta P_y$

FIGURE 16 - Typical flow characteristics of a pseudo-plastic fluid.

Gel strength is readily measured by means of a "Shearometer", which is a thin duraluminum tube of standard dimensions and weight. The gel strength, in terms of pounds per square foot (psf) is determined from the equilbrium depth of immersion attained under its own weight. Maximum values of 0.0065 psf initially and 0.0326 psf measured after 10 minutes are commonly recommended (44, p. 307). Due to the complex nature of fluid viscosity, it is common practice to use a relative rather than absolute measure of fluid viscosity to specify and monitor drilling fluid characteristics. The principal method used is the "Marsh Funnel" viscosity, which is the time in seconds required for one quart (946 cc) of a 1.5 liter sample of fluid to drain from a funnel of standard dimensions. For in situ mining applications, a drilling fluid with Marsh Funnel viscosity of from 32 to 38 seconds relative to 26 seconds for water is generally recommended (44, p. 431). This measurement integrates the effect of fluid density, viscosity, and gel strength on flow rate, and therefore should not be used alone to specify drilling fluid characteristics. However, it often provides a reliable method of monitoring significant changes in drilling fluid characteristics.

Solids Convection and Suspension:

The ability of a given fluid to either convey or suspend drill cuttings is a function of the fluid's density (ρ_f) and viscosity (μ_{eff}) characteristics as well as the size (ϕ_s) shape, and density (ρ_s) of the particles (44, p. 308).

As particle size increases, the ability of a particular fluid to convey drill cuttings in a practical sense becomes less dependent on fluid viscosity and more dependent on fluid velocity.

The maximum velocity attained by a particle relative to the fluid (U_{Mx}), referred to as slip velocity, is given by the following expression developed by Rittinger (44, p. 309):

$$U_{Mx} \simeq 2.6\alpha\sqrt{\phi_s\left(\frac{\rho_s - \rho_f}{\rho_f}\right)} \tag{9}$$

where α is a dimensionless empirical correction for particle shape, typically 0.4 for drill cuttings. To effectively convey cuttings from the drill hole, the fluid velocity through the largest cross-section of the annulus should be maintained at least 1.2 times the slip velocity of the largest cuttings generated. Depending on the particular fluid and formation characteristics, somewhat higher annular velocities may be required to control bridging[3] and optimize drilling rate.

The ability of the fluid to suspend drill cuttings during periods of interrupted circulation is related to the gel strength (G) of the fluid and the difference between the solid and fluid densities (ρ_s and ρ_f respectively). The maximum equivalent diameter (ϕ_{Mx}) of a suspendable particle is given by the following expression developed by Cardwell (44, p. 315):

$$\phi_{Mx} = \alpha \frac{72G}{(\rho_s - \rho_f)} \tag{10}$$

where "α" as before is an empirical correction for particle shape. The ability of a fluid to suspend drill cuttings is considerably less than its ability to convey those cuttings to the surface within the practical range of fluid velocities and gel strengths.

Solids Separation

Once conveyed to the surface, the drill cuttings must be separated from the fluid by either gravity or mechanical separation in order to maintain fluid quality. The characteristic slip velocity of the various size fractions of the cuttings will determine the minimum time required and the effectiveness of gravity separation. The limiting value of slip velocity (U_s) for the smaller size fractions is given by the following modified version of "Stoke's Equation" (44, p. 309):

$$U_s \simeq 0.185\alpha\left[\frac{\phi_s^2(\rho_s - \rho_f)}{\mu_{eff}}\right] \tag{11}$$

where μ_{eff} is the effective fluid viscosity in the vicinity of the particle under consideration, and all other variables are as previously defined.

[3] Bridging refers to the accumulation of large drill cuttings, which are not effectively conveyed to the surface, in the annulus immediately above the drill bit or collar(s).

While fluid viscosity (μ_{eff}) has a negligible effect on the efficiency with which cuttings are conveyed to the surface, it reduces the slip velocity of the smaller size fractions, thus reducing separation efficiency. Accordingly, it is recommended that the lowest practical fluid viscosity be maintained. Should it become impractical to maintain the desired fluid characteristics by gravity separation methods, it becomes necessary to add a mechanical separation method.

Filtration Characteristics

There are two important aspects of fluid filtration characteristics, namely the physical nature of the wall cake, and the fluid loss which occurs through the cake. From the standpoint of both the driller and the in situ mine operator, it is desirable that the drilling fluid build a thin, dense, and resilient wall cake with minimal fluid loss. This is particularly true of the fluid used to drill through the proposed well completion interval where drilling fluid or filtrate intrusion may cause significant permeability loss. Fluid filtration characteristics are reported as the filter cake thickness formed and the filtrate volume collected when a well mixed 0.6 litre sample of fluid is filtered through a 3 inch diameter #50 or #52 Watman filter under a differential pressure of 100 ± 5 psi for a period of 30 minutes. A filter cake thickness of approximately 1/32 inch, and a filtrate loss of less than 10 cc is generally recommended (44, p. 319) for the drilling fluid used through the well completion interval. For a given fluid, both the filter cake thickness and filtrate loss so measured have been shown to vary approximately in proportion to the square root of both the applied pressure and elapsed time. It should be noted, however, that the static conditions employed in the API test described have been found to generally yield a lower filtrate loss and a thicker filter cake than obtained under the dynamic conditions characteristic of drilling (35). To date no consistent correlation between static and dynamic filtration results has been identified, nor has a better test procedure been adopted. In view of this the results of any such test should be used with caution particularly when screening a wide variety of drilling fluids.

Types of Fluids

The interrelationship of the three fluid properties discussed above, and their relative importance in a particular application, combined with total drilling fluid related cost will determine the choice of drilling fluid used. Five types of fluid are in common use at present, namely: Bentonite base fluids, Natural or Synthetic Polymer base fluids, combination Bentonite and Polymer base fluids, Water, and Air or Foam. The characteristics and application of each fluid are discussed in the following paragraphs.

Bentonite Base Fluids

This group of fluids is probably the best known and most widely used of all the drilling fluids. Bentonite is a gel forming clay which is readily dispersable in water. It is predominantly comprised of either sodium or calcium montmorillonite depending on its source (the western or southern United States respectively). The fluid properties are a function of the relative quantity of active colloidal particles (less than 2 micron) present, and the nature and magnitude of the electrical charge on the active particles. The accepted measure of clay quality is the yield obtained, namely the number of barrels (at 42 gals/bbl) of fluid with an apparent viscosity of 15 centipoise produced from one ton of material. A high quality western bentonite will exhibit a yield of 100 bbls or more per ton as compared to 10 bbls/ton for typical native clays. Yields can be increased even further by treatment with various organic polymers, which increase colloidal dispersion by the process of peptization. Yield may also increase during drilling as a result of fines generated by sustained high shear rates and the addition of native clays from the formation.

A correctly designed bentonite base mud will fulfill all the functions required of a drilling fluid. The viscosity, gel strength, and filtration characteristics of bentonite base fluids can be varied over a considerable range by varying the quality of bentonite and quantity of water used. However, as with most of the primary drilling fluids, the realization of the optimum value for all three will generally require the use of one or more additives (20, p. 53, 40, p. 354). The parameters satisfied by the basic bentonite fluid should be either those most critical to the drilling operation or those least readily incorporated by means of additives.

Because of their low cost, this type of fluid is extensively used for exploration, ore delineation, and well drilling activities. However, in situ mining experience has shown that it is generally inferior to other types of drilling fluids for drilling through the completion interval, due to the greater difficulty of subsequent well development. Thus unless a perforated completion is planned, it may be desireable to switch to a drilling fluid which can be chemically broken down when drilling through the well completion interval.

Polymer Base Fluids

Polymers useful for drilling fluid formulation are either natural or synthetic colloidal materials which have a strong affinity for water (i.e., hydrophyllic) and develop swollen gels when dispersed in water (42, p. 345). The most frequently used materials are the group of carbohydrates classified as polysaccharides which includes various types of starch, gum, and cellulose. They are available in three forms, namely: (1) processed natural forms, (2) natural forms chemically modified to improve performance, and (3) forms synthesized to achieve specific performance characteristics. Because of their origin the natural forms are susceptible to bacterial attack and breakdown after a day or more depending on ambient conditions. The chemically modified forms are more expensive, but permit chemical control of the gel characteristics. Chemically synthesized forms are the most expensive and therefore the least utilized of the three forms. The most widely used materials at present are: (1) natural and modified Guar and Xanthum Gums, and (2) various modified forms of cellulose such as carboxymethyl and hydroxyethyl cellulose.

The gel structure produced by these polymers increases fluid viscosity and decreases filtration loss in both fresh and salt water. By suitable chemical adjustment, the fluid characteristics can be converted from viscous nonthixotropic to strongly thixotropic for control of lost circulation or they can be chemically destroyed to aid well development. This flexibility has led to the extensive use of such polymer base fluids for well installation, completion, and coring (20, p. 57).

Combination Mud/Polymer Fluids

This group of drilling fluids consists of two distinct types (40, p. 116). The first type uses a polymer which interacts with the bentonite to aggregate individual clay particles, thus trapping water within the gel structure. The most common polymers of this type are the polyacrylates, which act to increase fluid viscosity and decrease filtration loss without significant effect on the viscosity of the filtrate. Thus, they effectively increase bentonite yield by reducing the quantity of bentonite required to obtain a specified fluid viscosity. In addition, they serve to aggregate undesirable suspended fines and facilitate their removal from the drilling fluid.

The second type of fluid uses polymers which increase liquid viscosity without interacting significantly with the bentonite particles. Polymers of this group are typically produced by the action of the bacteria, genus xanthemonas compestris, on sugars and are referred to as X-C polymers. Mud/polymer fluids of this type thicken at low shear rates and thin at high shear rates, thus providing the gel strength characteristics necessary to support drill cuttings during periods of interrupted circulation.

By combining these two types of fluids a broader spectrum of gel, viscosity, and filtration characteristics is obtainable than with either bentonite or polymer fluids alone. However to date, their principal application for in situ mining has been improving an essential fluid characteristic, such as filtration control, of either mud or polymer base fluids, rather than the development of specially designed mud systems[4]. They are most often used to improve bentonite fluids by increasing yield or improving filtration characteristics.

Water

Although the ideal fluid in some respects, water alone is seldom used as a drilling fluid in conventional circulation drilling. When used, a natural drilling fluid gradually develops as a result of the mobilization of colloidal materials from the formation(s) drilled. In drilling through sedimentary strata the fluid so developed may approach the character and consistency of a correctly designed bentonite base drilling fluid. However, it is likely that the resultant fluid will exhibit high fluid and filtrate loss characteristics. Thus whether water offers an advantage over a correctly designed drilling fluid in a particular application will depend on: (1) the relative magnitude and impact of fluid and filtrate loss on the permeability of the formation,

[4]An example of a specially designed fluid is the use of a broad size distribution of calcium carbonate particles (ranging from submicron to several hundred microns) either alone or in combination with a non-ionic polymer dispersed in water to obtain an acid degradable drilling fluid (55).

and (2) the relative effectiveness with which the permeability of the exposed formation interval can be restored during well development. When the completion interval is comprised of relatively clean and competent sandstone (i.e., free of disseminated clay and organic material) water may prove to be the optimum drilling fluid. However, where the completion interval contains significant silt and colloidal material, water is likely to be inferior to other drilling fluids.

Air/Foam

Air/Foam, like water, is not extensively used as a drilling fluid for in situ mining applications. The principle reason is that it provides essentially no support for the drill hole wall as drilling progresses. In order to continuously remove cuttings from the drill hole, the hydraulic gradient must be maintained from the formation into the drill hole rather than the converse, which maximizes the potential for collapse. Nevertheless, as in the case of water, air/foam has found limited application. Where the formation is sufficiently competent to be self-supporting under the stresses of drilling, the exposed sand face is continually flushed by intruding groundwater as drilling progresses. Thus of all the drilling fluids available, air/foam drilling induces the least permeability damage and minimizes well development requirements. Where a foam of greater strength than developed by air and water alone is required to convey drill cuttings to the surface, a surfactant type foaming agent may be introduced via the air supply.

Under certain circumstances, air/foam drilling may be the only practical method of obtaining the desired information. An example is when it is necessary to assess the extent of contamination in a particular formation. In this case a liquid drilling fluid may either introduce additional contamination or dilute the contaminants present, thereby confounding the results. Providing there is adequate drill hole stability, air/foam drilling may also offer the best method of obtaining uncontaminated and correlatable drill cuttings. However in general, reverse circulation drilling utilizing double wall drill pipe is better suited to this purpose than conventional circulation drilling equipment.

Drilling Fluid Additives

When the optimal drilling fluid characteristics (density, fluid viscosity, gel strength, and filtration characteristics) for a particular application are unattainable with one of the three basic types of fluid described, one or more additives may be used to obtain them. There are five general types of additives, namely: viscosity modifiers, filtration loss additives, lost circulation additives, density modifiers, and chemical additives. Since most additives affect more than a single characteristic of the drilling fluid, it is important that the various combinations of basic fluid and additives which will yield the desired characteristics be evaluated to determine the optimum combination. Each of the five general types of additives are briefly described in the following paragraphs.[5]

[5]For additional information, the reader is referred to the following references: 40, p. 116, 44, p. 367, 12,35, or 63.

Viscosity Modifiers

As discussed previously (44, p. 367), two parameters are used to characterize the viscosity of a drilling fluid, namely yield point and plastic viscosity. The plastic viscosity component varies approximately in proportion to the concentration of colloidal material present in suspension. Once the desired plastic viscosity has been obtained, the yield point can be adjusted by the addition of a thinner or a thickener. Although a number of chemicals are effective thinners, only the complex sodium phosphates (such as sodium tetraphosphate and sodium acid pyrophosphate) are suitable for most in situ mining applications, where the impact of the additive on baseline water quality must be considered. The specific phosphate chosen will depend on the pH and composition of the natural drilling fluid and groundwater. These compounds act as dispersants, altering the electrical charge on the colloidal material, thus reducing the strength of the gel structure formed. Generally this has the additional effect of reducing filtration loss due to the closer packing of the solids in the filter cake. To increase the yield point of the fluid it is necessary to enhance gel structure formation between colloidal particles by the addition of either a suitable polymer (such as one of the polyacrylates) or a chemical reagent (such as lime or caustic) depending on the nature of the basic fluid. However, this generally has the additional effect of increasing both plastic viscosity and filtration loss due to the increased concentration of colloidal material.

Filtration Loss Additives

This group of additives alter the permeability of the filter cake by altering the quantity of colloidal soilds present, the gel structure produced, the size distribution of suspended material, or the liquid viscosity. Depending on the basic drilling fluid being used, bentonite, calcium carbonate, or a suitable polymer can be used to reduce filtration loss and filter cake thickness. Test results indicate that filtration loss can be minimized by maintaining a size distribution in the fluid of 50 to 60% colloidal material (i.e., less than 2 micron) plus 50 to 40% suspended material having a near logrithmic distribution of particle sizes ranging from 2 to approximately 100 microns (44, p. 404). Fluid viscosity and filtration loss characteristics are complexly interrelated, and it may be necessary to use a fluid composition which yields a practical compromise between these characteristics.

Lost Circulation Additives

This group of additives serves to alter the permeability of the formation face. There are three basic methods of altering the permeability depending on the cause and severity of the problem (44, p. 634). The first method consists of reducing the differential pressure imposed on the formation as a result of the drilling operation. This pressure is a function of the bottom hole pressure necessary to initiate and maintain fluid circulation, which in turn is a function of fluid density and viscosity as well as the drilling practices employed. Accordingly, by either reducing fluid density and viscosity or modifying the drilling practices, it may be possible to alleviate lost circulation problems. The second method consists of introducing either a natural or synthetic fibrous, flake, or bulk material into the drilling fluid to bridge or seal off the thief zone. The third method consists of injecting a slug of either high gel strength drilling fluid or flash setting cement grout into the thief zone by a squeeze cementing technique (49, p. 85). Because of the inherent problems involved, the last method of control is recommended only when all other methods of control have failed.

Density Modifiers

Since it is generally desirable to maintain the lowest fluid density consistent with a given application, the most commonly encountered problem is that of maintaining fluid density by minimizing the accumulation of drill cuttings in the fluid. Where this cannot be accomplished by modifying the filtration or sedimentation methods employed, it may be necessary to either reduce the fluid viscosity characteristics or add a flocculant to improve the separation of noncolloidal solids. Although less common, it may be necessary to increase the density of the drilling fluid to neutralize downhole pressures encountered during drilling or to reduce stresses on the well casing associated with grouting. The most commonly employed weighting agent is barium sulfate of 200 x 325 mesh size.

Other Chemical Additives

Three other types of additives are commonly used with drilling fluids. The first type consists of additives used to condition the mix water. The second type consists of additives used to adjust or maintain drilling fluid chemistry. The third type consists of lubricants used to reduce frictional drag between moving parts of the bit and between the drill string and filter cake formed on the drill hole wall. The need for and choice of such additives will depend on the quality of the mix water, the drilling fluid formulation, and the drilling conditions characteristic of a particular application.

The Drilling Fluid Specification

Development of practical drilling fluid specifications which are suitable for a particular in situ mining project is largely a process of trial and error and evolution. As a project proceeds, the drilling fluid characteristics found to be best suited for exploration and ore delineation are likely to differ significantly from those found to be best suited for drilling through and completing the ore zone. However, it is also impractical to develop and use a multiplicity of drilling fluid specifications. A solution frequently adopted to this dilema is the development and use of one or two standard drilling fluid specifications. Thus, emphasis is shifted from the drilling fluid to the methods of well completion, development, and stimulation for restoration of formation permeability.

Combining all the foregoing factors into a concise format yields the drilling fluid specification. Where more than one type of fluid is to be used, depending on either the purpose of the drill hole or the stage of completion involved, multiple specifications will be required. A typical specification follows:

Type or purpose of drill hole ______________________________.
Type of drilling fluid to be used ______________________________.
Nominal fluid volume to be mixed ______________________________ gal.
Quantities of ingredients to be used:
1. __________ lbs. of ______________________________
2. __________ lbs. of ______________________________
3. __________ lbs. of ______________________________
4. __________ gal. of mix water
Mix water quality: ______________________________
____

Mixed fluid characteristics:
Fluid density ____________ $\pm$ ____________ lbs/gal.
Marsh funnel viscosity ____________ $\pm$ ____________ sec.
Filtration characteristic ____________ $\pm$ ____________ cc. of filtrate after 30 min. from an 600 cc sample filtered through a __________ Whatman filter at 100 psig.
Gel-strength ____________ $\pm$ ____________ lbs/sq. ft as measured with a standard "Shearometer" of __________ gms.
Maximum sand content __________ wt. % as measured with a 100 mesh sieve
Type of records to be kept and data to be recorded: ______________
____
____

As mentioned previously with other specifications, it is essential that appropriate quality assurance procedures be used. In the case of drilling fluids, QA procedures have a two-fold purpose. The first is to insure that the drilling fluid satisfies the requirements of the particular site. The second is to optimize the drilling fluid with respect to well completion. Since the drilling fluid may either aggravate or facilitate various aspects of well completion, development, and utilization, the drilling procedure, the drilling fluid, and the methods of well completion and development should be optimized as a combination, rather than individually. Therefore, it is essential that all of the specifications be developed carefully and refined as the project proceeds.

Drill Bits

Four types of drill bits are used for in situ operations. They are the Drag Bit, Tri-Cone Roller or Rock Bit, Coring Bit, and Under-Reamer Bit. The choice of bit depends on one of two factors, either the characteristics of a particular formation or the purpose of the particular drill hole or interval. Each of the four types of drill bits is discussed in the following paragraphs.

Drag Bit

This type of bit has either two, three, or four contoured or stepped blades equally spaced around its circumference. The cutting edge of the blades may either be forged or surfaced with replaceable tungsten carbine inserts. Where extensive use and wear are anticipated, the latter is common practice. Flow nozzles in the body of the bit direct drilling fluid along the face of each blade to clean and cool it while drilling. This type of bit is well suited for drilling sand, clay, and soft mudstone, but is not suitable for drilling coarse gravel or medium to hard rock formations. The choice of number of blades is dependent on how much deviation in drill hole diameter and vertical alignment can be tolerated in a particular drill hole. Because it is not self-centering and takes a somewhat heavier cut with each blade, the two blade or fish tail bit tends to to drill somewhat less true, both with respect to hole diameter and alignment. As the hole diameter increases, both problems increase and may preclude use of a two blade bit altogether.

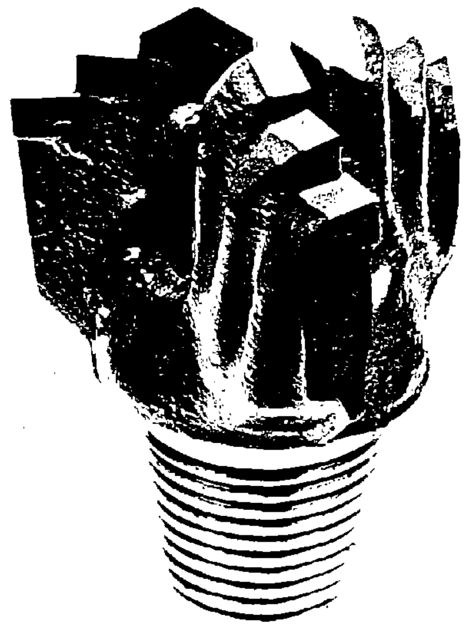


FIGURE 17 - Drag bit.
(Courtesy Varel Mfg. Co.)

Rock Bit

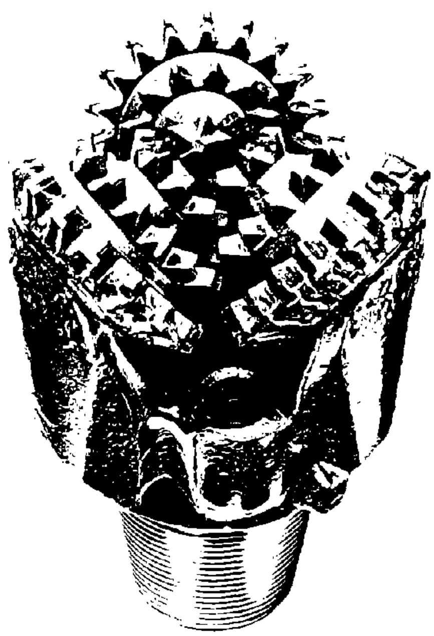


FIGURE 18 - Rock bit.
(Courtesy of Varel Mfg. Co.)

This type of bit consists of three or more toothed rollers mounted in bearings set at an angle to the axis of the bit. Of the various designs available, the tri-cone rock bit, which utilizes three conical rollers into which teeth have been forged, is the most commonly used. As the drill string and bit rotate, each cone rotates resulting in the weight of the drill string assembly being concentrated on succeeding sets of teeth. The concentrated force crushes and chips the formation into bits and pieces small enough to be flushed from the drill hole by the drilling fluid. Drilling fluid is directed from the body of the bit by means of flow nozzles onto the top of each roller to cool the teeth and flush out any remaining cuttings. The tri-cone roller can be used to drill almost any material except clays and soft mudstones. In the latter cases, the drilled material packs between the teeth of the rollers and cannot be dislodged by the drilling fluid thus preventing further drilling.

Selection of roller design for number and geometry of teeth depends on the characteristics of the formation being drilled.

Core Bit and Barrel Assembly

This assembly consists of three major components, namely: core bit, core barrel, and external collar which contains the core barrel and connects the core bit to the drill stem. As drilling proceeds, the core passes through the bit and into the core barrel where it is retained and protected from the drilling fluid pending recovery. Core barrels are of two types, the conventional type in which the core is retrieved by pulling the entire drill string, or a wire-line type in which the core is retrieved via a wire-line tool run through the drill string. The specific design of the core barrel and cutter(s) relative to the core bit and external collar depends on the particular core barrel type (17, p. 237). Generally a wire-line coring tool gives a smaller core diameter but a higher coring speed than a conventional coring tool.

One of three types of bit is used for coring dependent on the characteristics of the particular formation as follows: (1) a drag type bit for soft formations, which incorporates three blades for drilling alternated with three blades for core trimming, (2) a roller type bit for medium hard formations, which incorporates three tapered rollers oriented for drilling alternated with three similar rollers oriented for core trimming or (3) an abrasive type bit for hard/cemented formations, which utilizes an appropriate size and quantity of silicon carbide or diamond grit bonded to the bit cutting surfaces. To minimize core damage and loss, the entire core barrel assembly is designed to minimize drilling fluid contact with the core while still cooling and cleaning the cutting surfaces of the bit.

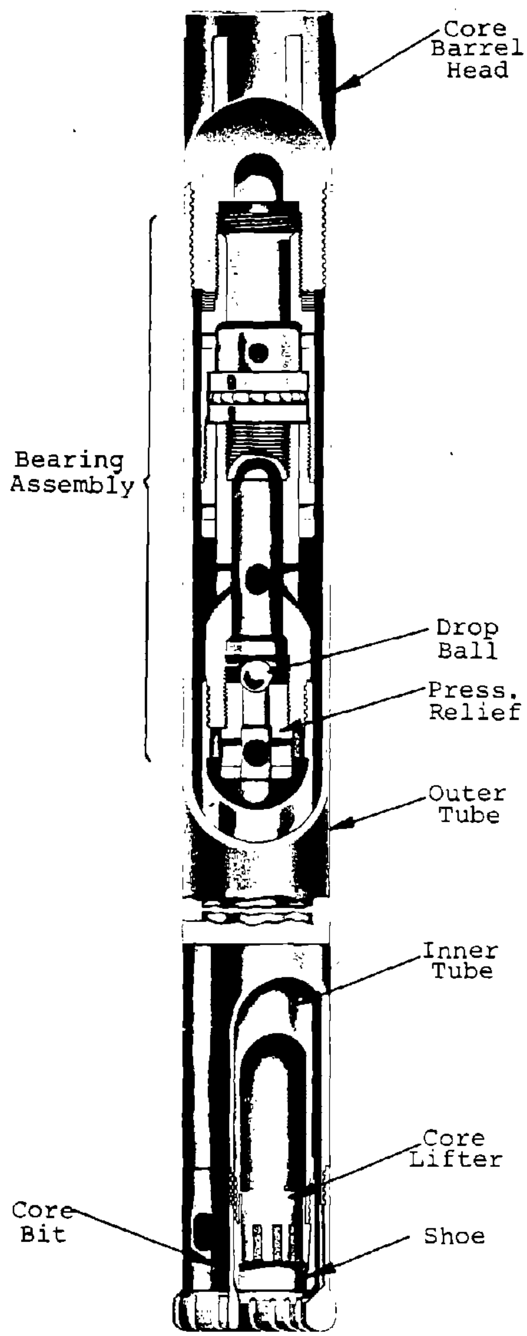


FIGURE 19 - Core bit and barrel assembly.
(Courtesy of Christensen, Inc.)

Under-Reamer Bit

As in the case of drag bits, this type of bit may be equipped with either two or three cutting blades. However, the blades are held recessed into the body of the bit by means of a spring and are expanded into the cutting position by a sudden increase in drilling fluid pressure. Since partial expansion of the blades is impractical, the effective under-ream diameter is established by the geometry of the particular blades used. The maximum possible diameter is fixed by the geometric and structural limitations imposed by the body of the bit and the articulation mechanism. The cutting edge of the blades may either be forged or surfaced with replaceable tungsten carbide inserts, depending on the wear anticipated.

