*Depth estimates are based on conditions imposed by the casing-cementing, well-simulation tests (API RP 10-B) and should be considered approximate values. The response of the cement to these conditions can be modified by additives.

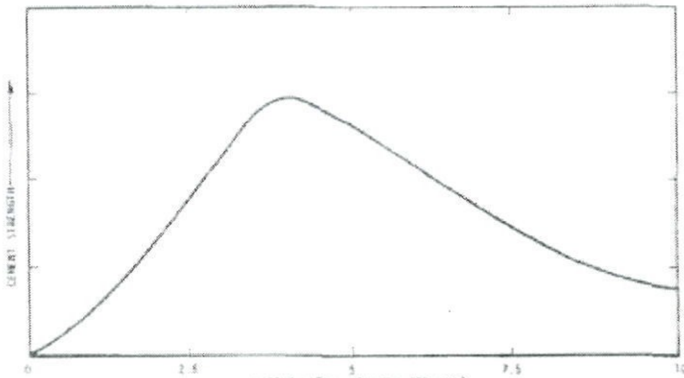
There are a number of other cements that do not fall specifically into any general classification. These cements are special blends of portland and additives or cements based on other chemistry. They include pozzlin cement, which incorporates organic resin technology, expanding cements, which increase in volume as the cement sets, silica and lime cement for hot wells, and low heat generating cements for permafrost applications. These cements are rarely used in general completions because they are more expensive than portland or have other traits that are less desirable than those of Portland.

Environmental conditions and available completion equipment may significantly affect the performance of the cement or place special requirements on the cement. The unique problems of the effect of temperature on cement setting and long-term strength of cements have led to development of special cements for both steam wells and those in arctic environments. High temperatures sharply reduce cement strength and durability, necessitating the development of stabilizers. Silica additives and lime based cements have proved effective in thermal wells. Permafrost cement was developed in response to a need to cement formations to depths of 2000 ft without producing sufficient heat of hydration from setting the cement to melt and destabilize the permafrost.

The most important aspect of cementing blending is obtaining a consistent slurry with the proper amount of additives and mix water. The optimum water-to-cement ratio for a cement slurry is a compromise. Maximum cement strength occurs at a water-to-cement ratio of about 2.8 gal/sack. This is the minimum amount of water necessary to fully hydrate and chemically react with the cement ground to a size that represents Class G. But, a slurry mixed at this water rate has a very high viscosity and cannot be pumped. If too much water is used to aid in pumping and displacement, low strength and a very high free water quantity will occur. The tradeoff between cement strength and the mixing water volume is seen in the data of Figure 3.2.[2] Free water is defined as water that is not needed by the cement for reaction. When flow stops, it separates out to the top of the cement column. Separation may occur at the top of a long column or in pockets in highly deviated wells.[3] These pockets contribute to annular gas leakage and other annular flow problems.

Cement is mixed by jet mixers that combine cement and water in a single pass operation or the more precision batch mixers that mix by circulating in a large tank but only mix a limited volume at a time.[1] Although an acceptable slurry can be achieved in the jet mixer by an experienced operator, the batch mixer allows closer control in critical, small jobs. The jet mixers are used for almost all large jobs that require a constant supply of cement slurry at a high rate. The density of slurries mixed by these methods must be checked periodically with a pressurized mud balance to obtain consistent density. Density is important to control the reservoir pressure and prevent formation fracture breakdown.

The quality of the water used to mix the cement varies widely depending upon the specifications required by the company involved. Fresh water, seawater and some brackish waters are used to mix cement slurries. For any source of water, the behavior of the resultant cement in terms of setting time and pumpability must be known before mixing. Pumpability is measured by a laboratory instrument called a consistometer.[4] This device measures the setting time of a cement slurry by stirring the slurry (under pressure) until it thickens too much to stir. The output is as units of consistency, and is time related. This test yields the time that a particular slurry can be pumped at a given temperature. Because of the development of offshore fields, seawater has become very widely used for cementing. Seawater, like most inorganic salt brines, slightly accelerates the set time of cement. Fortunately, as shown in Figure 3.3, the chemical composition of seawater throughout the world does not vary to a large degree,[5] but some chemical additive additions may be necessary to control effects of salt and temperature. Use of brackish water (from bays, swamps, sewage or produced waters) can cause problems. High salt contents, especially calcium chloride, may decrease the cement set time. Organic contaminates (such as oil-base mud) may slow the cement set time, sometimes so severely that the slurry does not set.



(Smith, SPE)

Figure 3.2: Cement compressive strength vs. mix water volume.

Constituents in Mg/L	Gulf of Mexico	Cook Inlet Alaska	Grand Banks Newfoundland	Trinidad W.I.	Persian Gulf (Kharg IS)	Gulf of Suez	Sable Island	Standard Sea Water ASTM.D-1141
Chloride	19000	16800	19500	19900	23000	22300	18900	19359
Sulfate	2500	2000	2580	2400	3100	3160	2260	2702
Bicarbonate	127	140	305	78	171	134	140	142
Carbonate	12	0	0	27	24	11		
Sodium & Potassium	10654	9319	11649	11170	13044	12499	10690	11155
Magnesium	1300	1080	1118	1300	1500	1570	1199	1297
Calcium	400	360	400	408	520	464	370	408
Total Dissolved Solids	33993	29499	35553	35283	41359	40078	33559	35169
pH	8.2	8.0		8.3	8.2	8.2	7.3	8.2

(Smith & Calvert, JPT, 1975)

Figure 3.3: Sea Water Analysis at Various Locations

Accelerators or retarders may be used in the cement to change the set time from a few minutes to many hours. A retarder is used in deep or very hot wells to prevent the set of the cement before the job is complete. Accelerators are used in shallow or cool wells to speed up the set of cement so less rig time is lost waiting on the cement to set. Values such as filtrate loss control and cement expansion can also be directly affected. Cement additives may be divided into two general classifications based on their reaction type; chemical and nonchemical. Nonchemical additives are usually materials which affect the cement by altering density or controlling fluid loss. Chemical additives modify the hydration (water intake).

Cement Density

Controlling the cement slurry density is critical for placing a column of cement where the formation may be fractured by a heavy slurry or would allow the well to flow if the cement slurry was lighter than the pore pressure. For a lighter weight cement than the normal 15 to 16 lb/gal, bentonite clay may be added to absorb water to yield a lighter cement with higher bound water volume. Ten to 12 lb/gal cement density can be achieved in this manner. Grinding the cement to a very small size will also require more water to satisfy the high surface area and lighten the slurry to the 10 to 12 lb/gal range. Ultra-light-weight cements,[6-7] using hollow ceramic or glass beads can reduce the overall weight of the cement slurry to less than 9 lbs per gallon. Even lower densities can be achieved by foaming the cement with a compressed gas such as nitrogen.[8,10] The foamed cements can create densities of 4 to 7 lb/gal but require careful control of annulus surface pressures to avoid gas channels and voids. All these light weight cements, although strong enough to support the pipe, have less strength than the regular portland cement. Heavy weight materials are added to the cement to increase the cement density, usually to control the pressure in the formation during the pumping of the cement. Iron ore, barite (barium sulfate) and sand can create slurries to 25 lbs/gal. Other methods of preparing heavyweight slurries include the use of dispersants which allow less water to be used in a cement and still maintain pumpability. A chart of cement density for various methods of density control is contained in Figure 3.4.

Cement Slurry Type	wt. range lb/gal
Densified and weighted	16 to 22
Neat Slurry	14to18
High water ratio slurries	11 to 15
Ceramic bead extended slurry	9.5to12+
Glass bubble extended slurry	7.5to12+
Foam cement	6to12+

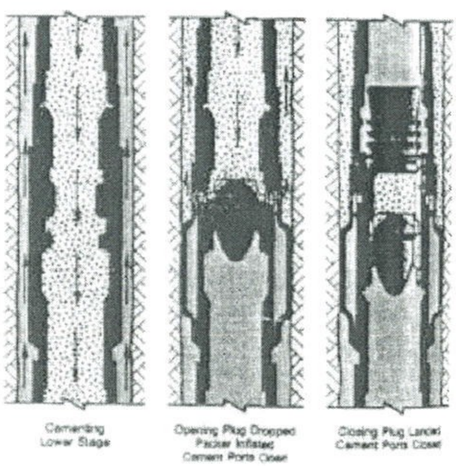
Figure 3.4: Density Ranges for Various Types of Cement Slurries

In some treatments where the light weight cements are not used either by preference, economics or for reasons of strength, stage tools can be used to control the pressures on a zone by running a multi stage cement job. A staged job separates the cement job into small cement jobs that only support a portion of the total column and weight. The tools prevent the cement columns from contacting each other until set. An example of a cement stage tool is seen in Figure 3.5. The simplest tool uses a drill-able plug to seal the pipe below the tool and to open a set of ports that allow the next cement stage to turn the corner and start up the annulus. Some tools are equipped with a seal device that prevents cement from falling down the annulus and ruining the job by creating channels or by exerting more pressure on the lower zones.

With these tools, even a deep well with several zones can be cemented by turning the job into several consecutive jobs. The staged concept can also be done by cementing with a small volume and perforating the pipe above the last cement top and repeating the process. However, the tuula save WOC time between jobs. The obvious drawback to the tools is the same for all downhole tools; reliability.

Fluid Loss

Lost circulation materials control the flow of whole cement into natural fractures or extremely large vugs. The control materials come in three basic types: granular, lamellated and fibrous. Granular materials such as sand and other products set a secondary matrix by filling cracks and vugs in the formation. They may have a size range from 1/4 in. diameter to fine powder to achieve control. Lamellated or flaked products such as shredded cellophane stopped at the formation face and create a blockage on which cement will form a filter cake. Fibrous material such as paper, nylon or polypropylene are best suited to bridge small fractures.



(Courtesy of Halliburton)

Figure 3.5: A schematic of a multiple stage cement tool with an inflatable seal to protect annular lower zones from pressure of upper cement job.

Loss of cement filtrate in permeable sections creates dehydrated masses of cement and impedes flow. Any decrease of cement flow rate may impair the ability of the cements.[1,11,12] Restrictions in the annular space also increases the circulating pressure and the risk of breaking down the formation. When fluid loss control cannot be achieved by traditional methods, a plug of cement is often set across the zone and the cement drilled out to continue with well operations. The thin sheath of cement on the formation and the cement that invades the natural fractures are often adequate to halt fluid loss.

Chemical additives react with the cement and usually alter the chemical process of hydration. Accelerators are usually inorganic salts that speed up the hydration of cement by increasing the temperature of the slurry.

Factors Affecting Cement

Increasing temperature accelerates the set time of cement. Both the bottom hole temperature and the heat produced by a large mass of cement during hydration may affect the set time. To correctly design a cementing job, the bottomhole temperature of the formation and an estimate of circulating temperature should be known. A temperature gradient is calculated from this information to give the temperature exposure the cement will face during the pumping operation. Thought must also be given to heat transfer from the cement rising in the annulus to the cement coming down the inside of the casing. Cementing computer simulators that model the temperature profile commonly provide a temperature schedule.

Pressure has a tendency to accelerate the thickening time and the set time of the cement, but the effect of pressure is not nearly so pronounced as that of temperature. Testing a cement design in the laboratory requires both simulated downhole pressure and temperature be applied to the test design.

The strength requirements of oil well cements are dependent on several factors. The cement must be strong enough to secure the pipe in the hole, to isolate the zone and to withstand the nominal shock of drilling, perforating and fracturing. For drilling ahead, the minimum WOC times are usually based on the time required for the cement to develop 50 psi tensile strength. The issue of the strength of cement has always been of interest since strength develops over a long period of time and rig time can be lost waiting on cement (WOC) to set. This WOC time can be shortened by the use of accelerators. Cement requires very little strength to physically support the casing. More strength is required in withstanding loading from drill bits and pressure. In designing the cementing operation, it is imperative that high strength cements be used around the casing shoe (the bottom end of the pipe) and across potential pay, thief zones (areas of fluid loss) and water producing zones. Filling the annulus behind pipe and zone separation requires very little strength and more economical cements or cement extenders may be used.

While the cement slurry is liquid, the hydrostatic force from the weight of the slurry exerts force to prevent entry of gas into the wellbore annulus. When pumping stops, the cement starts to gel and set and it begins to support itself by the initial bond to the formation. This initial attachment, coupled with fluid loss to the formation, reduces the applied hydrostatic load.[13] Fluids can then enter the annulus, causing voids and channels in the cement behind the pipe. Methods of control include reaction with the formation gas to plug the channels[14] and stopping the gas from entering by reducing permeability.[15] Use of an external inflatable casing packer (ECP) is also an option.[16] This tool operates like a hydraulic set packer between the casing and the open hole.

The necessary volume of cement is the volume of the openhole less the volume of the casing across the zone. An excess of 30% to 100% of the total is usually added to the cement volume to allow for washouts and mud contaminations. The 30% to 100% range of excess cement volumes is large, even for the technology of the oil field. It reflects the variability of drillers expertise and formation conditions. Hole volume is calculated from the caliper log. The bit diameter should not be used for hole volume calculations since it will not reflect washouts. In most operations, 4-arm caliper tools that give two independent diameters are more accurate than 3-arm calipers that give a maximum or averaged reading.

Cementing Design

The first use of cement in the oil industry is recorded as a water shutoff attempt in 1903 in California.[2] At first, cement was hand mixed and run in a dump bailer to spot a plug. Pumping the cement down a well was soon recognized as a benefit and a forerunner of the modern two-plug method was first used in 1910.[2] The plugs were seen as a way to minimize mud contact with the cement. Although both mechanical and chemical improvements have been made in the cementing process, the original plug concept is still valid.

Cement design includes the selection of additives and equipment to remove mud and properly place and evaluate the cement. The cement design depends upon the purpose of the cementing operation. The initial cement is usually to fill the annular space between the casing and the hole from the casing shoe to the surface or a point several hundred feet above the zone that must be isolated. The first cement job is called primary cementing and its success is absolutely critical to the success of subsequent well control and completion operations. When a primary cement job fails to completely isolate the section of interest, repair of the cement job must be done before drilling can proceed. These repair steps are covered by the collective label of squeeze cementing. In a squeeze job, cement is forced into the zone through perforations, ports in tools, hole produced by corrosion, or through the clearance between casing overlap liners or strings. Although squeeze cementing has become commonplace, it is expensive and its use can be curtailed through Improved primary cementing procedures.

Primary Cementing

In primary cementing, the object is to place a continuous sheath or band of cement around the pipe which extends without channels or voids outward to the formation face. Primary cementing is not an easy operation to do correctly. Many things can happen during this process to create problems or weak spots in the primary cement design.

Application

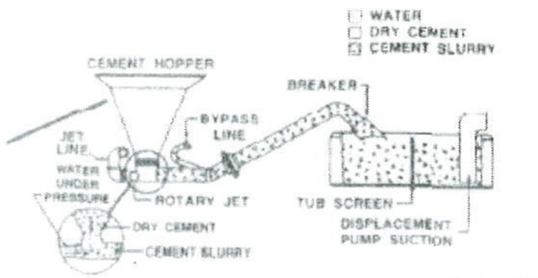
The mixing of cement and water is the first critical area of application of cementing technology. To prevent fracturing or loss of control, the water and cement must be blended together at the proper slurry density. The weight of the slurry is equal to the weight of the set cement less any weight of free water.

One of the first questions that should emerge in a design is the volume of cement needed for a job. In a short string or shallow string, complete cement fill of the annulus is needed, plus at least 30% excess to displace the lead cement that is in contact with the mud as the cement displaces the mud from the annulus. Cement contaminated with mud will not form an effective seal; it may have mud channels through it and may not develop any strength. In cases where the mud has not been adequately conditioned before cementing, as much as 100% excess may be appropriate.

The volume of the hole should be measured with a caliper after removing the drilling string and before running casing. Calipers may be available in 3-arm, 4-arm or multi-arm styles. Three-arm calipers report an average "round" hole diameter based on the smallest diameter reading of one of the arms. The four-arm calipers work as two 2-arm calipers. The data from this tool draws an average of the hole based on two circles or ellipses. Both tools are capable of underestimating the hole volume.

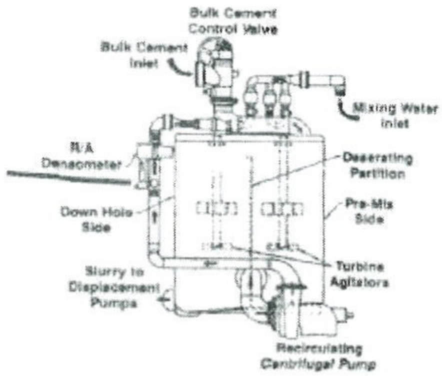
The caliper tools report the data on a log track that shows deviation from a theoretical line reflecting gage hole or bit size. Washouts and irregular hole volumes must be calculated to give an accurate reading on hole size. The easiest way to calculate hole volume in a washout is to use an average washout diameter equal to at least 90% of the maximum caliper measured diameter where the diameter is fluctuating widely and 100% of the maximum diameter where the hole diameter is more consistent. Calculating the volume of the hole in vertical segments of similar diameter yields usable results. The problems in cementing through a washout are that fluid velocity becomes very low in a washout; swept debris at the leading edge of the cement drops out or mixes in and the cement slurry will no longer scour or clean the mud cake in the washout.

There are two types of oilfield cement mixing equipment: on-the-fly and batch. Batch mixing is done in a large tank with circulation or paddle mixers. The cement and the water are measured into the tank, sometimes with an on-the-fly mixer, with small additions of cement or water to get the right slurry density. Although batch mixing is by far the most accurate method, the size of the cement job is limited by the volume of the tank at hand. Mixing on-the-fly involves moving steady streams of cement and water through a zone of turbulence produced by high velocity flow, Figure 3.6. The cement slurry produced in this manner is highly dependent on the experience and attention of the mixer operator. Numerous problems with variances in slurry weight have led to averaging "pods" or tanks, Figure 3.7, downstream of the on-the-fly mixer. To minimize the damage produced from lighter or heavier than designed slurries, most cementing service companies have density monitoring devices to report slurry density back to the mixer operator.



(Smith, SPE)

Figure 3.6: A "jet" mixer. The slurry density is very much dependent upon the operator.



(Smith, SPE)

Figure 3.7: A pod or batch mixer. The averaging characteristics makes the slurry density much more consistent.

Incorrect cement density can cause gas migration, poor set strength, inadequate cement bond, blow outs, formation fracturing and lack of mud displacement. Cement slurry density must be rigorously controlled to enable the subsequent well completion steps to be carried out successfully.

Once a consistent cement slurry blend has been achieved, the second critical area, that of the displacement step, begins. To effectively bond the pipe to the formation with cement, the drilling mud and the drilling mud filter cake must be completely removed. Failure to remove the cake or mud will lead to failure of the primary cement job by leaving mud channels in the cement. Failures necessitate squeeze cementing or repair operations.

Mud conditioning and displacement are the next critical areas of cementing application.[17,21] In order for cement to isolate zones, a sheath of cement must completely surround the pipe and bond the formation wall to the pipe. The mud cake must be removed and the pipe must be centralized. Centralization is needed to provide sufficient standoff or clearance between the casing and the borehole wall. Removal of the mud and mud cake is done by a combination of chemical and physical actions that are well documented but often overlooked during application. The ease of mud removal depends upon the physical condition of the mud and the access to the mud. Mud displacement begins with decreasing the gel strength of mud and removing cuttings. After casing is run in the well, the annular space open to flow is smaller than when drill pipe was present. The smaller annular area creates higher velocities that can disturb deposits of cuttings. Cuttings can accumulate in the lead portion of the cement, contaminating the cement and creating blockages that can create lost circulation. The presence of a mud cake will prevent bonding of the cement to the formation. An estimation of the volume of cement needed for removal of mud cake by turbulent flow is:[1]

$$V_t = (t_c)(q)5.616 \text{ ft}^3/\text{bbl} \tag{3.1}$$

where

- V_t = volume of fluid (in turbulent flow), ft^3
- t_c = contact time, minutes
- q = displacement rate, bbl/min

Studies have shown that a contact time (during pumping) of 10 minutes or longer provides better mud removal than shorter contact times.[1] The equation is valid as long as all the fluid passes the point of interest. The equation will not be valid for mud outside the path of the flowing fluid, such as when the casing is uncentralized and is pressing against the formation.

Movement of the pipe during cementing is one of the best methods of improving the mud displacement and reducing the number of mud channels remaining after cementing.[17,23] Reciprocation (up and down) and rotation of casing help force the mud from the pipe/formations contact areas and insure a more even distribution of cement. Rotation of the pipe requires special rotating heads to allow pumping while turning. Reciprocation, or moving the casing up and down a few feet while cementing, can be done more easily but does not force the mud from the contact area in the same manner as rotation. Addition of scrapers to the casing can help remove hard mud cake.[24] Use of centralizers minimizes contact area and may make pipe movement easier.

Displacement of the mud and the mud cake cannot always be accomplished by flowing cement. Heavily gelled muds and tightly compressed filter cakes are very resistant to removal by any flowing fluid. Special removal procedures are necessary. The basic mud removal step is to pump the cement in turbulent flow; the combination of the high velocity, high viscosity and abrasive nature of cement work in unison to scour the formation and casing. During scouring, much of the mud and cake materials are mixed in with the first cement pumped. This contaminated cement must be removed from the well. In the cement volume design, the allowance for contaminated cement is contained in part of the 30% to 100% excess cement normally designed into most jobs.