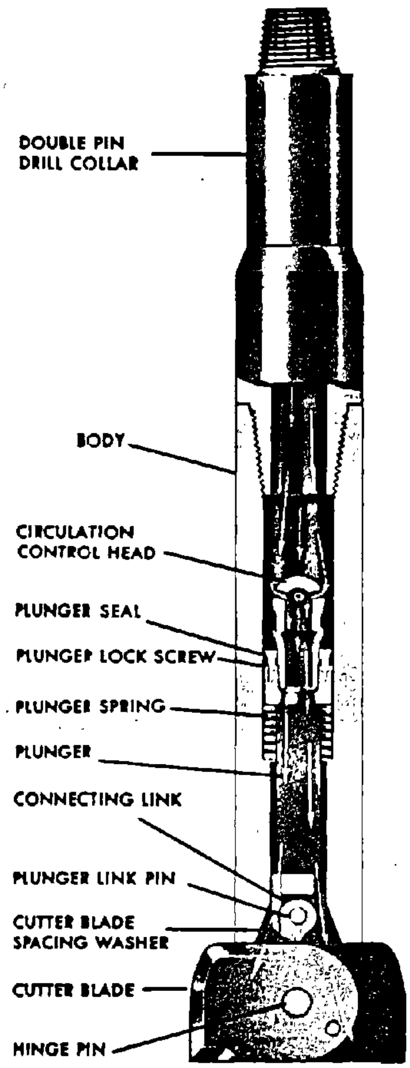


FIGURE 20 - Under-reamer bit. (Courtesy of Grant Oil Tool Co.)

This bit is employed only after a pilot hole has been drilled by some other method, and like other bits is operated from the top to the bottom of the particular interval being underreamed. However, several precautions should be taken when using under-reamer bits. As in the case of the drag bit, a three blade bit will generally cut smoother than a two blade bit. However, the bit body is weakened considerably in making the transition from a two to three blade design. This results from the greater complexity and size of the blades and the articulation mechanism which must be accommodated by the body of the bit. Particularly when under-reaming cased holes, there is a very high potential for damaging the casing while tripping the drill bit and string. Specifically, there is a potential for lowering the drill string onto the rotary table hard enough to cause extension of the under-reamer blades, thereby damaging the casing each time a new joint of drill pipe is added or removed from the drill string. On tripping into the well, the potential for such damage can be minimized by taping the bit to inhibit movement of the blades and insuring that the drill string is lowered gently onto the rotary table. On tripping out of the well, only the latter method can be used to prevent casing damage. If the tool is excessively stressed during under-reaming due to too high a rate of rotation or too high a rate of advance, the bit body or blades can be damaged and complete retraction of the blades prevented. Damage like this to the bit will invariably result in extensive damage to the casing while tripping out, and in severe cases may result in the loss of the bit, a portion of drill string, and possibly the well. The potential for bit damage can be minimized by adjusting the drive clutch of the rotary table so that it slips at a torque less than that which would damage the bit body or blades. WARNING: The under-reaming bit is unforgiving and should only be used by trained and experienced personnel and when alternative methods are either unavailable or impractical.

Drilling Procedures

Two basic procedures for drilling are practiced. In the first, a single drill pass is used of a diameter large enough for both logging and casing of the hole. In the second, two drill passes are used, the first is a pilot hole large enough for logging and the second reams the pilot hole to a diameter large enough for casing of the hole. The merits of one procedure relative to the other depend on a number of factors which ultimately relate to cost. A summary of the principal considerations and their impact on each approach is summarized in Table 3 below.

Table 3

Single Versus Double Pass Drilling

Item	Single Pass		Double Pass
1. Set-up cost	----------------------	same	--------------------
2. Cost of initial drill pass	About 1.5 times cost (A) of a pilot hole		A cost (A) depending on formation characteristics
3. Stand-by cost while logging.	----------------------	same	--------------------
4. Cost of reaming to final diameter	---------none---------		About 0.75 times cost (A) of a pilot hole
5. Cost of casing and grouting	----------------------	same	--------------------
6. Cost of grouting for abandonment	Variable from 1.5 to 2.0 times cost, (B)		A cost (B) depending on formation characteristics
7. Potential for hole deviation	----------------dependent on the driller----------------		
8. Average expected cost per well	$(1.5A)f_c + (1.75B)f_a$ + common costs		$(1.75A)f_c + (1.0B)f_a$ + common costs

where f_c and f_a represent the fractions of total drill holes completed and abandoned respectively. No general conclusion can be made, a priori, that one procedure is preferable to the other. The selection of one approach over the other should be based on relative cost, which will depend on the footage of ore delineation drilling relative to the footage of well installation drilling involved. The following discussion of drilling procedures is based on the use of double pass drilling.

Exploration/Delineation Drilling

To accommodate standard drill pipe as well as most commercial logging probes in use today, a drill hole ranging from 4 to 5 inches in diameter is required. Accordingly, the pilot hole diameter is established within this range of diameters. A typical drilling procedure would specify the following additional parameters:

Bit size and type to be used: ______________________________
Number, size, and weight of drill collars: ______________________________
Size of drill pipe to be used: __________ in. diameter at __________ lb/ft.
Maximum deviation of drill rig mast off vertical __________
Maximum permissible hole deviation off vertical __________
Drilling fluid specification to be used ______________________________
Maximum mud pump pressure ______ psi and flow rate ______ gpm to be used.
Maximum drilling speed to be used __________ rpm.
Maximum pull down force to be used __________ lbs.
Criteria to be used for total depth drilled ______________________________
Hole abandonment procedure to be used ______________________________
Hole completion procedure to be used ______________________________
Drilling records and parameters to be kept ______________________________
____
Quality assurance procedures to be used ______________________________
____

Three aspects of the foregoing procedure, drill hole alignment, total depth drilled, and abandonment procedure, warrant some elaboration.

Vertical hole alignment is important for two reasons. First, it is essential for reliable correlation of drill hole information obtained at depth to surface location. Second, significant deviation may confound and in the extreme prevent successful well installation. Three factors have been shown to influence drill hole deviation, namely: the characteristics of the drilled formations, deviation of the drill rig mast, and the type and magnitude of drill string loading (17, p. 372). Of these, the third is the most frequent and controllable cause for hole deviation. To minimize deviation it is essential that the drill string be in tension and that the bit support only enough weight to drill efficiently. To accomplish this dual purpose, drill collars are used to weight and stiffen the critical area of the drill string immediately above the bit. The recommended total weight is approximately 1/3 greater than the weight needed on a particular bit for efficient drilling. The excess weight serves to maintain tension in the drill string. Obtaining the maximum weight and stiffness in this section requires using collars with the largest wall thickness and diameter compatible with maintaining efficient fluid circulation and cuttings removal. If, through the use of drill collars alone, sufficient weight cannot be concentrated within half of the critical buckling length (ref. Eq. 7), then a stabilizer may be required at that location to further stiffen the bottom section of the drill string.[6] A telecoped

[6]Installation of a reamer or stabilizer immediately above the bit is not recommended, since in this location either tends to accelerate hole deviation.

transition from drill collars to drill pipe is typically used over the remaining supported collar length. Coupled with proper bit maintenance, rotary speeds, and fluid circulation rates, the described practice has produced holes within one to two degrees of vertical in most formations (17, p. 376).

The second aspect, total depth drilled, can result in unanticipated and unnecessary workover and remedial costs, if incorrectly specified or improperly controlled. In the case of exploration drill holes which are to be plugged and abandoned after logging, any logical depth criteria which insures obtaining the desired information is appropriate. However, in the case of ore delineation drill holes which may be either plugged or completed, a specific depth limitation is essential. If any such hole is drilled to a depth such that it either partially or completely penetrates the lower confining stratum (aquiclude) of the ore zone being developed, it will have to be plugged to restore aquiclude integrity. Generally, the agencies responsible for in situ mining permits require that monitor wells be located in the nearest water bearing strata overlying and underlying the mineralized production zone for the purpose of verifying leach solution containment during operation. Thus, any penetration of the lower confining stratum creates a potential conduit for leach solution migration. Extensive operating experience (60) has demonstrated that drilling fluid and drill cuttings do not seal such penetrations adequately to prevent leach solution migration. To obtain an adequate seal, it is necessary to flush the cuttings from the hole and plug the penetration with a suitable grout or mud polymer mix. Thus as in the case of drill hole alignment, the most cost-effective method of dealing with this potential problem is the exercise of great control over drilling operations by careful specification and verification of the total depth drilled.

The third aspect, the hole abandonment procedure used, is very important because when not done correctly, the abandoned hole can provide a conduit for leach solution migration into strata overlying the production zone. Until recently, the principle concern with regard to drill hole abandonment was to prevent intermixing of waters in the penetrated formations due to naturally occurring hydrostatic forces. More recently, concern with hole abandonment procedures has broadened to include the potential for ground water contamination as a result of the additional stresses imposed by solution mining activity. One of two procedures is typically specified at present: (1) filling from the bottom of hole to the surface with a mud polymer mix having a minimum gel strength of 0.2 lb./sq.ft. after 10 min. and API filter loss of 13.5 cc/half hr. at 100 psi plus a grout plug for the top 5 to 10 feet; or (2) filling from bottom of hole to the surface with a stable cement grout mixture. While specification of correct abandonment procedures will reduce the incidence of improperly abandoned drill holes, their occurrence is not precluded. In the past exploration and in situ mining operations had a record of ineffective hole abandonments because of either a lack of effective procedures or a lack of adherence to procedures. This suggests that the QA program for hole abandonment should be particularly strong. Further, it is not only important to insure that established procedures are adhered to, but to also insure that prior drilling activity does not leave improperly or ineffectively abandoned drill holes which can adversely affect in situ mining operations.

Cased Drill Holes

To accommodate the most commonly used casing sizes, namely 4" to 6" NPS (nominal pipe size) pipe, and to provide adequate clearance for a competent grout seal between the casing and drill hole, a hole diameter ranging from 6 to 9 inches is required. In those cases where a pilot hole is drilled initially, it must be reamed to the finished diameter on a second pass. Otherwise, the hole is drilled to the finished diameter on the initial pass. In either case, the components of the drilling procedure are identical to those outlined in the previous section. The specifications however may vary due to the larger drill hole size and because of the intention to case the completed hole. Thus in addition to the larger bit size, a larger number and weight of drill collars, a reduced drilling rate, and a specialized bit may be specified to insure that the reamed hole does not deviate from the pilot hole. Since the finished hole is to be cased, the drilling fluid specification and the total depth drilled may also be adjusted to the method of well completion.

Well Completion and Workover

Most of the well completion methods described previously require that a drill rig be used to workover the cased well after the casing has been grouted in place. To minimize damage to the cased well, rigorously defined completion and workover procedure is essential. Although the specifics will vary with the particular well completion or work over method, the essential components of such a procedure are indicated below. Since the greatest potential for damaging an installed well is associated with well completion and workover activities, this partcular procedure may well be the most important of all the drilling procedures considered.

Minimum cement cure time to be allowed __________ days.
Drill rig alignment specifications for work over ________________________

____

Description of the drill string components to be used: (i.e., type and size of bit; number, size and weight of collars; size of drill pipe; etc.)
Drilling fluid type and parameters: (i.e., the fluid specification, maximum flow rate, and supply pressure)
Drilling parameters: (i.e., drilled interval, nominal rpm and maximum pull down force).
Special instructions/precautions: ________________________________

____

____

Quality Assurance

There are two aspects of quality assurance which should be considered with regard to drilling operations. The first relates to the equipment and materials and the second relates to the drilling practices and procedures. Both are important in terms of the quality of drill hole or well and the overall cost of operation. The first of these two is typically given more consideration and generally can be monitored and controlled more readily than the second. Because of this, further discussion of the second is appropriate.

A significant number of the problems which arise during operation of an in situ project, especially regarding confinement of the leach solution to the mining zone and the effectiveness of ore leaching, have been found to relate to the drilling practices and procedures which were employed. This seems to be true regardless of whether drilling was done with in-house staff or with contract crews. In the case of contract drilling crews, the specific contract terms can aggravate such problems. Thus, problems are more apt to occur when drilling crews are paid on the basis of footage drilled rather than on the basis of hours worked. Since in the latter case, there is less incentive for the driller to develop more efficient drilling procedures, the operator must assume this responsibility. Finally, the nature of drilling operations makes it difficult to monitor the quality of the delivered product. However, it has been found that correcting the resultant problems is generally both time consuming and costly and may in fact cause an otherwise viable project to become impractical and unprofitable.

The best method available to minimize drilling related problems and the corrective costs is the development of appropriate drilling procedures coupled with a rigorous monitoring to assure their application. The specific procedures adopted will reflect both site specific conditions and economic aspects of the particular project. However, such procedures will be worthless without implementing and maintaining a suitable monitoring program to assure their application.

GROUTING CONSIDERATIONS

After the drill hole has been completed and the casing string set, a seal must be established between the casing and the drill hole. Without this seal, leach solution would migrate upwards along the injection well casing and contaminate the overlying strata and associated ground water. In the case of production wells, ground water from the overlying strata may be drawn into the well with the effect of diluting the leach solution.

There are two methods of sealing the annular space between the casing and drill hole. In the first, a grout mixture consisting primarily of cement and water is pumped into the annular space, and upon setting provides the necessary seal. In the second, a high gel-strength bentonite slurry (59) is pumped into the annular space to provide the necessary seal. While the latter method is approved for water well completion, it is not approved for in situ mining wells, and therefore will not be considered further. The balance of this chapter considers the design of cement grouts, methods of grout emplacement, the required grout volume, grouting hardware and accessories, and development of grouting procedures.

Cement Grouts

Portland cements are produced by calcining approximately two parts of limestone and one part of clay or shale plus iron ore. The resultant clinker product is pulverized and a small amount of gypsum is blended in to control setting time. When this product is hydrated by adding water, four crystalline phases form causing the cement to set. The two principle phases are dicalcium and tricalcium silicate, which together comprise approximately 75 to 80 wt. % of the set cement. The balance of the set cement consists of a mixture of tricalcium aluminate and tetra-calcium alumino-ferrite. The relative abundance of these four crystalline species establish the characteristics of a particular cement as indicated below.

Property	Relative Changes to Mix
1. High early strength	Increasing the tricalcium silicate content plus fine grinding.
2. Retardation of set time	Controlling the tricalcium silicate and aluminate content plus coarse grinding.
3. Low heat of hydration	Limiting tricalcium silicate and aluminate content.
4. Sulfate resistance	Limiting tricalcium aluminate content.

Note: Sulfate reacts with lime and tricalcium aluminate to form calcium sulfoaluminate, which is a larger less dense crystalline phase that induces fracturing of the cement matrix.

Types of Cement

There are two major classifications of cement, the first being the ASTM classification which was developed for cements used in the construction industries, and the second being the API classification which was developed for cements used in completing the deep wells characteristic of oil and gas production. The ASTM classification of cements consists of five types of portland cement which are briefly described below.

ASTM Type	Description
I	General concrete construction where special characteristics are not required.
II	Moderate heat of hydration and sulfate resistance.
III	High early strength cement.
IV	Low heat of hydration.
V	High sulfate resistance.

The API classification was developed to account for the wide range of temperatures and pressures encountered in completing deep wells and consists of eight types of cement (49, p. 7). Of these, only the three types most commonly used for in situ mining wells are described here.

API Class	Well Depth.	Temperature	Characteristics
A	0-6,000 ft.	80-170°F	Ordinary portland cement
B	0-6,000 ft.	80-170°F	Moderate to high sulfate resistance
C	0-6,000 ft.	80-170°F	High early strength and moderate to high sulfate resistance

The above cements are common to both the ASTM and API classification, namely; ASTM Types I, II, and III are equivalent to API Classes A, B, and C. Since at present in situ mining is generally limited to depths shallower than 1,000 feet, further discussion will be limited to these three types of cement.

Which type of cement is chosen for a particular project will depend on whether sulfate resistance or high early strength is required. If the sulfate content of the mix water, prevailing ground water, or proposed leach solution is expected to exceed 1.0 gram per liter, it is recommended that a moderate to high sulfate resistant cement be used. Sulfate reacts with the lime and tricalcium aluminate in cement to form calcium sulfoaluminate, which is a larger less dense crystalline phase and induces fracturing of the cement matrix. Although it occurs at lower temperature, such attack is most significant in the range of 80° to 120°F. Where formation sulfate concentrations between 1.0 and 3.0 grams per liter are encountered, use of a moderate sulfate resistant cement, such as Type II/Class B, is adequate. If sulfate concentrations are expected to exceed 3.0 grams per liter, use of a high sulfate resistant cement such as Type V/Class B or C is essential.

Whether high early strength is required depends largely on the drilling and completion procedures to be used, and the project schedule. In cases where high early strength is required, either an accelerated Type I/Class A cement or the appropriate Type III/Class C cement should be used depending on the sulfate resistance required.

Additives

As with drilling fluids, the need for and choice of additives to obtain the desired seal characteristics must be carefully evaluated with respect to: (1) prevailing formation characteristics, (2) the casing material and well completion method to be used, and (3) the impact on ground water quality. The formation characteristics may necessitate the use of certain additives to control thickening time, strength, slurry density, and filtrate or slurry loss. However, the casing material and well completion method may not be compatible with using such additives or they may have to be modified to accommodate use of the addivites. One example is using an accelerator to achieve a reasonable slurry thickening time where low ambient or formation temperatures prevail, or to achieve high early strength. Because of the accelerated rate of heat release in this case, either deformation or damage to certain types of casing, particularly PVC materials, may result. A second example involves the use of either filtration control or lost circulation additives due to formation conditions in the vicinity of the completion interval. Such circumstances may necessitate complete evaluation of well performance and leach solution confinement. Finally, the additives used may have a significant impact on the water quality immediately surrounding a well, thus making it difficult or impossible to obtain reliable baseline water quality data for some time following well completion. These examples illustrate why an overall cost benefit analysis may be required to develop the optimum cement slurry specification for a particular project.

The API classifies additives into eight groupings based on their primary function. For purposes of this discussion the number of groupings has been reduced to five, namely: set time modifiers, slurry density modifiers, filtration loss additives, lost circulation additives, and special additives. Essentially, all of the additives considered are available as free flowing powders which can either be dry blended with the cement prior to addition of the mix water or can be dispersed in the mix water prior to addition of the cement. The choice of one method over the other is largely a matter of preference, but may be influenced by the scale of a particular project and/or the availability of support services and facilities.

Set Time Modifier

This group of additives consists of both set time accelerators and retarders. Accelerators will be considered first, since their use is most frequently encountered in in situ mining applications. At ambient and/or formation temperatures less than 80°F, an accelerator may be necessary to reduce slurry thickening time and increase early strength. By means of their use, a compressive strength of 500 psi, which is generally considered the minimum necessary to bond and support a casing string (49, p. 16), can be developed in as little as four hours. However, considerable caution should be exercised in the use of an accelerator to insure that damage to thermoplastic casing components does not occur as a result. The two most commonly used accelerators are calcium chloride at 2 to 4 wt. % relative to cement, and sodium chloride at 1.5 to 5.0 wt. % relative to cement. The effect of various salt concentrations on thickening time and compressive strength, as a function of ambient temperature, are indicated in the following table for a slurry of ASTM Type I/API Class A cement made up to a slurry density of 15.6 lb./gal.

TABLE 4

Effect of Salt Concentration on Thickening Time and Compressive Strength[1]

Salt Concentration	Thickening Time (hrs) @ 0-2000 ft.	Compressive Strength (in psi) @ 6 hrs.			@ 12 hrs.			@ 24 hrs.		
		40°F	60°F	80°F	40°F	60°F	80°F	40°F	60°F	80°F
0 wt% $CaCl_2$	4.0	NS[2]	NS	80	NS	70	450	30	660	1700
2 wt% $CaCl_2$	1.8	NS	260	650	20	610	1410	420	1750	3200
4 wt% $CaCl_2$	0.9	NS	410	810	70	770	1550	400	1900	3180
0 wt% NaCl	4.0	--	--	--	--	70	410	--	660	1700
2 wt% NaCl	2.8	--	--	--	--	(290)	(960)	--	(890)	(1920)
4 wt% NaCl	2.8	--	--	--	--	(280)	(1150)	--	(1010)	(1980)

(1)The data presented here are the average data reported in three commonly used sources (23,27,49) of information regarding cement grouts. The thickening time and compressive strength data were found to vary considerably from one source to another; presumably due to the specific grout materials, preparation methods, and/or test conditions used. In view of this, it is strongly recommended that all published data be used with considerable caution. Where more accurate information is required, it should be experimentally determined for the actual materials and conditions which characterize the application.

(2)NS indicates Not Set.

(3)Parentheses indicate data obtained from a single source (39).

From these data it is evident that calcium chloride is the more effective accelerator and explains why it is more extensively used.

Another method of acceleration is to reduce the quantity of mix water used. However, this has the additional effect of increasing the density of the cement slurry and therefore is of more limited interest. When this method of acceleration is employed, it is also necessary to add a dispersant, at a nominal concentration of approximately 1.0 wt.%, to reduce the effective viscosity of the slurry and facilitate pumping.

When drill hole temperatures exceed 150°F, it may be necessary to employ a retarder in order to prevent premature setting of the slurry during placement. The three most commonly used methods of retarding set time are addition of either calcium or calcium/sodium ligno-sulfonate at a concentration of 0.1 to 1.0 wt.% relative to cement, addition of carboxymethyl hydroxyethyl cellulose at concentrations of 0.1 to 1.5 wt.% relative to cement, or use saturated salt water to make up the slurry. However, the conditions requiring the use of such retarders are generally only encountered at depths greater than 5,000 feet. The reader should consult References 23, 27, and 49 for additional information.

Slurry Density Modifiers

This group of additives consists of materials used to decrease or to increase the density of neat cement slurries. Those materials used to decrease slurry density will be considered first, since their use is most frequently encountered in in situ mining applications. Neat cement slurries prepared using the recommended quantity of mix water have densities in the range of 15 to 16 lbs./gal. In many cases a cement column of this density is impractical due to either the attendant filtration loss and slurry penetration, or the potential for damage to the casing and formation. Weight reduction additives are employed in such cases to reduce the slurry density to a practical level and reduce slurry cost. The density of cement slurries is reduced by increasing the water content or adding some other material of significantly lower density. The materials most commonly used for this purpose are indicated in Table 5 in order of their effectiveness and utilization. Each of the additives is discussed in the succeeding paragraphs.

TABLE 5

Weight Reduction Additives

Material	Quantities Used(1)
Bentonite	up to 16 wt% relative to cement
Diatomaceous Earth	up to 40 wt% relative to cement
Natural Hydrocarbons	up to 50 wt% relative to cement
Pozzolan/Fly Ash	up to 75 vol% of the dry ingredients
Expanded Perlite	up to 20 wt% relative to cement

Note:

(1)The designation wt% relative to cement refers to parts by weight of additive relative to 100 parts by weight of dry cement.

Bentonite

Bentonite can be used with any of the cements described in concentrations up to 16 wt. % relative to cement. At concentrations of less than 5 wt. %, the bentonite can be either premixed with the water prior to cement addition or dry mixed with the cement prior to water addition. In the former case, the time required for adequate prehydration of the bentonite varies from a minimum of 5 minutes, with high shear rate mixing, to a maximum of 30 minutes, with less intense mixing methods. Both insufficient (less than half an hour) and excessive (on the order of a day) prehydration should be avoided since the former may result in a nonhomogeneous slurry mixture and the latter may result in increased water separation and grout shrinkage. At bentonite concentrations greater than approximately 5 wt. %, dry mixing of the bentonite and cement prior to water addition is generally the most practical method of slurry preparation. Addition of a suitable dispersant to the mix water may also be required to maintain the slurry viscosity within practical limits.

The effect of various amounts of bentonite on the composition and characteristics of ASTM Type I and II API Class A and B cement slurries are indicated in Table 6. While the thickening time is unaffected the compressive strength decreases with increasing bentonite content. Also, resistance to chemical attack by either formation waters or the lixiviant decreases with increasing bentonite content. Due to the reduced physical strength and chemical resistance of bentonite modified grouts, it is essential that an adequate cure time be allowed for ultimate strength development prior to beginning any well workover operation. It is also essential that workover methods minimize stresses on the casing and grout seal, which could damage or compromise seal integrity.

Diatomaceous Earth

Diatomaceous earth imparts many of the same properties to cement slurries as bentonite. However, unlike bentonite, it does not significantly increase slurry viscosity as the weight fraction of additive is increased. Offsetting this advantage is a somewhat higher cost which accounts for its more limited use. The effect of various amounts of diatomaceous earth on the composition and characteristics of ASTM Type I and II/API Class A and B cement slurries are also presented in Table 6 to permit a ready comparison with other additives. The cautions noted previously with regard to the physical strength and chemical resistance of bentonite modified cement grouts, also apply to those modified with diatomaceous earth.

Natural Hydrocarbons

Generally, hydrocarbons of all types, even at low concentrations have a deleterious effect on the strength developed by cement grouts. However, two naturally occurring hydrocarbons gilsonite (a natural asphaltite), and coal are sufficiently inert to be used as weight reduction additives. Of the two, gilsonite finds the wider use because of its lower specific gravity, approximately 1.07 as compared to 1.2 to 1.5 for bituminous coals. Since neither

TABLE 6

Effect of Density Modifiers on the Composition and Characteristics of ASTM Type I & II/API Class A & B Cement Slurries[1]

Additive (Quantity)	Reqd. Water (gal/sk)	Slurry Density (lbs/gal)	Slurry Volume (cu ft/sk)	Thickening Time (hrs) at 80°F, 2000 ft	Approximate Compressive Strength (psi after 24 hrs.) 60°F	80°F	95°F
Neat Cement:	5.2	15.6	1.18	4.0	660	1640	2390
Bentonite (wt % relative to cement):							
2	6.5	14.8	1.36	4.0	(365)	980	1470
4	7.7	14.2	1.54	4.0	(225)	690	1050
6	8.9	13.6	1.71	4.0	(85)	400	730
8	10.0	13.2	1.89	4.0	(60)	290	520
10	11.2	12.9	2.03	4.0	--	220	370
Diatomaceous Earth (wt % relative to cement):							
10	10.2	13.2	1.92	4.0	--	200	520
20	13.5	12.4	2.42	4.0	--	100	270
30	18.2	11.7	3.12	4.0	--	--	--
40	25.6	11.0	4.19	4.0	--	20	50
Gilsonite (lbs. per sack of cement):							
12.5	5.6	14.4	1.41	4.0	--	--	--
25.0	6.0	13.6	1.66	4.0	--	1250	1660
50.0	7.0	12.5	2.17	4.0	--	740	960
Pozzolan/Fly Ash + Bentonite (vol. % relative to cement):							
50 + 0	(4.4)	(15.1)	(1.07)	4.0	--	(680)	(1140)
25 + 2	(6.0)	(14.6)	(1.29)	4.0	--	--	--
50 + 2	5.8	14.2	1.26	4.0	(100)	250	510
75 + 2	(5.7)	(14.0)	(1.25)	4.0	--	--	--

Notes:

(1)The data presented here are the average data reported in three commonly used sources (23, 27, 49) of information regarding cement grouts unless otherwise noted. The thickening time and compressive strength data were found to vary considerably from one source to another; presumably due to the specific grout materials, preparation methods and/or test conditions used. In view of this, it is strongly recommended that all such published data be used with considerable caution. Where more accurate information is required, it should be experimentally determined for the actual materials and conditions which characterize the application.