If muds and mud cakes cannot be removed by cement flow, special preflush fluids and mechanical devices are available to improve displacement. To improve mud and mud cake displacement, the binding agent in the mud must be broken down. In most cases, the mud binders are clay, polymers or surfactants. Chemical flushes of acids, solvents, or surfactants are useful but must be selected for action on specific muds. These flushes are pumped ahead of the cement or spotted in the annulus before the cement job.

Mechanical devices for mud and mud cake removal include casing centralizers, scratchers for cake removal and turbulence inducing devices to improve mud displacement.[1,2] The wire or wire rope scratchers break up the mud cake during running of the casing. Complete removal of the cake is not necessary; the action of the cement will often be sufficient to remove the cake fragments once the integrity of the cake has been disrupted.

The alignment of casing in the borehole is an often neglected factor that has a tremendous impact on mud conditioning, cementing, perforating, and production, particularly in highly deviated or horizontal holes.[24-26] Uncentralized casing always lays on the low side of the hole. In soft formations, the casing may even embed or bury into the wall of the formation. When casing contacts the wall, the drilling mud cake and some whole mud is trapped between the casing and the rock. This mud cannot be removed. Mud removal attempts by flushes and turbulent cement flow will have little contact as shown in the velocity profile sketches of Figure 3.8 and the photographs of mud displacement and channels created in a flow study recorded in Figure 3.9. Cement bypasses the mud and channels are left behind the pipe. These channels may completely undermine the principles of zone separation by cement and usually require repair by squeeze cementing. Channels are the most common form of primary cement failure.

Centralizers and pipe movement can improve cementing.[27-28] Centralizers hold the pipe away from the wall of the hole so that cement may more evenly displace the mud and completely fill the annulus. The design of centralizers varies widely with the application. Centralizing casing in nearly straight holes is relatively easy, but as holes become more deviated, centralization becomes more difficult. In the more deviated wells, the weight of the casing will flatten most spring centralizers and may deeply embed some of the solid fin body units. The actual number of centralizers needed for a well depends on the acceptable deflection of the pipe and the severity of dog legs in the well. Examples of centralizers and their spacing are shown in

Figure 3.10. Note in the examples that the centralizer spacing decreases (more centralizers needed) as hole angle, pipe size and clearance increase.[1-39]

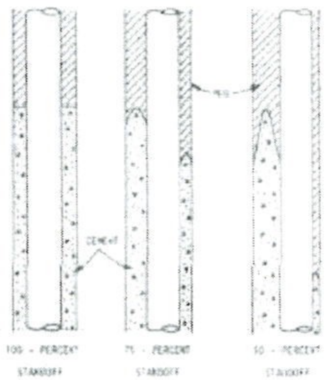


Figure 3.8: Cement velocity schematic at different casing standoffs.

The spacing is usually calculated by computer using a model such as that of Lee et al.[27] These programs project spacing on the input of depth, dogleg severity, lateral load, tension and deviation. Typical spacing is from 30 to 60 ft between centralizers.

The variance in casing weight can be illustrated by the following examples of buoyed weight of casing.

$$W_{cb} = W_{cd} + 0.0408\,(\rho_i di^2 - \rho_o do^2) \qquad (3.2)$$

where:

W_{cb} = buoyant weight of casing, lb/ft
W_{cd} = dry wt of casing, lb/ft
ρ_i = density of fluid in casing, lb/gal
ρ_o = density of fluid in annulus, lb/gal
di = inside diameter of casing, in.
do = outer diameter of casing, in.

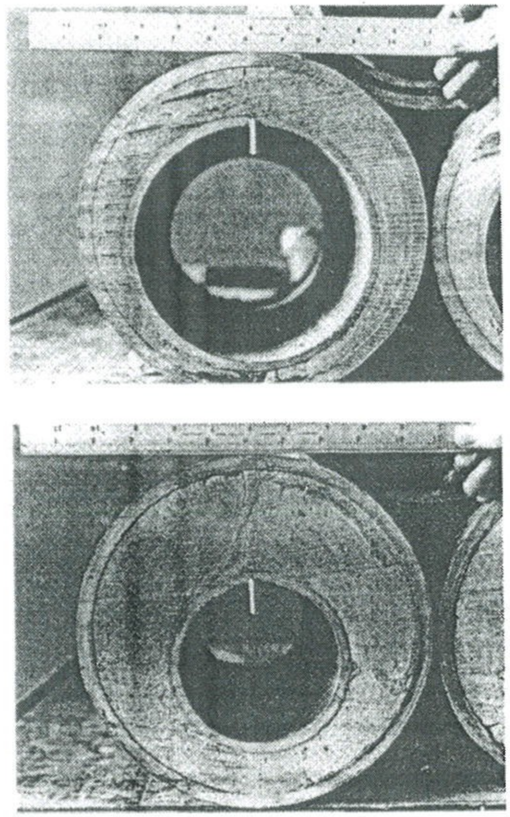
for circulation with an 11.5 lb/gal mud in a 7 in., 26 lb/ft, N-80 casing:

$$W_{cb} = (26) + 0.0408\,(11.5\,(6.276)^2 - 11.5\,(7.0)^2) = 21.5 \text{ lb/ft}$$

If fresh water (8.33 lb/gal) is used to displace 16 lb/gal cement to the float collar, the buoyed weight becomes:

$$W_{cb} = (26) + 0.0408\,(8.33\,(6.276)^2 - 16\,(7)^2) = 7.4 \text{ lb/ft}$$

Mud retards (slows) the set of cement. Minimizing this effect requires mud removal and separation from the cement whenever possible. Most casing strings are run full of mud during casing placement for assistance in well control. Cement displaces the mud from the casing before it flows up the annu-



(Wilson & Sabins, SPE)

Figure 3.9: Examples of 5" (bottom) and 7" (top) casing in 9-5/8" showing the effect of the flow area at a standoff of 60% (both cases). The smaller flow area in the 7" test leaves a mud channel that will allow communication.

lus. If the mud is lighter than the cement or the mud has high gel strength, the cement will tend to finger or channel through the mud during its trip down the casing, mixing cement with mud. Mixing of mud and cement in the tubulars can be prevented by use of the two plug system. Before the cement is circulated down the well, a hollow rubber plug (Figure 3.11), with a disk that can be ruptured at high pressure, is placed in front of the cement. The cement pushes this plug down to the bottom of the well, wiping the inside of the casing and displacing the mud from inside the casing ahead of the cement. At the bottom of the well, the plug "lands" or is "bumped" and pressure builds up, rupturing the disk. Cement comes through the plug and can "turn" up the annulus. The second plug is dropped at the end of the calculated cement volume and the cement is displaced down the well with mud or water. The second plug, or top plug, is solid and has the same set of wipers as the first plug. At the bottom of the hole, the top plug reaches the top of the first plug and pressure rises, indicating that the plug has been "bumped." The plugs are made of drillable material that can be easily removed if the well is deepened.

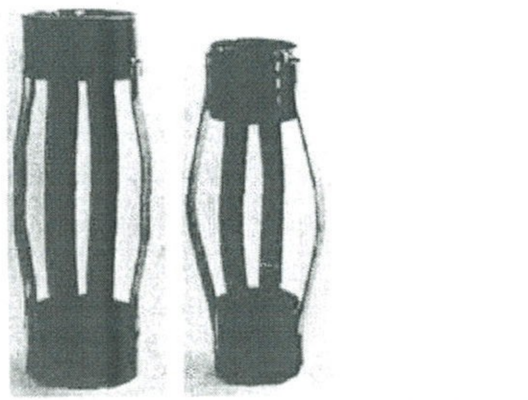
Correct loading of the plugs is critical. If the plug sequence is accidentally reversed and the top plug is dropped first, the job will "end" when this solid plug hits bottom and the casing is left filled with cement.

The actual displacement in the wellbore is very much different than the surface pump rate might indicate, especially when the density of the mud is much less than the density of the cement.[29] When a lighter mud is displaced, the cement is in a "free fall." The cement density is enough to rapidly push the mud ahead and displace it from the well without the driving pressure of the pump.

Maximum Spacing Between
Centralizers, (ft) (Standoff = 1 in.)

*Casing size and **hole size						
Hole Angle	*5-1/2 in. **8-3/4 in.	7 in. 9-5/8 in.	7-5/8 in. 10-3/4 in.	9-5/8 in. 12-1/4 in.	10-3/4 in. 14-3/4 in.	13-3/8 in. 17-1/2 in.
10°	63	62	65	66	73	70
15°	57	53	55	56	60	53
20°	53	49	48	48	50	42
25°	50	45	40	43	40	36
30°	48	42	38	39	37	29
35°	46	38	33	36	33	26
40°	44	35	30	33	30	22
45°	42	33	28	29	27	20
50°	40	30	26	27	25	18

(Brouse, World Oil, 1983)

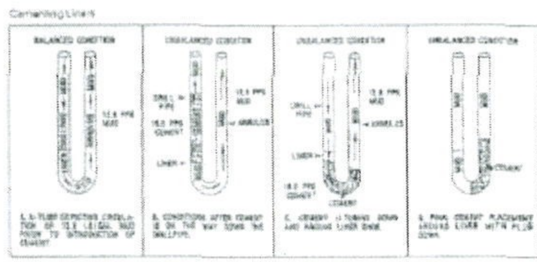


(World Oil, 1988)

Figure 3.10: Examples of centralizers and centralizer spacing.

Figure 3.11: Schematics of the plugs involved in the two plug system. Note the color difference between the plugs. The color makes identification easier when drilling out a problem well where the cement has set p in the pipe.

This is most noticeable in the later stages of the job during displacement when the casing contains more mud than cement. Surface pressure can go to almost zero at low injection rates (the well is said to go on "vacuum"). At this point, the well is taking fluid faster than it is being injected and mud return rate from the well can be more than the cement injection rate (a vacuum, with void space, is being created in the casing at the surface). As the cement turns the corner at the bottom of the well and starts up the annu-lus, the injection pressures caused by the heavier cement density will climb. The well returns, which are monitored continuously at the surface, may go to zero as the cement fills the void volume in the pipe that was evacuated during free fall. It may appear that the well has lost returns by breaking down (fracturing) the formation. This rapid movement of fluids must be included in the design to allow control of the mud. The problems involved with free fall are rapidly increasing bottomhole pressure caused by resistance to faster than design mud flow rates around the shoe and an apparent "loss of returns," as the cement fills the voids created during the initial free fall. An example of a field job showing pump and return rates is shown in Figure 3.12.[29] If, for example, the low rate of returns after 2 hrs, caused the operator to reduce the injection rate in an attempt to limit the apparent "loss" of cement, the cement would not be in turbulent flow and the mud cake might not be cleaned off the formation.[16]



(Mahony & Barrios)

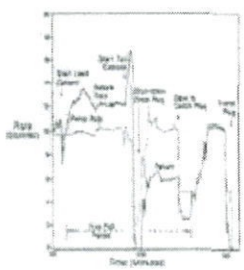


Figure 3.12: The problem of free fall of a heavier cement in a lighter mud system. The upper schematic shows the placement of the 16 lb/gal cement with the lighter mud. The graph at left is a model prediction with measured data from the field (Beirute).

After the plug has been bumped, the waiting-on-cement time, WOC, begins and pressure is held until cement has set. Pressure control is assisted by the float equipment. These devices are flapper or poppet valves near the bottom of the string that prevent the cement from returning to the casing. The oneway valves are of drillable material and are designed to stand the high velocity flow of large quantities of abrasive cement without damaging the sealing mechanism. Examples of the fluat valve are shown in Figure 3.13. If the float is at the end of the casing string, it is called float shoe. If it is placed a joint or two off bottom, then it is called a float collar. The preferred location will depend upon the operator but for reasons of cement contamination control, float collars are usually preferred. The float collar results in a joint or two above the shoe being filled with the last cement pumped. This last cement may be contaminated with residual mud scraped from the casing wall by the top plug. Use of both a float collar and a float shoe are accepted practice in some areas. The dual floats are used as an extra barrier against pressure leak back.

After WOC, drill bit just smaller than the casing id is then run if the well is to be deepened. The hole is drilled through the casing shoe and into the formation beneath this string. At this point, the casing shoe is generally tested to insure that a good, leak-tight cement job has been obtained. If there are leaks during this pressure test, the well is squeezed with cement until a pressure tight seal can be obtained. Since the casing shoe is the weak spot for blowout control, this step is a necessity.

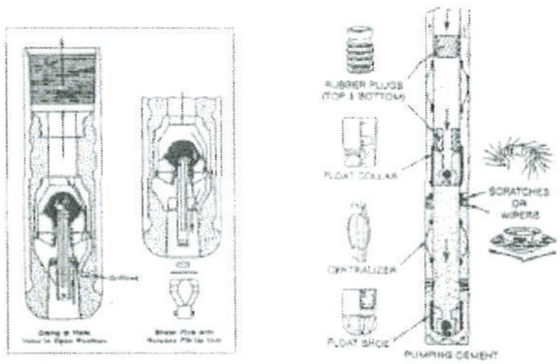


Figure 3.13: Examples of floats and float locations from Smith (SPE). Note that the float collar is located one joint (or more) above the end of the string.

In summary, to properly place a good primary cement job requires several factors: selection of the right cement blend, the conditioning of mud, the removal of mud cake, centralization and movement of the pipe to insure full cement contact around the perimeter of the outside casing wall and use of enough cement to isolate the full zone.

Cementing Calculations

The following calculations follow the formulas used in the cementing monograph.[1]

Buoyant force on the casing by the fluid in the hole tries to float the casing. Hydrostatic pressure acts against the effective area of the casing, causing the upward force. The pressure acts on the full area of the closed end casing if the float is in place and holding or on the area created by do-di if the casing is open ended. The weight of the casing string minus the upward buoyancy force gives the buoyed or true weight of the casing string in the hole.

For 13-3/8 in., 61 lb/ft, K-55 casing in a 17 in. hole, filled with 10 lb/gal mud:

closed end area = π (do2/4) = 141 in.^{2}
effective area = (1/4)π (do^{2}di^2) = 17.5 in.^{2}
hydrostatic at 4000 ft = 4000 ft (10 x 0.052 psi/ft = 2080 psi
hydrostatic effect on casing = 2080 psi x 17.5 in.^{2} = 36,400 lb
casing string weight on air = 61 lb/ft x 4000 ft = 244,000 lb

The buoyed weight of the casing in mud divided by the outside area of the casing gives the pressure needed to balance the string:

207, 600 lb/141 in.^{2} - 1472 psi

Thus, a bottomhole kick or other pressure increase of over 1472 psi (additional 0.368 psi/ft or 7.1 lb/gal) could start the casing moving upwards. At shallower depths, especially with large diameter casing, the additional pressure to lift the buoyed weight can be 100 psi or less.

The pressure to land the top plug when displacing 16 lb/gal cement with fresh water to 4000 ft (assuming complete annulus fill with cement) is:

cement hydrostatic in annuls = 4000 ft x 16 lb/gal x 0.052 psi/lb ft = 3328 psi

water hydrostatic in casing = 4000 ft x 8.33 lb/gal x 0.052 psi gal/lb ft = 1733 psi

pressure to land plug = 3328 -1733 = 1595 psi

In wells where al the exposed formations will not support the full weight of the cement while fracturing, the cement must be lightened or the zone must be protected by only filling the annulus with a partial column of cement (staged cementing).

Assume the zone at 4000 ft (bottomhole) has a fracture gradient of 0.72 psi/ft. Calculate the height of a 16 lb/gal cement column that will be 200 psi below fracturing pressure:

bottomhole frac pressure = 4000 ft x 0.72 psi/ft = 2880 psi

allowable bottomhole pressure = 2880 psi - 200 psi = 2680 psi

cement gradient = 16 lb/gal x 0.052 = 0.832 psi/ft

full column pressure = 4000 ft x 0.832 psi/ft = 3328 psi

If 16 lb/gal cement is used, the maximum column height (within the allowable pressure) is:

column height = 2680 psi/0.832 psi/ft = 3221 ft

If a full cement column is needed, the maximum cement density is:

maximum density = 2680 psi/4000 ft = 0.67 psi/ft or 12.9 lb/gal

Cement densities are only part of the picture, the friction pressures developed by pumping the cement past restrictions adds to the hydrostatistic pressure of the cement.

Balanced Plug Setting

Determining the height that cement will rise where it can equalize height requires use of a simple balanced plug formula.

$$H = N/C+T$$

Where

H = height of balanced cement column,

N = cubic ft of cement slurry pumped,

C = ft^3 per linear ft of annulus,

T = ft^3 per linear ft of tubing.

Squeeze Cementing

Squeeze cementing forces a cement slurry behind the pipe to repair leaks or shut of fluid loss.[31] Squeeze cementing is normally thought to be a repair step, but is also used to seal off depleted zones or unwanted fluid production.

Smith[2] documents eight major uses of squeeze cementing for repair and recovery control purposes:

1. To control high GORs. By squeezing the top section of the perfs, gas production can be made to pass vertically through the top part of the formation matrix, slowing the gas production by the contrast in vertical vs. horizontal permeabilities.

2. To control excessive water, squeezing lower perfs can delay water production. Only if an impenetrable barrier separates the oil and water or if vertical permeability is very low, will effective water reduction be achieved.

3. Repairing casing leaks. Cement can be squeezed through holes in casing. This is best accomplished by very small particle cement.

4. To seal thief zones or lost-circulation zones. Cement slurry may penetrate natural fractures for only a centimeter or two but may develop sufficient blockage to help control leakoff. The cement slurry bridges on the face of the matrix. Sealing off natural fractures is often difficult.

5. To stop fluid migration from a separate zone. This is usually a block squeeze or channel repair operation.

6. Isolation of zones. Selective shutoff of depleted or abnormally low or high pressure zones.

7. Repair of primary cement job. Filling voids or channels, and repair of liner tops are common.
8. Abandonment squeezes. Shutting off depleted reservoirs or protecting fresh water sands.

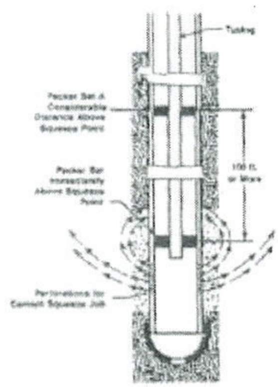
Squeeze cementing is separated into high pressure squeezing and low pressure squeezing.[31,32]

High pressure squeezing involves fracturing the formation with cement until a required surface pressure is reached. The importance of high pressures at the end of the job, although popular with many companies, is actually of little importance and should be well below 1 psi/ft.[32,33] The high pressure squeeze uses "neat" cement (no additives) with very high fluid loss. The best use of the technique is usually to shutoff depleted zones and to seal perforations.[32]

The low pressure squeeze technique is probably more efficient in placing a controlled amount of cement in a problem area of the well. With this technique, formation fracturing is completely avoided. The pressure is achieved by pressuring up on the cement and allowing the cement to filter out on the formation creating a block in the annulus. Once the cement slurry has hardened or dehydrated to a sufficient extent, no more fluid will be displaced. The excess cement that is still the drill pipe or the annulus can be displaced from the well by opening the casing valve and flushing with a displacement fluid. The advantages of the low pressure squeeze are less pressure exposure to tubing and casing and special cementing tools, and a smaller quantity of cement.

For either of the squeeze cementing process, a relatively low water loss, strong cement is part of the design. Most operations use nonretarded API Class A, G or H, which are suitable for squeeze conditions to 6,000 ft without additives. For deeper wells, Class G or H can be retarded to gain necessary pumping time. In hotter wells (above 230°F), additives should be considered at high temperature to increase strength.

Although squeeze cementing is often used to help repair primary cement failures to protect the pipe, it is possible to collapse the casing during squeeze cementing. If a packer is set immediately above the zone to be squeezed and an open channel exists that links the backside of the casing above the packer to the interval being squeezed Figure 3.14, then the outside of the casing above the packer may be exposed to the full pressure of the cement squeeze. If the inside of the casing is not be loaded or pressurized, casing failure can occur if the Ap is above pipe strength.



(Hodges, API, 1959)

Figure 3.14: An illustration of how cement squeezes below a packer can result in casing collapse above the packer. Some zone of communication is required.

The thickening time and set time of cement used in squeeze operations are calculated in the same manner as those used in primary cementing. Squeeze pressure does effect the dehydration of the slurry, particularly across zones which are very permeable. Fluid loss additives may be included if the slurry is designed to move any significant distance across a permeable formation. Normal dehydration of a cement on a permeable section is severe enough to seal off the flow channel before complete displacement is accomplished.

Cement Squeeze Tools

A drillable or retrievable cement retainer is a modified packer that helps control the placement of cement and protects other zones from pressure and excess cement. Retrievable tools can be set and released several items and can be used for several squeeze repairs in one trip. Drillable tools are a single use tool that stays in place and is drilled out (if needed) after the cement has set. The tools are modified packers and are available in compression set and tension set models. Compression set models are normally used below 3000 ft where the weight of the string is adequate to completely engage the slips.