(2)Parentheses indicate data available in only one of the three sources (27) cited.

material absorbs water under pressure, a higher strength is obtained at a given age for a particular grout density. Like diatomaceous earth, neither material significantly affects the viscosity of the resultant slurry. The effect of various amounts of gilsonite on the composition and characteristics of ASTM Type I and II/API Class A and B cement slurries are also presented in Table 6. When natural hydrocarbons are used in combination with bentonite, it is recommended that the bentonite be prehydrated completely prior to addition of the cement and natural hydrocarbon in order to obtain a homogeneous slurry. The cautions noted previously with regard to the physical strength and chemical resistance of bentonite cement grouts also apply to those modified with natural hydrocarbons.

Pozzolan/Fly Ash

This class of materials is produced by either the natural or artificial heat treating of certain siliceous materials such as clays and shales. In the presence of lime, the resultant material develops a cemented structure. By blending pozzolan and cement, the lime generated during hydration of the cement is utilized to produce a stronger more water tight grout. Due to its lower specific gravity relative to cement (typically 2.3 to 2.7 versus 3.1 to 3.2) it also serves to reduce grout density. Because of its ready availability and lower relative cost, fly ash is the most commonly used pozzolanic material. The effect of various amounts of commercially available fly ash on the composition and characteristics of ASTM Type I and II/API Class A and B cement slurries are also indicated in Table 6. For a given slurry density the compressive strength developed by the pozzolanic cements are the lowest of the grout formulations tabulated, although, this is not true of the ultimate strength developed by such formulations. Where greater early strength is required in a particular application, a suitable quantity of an accelerator such as $CaCl_2$ must be incorporated into the grout formulation.

Expanded Perlite

This is a cellular material of very low bulk density produced by heating the naturally occurring glass mineral. Since it is comprised of a mixture of open and closed pores, a particle takes on increasing water as the surrounding pressure increases. This necessitates the use of excess mix water and generally some quantity of bentonite (typically 2 to 6 wt%) to increase slurry viscosity and gel strength sufficiently to prevent segregation of the perlite particles. Because of these characteristics, expanded perlite is seldom used for density reduction.

Other Density Modifiers

Although infrequently encountered in in situ mining applications, it may be necessary to increase the density of a particular slurry in order to compensate for high downhole pressures. For this purpose, it is desirable to have an additive, with a specific gravity of between 3.5 and 5.0, which is chemically inert and will not otherwise significantly effect slurry design, strength, or placement. The materials most often employed in this regard are Hematite (iron oxide), Ilmenite (iron-titanium oxide), Barite (barium sulfate), Sand (silica) and Salt (sodium chloride). As in the case of retarders, the conditions requiring the use of such weighting agents are generally encountered at depths greater than 5,000 feet, and in association with petroleum rather than mineral deposits. Therefore, the reader should consult Reference 49 for additional information.

Filtration Loss Additives

The purpose of this group of additives is to prevent premature dehydration of the slurry due to high permeability zones and/or damage of sensitive zones due to filtrate intrusion. Filtration loss control can be obtained by two methods. The first method employs an additive which produces a colloidal film on the drill hole wall which either retards or inhibits water loss to the adjacent strata. The most widely used materials of this type are high molecular weight organic polymers such as cellulose derivatives in concentrations of 0.5 to 1.5 wt% or latex derivatives in concentrations of 0.5 to 3.0 wt%. The second method of reducing filtration loss is to alter the particle size distribution or density of the slurry, thereby improving water retention and reducing filtration loss. The chemical additives in this group are dispersants such as certain organic polymers and the complex sodium phosphates at concentrations of 0.5 to 2.0 wt.% relative to cement as well as sodium chloride at concentrations of up to 16 wt.% relative to cement. The effect of additive concentration on filtration loss from a typical cement slurry are summarized in Table 7 for two commonly used types of additive. Some of the filtration loss additives may have an adverse effect on the grout seal obtained and the permeability of the completed interval. Accordingly, caution should be exercised in their selection and use.

TABLE 7

Effect of Various Additive Concentrations on API Filtration Loss(1) From a Typical Cement Slurry

Type Additive	Wt% Additive							
	0.0	0.50	0.75	1.00	1.25	1.50	1.75	2.00
Cellulose base polymer:								
	1,200	300	100	50	-	-	-	-
Chemical dispersant used with grout made up to:								
5.20 gal H_2O/sk	1,200	690	530	286	224	-	-	-
4.75 gal H_2O/sk		580	476	222	146	92	64	48
4.24 gal H_2O/sk		504	368	208	130	80	54	40
3.75 gal H_2O/sk		490	310	174	118	72	50	36

Note:

(1) API filtration loss refers to the volume of filtrate (in cc) collected through a 325 mesh screen during 30 minutes at 80°F and a differential pressure of 1,000 psi.

Lost Circulation Additives

The purpose of this group of additives is to prevent significant loss of cement slurry to either high permeability or fractured zones. There are three methods of coping with lost circulation, namely: reducing the slurry density thereby reducing the hydrodynamic driving force, adding a suitable bridging material thereby blocking the flow channels, and altering the slurry formulation to obtain either quick gelling or flash setting. The first of these approaches was discussed previously (refer to the discussion of Slurry Density Modifiers). The second consists of adding a granular material such as gilsonite, coal, or perlite; a fibrous material such as nylon, or cellulose; or a lamelar material such as mica flake or plastic film to the cement slurry in sufficient quantity to remedy the problem. The third method represents a complete departure from the slurry specification developed for a particular situation. Therefore, it is not a recommended method of handling the periodic problem of lost circulation. The reader should consult Reference 49 for additional information regarding quick gelling and flash setting grouts.

Special Additives

A number of special additives have been employed in cement slurries for oil and gas well completion. Of those, only five are considered applicable to in situ mining applications. In addition, existing regulations may limit or preclude the use of one or more of these in a particular situation.

(1) Dispersants: The purpose of this group of additives is to improve the flow properties of cement slurries by reducing their yield point and gel strength thereby reducing their effective viscosity. The two most common types of dispersants are certain organic polymers and the complex sodium phosphates which are typically used at concentrations of 0.5 to 2.0 wt% relative to cement, and sodium chloride which is used at concentrations ranging up to 16.0 wt% relative to cement. The polymer additives markedly reduce the effective viscosity of a cement slurry without causing significant water separation or altering slurry set characteristics. Although they are compatible with most other additives, the polymer dispersants are not compatible with salt and should not be used with cement slurries containing any significant quantity of sodium chloride. In addition to its other uses as an additive, sodium chloride is an effective dispersant, particularly where bentonite or diatomaceous earth are added to reduce slurry density.

(2) Mud Decontaminants: Additives of this type are used to neutralize the retarding effect of various drilling fluid additives, where contamination from drilling fluid is probable, as in the case of open hole plugging and squeeze cementing. Paraformaldhyde or a 60/40 mixture of paraformaldehyde and sodium chromate, at a concentration of less than or equal to 10 wt.% relative to cement, are typically used.

(3) Fiberous Material: To improve impact resistance and prevent shattering, a resilient fibrous material may be added to the cement slurry. Nylon fibers in lengths up to 1 inch and concentrations up to 0.5 wt% relative to cement is the most common material used for this purpose. Caution should be exercised to avoid damage to pumping equipment when materials of this type are used.

(4) Gypsum: When added in concentrations of from 3 to 6 wt% relative to cement, gypsum will react with the tricalcium aluminate fraction of the cement causing modest expansion of the set cement, thereby improving the cement bond between the casing and formation. At concentrations of 4 to 10 wt% relative to cement, gypsum will cause rapid gelling of static cement slurries, which may be desirable in minimizing the potential for lost circulation when cementing past permeable or fractured zones. At concentrations of 30 to 50 wt% relative to cement, gypsum will cause flash setting of a cement slurry within 10 to 20 minutes. Gypsum should only be used as an additive with sulfate resistant cements. Also, considerable caution should be exercised in its use with thermoplastic well casings, which may be severely damaged as a result of the accelerated heat release from the grout.

(5) Radioactive Tracers: Short lived isotopes with half lives of 90 days or less may, under certain circumstances, be added to a cement slurry to determine its ultimate location, such as with squeeze cementing. Special permits must be obtained to employ such materials, and only licensed persons and organizations are authorized to use them.

Mix Water

Three aspects of the mix water used in preparing cement slurries are important in determining the set time and strength characteristics realized. They are the quantity, quality, and temperature of the mix water. In addition, both the temperature and water quality of the host formations may impact the set time and strength characteristics realized.

Quantity of Mix Water

Ideally, the cement slurry should have a density and viscosity or consistency which permit efficient displacement of the drilling and clean-up fluid and development of a good bond with both the casing and the formation. To achieve these objectives, the slurry should be at least 1.0 lbs/gal. more dense than the drilling fluid. Also, the quantity of mix water should be adequate to give a set volume of not less than 99.0% of the original slurry volume. Free water separation greater than 1.5 vol%, will cause shrinkage as the slurry sets, and inadequate bonding may result. In addition, excess mix water has three other adverse effects: it retards set time, it reduces ultimate set strength, and it introduces voids. Thus, the quantity of mix water should be carefully matched to the cement formulation developed for a particular application.

Quality of Mix and Formation Water

As noted previously (refer to the discussion of Types of Cement), sulfate content is the most significant water quality parameter regarding cement formulation. Sulfate concentration should be routinely monitored to insure compatibility between the mix water and the cement being used. In addition to sulfate content, the total dissolved solids and the suspended solids content of the mix water may affect the set time and strength of the slurry. Unlike sulfate, no general rules can be stated regarding the effect of such dissolved or suspended solids. Thus, it is generally recommended that: (1) the mix water be analyzed at the outset of a project to establish a reference water quality, (2) the effect of that particular water on the set time and strength of the developed slurry formulation be determined experimentally, and (3) the quality of the mix water and its effect on set time and strength be monitored routinely throughout the project.

Temperature of Formation and Mix Water

Both the temperature of the formation and mix water influence the set time required for and the strength developed by a particular slurry formulation. Generally, set time will be retarded as water temperature decreases below 60°F and will be accelerated as water temperature increases above 100°F. Thus, appropriate additives may have to be added to the slurry to obtain the set time and strength characteristics specified.

Cement Slurry Design

As indicated throughout the preceding discussion of cement and additives, a number of factors can be expected to affect the slurry design for a particular grouting application. Principal among these are:

- the quality of formation water and mix water,
- the bottom hole formation temperature and pressure,
- the drilling fluid characteristics,
- the permeability of the formations to be cemented,
- the minimum practical slurry thickening time,
- the minimum set strength required as a function of time, and
- the sensitivity of various casing materials to set temperature.

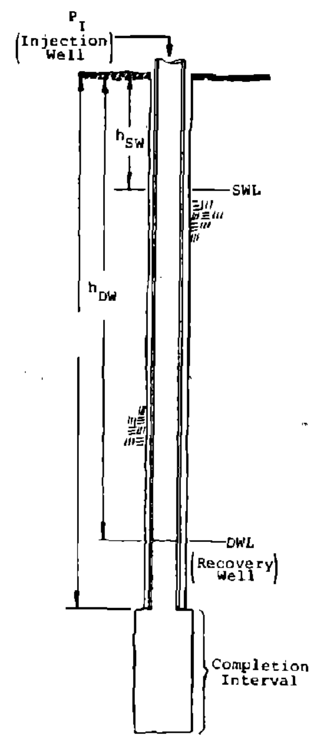
These factors interact in a complex fashion to influence the slurry design for a specific grouting application. Therefore, what will be described is a design sequence that will lead to a practical slurry design, which can then be optimized in terms of slurry characteristics and cost.

The following design sequence is suggested as a direct method for arriving at a practical slurry design.

1) Select the type of cement to be used based on hole depth, quality of formation and mix water, and anticipated leach solution composition.

2) Determine the minimum slurry density necessary to withstand the bottom hole pressure and to displace the drilling and clean-up fluids.

3) Establish the minimum strength which must be developed by the grout. The theoretical minimum ultimate strength required is a function of the nominal drill hole and casing diameters, the slurry density, casing weight, and net operating pressure at the completion interval. The magnitude and sign of these components for defining the minimum ultimate grout strength required are depicted in Figure 21. While the static forces are readily quantified, the dynamic forces, which arise as a result of well workover and completion, well development and stimulation, and normal operation are less well defined. The first of this group of dynamic forces is next to impossible to quantify.



Forces Acting on the Grout Seal:

Net Injection Force $= F_I = -P_I \frac{\pi}{4}\left[\phi_{DH}^2 - \phi_i^2\right]$

Bouyant Force $= F_B = -\frac{\pi}{576}\rho_w\left[\phi_{DH}^2(h_{TC} - h_{SW}) - \phi_i^2(h_{TC} - h_{DW})\right]$

Casing + Grout $= F_{wt} = \frac{\pi}{576} h_{TC}\left[\rho_c(\phi_o^2 - \phi_i^2) + \rho_G(\phi_{DH}^2 - \phi_o^2)\right]$

Net Axial Force (F_z) on the Grout Seal:

Injection Wells: $F_z = F_I + F_B + F_{wt}$

Production Wells: $F_z = F_B + F_{wt}$

Minimum Tensile Strength (σ_T) Required: $\sigma_T = \frac{F_z}{12\pi\phi_{DH}h_{TC}}$

Minimum Compressive Strength (σ_C) Required: $\sigma_C = 8\lambda\sigma_T$

FIGURE 21 - Minimum grout strength requirements.

The magnitude of the second and third can be estimated (refer to Figures 4 and 2 respectively) with some degree of reliability. In view of this uncertainty, it is common practice to use a multiplier ranging between 3 and 10 times the calculable static and dynamic stresses as the minimum practical strength for the grout formulation.

4) Examine the effect of various density modifiers on slurry density, strength characteristics, and slurry cost to establish a combination which achieves the required strength as near the minimum slurry density and cost as possible.

5) Establish the minimum practical thickening time for the slurry. As a rule of thumb, this is considered to be twice the time necessary to mix and place the slurry by means of a particular procedure.

6) Based on the minimum practical thickening time, the early strength requirements establish the type and quantity of accelerator or retarder addition which will be required for the downhole temperature and pressure.

7) Determine the maximum practical or acceptable filtration loss based on the formation characteristics over the interval to be cemented. From the specification of filtration loss determine the type and quantity of filtration control additive necessary to meet this specification.

Some of the data required for this design sequence may have to be developed experimentally in a cement testing laboratory such as those maintained and operated by the ASTM and the API. The preliminary grout design can be developed using established design criteria and guidelines available from any of several sources (22,23,27,50). This initial design can then be optimized as required in terms of its characteristics and cost for project-specific conditions.

Cement Slurry Specification

Combining the above factors into a concise format yields the grout slurry specification, which would typically consist of the following components:

Type of cement ____________________
Quantity of Mix Water ____________ gal/sack cement
Source and quality of mix water to be used: ____________
____

Additives:
1. Type ________ and Quantity ________ lbs/sack cement
2. Type ________ and Quantity ________ lbs/sack cement
3. ____________________
Slurry density ________ $\pm$ ________ lbs/gal
Mix water temp. ________ to ________ °F
Samples to be taken: ____________________
____
Tests to be conducted: ____________________
____
Records to be kept: ____________________
____

As has been mentioned previously, development of a grout specification for a particular application is of negligible value unless a quality assurance program is also implemented. This specification includes several items which are part of a QA program, namely: the samples to be taken, tests to be conducted, and records to be kept. With plastic well casing, it is virtually impossible using currently available logging techniques to determine whether an adequate bond to the casing and to the formation has been obtained. Generally, the first indication that one or both of these bonds were inadequate is evidence of fluid migration either along the casing or into strata adjacent to the mineralized formation. To remedy this problem is both time consuming and costly. While the quality assurance measures will not preclude the occurrence of inadequate bonding, they are the best available way of insuring that work is correctly done, thus increasing the likelihood of success (60).

Mixing Equipment

In mixing the cement, additives, and water to be used for grouting, it is essential that a uniform mixture of the required volume be obtained in the shortest practical time. Mixing should be completed within 10 to 30% of the slurry thickening time to allow adequate time for grout emplacement. The two principal mixing methods used are jet and batch mixing. Both methods are discussed in detail in the following sections.

Jet Mixing

This type of mixing system is depicted in Figure 22. The principal components of the system are: a mix water tank, solids feed hopper, eductor, mixer tube, slurry mix tank and slurry pump. The mix water tank is equipped with a high velocity recirculation/feed pump which can be used to either mix additives such as bentonite or soluble salts with the mix water or deliver mix water to the eductor at the solids feed hopper. The required quantity of dry cement is continuously supplied to the solids feed hopper from either bags or bulk storage. As mix water is supplied to the eductor, the desired quantity of dry cement is continuously drawn from the hopper and mixed with the water as it flows through the mix tube. The latter may be equipped with auxiliary water jets or rigid baffles for the purpose of promoting turbulent mixing. The mixed slurry then flows into the slurry mix/surge tank, where it can be recirculated at a high rate to eliminate any nonuniformity of composition, while a portion is continuously withdrawn and pumped downhole.

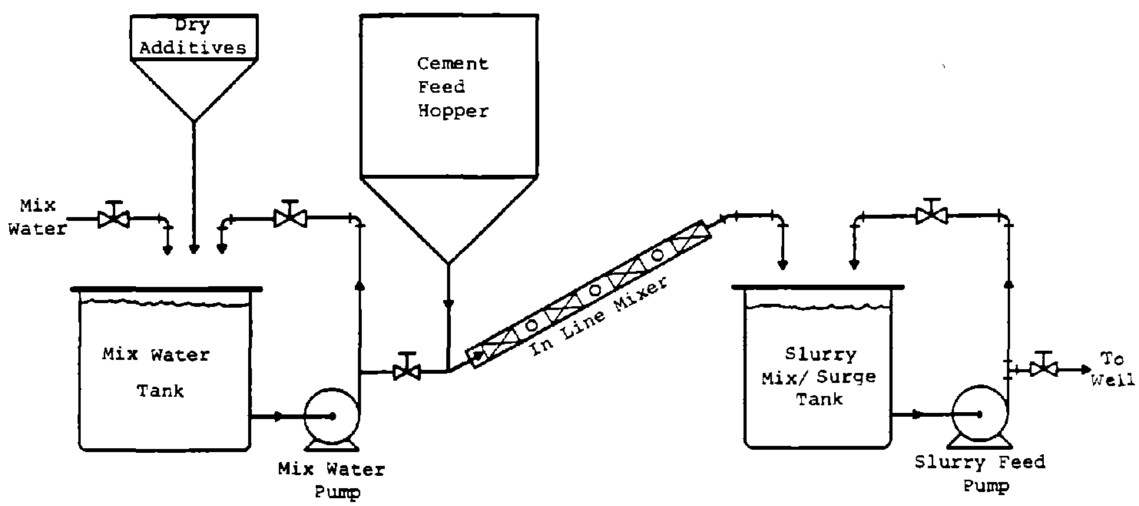


FIGURE 22 - Schematic of a continuous jet mixing system.

This method of mixing was developed for and is particularly well suited to cases where the volume of grout required is greater than 20 to 50 cubic feet (i.e., a 20 to 50 sack mix). Since the grout is emplaced simultaneously as it is mixed, there is little risk of premature thickening, and a significantly greater time is available for grout emplacement than with batch mixing. Offsetting these advantages is the possibility of variability in grout composition during emplacement due to variations in liquid and/or cement flow rates. Such variability is a problem both in terms of the quality of seal obtained and the quality assurance procedures used.

Batch Mixing

There is only one difference in principle between batch and jet mixing, that is the capacity of the slurry mix/surge tank. In the case of batch mixing, the tank has a significantly larger capacity, since it must be greater than the volume of grout required. Additionally in the case of batch mixing, a single tank and pump may serve as the mix water tank and pump, as well as the slurry mix tank and pump. As indicated in the previous section, this method of mixing is typically limited to those situations where less than 50 cubic feet of grout are required. Although equipment for batch mixing and transporting significantly larger quantities of grout are available, it is generally not well suited for off-road use under field conditions and therefore finds only limited use. The principal advantage of batch mixing over jet mixing is the better uniformity of grout composition obtained. Its principal disadvantages are the practical limitations on the volume of grout handled and the shorter time available for grout emplacement, due to the retention time required for mixing.

In Situ Mining Applications

Both of the grout mixing methods described have been used extensively for grouting in situ mining wells. Within the range of drill hole and casing sizes utilized, there is little to recommend one method over the other for wells ranging from 200 to 600 feet in depth, provided adequate quality assurance can be maintained. However if a significant difference in quality assurance exists between the two methods, the method yielding the most consistent quality is recommended. At depths less than 200 feet, it is probable that batch mixing will be preferable to jet mixing, while at depths greater than 600 feet, the reverse will be true.

Regardless of the method chosen for a particular application, it is essential that a suitable quality assurance program be developed and followed. As was stated previously, grout is the primary seal used to confine lixiviant to the mineralized formation and prevent contamination of other formations and aquifers. Thus, it is not only essential that a suitable grout formulation be developed but that the quality of the grout used be consistent with the formulation developed. Lacking a suitable quality assurance program, it is likely that: (1) grouting problems will go undetected for some length of time due to the lag time between well installation and operation, (2) such problems will only become evident as lixiviant excursions occur, and (3) the costs of associated repair and remedial activities will far exceed the cost of a practical quality assurance program. The essential elements of a good QA program are:

1. number, location, and size of grout samples to be taken during grout mixing and placement,
2. tests to be performed on each of the samples collected,
3. test results to be reported on each sample, and
4. samples and records to be maintained.

Grout Emplacement Methods

To ensure a satisfactory seal between the casing and formation, it is essential that the grout be emplaced in a single continuous operation before thickening begins. Furthermore, to minimize dilution and contamination of the grout and to realize a competent seal, it is essential that the grout be introduced at the bottom of the casing. The volume used should give complete displacement of the fluid(s) in the annulus. To avoid any problems due to premature thickening, grout mixing and emplacement should be completed in less than 50% of the slurry thickening time under prevailing ambient conditions (49, p. 36). Also the grout slurry should have a density at least 1.0 lb/gal and a gel strength approximately 0.2 lbs/sq ft greater than the fluids to be displaced from the annulus (15). Either of two methods of grout emplacement may be used, namely, through the casing or through a separate grout pipe. In the following section each method is described in detail.

Emplacement Through the Casing

This method of emplacement (Figure 23) was developed originally for grouting oil and gas wells. With relatively few exceptions, it has been adopted as the standard method for grouting in situ mining wells. After the casing has been set in the bore hole and a pre-grout flush circulated through the casing and annulus to remove drilling fluid residuals, grout is introduced into the top of the casing. It is then pumped continuously down through the casing and up through the annulus. Concurrently the casing is rotated/reciprocated in the drill hole to minimize the possibility of entraining pockets of drilling or clean-up fluid in the grout seal. The grout volume is such that complete displacement of the pregrout flush fluid occurs and the pumping rate is such that the volume of the mixed zone at the leading edge of the grout slug is minimized. Where practical, a displacement velocity adequate to realize turbulent flow in the annulus is recommended, typically 50 to 100 ft./min. After the required quantity of grout has been pumped into the well, a predetermined quantity of displacement fluid is introduced to displace most but not all of the grout from the casing. To insure maintenance of grout quality and thereby seal integrity between the casing and formation, a quantity of grout approximately equal to the volume of the mixed zone between the displacement fluid and grout is not displaced from the casing (estimation of this volume is discussed on p. 75 to 77).

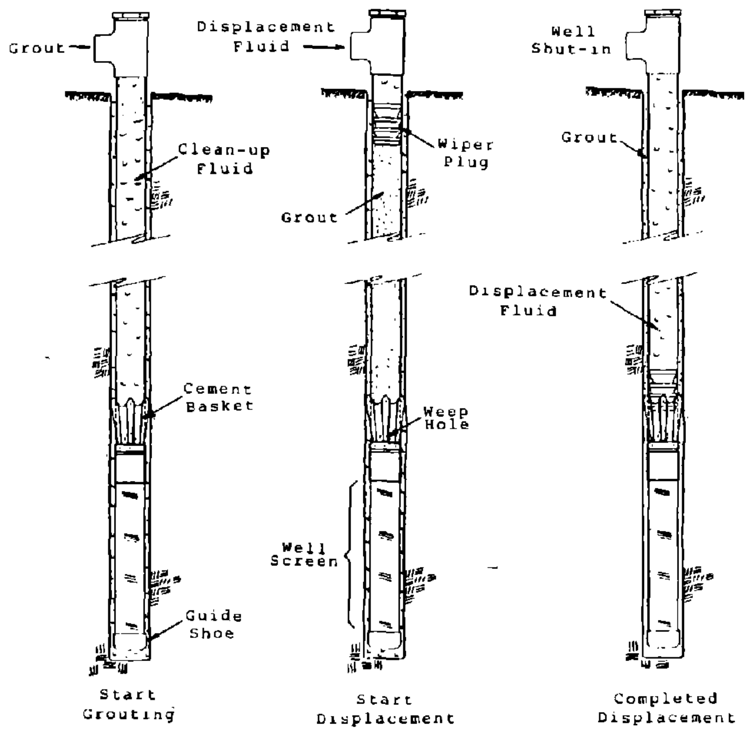


FIGURE 23 - Grout emplacement through the casing.

If a float shoe with a check valve (Figure 28) is used on the casing string, the full displacement pressure need not be maintained following grout displacement provided that the check valve seats properly. This can be checked by observing whether displacement fluid continues flowing from the casing after the fluid pressure is relieved at the well head. If the check valve fails to seat, or a guide shoe rather than a float shoe (Figure 28) is used on the casing string, the well must be shut in under adequate pressure to maintain the position of the fluid/grout interface. This pressure must be maintained on the well head until the grout has developed sufficient strength to be completely self supporting. This time is typically 3 to 8 hours, depending on the grout formulation and ambient conditions.

The use of a guide shoe versus a float shoe in a particular application may have a significant influence on the competency of the bond obtained between grout and casing. With a guide shoe, the casing string is maintained under tension following grout emplacement (ref. to Figure). Accordingly the most probable cause of seal failure is parting between the casing and grout as well head pressure is reduced. With a float shoe, the casing string may be maintained under either compression or tension depending on the well head pressure maintained following grout emplacement. In the former case the most probable cause of seal failure is fracture of the grout seal at elevated injection pressures. The most probable cause of seal failure in the latter case is parting between the casing and grout as well head pressure is reduced. Thus, the combined stresses on both the casing and grout seal following grout emplacement, relative to those during operation, can be expected to affect the quality of seal obtained. Accordingly, it is advisable that the casing design and grout emplacement procedure be selected to minimize the stress differences on the grout seal.

During casing and grout emplacement a combination of support and hold down is required to compensate for the net force acting on the casing string. The support provided must be adequate to suspend the net weight of the casing string full of grout slurry in the bore hole fluid (Figure 5). With the plastic casing materials typically used for in situ mining wells a hold down device is also required to resist the buoyant force which develops on the casing string as grouting proceeds. The required support and hold down may be provided by the drill rig or by independent means.

Emplacement Through a Grout Pipe

Grout emplacement through a separate pipe has found only limited application for in situ mining. The first reason is that it is more expensive than through casing emplacement. The second reason is that it is more difficult to obtain a competent grout seal because lower displacement velocities are attainable at comparable pressures with attendant incomplete removal of drilling fluid residuals from both the casing and drill hole walls. Despite these disadvantages, the method is described briefly for the sake of completeness.