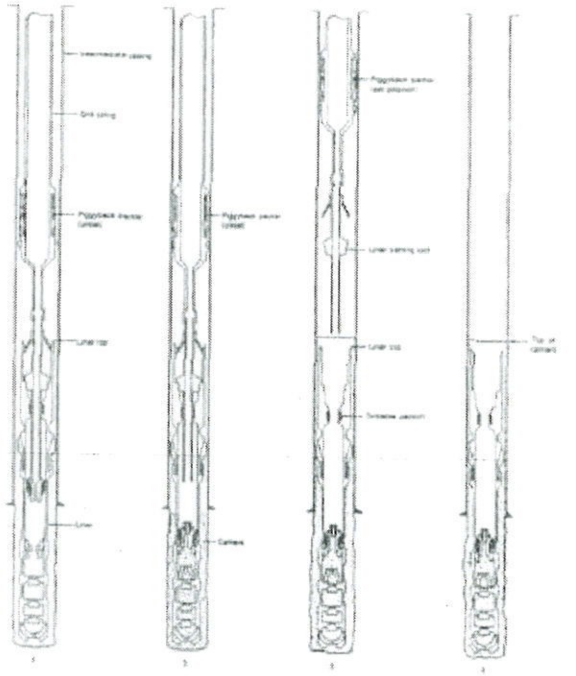
Drillable cement tools are more restricted in setting and application than retrievables but offer more control on the set cement. The drillable models are preferred where continued pressure must be maintained after squeezing.[34]

When squeezing formations that are naturally fractured, it is more important to fill the fractures rather than buildup a filter cake.[1]

Smith[1] cites a two slurry system as successful in fractures: a highly accelerated slurry and a moderate-fluid-loss slurry. Accelerated slurries are pumped into the zones of least resistance and allowed to take an initial set. After the first slurry has gelled, the moderate fluid loss slurry is forced into the narrower fractures. The first slurry used for this type of squeeze should take an initial set 10 to 15 minutes after placement.

Liner Cementing

Cementing of liners requires special equipment and techniques to obtain a seal in the close clearances found between the liner and the open hole or the casing string. For more information, the reader is referred to a set of articles by Bowman and Sherer, published in World Oil.[23, 47-54] Two cementing techniques are use for liner cementing; a modified circulation job (looks much like a cement squeeze) and a puddle cement technique. In the circulation/squeeze, Figure 3.15, the liner and associated equipment is run on drill string with a liner running tool and a retrievable packer assembly. After the base of the liner is squeezed, usually up to the shoe of the outer casing or slightly above, the liner running tool is pulled out of the liner up to a point just above the liner top and the top section of the liner is squeezed. After drillout of the remaining cement, a liner packer, may be run.



(Bowman & Sherrer)

Figure 3.15: Liner cementing sequence.

Cementing liners, especially deep liners at high pressures, is complicated since the liner is often isolated from the rest of the string by packers and close clearances. The result is that pressures are often trapped behind the pipe. Pipe collapse and deformation are common.[45,46] Liner cementing technology is little different from full string technology except that pipe movement (including rotation) is done on drill pipe[40,43] and use of plugs requires two part plugs. Liner tie back operations may require special circulating guidelines because of the narrow clearances.[44]

Liner hanger clearances near the top will be critical in minimizing backpressure if the cement is circulated around the top of the liner in a complete circulation job. Close clearances created by a large liner hanger can raise the backpressure and the equivalent circulation density. In some cases, this increase in equivalent density is enough to fracture the well.

In a puddle job, the cement slurry is spotted by the drill pipe over the section in which the liner is to be run. The volume calculation for the puddle of cement must consider hole volume and liner volume. Undetected washouts in the hole can lead to lack of cement around the liner top. Although the procedure is much simpler than the circulation/squeeze technique, it is also often less effective in providing a seal. The technique is used for short liner sections.

Frictional Pressure Dropin Pipe

The pressure drop of general slurries in pipe is given by:

$$\Delta p_f = \frac{0.039\ L\ \rho v^2 f}{d}$$

where

dpf = friction loss, psi,
L = length of pipe, ft,
p = slurry density, lb/gal,
v = velocity, ft/sec,
f = frictional factor, dimensionless.

The frictional factor is

for general, nonviscous slurries in turbulent flow

$$f = \frac{0.0303}{N_{Re}^{0.1612}}$$

for plug and laminar flow

$$f = \frac{16}{N_{Re}}$$

Reynolds number, N_{Re}, is

$$N_{Re} = \frac{1.86\,V^{2-N'}.\rho}{K'\left(\frac{96}{D}\right)^{N'}}$$

where:

K' = consistency index, lb-sec^{N} per ft^2.
N' = flow behavior index, dimensionless.

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Cementing; Review Questions

1. Calculate the buoyant weight of 9-5/8 in., 47 lb/ft, N-80 casing when 16.4 lb/gal cement just reaches the shoe and there is a 8.33 lb/gal surfactant water flush in the annulus.

2. Derive a formula for the required density of a displacing flush that will give a neutral density with a flush po.

3. For a well with a fracture gradient of 0.6 psi/ft at 7000 ft, calculate the maximum cement height above the zone when using 16.4 lb/gal cement (use a maximum bottomhole pressure of 200 psi below frac pressure).

4. For the example in #3, calculate the cement density that will allow a full cement column to surface (use a maximum bottomhole pressure of 200 psi below frac pressure).

Appendix: 9

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HALLIBURTON CEMENTING TABLES

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Tubing Size
O.D. 1.050"
ONE STRING

TABLE
VOLUME & HEIGHT

Diameter of Hole In.	Gallons Per Lin. Ft.	Lin. Ft. Per Gallon	Barrels Per Lin. Ft.
1½	.0468	21.3594	.0011
⅝	.0628	15.9349	.0015
¾	.0800	12.5050	.0019
⅞	.0985	10.1569	.0023
2	.1182	8.4590	.0028
⅛	.1393	7.1811	.0033
¼	.1616	6.1894	.0038
⅜	.1852	5.4009	.0044
½	.2100	4.7615	.0050
⅝	.2362	4.2345	.0056
¾	.2636	3.7941	.0063
⅞	.2923	3.4217	.0070
3	.3222	3.1035	.0077
⅛	.3535	2.8292	.0084
¼	.3860	2.5909	.0092
⅜	.4198	2.3823	.0100
½	.4548	2.1987	.0108
⅝	.4912	2.0360	.0117
¾	.5288	1.8912	.0126
⅞	.5677	1.7616	.0135
4	.6078	1.6452	.0145
⅛	.6493	1.5402	.0155
¼	.6920	1.4452	.0165
⅜	.7360	1.3588	.0175
½	.7812	1.2801	.0186
⅝	.8278	1.2081	.0197
¾	.8756	1.1421	.0208
⅞	.9247	1.0815	.0220
5	.9750	1.0256	.0232
⅛	1.0267	.9740	.0244
¼	1.0796	.9263	.0257
⅜	1.1338	.8820	.0270
½	1.1892	.8409	.0283
⅝	1.2460	.8026	.0297
¾	1.3040	.7669	.0310
⅞	1.3633	.7335	.0325
6	1.4238	.7023	.0339
⅛	1.4857	.6731	.0354
¼	1.5488	.6457	.0369
⅜	1.6132	.6199	.0384
½	1.6788	.5957	.0400
⅝	1.7458	.5728	.0416
¾	1.8140	.5513	.0432
⅞	1.8835	.5309	.0448
7	1.9542	.5117	.0465
⅛	2.0263	.4935	.0482
¼	2.0996	.4763	.0500
⅜	2.1742	.4599	.0518
½	2.2500	.4444	.0536
⅝	2.3272	.4297	.0554

NO. 122-A
BETWEEN TUBING & HOLE**

Tubing Size
O.D. 1.050"
ONE STRING

Lin. Ft. Per Barrel	Cu. Ft. Per Lin. Ft.	Lin. Ft. Per Cu. Ft.	Diameter of Hole In.
897.0929	.0063	159.7791	1½
669.2656	.0084	119.2013	⅝
525.2114	.0107	93.5441	¾
426.5897	.0132	75.9789	⅞
355.2767	.0158	63.2775	2
301.6046	.0186	53.7181	⅛
259.9531	.0216	46.2996	¼
226.8369	.0248	40.4014	⅜
199.9833	.0281	35.6186	½
177.8493	.0316	31.6763	⅝
159.3520	.0352	28.3818	¾
143.7102	.0391	25.5959	⅞
130.3468	.0431	23.2158	3
118.8271	.0473	21.1640	⅛
108.8176	.0516	19.3812	¼
100.0585	.0561	17.8212	⅜
92.3449	.0608	16.4473	½
85.5128	.0657	15.2305	⅝
79.4301	.0707	14.1471	¾
73.9887	.0759	13.1780	⅞
69.0998	.0813	12.3072	4
64.6896	.0868	11.5217	⅛
60.6966	.0925	10.8105	¼
57.0688	.0984	10.1644	⅜
53.7623	.1044	9.5755	½
50.7397	.1107	9.0371	⅝
47.9690	.1170	8.5436	¾
45.4224	.1236	8.0901	⅞
43.0762	.1303	7.6722	5
40.9096	.1372	7.2863	⅛
38.9045	.1443	6.9292	¼
37.0451	.1516	6.5980	⅜
35.3174	.1590	6.2903	½
33.7091	.1666	6.0039	⅝
32.2095	.1743	5.7367	¾
30.8087	.1822	5.4873	⅞
29.4982	.1903	5.2539	6
28.2704	.1986	5.0352	⅛
27.1184	.2070	4.8300	¼
26.0360	.2156	4.6372	⅜
25.0177	.2244	4.4558	½
24.0584	.2334	4.2850	⅝
23.1537	.2425	4.1239	¾
22.2995	.2518	3.9717	⅞
21.4920	.2612	3.8279	7
20.7279	.2709	3.6918	⅛
20.0042	.2807	3.5629	¼
19.3179	.2906	3.4407	⅜
18.6666	.3008	3.3247	½
18.0478	.3111	3.2145	⅝

**NOTE: No allowance made for couplings.

Tubing Size
O.D. 1.315"
ONE STRING

TABLE VOLUME & HEIGHT

Diameter of Hole In.	Gallons Per Lin. Ft.	Lin. Ft. Per Gallon	Barrels Per Lin. Ft.
1 3/4	.0544	18.3829	.0013
7/8	.0729	13.7201	.0017
2	.0926	10.7935	.0022
1/8	.1137	8.7962	.0027
1/4	.1360	7.3530	.0032
3/8	.1596	6.2662	.0038
1/2	.1844	5.4216	.0044
5/8	.2106	4.7487	.0050
3/4	.2380	4.2017	.0057
7/8	.2667	3.7497	.0063
3	.2966	3.3710	.0071
1/8	.3279	3.0498	.0078
1/4	.3604	2.7747	.0086
3/8	.3942	2.5369	.0094
1/2	.4292	2.3297	.0102
5/8	.4656	2.1478	.0111
3/4	.5032	1.9873	.0120
7/8	.5421	1.8447	.0129
4	.5822	1.7175	.0139
1/8	.6237	1.6034	.0148
1/4	.6664	1.5006	.0159
3/8	.7104	1.4077	.0169
1/2	.7556	1.3234	.0180
5/8	.8022	1.2466	.0191
3/4	.8500	1.1765	.0202
7/8	.8991	1.1122	.0214
5	.9494	1.0532	.0226
1/8	1.0011	.9989	.0238
1/4	1.0540	.9488	.0251
3/8	1.1082	.9024	.0264
1/2	1.1636	.8594	.0277
5/8	1.2204	.8194	.0291
3/4	1.2784	.7822	.0304
7/8	1.3377	.7476	.0318
6	1.3982	.7152	.0333
1/8	1.4601	.6849	.0348
1/4	1.5232	.6565	.0363
3/8	1.5876	.6299	.0378
1/2	1.6532	.6049	.0394
5/8	1.7202	.5813	.0410
3/4	1.7884	.5592	.0426
7/8	1.8579	.5382	.0442
7	1.9286	.5185	.0459
1/8	2.0007	.4998	.0476
1/4	2.0740	.4822	.0494
3/8	2.1486	.4654	.0512
1/2	2.2244	.4496	.0530
5/8	2.3016	.4345	.0548
3/4	2.3800	.4202	.0567
7/8	2.4597	.4066	.0586

NO. 122-A

BETWEEN TUBING & HOLE**

Tubing Size
O.D. 1.315"
ONE STRING

Lin. Ft. Per Barrel	Cu. Ft. Per Lin. Ft.	Lin. Ft. Per Cu. Ft.	Diameter of Hole In.
772.0800	.0073	137.5133	1 3/4
576.2426	.0097	102.6332	7/8
453.3267	.0124	80.7409	2
369.4391	.0152	65.7999	1/8
308.8273	.0182	55.0045	1/4
263.1814	.0213	46.8746	3/8
227.7062	.0247	40.5562	1/2
199.4438	.0282	35.5225	5/8
176.4720	.0318	31.4310	3/4
157.4889	.0357	28.0500	7/8
141.5820	.0397	25.2168	3
128.0935	.0438	22.8144	1/8
116.5379	.0482	20.7563	1/4
106.5489	.0527	18.9772	3/8
97.8456	.0574	17.4270	1/2
90.2091	.0622	16.0669	5/8
83.4662	.0673	14.8660	3/4
77.4786	.0725	13.7995	7/8
72.1343	.0778	12.8477	4
67.3417	.0834	11.9941	1/8
63.0255	.0891	11.2253	1/4
59.1229	.0950	10.5302	3/8
55.5815	.1010	9.8995	1/2
52.3571	.1072	9.3252	5/8
49.4120	.1136	8.8006	3/4
46.7142	.1202	8.3202	7/8
44.2363	.1269	7.8788	5
41.9545	.1338	7.4724	1/8
39.8483	.1409	7.0973	1/4
37.8999	.1481	6.7503	3/8
36.0935	.1556	6.4285	1/2
34.4154	.1631	6.1296	5/8
32.8537	.1709	5.8515	3/4
31.3976	.1788	5.5921	7/8
30.0376	.1869	5.3499	6
28.7655	.1952	5.1234	1/8
27.5736	.2036	4.9111	1/4
26.4553	.2122	4.7119	3/8
25.4046	.2210	4.5248	1/2
24.4160	.2300	4.3487	5/8
23.4848	.2391	4.1828	3/4
22.6064	.2484	4.0264	7/8
21.7770	.2578	3.8786	7
20.9928	.2675	3.7390	1/8
20.2508	.2773	3.6068	1/4
19.5478	.2872	3.4816	3/8
18.8811	.2974	3.3629	1/2
18.2483	.3077	3.2502	5/8
17.6471	.3182	3.1431	3/4
17.0754	.3288	3.0413	7/8

**NOTE: No allowance made for couplings.

Tubing Size
O.D. 1.660"
ONE STRING

TABLE NO. 122-A

VOLUME & HEIGHT BETWEEN TUBING & HOLE**

Diameter of Hole In.	Gallons Per Lin. Ft.	Lin. Ft. Per Gallon	Barrels Per Lin. Ft.	Lin. Ft. Per Barrel	Cu. Ft. Per Lin. Ft.	Lin. Ft. Per Cu. Ft.	Diameter of Hole In.
2 1/8	.0718	13.9259	.0017	584.8861	.0096	104.1727	2 1/8
1/4	.0941	10.6246	.0022	446.2327	.0126	79.4774	1/4
3/8	.1177	8.4955	.0028	356.8129	.0157	63.5511	3/8
1/2	.1426	7.0140	.0034	294.5897	.0191	52.4687	1/2
5/8	.1687	5.9274	.0040	248.9499	.0226	44.3399	5/8
3/4	.1961	5.0989	.0047	214.1534	.0262	38.1424	3/4
7/8	.2248	4.4482	.0054	186.8257	.0301	33.2751	7/8
3	.2548	3.9251	.0061	164.8540	.0341	29.3617	3
1/8	.2860	3.4964	.0068	146.8489	.0382	26.1549	1/8
1/4	.3185	3.1395	.0076	131.8595	.0426	23.4852	1/4
3/8	.3523	2.8384	.0084	119.2138	.0471	21.2329	3/8
1/2	.3874	2.5815	.0092	108.4233	.0518	19.3110	1/2
5/8	.4237	2.3601	.0101	99.1249	.0566	17.6549	5/8
3/4	.4613	2.1677	.0110	91.0430	.0617	16.2155	3/4
7/8	.5002	1.9992	.0119	83.9651	.0669	14.9548	7/8
4	.5404	1.8506	.0129	77.7245	.0722	13.8433	4
1/8	.5818	1.7188	.0139	72.1888	.0778	12.8574	1/8
1/4	.6245	1.6012	.0149	67.2516	.0835	11.9780	1/4
3/8	.6685	1.4959	.0159	62.8265	.0894	11.1899	3/8
1/2	.7138	1.4010	.0170	58.8425	.0954	10.4803	1/2
5/8	.7603	1.3153	.0181	55.2408	.1016	9.8388	5/8
3/4	.8081	1.2374	.0192	51.9725	.1080	9.2567	3/4
7/8	.8572	1.1666	.0204	48.9963	.1146	8.7266	7/8
5	.9076	1.1018	.0216	46.2775	.1213	8.2424	5
1/8	.9592	1.0425	.0228	43.7862	.1282	7.7987	1/8
1/4	1.0121	.9880	.0241	41.4971	.1353	7.3909	1/4
3/8	1.0663	.9378	.0254	39.3883	.1425	7.0154	3/8
1/2	1.1218	.8914	.0267	37.4409	.1500	6.6685	1/2
5/8	1.1785	.8485	.0281	35.6383	.1575	6.3475	5/8
3/4	1.2365	.8087	.0294	33.9663	.1653	6.0497	3/4
7/8	1.2958	.7717	.0309	32.4123	.1732	5.7729	7/8
6	1.3564	.7373	.0323	30.9650	.1813	5.5151	6
1/8	1.4182	.7051	.0338	29.6149	.1895	5.2746	1/8
1/4	1.4813	.6751	.0353	28.3531	.1980	5.0499	1/4
3/8	1.5457	.6470	.0368	27.1721	.2066	4.8396	3/8
1/2	1.6114	.6206	.0384	26.0648	.2154	4.6423	1/2
5/8	1.6783	.5958	.0400	25.0252	.2244	4.4572	5/8
3/4	1.7465	.5726	.0416	24.0479	.2335	4.2831	3/4
7/8	1.8160	.5507	.0432	23.1277	.2428	4.1192	7/8
7	1.8868	.5300	.0449	22.2603	.2522	3.9647	7
1/8	1.9588	.5105	.0466	21.4417	.2619	3.8189	1/8
1/4	2.0321	.4921	.0484	20.6681	.2717	3.6811	1/4
3/8	2.1067	.4747	.0502	19.9364	.2816	3.5508	3/8
1/2	2.1826	.4582	.0520	19.2434	.2918	3.4274	1/2
5/8	2.2597	.4425	.0538	18.5865	.3021	3.3104	5/8
3/4	2.3381	.4277	.0557	17.9632	.3126	3.1994	3/4
7/8	2.4178	.4136	.0576	17.3711	.3232	3.0939	7/8
8	2.4988	.4002	.0595	16.8083	.3340	2.9937	8
1/8	2.5810	.3874	.0615	16.2727	.3450	2.8983	1/8
1/4	2.6645	.3753	.0634	15.7627	.3562	2.8075	1/4

**NOTE No allowance made for couplings.

122

Tubing Size
O.D. 1.900"
ONE STRING

TABLE
VOLUME & HEIGHT

Diameter of Hole In	Gallons Per Lin. Ft.	Lin. Ft. Per Gallon	Barrels Per Lin. Ft.
2 3/8	.0828	12.0701	.0020
1/2	.1077	9.2840	.0026
5/8	.1338	7.4711	.0032
3/4	.1613	6.2011	.0038
7/8	.1899	5.2646	.0045
3	.2199	4.5473	.0052
1/8	.2511	3.9817	.0060
1/4	.2837	3.5253	.0068
3/8	.3174	3.1501	.0076
1/2	.3525	2.8368	.0084
5/8	.3888	2.5717	.0093
3/4	.4265	2.3449	.0102
7/8	.4653	2.1489	.0111
4	.5055	1.9782	.0120
1/8	.5469	1.8283	.0130
1/4	.5897	1.6959	.0140
3/8	.6336	1.5782	.0151
1/2	.6789	1.4729	.0162
5/8	.7254	1.3785	.0173
3/4	.7733	1.2932	.0184
7/8	.8223	1.2160	.0196
5	.8727	1.1459	.0208
1/8	.9243	1.0818	.0220
1/4	.9773	1.0233	.0233
3/8	1.0314	.9695	.0246
1/2	1.0869	.9200	.0259
5/8	1.1436	.8744	.0272
3/4	1.2017	.8322	.0286
7/8	1.2609	.7931	.0300
6	1.3215	.7567	.0315
1/8	1.3833	.7229	.0329
1/4	1.4465	.6913	.0344
3/8	1.5108	.6619	.0360
1/2	1.5765	.6343	.0375
5/8	1.6434	.6085	.0391
3/4	1.7117	.5842	.0408
7/8	1.7811	.5614	.0424
7	1.8519	.5400	.0441
1/8	1.9239	.5198	.0458
1/4	1.9973	.5007	.0476
3/8	2.0718	.4827	.0493
1/2	2.1477	.4656	.0511
5/8	2.2248	.4495	.0530
3/4	2.3033	.4342	.0548
7/8	2.3829	.4196	.0567
8	2.4639	.4059	.0587
1/8	2.5461	.3928	.0606
1/4	2.6297	.3803	.0626
3/8	2.7144	.3684	.0646
1/2	2.8005	.3571	.0667