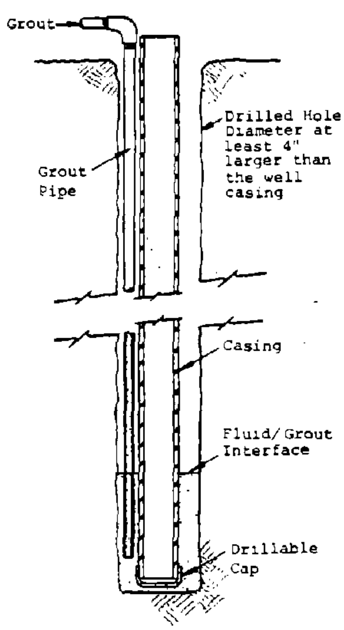


FIGURE 24 - Grout emplacement through a grout pipe.

There are three common variations of this basic method (30, p. 239). In the first and most frequently used method, grout is injected through a pipe which extends to the bottom of the casing along the outside of the casing. This requires that the clearance between the casing and drill hole be sufficient to accommodate both the casing and the grout pipe. Typically, a hole diameter 4 to 6 inches greater than the casing diameter is required. Without clearance of this magnitude, it is either necessary to use an undersized grout pipe in order to maintain coaxial alignment of the casing in the drill hole or it is necessary to displace the casing off center in order to accommodate a suitably sized grout pipe. In the former case the grout displacement velocity is reduced even further, while in the latter case uneven grout emplacement occurs around the casing (21, 37). Slurry is then delivered through the grout pipe into the annulus until returns are obtained at the surface. If a retrievable grout pipe is used, it is gradually withdrawn as additional grout is simultaneously injected to maintain slurry returns at the surface. Frequently however, a disposable grout pipe is used which is set in combination with the casing to insure proper installation. This method suffers from an additional disadvantage in that it is likely that a poor seal will be obtained in the vicinity of the contacts between the grout pipe and the drill hole and casing walls. If the completed well is used as an injection well, such areas may develop into pathways for leach solution migration.

Since grout is not introduced into the casing, this method of emplacement has an advantage over through casing emplacement under certain circumstances. The most notable of these is installation of under size wells, namely those employing either 2" or 3" NPS casing. In this case grout emplacement via an external grout pipe may prove the most practical method of installation, since specialized drilling equipment and methods are required to remove the grout residue left following through casing emplacement. Whether such wells offer any significant advantage over the larger casing sizes (i.e., 4" NPS and greater) more typically employed remains to be determined. With the casing diameters and depths most commonly employed, through casing emplacement has generally proven to be the more cost effective method of grout emplacement.

In the second and third variations of grout pipe emplacement, the grout pipe is run inside the casing. Both methods are similar in principal to through casing grout emplacement, but involve the added complication of a separate grout pipe. With the casing diameters and depths currently of interest to in situ mining, neither method offers any advantage over through casing emplacement for well installation. Since there is no evidence that either method has received serious consideration as a grouting method, they will not be described here. The interested reader is referred to either Ground Water and Wells (30) or Water Well Technology (20) for a detailed discussion.

Volume Calculations

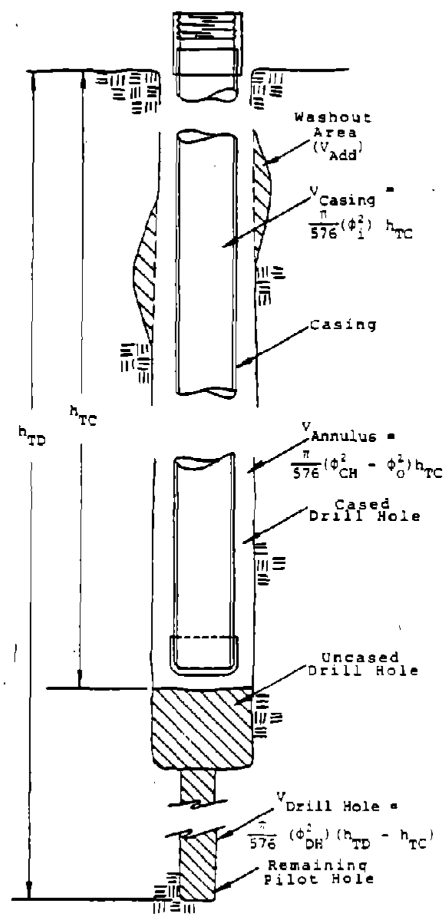


FIGURE 25 - Contributions to the volume to be grouted.

Two characteristic volumes are important in grouting, they are the internal casing volume and the volume to be cemented. Of these two, the latter is the least straight forward in that it may be the entire bore hole, the annular volume between the casing and bore hole, or one of the preceding, plus additional and perhaps unknown volumes due to wash outs, shale swelling, or pilot hole contributions (Figure 25). It is common practice to refer pre-grout clean-up fluid, cement slurry, and post-grout displacement fluid volumes to one of the two indicated volumes. Accordingly, procedures for calculating the internal casing volume and grouted volume will be considered first. Thereafter, rules of thumb for determining the volume of pre-grout clean-up fluid, grout slurry, and post-grout displacement fluid are discussed.

In all such volume calculations and specifications a question arises as to what units of volume should be used. In the oil industry, the convention is to use barrels (1 bbl. = 42 gals.) as the standard measure of volume. However, the convention in most water treatment and hydrometallurgical processes is to use gallons or thousands of gallons as the standard measure of volume. In the ensuing discussion of volume calculations, results are all presented in units of gallons only. Those interested in using units of barrels should modify the results accordingly. It is recommended that one measure of volume be adopted and used throughout a particular operation so as to minimize confusion and errors.

Internal Casing Volume

The internal casing volume (V_C) in terms of gallons is given by the following equation.

$$V_C = \frac{h_{TC}(\phi_1)^2}{24.5} \tag{12}$$

where the variables used are identified in Figure 25 and defined in Appendix A. For a nominal casing size, the inside diameter generally decreases as the wall thickness increases. The principal exception to this generalization is fiber reinforced plastic (FRP) casing, which is manufactured by continuous wrapping of resin coated fiber filaments, around an internal mandrel to obtain the desired wall thickness. Thus, if there is any question about the inside diameter of the casing being used, it should be measured rather than relying on nominal size information provided by the manufacturer. Once standard casing sizes have been established for a given project, it is more convenient to prepare a set of tables relating casing volume to casing diameter and length, rather than performing the indicated calculation each time a volume determination is required. This has the additional advantage of reducing errors in calculation.

Volume to be Grouted

The volume to be grouted depends on three factors: 1) the drilling sequence employed, 2) the casing size being being used, and 3) drilling difficulties encountered, such as washouts. Thus, the total volume to be grouted is given by:

$$V_{Grouted} = V_{Annulus} + V_{Drill\ Hole} + V_{Add} \tag{13}$$

Each of these contributions to the total volume is depicted in Figure 25. The annulus volume (V_A) in terms of gallons is given by the following equation:

$$V_A = \frac{h_{TC}(\phi_{CH}^2 - \phi_O^2)}{24.5} \tag{14}$$

The uncased drill hole volume (V_{DH}) in terms of gallons is given by the following equation:

$$V_{DH} = \sum \frac{(h_{TD} - h_{TC})(\phi_{DH})^2}{24.5} \tag{15}$$

This expression indicates that both full diameter and pilot hole contributions must be accounted for.

The third component of volume to be grouted V_{Add}, is undefined and arises due to deviations in the nominal hole diameter. Unless a caliper log is included in the standard suite of logs run on a drill hole prior to completion, insufficient information will be available to estimate this component. Even when such information is available, it may prove less cost effective to refine the estimate of grout volume than to use an incremental additional volume of grout based on experience gained at a particular site. More often such information is not available because the incremental cost of obtaining a caliper survey can not be justified relative to the cost of an incremental additional volume of grout based on experience gained at a particular site.

Required Grout Volume

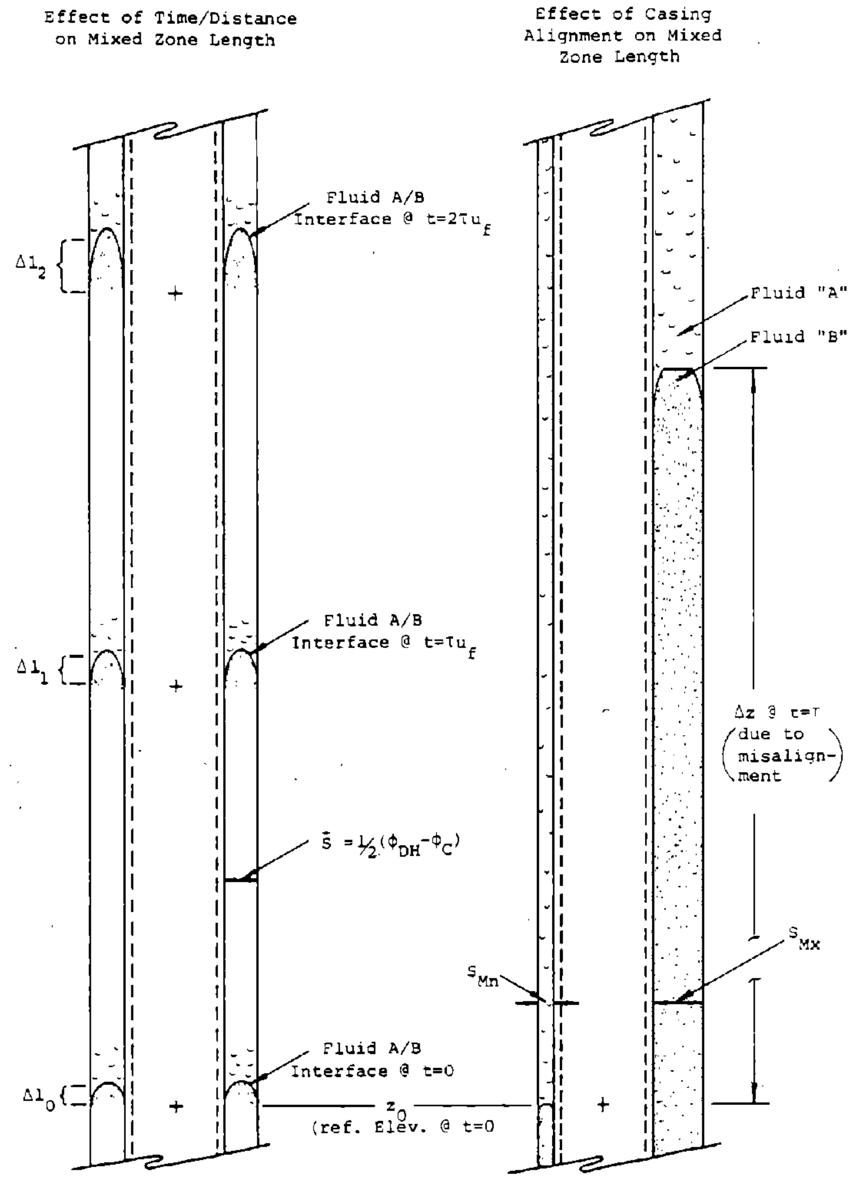
The actual volume of grout required in a particular case will be greater than the calculated volume to be grouted due to two factors. The first factor results from mixing of the fluids at the leading and trailing edges of the grout slug. The second factor is due to loss of slurry and water to the formations during emplacement.

The first factor, mixing at the fluid/grout interfaces is a function of the velocity during emplacement, the length and geometry of the flow path, and the relative densities and viscosities of the fluids. A qualitative summary of the impact of each of the indicated parameters on the volume of the resultant mixed zone at the fluid/grout interfaces is given below:

Parameter	Effect on Interface Mixing
Displacement velocity	Volume decreases with increasing displacement velocity
Channel length	Volume increases with increasing channel length
Channel cross section	Volume increases with increasing asymmetry of channel cross sectional area (i.e., casing misalignment)
Fluid density ratio	Volume increases as the density of the displaced fluid relative to the displacing fluid exceeds 1.0
Fluid viscosity ratio	Volume increases as the viscosity of the displaced fluid relative to the displacing fluid exceeds 1.0

A transition from the characteristics of the displaced fluid to those of the displacing fluid occurs across this mixed zone (24,32,46,50) as depicted in Figure 26. If the casing to formation seal is not to be affected, it is essential that the quantity of grout be increased and the mixed fluid/grout volume be either displaced or excluded from the critical seal area.

Three methods are available for minimizing the mixed volume at the fluid interface as well as its impact on the casing to formation seal. The first is specifying an adequate number of centralizers to maintain casing alignment in the bore hole (21,37), which is considered in a subsequent section. The second is to specify fluid properties and displacement velocities for the drilling fluid, clean-up fluid, grout slurry, and displacement fluid to minimize mixing at the fluid interfaces. The third is to use wiper plugs to maintain fluid isolation in critical areas (49).



where:

Δl_i = Length over which either Fluid is less than 90% pure.

$$\simeq c\left[\sqrt{u_f z \left(\frac{\rho}{\mu_{eff}}\right)_{Av.}}\right]$$

Δz = maximum distance between the fluid interfaces in an eccentric annulus.

$$\simeq \frac{2G_F\,(S_{Mx}-S_{Mn})}{\left[S_{Mn}\;S_{Mx}(\rho_G-\rho_F) + 2(G_G-G_F)\right]}$$

FIGURE 26 - Factors affecting mixed zone volume.

However, the actual volume of the mixed zones occurring at the fluid/grout interfaces cannot be reliably predicted. Thus it is necessary to specify and maintain both fluid properties and displacement conditions which maintain such volumes within acceptable and reproducible limits. Once this is done a suitable volume allowance can be established on the basis of field experience.

The second factor contributing to a greater than theoretical grout requirement is the loss of slurry and water to the wall formation. As discussed previously, the bottom hole hydrostatic pressure exerted by the grout column must be greater than the natural hydrostatic pressure in the bore hole to achieve grout emplacement and obtain an effective seal between the casing and the drill hole wall. Frequently the bottom hole hydrostatic pressure exerted by the grout column is significantly greater than the natural hydrostatic pressure. Accordingly, a significant lateral pressure gradient exists between the drill hole and adjacent formations. Slurry and water flow are induced into the wall formations as a result and continue until either the permeability of the bore hole wall decreases sufficiently as a result of filter cake accumulation to prevent further flow, or the grout sets sufficiently to become self supporting, thus relieving the pressure gradient. In any practical situation, some slurry and water loss will occur to the wall formations after grouting with a sufficient volume to obtain slurry return to the surface. To some extent the grout formulation can be adjusted to minimize such losses, as discussed previously (reference discussion of Filtration Loss Additives). Thereafter it becomes necessary to make up such losses once the initial grout column has set by topping off the annulus with an additional volume of grout.

Thus, the quantity of slurry required (V_{Rqd}) in a particular situation will be greater than the volume to be grouted (V_G) by an amount equal to the sum of the mixed volumes occurring at the fluid/grout interfaces (V_{Mxd}), and the volume loss to the wall formation (V_{Loss}) as indicated below.

$$V_{Rqd} = V_G + V_{Mxd} + V_{Loss} \tag{16}$$

Typically, the quantity of slurry required is found to range from 20 to 50% greater than the actual volume to be grouted. However, actual experience gained at a particular site should be relied upon for estimating the incremental slurry volume required to compensate for these additional losses.

Pre-Grout Flush

The purpose of a pre-grout flush is to: (1) minimize mixing between the drilling fluid and grout by separating them, (2) remove residual drilling fluid from the casing wall, (3) penetrate, loosen, and remove excess accumulated solids from the filter cake at the drill hole wall, and (4) remove any slough material from the annulus which may have accumulated during casing emplacement. A pre-grout flush will help insure that good seals are established between the grout and the casing and the formation. For water base drilling fluids of the type used for in situ mining, either water alone or a dilute grout slurry are good clean-up fluids. They have the advantage of being readily available and compatible with both the drilling fluid and grout. When water is used, it should be of a quality similar to the prevailing groundwater(s) and that used for drilling fluid and grout makeup. If a significantly different water quality is employed, it may result in unnecessary contamination of the natural groundwater(s), dispersion of the suspended solids in the drilling fluid and/or grout, and shrinkage or swelling of clay and shale strata. In most cases dilute grout slurry is considered preferable to water, since its properties are intermediate between those of the drilling fluid and grout slurry.

The volume of pre-grout flush should be adequate to give a contact time of 10 minutes or longer to remove drilling fluid and tramp solid residuals. As with grouting, a displacement velocity which produces turbulent flow to scour the casing and bore hole walls is recommended. The flow rates for necessary turbulent flow in the casing and the annular space surrounding the casing, are given by the following expressions.

$$q_C > 1100 \left(\frac{\phi_I \cdot \mu_{eff}}{\rho_G}\right) \quad \text{through the casing, and} \qquad (17)$$

$$q_A > 1100(\phi_{CH} + \phi_O)\left(\frac{\mu_{eff}}{\rho}\right) \quad \text{through the annulus.} \qquad (18)$$

where all terms are defined as previously (refer to Appendix A). The greater of these two flow rates, q_A, should be circulated for 10 minutes or longer to obtain an effective pre-grout flush.

Grout Displacement

When the slurry is emplaced by grouting through the casing, a quantity of fluid is necessary to displace the grout from the casing into the annulus surrounding the casing. As for pre-grout flush, this fluid is typically water because of its ready availability and compatibility with the grout. However in some cases, it may be preferable to employ a recoverable water base fluid with a density similar to the grout (such as suitably weighted drilling mud), to reduce or eliminate the need for maintaining a high well head pressure until the grout sets. Regardless of the displacing fluid selected, it is essential that the correct volume be employed. If too large a volume is used, the displacing fluid will be driven into the annulus and result in a poor casing to formation seal over at least some length. Depending on the relative densities and viscosities of the displacing fluid and grout, countercurrent migration of the displacing fluid and grout may result, and continue until the grout sets sufficiently to be self supporting. The latter mechanism will significantly expand the length over which an unsatisfactory seal results. If on the other hand too little fluid is used, a significant grout residue will remain in the casing, which will then have to be drilled out prior to well completion. Generally, erring on the side of insufficient displacement fluid is preferable to excessive displacement fluid, since the quality of the grout seal is preserved rather than compromised.

There are essentially two methods of displacing the grout with a second fluid. In the first method, the displacing fluid is introduced immediately behind the grout without any type of mechanical separation between the two fluids. As discussed previously, a zone of mixed fluid/grout characteristics develops at this interface during displacement, which must be taken into account in establishing the volume of displacement fluid required. Thus, the volume of displacement fluid (V_D) required is somewhat less than the casing volume (V_C) as indicated by the following expression:

$$V_D = V_C - V_{Mxd} \tag{19}$$

Provided that turbulent flow is maintained during displacement and a fluid less dense than the grout slurry is used for displacement the volume of the mixed zone (V_{Mxd}) can generally be maintained within acceptable limits. Over The range of casing sizes and depths typically employed for in situ mining, the mixed zone can generally be maintained between 5 and 10% of the casing volume (refer to Figure 26).

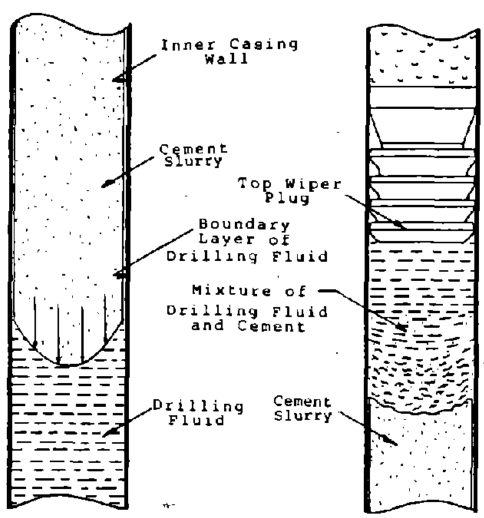


FIGURE 27 - Mixed fluid accumulation ahead of a wiper plug.

In the second method, the displacing fluid is separated from the grout slurry by a wiper plug as depicted in Figure 27. This arrangement prevents mixing of the two fluids and minimizes the residual volume remaining in the casing following displacement. However, as depicted, a small volume of drilling fluid and grout will accumulate between the top of the grout and the wiper plug as a result of incomplete scouring of the casing wall during the pre-grout flush. The volume of tramp fluids accumulated in this manner is dependent on the characteristics of the drilling fluid, the effectiveness of the pre-grout flush, and whether or not a pre-grout wiper plug was also used. The resultant mixed volume will be significantly less than that obtained without mechanical separation of the two fluids. The volume of displacing fluid required is given by the same expression indicated previously, however in this case, the volume of the mixed zone (in gallons) can be predicted by the following expression:

$$V_{Mxd} = 1.96\phi_l\left(\frac{G}{\rho_f}\right)h_{F/G} \tag{20}$$

where all terms are defined as previously (refer to Appendix A). Over the range of drilling fluid properties and casing sizes typically employed for in situ mining, the volume of this mixed zone would be less than 1% of the casing volume. Thus, the mixed zone volume is significantly reduced by the use of wiper plugs.

Casing/Grouting Accessories

Several types of accessories may be employed in casing and grouting a drill hole. There are two categories of accessories, the first category is used regardless of the grout emplacement technique employed, and the second category is used primarily when the grout is emplaced through the casing.

Casing Accessories

There are four types of accessories which may be incorporated with the casing string at the time it is set in the drill hole. Which ones are used will depend on the type of well completion planned, the method of grout emplacement used, and the formation conditions encountered. The four types of accessories are the guide or float shoe, cement basket and diverter plug, centralizers, and scratchers. Two of these accessories, the guide or float shoe and centralizers, are essential and are always used. Whether a cement basket and diverter plug or scratchers are used will depend on the particular well design and prior grouting experience. Each accessory and its function is described in the following paragraphs.

Guide or Float Shoe

The principal difference between these two devices is that the float shoe incorporates an internal check valve while the guide shoe does not. Both devices are installed at the bottom of the casing string and are intended to guide the casing past any surface irregularities as the casing string is lowered into the drill hole. They are available in both steel and plastic shells with drillable internal materials, and can be used with any of the casing materials. Because it does not include a check valve, the guide shoe permits unrestricted flow between the casing and drill hole. In this case flow can be prevented by imposing sufficient shut in pressure at the well head to support the grout column. With a guide shoe, the net weight of the casing string must be supported from the surface as the casing and grout are emplaced. Because it includes a check valve, the float shoe prevents fluid flow from the drill hole back into the casing. Thus, depending on the

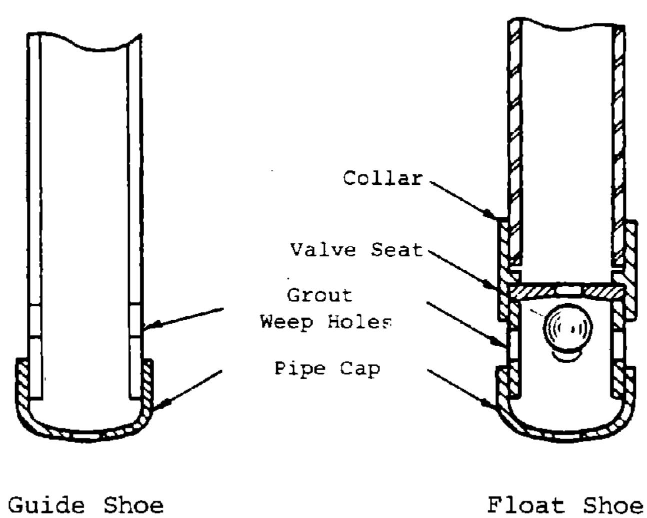


FIGURE 28 - Guide and float shoes.

densities of the casing material and fluids used, the casing string can be made partially to completely self supporting. In the case of deep wells, this becomes a major consideration due to the tensile stress on the casing and to the hoist capacity available at the surface.

Centralizers

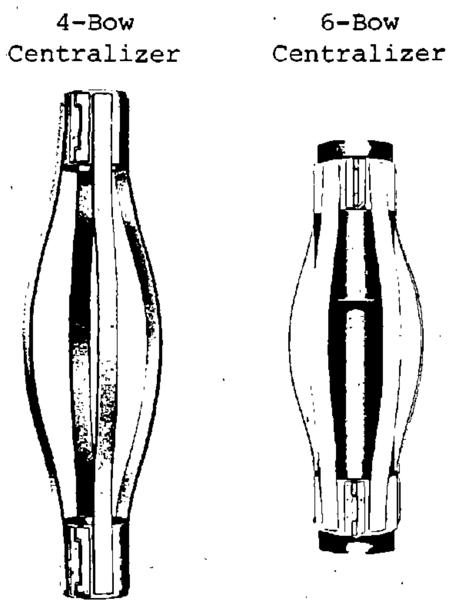


FIGURE 29 - Centralizers
(Courtesy of Halliburton Services)

The most common centralizer design consists of two cylindrical collars of either slip-on (one piece) or clamp-on (two pieces hinged) construction separated by a number of bow spring strips. They are usually fabricated from steel, but with the increased use of plastic casing materials they have become available in various plastics as well. They are also available in several different configurations regarding the number and strength of the bow spring strips and the incorporation of turbulence inducing deflectors. Another centralizer style consists of thin solid segments, which are oriented axially and glued directly onto the wall of the casing as required. This design is attractive because of its significantly lower cost, but is relatively untried at present. It is uncertain whether problems may develop with this design, such as casing distortion or damage due to localized compressive stresses during casing emplacement and grouting.

As their name implies, a centralizer's function is to center the casing in the drill hole and maintain that alignment during both casing and grout emplacement. To do this, it is essential that the spacing and characteristics of the centralizers meet certain criteria. The nature and magnitude of the net axial load on the casing string during emplacement depends on the difference between its weight and the combined drag and buoyant forces acting on it. Where a net tensile load exists, maximum recommended centralizer spacing is a function of hole deviation characteristics alone. Specifically centralizer spacing is established so as to maintain some minimum clearance between the casing string and drill hole wall, typically one-half of the nominal clearance. Where a net compressive load exists, the relationship between maximum recommended centralizer spacing (l_{Mx}), and the axial compressive force ($F_{z,C}$) and casing characteristics is given by the following equation:

$$l_{Mx} < \sqrt[3]{\frac{EI(h_{F/G})}{|F_{z,C}|}\pi^2} \qquad (21)$$

In this equation all terms have the same definitions as indicated in Figure 5 and Appendix "A". For a given axial compressive load, the deviation in alignment of the well casing from the drill hole increases rapidly as centralizer spacing exceeds the calculated value. Thus it is essential to maintain centralizer spacing less than or equal to the calculated value to maintain alignment between the casing and drill hole during grouting.

To minimize the probability of developing axial compressive loads on the casing during casing emplacement, it is recommended that the characteristic starting force[7] of the selected centralizer for the nominal drill hole size employed be less than the weight of a casing string equivalent to the specified centralizer spacing. It is also recommended that the lateral restoring force[7] of the specified centralizer at a displacement between the casing and drill hole centerlines of approximately one-half the nominal spacing be similar to its characteristic starting force. The recommended starting and restoring forces for centralizers used with common well casing materials and sizes are tabulated in Appendix C. Also given are the maximum recommended spacings for various grout slurry densities.

Cement Basket and Diverter Plug

The cement basket (Figure 30), consists of a conical fabric liner attached to and supported by a number of bow spring strips, which are attached to a one-piece cylindrical collar. They are typically fabricated from heavy duck canvas and spring steel rather than plastics, which tend to be marginal in terms of structural strength. The purpose of this device is to support the grout column until it sets and prevent leakage of either slurry or filtrate into the formation(s) below. To be effective in this regard, a seal at the drill hole wall is essential. This requires that the cement basket be set in a competent clay or shale immediately above the mineralized sand. Even so, significant slurry and filtrate leakage past the basket may occur during grout emplacement, due to the high differential pressure[8] which must be supported. This problem may be mitigated by modification of the grout formulation and use multiple cement baskets.