NO. 122-A
BETWEEN TUBING & HOLE**

Tubing Size
O.D. 1.900"
ONE STRING

Lin. Ft. Per Barrel	Cu. Ft. Per Lin. Ft.	Lin. Ft. Per Cu. Ft.	Diameter of Hole In.
506.9445	.0111	90.2907	2 3/8
389.9296	.0144	69.4494	1/2
313.7860	.0179	55.8877	5/8
260.4464	.0216	46.3875	3/4
221.1119	.0254	39.3817	7/8
190.9859	.0294	34.0160	3
167.2315	.0336	29.7852	1/8
148.0639	.0379	26.3713	1/4
132.3048	.0424	23.5645	3/8
119.1452	.0471	21.2207	1/2
108.0112	.0520	19.2376	5/8
98.4850	.0570	17.5409	3/4
90.2550	.0622	16.0751	7/8
83.0843	.0676	14.7979	4
76.7897	.0731	13.6768	1/8
71.2274	.0788	12.6861	1/4
66.2829	.0847	11.8055	3/8
61.8638	.0908	11.0184	1/2
57.8953	.0970	10.3116	5/8
54.3155	.1034	9.6740	3/4
51.0733	.1099	9.0965	7/8
48.1260	.1167	8.5716	5
45.4375	.1236	8.0928	1/8
42.9773	.1306	7.6546	1/4
40.7195	.1379	7.2525	3/8
38.6417	.1453	6.8824	1/2
36.7246	.1529	6.5409	5/8
34.9517	.1606	6.2252	3/4
33.3083	.1686	5.9325	7/8
31.7819	.1767	5.6606	6
30.3612	.1849	5.4076	1/8
29.0364	.1934	5.1716	1/4
27.7990	.2020	4.9512	3/8
26.6412	.2107	4.7450	1/2
25.5561	.2197	4.5517	5/8
24.5376	.2288	4.3703	3/4
23.5803	.2381	4.1998	7/8
22.6793	.2476	4.0394	7
21.8301	.2572	3.8881	1/8
21.0288	.2670	3.7454	1/4
20.2718	.2770	3.6106	3/8
19.5557	.2871	3.4830	1/2
18.8777	.2974	3.3623	5/8
18.2351	.3079	3.2478	3/4
17.6253	.3186	3.1392	7/8
17.0461	.3294	3.0360	8
16.4955	.3404	2.9380	1/8
15.9717	.3515	2.8447	1/4
15.4728	.3629	2.7558	3/8
14.9973	.3744	2.6711	1/2

**NOTE: No allowance made for couplings.

Tubing Size
O.D. 2.063"
ONE STRING

TABLE VOLUME & HEIGHT

Diameter of Hole In.	Gallons Per Lin. Ft.	Lin. Ft. Per Gallon	Barrels Per Lin. Ft.
2 1/2	.0814	12.2912	.0019
5/8	.1075	9.3026	.0026
3/4	.1349	7.4124	.0032
7/8	.1636	6.1126	.0039
3	.1936	5.1664	.0046
1/8	.2248	4.4485	.0054
1/4	.2573	3.8864	.0061
3/8	.2911	3.4353	.0069
1/2	.3262	3.0660	.0078
5/8	.3625	2.7587	.0086
3/4	.4001	2.4993	.0095
7/8	.4390	2.2779	.0105
4	.4792	2.0870	.0114
1/8	.5206	1.9209	.0124
1/4	.5633	1.7752	.0134
3/8	.6073	1.6466	.0145
1/2	.6526	1.5324	.0155
5/8	.6991	1.4304	.0166
3/4	.7469	1.3389	.0178
7/8	.7960	1.2563	.0190
5	.8464	1.1815	.0202
1/8	.8980	1.1136	.0214
1/4	.9509	1.0516	.0226
3/8	1.0051	.9949	.0239
1/2	1.0606	.9429	.0253
5/8	1.1173	.8950	.0266
3/4	1.1753	.8508	.0280
7/8	1.2346	.8100	.0294
6	1.2952	.7721	.0308
1/8	1.3570	.7369	.0323
1/4	1.4201	.7042	.0338
3/8	1.4845	.6736	.0353
1/2	1.5502	.6451	.0369
5/8	1.6171	.6184	.0385
3/4	1.6853	.5934	.0401
7/8	1.7548	.5699	.0418
7	1.8256	.5478	.0435
1/8	1.8976	.5270	.0452
1/4	1.9709	.5074	.0469
3/8	2.0455	.4889	.0487
1/2	2.1214	.4714	.0505
5/8	2.1985	.4549	.0523
3/4	2.2769	.4392	.0542
7/8	2.3566	.4243	.0561
8	2.4376	.4102	.0580
1/8	2.5198	.3969	.0600
1/4	2.6033	.3841	.0620
3/8	2.6881	.3720	.0640
1/2	2.7742	.3605	.0661
5/8	2.8615	.3495	.0681

NO. 122-A BETWEEN TUBING & HOLE**

Tubing Size
O.D. 2.063"
ONE STRING

Lin. Ft. Per Barrel	Cu. Ft. Per Lin. Ft.	Lin. Ft. Per Cu. Ft.	Diameter of Hole In.
516.2300	.0109	91.9445	2 1/2
390.7103	.0144	69.5885	5/8
311.3211	.0180	55.4487	3/4
256.7294	.0219	45.7255	7/8
216.9883	.0259	38.6473	3
186.8359	.0301	33.2769	1/8
163.2281	.0344	29.0722	1/4
144.2823	.0389	25.6978	3/8
128.7717	.0436	22.9352	1/2
115.8634	.0485	20.6361	5/8
104.9716	.0535	18.6962	3/4
95.6729	.0587	17.0401	7/8
87.6537	.0641	15.6118	4
80.6768	.0696	14.3692	1/8
74.5596	.0753	13.2796	1/4
69.1591	.0812	12.3178	3/8
64.3621	.0872	11.4634	1/2
60.0777	.0935	10.7003	5/8
56.2319	.0998	10.0153	3/4
52.7642	.1064	9.3977	7/8
49.6244	.1131	8.8385	5
46.7709	.1200	8.3302	1/8
44.1684	.1271	7.8667	1/4
41.7871	.1344	7.4426	3/8
39.6018	.1418	7.0534	1/2
37.5908	.1494	6.6952	5/8
35.7354	.1571	6.3647	3/4
34.0193	.1650	6.0591	7/8
32.4285	.1731	5.7758	6
30.9508	.1814	5.5126	1/8
29.5753	.1898	5.2676	1/4
28.2925	.1984	5.0391	3/8
27.0941	.2072	4.8257	1/2
25.9725	.2162	4.6259	5/8
24.9213	.2253	4.4387	3/4
23.9345	.2346	4.2629	7/8
23.0067	.2440	4.0977	7
22.1333	.2537	3.9421	1/8
21.3100	.2635	3.7955	1/4
20.5330	.2734	3.6571	3/8
19.7987	.2836	3.5263	1/2
19.1040	.2939	3.4026	5/8
18.4461	.3044	3.2854	3/4
17.8224	.3150	3.1743	7/8
17.2304	.3259	3.0689	8
16.6681	.3368	2.9687	1/8
16.1333	.3480	2.8735	1/4
15.6245	.3593	2.7828	3/8
15.1398	.3709	2.6965	1/2
14.6777	.3825	2.6142	5/8

**NOTE. No allowance made for couplings.

Tubing Size
O.D. 2.375"
ONE STRING

TABLE
VOLUME & HEIGHT

Diameter of Hole In.	Gallons Per Lin. Ft.	Lin. Ft. Per Gallon	Barrels Per Lin. Ft.
3 1/2	.2697	3.7083	.0064
5/8	.3060	3.2680	.0073
3/4	.3436	2.9103	.0082
7/8	.3825	2.6144	.0091
4	.4227	2.3660	.0101
1/8	.4641	2.1547	.0110
1/4	.5068	1.9731	.0121
3/8	.5508	1.8155	.0131
1/2	.5961	1.6777	.0142
5/8	.6426	1.5562	.0153
3/4	.6904	1.4484	.0164
7/8	.7395	1.3523	.0176
5	.7899	1.2660	.0188
1/8	.8415	1.1884	.0200
1/4	.8944	1.1181	.0213
3/8	.9486	1.0542	.0226
1/2	1.0041	.9960	.0239
5/8	1.0608	.9427	.0253
3/4	1.1188	.8938	.0266
7/8	1.1781	.8488	.0280
6	1.2387	.8073	.0295
1/8	1.3005	.7689	.0310
1/4	1.3636	.7333	.0325
3/8	1.4280	.7003	.0340
1/2	1.4937	.6695	.0356
5/8	1.5606	.6408	.0372
3/4	1.6288	.6139	.0388
7/8	1.6983	.5888	.0404
7	1.7691	.5653	.0421
1/8	1.8411	.5432	.0438
1/4	1.9144	.5224	.0456
3/8	1.9890	.5028	.0474
1/2	2.0649	.4843	.0492
5/8	2.1420	.4669	.0510
3/4	2.2204	.4504	.0529
7/8	2.3001	.4348	.0548
8	2.3811	.4200	.0567
1/8	2.4633	.4060	.0586
1/4	2.5468	.3926	.0606
3/8	2.6316	.3800	.0627
1/2	2.7177	.3680	.0647
5/8	2.8050	.3565	.0668
3/4	2.8936	.3456	.0689
7/8	2.9835	.3352	.0710
9	3.0747	.3252	.0732
1/8	3.1671	.3157	.0754
1/4	3.2608	.3067	.0776
3/8	3.3558	.2980	.0799
1/2	3.4521	.2897	.0822

NO. 122-A
BETWEEN TUBING & HOLE**

Tubing Size
O.D. 2.375"
ONE STRING

Lin. Ft. Per Barrel	Cu. Ft. Per Lin. Ft.	Lin. Ft. Per Cu. Ft.	Diameter of Hole In.
155.7506	.0360	27.7404	3 1/2
137.2552	.0409	24.4462	5/8
122.2310	.0459	21.7703	3/4
109.8042	.0511	19.5570	7/8
99.3703	.0565	17.6986	4
90.4979	.0620	16.1184	1/8
82.8711	.0678	14.7600	1/4
76.2529	.0736	13.5812	3/8
70.4626	.0797	12.5499	1/2
65.3596	.0859	11.6410	5/8
60.8333	0923	10.8349	3/4
56.7953	0989	10.1157	7/8
53.1739	.1056	9.4707	5
49.9110	.1125	8.8895	1/8
46.9583	.1196	8.3636	1/4
44.2759	.1268	7.8859	3/8
41.8302	.1342	7.4503	1/2
39.5929	.1418	7.0518	5/8
37.5399	.1496	6.6861	3/4
35.6507	.1575	6.3497	7/8
33.9076	.1656	6.0392	6
32.2953	.1739	5.7520	1/8
30.8006	.1823	5.4858	1/4
29.4118	.1909	5.2385	3/8
28.1189	.1997	5.0082	1/2
26.9128	.2086	4.7934	5/8
25.7857	.2177	4.5926	3/4
24.7307	.2270	4.4047	7/8
23.7414	.2365	4.2285	7
22.8125	.2461	4.0631	1/8
21.9389	.2559	3.9075	1/4
21.1162	.2659	3.7610	3/8
20.3404	.2760	3.6228	1/2
19.6079	.2863	3.4923	5/8
18.9154	.2968	3.3690	3/4
18.2601	.3075	3.2523	7/8
17.6392	.3183	3.1417	8
17.0503	.3293	3.0368	1/8
16.4912	.3405	2.9372	1/4
15.9599	.3518	2.8426	3/8
15.4545	.3633	2.7526	1/2
14.9733	.3750	2.6669	5/8
14.5148	.3868	2.5852	3/4
14.0775	.3988	2.5073	7/8
13.6601	.4110	2.4330	9
13.2614	.4234	2.3620	1/8
12.8803	.4359	2.2941	1/4
12.5157	.4486	2.2291	3/8
12.1667	.4615	2.1670	1/2

**NOTE: No allowance made for couplings.

Tubing Size
O.D. 2.875"
ONE STRING

TABLE
VOLUME & HEIGHT

Diameter of Hole In.	Gallons Per Lin. Ft.	Lin. Ft. Per Gallon	Barrels Per Lin. Ft.
3 1/2	.1626	6.1515	.0039
5/8	.1989	5.0277	.0047
3/4	.2365	4.2281	.0056
7/8	.2754	3.6311	.0066
4	.3156	3.1690	.0075
1/8	.3570	2.8011	.0085
1/4	.3997	2.5018	.0095
3/8	.4437	2.2538	.0106
1/2	.4890	2.0452	.0116
5/8	.5355	1.8674	.0127
3/4	.5833	1.7144	.0139
7/8	.6324	1.5813	.0151
5	.6828	1.4646	.0163
1/8	.7344	1.3617	.0175
1/4	.7873	1.2701	.0187
3/8	.8415	1.1884	.0200
1/2	.8970	1.1149	.0214
5/8	.9537	1.0486	.0227
3/4	1.0117	.9884	.0241
7/8	1.0710	.9337	.0255
6	1.1316	.8837	.0269
1/8	1.1934	.8379	.0284
1/4	1.2565	.7959	.0299
3/8	1.3209	.7571	.0314
1/2	1.3866	.7212	.0330
5/8	1.4535	.6880	.0346
3/4	1.5217	.6572	.0362
7/8	1.5912	.6285	.0379
7	1.6620	.6017	.0396
1/8	1.7340	.5767	.0413
1/4	1.8073	.5533	.0430
3/8	1.8819	.5314	.0448
1/2	1.9578	.5108	.0466
5/8	2.0349	.4914	.0484
3/4	2.1133	.4732	.0503
7/8	2.1930	.4560	.0522
8	2.2740	.4398	.0541
1/8	2.3562	.4244	.0561
1/4	2.4397	.4099	.0581
3/8	2.5245	.3961	.0601
1/2	2.6106	.3831	.0622
5/8	2.6979	.3707	.0642
3/4	2.7865	.3589	.0663
7/8	2.8764	.3477	.0685
9	2.9676	.3370	.0707
1/8	3.0600	.3268	.0729
1/4	3.1537	.3171	.0751
3/8	3.2487	.3078	.0773
1/2	3.3450	.2990	.0796

Tubing Size
O.D. 2.875"
ONE STRING

NO. 122-A
BETWEEN TUBING & HOLE**

Lin. Ft. Per Barrel	Cu. Ft. Per Lin. Ft.	Lin. Ft. Per Cu. Ft.	Diameter of Hole In.
258.3628	.0217	46.0164	3 1/2
211.1619	.0266	37.6095	5/8
177.5809	.0316	31.6285	3/4
152.5058	.0368	27.1624	7/8
133.0960	.0422	23.7054	4
117.6473	.0477	20.9539	1/8
105.0758	.0534	18.7148	1/4
94.6588	.0593	16.8594	3/8
85.8964	.0654	15.2988	1/2
78.4316	.0716	13.9693	5/8
72.0027	.0780	12.8242	3/4
66.4138	.0845	11.8288	7/8
61.5149	.0913	10.9563	5
57.1897	.0982	10.1859	1/8
53.3462	.1052	9.5014	1/4
49.9110	.1125	8.8895	3/8
46.8248	.1199	8.3399	1/2
44.0391	.1275	7.8437	5/8
41.5139	.1352	7.3939	3/4
39.2158	.1432	6.9846	7/8
37.1169	.1513	6.6108	6
35.1936	.1595	6.2683	1/8
33.4259	.1680	5.9534	1/4
31.7966	.1766	5.6632	3/8
30.2908	.1854	5.3950	1/2
28.8958	.1943	5.1466	5/8
27.6005	.2034	4.9159	3/4
26.3952	.2127	4.7012	7/8
25.2714	.2222	4.5010	7
24.2215	.2318	4.3140	1/8
23.2390	.2416	4.1390	1/4
22.3179	.2516	3.9750	3/8
21.4531	.2617	3.8210	1/2
20.6399	.2720	3.6761	5/8
19.8741	.2825	3.5397	3/4
19.1519	.2932	3.4111	7/8
18.4700	.3040	3.2896	8
17.8254	.3150	3.1748	1/8
17.2152	.3261	3.0662	1/4
16.6370	.3375	2.9632	3/8
16.0885	.3490	2.8655	1/2
15.5677	.3607	2.7727	5/8
15.0726	.3725	2.6846	3/4
14.6016	.3845	2.6007	7/8
14.1531	.3967	2.5208	9
13.7255	.4091	2.4446	1/8
13.3177	.4216	2.3720	1/4
12.9283	.4343	2.3026	3/8
12.5562	.4472	2.2364	1/2

**NOTE. No allowance made for couplings.

Tubing Size
O.D. 3.500"
ONE STRING

TABLE
VOLUME & HEIGHT

Diameter of Hole Ins.	Gallons Per Lin. Ft.	Lin. Ft. Per Gallon	Barrels Per Lin. Ft.
4	.1530	6.5360	.0036
1/8	.1944	5.1431	.0046
1/4	.2371	4.2168	.0056
3/8	.2811	3.5570	.0067
1/2	.3264	3.0637	.0078
5/8	.3729	2.6814	.0089
3/4	.4207	2.3767	.0100
7/8	.4698	2.1284	.0112
5	.5202	1.9223	.0124
1/8	.5718	1.7488	.0136
1/4	.6247	1.6006	.0149
3/8	.6789	1.4729	.0162
1/2	7344	1.3617	.0175
5/8	7911	1.2640	.0188
3/4	8491	1.1777	.0202
7/8	9084	1.1008	.0216
6	.9690	1.0320	.0231
1/8	1 0308	.9701	.0245
1/4	1 0939	.9141	.0260
3/8	1.1583	.8633	.0276
1/2	1 2240	8170	.0291
5/8	1 2909	.7746	.0307
3/4	1 3591	.7358	.0324
7/8	1 4286	.7000	.0340
7	1 4994	.6669	.0357
1/8	1.5714	.6364	.0374
1/4	1.6447	.6080	.0392
3/8	1.7193	.5816	.0409
1/2	1 7952	.5570	.0427
5/8	1 8723	.5341	.0446
3/4	1 9507	.5126	.0464
7/8	2 0304	.4925	.0483
8	2 1114	.4736	.0503
1/8	2.1936	.4559	.0522
1/4	2.2771	.4391	.0542
3/8	2.3619	.4234	.0562
1/2	2.4480	.4085	.0583
5/8	2.5353	.3944	.0604
3/4	2.6239	.3811	.0625
7/8	2.7138	.3685	.0646
9	2 8050	.3565	.0668
1/8	2.8974	.3451	.0690
1/4	2.9911	.3343	0712
3/8	3.0861	.3240	.0735
1/2	3 1824	.3142	0758
5/8	3 2799	.3049	0781
3/4	3.3787	.2960	.0804
7/8	3.4788	.2875	.0828
10	3.5802	.2793	.0852

NO. 122-A
BETWEEN TUBING & HOLE**

Tubing Size
O.D. 3.500"
ONE STRING

Lin. Ft. Per Barrel	Cu. Ft. Per Lin. Ft.	Lin. Ft. Per Cu. Ft.	Diameter of Hole In.
274.5104	.0205	48.8924	4
216.0082	.0260	38.4727	1/8
177.1035	.0317	31.5435	1/4
149.3934	.0376	26.6081	3/8
128.6768	.0436	22.9183	1/2
112.6197	.0499	20.0584	5/8
99.8220	.0562	17.7791	3/4
89.3928	.0628	15.9215	7/8
80.7384	.0695	14.3801	5
73.4475	.0764	13.0816	1/8
67.2270	.0835	11.9736	1/4
61.8615	.0908	11.0180	3/8
57.1897	.0982	10.1859	1/2
53.0882	.1058	9.4554	5/8
49.4613	.1135	8.8094	3/4
46.2333	.1214	8.2345	7/8
43.3438	.1295	7.7199	6
40.7437	.1378	7.2568	1/8
38.3931	.1462	6.8381	1/4
36.2589	.1548	6.4580	3/8
34.3138	.1636	6.1115	1/2
32.5346	.1726	5.7947	5/8
30.9017	.1617	5.5038	3/4
29.3987	.1910	5.2361	7/8
28.0113	.2004	4.9890	7
26.7272	.2101	4.7603	1/8
25.5359	.2199	4.5481	1/4
24.4281	.2298	4.3508	3/8
23.3958	.2400	4.1670	1/2
22.4319	.2503	3.9953	5/8
21.5302	.2608	3.8347	3/4
20.6852	.2714	3.6842	7/8
19.8921	.2823	3.5429	8
19.1463	.2932	3.4101	1/8
18.4442	.3044	3.2850	1/4
17.7821	.3157	3.1671	3/8
17.1569	.3272	3.0558	1/2
16.5659	.3389	2.9505	5/8
16.0064	.3508	2.8509	3/4
15.4763	.3628	2.7564	7/8
14.9733	.3750	2.6669	9
14.4956	.3873	2.5818	1/8
14.0415	.3999	2.5009	1/4
13.6093	.4126	2.4239	3/8
13.1976	.4254	2.3506	1/2
12.8052	.4385	2.2807	5/8
12.4307	.4517	2.2140	3/4
12.0730	.4651	2.1503	7/8
11.7312	.4786	2.0894	10

**NOTE — No allowance made for couplings.

Tubing or Csg. Size
O.D. 4½"
4.500"

TABLE NO. 122-A

VOLUME & HEIGHT BETWEEN

Diameter of Hole In.	Gallons Per Lin. Ft.	Lin. Ft. Per Gallon	Barrels Per Lin. Ft.
5	.1938	5.1600	.0046
1/8	.2454	4.0744	.0058
1/4	.2983	3.3518	.0071
3/8	.3525	2.8366	.0084
1/2	.4080	2.4510	.0097
5/8	.4647	2.1518	.0111
3/4	.5227	1.9130	.0124
7/8	.5820	1.7181	.0139
6	.6426	1.5562	.0153
1/8	.7044	1.4196	.0168
1/4	.7675	1.3029	.0183
3/8	.8319	1.2020	.0198
1/2	.8976	1.1141	.0214
5/8	.9645	1.0368	.0230
3/4	1.0327	.9683	.0246
7/8	1.1022	.9072	.0262
7	1.1730	.8525	.0279
1/8	1.2450	.8032	.0296
1/4	1.3183	.7585	.0314
3/8	1.3929	.7179	.0332
1/2	1.4688	.6808	.0350
5/8	1.5459	.6469	.0368
3/4	1.6243	.6156	.0387
7/8	1.7040	.5868	.0406
8	1.7850	.5602	.0425
1/8	1.8672	.5356	.0445
1/4	1.9507	.5126	.0464
3/8	2.0355	.4913	.0485
1/2	2.1216	.4713	.0505
5/8	2.2089	.4527	.0526
3/4	2.2975	.4352	.0547
7/8	2.3874	.4189	.0568
9	2.4786	.4035	.0590
1/8	2.5710	.3889	.0612
1/4	2.6647	.3753	.0634
3/8	2.7597	.3624	.0657
1/2	2.8560	.3501	.0680
5/8	2.9535	.3386	.0703
3/4	3.0523	.3276	.0727
7/8	3.1524	.3172	.0751
10	3.2538	.3073	.0775
1/8	3.3564	.2979	.0799
1/4	3.4603	.2890	.0824
3/8	3.5655	.2805	.0849
1/2	3.6720	.2723	.0874
5/8	3.7797	.2646	.0900
3/4	3.8887	.2572	.0926
7/8	3.9990	.2501	.0952

AND NO. 122-B

Tubing or Csg. Size O.D. 4½" 4.500"

{O.D. 4½"-4.500" Tubing or 4½" O.D. 4.500" Casing} & HOLE**

Lin. Ft. Per Barrel	Cu. Ft. Per Lin. Ft.	Lin. Ft. Per Cu. Ft.	Diameter of Hole In.
216.7189	.0259	38.5993	5
171.1235	.0328	30.4784	1/8
140.7747	.0399	25.0730	1/4
119.1306	.0471	21.2191	3/8
102.9415	.0545	18.3347	1/2
90.3739	.0621	16.0963	5/8
80.3446	.0699	14.3100	3/4
72.1605	.0778	12.8523	7/8
65.3597	.0859	11.6411	6
59.6222	.0942	10.6192	1/8
54.7197	.1026	9.7460	1/4
50.4847	.1112	8.9917	3/8
46.7916	.1200	8.3339	1/2
43.5443	.1289	7.7556	5/8
40.6682	.1381	7.2433	3/4
38.1044	.1473	6.7867	7/8
35.8057	.1568	6.3773	7
33.7340	.1664	6.0083	1/8
31.8581	.1762	5.6742	1/4
30.1522	.1862	5.3703	3/8
28.5949	.1963	5.0930	1/2
27.1681	.2067	4.8388	5/8
25.8606	.2171	4.6053	3/4
24.6474	.2278	4.3899	7/8
23.5295	.2386	4.1908	8
22.4932	.2496	4.0062	1/8
21.5302	.2608	3.8347	1/4
20.6334	.2721	3.6750	3/8
19.7964	.2836	3.5259	1/2
19.0137	.2953	3.3865	5/8
18.2804	.3071	3.2559	3/4
17.5921	.3192	3.1333	7/8
16.9451	.3313	3.0181	9
16.3359	.3437	2.9095	1/8
15.7614	.3562	2.8072	1/4
15.2189	.3689	2.7106	3/8
14.7059	.3818	2.6192	1/2
14.2203	.3948	2.5327	5/8
13.7599	.4080	2.4507	3/4
13.3231	.4214	2.3729	7/8
12.9080	.4350	2.2990	10
12.5133	.4487	2.2287	1/8
12.1375	.4626	2.1618	1/4
11.7795	.4766	2.0980	3/8
11.4379	.4909	2.0372	1/2
11.1119	.5053	1.9791	5/8
10.8004	.5198	1.9236	3/4
10.5026	.5346	1.8706	7/8

**NOTE. No allowance made for couplings.

Tubing or Csg. Size
O.D. 4½"
4.500"

TABLE NO. 122-A

VOLUME & HEIGHT BETWEEN

Diameter of Hole In.	Gallons Per Lin. Ft.	Lin. Ft. Per Gallon	Barrels Per Lin. Ft.
11	4.1106	.2433	.0979
⅛	4.2234	.2368	.1006
¼	4.3375	.2305	.1033
⅜	4.4529	.2246	.1060
½	4.5696	.2188	.1088
⅝	4.6875	.2133	.1116
¾	4.8067	.2080	.1144
⅞	4.9272	.2030	.1173
12	5.0490	.1981	.1202
⅛	5.1720	.1933	.1231
¼	5.2963	.1888	.1261
⅜	5.4219	.1844	.1291
½	5.5488	.1802	.1321
⅝	5.6769	.1762	.1352
¾	5.8063	.1722	.1382
⅞	5.9370	.1684	.1414
13	6.0690	.1648	.1445
⅛	6.2022	.1612	.1477
¼	6.3367	.1578	.1509
⅜	6.4725	.1545	.1541
½	6.6096	.1513	.1574
⅝	6.7479	.1482	.1607
¾	6.8875	.1452	.1640
⅞	7.0284	.1423	.1673
14	7.1706	.1395	.1707
⅛	7.3140	.1367	.1741
¼	7.4587	.1341	.1776
⅜	7.6047	.1315	.1811
½	7.7520	.1290	.1846
⅝	7.9005	.1266	.1881
¾	8.0503	.1242	.1917
⅞	8.2014	.1219	.1953
15	8.3538	.1197	.1989
⅛	8.5074	.1175	.2026
¼	8.6623	.1154	.2062
⅜	8.8185	.1134	.2100
½	8.9760	.1114	.2137
⅝	9.1347	.1095	.2175
¾	9.2947	.1076	.2213
⅞	9.4560	.1058	.2251
16	9.6186	.1040	.2290

AND NO. 122-B

Tubing or Csg. Size

{ O.D. 4½"-4.500" Tubing or 4½" O.D. 4.500" Casing } & HOLE** O.D. 4½" 4.500"

Lin. Ft. Per Barrel	Cu. Ft. Per Lin. Ft.	Lin. Ft. Per Cu. Ft.	Diameter of Hole In.
10.2175	.5495	1.8198	11
9.9445	.5646	1.7712	⅛
9.6829	.5798	1.7246	¼
9.4320	.5953	1.6799	⅜
9.1912	.6109	1.6370	½
8.9600	.6266	1.5958	⅝
8.7377	.6426	1.5563	¾
8.5241	.6587	1.5182	⅞
8.3185	.6750	1.4816	12
8.1206	.6914	1.4463	⅛
7.9300	.7080	1.4124	¼
7.7463	.7248	1.3797	⅜
7.5692	.7418	1.3481	½
7.3984	.7589	1.3177	⅝
7.2335	.7762	1.2883	¾
7.0743	.7937	1.2600	⅞
6.9204	.8113	1.2326	13
6.7718	.8291	1.2061	⅛
6.6280	.8471	1.1805	¼
6.4890	.8653	1.1557	⅜
6.3544	.8836	1.1318	½
6.2241	.9021	1.1086	⅝
6.0980	.9207	1.0861	¾
5.9757	.9396	1.0643	⅞
5.8573	.9586	1.0432	14
5.7424	.9777	1.0228	⅛
5.6310	.9971	1.0029	¼
5.5229	1.0166	.9837	⅜
5.4180	1.0363	.9650	½
5.3161	1.0561	.9468	⅝
5.2172	1.0762	.9292	¾
5.1211	1.0964	.9121	⅞
5.0277	1.1167	.8955	15
4.9369	1.1373	.8793	⅛
4.8486	1.1580	.8636	¼
4.7627	1.1789	.8483	⅜
4.6792	1.1999	.8334	½
4.5978	1.2211	.8189	⅝
4.5187	1.2425	.8048	¾
4.4416	1.2641	.7911	⅞
4.3666	1.2858	.7777	16

**NOTE: No allowance made for couplings.

Casing Size
*O.D. 4¾"
4.750"

TABLE
VOLUME & HEIGHT

Diameter of Hole In.	Gallons Per Lin. Ft.	Lin. Ft. Per Gallon	Barrels Per Lin. Ft.
5	.0994	10.0553	.0024
⅛	.1511	6.6187	.0036
¼	.2040	4.9020	.0049
⅜	.2582	3.8732	.0061
½	.3136	3.1883	.0075
⅝	.3704	2.6999	.0088
¾	.4284	2.3343	.0102
⅞	.4877	2.0505	.0116
6	.5482	1.8240	.0131
⅛	.6101	1.6391	.0145
¼	.6732	1.4854	.0160
⅜	.7376	1.3558	.0176
½	.8032	1.2449	.0191
⅝	.8702	1.1492	.0207
¾	.9384	1.0656	.0223
⅞	1.0079	.9922	.0240
7	1.0786	.9271	.0257
⅛	1.1507	.8690	.0274
¼	1.2240	.8170	.0291
⅜	1.2986	.7701	.0309
½	1.3744	.7276	.0327
⅝	1.4516	.6889	.0346
¾	1.5300	.6536	.0364
⅞	1.6097	.6212	.0383
8	1.6906	.5915	.0403
⅛	1.7729	.5641	.0422
¼	1.8564	.5387	.0442
⅜	1.9412	.5151	.0462
½	2.0272	.4933	.0483
⅝	2.1146	.4729	.0503
¾	2.2032	.4539	.0525
⅞	2.2931	.4361	.0546
9	2.3842	.4194	.0568
⅛	2.4767	.4038	.0590
¼	2.5704	.3890	.0612
⅜	2.6654	.3752	.0635
½	2.7616	.3621	.0658
⅝	2.8592	.3498	.0681
¾	2.9580	.3381	.0704
⅞	3.0581	.3270	.0728
10	3.1594	.3165	.0752
⅛	3.2621	.3066	.0777
¼	3.3660	.2971	.0801
⅜	3.4712	.2881	.0826
½	3.5776	.2795	.0852
⅝	3.6854	.2713	.0877
¾	3.7944	.2635	.0903
⅞	3.9047	.2561	.0930
11	4.0162	.2490	.0956

*Not API Standard. Shown for information only.

NO. 122-B
BETWEEN CASING & HOLE**

Casing Size
*O.D. 4¾"
4.750"

Lin. Ft. Per Barrel	Cu. Ft. Per Lin. Ft.	Lin. Ft. Per Cu. Ft.	Diameter of Hole In.
422.3237	.0133	75.2191	5
277.9853	.0202	49.5113	⅛
205.8828	.0273	36.6693	¼
162.6729	.0345	28.9733	⅜
133.9075	.0419	23.8500	½
113.3950	.0495	20.1965	⅝
98.0394	.0573	17.4616	¾
86.1209	.0652	15.3388	⅞
76.6076	.0733	13.6444	6
68.8427	.0816	12.2614	⅛
62.3887	.0900	11.1119	¼
56.9425	.0986	10.1419	⅜
52.2877	.1074	9.3128	½
48.2656	.1163	8.5965	⅝
44.7571	.1254	7.9716	¾
41.6714	.1347	7.4220	⅞
38.9377	.1442	6.9351	7
36.5000	.1538	6.5009	⅛
34.3138	.1636	6.1115	¼
32.3429	.1736	5.7605	⅜
30.5577	.1837	5.4426	½
28.9339	.1940	5.1533	⅝
27.4510	.2045	4.8892	¾
26.0921	.2152	4.6472	⅞
24.8426	.2260	4.4247	8
23.6902	.2370	4.2194	⅛
22.6245	.2482	4.0296	¼
21.6363	.2595	3.8536	⅜
20.7178	.2710	3.6900	½
19.8621	.2827	3.5376	⅝
19.0632	.2945	3.3953	¾
18.3160	.3065	3.2622	⅞
17.6156	.3187	3.1375	9
16.9582	.3311	3.0204	⅛
16.3399	.3436	2.9103	¼
15.7576	.3563	2.8065	⅜
15.2083	.3692	2.7087	½
14.6895	.3822	2.6163	⅝
14.1988	.3954	2.5289	¾
13.7341	.4088	2.4461	⅞
13.2935	.4224	2.3677	10
12.8752	.4361	2.2932	⅛
12.4777	.4500	2.2224	¼
12.0996	.4640	2.1550	⅜
11.7396	.4783	2.0909	½
11.3964	.4927	2.0298	⅝
11.0690	.5072	1.9715	¾
10.7563	.5220	1.9158	⅞
10.4575	.5369	1.8626	11

**NOTE. No allowance made for couplings.

Casing Size
O.D. 5"
5.000"

TABLE NO. 122-B

VOLUME & HEIGHT BETWEEN CASING & HOLE**

Diameter of Hole In.	Gallons Per Lin. Ft.	Lin. Ft. Per Gallon	Barrels Per Lin. Ft.	Lin. Ft. Per Barrel	Cu. Ft. Per Lin. Ft.	Lin. Ft. Per Cu. Ft.
5 ½	.2142	4.6685	.0051	196.0789	.0286	34.9231
⅝	.2709	3.6909	.0065	155.0177	.0362	27.6098
¾	.3289	3.0400	.0078	127.6793	.0440	22.7407
⅞	.3882	2.5757	.0092	108.1815	.0519	19.2679
6	.4488	2.2282	.0107	93.5831	.0600	16.6679
⅛	.5106	1.9583	.0122	82.2503	.0683	14.6494
¼	.5737	1.7429	.0137	73.2028	.0767	13.0380
⅜	.6381	1.5671	.0152	65.8167	.0853	11.7225
½	.7038	1.4209	.0168	59.6762	.0941	10.6288
⅝	.7707	1.2975	.0184	54.4934	.1030	9.7057
¾	.8389	1.1920	.0200	50.0627	.1122	8.9165
⅞	.9084	1.1008	.0216	46.2333	.1214	8.2345
7	.9792	1.0212	.0233	42.8923	.1309	7.6394
⅛	1.0512	.9513	.0250	39.9530	.1405	7.1159
¼	1.1245	.8892	.0268	37.3484	.1503	6.6520
⅜	1.1991	.8339	.0286	35.0253	.1603	6.2383
½	1.2750	.7843	.0304	32.9413	.1704	5.8671
⅝	1.3521	.7396	.0322	31.0620	.1808	5.5324
¾	1.4305	.6990	.0341	29.3594	.1912	5.2291
⅞	1.5102	.6621	.0360	27.8103	.2019	4.9532
8	1.5912	.6285	.0379	26.3952	.2127	4.7012
⅛	1.6734	.5976	.0398	25.0981	.2237	4.4702
¼	1.7569	.5692	.0418	23.9051	.2349	4.2577
⅜	1.8417	.5430	.0439	22.8046	.2462	4.0617
½	1.9278	.5187	.0459	21.7865	.2577	3.8803
⅝	2.0151	.4962	.0480	20.8423	.2694	3.7122
¾	2.1037	.4753	.0501	19.9644	.2812	3.5558
⅞	2.1936	.4559	.0522	19.1463	.2932	3.4101
9	2.2848	.4377	.0544	18.3824	.3054	3.2740
⅛	2.3772	.4207	.0566	17.6676	.3178	3.1467
¼	2.4709	.4047	.0588	16.9976	.3303	3.0274
⅜	2.5659	.3897	.0611	16.3683	.3430	2.9153
½	2.6622	.3756	.0634	15.7765	.3559	2.8099
⅝	2.7597	.3624	.0657	15.2189	.3689	2.7106
¾	2.8585	.3498	.0681	14.6928	.3821	2.6169
⅞	2.9586	.3380	.0704	14.1958	.3955	2.5284
10	3.0600	.3268	.0729	13.7255	.4091	2.4446
⅛	3.1626	.3162	.0753	13.2801	.4228	2.3653
¼	3.2665	.3061	.0778	12.8576	.4367	2.2900
⅜	3.3717	.2966	.0803	12.4565	.4507	2.2186
½	3.4782	.2875	.0828	12.0752	.4650	2.1507
⅝	3.5859	.2789	.0854	11.7124	.4794	2.0861
¾	3.6949	.2706	.0880	11.3669	.4939	2.0245
⅞	3.8052	.2628	.0906	11.0374	.5087	1.9659
11	3.9168	.2553	.0933	10.7231	.5236	1.9099
⅛	4.0296	.2482	.0959	10.4228	.5387	1.8564
¼	4.1437	.2413	.0987	10.1358	.5539	1.8053
⅜	4.2591	.2348	.1014	9.8612	.5694	1.7564
½	4.3758	.2285	.1042	9.5983	.5850	1.7095

**NOTE No allowance made for couplings.

Casing Size
O.D. 5½"
5.500"

TABLE
VOLUME & HEIGHT

Diameter of Hole In.	Gallons Per Lin. Ft.	Lin. Ft. Per Gallon	Barrels Per Lin. Ft.
5⅝	.0567	17.6251	.0014
¾	.1147	8.7146	.0027
⅞	.1740	5.7459	.0041
6	.2346	4.2626	.0056
⅛	.2964	3.3734	.0071
¼	.3595	2.7813	.0086
⅜	.4239	2.3588	.0101
½	.4896	2.0425	.0117
⅝	.5565	1.7968	.0133
¾	.6247	1.6006	.0149
⅞	.6942	1.4404	.0165
7	.7650	1.3072	.0182
⅛	.8370	1.1947	.0199
¼	.9103	1.0985	.0217
⅜	.9849	1.0153	.0235
½	1.0608	.9427	.0253
⅝	1.1379	.8788	.0271
¾	1.2163	.8221	.0290
⅞	1.2960	.7716	.0309
8	1.3770	.7262	.0328
⅛	1.4592	.6853	.0347
¼	1.5427	.6482	.0367
⅜	1.6275	.6144	.0388
½	1.7136	.5836	.0408
⅝	1.8009	.5553	.0429
¾	1.8895	.5292	.0450
⅞	1.9794	.5052	.0471
9	2.0706	.4830	.0493
⅛	2.1630	.4623	.0515
¼	2.2567	.4431	.0537
⅜	2.3517	.4252	.0560
½	2.4480	.4085	.0583
⅝	2.5455	.3928	.0606
¾	2.6443	.3782	.0630
⅞	2.7444	.3644	.0653
10	2.8458	.3514	.0678
⅛	2.9484	.3392	.0702
¼	3.0523	.3276	.0727
⅜	3.1575	.3167	.0752
½	3.2640	.3064	.0777
⅝	3.3717	.2966	.0803
¾	3.4807	.2873	.0829
⅞	3.5910	.2785	.0855
11	3.7026	.2701	.0882
⅛	3.8154	.2621	.0908
¼	3.9295	.2545	.0936
⅜	4.0449	.2472	.0963
½	4.1616	.2403	.0991
⅝	4.2795	.2337	.1019
¾	4.3987	.2273	.1047
⅞	4.5192	.2213	.1076

NO. 122-B
BETWEEN CASING & HOLE**

Casing Size
O.D. 5½"
5.500"

Lin. Ft. Per Barrel	Cu. Ft. Per Lin. Ft.	Lin. Ft. Per Cu. Ft.	Diameter of Hole In.
740.2533	.0076	131.8447	5⅝
366.0142	.0153	65.1899	¾
241.3280	.0233	42.9823	⅞
179.0287	.0314	31.8864	6
141.6829	.0396	25.2348	⅛
116.8130	.0481	20.8053	¼
99.0715	.0567	17.6454	⅜
85.7846	.0654	15.2789	½
75.4668	.0744	13.4412	⅝
67.2271	.0835	11.9737	¾
60.4982	.0928	10.7752	⅞
54.9021	.1023	9.7785	7
50.1771	.1119	8.9369	⅛
46.1362	.1217	8.2172	¼
42.6424	.1317	7.5949	⅜
39.5929	.1418	7.0518	½
36.9090	.1521	6.5738	⅝
34.5296	.1626	6.1500	¾
32.4066	.1733	5.7719	⅞
30.5012	.1841	5.4325	8
28.7822	.1951	5.1263	⅛
27.2242	.2062	4.8488	¼
25.8059	.2176	4.5962	⅜
24.5099	.2291	4.3654	½
23.3213	.2407	4.1537	⅝
22.2276	.2526	3.9589	¾
21.2182	.2646	3.7791	⅞
20.2840	.2768	3.6127	9
19.4172	.2892	3.4583	⅛
18.6109	.3017	3.3147	¼
17.8592	.3144	3.1809	⅜
17.1569	.3272	3.0558	½
16.4995	.3403	2.9387	⅝
15.8830	.3535	2.8289	¾
15.3037	.3669	2.7257	⅞
14.7586	.3804	2.6286	10
14.2449	.3941	2.5371	⅛
13.7599	.4080	2.4507	¼
13.3015	.4221	2.3691	⅜
12.8677	.4363	2.2918	½
12.4565	.4507	2.2186	⅝
12.0664	.4653	2.1491	¾
11.6958	.4801	2.0831	⅞
11.3434	.4950	2.0203	11
11.0079	.5100	1.9606	⅛
10.6883	.5253	1.9037	¼
10.3834	.5407	1.8494	⅜
10.0923	.5563	1.7975	½
9.8142	.5721	1.7480	⅝
9.5482	.5880	1.7006	¾
9.2936	.6041	1.6553	⅞

**NOTE: No allowance made for couplings.

122

Casing Size
O.D. 5½"
5.500"