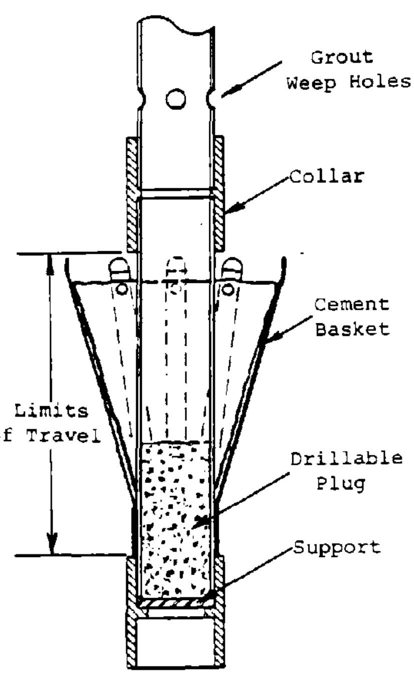


FIGURE 30 - Cement basket diverter plug assembly.

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[7] The recommended procedures for measuring the starting and restoring force characteristics of bow spring centralizers can be found in reference 2.

[8] The magnitude of the differential pressure which must be supported by the cement basket and diverter plug = $h_{F/G}\ (\rho_g - \rho_w) + h_{SW}\ (\rho_w)$.

When an integral well screen and casing is used and grout is emplaced through the casing, it is necessary to block flow into the well screen and divert flow through the casing into the annulus above the cement basket. The standard method of accomplishing this is the combination of a drillable or recoverable diverter plug located just above the transition from casing to well screen (Figure 30). As in the case of the cement basket, the plug must support a high differential pressure during grout emplacement, which may lead to slurry and filtrate leakage or even complete plug failure as the depth increases. In view of the potential for leakage past the cement basket and the diverter plug, considerable caution must be exercised in using an integral screen and casing design at depths greater than 200 feet.

As depicted in Figure 31, the diverter plug and cement basket are typically incorporated in a short length of casing which serves as the transition section between the casing and well screen or guide shoe. This section is sized to permit free travel of the cement basket over a limited distance, typically 2 to 3 feet. Such travel is required during makeup and emplacement of the casing string. Weep holes are then installed near the bottom of the first casing joint to permit fluid communication between the casing and annulus.

Scratchers

These devices are of two basic types, either reciprocating or rotating. They are typically fabricated from spring steel wire which is attached to either a steel collar or strip which can be attached to the casing in one or more locations. Their purpose is removal of excessive filter cake from the drill hole wall via reciprocal or rotary motion of the casing as it is being emplaced. However, the scratching action may cause sloughing from the drill hole wall. Thus they should only be used where filter cake removal by means of suitable pregrout flushing has proven unsuccessful and the formations involved are competent and well cemented. These devices are virtually unused at present in the construction of in situ mining wells.

Grouting Accessories

There are essentially three types of accessories which are used when grout is emplaced through the casing. Each accessory and its function is described in the following paragraphs.

Wiper Plugs

These plugs are designed to separate two fluid phases and remove fluid residue from the wall as they move through the casing (Figure 27). They are used to isolate the grout slug from the pre-grout flush or grout displacement fluid, thereby reducing the volume of the mixed zone occurring during emplacement at the leading and trailing grout interfaces. Although a variety of expedient materials have been used for this purpose, current practice is to use a specially fabricated plug consisting of either waxed cardboard or a flexible surface material covering a drillable core material. The style of wiper plug used depends on its location relative to the grout slug and the principal direction of grout flow from the casing into the annulus. The latter is determined by the specific casing design and the particular grouting requirements. If grout is to be displaced axially from the bottom of the casing, a hollow core plug is used, whose top surface contains a precast diaphragm designed to rupture when the plug bottoms on the guide/float shoe. If grout is to be displaced radially from the bottom of the casing, a solid core plug is used. In this case, radial weep holes are drilled in the casing wall at a sufficient distance above either the diverter plug or guide/float shoe that the bottom plug will clear them during grout emplacement and the top plug will seal them following grout emplacement. The top wiper plug is also a solid core plug which is designed to prevent further fluid flow from the casing into the annulus once it is seated against the bottom wiper plug. A specialized form of this plug, referred to as a latch plug, is sometimes used. It is designed to seat against and lock into a special collar installed in the casing string above the guide shoe. When seated it acts as a check valve to prevent flow back into the casing from the annulus.

Opinion and practice vary regarding wiper plugs, because of the additional costs associated with grout emplacement and damage during well completion. If plugs are not used, the volume of grout and chase fluid must be adjusted to account for the mixed zone which develops at both the leading and trailing edge of the grout slug. This necessitates increasing the grout volume and decreasing the displacement fluid volume to compensate for the mixed zones as discussed previously. In addition, it results in a greater volume of mixed grout and chase fluid being left in the casing which must be drilled out at the time of well completion. A compromise practice adopted by some in situ mining operators is to use one rather than two wiper plugs. When this is done, it is important that the plug,which has the greatest impact on the aggregate mixed volume produced and the quality of seal obtained, be retained. Since generally the grout slurry is more dense than either the clean-up or displacement fluid, it is preferable to retain the bottom plug. Where a positive safeguard against the use of excessive displacement fluid is the primary consideration, the top wiper plug should be retained. In this case a physical stop to limit plug travel and provide a sump for hold up of the mixed volume should also be incorporated into the casing string design.

Grouting Well Head

This specialized well head (Figure 31) provides for quick connection and disconnection between the drill rig and grouting rig, and shut in of the well when grouting is completed. In addition, it may contain provision for storing and introducing either one or two wiper plugs into the casing during grout emplacement. As depicted, the well head contains no provision for valving from drilling fluid to pre-grout flush to grout slurry to displacement fluid. For this discussion, it is presumed that the grouting rig incorporates the valving. In its simplest form the grouting well head consists of a large size pipe tee (not necessarily casing size) equipped for hold down during and following grout emplacement with a shut off valve and quick disconnect hose coupling installed on the lateral and no provision for introducing wiper plugs. By contrast, in its most complex form the cementing well head is casing size and incorporates storage area for two wiper plugs and the valving

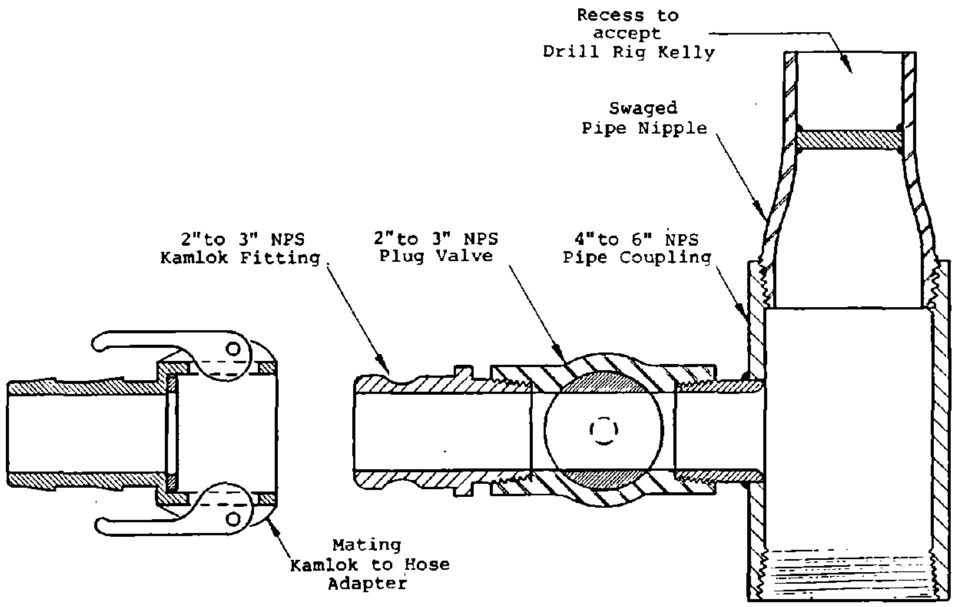


FIGURE 31 - Typical grouting well head.

necessary for their introduction. Clearly the selection of one type over another will depend on the number of wiper plugs to be used and the number of wells to be cemented. Once the grout slurry has set sufficiently to be self supporting over the entire length of the seal, the grouting well head is removed and available for reuse.

Support/Hold Down Equipment

Some means of support/hold down must be provided to counteract the net forces (Figures 4 & 5) acting on the casing string throughout the period of casing and grout emplacement and until the grout sets sufficiently to be self supporting. The drill rig is generally found to be the most convenient piece of equipment for this purpose until grout emplacement has been completed. Thereafter some less expensive support/hold down method is generally substituted. Any readily implemented method, with sufficient capacity to resist the forces involved is suitable for this purpose.

Grouting Procedures

Some of the holes drilled as part of an in situ mining project will not be completed. Holes may be abandoned as a consequence of further exploration, inadequate grade and thickness of mineralization, or problems encountered in drilling, casing, grouting, or completing a particular well. Regardless of the reason, two cementing procedures are used, one for well completion and one for hole abandonment. The essential components of each procedure are discussed in the following sections.

Grouting Well Casing

This procedure combines in a concise format the essential items regarding grouting which were discussed previously. The major components of the procedure are listed:

1. Grout Specification:
   Type of Cement ______________________________
   Quantity of Mix Water _____ gal/sack of cement
   Quality of Mix Water (specify maximum allowable concentration of any critical constituent(s) and the allowable temperature range.)
   Additives to be used:
   a. Type ____________ and Quantity ________ lbs/sk. cement
   b. Type ____________ and Quantity ________ lbs/sk. cement
   c. Type ____________ and Quantity ________ lbs/sk. cement
   Slurry density ____________ lbs/gal.
   Slurry viscosity ____________ sec (Marsh Funnel)
   Slurry gel strength _________ lb/sq. ft.
2. Volumes and flow rates to be used:
   Type of pre-grout flush __________ at _________ ft/min.
   Slurry vol: ________ x volume to be grouted
   Grout flow rate ___________ ft/min and max pressure ______ psi
   Type of displacement fluid __________ at _________ ft/min.
   Displacement fluid vol: (_______) x Internal Casing Volume
3. Accessories to be used:
   Description and schematic of the casing string design and accessories to be used.
   Type and maximum spacing between Centralizers.
   Type of Cementing Well Head and Wiper Plugs to be used.
4. Method of grout mixing to be used including the quality assurance samples, tests, and records to be kept.
5. Method to be used for grout emplacement.
6. Hold down method, minimum weight, and method of attachment to the casing string to be used.
7. Minimum set time to be allowed before removal of grouting well head and hold down ______ hours.
8. Minimum cure time to be allowed before any well completion or development work-over is begun ______ days.

Generally, some shrinkage of the grout column will occur prior to thickening and setting as a result of filtration loss to the wall formations. The magnitude of the shrinkage experienced will depend on both the grout formulation and the permeability of the formations, but is typically 10 feet or less. Unless shrinkage is less than a foot, it is advisable to top off the grout column in order to provide lateral support for the upper casing during any work-over. This should be done after the grout has achieved initial set, but before any well completion activity to permit thorough curing of the additional grout. The same grout mixture should be used for topping off as was used to grout the casing. The preferred method of grout emplacement for topping-off is with a grout pipe extending along the outside of the casing. Although it is generally not necessary to obtain a fluid tight seal between casing and formation when topping off, it is advisable to employ good grouting practice.

Abandoned Holes and Wells

Current regulations generally require that abandoned drill holes be filled from the bottom of hole to the surface with a plugging material which will prevent ground water intermixing between water bearing strata as a result of naturally occurring hydrostatic forces and hydraulic gradients. One of two plugging procedures is recommended at present (57): (1) filling from the bottom of hole to the surface with a bentonite/polymer mixture having a minimum gel strength of 0.2 lb/sq. ft., after 10 min. and a maximum API filter loss of 13.5 cc/half hr. at 100 psi followed by installation of a grout plug of 5 to 10 feet thick at the surface, or (2) filling from the bottom of hole to the surface with a stable cement grout mixture. Properly implemented, either of these plugging procedures should provide a seal adequate to withstand the naturally occurring hydrostatic forces and hydraulic gradients and also those associated with in situ mining operations. Site specific conditions could require changes to these procedures and should be considered when adopting a particular procedure.

In addition to a complete specification of the material to be used for abandonment plugging, this procedure should also include: (1) the type, quantity, and flow rate of any clean-up fluid to be circulated prior to plug emplacement, (2) the method of mixing to be used in preparing the plug material, (3) the quantity of material and rate of emplacement to be used, and (4) the type of quality assurance samples, tests, and records to be kept. The method of emplacement is by either drill or grout pipe suspended from and supplied through a drill rig or well service rig, respectively, with material emplacement starting at the bottom and proceeding to the top of the hole. Although the drill/grout pipe can be retrieved as plugging progresses or as returns are maintained at the surface, the latter method provides greater assurance of thorough plugging.

Well Testing Requirements

Current regulations governing in situ mining operations (53,57) require that all injection wells be tested by two different methods prior to use to verify suitable confinement of the injected fluids. The two methods specified are: (1) pressure testing of the casing string with either a gas or liquid to verify casing integrity, and (2) either a noise or temperature log survey of the casing string to verify the integrity and competency of the grout seal. Where the casing material precludes use of the second method (as in the case of plastic materials), it is alternately required that: (1) suitable cementing records be maintained to verify that procedures were proper for an adequate grout seal, and (2) a monitoring program be designed and implemented to detect any fluid migration into surrounding ground water. The monitoring program includes maintaining a hydraulic gradient from the surrounding area and formations toward the production zone coupled with periodic monitoring of both water quality and water levels in the surrounding area and formations.

Three types of pressure testing have been employed to verify casing integrity. The first method involves testing the well between the time grouting is completed and well completion is begun, while the other two methods involve testing the well following completion. In the first method either the shut in well head pressure at the time of grouting is used to verify casing integrity, or the well is repressurized with air and the rate of pressure decay with time used to determine casing integrity. The second method consists of using air to pressurize the well and to displace water from the casing to a depth just above the completion interval. The well is then shut in and the pressure decay rate measured. The third method consists of isolating the completion interval by means of an inflatable packer, then pressurizing the casing with water or air, and determining the pressure decay rate while shut in. At the present time, no specific criteria have been established regarding preferred test procedures, minimum test pressure, pressurizing fluid, or maximum acceptable decay rate.

Well Repair Methods

Well repair may be necessitated by evidence of inadequate integrity of the well casing or grout seal. There should be verification that the damage is not due to inappropriate specifications for well design, materials of construction, or method of construction and completion. If the specifications were proper, it is probable that the damage can be traced to either (1) defective or inappropriate materials of construction, or (2) deficiencies in the well construction and completion practices. As discussed before, the most effective method of eliminating the second cause of damage is the implementation of appropriate quality assurance procedures.

Periodically, it may be necessary to repair a damaged well. If casing damage is limited to near surface (i.e., less than 10 feet in depth), excavation and replacement of the damaged section is probably the best repair method. At greater depths, repair of the damaged area may be possible by means of an appropriate squeeze cementing technique (50, p. 87). Otherwise it will become necessary to install a liner of smaller diameter pipe and sufficient length to isolate the damaged area when sealed to the original casing. The necessary seal may be made with either packer assemblies or cement grout. The choice of seal will depend on the nature and extent of casing damage, the quality of seal required, and the intended well function. If the extent of casing damage is such that there is any question regarding grout seal integrity behind the casing, it is inadvisable to attempt casing repair of any type.

Since at present no practical method exists to evaluate or repair grout seal integrity, the grouting, well completion, and work-over practices used must be relied on to obtain and maintain integrity. When there is evidence that grout seal integrity has been lost by detecting solution leakage or casing damage, the well in question should be drilled out to a larger hole diameter than the original and a new well installed[9]. Under no circumstances should the well in question be plugged and an off-set well installed, since pathways of fluid migration are not eliminated in the process and recurring fluid migration is probable.

[9] Because of this possibility, it is recommended that either plastic or drillable casing accessories be used wherever possible in the casing string.

DEVELOPMENT/STIMULATION METHODS

Completion of a well can proceed once the grout seal has cured sufficiently to withstand the stresses of work-over. The purpose of well completion is to expose a selected portion or portions of the mineralized formation. The various methods of well completion commonly used were discussed previously. The well completion process, as well as prior drilling and grouting activities, may leave drilling fluid or cement residuals on the exposed sand face. The function of well development is to remove the residuals and maximize the rate of solution flow into or out of, the completed interval. Due to the dual function of the completed wells, well development is critical to well performance. This is particularly true for injection wells, where normal hydrodynamic forces tend to hinder rather than aid well development, thus increasing later well stimulation requirements. The function of well stimulation is the restoration of well capacity after some period of operation. Loss of flow may result from: (1) solids accumulation due to filtration or precipitation, (2) gas accumulation due to convective transport, reaction, or supersaturation, and (3) biological activity in the well bore. The balance of this section is devoted first to a discussion of well development methods, and then a discussion of well stimulation methods.

Development Methods

As indicated above, the purpose of well development is to maximize either the rate of solution injection or production for the completed well. The factors involved are a function of both the formation characteristics and the well completion method. Assuming that the optimum well completion method has been used, the factors involved relate only to the formation characteristics. In the case of unconsolidated or poorly consolidated sands and a screened completion, effective well development will accomplish the following: 1) remove drilling and cementing residuals from the sand, 2) increase the porosity and permeability of the sand face, and 3) stabilize the remaining sand. Thus, effective development involves removing the fines and rearranging the formation material to increase its stability, porosity, and permeability (ref. Figure 8). In the case of a stabilized or gravel-packed well, the same elements of well development are involved although the range of grain sizes is typically greater. As the competency of the host sand increases, it becomes more difficult to modify its natural arrangement and thereby influence stability, porosity, and permeability. Thus as the competency of the host sand increases, the function of well development is increasingly limited to removal of drilling and cementing residuals from the pore structure.

Regardless of the natural formation characteristics, a combination of impulse, cyclic, and steady forces must be applied to effectively develop a well. The optimum combination of forces in a particular case will depend on the specific objective for the well, formation characteristics, and well completion method. Impulse or cyclic forces are best suited to dislodging and rearranging the formation material, while steady forces are best suited to moving the dislodged material. The most common well development techniques are: high rate/ cyclic pumping, air lifting, hydraulic jetting, and mechanical surging. All of these methods utilize the three types of forces to varying degrees. Chemicals, such as acids or dispersants may be used in combination with any of the development techniqes to facilitate well development. The balance of this section is devoted to a discussion of each technique and their relative merits for well development.

High-Rate/Cyclic Pumping

This method of development consists initially of pumping the well at a significantly greater rate than will be employed during operation, thereby dislodging by means of hydrodynamic drag any drilling or grouting residues and fines from the exposed sand face. The solids dislodged are continuously swept into the well bore and removed with the water pumped from the well. Once the exposed sand face has been cleaned up by the high rate pumping, well development is continued by a combination of cyclic and high rate pumping to achieve maximum fines removal plus sand grain rearrangement and stabilization. If begun prematurely or done without periodic high rate pumping, cyclic pumping may result in solid residues and formation fines becoming packed in the exposed sand face rather than being removed. Thus the opposite of the intended effect could be obtained.

With any cyclic development method, it is advisable to convert gradually from steady pumping to cyclic pumping at a moderate cycle frequency and magnitude to minimize damage to the pump, well screen, and sand face. The highest cycle frequency obtainable will depend on the pump motor control and the power supply. However, the magnitude of the pulse obtained will decrease as the cycle frequency increases. Therefore, the effectiveness of the cycling increases up to some frequency, beyond which it decreases. In practice there is some cycle frequency and magnitude above which no further beneficial effect is realized. In addition it can be expected that cyclic pumping will be somewhat less effective than either cyclic air lifting or hydro-mechanical surging due to the generally lower pumping rates and greater friction losses.

When used for well development, it is generally advisable to employ a special pump rather than the production pump. The reasons for this are: (1) the pump must be capable of handling the solids burden produced during development without excessive wear, and (2) the pump capacity should be significantly greater than the maximum injection/production capacity anticipated. For the casing diameters typically employed (4" to 6" NPS), finding a suitable pump for well development is a problem, since the readily available downhole pumps are multi-stage centrifugals, which have a low tolerance for suspended solids. For this reason, as well as its limited effectiveness related to other development methods, high rate/cyclic pumping is not widely used as a well development method.

Air Lifting

The air lift principle is based on lowering the effective density of fluid within a column sufficiently for the external hydrostatic pressure to induce flow up the column (Figure 32). Thus, the effective pumping rate attainable with an air lift is a function of the available hydrostatic head, the well recharge rate, the lift necessary, the submergence maintained, and the

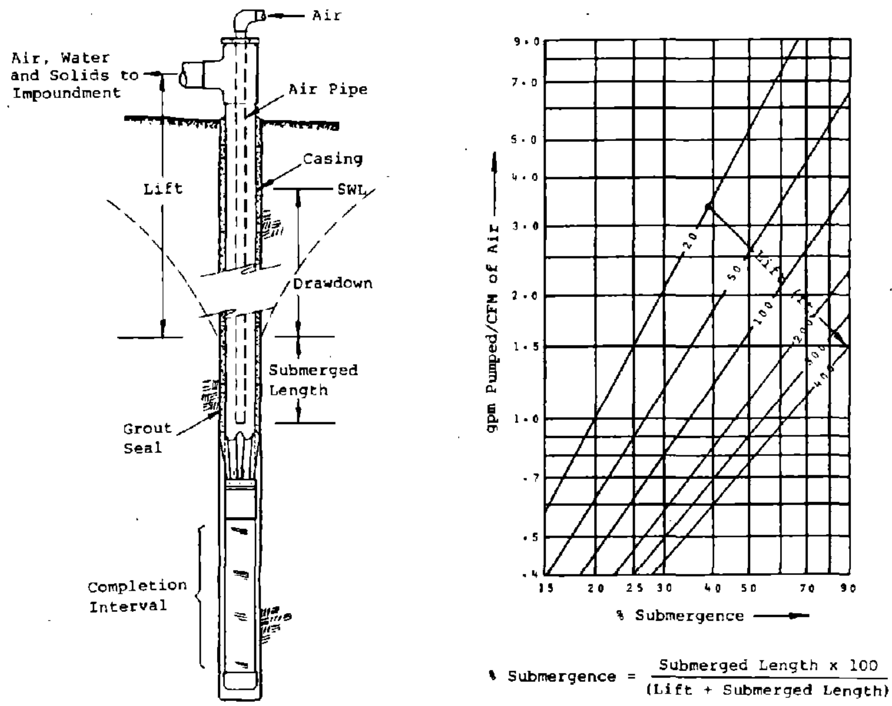


FIGURE 32 - Air lift pumping.

quantity of air used. The relative effect of lift and submergence on the effective water pumping rate of an air lift is indicated in the associated graph. However, this is only a guide to designing an air lift for well development, since only the quantity of air can be controlled and not the submergence. Thus for a given air supply rate, the dynamic water level in the well bore will equilibrate at the level where the rate of pumping matches the rate of recharge.

Two different air lift configurations can be utilized for well development. In the simplest configuration, only an air pipe is utilized and the casing serves as the eductor pipe through which water and air are conveyed to the surface. The more complex configuration utilizes a separate eductor pipe in addition to the air pipe. For the range of casing sizes of primary interest, namely, 4" to 6" NPS, the simpler configuration generally provides adequate pumping capacity and is much less cumbersome and costly to employ. In this case, the air pipe is typically either flexible or rigid tubing of 1" to 1.5" NPS, with sufficient strength and mass to resist the reactive force associated with the exiting air stream. When the well casing is used as the eductor pipe, the air pipe should generally not be lowered into the completion interval since air scouring may damage the exposed sand face. It is also necessary to support the air pipe string and provide some means of diverting and collecting the produced water at the surface, in order to minimize soil contamination. A well head (Figure 33) consisting of a full diameter pipe tee and packing gland/support for the air pipe can be utilized in combination with adequate tankage for collection of the water produced.

Because of the air lift's high pumping capacity, it is possible to severely damage the well screen or casing as a result of the radial compressive stresses developed. Therefore, considerable caution should be exercised during air lift development. To minimize the possibility of damage, air injection should begin at the lowest practical rate which yields water and be increased gradually until maximum water yield is realized. Steady air lifting should be continued at the maximum practical rate until the water produced appears to be free of silt and clay. Following this, it may be beneficial to gradually convert from steady pumping to a combination of cyclic and steady pumping to improve the effectiveness of residual fines removal and rearrangement/stabilization of the remaining sand grains. Great care must also be exercised during cyclic operation to avoid well screen or casing damage as a result of the pressure surges. This can be done by: 1) limiting the magnitude of the pressure surges to a safe level by adjusting the depth of immersion of the air pipe, and 2) beginning cyclic operation at a relatively high cycle frequency which is then reduced as development proceeds. As noted previously, intermittent steady-pumping is essential for effective well development and removal of the mobilized fines.

The air lift method of well development is generally superior to high rate/cyclic pumping because of its effectiveness and ease of implementation. Its effectiveness relative to other development methods can vary depending on the specific formation characteristics. However, it is generally both less cumbersome and less costly to implement. Partially offsetting these advantages is the greater difficulty associated with handling and containing the produced air/water/solids stream during well development. That its advantages generally outweigh its disadvantages is evident from the fact that it is the most widely employed of all the well development methods.

Hydraulic Jetting

This method of well development is particularly well suited for either poorly to moderately consolidated sands in which a screened well completion is used or for well consolidated sands in which an open hole or under-reamed completion is used. Hydraulic jetting has no practical value for development of a well completed by perforating. In one design of hydraulic jet, water at high pressure (100 to 500 psi) is supplied to two or more horizontal nozzles which are equally spaced around the circumference of a tool to neutralize the reactive force of the jets (Figure 38). An alternative design, consists of a signal jet at the end of a length of flexible tubing, (Haliburton's Hydra-Jet) and utilizes the reactive force of the jet to create random motion for scouring a greater portion of the completion interval (Figure 38). Due to the difference in the jet action on the exposed sand face, the former is best suited to development of screened completions in poorly to moderately consolidated sands, while the latter is best suited to development of open hole or underreamed completions in well consolidated sands. Exit velocities on the order of 150 to 300 ft/sec. are required to obtain good development of the sand face. Table 8 summarizes the differential pressures necessary to obtain this range of velocities from a single nozzle of various sizes. The associated water flow rates are also tabulated.

The momentum of the jets induces sand circulation and fines removal in the vicinity of their impact on the exposed sand face. By gradually rotating the tool and traversing from the top to the bottom of the well screen, the entire sand face is developed. It is essential that the well be pumped at an equal or greater rate than the flow rate from the jets in order to supply the required water and to remove the dislodged solids.

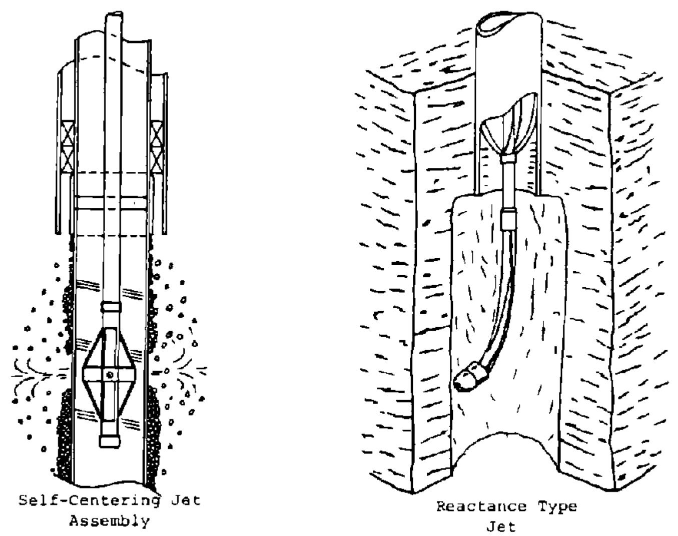


FIGURE 33 - Hydraulic jetting tools.