TABLE
VOLUME & HEIGHT

Diameter of Hole In.	Gallons Per Lin. Ft.	Lin. Ft. Per Gallon	Barrels Per Lin. Ft.
12	4.6410	.2155	.1105
⅛	4.7640	.2099	.1134
¼	4.8883	.2046	.1164
⅜	5.0139	.1994	.1194
½	5.1408	.1945	.1224
⅝	5.2689	.1898	.1255
¾	5.3983	.1852	.1285
⅞	5.5290	.1809	.1316
13	5.6610	.1766	.1348
⅛	5.7942	.1726	.1380
¼	5.9287	.1687	.1412
⅜	6.0645	.1649	.1444
½	6.2016	.1612	.1477
⅝	6.3399	.1577	.1510
¾	6.4795	.1543	.1543
⅞	6.6204	.1510	.1576
14	6.7626	.1479	.1610
⅛	6.9060	.1448	.1644
¼	7.0507	.1418	.1679
⅜	7.1967	.1390	.1714
½	7.3440	.1362	.1749
⅝	7.4925	.1335	.1784
¾	7.6423	.1309	.1820
⅞	7.7934	.1283	.1856
15	7.9458	.1259	.1892
⅛	8.0994	.1235	.1928
¼	8.2543	.1211	.1965
⅜	8.4105	.1189	.2003
½	8.5680	.1167	.2040
⅝	8.7267	.1146	.2078
¾	8.8867	.1125	.2116
⅞	9.0480	.1105	.2154
16	9.2106	.1086	.2193

NO. 122-B
BETWEEN CASING & HOLE**

Casing Size
O.D. 5½"
5.500"

Lin. Ft. Per Barrel	Cu. Ft. Per Lin. Ft.	Lin. Ft. Per Cu. Ft.	Diameter of Hole In.
9.0498	.6204	1.6118	12
8.8161	.6369	1.5702	⅛
8.5919	.6535	1.5303	¼
8.3767	.6703	1.4919	⅜
8.1700	.6872	1.4551	½
7.9713	.7044	1.4197	⅝
7.7802	.7217	1.3857	¾
7.5963	.7391	1.3530	⅞
7.4192	.7568	1.3214	13
7.2486	.7746	1.2910	⅛
7.0841	.7926	1.2617	¼
6.9255	.8107	1.2335	⅜
6.7725	.8290	1.2062	½
6.6247	.8475	1.1799	⅝
6.4819	.8662	1.1545	¾
6.3440	.8850	1.1299	⅞
6.2106	.9040	1.1062	14
6.0817	.9232	1.0832	⅛
5.9568	.9425	1.0610	¼
5.8360	.9621	1.0394	⅜
5.7190	.9817	1.0186	½
5.6056	1.0016	.9984	⅝
5.4957	1.0216	.9788	¾
5.3892	1.0418	.9599	⅞
5.2858	1.0622	.9414	15
5.1856	1.0827	.9236	⅛
5.0882	1.1034	.9063	¼
4.9937	1.1243	.8894	⅜
4.9020	1.1454	.8731	½
4.8128	1.1666	.8572	⅝
4.7262	1.1880	.8418	¾
4.6419	1.2095	.8268	⅞
4.5600	1.2313	.8122	16

**NOTE: No allowance made for couplings.

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122

Casing Size
*O.D. 5¾"
5.750"

TABLE VOLUME & HEIGHT

Diameter of Hole In.	Gallons Per Lin. Ft.	Lin. Ft. Per Gallon	Barrels Per Lin. Ft.
6	.1198	8.3438	.0029
⅛	.1817	5.5040	.0043
¼	.2448	4.0850	.0058
⅜	.3092	3.2343	.0074
½	.3748	2.6677	.0089
⅝	.4418	2.2635	.0105
¾	.5100	1.9608	.0121
⅞	.5795	1.7257	.0138
7	.6502	1.5379	.0155
⅛	.7223	1.3845	.0172
¼	.7956	1.2569	.0189
⅜	.8702	1.1492	.0207
½	.9460	1.0570	.0225
⅝	1.0232	.9773	.0244
¾	1.1016	.9078	.0262
⅞	1.1813	.8465	.0281
8	1.2622	.7922	.0301
⅛	1.3445	.7438	.0320
¼	1.4280	.7003	.0340
⅜	1.5128	.6610	.0360
½	1.5988	.6255	.0381
⅝	1.6862	.5931	.0401
¾	1.7748	.5634	.0423
⅞	1.8647	.5363	.0444
9	1.9558	.5113	.0466
⅛	2.0483	.4882	.0488
¼	2.1420	.4669	.0510
⅜	2.2370	.4470	.0533
½	2.3332	.4286	.0556
⅝	2.4308	.4114	.0579
¾	2.5296	.3953	.0602
⅞	2.6297	.3803	.0626
10	2.7310	.3662	.0650
⅛	2.8337	.3529	.0675
¼	2.9376	.3404	.0699
⅜	3.0428	.3286	.0724
½	3.1492	.3175	.0750
⅝	3.2570	.3070	.0775
¾	3.3660	.2971	.0801
⅞	3.4763	.2877	.0828
11	3.5878	.2787	.0854
⅛	3.7007	.2702	.0881
¼	3.8148	.2621	.0908
⅜	3.9302	.2544	.0936
½	4.0468	.2471	.0964
⅝	4.1648	.2401	.0992
¾	4.2840	.2334	.1020
⅞	4.4045	.2270	.1049
12	4.5262	.2209	.1078

*Not API Standard, Shown for information only.

NO. 122-B BETWEEN CASING & HOLE**

Casing Size
*O.D. 5¾"
5.750"

Lin. Ft. Per Barrel	Cu. Ft. Per Lin. Ft.	Lin. Ft. Per Cu. Ft.	Diameter of Hole In.
350.4388	.0160	62.4158	6
231.1667	.0243	41.1726	⅛
171.5690	.0327	30.5577	¼
135.8402	.0413	24.1942	⅜
112.0451	.0501	19.9561	½
95.0686	.0591	16.9324	⅝
82.3531	.0682	14.6677	¾
72.4780	.0775	12.9089	⅞
64.5907	.0869	11.5041	7
58.1487	.0966	10.3567	⅛
52.7905	.1064	9.4024	¼
48.2656	.1163	8.5965	⅜
44.3952	.1265	7.9071	½
41.0493	.1368	7.3110	⅝
38.1265	.1473	6.7906	¾
35.5545	.1579	6.3325	⅞
33.2740	.1687	5.9264	8
31.2387	.1797	5.5639	⅛
29.4118	.1909	5.2385	¼
27.7634	.2022	4.9449	⅜
26.2689	.2137	4.6787	½
24.9083	.2254	4.4364	⅝
23.6647	.2373	4.2149	¾
22.5239	.2493	4.0117	⅞
21.4741	.2615	3.8247	9
20.5050	.2738	3.6521	⅛
19.6079	.2863	3.4923	¼
18.7753	.2990	3.3440	⅜
18.0007	.3119	3.2061	½
17.2784	.3249	3.0774	⅝
16.6035	.3382	2.9572	¾
15.9715	.3515	2.8446	⅞
15.3787	.3651	2.7391	10
14.8217	.3788	2.6399	⅛
14.2974	.3927	2.5465	¼
13.8032	.4068	2.4584	⅜
13.3365	.4210	2.3753	½
12.8954	.4354	2.2968	⅝
12.4777	.4500	2.2224	¾
12.0819	.4647	2.1519	⅞
11.7062	.4796	2.0850	11
11.3493	.4947	2.0214	⅛
11.0098	.5100	1.9609	¼
10.6865	.5254	1.9034	⅜
10.3785	.5410	1.8485	½
10.0846	.5567	1.7961	⅝
9.8039	.5727	1.7462	¾
9.5358	.5888	1.6984	⅞
9.2792	.6051	1.6527	12

**NOTE: No allowance made for couplings.

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122

Casing Size
*O.D. 6"
6.000"

TABLE
VOLUME & HEIGHT

Diameter of Hole In.	Gallons Per Lin. Ft.	Lin. Ft. Per Gallon	Barrels Per Lin. Ft.
6 1/8	.0618	16.1715	.0015
1/4	.1249	8.0032	.0030
3/8	.1893	5.2816	.0045
1/2	.2550	3.9216	.0061
5/8	.3219	3.1062	.0077
3/4	.3901	2.5631	.0093
7/8	.4596	2.1756	.0109
7	.5304	1.8854	.0126
1/8	.6024	1.6599	.0143
1/4	.6757	1.4798	.0161
3/8	.7503	1.3327	.0179
1/2	.8262	1.2104	.0197
5/8	.9033	1.1070	.0215
3/4	.9817	1.0186	.0234
7/8	1.0614	.9421	.0253
8	1.1424	.8754	.0272
1/8	1.2246	.8166	.0292
1/4	1.3081	.7644	.0311
3/8	1.3929	.7179	.0332
1/2	1.4790	.6761	.0352
5/8	1.5663	.6384	.0373
3/4	1.6549	.6042	.0394
7/8	1.7448	.5731	.0415
9	1.8360	.5447	.0437
1/8	1.9284	.5186	.0459
1/4	2.0221	.4945	.0481
3/8	2.1171	.4723	.0504
1/2	2.2134	.4518	.0527
5/8	2.3109	.4327	.0550
3/4	2.4097	.4150	.0574
7/8	2.5098	.3984	.0598
10	2.6112	.3830	.0622
1/8	2.7138	.3685	.0646
1/4	2.8177	.3549	.0671
3/8	2.9229	.3421	.0696
1/2	3.0294	.3301	.0721
5/8	3.1371	.3188	.0747
3/4	3.2461	.3081	.0773
7/8	3.3564	.2979	.0799
11*	3.4680	.2884	.0826
1/8	3.5808	.2793	.0853
1/4	3.6949	.2706	.0880
3/8	3.8103	.2624	.0907
1/2	3.9270	.2546	.0935
5/8	4.0449	.2472	.0963
3/4	4.1641	.2401	.0991
7/8	4.2846	.2334	.1020
12	4.4064	.2269	.1049

*Not API Standard. Shown for information only.

NO. 122-B
BETWEEN CASING & HOLE**

Casing Size
*O.D. 6"
6.000"

Lin. Ft. Per Barrel	Cu. Ft. Per Lin. Ft.	Lin. Ft. Per Cu. Ft.	Diameter of Hole In.
679.2011	.0083	120.9709	6 1/8
336.1353	.0167	59.8682	1/4
221.8266	.0253	39.5090	3/8
164.7063	.0341	29.3354	1/2
130.4604	.0430	23.2360	5/8
107.6512	.0522	19.1735	3/4
91.3766	.0614	16.2749	7/8
79.1857	.0709	14.1036	7
69.7169	.0805	12.4171	1/8
62.1533	.0903	11.0700	1/4
55.9749	.1003	9.9696	3/8
50.8353	.1104	9.0541	1/2
46.4944	.1208	8.2810	5/8
42.7808	.1312	7.6196	3/4
39.5691	.1419	7.0476	7/8
36.7648	.1527	6.5481	8
34.2959	.1637	6.1084	1/8
32.1065	.1749	5.7184	1/4
30.1522	.1862	5.3703	3/8
28.3976	.1977	5.0578	1/2
26.8142	.2094	4.7758	5/8
25.3785	.2212	4.5201	3/4
24.0711	.2333	4.2872	7/8
22.8759	.2454	4.0744	9
21.7793	.2578	3.8791	1/8
20.7700	.2703	3.6993	1/4
19.8382	.2830	3.5333	3/8
18.9754	.2959	3.3797	1/2
18.1745	.3089	3.2370	5/8
17.4292	.3221	3.1043	3/4
16.7342	.3355	2.9805	7/8
16.0846	.3491	2.8648	10
15.4763	.3628	2.7564	1/8
14.9055	.3767	2.6548	1/4
14.3691	.3907	2.5593	3/8
13.8642	.4050	2.4693	1/2
13.3880	.4194	2.3845	5/8
12.9384	.4339	2.3044	3/4
12.5133	.4487	2.2287	7/8
12.1108	.4636	2.1570	11
11.7291	.4787	2.0890	1/8
11.3669	.4939	2.0245	1/4
11.0227	.5094	1.9632	3/8
10.6952	.5250	1.9049	1/2
10.3834	.5407	1.8494	5/8
10.0861	.5567	1.7964	3/4
9.8025	.5728	1.7459	7/8
9.5316	.5890	1.6977	12

**NOTE: No allowance made for couplings.

Casing Size
O.D. 6 5/8"
6.625"

TABLE
VOLUME & HEIGHT

Diameter of Hole In.	Gallons Per Lin. Ft.	Lin. Ft. Per Gallon	Barrels Per Lin. Ft.
7	.2085	4.7970	.0050
1/8	.2805	3.5651	.0067
1/4	.3538	2.8264	.0084
3/8	.4284	2.3343	.0102
1/2	.5043	1.9831	.0120
5/8	.5814	1.7200	.0138
3/4	.6598	1.5156	.0157
7/8	.7395	1.3523	.0176
8	.8205	1.2188	.0195
1/8	.9027	1.1078	.0215
1/4	.9862	1.0140	.0235
3/8	1.0710	.9337	.0255
1/2	1.1571	.8643	.0275
5/8	1.2444	.8036	.0296
3/4	1.3330	.7502	.0317
7/8	1.4229	.7028	.0339
9	1.5141	.6605	.0360
1/8	1.6065	.6225	.0382
1/4	1.7002	.5882	.0405
3/8	1.7952	.5570	.0427
1/2	1.8915	.5287	.0450
5/8	1.9890	.5028	.0474
3/4	2.0878	.4790	.0497
7/8	2.1879	.4571	.0521
10	2.2893	.4368	.0545
1/8	2.3919	.4181	.0569
1/4	2.4958	.4007	.0594
3/8	2.6010	.3845	.0619
1/2	2.7075	.3694	.0645
5/8	2.8152	.3552	.0670
3/4	2.9242	.3420	.0696
7/8	3.0345	.3295	.0722
11	3.1461	.3179	.0749
1/8	3.2589	.3069	.0776
1/4	3.3730	.2965	.0803
3/8	3.4884	.2867	.0831
1/2	3.6051	.2774	.0858
5/8	3.7230	.2686	.0886
3/4	3.8422	.2603	.0915
7/8	3.9627	.2524	.0943
12	4.0845	.2448	.0972
1/8	4.2075	.2377	.1002
1/4	4.3318	.2309	.1031
3/8	4.4574	.2243	.1061
1/2	4.5843	.2181	.1091
5/8	4.7124	.2122	.1122
3/4	4.8418	.2065	.1153
7/8	4.9725	.2011	.1184
13	5.1045	.1959	.1215

NO. 122-B
BETWEEN CASING & HOLE**

Casing Size
O.D. 6 5/8"
6.625"

Lin. Ft. Per Barrel	Cu. Ft. Per Lin. Ft.	Lin. Ft. Per Cu. Ft.	Diameter of Hole In.
201.4756	.0279	35.8843	7
149.7330	.0375	26.6686	1/8
118.7072	.0473	21.1427	1/4
98.0394	.0573	17.4616	3/8
83.2901	.0674	14.8346	1/2
72.2396	.0777	12.8664	5/8
63.6546	.0882	11.3374	3/4
56.7953	.0989	10.1157	7/8
51.1908	.1097	9.1175	8
46.5272	.1207	8.2868	1/8
42.5873	.1318	7.5851	1/4
39.2158	.1432	6.9846	3/8
36.2989	.1547	6.4651	1/2
33.7513	.1664	6.0114	5/8
31.5077	.1782	5.6118	3/4
29.5173	.1902	5.2572	7/8
27.7400	.2024	4.9407	9
26.1439	.2148	4.6564	1/8
24.7029	.2273	4.3998	1/4
23.3958	.2400	4.1670	3/8
22.2051	.2529	3.9549	1/2
21.1162	.2659	3.7610	5/8
20.1168	.2791	3.5830	3/4
19.1965	.2925	3.4190	7/8
18.3466	.3060	3.2677	10
17.5593	.3197	3.1274	1/8
16.8282	.3336	2.9972	1/4
16.1477	.3477	2.8760	3/8
15.5127	.3619	2.7629	1/2
14.9190	.3763	2.6572	5/8
14.3629	.3909	2.5581	3/4
13.8409	.4057	2.4652	7/8
13.3501	.4206	2.3777	11
12.8878	.4357	2.2954	1/8
12.4518	.4509	2.2178	1/4
12.0399	.4663	2.1444	3/8
11.6503	.4819	2.0750	1/2
11.2813	.4977	2.0093	5/8
10.9312	.5136	1.9469	3/4
10.5989	.5297	1.8877	7/8
10.2829	.5460	1.8315	12
9.9822	.5625	1.7779	1/8
9.6957	.5791	1.7269	1/4
9.4226	.5959	1.6782	3/8
9.1618	.6128	1.6318	1/2
8.9127	.6300	1.5874	5/8
8.6745	.6473	1.5450	3/4
8.4465	.6647	1.5044	7/8
8.2281	6824	1.4655	13

**NOTE. No allowance made for couplings.

Casing Size
O.D. 7"
7.000"

TABLE
VOLUME & HEIGHT

NO. 122-B
BETWEEN CASING & HOLE**

Casing Size
O.D. 7"
7.000"

Diameter of Hole In.	Gallons Per Lin. Ft.	Lin. Ft. Per Gallon	Barrels Per Lin. Ft.	Lin. Ft. Per Barrel	Cu. Ft. Per Lin. Ft.	Lin. Ft. Per Cu. Ft.	Diameter of Hole In.
7 1/8	.0720	13.8817	.0017	583.0313	.0096	103.8423	7 1/8
1/4	.1453	6.8800	.0035	288.9585	.0194	51.4657	1/4
3/8	.2199	4.5468	.0052	190.9639	.0294	34.0121	3/8
1/2	.2958	3.3807	.0070	141.9883	.0395	25.2892	1/2
5/8	.3729	2.6814	.0089	112.6197	.0499	20.0584	5/8
3/4	.4513	2.2156	.0107	93.0545	.0603	16.5737	3/4
7/8	.5310	1.8831	.0126	79.0907	.0710	14.0867	7/8
8	.6120	1.6340	.0146	68.6277	.0818	12.2231	8
1/8	.6942	1.4404	.0165	60.4982	.0928	10.7752	1/8
1/4	.7777	1.2858	.0185	54.0021	.1040	9.6182	1/4
3/8	.8625	1.1594	.0205	48.6937	.1153	8.6727	3/8
1/2	.9486	1.0542	.0226	44.2759	.1268	7.8859	1/2
5/8	1.0359	.9653	.0247	40.5431	.1385	7.2210	5/8
3/4	1.1245	.8892	.0268	37.3484	.1503	6.6520	3/4
7/8	1.2144	.8234	.0289	34.5840	.1623	6.1597	7/8
9	1.3056	.7659	.0311	32.1692	.1745	5.7296	9
1/8	1.3980	.7153	.0333	30.0422	.1869	5.3507	1/8
1/4	1.4917	.6704	.0355	28.1549	.1994	5.0146	1/4
3/8	1.5867	.6302	.0378	26.4695	.2121	4.7144	3/8
1/2	1.6830	.5942	.0401	24.9555	.2250	4.4448	1/2
5/8	1.7805	.5616	.0424	23.5884	.2380	4.2013	5/8
3/4	1.8793	.5321	.0447	22.3482	.2512	3.9804	3/4
7/8	1.9794	.5052	.0471	21.2182	.2646	3.7791	7/8
10	2.0808	.4806	.0495	20.1846	.2782	3.5950	10
1/8	2.1834	.4580	.0520	19.2358	.2919	3.4260	1/8
1/4	2.2873	.4372	.0545	18.3619	.3058	3.2704	1/4
3/8	2.3925	.4180	.0570	17.5546	.3198	3.1266	3/8
1/2	2.4990	.4002	.0595	16.8068	.3341	2.9934	1/2
5/8	2.6067	.3836	.0621	16.1121	.3485	2.8697	5/8
3/4	2.7157	.3682	.0647	15.4654	.3630	2.7545	3/4
7/8	2.8260	.3539	.0673	14.8618	.3778	2.6470	7/8
11	2.9376	.3404	.0699	14.2974	.3927	2.5465	11
1/8	3.0504	.3278	.0726	13.7686	.4078	2.4523	1/8
1/4	3.1645	.3160	.0753	13.2721	.4230	2.3639	1/4
3/8	3.2799	.3049	.0781	12.8052	.4385	2.2807	3/8
1/2	3.3966	.2944	.0809	12.3653	.4541	2.2024	1/2
5/8	3.5145	.2845	.0837	11.9504	.4698	2.1285	5/8
3/4	3.6337	.2752	.0865	11.5583	.4858	2.0586	3/4
7/8	3.7542	.2664	.0894	11.1874	.5019	1.9926	7/8
12	3.8760	.2580	.0923	10.8359	.5181	1.9300	12
1/8	3.9990	.2501	.0952	10.5026	.5346	1.8706	1/8
1/4	4.1233	.2425	.0982	10.1859	.5512	1.8142	1/4
3/8	4.2489	.2354	.1012	9.8849	.5680	1.7606	3/8
1/2	4.3758	.2285	.1042	9.5983	.5850	1.7095	1/2
5/8	4.5039	.2220	.1072	9.3252	.6021	1.6609	5/8
3/4	4.6333	.2158	.1103	9.0647	.6194	1.6145	3/4
7/8	4.7640	.2099	.1134	8.8161	.6369	1.5702	7/8

**NOTE: No allowance made for couplings.

Casing Size
O.D. 7"
7.000"