Over the range of casing sizes typically employed, air lift pumping is the only practical method of concurrent pumping. The requirements for recovery of the produced air, water, solids stream and a high pressure water supply for the jets result in a very cumbersome method of well development. In addition, while the high fluid velocities employed result in very effective development of the exposed sand face, they may cause damage to the plastic well screen and casing if caution is not exercised. For these reasons, use of hydraulic jetting as a development method has been quite limited.

TABLE 8

Fluid Velocities and Discharge Rates as a Function of Nozzle Size and Differential Pressure

Orifice Diameter (inches)	Discharge Rate @ 100 psi fps	gpm	@ 140 psi fps	gpm	@ 200 psi fps	gpm	@ 300 psi fps	gpm	@ 500 psi fps	gpm
1/8	110	4.2	130	5.0	155	5.9	190	7.3	245	9.4
3/16	110	9.4	130	11.2	155	13.4	190	16.4	245	21.1
1/4	110	16.8	130	19.9	155	23.7	190	29.1	245	37.5
3/8	110	37.8	130	44.7	155	53.4	190	65.4	245	84.4

Basis: Coefficient of discharge 0.90

Mechanical Surging

This method of development can be used for all types of well completions and for all types of formations from poor to well consolidated. However, as discussed previously for cyclic pumping and air lifting, mechanical surging should be employed only after the completion interval has been cleaned up by some method of high rate pumping to remove drilling and grouting residues and fines from the exposed sand face.

Surging of the fluid in the well bore is induced by alternately raising and lowering a suitable valved packer valve or swab assembly (Figure 34). Alternate injection and projection flows are induced through the sand face as a result. The magnitude of the induced flow depends on the cycle frequency, stroke length, and the packer or swab characteristics. In the case of the valved packer depicted, the induced injection and production flows differ by an amount which depends on the valve characteristics, cycle frequency, and formation characteristics. Thus some net pumping, which can be varied from essentially zero to one hundred percent, occurs as surging progresses. In the case of a solid packer assembly, the induced injection and production flows are of similar magnitude and no net pumping occurs. Because of this a solid packer assembly should only be used for the final stage of well development, if at all.

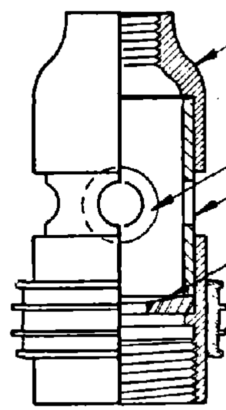


FIGURE 34 - Valved packer assembly.

Mechanical surging can result in the imposition of very large differential stresses on both the well casing and completion interval. Thus, as in the case of cyclic pumping and air lifting, it is important that surging be started at a low amplitude and frequency, and only gradually increased as development of the sand face progresses. Various combinations of high rate pumping and mechanical surging can be used to effectively develop the complete spectrum of formation characteristics and well completions. However, its application typically requires several hours of either a drill rig or well service rig and associated crew time. In contrast to this, air-lift development utilizes less expensive equipment and can proceed essentially unattended once it has been set up and initiated at a particular well. Because of its greater cost, mechanical surging is generally only employed in those cases where air lifting has proven unsatisfactory for well development.

Chemical Additives

Two types of chemical additive, inorganic acids and salts, are used to facilitate well development. Being strong electrolytes both act as dispersants neutralizing the characteristic charge distribution between the solid particles and interstitial fluid of the drilling and grouting residues. Inorganic acids serve the additional function of chemically attacking and breaking down residues at the surface and within the pore structure of the exposed sand face. As a result, the residues are more readily removed by the hydromechanical forces utilized for well development. However, caution should be exercised in both the selection and use of such additives because of their potential effect on the grout seal, host formation characteristics, ground water quality, and surface operations.

Two inorganic acids are commonly used for well development, namely hydrochloric acid and a mixture of hydrochloric and hydrofloric acids called mud acid. Hydrochloric acid is available in a variety of commercial grades ranging from approximately 22 wt.% (muriatic) to 36 wt.% (concentrated) HCl in aqueous solution. Mud acid consists of 3 to 6 wt.% hydrofloric acid plus 12 wt.% hydrochloric acid in aqueous solution. Hydrochloric acid is used primarily to break down carbonate base materials, while mud acid is used primarily to break down silica base materials in the formation. Since these acids are non-selective and attack all materials in the formation, they should be used sparingly to avoid damage to the host formation during well development.

A variety of inorganic salts are effective dispersants for particular types of drilling fluid residues. The complex sodium phosphates are effective at low concentrations and are widely used for this purpose. Although numerous complex phosphates are effective dispersants, those most frequently used are sodium tetraphosphate, and sodium acid pyrophosphate at concentrations of approximately 1 gram per liter. They should be used cautiously since, even at low concentrations (i.e., 10 ppm and less), they can cause precipitation of metal ions, including uranium, as well as poisoning the ion exchange resins used in the surface operations.

One of two methods is used to deliver these chemical additives. In the first method, solution containing the additive is circulated to remove residues which are accumulated on and near the formation surface, prior to the surge-pumping phase of well development. In the second method, solution containing the additive is used in combination with either hydraulic jetting or mechanical surging to remove residues which have penetrated the formation. The optimum method in a particular situation will depend on the nature of the residues involved and the method of well development utilized.

Stimulation Methods

During the course of operation, the performance of a well may decay with time regardless of its function. There are many causes for declining performance, but most involve one or more of the following components: solids accumulation as a result of filtration or precipitation; gas accumulation due to covective transport, reaction, or supersaturation; biological organisms; and aquifer discharge/recharge characteristics. Although all of these components are commonly encountered causes of decaying well performance, their effect is generally exaggerated in the case of in situ mining wells. The first and foremost reason for declining performance is the disruption of the natural ground water chemistry which is necessary to mobilize the mineral values in the host formation. Since the various reactions which occur between the lixiviant components and the host formation proceed at differing rates, equilibrium is seldom achieved. Accordingly, there is a high probability that the lixiviant will be supersaturated with respect to one or more precipitable species such as calcium and magnesium carbonates or sulfates as well as aluminum, iron, or magnesium hydroxides. This situation may be further aggravated by the concurrent transport of various gaseous species such as oxygen, nitrogen, or carbon dioxide, by accident due to aspiration or by intent as chemical reagents, or as a consequence of chemical reactions in situ. Like tramp solids, such gases may accumulate at either the injection or production well bore and inhibit flow into or from the affected well. Third, certain bacteria and fungi have been found to thrive in the near neutral pH bicarbonate/carbonate lixiviant commonly employed for in situ uranium mining. The natural life cycle of such organisms may produce an iron oxide/ hydroxide slime (as in the case of ferro oxidans) which rapidly degrades well performance as it accumulates and filters other tramp solids. The fourth cause of declining well performance may be the aquifer discharge characteristics of a particular operation relative to the natural recharge characteristics. In other words, excessive over-production for the purpose of excursion control or aquifer restoration may cause aquifer depletion and a decline in production well performance, and a concurrent increase in injection well performance.

The causes of declining well performance can be classified with the injection or the production wells, as indicated in the following table.

TABLE 9

Analysis of Declining Well Performance

Cause of Decline	Injection Well	Production Well
1) Filtered Solids	Likely to decrease well capacity.	Unlikely to affect well capacity
2) Precipitated Solids	Likely to decrease well capacity if supersaturation is caused by lixiviant make up.	Likely to decrease well capacity if supersaturation is caused by in situ reactions.
3) Gas Accumulation	Likely to decrease well capacity if excess gaseous oxidant is used or air aspiration occurs.	Likely cause of decreased well capacity, due to reduced hydrostatic pressure.
4) Biological Accumulations	Likely to decrease well capacity if injection filters or a lethal chemical oxidant are not used.	Likely cause of decreased well capacity due to the ready availability of necessary nutrients.
5) Aquifer Depletion	Negligible effect.	Likely cause of decreased well capacity.

The actual causes of declining well performance should be established prior to selecting a particular well stimulation method for two very important reasons. The first is that well stimulation methods are typically quite selective and, therefore, a given method may be ineffective if inappropriately applied. The second is that identification and implementation of changed process and operation methods to reduce or eliminate the causes of deterioration in well performance are essential to the success of an in situ mining project. Because of the large number of wells involved, it is generally more cost effective to treat the causes of deterioration in well performance than to use well stimulation methods. Furthermore, it is seldom possible to completely restore well performance by practical methods of well stimulation.

The methods of well stimulation fall into one of three categories, namely, hydraulic, chemical, or miscellaneous. The hydraulic methods of stimulation are similar to those used for well development, and are best suited to removal of poorly cemented accumulations of solids. The chemical methods of stimulation include treatment with inorganic acids, chemical oxidants, and polyphosphates for the removal of various precipitates or biological accumulations. The category "miscellaneous stimulation methods" includes methods such as, under-reaming, ultrasonics, perforating, and fracturing to renew the sand face or to develop an auxiliary sand face. None of the stimulation methods mentioned above is suitable for restoring loss of performance due to gas accumulation or aquifer depletion. Both these causes of reduced well performance must be remedied by reducing or eliminating the causative factors, namely, the source of entrainment, the quantity of reagent, or the rate of production from the aquifer. Based on this background, the balance of this section is devoted to a discussion of each type of well stimulation method.

Hydraulic Methods

Hydraulic methods of stimulation are identical to the well development methods described in the previous section. Therefore, the reader is referred to that section for a detailed description of the four basic methods, namely: high rate pumping, air lifting, hydraulic jetting, and mechanical surging. By themselves, the four methods are suitable only for removal of filtered solids and poorly cemented precipitates. Therefore, it is common practice to use some combination of hydraulic plus chemical methods for well stimulation.

Chemical Methods

Three groups of chemicals are used for well stimulation, namely: inorganic acids, oxidants, and polyphosphates. However, the effectiveness of any particular chemical is dependent on how it is delivered to and recovered from, the fouled formation face. Consequently it is common practice to utilize a combination of hydraulic and chemical stimulation methods. The following discussion considers each of the principal chemical groups followed by a discussion of the hydraulic methods used for chemical delivery and recovery.

Inorganic Acids

Two inorganic acids are commonly employed for well stimulation, namely; hydrochloric (HCl) and sulfamic acid (NH_2SO_3H). Sulfuric acid (H_2SO_4) should never be used for well stimulation since gypsum ($CaSO_4$), an extremely insoluble precipitate, may be formed as a result. Both hydrochloric and sulfamic acid readily react with the commonly encountered carbonate and hydroxide precipitates to yield readily soluble by products. Hydrochloric acid is commercially available in aqueous solution of varying concentration up to a maximum of approximately 36 wt.% HCl. Sulfamic acid, on the other hand, is commercially available as a dry granular product which can be readily dissolved to produce an aqueous solution of up to 19 wt.% at room temperature. Although both acids are quite corrosive to aluminum, copper, and iron bearing alloys; hydrochloric acid is significantly more corrosive than sulfamic acid. Normal chemical safety precautions should be observed in using either acid for well stimulation purposes, since large quantities of carbon dioxide can be liberated suddenly and violently during the process. Additional caution should be exercised in using sulfamic acid, since it can react with various mineral sulfides to produce hydrogen sulfide, a highly toxic gas.

Oxidants

Strong chemical oxidants such as chlorine, hydrogen peroxide, and sodium or calcium hypochlorite have been shown to be effective oxidants for the organic cell material of biological cultures, thereby facilitating their removal by hydraulic stimulation methods. Somewhat more effective than treatment with oxidant alone have been one or more cycles of an acid treatment, followed by oxidant treatment. Chlorine is generally regarded as the most effective of the chemical oxidants for this purpose, but is also the most dangerous and difficult to use. For in situ mining applications, it would appear that hydrogen peroxide is a preferable oxidant since it is readily available in aqueous solution, may already be present on site and introduces no contaminants into the lixiviant. Effective shock treatment of bacterial cultures generally requires that oxidant concentrations ranging from 50 to 100 ppm hydrogen peroxide or from 100 to 200 ppm free chlorine equivalent be maintained for a period of several hours. In those circumstances where a biological culture has been identified as the cause of decline in well performance, it is not only important that an effective method of well stimulation be identified, but that an effective method of either controlling or eliminating the culture be implemented. This may involve some process modification such as continual injection of trace levels of a suitable boicide or fungicide, or modification of the leach chemistry. These process modifications will usually prove more cost effective overall than recurring well stimulation.

Dispersants

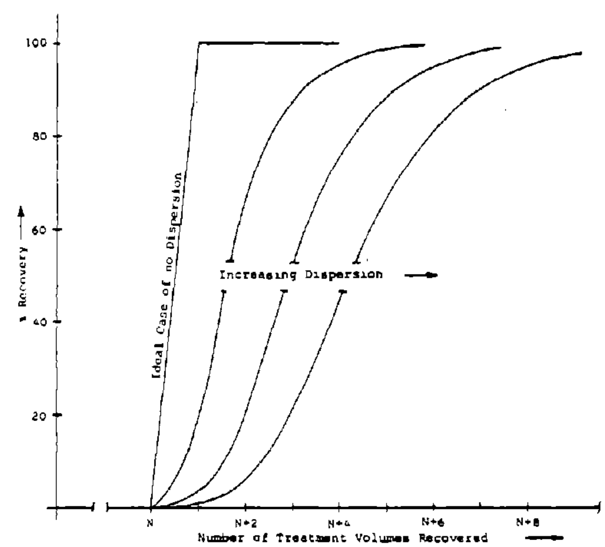
The principal class of dispersants are the polyphosphates, which neutralize the electrical charge on the suspended solids. Thus, they do not react chemically with the material responsible for declining well performance, as the previous chemical groups do, but rather act to disperse the material.

Dispersion facilitates removal of the solids by various hydraulic methods. Concentrations of up to 5 grams per liter in water are used alone or in combination with an inorganic acid or oxidant to enhance dispersant effectiveness. As noted previously, they should be used with caution, since even at low concentrations they may cause irreversible precipitation of certain metal species, including uranium, as well as foul or poison the ion exchange resins used for recovery of those metal species.

Chemical Delivery and Recovery

There are two major considerations regarding the methods used to deliver and recover any chemical used for well stimulation. The first consideration is the impact of chemical residuals as either active or passive contaminants in the leach circuit. The second consideration is the most effective method of reagent delivery to and by-product recovery from the formation. Typically, 1 to 5 years and 40 to 100 pore volume displacements are required to realize economic mineral recovery by in situ mining. In view of this, the selection of chemicals, and the delivery/recovery methods should proceed with caution to minimize and avoid problems with contaminant accumulation. Cost considerations also dictate that the selected methods minimize labor and down time while achieving maximum effectiveness in terms of restoring well capacity.

To meet these requirements, one of two chemical delivery/recovery methods is utilized. In the first method, the quantity of chemical(s) to be used is added at the well head and allowed to settle into the completion interval or introduced through a delivery pipe extending to the completion interval. After allowing the well to remain static for some period or until violent gas evolution ceases, mechanical surging at a low to moderate frequency, and amplitude is begun and continued for some additional period. This combination of static and surge cycles may be repeated once or twice to insure thorough contact between the chemicals and formation. Thereafter, the well is pumped by an appropriate method to recover the chemical residues and reaction products. Because of the dispersion which occurs during solution displacement and surging, a quantity of water significantly greater than the quantity of chemical(s) originally used, must be recovered to completely recover the chemical residues and and reaction products. The volume of water which must be removed from a well to obtain various degrees of clean-up relative to the quantity



Where:
One (1) Treatment Volume refers to the volume of Regent used, and
N = number of Treatment Volumes required to emplace the Regent at and recover the Regent from the well completion interval.

FIGURE 35 - Percent chemical recovery versus number of treatment volumes recovered.

of chemical(s) used is indicated qualitatively in Figure 35. Solution recovery is continued until either some prescribed volume of solution is recovered, or the conductivity of the recovered solution declines to some prescribed level.

In the second method, the quantity of chemical(s) to be used is introduced either into the injection manifold piping or at the well head, then slowly displaced down the casing, through the completion interval, and into the host formation. However, no effort is made to recover the chemical residues and reaction products at the point of injection. Rather, their recovery is incorporated into the process facilities for the recovered lixiviant. Clearly, the second method is less labor intensive and appears to produce less waste than the first. However, its cost effectiveness relative to the first is less evident. Its relative effectiveness hinges on the nature of well stimulation requirements, the quantity and type of chemical(s) required, the effectiveness of well stimulation realized, and the impact of the contaminants introduced on the in situ leach operation. While generally more costly, the first method of delivery and recovery is more effective than the second method. In both methods, the reagent(s) are more effectively delivered to the higher permeability strata, while the lower permeability strata are less effectively or adequately treated. However, this difference in treatment efficiency is more pronounced with the second method of delivery. In addition the second method of delivery is only suitable where the delivered reagent(s) thoroughly solubilize the material responsible for the loss of well capacity.

Other Stimulation Methods

This group of stimulation methods, which includes under-reaming, ultrasonics, perforating, and fracturing, is fundamentally different from the stimulation methods discussed thus far. With the exception of ultrasonics, they are based on development of a new formation face for either injection or production, rather than rehabilitation of the original formation face. They are generally more expensive to employ and are only used when either hydraulic or chemical methods have proven ineffective. Each of the four methods is described briefly in the following paragraphs.

Under-Reaming

As described in a previous section, this procedure consists of expanding the diameter of the completed sand face using a special bit equipped with retractable blades (Figure 21). To be useful as a method of well stimulation, the exposed formation must be competent and a low residual drilling fluid must be used to minimize formation damage. If an under-reamed completion was used originally, it is unlikely that an additional under-reaming will be a practical method of stimulation. It is more likely that some preventative measure or alternative well completion or development method should be used. Where an under-reamed completion was not used, it offers a method of increasing the exposed formation area to compensate for low formation permeability.

Ultrasonics

This is the only well stimulation method of this group which does not produce a new formation face. Ultrasonics is characterized by very short duration pressure pulses. Thus it is at the opposite end of the frequency spectrum from mechanical surging. Pulses of the required duration and amplitude can be generated by three methods, namely: by an electro-mechanical oscillator, by electrical discharge, or by sequential detonation of very small explosive charges. Thus far only the third method described has received serious attention as a well stimulation method for in situ mining. This procedure consists of setting off a series of small explosive charges (typically 5 to 10 grains each), at intervals ranging from a few tenths of a second up to several seconds depending on casing and formation characteristics. The number of, size of, and interval between explosive discharges, are designed to develop resonance in the well screen and adjacent formation material thereby dislodging accumulated solids. Following this treatment, one of the hydraulic stimulation methods is used to transport the dislodged material from the formation face and well bore. While this method is quite effective in restoring well capacity lost as a result of solids accumulation due to either filtered or precipitated solids, it is not effective where the loss is due in whole or part to biological activity.

Perforating

As indicated previously (refer to discussion of Well Completion Methods), three methods of perforation are in common use, namely: the hydraulic jet, the combination abrasive/hydraulic jet, and wire-line explosive methods. The particular method used must be matched to the well casing and the host formation characteristics. With all of the perforation methods, the host formation must be sufficiently competent to suport the resultant channel and maintain sand control. As noted with under-reaming, perforating is a practical method of increasing the exposed formation area to compensate for low formation permeability. Depending on the cause of decreased well performance, perforating may be an effective method of stimulation for wells originally completed with either open hole or perforated completions. However, a better long term solution would probably be appropriate preventive measures.

Fracturing

Fracturing is extensively used to stimulate oil and gas wells, but this method should only be used when all other methods have failed. Even then it should be used only under carefully controlled conditions. First and foremost, it is unclear whether and under what circumstances the regulations governing in situ mining permit the use of fracturing as a stimulation method. It can be anticipated that special regulatory approvals would be required due to the potential for creating pathways for lixiviant migration and causing ground water contamination. Second, while increasing the effective permeability of the formation, fracturing may reduce the produced solution grades as well as the rate and extent of mineral recovery due to lixiviant short circuiting or bypassing. Third, unless carefully designed, executed, and monitored, it may result in damage to the casing, cement seal, and natural aquicludes. Any of these types of damage can aggravate or cause lixiviant leakage into adjacent formations. If fracturing is identified as the only viable method of well stimulation in a particular situation, then an experienced commercial firm should be contacted to design and execute the job.

SURVEY OF CURRENT PRACTICE

To determine current well design, construction, and development practices, eight companies actively engaged in in situ mining were interviewed. The participaing companies and an indication of their scale of operation are tabulated below:

Company	Operating Sites	Total Capacity
Everest Minerals and Exploration	2	1,500 gpm
International Energy Corporation	2	1,600 gpm
Mobil Oil-Uranium Minerals Division	2	3,800 gpm
Rocky Mountain Energy	2	100 gpm
Tenneco Uranium, Incorporated	1	1,500 gpm
Uranium Resources, Incorporated	2	1,700 gpm
U.S. Steel Corporation, Texas Uranium Operations[10]	2	24,000 gpm
Wyoming Minerals Corporation	3	3,500 gpm

It will be noted that with the exception of Rocky Mountain Energy all of the companies interviewed had one or more production facilities in operation at or about the time of the survey. Only two companies with production facilities either under construction or in operation at the time were not included. These were Conoco Incorporated and Ogle Petroleum Incorporated, who were unable to participate.

A questionnaire was sent to each participant covering the four major topic areas discussed in the preceeding chapters, namely well design practice, drilling practices, grouting practices, and well development/stimulation practices. A follow-up interview was conducted with each participant to review their response to the questionnaire and obtain additional relevant information. The results of that survey are presented and discussed by major topic area in the following sections.

Well Design Practice

This portion of the survey was broken into four sub-topics relating to the selection and specification of the down hole pump, well casing, well completion method, and casing accessories. The results are summarized in Table 10 by participant, and the principal features are discussed in the following paragraphs.

Down Hole Pump

The size and capacities of down hole pumps varied over a wide range depending on site characteristics, as would be expected. However, the

[10] Site refers to the: (1) Burn's Ranch Operation which is owned and operated by U.S. Steel Corp., and (2) Clay West Operation which is a 50% joint venture with Niagara Mohawk Power Co. operated by U.S. Steel Corp.

Table 10 A

SUMMARY OF WELL DESIGN PRACTICES

Company	Everest Minerals	International Energy Corp.	Mobil Oil Corp. Texas	Mobil Oil Corp. New Mexico
DOWN HOLE PUMP:				
Nominal Capacity (gpm)	5 to 60	10 to 50	5 to 20	25
Nominal Lift (ft)	170 to 600	120 to 250	250	600
Pump Horsepower (Hp)	3 to 7.5	1.5, 3 & 5	1.5 & 3	10 to 15
Materials of Construction	Stainless Steel	Stainless Steel	Stainless Steel	Carbon or Stainless Steel
Type of Pump Control	Manual Control at Surface	Manual Control at Surface	Manual Control at Surface	Manual Control at Surface
WELL CASING:				
Material of Construction	PVC	PVC	Spiral Wound FRP	Spiral Wound FRP
Nominal Depth (ft)	200 to 650	120 to 300	650	1600 to 2100
Nominal Inside Diameter (in)	4.0, 5.0 & 6.0	4.0	4.33	4.33/6.40
Nominal Wall Thickness (in)	(Sch. 40)	(Sch. 40)	0.20	0.20/0.34
Nominal Casing Length (ft)	20	20	30	30
Type of Casing Joint	Solvent Welded 6" or greater Bell & Spigot	Solvent Welded 6" Bell & Spigot	Acme Thread & "O" Ring	Acme Thread & "O" Ring
WELL COMPLETION:				
Type of Well Completion	Integral full diameter Well Screen w/ 4 ft Sand Trap	Integral 4" Well Screen w/ 3 ft Tail Piece	Perforated @ 4 ea/ft with Carrier Gun	Perforated @ 4 ea/ft with Carrier Gun
Type of Well Screen	PVC, Wire Wrap over Perforated Pipe	PVC, Wire Wrap over Perforated Pipe	N/A	N/A
CASING ACCESSORIES:				
Type of Casing Shoe or Diverter Plug	3 ft PVC Sec. w/1 ft Cement Plug	3 ft PVC Sec. w/1 ft Cement Plug	Latch Shoe	Latch Shoe
Type of Cement Basket	Canvas Basket w/Steel Leaf	Canvas Basket w/Steel Leaf	N/A	N/A
Type of Centralizer	Steel or PVC Bow Spring	Steel or PVC Bow Spring	Steel or PVC Bow Spring	Steel Bow Spring
Number or Spacing (ft) of Centralizers	3/hole	50 ft	30 ft thru the ore zone & 100 ft to the surface	30 ft thru the ore zone & 100 ft to the surface

Table 10 B

SUMMARY OF WELL DESIGN PRACTICES

Rocky Mountain Energy	Tenneco Uranium, Inc.	Uranium Resources, Inc.	United States Steel Corp.	Wyoming Mineral Corp.
15 to 30	20	10 to 20	30 to 100	10 to 25
150 to 450	200	200 to 500	200 to 500	130 to 350
3 & 5	3	2 to 7.5	5 to 15	1.5 & 3
Stainless Steel	Stainless Steel	Stainless Steel	Cast Iron	Stainless Steel
Manual Control at Surface	Manual Control at Surface	Manual Control at Surface	Downhole Liquid Level Control & Manual Control @ Surface	Downhole Liquid Level Control & Manual Control @ Surface
Spiral Wound FRP	PVC	Spiral Wound FRP w/Gauze Wrap	PVC	PVC or Spiral Wound FRP
200 to 500	240	300 to 700	350 to 600	150 to 500
4.33	5.0	4.33	4.0 & 6.0	4.5/4.33
0.18	(Sch. 40)	0.18	(Sch. 40)	0.28/0.18
30	20	30	40	20/30
Acme Thread & "O" Ring	Solvent Welded 8" Bell & Spigot	Acme Thread & "O" Ring	Solvent Welded 6" or greater Bell & Spigot	Solvent Welded 6" Bell & Spigot or Acme Thread & "O" Ring
Perforated or Under-reamed w/ Telescoped Screen	Integral 3" Well Screen w/ 5 ft Sand Trap	Integral 4" Well Screen or Perforated	Integral full diameter Well Screen w/ 3 to 5 ft Sand Trap	Under-Reamed w/ or w/o Telescoped Screen (No Sand Trap)
PVC, Wire Wrap over Perforated Pipe	PVC, Wire Wrap over Perforated Pipe	PVC, Wire Wrap over Perforated Pipe	PVC, Wire Wrap over Perforated Pipe w/Underbar	PVC, Wire Wrap over Perforated Pipe
FRP or PVC Guide Shoe	3 ft PVC Sec. w/8 in Plaster Plug	2 ft PVC Sec w/1 ft Cement Plug or ABS Guide Shoe	3.5 ft PVC Sec. w/1 ft Plaster Plug	PVC or FRP Guide Shoe
N/A	Canvas Basket w/Steel Leaf	Canvas Basket w/Steel Leaf	Canvas Basket w/ PVC or Steel Leaf	N/A
Steel or PVC Bow Spring	Steel Bow Spring	Steel Bow Spring	PVC or Steel Bow Spring	Principally PVC Bow Spring
90 to 120 ft	80 ft	3/hole	3/hole	60 to 100 ft

preferred pump regardless of size was the Grundfos[11] stainless steel submersible pump. Despite its higher initial cost, its availability in stainless steel and lower maintenance cost as a result of both component design and materials selection have led to its dominance with regard to in situ mining applications at present. Based on maintenance considerations and experience, most operators favor manual pump and flow controls located at the surface rather than automatic controls located either at the surface or down hole.