TABLE
VOLUME & HEIGHT

Diameter of Hole In.	Gallons Per Lin. Ft.	Lin. Ft. Per Gallon	Barrels Per Lin. Ft.
13	4.8960	.2042	.1166
1/8	5.0292	.1988	.1197
1/4	5.1637	.1937	.1229
3/8	5.2995	.1887	.1262
1/2	5.4366	.1839	.1294
5/8	5.5749	.1794	.1327
3/4	5.7145	.1750	.1361
7/8	5.8554	.1708	.1394
14	5.9976	.1667	.1428
1/8	6.1410	.1628	.1462
1/4	6.2857	.1591	.1497
3/8	6.4317	.1555	.1531
1/2	6.5790	.1520	.1566
5/8	6.7275	.1486	.1602
3/4	6.8773	.1454	.1637
7/8	7.0284	.1423	.1673
15	7.1808	.1393	.1710
1/8	7.3344	.1363	.1746
1/4	7.4893	.1335	.1783
3/8	7.6455	.1308	.1820
1/2	7.8030	.1282	.1858
5/8	7.9617	.1256	.1896
3/4	8.1217	.1231	.1934
7/8	8.2830	.1207	.1972
16	8.4456	.1184	.2011

NO. 122-B
BETWEEN CASING & HOLE**

Casing Size
O.D. 7"
7.000"

Lin. Ft. Per Barrel	Cu. Ft. Per Lin. Ft.	Lin. Ft. Per Cu. Ft.	Diameter of Hole In.
8.5785	.6545	1.5279	13
8.3512	.6723	1.4874	1/8
8.1336	.6903	1.4487	1/4
7.9252	.7084	1.4115	3/8
7.7254	.7268	1.3760	1/2
7.5337	.7453	1.3418	5/8
7.3497	.7639	1.3090	3/4
7.1728	.7828	1.2775	7/8
7.0028	.8018	1.2473	14
6.8393	.8209	1.2181	1/8
6.6818	.8403	1.1901	1/4
6.5301	.8598	1.1631	3/8
6.3840	.8795	1.1370	1/2
6.2430	.8993	1.1119	5/8
6.1070	.9194	1.0877	3/4
5.9757	.9396	1.0643	7/8
5.8489	.9599	1.0417	15
5.7264	.9805	1.0199	1/8
5.6080	1.0012	.9988	1/4
5.4934	1.0221	.9784	3/8
5.3826	1.0431	.9587	1/2
5.2752	1.0643	.9396	5/8
5.1713	1.0857	.9211	3/4
5.0706	1.1073	.9031	7/8
4.9730	1.1290	.8857	16

**NOTE. No allowance made for couplings.

Casing Size O.D. 7⅝" 7.625"

TABLE NO. 122-B VOLUME & HEIGHT BETWEEN CASING & HOLE**

Diameter of Hole In.	Gallons Per Lin. Ft.	Lin. Ft. Per Gallon	Barrels Per Lin. Ft.	Lin. Ft. Per Barrel	Cu. Ft. Per Lin. Ft.	Lin. Ft. Per Cu. Ft.
8	.2391	4.1830	.0057	175.6867	.0320	31.2911
1/8	.3213	3.1124	.0076	130.7193	.0430	23.2821
1/4	.4048	2.4703	.0096	103.7520	.0541	18.4790
3/8	.4896	2.0425	.0117	85.7845	.0654	15.2789
1/2	.5757	1.7371	.0137	72.9596	.0770	12.9947
5/8	.6630	1.5083	.0158	63.3486	.0886	11.2829
3/4	.7516	1.3305	.0179	55.8800	.1005	9.9527
7/8	.8415	1.1884	.0200	49.9110	.1125	8.8895
9	.9327	1.0722	.0222	45.0325	.1247	8.0206
1/8	1.0251	.9755	.0244	40.9717	.1370	7.2974
1/4	1.1188	.8938	.0266	37.5399	.1496	6.6861
3/8	1.2138	.8239	.0289	34.6022	.1623	6.1629
1/2	1.3101	.7633	.0312	32.0596	.1751	5.7101
5/8	1.4076	.7104	.0335	29.8381	.1882	5.3144
3/4	1.5064	.6638	.0359	27.8809	.2014	4.9658
7/8	1.6065	.6225	.0382	26.1439	.2148	4.6564
10	1.7079	.5855	.0407	24.5922	.2283	4.3801
1/8	1.8105	.5523	.0431	23.1981	.2420	4.1318
1/4	1.9144	.5224	.0456	21.9389	.2559	3.9075
3/8	2.0196	.4951	.0481	20.7962	.2700	3.7040
1/2	2.1261	.4704	.0506	19.7549	.2842	3.5185
5/8	2.2338	.4477	.0532	18.8021	.2986	3.3488
3/4	2.3428	.4268	.0558	17.9272	.3132	3.1930
7/8	2.4531	.4076	.0584	17.1212	.3279	3.0494
11	2.5647	.3899	.0611	16.3765	.3428	2.9168
1/8	2.6775	.3735	.0637	15.6863	.3579	2.7939
1/4	2.7916	.3582	.0665	15.0451	.3732	2.6796
3/8	2.9070	.3440	.0692	14.4479	.3886	2.5733
1/2	3.0237	.3307	.0720	13.8905	.4042	2.4740
5/8	3.1416	.3183	.0748	13.3690	.4200	2.3811
3/4	3.2608	.3067	.0776	12.8803	.4359	2.2941
7/8	3.3813	.2957	.0805	12.4213	.4520	2.2123
12	3.5031	.2855	.0834	11.9895	.4683	2.1354
1/8	3.6261	.2758	.0863	11.5827	.4847	2.0630
1/4	3.7504	.2666	.0893	11.1988	.5014	1.9946
3/8	3.8760	.2580	.0923	10.8359	.5181	1.9300
1/2	4.0029	.2498	.0953	10.4925	.5351	1.8688
5/8	4.1310	.2421	.0984	10.1671	.5522	1.8108
3/4	4.2604	.2347	.1014	9.8582	.5695	1.7558
7/8	4.3911	.2277	.1045	9.5648	.5870	1.7036
13	4.5231	.2211	.1077	9.2858	.6046	1.6539
1/8	4.6563	.2148	.1109	9.0201	.6225	1.6065
1/4	4.7908	.2087	.1141	8.7668	.6404	1.5614
3/8	4.9266	.2030	.1173	8.5252	.6586	1.5184
1/2	5.0637	.1975	.1206	8.2944	.6769	1.4773
5/8	5.2020	.1922	.1239	8.0738	.6954	1.4380
3/4	5.3416	.1872	.1272	7.8628	.7141	1.4004
7/8	5.4825	.1824	.1305	7.6608	.7329	1.3644
14	5.6246	.1778	.1339	7.4671	.7519	1.3300
1/8	5.7681	.1734	.1373	7.2814	.7711	1.2969
1/4	5.9128	.1691	.1408	7.1032	.7904	1.2651
3/8	6.0588	.1650	.1443	6.9321	.8099	1.2347
1/2	6.2060	.1611	.1478	6.7676	.8296	1.2054

**NOTE: No allowance made for couplings.

Casing Size O.D. 7¾" 7.750"

TABLE VOLUME & HEIGHT

Diameter of Hole In.	Gallons Per Lin. Ft.	Lin. Ft. Per Gallon	Barrels Per Lin. Ft.
8	.1606	6.2247	.0038
1/8	.2429	4.1171	.0058
1/4	.3264	3.0637	.0078
3/8	.4112	2.4320	.0098
1/2	.4972	2.0111	.0118
5/8	.5846	1.7106	.0139
3/4	.6732	1.4854	.0160
7/8	.7631	1.3105	.0182
9	.8542	1.1706	.0203
1/8	.9467	1.0563	.0225
1/4	1.0404	.9612	.0248
3/8	1.1354	.8808	.0270
1/2	1.2316	.8119	.0293
5/8	1.3292	.7523	.0316
3/4	1.4280	.7003	.0340
7/8	1.5281	.6544	.0364
10	1.6294	.6137	.0388
1/8	1.7321	.5773	.0412
1/4	1.8360	.5447	.0437
3/8	1.9412	.5152	.0462
1/2	2.0476	.4884	.0488
5/8	2.1554	.4640	.0513
3/4	2.2644	.4416	.0539
7/8	2.3747	.4211	.0565
11	2.4862	.4022	.0592
1/8	2.5991	.3848	.0619
1/4	2.7132	.3686	.0646
3/8	2.8286	.3535	.0673
1/2	2.9452	.3395	.0701
5/8	3.0632	.3265	.0729
3/4	3.1824	.3142	.0758
7/8	3.3029	.3028	.0786
12	3.4246	.2920	.0815
1/8	3.5477	.2819	.0845
1/4	3.6720	.2723	.0874
3/8	3.7976	.2633	.0904
1/2	3.9244	.2548	.0934
5/8	4.0526	.2468	.0965
3/4	4.1820	.2391	.0996
7/8	4.3127	.2319	.1027
13	4.4446	.2250	.1058
1/8	4.5779	.2184	.1090
1/4	4.7124	.2122	.1122
3/8	4.8482	.2063	.1154
1/2	4.9852	.2006	.1187
5/8	5.1236	.1952	.1220
3/4	5.2632	.1900	.1253
7/8	5.4041	.1850	.1287
14	5.5462	.1803	.1321
1/8	5.6897	.1758	.1355
1/4	5.8344	.1714	.1389
3/8	5.9804	.1672	.1424
1/2	6.1276	.1632	.1459

**NOTE: No allowance made for couplings.

Casing Size O.D. 7¾" 7.750"

NO. 122-B BETWEEN CASING & HOLE**

Lin. Ft. Per Barrel	Cu. Ft. Per Lin. Ft.	Lin. Ft. Per Cu. Ft.	Diameter of Hole In.
261.4386	.0215	46.5642	8
172.9201	.0325	30.7984	1/8
128.6769	.0436	22.9183	1/4
102.1435	.0550	18.1925	3/8
84.4648	.0665	15.0438	1/2
71.8457	.0781	12.7963	5/8
62.3888	.0900	11.1119	3/4
55.0397	.1020	9.8030	7/8
49.1661	.1142	8.7569	9
44.3653	.1266	7.9018	1/8
40.3692	.1391	7.1901	1/4
36.9919	.1518	6.5885	3/8
34.1007	.1646	6.0736	1/2
31.5983	.1777	5.6279	5/8
29.4118	.1909	5.2385	3/4
27.4854	.2043	4.8954	7/8
25.7756	.2178	4.5908	10
24.2483	.2315	4.3188	1/8
22.8759	.2454	4.0744	1/4
21.6363	.2595	3.8536	3/8
20.5114	.2737	3.6532	1/2
19.4861	.2881	3.4706	5/8
18.5480	.3027	3.3035	3/4
17.6866	.3174	3.1501	7/8
16.8930	.3324	3.0088	11
16.1596	.3474	2.8781	1/8
15.4799	.3627	2.7571	1/4
14.8484	.3781	2.6446	3/8
14.2603	.3937	2.5399	1/2
13.7112	.4095	2.4421	5/8
13.1976	.4254	2.3506	3/4
12.7162	.4415	2.2648	7/8
12.2641	.4578	2.1843	12
11.8387	.4743	2.1086	1/8
11.4379	.4909	2.0372	1/4
11.0597	.5077	1.9698	3/8
10.7022	.5246	1.9061	1/2
10.3638	.5418	1.8459	5/8
10.0431	.5591	1.7887	3/4
9.7387	.5765	1.7345	7/8
9.4496	.5942	1.6830	13
9.1746	.6120	1.6341	1/8
8.9127	.6300	1.5874	1/4
8.6631	.6481	1.5430	3/8
8.4249	.6664	1.5005	1/2
8.1974	.6849	1.4600	5/8
7.9800	.7036	1.4213	3/4
7.7719	.7224	1.3842	7/8
7.5727	.7414	1.3488	14
7.3818	.7606	1.3148	1/8
7.1987	.7799	1.2821	1/4
7.0230	.7995	1.2508	3/8
6.8542	.8191	1.2208	1/2

**NOTE: No allowance made for couplings.

122

Casing Size
*O.D. 8"
8.000"

TABLE NO. 122-B
VOLUME & HEIGHT BETWEEN CASING & HOLE**

Diameter of Hole In.	Gallons Per Lin. Ft.	Lin. Ft. Per Gallon	Barrels Per Lin. Ft.	Lin. Ft. Per Barrel	Cu. Ft. Per Lin. Ft.	Lin. Ft. Per Cu. Ft.
8½	.3366	2.9709	.0080	124.7775	.0450	22.2238
⅝	.4239	2.3588	.0101	99.0714	.0567	17.6454
¾	.5125	1.9510	.0122	81.9434	.0685	14.5947
⅞	.6024	1.6599	.0143	69.7169	.0805	12.4171
9	.6936	1.4418	.0165	60.5538	.0927	10.7851
⅛	.7860	1.2722	.0187	53.4327	.1051	9.5168
¼	.8797	1.1367	.0209	47.7409	.1176	8.5030
⅜	.9747	1.0259	.0232	43.0886	.1303	7.6744
½	1.0710	.9337	.0255	39.2158	.1432	6.9846
⅝	1.1685	.8558	.0278	35.9424	.1562	6.4016
¾	1.2673	.7890	.0302	33.1401	.1694	5.9025
⅞	1.3674	.7313	.0326	30.7145	.1828	5.4705
10	1.4688	.6808	.0350	28.5948	.1963	5.0930
⅛	1.5714	.6364	.0374	26.7272	.2101	4.7603
¼	1.6753	.5969	.0399	25.0694	.2240	4.4651
⅜	1.7805	.5616	.0424	23.5884	.2380	4.2013
½	1.8870	.5299	.0449	22.2576	.2523	3.9642
⅝	1.9947	.5013	.0475	21.0555	.2667	3.7501
¾	2.1037	.4753	.0501	19.9644	.2812	3.5558
⅞	2.2140	.4517	.0527	18.9699	.2960	3.3787
11	2.3256	.4300	.0554	18.0599	.3109	3.2166
⅛	2.4384	.4101	.0581	17.2242	.3260	3.0678
¼	2.5525	.3918	.0608	16.4542	.3412	2.9306
⅜	2.6679	.3748	.0635	15.7425	.3567	2.8039
½	2.7846	.3591	.0663	15.0830	.3722	2.6864
⅝	2.9025	.3445	.0691	14.4701	.3880	2.5772
¾	3.0217	.3309	.0719	13.8993	.4039	2.4756
⅞	3.1422	.3182	.0748	13.3663	.4201	2.3806
12	3.2640	.3064	.0777	12.8677	.4363	2.2918
⅛	3.3870	.2952	.0806	12.4002	.4528	2.2086
¼	3.5113	.2848	.0836	11.9612	.4694	2.1304
⅜	3.6369	.2750	.0866	11.5482	.4862	2.0568
½	3.7638	.2657	.0896	11.1590	.5031	1.9875
⅝	3.8919	.2569	.0927	10.7916	.5203	1.9221
¾	4.0213	.2487	.0957	10.4443	.5376	1.8602
⅞	4.1520	.2408	.0989	10.1155	.5550	1.8017
13	4.2840	.2334	.1020	9.8039	.5727	1.7462
⅛	4.4172	.2264	.1052	9.5082	.5905	1.6935
¼	4.5517	.2197	.1084	9.2272	.6085	1.6434
⅜	4.6875	.2133	.1116	8.9599	.6266	1.5958
½	4.8246	.2073	.1149	8.7054	.6450	1.5505
⅝	4.9629	.2015	.1182	8.4627	.6634	1.5073
¾	5.1025	.1960	.1215	8.2312	.6821	1.4660
⅞	5.2434	.1907	.1248	8.0100	.7009	1.4266
14	5.3856	.1857	.1282	7.7986	.7199	1.3890
⅛	5.5290	.1809	.1316	7.5963	.7391	1.3530
¼	5.6737	.1763	.1351	7.4025	.7585	1.3184
⅜	5.8197	.1718	.1386	7.2168	.7780	1.2854
½	5.9670	.1676	.1421	7.0387	.7977	1.2537

*Not API Standard. Shown for information only.

**NOTE: No allowance made for couplings.

Casing Size
*O.D. 8⅛"
8.125"

TABLE VOLUME & HEIGHT

Diameter of Hole In.	Gallons Per Lin. Ft.	Lin. Ft. Per Gallon	Barrels Per Lin. Ft.
8½	.2544	3.9314	.0061
⅝	.3417	2.9266	.0081
¾	.4303	2.3239	.0102
⅞	.5202	1.9223	.0124
9	.6114	1.6357	.0146
⅛	.7038	1.4209	.0168
¼	.7975	1.2539	.0190
⅜	.8925	1.1205	.0212
½	.9888	1.0114	.0235
⅝	1.0863	.9206	.0259
¾	1.1851	.8438	.0282
⅞	1.2852	.7781	.0306
10	1.3866	.7212	.0330
⅛	1.4892	.6715	.0355
¼	1.5931	.6277	.0379
⅜	1.6983	.5888	.0404
½	1.8048	.5541	.0430
⅝	1.9125	.5229	.0455
¾	2.0215	.4947	.0481
⅞	2.1318	.4691	.0508
11	2.2434	.4458	.0534
⅛	2.3562	.4244	.0561
¼	2.4703	.4048	.0588
⅜	2.5857	.3867	.0616
½	2.7024	.3700	.0643
⅝	2.8203	.3546	.0671
¾	2.9395	.3402	.0700
⅞	3.0600	.3268	.0729
12	3.1818	.3143	.0758
⅛	3.3048	.3026	.0787
¼	3.4291	.2916	.0816
⅜	3.5547	.2813	.0846
½	3.6816	.2716	.0877
⅝	3.8097	.2625	.0907
¾	3.9391	.2539	.0938
⅞	4.0698	.2457	.0969
13	4.2018	.2380	.1000
⅛	4.3350	.2307	.1032
¼	4.4695	.2237	.1064
⅜	4.6053	.2171	.1096
½	4.7424	.2109	.1129
⅝	4.8807	.2049	.1162
¾	5.0203	.1992	.1195
⅞	5.1612	.1938	.1229
14	5.3034	.1886	.1263
⅛	5.4468	.1836	.1297
¼	5.5915	.1788	.1331
⅜	5.7375	.1743	.1366
½	5.8847	.1699	.1401

*Not API Standard. Shown for information only

NO. 122-B

BETWEEN CASING & HOLE**

Casing Size
*O.D. 8⅛"
8.125"

Lin. Ft. Per Barrel	Cu. Ft. Per Lin. Ft.	Lin. Ft. Per Cu. Ft.	Diameter of Hole In.
165.1191	.0340	29.4090	8½
122.9151	.0457	21.8921	⅝
97.6037	.0575	17.3840	¾
80.7384	.0695	14.3801	⅞
68.6992	.0817	12.2358	9
59.6762	.0941	10.6288	⅛
52.6639	.1066	9.3798	¼
47.0589	.1193	8.3816	⅜
42.4774	.1322	7.5656	½
38.6634	.1452	6.8863	⅝
35.4398	.1584	6.3121	¾
32.6798	.1718	5.8205	⅞
30.2908	.1854	5.3950	10
28.2031	.1991	5.0232	⅛
26.3635	.2130	4.6955	¼
24.7307	.2270	4.4047	⅜
23.2718	.2413	4.1449	½
21.9608	.2557	3.9114	⅝
20.7766	.2702	3.7005	¾
19.7017	.2850	3.5090	⅞
18.7219	.2999	3.3345	11
17.8254	.3150	3.1748	⅛
17.0019	.3302	3.0282	¼
16.2432	.3457	2.8930	⅜
15.5420	.3613	2.7681	½
14.8921	.3770	2.6524	⅝
14.2881	.3930	2.5448	¾
13.7255	.4091	2.4446	⅞
13.2003	.4253	2.3511	12
12.7088	.4418	2.2635	⅛
12.2481	.4584	2.1815	¼
11.8154	.4752	2.1044	⅜
11.4082	.4922	2.0319	½
11.0245	.5093	1.9636	⅝
10.6623	.5266	1.8990	¾
10.3199	.5441	1.8381	⅞
9.9958	.5617	1.7803	13
9.6886	.5795	1.7256	⅛
9.3970	.5975	1.6737	¼
9.1199	.6156	1.6243	⅜
8.8564	.6340	1.5774	½
8.6053	.6525	1.5327	⅝
8.3660	.6711	1.4901	¾
8.1377	.6900	1.4494	⅞
7.9195	.7090	1.4105	14
7.7110	.7281	1.3734	⅛
7.5114	.7475	1.3378	¼
7.3203	.7670	1.3038	⅜
7.1371	.7867	1.2712	½

**NOTE No allowance made for couplings.

Casing Size
O.D. 8⅝"
8.625"

TABLE
VOLUME & HEIGHT

Diameter of Hole In.	Gallons Per Lin. Ft.	Lin. Ft. Per Gallon	Barrels Per Lin. Ft.
9	.2697	3.7083	.0064
⅛	.3621	2.7617	.0086
¼	.4558	2.1939	.0109
⅜	.5508	1.8155	.0131
½	.6471	1.5454	.0154
⅝	.7446	1.3430	.0177
¾	.8434	1.1857	.0201
⅞	.9435	1.0599	.0225
10	1.0449	.9571	.0249
⅛	1.1475	.8715	.0273
¼	1.2514	.7991	.0298
⅜	1.3566	.7371	.0323
½	1.4631	.6835	.0348
⅝	1.5708	.6366	.0374
¾	1.6798	.5953	.0400
⅞	1.7901	.5586	.0426
11	1.9017	.5259	.0453
⅛	2.0145	.4964	.0480
¼	2.1286	.4698	.0507
⅜	2.2440	.4456	.0534
½	2.3607	.4236	.0562
⅝	2.4786	.4035	.0590
¾	2.5978	.3849	.0619
⅞	2.7183	.3679	.0647
12	2.8401	.3521	.0676
⅛	2.9631	.3375	.0705
¼	3.0874	.3239	.0735
⅜	3.2130	.3112	.0765
½	3.3399	.2994	.0795
⅝	3.4680	.2884	.0826
¾	3.5974	.2780	.0857
⅞	3.7281	.2682	.0888
13	3.8601	.2591	.0919
⅛	3.9933	.2504	.0951
¼	4.1278	.2423	.0983
⅜	4.2636	.2345	.1015
½	4.4007	.2272	.1048
⅝	4.5390	.2203	.1081
¾	4.6786	.2137	.1114
⅞	4.8195	.2075	.1147
14	4.9617	.2015	.1181
⅛	5.1051	.1959	.1215
¼	5.2498	.1905	.1250
⅜	5.3958	.1853	.1285
½	5.5430	.1804	.1320
⅝	5.6916	.1757	.1355
¾	5.8414	.1712	.1391
⅞	5.9925	.1669	.1427
15	6.1448	.1627	.1463