Well Casing

The two most commonly employed well casings are polyvinyl chloride (PVC) pipe with solvent-welded bell and spigot joints and spiral wound glass-fiber-reinforced plastic (FRP) pipe with integral Acme thread and "O" ring seal joints. The casing sizes range from 4.0 to 6.4 inch internal diameter. At present PVC casing is being used routinely by some operators to depths as great as 650 feet and FRP casing is being used to depths as great as 2100 feet. The practical depth limitation for each casing material depends on: the structural characteristics of the particular casing used, the specific casing and grouting methods employed, the skill of the particular well installation/completion crew, and the prevailing ambient conditions. However, where initial material cost is balanced against the cost of insuring and maintaining well integrity, threaded FRP casing was generally selected over solvent welded PVC casing.

Well Completion Method

As might be expected there is more divergence in well completion methods than any other aspect of well design practice, due to local formation conditions and past operator experience. The most frequently used completion method is the integral well screen completion. This is followed to varying degrees by the use of: open hole, under-reamed, or perforated completions either alone or in combination with a telescoped well screen for maintenance of sand control. Continuous slot PVC well screen wrapped over a perforated pipe support with optional underbars is used exclusively because of its greater strength relative to available flow area. Where perforated well completions are used, the carrier gun has displaced other perforation methods due to its lower cost.

Casing Accessories

The casing accessories employed by the various operators were consistent with the well completion methods employed. The choice of steel versus plastic accessories generally reflected a compromise between the required function, strength, and cost. Thus, steel cement baskets were generally favored over PVC because of greater strength and lower failure potential. Steel and PVC

11 Reference to specific brands, equipment or trade names in this report is made to facilitate understanding and does not imply endorsement by the Bureau of Mines.

centralizers were generally considered interchangeable and selection was based largely on cost. The notable exception was in case of anticipated multiple completions by under-reaming. In this case, PVC centralizers were preferred over steel, since they would not interfere with subsequent under-reaming operations.

Drilling Practices

This portion of the survey was divided into four subtopics, namely: type of drilling equipment, well installation practice, well completion practice, and coring practice. Table 11 summarizes the results of this portion of the survey by participant. The principal features of those results are discussed in the following paragraphs.

Type of Drilling Equipment

All of the operators exclusively used portable hydraulic-rotary drilling equipment with conventional circulation for both exploration and well development drilling. For the range of well depths involved (from 120 to 2,100 feet), they generally favored equipment with a depth capacity of approximately two to three times that of the completed well, in order to obtain satisfactory drilling rates. Where nonstandard casing lengths were used (i.e., greater than 20 ft.), an appropriate mast height was specified. Most operators also specified a larger than standard mud pump size (for example a 5.5" D x 8.0" L rather than a 5.0" D x 6" L (duplex pump) when drilling holes of 7.0" diameter or larger to obtain adequate cuttings removal at the drilling rates desired. The type and number of mud pits used varied considerably depending on the experience developed at a particular site with a particular drilling fluid.

Well Installation Practice

With the exception of those with oil field experience, operators tended to rely on simple drilling fluid formulations and minimal specification or confirmation of fluid properties. The two most used drilling fluids were native/bentonite mud and modified guar gum incorporating suitable lost circulation or filtrate loss additives based on the characteristics of the particular site. Apart from specification of the fluid density and/or viscosity, most operators left the drilling fluid properties unspecified and to the discretion of the individual driller. This seemed to be based on the pragmatic logic that it was more cost effective to correct drilling induced formation damage via well development than to prevent or minimize such damage via drilling fluid formulation and monitoring the drilling operations.

Opinion and practice were found to be divided as to whether single or double pass drilling is more cost effective for in situ operations. The first drilling pass was usually done with either a drag or rock type bit depending on local formation characteristics and operator experience. Where a second reaming pass was used, a suitably sized rock bit was generally employed. A nominal difference of 2.0 to 3.0 inches between the casing and drill hole

Table 11 A

SUMMARY OF DRILLING PRACTICES

Company	Everest Minerals	International Energy Corp.	Mobil Oil Corp. Texas	Mobil Oil Corp. New Mexico
PORTABLE DRILL RIG:				
Nominal Size	1500 Series	1000 Series	1500 Series w/52 ft Mast	6000 ft Capacity, w/108 ft Mast, & 150 Ton Derrick
Mud Pump Type & Size	5-1/2" D x 8" L Duplex	5" D x 6" L Duplex	5-1/2" D x 8" L Duplex	Triplex
Mud Pits	2 ea, 25 bbl Earthen Pits	1 ea, 12 bbl Portable Pit	2 ea, 100 bbl Earthen Pits	1 ea, 250 bbl Steel & 500 bbl Earthen Pits
WELL INSTALLATION PRACTICE:				
Type Drilling Fluid	Bentonite Gel & Cellulose Base Polymer Mix	Mod. Guar Gum + Cotton Seed Hulls	Bentonite Gel & Cellulose Base Polymer Mix	Bentonite Gel & Cellulose Base Polymer Mix
Drilling Fluid Specification:				
Density (lbs/gal)	~8.5	Specify quantity of additives rather than fluid properties	9.0 to 9.2	~9.0
Viscosity (sec/qt)	~35		38 to 42	36 to 40
Filtration Rate (cc/30 min)	No Spec.		<12 in Ore Zone	<10 in Ore Zone
Gel Strength (lbs/sq ft)	No Spec.		No Spec.	No Spec.
Maximum Sand Content	Minimum Possible		<5%	<5%
Pilot Bit Size & Type	N/A	5-1/8", 3 Blade Drag Bit	N/A	N/A
Final Bit Size & Type	6-3/4" or 9-7/8" Rock or Drag Bit	7-3/8" Soft Formation Rock Bit	6-3/4" Drag Bit	9-7/8" Mill Tooth Rock Bit
Drill Collars/Stabilizers	2 ea, 4-1/2" x 20 ft Collars w/ 2-7/8" Drill Pipe	3 ea, 3-3/4" x 20 ft Collars w/ 2-7/8" Drill Pipe	4 ea, 4-1/2" x 20 ft Collars w/ 2-7/8" Drill Pipe	9 ea, 7" x 20 ft; 5 ea, 6-1/4" x 30 ft & 9 ea, 4-1/2" x 30 ft Collars w/4-1/2" Drill Pipe
Av. Drilling Rate (ft/hr)	~100	~80/~60	~65	~145
WELL COMPLETION PRACTICE:				
Type Drilling Fluid (thru the completion interval)	Local water supply	Formation Water	N/A	N/A
Bit Size & Type	0.12 to 0.25" Undersize Rock Bit	3.75" Rock Bit		
CORING PRACTICE:				
Type Drilling Fluid (thru the cored interval)	Cellulose Base Polymer	Mod. Guar Gum @ 2.5 x Normal Conc.	Bentonite & Cellulose Polymer Mix	Bentonite & Cellulose Polymer Mix
Drilling Fluid Specification				
Density (lbs/gal)	~8.5	No Spec.	No Spec.	No Spec.
Viscosity (sec/qt)	~40	No Spec	~55	~50
Filtration Rate (cc/30 min)	No Spec.	No Spec.	No Spec	<6
Type Core Bit & Barrel	Diamond Bit w/ 2" x 10 ft Randolph or Christensen barrel	Diamond Bit w/ 2" x 10 ft conventional barrel	Diamond Bit w/ 3" x 10 ft Conventional barrel	Diamond Bit w/ 4" x 30 ft Conventional barrel

Table 11 B

SUMMARY OF DRILLING PRACTICES

Rocky Mountain Energy	Tenneco Uranium, Inc.	Uranium Resources, Inc.	United States Steel Corp.	Wyoming Mineral Corp.
1000 or 1500 Series	1500 Series	1000 or 1500 Series	1500 Series w/52 ft Mast	1000, 1250 & 1500 Series
5" D x 6" L Duplex or Larger	5-1/2" D x 8" L Duplex (Generally)	5-1/2" D x 8" L Duplex	5" D x 8" L Duplex	5 or 5-1/2" D x 8" L Duplex at a Minimum
2 ea, 40 bbl or Larger Earthen Pits	2 ea, 70 bbl Earthen Pits	2 ea, 34 bbl Earthen Pits	2 ea, 56 bbl Earthen Pits	2 ea, 30 bbl Earthen Pits or 1 ea, 12 bbl Portable Pit
Native Mud or Bentonite Gel	Native Mud, Bentonite & Polymer Mix	Native Mud or Polyacrylamide	Mod. Guar Gum	Bentonite Gel + Bran or Cotton Seed Hulls
No Spec. 35 to 40 No Spec. No Spec. Minimum Possible	No Spec. 38 to 42 No Spec. No Spec. Minimum Possible	8.8 to 9.2 35 to 50 3 to 5 in Ore Zone <20 @ 1 hour Minimum Possible	~8.5 35 to 40 No Spec. No Spec. Minimum Possible	No Spec. ~40 No Spec. No Spec. < 5%
5-1/8" Kenclaw Bit 7-1/8" Soft Formation Rock Bit	N/A 7-7/8" Rock or Drag Bit	N/A 6-3/4", 3 Blade Drag Bit	4-1/2" or 5-5/8" Rock or Drag Bit 6-3/4" or 9-7/8" Rock Bit	4-3/4" or 5-1/8" 3 Blade Drag Bit 6-3/4" Soft Formation Rock Bit
2 to 4 ea, 4-1/2" x 20 ft Collars w/2-3/8" Drill Pipe	2 ea, 7" x 10 ft Collars w/ 2-2/8" Drill Pipe	1 ea, 6-3/4" x 5 ft Stabilizer & 2 ea, 5-1/2" x 20 ft Collars w/ 2-7/8" Drill Pipe	1 ea, 6" x 20 ft 4 ea, 3-1/2" x 20 ft Collars w/ 2-7/8" Drill Pipe	2 ea, 3-1/2" or 4" x 20 ft Collars w/ 2-7/8" Drill Pipe
~80/~55	~60	~65	~100	~70
Formation Water or Mod. Guar Gum	Formation Water	Formation Water	Formation Water	Mod. Guar Gum
10.5" D, 2 Blade Under-Reamer	3.75" Rock Bit	3.88" Rock Bit	3.75" or 5.75" Rock Bit	11" D, 2 Blade Under-Reamer
Mod. Guar Gum	Native Mud, Bentonite & Polymer Mix	Cellulose Polymer or Polyacrylamide	Mod. Guar Gum	Mod. Guar Gum
No Spec. 35 to 40 No Spec.	No Spec. No Spec. No Spec.	<8.6 ~60 Minimal	8.5 45 to 50 No Spec.	No Spec. 40 to 45 No Spec.
Diamond/Carbide Combination Bit w/3" x 10 ft Conventional barrel	Diamond Bit w/ 2" x 10 ft Conventional barrel	Pilot Style Carbide Bit w/3" x 10 ft Conventional barrel	Diamond Bit w/ 2 to 3" Conventional or 2.5" Wire-Line x 10 ft Core barrel	Diamond Bit w/ 3" x 5 or 10 ft Conventional Drop Ball Type barrel

diameters, increasing with casing diameter, was used for cased holes. While drill collars were incorporated in the drill string by all operators to maintain alignment and minimize drift, the number and their weight varied considerably depending on drilling practice, hole depth, and formation characteristics (Table 11). For similar reasons, average drilling rates from 60 to 100 ft/hr for common hole depths and equipment types used. Common hole depths were 650 ft and common rig types were the 1000-1500 series portable hydraulic-rotary rigs.

Well Completion Practice

Among operators using an integral well screen completion, it was common practice for removal of the diverter plug above the well screen to use a rock bit sized for a 0.25 to 0.5 inch clearance with the casing I.D. and ground water as the drilling fluid. Those operators using an under-reamed well completion method favored a 2-blade under-reamer modified to ream a nominal 11.0" diameter and either formation water or a modified guar gum drilling fluid. Due to the number of factors involved, practical limits could not be effectively defined on drill rig alignment and drilling speed necessary for prevention of well damage during well completion workover. However, there seemed to be general agreement among the operators interviewed, that the most cost effective approach was to leave all well completion work to one or two specially trained drilling crews. Experience has repeatedly shown that when this was not done, the number of damaged wells requiring repair or replacement increases to an unacceptable level.

Coring Practice

Essentially all of the operators interviewed used a standard carbide or diamond grit bit with either a 2" or 3" diameter conventional core barrel assembly. The only significant difference in coring equipment as a function of depth was generally the length of core barrel used (ref. Table 11). One operator, U.S. Steel Corp., had also used a wire-line retrievable core barrel, when the quantity of core to be collected warranted its use over a conventional core barrel. In coring, one of the following three drilling fluids was used depending on local formation characteristics: (1) a bentonite gel and organic polymer mixture, (2) a modified guar gum, or (3) a cellulose base polymer. As in the case of primary drilling fluids, it was unusual for an operator to specify more than fluid density and/or viscosity for coring operations. The comments of operators concerning the need to use trained drilling crews for well completion applied to coring as well.

Grouting Practices

This portion of the survey was divided into three subtopics, namely: slurry design and preparation, slurry emplacement practice, and quality control/assurance. Table 12 summarizes the results of this portion of the survey by participant. The principal features of those results are discussed in the following paragraphs.

Slurry Design and Preparation

The most commonly used cements have been ASTM Type I and II or API Class A and B depending on the level of sulfate resistance required in a particular application. However, slurry cost and density considerations have led two operators to use pozzolan cement rather than pure cement grout formulations. All of the operators interviewed were using slurry densities ranging from 12.0 to 14.0 lbs/gal, which were generally obtained by the addition of 3 to 8 wt% bentonite plus excess mix water to the basic cement formulation. In addition, because of local formation conditions, some operators also added 0.5% polymer-type fluid loss additive or 0.5 to 8% flake-type lost circulation additive. As indicated in Table 11, only one operator, U.S. Steel Corp., has an accelerator in the grout formulation to decrease set time and increase early strength.

The majority of operators favored batch mixing over jet mixing for well depths up to 700 feet due to the greater degree of quality control possible. Because of their extensive oil field experience and the relatively great well depths involved, Mobil Oil Corp. adopted continuous-jet-mixing instead. In the case of Wyoming Mineral Corp., the change from batch to continuous-jet-mixing at some sites was prompted by acceleration of their well field installation program.

Slurry Emplacement Practice

Without exception, grout slurry emplacement for injection and production wells was by single stage displacement through the casing. Although some operators had experimented with undersize wells, i.e., 2 and 3 inch NPS casing, and grout pipe emplacement methods, none was regularly using or planning the use of such wells and emplacement methods. With one exception, U.S. Steel Corp., a slug of water ranging from 0.1 to 1.0 times the nominal annulus volume was generally introduced ahead of the grout slurry. The volume of grout slurry used to obtain a satisfactory grout seal varied from slightly greater than 1.0 to as much as 1.5 times the nominal annulus volume depending on well depth and formation characteristics. Generally this was followed by a volume of displacement fluid sufficient to leave a grout heel of 20 feet or less within the casing. Only Mobil Oil Corp. and Uranium Resources, Inc. made a practice of using some type of wiper plug to segregate the grout and displacement fluid during grout emplacement. Most operators preferred not to use wiper plugs due to the higher associated cost and the increased potential for casing damage during workover for well completion. Water was generally used as the grout displacement fluid. However, to minimize the net buoyant force on the casing string, Everest Minerals Corp. used a barite weighted bentonite fluid and Mobil Oil Corp. used a calcium bromide/chloride brine for grout displacement. The balance of the grouting accessories consisted of an appropriate grouting well head and suitable dead weight or chain hold down device to resist the net buoyant force on the casing.

Table 12 A

SUMMARY OF GROUTING PRACTICES

Company	Everest Minerals	International Energy Corp.	Mobil Oil Corp. Texas	Mobil Oil Corp. New Mexico
Grout Design & Preparation:				
Cement Type	API Class "A"	ASTM Type I or API Class "A"	API Class "A"	65% Class "B" + 35% Pozzolan w/6% Bentonite
Additives:				
Amount (wt%) & Type	~8% Bentonite	~3% Prehydrated Bentonite	~4% Prehydrated Bentonite	~.25% Celloflake
Amount (wt%) & Type	--	--	0.5% Celloflake	~0.5% Fluid Loss Agent
Amount (wt%) & Type	--	--	~0.5% Fluid Loss Agent	~0.1% Friction Reducer
Slurry Density (lbs/gal)	~12.6	12.0 to 12.5	~12.0	~12.0
Preparation Method	Batch Mix	Batch Mix	Jet Mixer	Recirculation Jet Mixer
Slurry Emplacement Practice:				
Emplacement Method:	Thru Casing	Thru Casing	Thru Casing	Thru Casing
Volumes Used:				
Clean-Up Fluid	~5 bbl water (0.15 to 0.35 x Annulus Vol.)	~1 bbl water (0.15 to 0.25 x Annulus Vol.)	~10 bbl water (0.6 to 0.7 x Annulus Vol.)	~10 bbl water (~0.1 x 7 Annulus Vol.)
Grout Slurry	~1.0 x Annulus Vol.	1.25 to 1.5 x Annulus Vol.	~1.5 x Annulus Vol.	~1.5 x Annulus Vol.
Displacement Fluid	<1.0 Casing Vol. of Barite + Gel @~11.0 lb/gal	Sufficient water to leave an ~15 ft grout heel	<1.0 Casing Vol. of Water	<1.0 Casing Vol. of $CaCl_2$/$CaBr_2$ Brine @~12 lb/gal
Casing Accessories	Grouting Well Head + Water Tub Hold Down	Grouting Well Head + Stake & Chain Hold Down	Grouting Well Head, Latch Plug, + Chain Hold Down	Grouting Well Head, Latch Plug, + Chain Hold Down
Quality Control/Assurance:				
Type & Number of Samples	None	Periodic Grab Sample	One Grab Sample/well	Four Grab Samples/Well
Tests Conducted	None	Check grout density & set characteristics	Check grout density & set characteristics	Check grout density & set characteristics
Records Kept		Drilling, Casing & Grouting Records + Perf		
Minimum Set Time	~12 hrs.	~16 hrs.	~5.5 hrs.	~6 hrs.
Minimum Cure Time	~3 days	~16 hrs.	~2 days	~2 days

Table 12 B

SUMMARY OF GROUTING PRACTICES

Rocky Mountain Energy	Tenneco Uranium, Inc.	Uranium Resources, Inc.	United States Steel Corp.	Wyoming Mineral Corp.
65% Class "G" + 35% Pozzolan Mixture	ASTM Type I or API Class "A"	ASTM Type I or II	API Class "A"	ASTM Type II or API Class "B"
~2% Bentonite	~3% Prehydrated Bentonite	~4% Prehydrated Bentonite	~3% Bentonite	~4% Dry Preblended Bentonite
--	--	--	~2% Mica-Tex	~8% Mica-Tex
--	--	—	0.5 to 2.0% $CaCl_2$	--
~14	~12.0	~13.2	~13	12.5 to 13.0
Batch or Recirculation Jet Mixer	Batch Mix	Batch Mix	Batch Mix	Continuous Jet Mixer
Thru Casing	Thru Casing	Thru Casing	Thru Casing	Thru Casing
~10 bbl water (~0.5 x Annulus Vol.)	~8 bbl water (~1.0 x 7 Annulus Vol.)	5 bbl water (~0.35 x Annulus Vol.)	None	~2.5 bbl water + 1.5 bbl of thin grout (~0.7 x Annulus Vol.)
~1.2 x Annulus Vol.	~1.0 x Annulus Vol.	~1.2 x Annulus Vol.	1.25 to 1.4 x Annulus Vol.	1.1 x Annulus Vol.
< 1.0 Casing Vol. of Water	< 1.0 Casing Vol. of Water	< 1.0 Casing Vol. of Water	Sufficient water to leave an~20 ft grout heel	Sufficient water to leave an~10 ft grout heel
Grouting Well Head + Convenient dead wt Hold Down	Grouting Well Head + Weighted Barrel Hold Down	Grouting Well Head, Expedient wiper plug, + convenient dead wt	Grouting Well Head + Screw Auguer & Chain Hold Down	Grouting Well Head + Water Tub Hold Down
Grab Sample of Slurry Return	None	One Grab Sample/Well	One or More Grab Samples/Well	One Grab Sample/Well
	None	Check set characteristics	Check grout density & set characteristics	Check grout Density & set characteristics
orating Records				
12 to 14 hrs.	16 to 24 hrs.	3 hrs.	~24 hrs.	~24 hrs.
~ 3 days	> 2 days	16 hrs.	~24 hrs.	~3 days

Quality Control/Assurance

Generally the operators maintained complete descriptions of the drill hole and installed casing string as well as records of the quantities of materials used in drilling, casing, and grouting a particular drill hole. In addition a single grab sample of the slurry was normally collected during grout emplacement to check slurry density and set characteristics. However, no formal QA procedure existed for the collection of slurry samples, evaluation of either slurry or set characteristics, and documentation of the results.

The minimum set time allowed before removal of grouting accessories for use on the other wells ranged from as little as three (3) hours to as much as one (1) day. The minimum cure time allowed before workover for well completion varied from as little as 16 hours to as much as 3 days. The basis for establishing minimum set and cure times was the operator's experience with a particular set of construction conditions, materials, and operations. Thus, the set and cure times used by some operators were probably greater than the minimums required.

Well Development and Stimulation Practices

This portion of the survey was broken into three major subtopics, namely: well integrity testing, well development methods, and well simulation methods. The results are summarized in Table 13 by participant, and the principal features discussed in the following paragraphs.

Well Integrity Testing

The Underground Injection Control Regulations recently established by the U.S. Environmental Protection Agency (57) require that all injection wells used for in situ mining be tested to verify well casing and grout seal integrity prior to being placed into service and periodically thereafter. At the time of the survey it had only been necessary for operators who were either licensing new injection wells or renewing licenses for existing wells to comply with this requirement. Because of this, two operators, Everest Minerals Corp. and U.S. Steel Corp., had not adopted the newer integrity test procedures. Previously, a resistivity survey of the completed well was the standard method of verifying casing integrity. Currently operators either have implemented or are in the process of implementing various hydrostatic test methods to verify casing integrity.

The most commonly used method is to: (1) verify that the casing is hydrostatically full of displacement fluid at the time the grouting well head is removed, (2) pressurize the well with air to a pressure similar to the anticipated injection pressure, and (3) shut in the well and monitor well head pressure to verify that a drop of less than 10% occurs over a period ranging from 10 mintues to 1 hour. A less extensively used method is to perform a similar hydrostatic test on the completed well by either using a packer (Tenneco Uranium, Inc.) or adjusting the test pressure (Wyoming Mineral Corp.)

to isolate the completion interval during the test (refer to the discussion of Well Testing Requirements, pp. 87 and 88).

Well Development Methods

As might be expected, well development methods varied considerably from one site and operator to another. The most widely used method consisted of: (1) circulating water through the drill string following well completion workover to remove drilling residues, (2) high rate pumping with a suitable pump, swab assembly, or air lift followed in some cases by (3) alternate steady and cyclic pumping. Generally well development was continued until sand production ceased and clear water was produced. One operator (Everest Minerals Corp.) has made it a practice to acidize the screened interval with hydrochloric acid and remove the spent acid by air lifting before initiating high rate pumping. A second operator (International Energy Corp.) has made it a practice to develop the screened interval by hydraulic jetting, before completing development by air lifting.

Well Stimulation Methods

Well stimulation methods also varied considerably from one site and operator to another. However, the most widely used method consisted of: (1) introducing from 20 to 50 gallons of concentrated hydrochloric acid into the screened interval, (2) circulating the acid through the screened interval and adjacent sand face by gravity flow, hydraulic jetting, swabbing, or pumping, and (3) recovering the spent acid by means of either air lifting or swabbing. One operator (Wyoming Mineral Corp.) had for some time made it a practice to introduce acid through the injection manifold to several wells at once and circulate it completely through the formation. A second operator (Uranium Resources, Inc.) made it a practice to periodically lower the injection solution pH 0.3 to 0.5 units by addition of excess carbon dioxide to remove developing calcium carbonate scale.

Only one of the operators interviewed, U.S. Steel Corp., indicated any significant problem with the control of biological cultures and related well stimulation problems. Due to such problems, it was their practice to continually maintain a 5 to 10 ppm concentration of free chlorine in the injection solution. In localized instances where this proved inadequate, a shock treatment consisting of approximately five (5) pounds of sodium hypochlorite was introduced into the well, circulated in the screen interval, and recovered by air lifting, which was then continued until well stimulation was complete.

Table 13 A

SUMMARY OF WELL DEVELOPMENT/STIMULATION PRACTICES

Company	Everest Minerals	International Energy Corp.	Mobil Oil Corp. Texas	Mobil Oil Corp. New Mexico
WELL INTEGRITY TESTING:				
Method Used	Resistivity survey to identify any casing breaks	20 psi Hydro-Test w/Air over Water prior to drill out of the grout plug	Check for full casing when the grouting well head is removed	Check for full casing when the grouting well head is removed
Acceptability Criteria	--	No Pres. Drop after 5 to 10 min.	--	--
WELL DEVELOPMENT METHOD(S):	Circulate water to remove drilling residues, circulate HCl to remove cement residues, air lift to remove acid residue, & complete by high rate pumping.	Circulate water to remove drilling residues, develop the screened interval by hydraulic jetting with a dispersant, & air lift to complete development.	Air lift to develop the perforated interval.	Either swab or pump to develop the perforated interval.
WELL STIMULATION:				
Tramp Solids and/or Precipitates	Circulate water to dislodge and remove loose residue, circulate HCl to remove hard residue, & remove acid/solid residues by air lifting.	Introduce 20 gal HCl into the well, circulate the acid via hydraulic jetting, & remove acid/solid residue by swabbing	Introduce 35 to 50 gal HCl into the well, displace the acid into the completion interval, & recover acid/solid residue by swabbing	No Experience to date
Biological Accumulations	Circulate bleach to kill the culture, circulate HCl to break up the residue, & air lift to remove any residues.	No problem to date	No problem to date	No Experience to date

Note: All acid quantities refer to concentrated HCl (i.e., 36 wt%)

Table 13 B

SUMMARY OF WELL DEVELOPMENT/STIMULATION PRACTICES

Rocky Mountain Energy	Tenneco Uranium, Inc.	Uranium Resources, Inc.	United States Steel Corp.	Wyoming Mineral Corp.
100 psi Hydro-Test w/Air over Water after well completion using an inflatable packer	50 psi Hydro-Test w/Air over Water prior to perforation	125 psi Hydro-Test w/Air over Water prior to perforation	None in use at present.	Resistivity survey or medium pressure air displacement of water from the casing above the well completion.
10% Pres. Drop after 10 min.	10% Pres. Drop after 10 min.	20% Pres. Drop after 1 hour.	--	10% Pres. Drop after 30 min.
Air lift to remove drilling residues and/or develop the completed interval.	Air lift until clear water is produced & the conductivity stabilizes.	Circulate water to remove drilling residues, air lift to remove fines from the completed interval, & complete development by swabbing.	Circulate water to remove drilling residues, alternate surge & air lift until clear water is produced.	Combination of steady & pulsed air lift until clear water is produced.
Introduce 20 gal HCL into the well, & remove acid/solid residues by air lifting to a neutral pH	Introduce 20 gal HCl into the well, & remove acid/solid residues by swabbing	Introduce HCl into the well, & remove acid/solid residues by air lifting or swabbing. (Periodically drop lixiviant pH w/CO_2 to dissolve $CaCO_3$ accumulations.)	Introduce 30 gal HCl into the well, pressure surge the well to circulate the acid, & remove acid/solid residues by air lifting.	Introduce HCl or Sulfamic acid into the well & remove acid/solid residues by air lifting; interrupt Lixiviant circulation & inject an HCl pulse.
Periodic treatment with formaldehyde, & air lift to remove residues.	No problem to date	No problem to date	Routinely inject 5 to 10 ppm dissolved Cl_2 to control bio-organisms & introduce 5 gal of 10 wt% $NaHClO_3$ into any well requiring additional treatment.	No Significant Problem.

RECOMMENDATIONS AND CONCLUSIONS

During the survey to determine current practice, special efforts were made to collect from the eight operators recommendations and cautions regarding well design, construction, and development. The operators were asked to comment on how and why their current practices had evolved as well as how and why they might evolve further. The results are presented in this section as a set of recommendations and cautions for each of the four major topic areas which have been discussed. No effort has been made to identify individual sources for the material presented. Where possible a consensus view as understood by the authors is presented.

Well Design

Pump specification and selection will depend on the characteristics of a particular site and the leach chemistry adopted. Because of the large number of pumps used, the total pumping cost should be used as the basis for their selection. The total pumping cost includes power costs, maintenance costs, and replacement costs. It is recommended that excessive throttling or switching of oversized pumps be avoided. Because of the natural variability in performance of individual wells, it may be necessary to specify more than a single pump size. Regardless of size, the pump must be hung on a pipe or tubing string of adequate strength to resist numerous starting torque cycles. If any doubt exists a separate safety line is recommended.

Despite its lower cost and wide use, solvent welded PVC casing is considered inferior to threaded FRP casing for in situ mining applications. This is based on the greater time required to obtain adequate joint strength for casing emplacement and grouting, and the greater sensitivity of joint strength to ambient conditions and make-up procedure. If PVC is specified because of overriding considerations of first cost, proper procedures (7) for joint make-up, casing emplacement, and grouting should be implemented and monitored to insure adequate casing integrity.

It is recommended that the well completion interval be restricted to the mineralized intercepts of the host formation, even though this does not insure confinement of the leach solution to those intercepts. Where multiple completion intervals are warranted by virtue of the natural ore distribution, it is recommended that the well design permit independent operation of each interval. Although widely used, the integral-screen well design should be carefully evaluated against alternative well completion methods. Particularly in formations of low to moderate permeability, alternative completion methods may be superior because of greater control of the drilling fluid and its impact on the completion interval.

Wherever practical the use of PVC or FRP casing accessories is recommended over the use of steel accessories, because of the reduced potential for casing damage during any subsequent work-over operations. Casing accessory specification will depend on the type of well completion specified.

Drilling

Because of cost and availability, hydraulic-rotary equipment with conventional circulation is recommended for in situ mining applications. The drilling rig should have a depth capability of two to three times the planned well depth. The drill rig should have a rotary table which allows setting and grouting of the casing while still set up on the hole. In addition the rig should be equipped with a mud pump of sufficient size to maintain turbulent flow in the ascending fluid (i.e., a fluid velocity of 60 to 100 ft/min.). Mud pits should be sized to permit maintenance of optimum drilling fluid properties for the particular site. This generally requires a pit volume at least 2.5 times the anticipated drill hole volume.

The choice of single versus double pass drilling should be based on the relative economics for a given project. Sufficient weight and stiffness should be incorporated into the drill string immediately above the bit by means of drill collars to maintain the drill string in tension and obtain optimum drilling rates without pull down on the drill string. To minimize supplemental grouting requirements for maintaining leach solution confinement, the total depth drilled should be as close as practical to the final cased depth, but with sufficient clearance to prevent contact of the grout with the ore zone during grout emplacement. The type of bit(s) used to drill the hole will depend on the particular formation characteristics, but the bit should have a diameter at least 2" greater than the maximum external diameter of a casing joint. Drilling fluid selection should be matched to the well drilling and completing sequence to permit tight control of its characteristics when drilling the completion interval. To minimize the poential for damaging the formation while drilling, bottom hole pressures should be maintained well below the formation fracture pressure.

Wherever practical air drilling of the completion interval is recommended to minimize drilling induced damage to the exposed formation face. A chemically degradable polymer base fluid is recommended where air drilling proves impractical. The four principal fluid characteristics should be maintained at the minimum practical levels while drilling through this interval. As a target the following levels are recommended: recovered fluid density of 8.5 to 8.7 lbs/gal, Marsh funnel viscosity about 35 sec/qt, filtration rate of 5 to 10 cc/half hour at 100 psi pressure difference, and the minimum possible gel strength.

Selection of a core barrel assembly and bit will depend on the planned coring program, formation characteristics, and average depth of core interval. The choice of drilling fluid will likewise depend on the use intended for the recovered core. Where the core will be used to determine pore water composition or leach/restoration characteristics, an immiscible organic fluid may be preferable to a conventional water base fluid. Otherwise a suitable water base fluid which maximizes core recovery is recommended.

To assure the required quality of drilling services, it is considered essential to thoroughly document the drilling procedures to be used, to train the drilling crews, and to monitor their work. Giving responsibility for one or more of these tasks to the driller has seldom proved reliable. When left to the driller, costly work-over at a later date to correct problems ranging from fluid excursion as a result of unplugged drill holes to well repair or replacement as a result of damage caused during well completion has frequently resulted.

Grouting

It is essential that the type of cement specified be compatible with both the local ground waters and the leach solution composition throughout the course of the project. The grout should also be formulated to yield the required strength versus time characteristics at the lowest practical slurry density. When the well design involves running casing through the target ore zone and either an under-reamed or perforated completion interval, the grout formulation should also have the lowest practical filtration loss. The need for incorporation of other additives will depend on specific formation characteristics and ambient conditions. Where practical, batch mixing is recommended over continuous jet mixing because of the greater quality control possible.

A minimum initial clearance of 1% of its calculated length should be allowed between the casing and bottom of hole to prevent contact during grout emplacement. To assure the quality of grout seal required for in situ mining wells, through casing emplacement with wiper plugs is recommended. A pre-grout flush consisting of grout thinned to a density somewhat greater than the drilling fluid is recommended over water. It should be circulated at a flow rate sufficient to obtain turbulent flow in the annulus and continued for 5 to 10 minutes before grout emplacement is begun. The grout slurry volume used should be sufficient to obtain a return to the surface with the desired set characteristics. Once begun grout emplacement should continue smoothly and continuously at a bottom hole pressure kept well below the formation fracture pressure. The volume of displacement fluid used should insure that a grout heel of at least 10 feet is left within the casing when wiper plugs are not employed. To maintain grout displacement, it is essential that the grouting well head be leak-tight at the required shut in pressure. Use of a weighted fluid which renders the casing neutrally buoyant is recommended where possible. As in the case of casing accessories, it is suggested that PVC or FRP grouting accessories be used downhole wherever practical to minimize subsequent work-over damage.

Polymer enhanced bentonite (with a gel strength 0.2 lb/sq.ft.) is generally recommended over cement grout for plugging of exploration or abandoned holes. Because it gels rather than setting, plugged holes are more readily recovered if necessary. However, ordinary drilling mud should never be used for this purpose, since its gel strength is inadequate for effective plugging.

The minimum drilling, casing, grouting, and completion records which should be maintained are stipulated by current regulations governing in situ mining operations. Sufficient additional data regarding the quantity and quality of materials used should be collected and maintained to prevent or diagnose well related problems during operation. It is recommended that a sample of both the mixed slurry and the slurry returns be collected routinely to verify that specified characteristics are maintained.

Well Development/Stimulation

Current regulations require that injection well integrity be verified prior to use. Of the several test methods available for testing well integrity, use of the one most representative of stresses during operation is recommended. If variable pumping arrangements are anticipated during operation, it may be preferable to test all wells rather than injection wells only prior to beginning operation.

It is generally recommended that well development begin as soon as practical after grouting is completed and that the least vigorous method which proves effective be used. The combination of chemical treatment to break down drilling fluid and grout residues followed by air lifting to remove the associated residues appears to be the most generally applicable and cost effective development method. Chemical reagent(s) used for this purpose should be limited to those with minimal impact(s) on ground water composition and related water processing for mineral recovery and ground water restoration. During both chemical treatment and air lifting, caution should be exercised to prevent thermal damage to the casing as a result of either the heat of reaction or heat of compression. Only after such preliminary development should any of the more vigorous methods be used to complete well development.

The most effective method of maintaining well performance is the timely identification and correction of the cause(s) for declining well performance. When well stimulation is required, the combination of chemical treatment and pumping for reagent circulation and recovery is recommended. The type of pumping (cyclic followed by recovery versus flow through) employed in a given situation should be based on a complete evaluation of the material to be removed, the reagents to be used, and the reaction products to be recovered. As in the case of well development, the chemical reagents should be carefully selected and sparingly used.

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APPENDIX A

NOMENCLATURE

A_{well} = area of influence of an individual well, ft^2
b = mean aquifer thickness, ft
c = constant in the expression for eff,
e_m = motor efficiency, dimensionless
e_p = pump efficiency, dimensionless
E = modulus of elasticity of the casing material, psi (ref. Appendix C)
f = friction factor for pump support piping, dimensionless (ref. Fig. B-1 of Appendix B)
f_a = fraction of drill holes abandoned
f_c = fraction of drill holes completed
F_{Mx} = maximum axial compressive load which can be supported without column buckling, lbs.
$F_{z,C}$ = axial compressive force acting on the casing string, lbs
$F_{z,T}$ = axial tensile force acting on the casing string, lbs
g_c = acceleration due to gravity = 32.174 ft/sec^2
G_F = gel strength of a given fluid, lb/sq ft
G_G = gel strength of the grout slurry, lb/sq ft
GxT = grade-thickness product of ore zone, %·ft
h = arbitrary depth below grade, ft

h_F = friction head, ft = $(0.002594)\ \frac{f}{\phi}\left(\frac{q}{\phi^2}\right)^2 = h_V\left(\frac{f}{\phi}\right)$

h_L = total vertical lift required, ft
h_M = surface manifold pressure, ft = $2.308P_M$
h_p = mean depth to the pump suction, ft
h_T = total dynamic head, ft = $(h_L + h_F + h_V + h_M)$

h_V = velocity head, ft = $(.002594)\left(\frac{q}{\phi^2}\right)^2$

h_{DW} = depth to the dynamic water level, ft
$h_{F/G}$ = depth to the fluid/grout interface, ft
h_{SW} = depth to the static water level, ft
h_{TC} = total cased depth, ft.
h_{TD} = total drilled depth, ft.

I = moment of inertia (planar) of casing, $in^4 = \frac{\pi}{64}\ (\phi_o^4 - \phi_i^4)$

K = bulk modulus of compressibility of the fluid, psi
l_{Mx} = maximum recommended spacing between centralizers, feet
NV = expected net product value, i.e., sales price less all non-well-related production costs, \$/lb.
P_A = actual pump horsepower, Hp
P_D = well head displacement pressure, psi
P_G = well head grouting pressure, psi
P_I = well head injection pressure, psi
P_M = surface manifold pressure, psi
P_S = shut in well head pressure, psi

P_T = theoretical pump horsepower, Hp
P_{Mx} = unspecified maximum pressure difference, psi
$P_{r,C}$ = maximum pressure difference inducing radial compression, psi
$P_{r,T}$ = maximum pressure difference inducing radial tension, psi
P_{WH} = pressure necessary to displace grouting fluids through the casing and annulus at a given flow rate (refer to Figure 16), psi
q = fluid flow rate, gpm
q_A = average flow rate within the annulus, gpm
q_C = average flow rate within the casing, gpm
r_e = mean radius at which the hydrostatic head can be considered constant during operation, ft $\simeq \sqrt{A_{well}/\pi}$,
r_w = effective well radius, ft
Re = Reynolds number, dimensionless
RF = recovery factor, dimensionless
S_z = axial stress in the casing, psi = $\dfrac{4F_z}{\pi(\phi_0^2 - \phi_1^2)}$
$S_{z,C}$ = axial compressive stress in the casing, psi
t_M = minimum practical wall thickness, inches
t_T = effective minimum wall thickness at the base of threads, inches
t_W = minimum wall thickness of the unthreaded portion of the casing, inches
T = mean aquifer transmissivity, gpd/ft
TF = tonnage factor for the ore zone, ft^3/ton
U_d = displacement velocity, ft/sec
U_f = average fluid velocity, ft/sec
U_s = settling velocity of a particle relative to the fluid (under laminar flow conditions), ft/sec
U_{Mx} = maximum settling velocity of a particle relative to the fluid (under turbulent flow conditions), ft/sec
V_A = volme of the annulus, gal
V_C = internal casing volume, gal
V_D = volume of post-grout displacement fluid, gal
V_F = volume of pre-grout flush fluid, gal
V_G = total volume to be grouted, gal
V_{DH} = uncased drill hole volume, gal
V_{Mxd} = mixed zone volume at the interface between two fluids, gal
V_{Rqd} = required grout volume, gal
W = expected total of all well-related costs, including preproduction, production, restoration and reclamation costs, $
α = particle shape parameter, dimensionless $\simeq$ 0.4 for drill cuttings
β = fraction of the aquifer thickness over which a typical well is completed, dimensionless ≤ 1
γ = mean well efficiency, dimensionless ≤ 1
Δ = net change or difference in some variable, dimensionless
Δl = mixed zone length over which either fluid A or B is less than 90% pure
ΔF_z = net axial force acting on the casing, lbs
ΔP_r = net radial pressure acting on the casing, psi
Δs = mean possible drawdown, ft = $(h_p - h_{SW})$
λ = appropriate design factor, dimensionless (ref. Appendix C)
ν = Poisson's ratio, dimensionless (ref. Appendix C)

μ_{eff} = effective viscosity of non-Newtonian fluid (a function of fluid velocity/shear rate), lb/ft·sec = 0.0672 (viscosity in poise)
μ_f = viscosity of a Newtonian fluid, lb/ft sec
ρ_c = effective density of the casing string, lbs/ft^3
ρ_f = density of the drilling fluid, lbs/ft^3
ρ_g = density of the grout slurry, lbs/ft^3
ρ_s = density of the drill cuttings, lbs/ft^3
ρ_w = density of water, lbs/ft^3
σ_T = design tensile stress, psi (ref. Appendix C)
ϕ = inside diameter of pipe string supporting the pump, inches
ϕ_c = major outside diameter of the casing, excluding the joint, inches (ref. Figure 25)
ϕ_{CH} = average diameter of the cased portion of the drill hole, inches
ϕ_{DH} = average diameter of the uncased portion of the drill hole, inches
ϕ_i = average inside diameter of the casing, inches
ϕ_j = maximum outside dimension of the casing joint, inches
ϕ_o = average outside diameter of the casing, inches
ϕ_s = equivalent spherical diameter of a solid particle, inches
ϕ_t = average casing diameter at the base of the threads, inches
ϕ_{Mx} = maximum size spherical particle which can be suspended by a non-Newtonian fluid, inches
ϕ_{eff} = effective diameter of a flow channel, $_i$ for flow inside the casing and (ϕ_{CH} - ϕ_o) for flow in the annulus surrounding the casing.

Sign convention used:

depth: + in the direction of increasing depth from the surface

forces: + in the direction of increasing radial or axial distance

stresses: + indicates tensile stress, and - indicates compressive stress

APPENDIX B

PRESSURE DROP DATA FOR COMMONLY USED PIPE
(Approximate Head Loss[1] in ft per 100 ft of Sch. 80 Pipe[2])

Flow Rate (gpm)	Velocity (ft/sec)	Head Loss (ft)	Velocity (ft/sec)	Head Loss (ft)	Velocity (ft/sec)	Head Loss (ft)	Velocity (ft/sec)	Head Loss (ft)
	1" NPS							
2	0.94	0.88	1.5" NPS					
5	2.34	2.75	0.94	0.30	2" NPS			
7	3.28	5.04	1.32	0.55	0.78	0.15		
10	4.68	9.61	1.88	1.04	1.12	0.29	3" NPS	
15	7.01	20.36	2.81	2.20	1.68	0.62	0.75	0.09
20	9.35	34.68	3.75	3.75	2.23	1.06	1.00	0.15
25			4.69	5.67	2.79	1.60	1.25	0.22
30	4" NPS		5.63	7.95	3.35	2.25	1.49	0.31
35	1.00	0.11	6.57	10.58	3.91	2.99	1.74	0.42
40	1.15	0.14	7.50	13.55	4.47	3.83	1.99	0.54
45	1.29	0.17	8.44	16.85	5.03	4.76	2.24	0.67
50	1.43	0.21	9.38	20.48	5.58	5.79	2.49	0.81
60	1.72	0.30	11.26	28.70	6.70	8.12	2.99	1.14
70	2.01	0.39	13.14	39.08	7.82	10.80	3.49	1.51
75	2.15	0.45			8.38	12.27	3.74	1.72
80	2.29	0.50			8.93	13.83	3.99	1.94
90	2.58	0.63	6" NPS		10.05	17.20	4.48	2.41
100	2.87	0.76	1.25	0.10	11.17	20.90	4.98	2.93
125	3.59	1.16	1.57	0.16			6.23	4.43
150	4.30	1.61	1.88	0.22			7.47	6.20
175	5.02	2.15	2.20	0.29	8" NPS		8.72	8.26
200	5.73	2.75	2.51	0.37	1.43	0.09	9.97	10.57
250	7.16	4.16	3.14	0.56	1.79	0.14	12.46	16.00
300	8.60	5.83	3.76	0.78	2.14	0.20		
350	10.03	7.76	4.39	1.04	2.50	0.27	10" NPS	
400	11.47	9.93	5.02	1.33	2.86	0.34	1.61	0.11
450			5.64	1.65	3.21	0.42	2.04	0.14
500			6.27	2.00	3.57	0.51	2.27	0.17
750			9.40	4.25	5.36	1.08	3.40	0.36
1000			12.54	7.23	7.14	1.84	4.54	0.61
1250					8.93	2.78	5.67	0.92
1500					10.71	3.89	6.80	1.29
2000							9.07	2.19
2500							11.34	3.33

1. The tabulated head losses are for water flowing through clean-smooth walled plastic pipe. Significantly greater head losses may be experienced if chemical precipitation or biological accumulation on the pipe wall occurs during operation.

2. For pipe sizes other than Schedule 80 the indicated head losses should be adjusted as follows:

$$\text{Head Loss} \simeq \left[\frac{\text{I.D. of Sch. 80 pipe}}{\text{I.D. of the Pipe Used}}\right]^4 \cdot (\text{Tabulated Head Loss})$$

3. For flow rates other than those tabulated, the head loss can be estimated as follows:

$$\text{Head Loss} \simeq \left[\frac{q \text{ Desired}}{q \text{ Tabulated}}\right]^2 \cdot (\text{Tabulated Head Loss})$$

4. For fluids exhibiting a kinematic viscosity significantly different than water a reference such as Cameron Hydraulic Data (47, p. 96) should be consulted for head loss data.

APPENDIX C

PHYSICAL PROPERTIES AND CHARACTERISTICS OF COMMONLY USED PLASTIC PIPE

Material Properties[1]

Material	Specific Gravity (-)	Coef. of Thermal Expansion (10^{-5}/°F)	Minimum Tensile Strength (psi)	Maximum Sustained Stress (psi)	Recommended Design Stress (psi)	Modulus of Elasticity (10^5 psi)	Poisson's Ratio (-)
Polyvinyl Chloride:							
Type I, Rigid PVC	1.41	3.0	7,000	4,200	2,000	3.6	0.33
Type IV, Rigid CPVC	1.55	3.5	7,000	4,200	2,000	4.0	0.33
Fiber Reinforced Plastics:[2]							
Filament Wound	1.86	0.7-1.1	30-50,000	20-35,000	10-16,000	2.0-3.0	0.33
Centrifugally Cast	1.58	1.3	20-30,000	14-22,000	10-16,000	1.3-1.9	0.15

Recommended Design Factors

Maximum short term axial or hoop stress	0.9 x Minimum Tensile Stress
Maximum sustained hydrostatic pressure	0.6 x Minimum Tensile Stress
Maximum long term hydrostatic pressure	0.3 x Minimum Tensile Stress
Maximum long term cyclic pressure	0.15 x Minimum Tensile Stress

Derating Factors for the effect of Temperature on Minimum Tensile Stress:

Ambient Temperature	Type I PVC	Type IV CPVC	Filament Wound FRP	Centrifugally Cast FRP
40			1.00	1.00
50			"	"
60			"	"
73.4±2	1.00	1.00	1.00	1.00
80	.88	.88	"	"
90	.75	.76	"	"
100	.62	.66	1.00	1.00

1. The material properties indicated are those common to both the API (5) and ASTM (8,9) specifications for line pipe and well casing.

2. Several different grades of FRP pipe and casing have been specified having properties which fall within the ranges indicated.

Rigid PVC and CPVC Pipe[3]

Nominal Pipe Size	1"	1.5"	2"	3"	4"	6"	8"
Outside Diameter (in.)	1.315	1.900	2.375	3.500	4.500	6.625	8.625
Schedule 80:							
Min. Wall Thickness (in.)	0.179	0.200	0.218	0.300	0.337	0.432	0.500
Burst Pressure[4] (psi)	2020	1510	1290	1200	1040	890	790
Collapse Pressure[5] (psi)	2460	1060	680	550	360	230	160
Appx. Weight[6] (lb/ft)	0.41	0.69	0.94	2.02	3.00	5.67	8.60
Schedule 40:							
Min. Wall Thickness (in.)	0.133	0.145	0.154	0.216	0.237	0.280	0.322
Burst Pressure[4] (psi)	1440	1060	890	840	710	560	500
Collapse Pressure[5] (psi)	930	380	230	190	120	60	40
Appx. Weight[6] (lb/ft)	0.32	0.51	0.70	1.42	2.04	3.57	5.45
SDR - 13.5:							
Min. Wall Thickness (in.)	0.097	0.141	0.176	0.259	0.333	0.491	0.639
Burst Pressure[4] (psi)	1000 for all NPS						
Collapse Pressure[5] (psi)	340 for all NPS						
Appx. Weight[6] (lb/ft)	0.25	0.51	0.81	1.77	2.97	6.38	10.80
SDR - 17:							
Min. Wall Thickness (in.)	0.077	0.112	0.140	0.206	0.265	0.390	0.508
Burst Pressure[4] (psi)	800 for all NPS						
Collapse Pressure[5] (psi)	170 for all NPS						
Appx. Weight[6] (lb/ft)	0.20	0.41	0.68	1.50	2.46	5.30	8.80
SDR - 21:							
Min. Wall Thickness (in.)	0.063	0.090	0.113	0.167	0.214	0.316	0.410
Burst Pressure[4] (psi)	630 for all NPS						
Collapse Pressure[5] (psi)	90 for all NPS						
Appx. Weight[6] (lb/ft)	0.16	0.33	0.55	1.20	1.97	4.22	7.17
SDR - 26:							
Min. Wall Thickness (in.)	0.051	0.073	0.091	0.135	0.173	0.255	0.332
Burst Pressure[4] (psi)	500 for all NPS						
Collapse Pressure[5] (psi)	45 for all NPS						
Appx. Weight[6] (lb/ft)	0.13	0.28	0.43	0.93	1.64	3.52	5.96

3. The wall thicknesses, burst pressures, and collapse pressures indicated are the minima specified for rigid PVC and CPVC pipe in the relevant API and ASTM specifications.

4. Burst Pressure refers to the net internal hydrostatic pressure which would produce a Tensile Hoop Stress equal to 90% of the materials's Minimum Tensile Strength in an otherwise unstressed cylinder of uniform diameter. The tabulated values should be adjusted to reflect any significant difference in material characteristics and a suitable design factor for the particular application (ref. Eq. 5).

5. Collapse Pressure refers to the net external hydrostatic pressure which would produce a compressive Hoop Stress equal to 90% of that which would cause collapse of an otherwise unstressed cylinder of uniform diameter. The tabulated values should be adjusted to reflect any significant difference in material characteristics and a suitable design factor for the particular application (ref. Eq. 6).

6. The tabulated weights should only be considered representative of Bell End rigid PVC pipe. For rigid CPVC pipe the tabulated weights whould be increased by appx. 10%.

Fiber Glass Reinforced Plastic Pipe[7]

Nominal Pipe Size	2"	3"	4"	6"	8"
Outside Diameter (in.)	2.375	3.500	4.500	6.625	8.625
Filament Wound Pipe:					
Thin Wall:					
Min. Wall Thickness (in.)	.070	.070	.070		
Min. Reinforcement Tkns. (in.)	.060	.060	.060		
Burst Pressure[4] (psi)	1,450-2,280	980-1,530	1080		
Collapse Pressure[5] (psi)	95	30	15		
Appx. Weight (lb/ft)	0.40	0.60	0.80		
Medium Wall:					
Min. Wall Thickness (in.)	.120	.120	.120	.110	.135
Min. Reinforcement Tkns. (in.)	.100	.100	.100	.100	.125
Burst Pressure[4] (psi)	2,460	1,650	1,270	860-1,350	820-1,030
Collapse Pressure[5] (psi)	435	135	65	20	20
Appx. Weight (lb/ft)	0.65	1.00	1.30	1.70	2.00
Heavy Wall:					
Min. Wall Thickness (in.)	.190			.160	.180
Min. Reinforcement Tkns. (in.)	.166			.140	.160
Burst Pressure[4] (psi)	4,210-5,260			1210	1060
Collapse Pressure[5] (psi)	1980			55	35
Appx. Weight (lb/ft)	1.19			2.60	3.80
Centrifugally Cast Pipe:					
Medium Wall:					
Min. Wall Thickness (in.)	.200	.200	.200		
Min. Reinforcement Tkns. (in.)	.140	.140	.140		
Burst Pressure[4] (psi)	3510	2330	1800		
Collapse Pressure[5] (psi)	1190	370	175		
Appx. Weight (lb/ft)	0.83	1.40	1.77		
Heavy Wall:					
Min. Wall Thickness (in.)	.250	.250	.250	.250	.250
Min. Reinforcement Tkns. (in.)	.170	.170	.170	.170	.170
Burst Pressure[4] (psi)	4320	2860	2200	1470	1130
Collapse Pressure[5] (psi)	2125	665	315	100	45
Appx. Weight (lb/ft)	1.25	1.75	2.40	3.50	4.50
Extra Heavy Wall:					
Min. Wall Thickness (in.)	.300	.300	.300	.300	.300
Min. Reinforcement Tkns. (in.)	.220	.220	.220	.220	.220
Burst Pressure[4] (psi)	5720	3760	2880	1920	1470
Collapse Pressure[5] (psi)	4610	1440	680	210	95
Appx. Weight (lb/ft)	1.40	2.10	2.90	4.15	5.40

7. The wall thicknesses, burst pressures, and collapse pressures indicated are the minima specified for fiberglass reinforced plastic pipe by the relevant API specifications. However, the grouping in terms of wall thickness was done for the sake of data presentation.