NO. 122-B
BETWEEN CASING & HOLE**

Casing Size
O.D. 8⅝"
8.625"

Lin. Ft. Per Barrel	Cu. Ft. Per Lin. Ft.	Lin. Ft. Per Cu. Ft.	Diameter of Hole In.
155.7506	.0360	27.7404	9
115.9903	.0484	20.6588	⅛
92.1434	.0609	16.4114	¼
76.2529	.0736	13.5812	⅜
64.9089	.0865	11.5608	½
56.4063	.0995	10.0464	⅝
49.7978	.1127	8.8694	¾
44.5152	.1261	7.9285	⅞
40.1968	.1397	7.1594	10
36.6014	.1534	6.5190	⅛
33.5622	.1673	5.9777	¼
30.9598	.1814	5.5142	⅜
28.7070	.1956	5.1129	½
26.7380	.2100	4.7622	⅝
25.0028	.2246	4.4532	¾
23.4624	.2393	4.1788	⅞
22.0860	.2542	3.9337	11
20.8489	.2693	3.7133	⅛
19.7312	.2846	3.5143	¼
18.7166	.3000	3.3336	⅜
17.7917	.3156	3.1688	½
16.9451	.3313	3.0180	⅝
16.1675	.3473	2.8796	¾
15.4509	.3634	2.7519	⅞
14.7884	.3797	2.6339	12
14.1744	.3961	2.5246	⅛
13.6037	.4127	2.4229	¼
13.0719	.4295	2.3282	⅜
12.5754	.4465	2.2398	½
12.1108	.4636	2.1570	⅝
11.6751	.4809	2.0794	¾
11.2658	.4984	2.0065	⅞
10.8807	.5160	1.9379	13
10.5176	.5338	1.8733	⅛
10.1749	.5518	1.8122	¼
9.8509	.5700	1.7545	⅜
9.5440	.5883	1.6999	½
9.2532	.6068	1.6481	⅝
8.9770	.6254	1.5989	¾
8.7146	.6443	1.5521	⅞
8.4649	.6633	1.5077	14
8.2271	.6825	1.4653	⅛
8.0003	.7018	1.4249	¼
7.7839	.7213	1.3864	⅜
7.5771	.7410	1.3495	½
7.3793	.7609	1.3143	⅝
7.1901	.7809	1.2806	¾
7.0088	.8011	1.2483	⅞
6.8350	.8214	1.2174	15

**NOTE: No allowance made for couplings.

TABLE NO. 211 CAPACITY OF TUBING

Size O. D. In.	Wt. Per Ft. With Couplings, Lb.			Inside Diameter In.	Drift Diameter In.	Gallons Per Lin. Ft.	Lin. Ft. Per Gallon	Barrels Per Lin. Ft.	Lin. Ft. Per Barrel	Cu. Ft. Per Lin. Ft.	Lin. Ft. Per Cu. Ft.
	Non Upset	Upset	Integral Joint								
1.050	1.14	1.20	1.20	.824	.730	.0277	36 0983	.00066	1516.13	.00370	270.034
1.315	1.70	1.80	1.72	1.049	.955	0449	22 2736	.00107	935.49	.00600	166.618
	—	—	*2.25	.957	.848	0374	26 7619	.00089	1124 00	.00500	200.193
1.660	—	—	2.10	1.410	1.286	0811	12.3283	.00193	517.79	.01084	92.222
	2 30	2 40	2.33	1.380	1.286	.0777	12.8701	.00185	540.55	.01039	96.275
	—	—	*3.02	1.278	1.184	0666	15 0065	.00159	630.27	00891	112 256
1.900	—	—	2.40	1 650	1.516	1111	9 0027	.00264	378.11	.01485	67.345
	2.75	2.90	2.76	1.610	1.516	1058	9 4556	.00252	397.14	.01414	70.733
	—	—	*3.64	1.500	1 406	0918	10 5933	00219	457 52	.01227	81.487
2.063	—	—	3.25	1.751	1 657	1251	7 9941	.00298	335.75	.01672	59.800
2.375	4 00	—	—	2.041	1.947	.1700	5 8838	.00405	247.12	.02272	44.014
	4.60	4.70	4.70	1.995	1.901	.1624	6.1582	.00387	258.65	.02171	46.067
	—	—	5.30	1 939	1.845	.1534	6 5191	.00365	273.80	.02051	48.766
	5 80	5 95	5.95	1.867	1.773	.1422	7.0316	.00339	295.33	.01901	52.600
	—	—	*6.20	1.853	1.759	.1401	7 1382	.00334	299.81	.01873	53.398
	—	—	*7.70	1.703	1.609	.1183	8 4511	.00282	354.95	.01582	63.218
2.875	6 40	6 50	6.50	2.441	2.347	.2431	4 1134	.00579	172.76	.03250	30.771
	—	—	7.90	2.323	2.229	.2202	4 5420	.00524	190.76	.02943	33.976
	8.60	8.70	8.70	2.259	2.165	.2082	4.8030	.00496	201.72	.02783	35.929
	—	—	*9.50	2.195	2.101	.1966	5.0871	.00468	213.66	.02628	38.054
	—	—	*10.70	2.091	1.997	.1784	5 6057	.00425	235.44	.02385	41 934
	—	—	*11.00	2.065	1.971	1740	5 7478	.00414	241.41	.02326	42.996
3.500	7.70	—	—	3.068	2.943	.3840	2.6039	.00914	109.37	.05134	19.479
	9.20	9 30	9.30	2.992	2.867	.3652	2.7379	(.00870)	114.99	.04883	20.481
	10.20	—	10.30	2.922	2.797	.3484	2.8707	.00829	120.57	.04657	21.474
	—	—	*12.80	2.764	2.639	.3117	3 2082	00742	134.75	.04167	23.999
	12.70	12.95	12.95	2.750	2.625	3085	3 2410	.00735	136.12	.04125	24.244
	—	—	*15.80	2.548	2.423	2649	3 7752	00631	158 56	.03541	28.241
	—	—	*16.70	2.480	2.355	2509	3 9851	.00597	167.37	.03355	29.811
4.000	9.50	—	—	3.548	3.423	.5136	1 9474	01223	81.78	.06866	14.565
	—	11.00	11.00	3.476	3.351	.4930	2 0285	.01174	85.20	.06590	15.174
	—	—	*11.60	3.428	3.303	.4794	2.0857	.01142	87.60	.06409	15.602
	—	—	*13.40	3.340	3.215	4551	2 1971	.01084	92.28	.06084	16 435
4.500	12.60	12.75	12.75	3.958	3 833	.6392	1.5645	.01522	65.71	.08544	11.704
	—	—	*13.50	3.920	3.795	.6269	1.5950	.01493	66.99	.08381	11.932
	—	—	*15.50	3 826	3.701	.5972	1 6744	.01422	70.32	.07984	12.525
	—	—	*19.20	3.640	3.515	.5406	1.8499	.01287	77 69	.07227	13.838

*Not API standard. Shown for information only.

TABLE NO. 213 CAPACITY OF HOLE

Diameter of Hole In.	Gallons Per Lin. Ft.	Lin. Ft. Per Gallon	Barrels Per Lin. Ft.	Lin. Ft. Per Barrel	Cu. Ft. Per Lin. Ft.	Lin. Ft. Per Cu. Ft.	Diameter of Hole In.
2	.1632	6.1275	.0039	257.3536	.0218	45.8366	2
1/8	.1842	5.4278	.0044	227.9672	.0246	40.6027	1/8
1/4	.2065	4.8415	.0049	203.3411	.0276	36.2166	1/4
3/8	.2301	4.3452	.0055	182.5000	.0308	32.5046	3/8
1/2	.2550	3.9216	.0061	164.7063	.0341	29.3354	1/2
5/8	.2811	3.5570	.0067	149.3934	.0376	26.6081	5/8
3/4	.3085	3.2410	.0073	136.1209	.0412	24.2442	3/4
7/8	.3372	2.9653	.0080	124.5416	.0451	22.1818	7/8
3	.3672	2.7233	.0087	114.3794	.0491	20.3718	3
1/8	.3984	2.5098	.0095	105.4120	.0533	18.7747	1/8
1/4	.4309	2.3205	.0103	97.4593	.0576	17.3582	1/4
3/8	.4647	2.1518	.0111	90.3738	.0621	16.0963	3/8
1/2	.4998	2.0008	.0119	84.0338	.0668	14.9671	1/2
5/8	.5361	1.8652	.0128	78.3383	.0717	13.9526	5/8
3/4	.5737	1.7429	.0137	73.2028	.0767	13.0380	3/4
7/8	.6126	1.6323	.0146	68.5562	.0819	12.2104	7/8
4	.6528	1.5319	.0155	64.3384	.0873	11.4592	4
1/8	.6942	1.4404	.0165	60.4982	.0928	10.7752	1/8
1/4	.7369	1.3569	.0175	56.9918	.0985	10.1507	1/4
3/8	.7809	1.2805	.0186	53.7816	.1044	9.5789	3/8
1/2	.8262	1.2104	.0197	50.8353	.1104	9.0541	1/2
5/8	.8727	1.1458	.0208	48.1245	.1167	8.5713	5/8
3/4	.9205	1.0863	.0219	45.6250	.1231	8.1262	3/4
7/8	.9696	1.0313	.0231	43.3153	.1296	7.7148	7/8
5	1.0200	.9804	.0243	41.1766	.1364	7.3319	5
1/8	1.0716	.9332	.0255	39.1924	.1433	6.9805	1/8
1/4	1.1245	.8892	.0268	37.3484	.1503	6.6520	1/4
3/8	1.1787	.8484	.0281	35.6314	.1576	6.3462	3/8
1/2	1.2342	.8102	.0294	34.0302	.1650	6.0610	1/2
5/8	1.2909	.7746	.0307	32.5346	.1726	5.7947	5/8
3/4	1.3489	.7413	.0321	31.1354	.1803	5.5455	3/4
7/8	1.4082	.7101	.0335	29.8246	.1883	5.3120	7/8
6	1.4688	.6808	.0350	28.5948	.1963	5.0930	6
1/8	1.5306	.6533	.0364	27.4396	.2046	4.8872	1/8
1/4	1.5937	.6275	.0379	26.3530	.2131	4.6937	1/4
3/8	1.6581	.6031	.0395	25.3297	.2217	4.5114	3/8
1/2	1.7238	.5801	.0410	24.3648	.2304	4.3396	1/2
5/8	1.7907	.5584	.0426	23.4541	.2394	4.1773	5/8
3/4	1.8589	.5379	.0443	22.5935	.2485	4.0241	3/4
7/8	1.9284	.5186	.0459	21.7793	.2578	3.8791	7/8
7	1.9992	.5002	.0476	21.0085	.2673	3.7418	7
1/8	2.0712	.4828	.0493	20.2778	.2769	3.6116	1/8
1/4	2.1445	.4663	.0511	19.5846	.2867	3.4882	1/4
3/8	2.2191	.4506	.0528	18.9263	.2967	3.3709	3/8
1/2	2.2950	.4357	.0546	18.3007	.3068	3.2595	1/2
5/8	2.3721	.4216	.0565	17.7056	.3171	3.1535	5/8
3/4	2.4505	.4081	.0583	17.1390	.3276	3.0526	3/4
7/8	2.5302	.3952	.0602	16.5993	.3382	2.9565	7/8

TABLE NO. 213 CAPACITY OF HOLE

Diameter of Hole In.	Gallons Per Lin. Ft.	Lin. Ft. Per Gallon	Barrels Per Lin. Ft.	Lin. Ft. Per Barrel	Cu. Ft. Per Lin. Ft.	Lin. Ft. Per Cu. Ft.	Diameter of Hole In.
8	2.6112	.3830	.0622	16.0846	.3491	2.8648	8
⅛	2.6934	.3713	.0641	15.5935	.3601	2.7773	⅛
¼	2.7769	.3601	.0661	15.1245	.3712	2.6938	¼
⅜	2.8617	.3494	.0681	14.6764	.3826	2.6140	⅜
½	2.9478	.3392	.0702	14.2479	.3941	2.5377	½
⅝	3.0351	.3295	.0723	13.8380	.4057	2.4646	⅝
¾	3.1237	.3201	.0744	13.4454	.4176	2.3947	¾
⅞	3.2136	.3112	.0765	13.0693	.4296	2.3277	⅞
9	3.3048	.3026	.0787	12.7088	.4418	2.2635	9
⅛	3.3972	.2944	.0809	12.3630	.4541	2.2019	⅛
¼	3.4909	.2865	.0831	12.0311	.4667	2.1428	¼
⅜	3.5859	.2789	.0854	11.7124	.4794	2.0861	⅜
½	3.6822	.2716	.0877	11.4063	.4922	2.0315	½
⅝	3.7797	.2646	.0900	11.1119	.5053	1.9791	⅝
¾	3.8785	.2578	.0923	10.8288	.5185	1.9287	¾
⅞	3.9786	.2513	.0947	10.5564	.5319	1.8802	⅞
10	4.0800	.2451	.0971	10.2941	.5454	1.8335	10
⅛	4.1826	.2391	.0996	10.0415	.5591	1.7885	⅛
¼	4.2865	.2333	.1021	9.7981	.5730	1.7451	¼
⅜	4.3917	.2277	.1046	9.5634	.5871	1.7033	⅜
½	4.4982	.2223	.1071	9.3371	.6013	1.6630	½
⅝	4.6059	.2171	.1097	9.1187	.6157	1.6241	⅝
¾	4.7149	.2121	.1123	8.9079	.6303	1.5866	¾
⅞	4.8252	.2072	.1149	8.7043	.6450	1.5503	⅞
11	4.9368	.2026	.1175	8.5076	.6600	1.5153	11
⅛	5.0496	.1980	.1202	8.3174	.6750	1.4814	⅛
¼	5.1637	.1937	.1229	8.1336	.6903	1.4487	¼
⅜	5.2791	.1894	.1257	7.9559	.7057	1.4170	⅜
½	5.3958	.1853	.1285	7.7839	.7213	1.3864	½
⅝	5.5137	.1814	.1313	7.6174	.7371	1.3567	⅝
¾	5.6329	.1775	.1341	7.4561	.7530	1.3280	¾
⅞	5.7534	.1738	.1370	7.3000	.7691	1.3002	⅞
12	5.8752	.1702	.1399	7.1487	.7854	1.2732	12
⅛	5.9982	.1667	.1428	7.0021	.8018	1.2471	⅛
¼	6.1225	.1633	.1458	6.8599	.8185	1.2218	¼
⅜	6.2481	.1600	.1488	6.7220	.8353	1.1972	⅜
½	6.3750	.1569	.1518	6.5883	.8522	1.1734	½
⅝	6.5031	.1538	.1548	6.4584	.8693	1.1503	⅝
¾	6.6325	.1508	.1579	6.3324	.8866	1.1279	¾
⅞	6.7632	.1479	.1610	6.2101	.9041	1.1061	⅞
13	6.8952	.1450	.1642	6.0912	.9218	1.0849	13
⅛	7.0284	.1423	.1673	5.9757	.9396	1.0643	⅛
¼	7.1629	.1396	.1705	5.8635	.9575	1.0443	¼
⅜	7.2987	.1370	.1738	5.7544	.9757	1.0249	⅜
½	7.4358	.1345	.1770	5.6484	.9940	1.0060	½
⅝	7.5741	.1320	.1803	5.5452	1.0125	.9876	⅝
¾	7.7137	.1296	.1837	5.4448	1.0312	.9698	¾
⅞	7.8546	.1273	.1870	5.3472	1.0500	.9524	⅞

TABLE NO. 213
CAPACITY OF HOLE

Diameter of Hole In.	Gallons Per Lin. Ft.	Lin. Ft. Per Gallon	Barrels Per Lin. Ft.	Lin. Ft. Per Barrel	Cu. Ft. Per Lin. Ft.	Lin. Ft. Per Cu. Ft.	Diameter of Hole In.
14	7.9968	.1251	.1904	5.2521	1.0690	.9354	14
1/8	8.1402	.1228	.1938	5.1596	1.0882	.9190	1/8
1/4	8.2849	.1207	.1973	5.0694	1.1075	.9029	1/4
3/8	8.4309	.1186	.2007	4.9817	1.1270	.8873	3/8
1/2	8.5782	.1166	.2042	4.8961	1.1467	.8720	1/2
5/8	8.7267	.1146	.2078	4.8128	1.1666	.8572	5/8
3/4	8.8765	.1127	.2113	4.7316	1.1866	.8427	3/4
7/8	9.0276	.1108	.2149	4.6524	1.2068	.8286	7/8
15	9.1800	.1089	.2186	4.5752	1.2272	.8149	15
1/8	9.3336	.1071	.2222	4.4999	1.2477	.8015	1/8
1/4	9.4885	.1054	.2259	4.4264	1.2684	.7884	1/4
3/8	9.6447	.1037	.2296	4.3547	1.2893	.7756	3/8
1/2	9.8022	.1020	.2334	4.2848	1.3104	.7631	1/2
5/8	9.9609	.1004	.2372	4.2165	1.3316	.7510	5/8
3/4	10.1209	.0988	.2410	4.1498	1.3530	.7391	3/4
7/8	10.2822	.0973	.2448	4.0847	1.3745	.7275	7/8
16	10.4448	.0957	.2487	4.0211	1.3963	.7162	16
1/4	10.7737	.0928	.2565	3.8984	1.4402	.6943	1/4
1/2	11.1078	.0900	.2645	3.7811	1.4849	.6734	1/2
3/4	11.4469	.0874	.2725	3.6691	1.5302	.6535	3/4
17	11.7912	.0848	.2807	3.5620	1.5763	.6344	17
1/4	12.1405	.0824	.2891	3.4595	1.6230	.6162	1/4
1/2	12.4950	.0800	.2975	3.3614	1.6703	.5987	1/2
3/4	12.8545	.0778	.3061	3.2673	1.7184	.5819	3/4
18	13.2192	.0756	.3147	3.1772	1.7671	.5659	18
1/4	13.5889	.0736	.3235	3.0908	1.8166	.5505	1/4
1/2	13.9638	.0716	.3325	3.0078	1.8667	.5357	1/2
3/4	14.3437	.0697	.3415	2.9281	1.9175	.5215	3/4
19	14.7288	.0679	.3507	2.8516	1.9689	.5079	19
1/4	15.1189	.0661	.3600	2.7780	2.0211	.4948	1/4
1/2	15.5142	.0645	.3694	2.7072	2.0739	.4822	1/2
3/4	15.9145	.0628	.3789	2.6391	2.1275	.4700	3/4
20	16.3200	.0613	.3886	2.5735	2.1817	.4584	20
1/4	16.7305	.0598	.3983	2.5104	2.2365	.4471	1/4
1/2	17.1462	.0583	.4082	2.4495	2.2921	.4363	1/2
3/4	17.5669	.0569	.4183	2.3909	2.3484	.4258	3/4
21	17.9928	.0556	.4284	2.3343	2.4053	.4158	21
1/4	18.4237	.0543	.4387	2.2797	2.4629	.4060	1/4
1/2	18.8598	.0530	.4490	2.2270	2.5212	.3966	1/2
3/4	19.3009	.0518	.4595	2.1761	2.5802	.3876	3/4
22	19.7472	.0506	.4702	2.1269	2.6398	.3788	22
1/4	20.1985	.0495	.4809	2.0794	2.7001	.3704	1/4
1/2	20.6550	.0484	.4918	2.0334	2.7612	.3622	1/2
3/4	21.1165	.0474	.5028	1.9890	2.8229	.3542	3/4
23	21.5831	.0463	.5139	1.9460	2.8852	.3466	23
1/4	22.0549	.0453	.5251	1.9043	2.9483	.3392	1/4
1/2	22.5317	.0444	.5365	1.8640	3.0121	.3320	1/2
3/4	23.0137	.0435	.5479	1.8250	3.0765	.3250	3/4

TABLE

CAPACITY

Size O. D. In.	Wt. Per Ft. With Couplings Lb.	Inside Diameter In.	Drift Diameter In.	Gallons Per Lin. Ft.	Lin. Ft. Per Gallon
4½	9.50	4.090	3.965	.6825	1.4652
4½	10.50	4.052	3.927	.6699	1.4928
4½	11.60	4.000	3.875	.6528	1.5319
4½	13.50	3.920	3.795	.6269	1.5950
4½	15.10	3.826	3.701	.5972	1.6744
*4½	16.60	3.754	3.629	.5750	1.7392
*4½	18.80	3.640	3.515	.5406	1.8499
*4¾	16.00	4.082	3.957	.6798	1.4709
5	11.50	4.560	4.435	.8484	1.1787
5	13.00	4.494	4.369	.8240	1.2136
5	15.00	4.408	4.283	.7928	1.2614
5	18.00	4.276	4.151	.7460	1.3405
*5	20.30	4.184	4.059	.7142	1.4001
*5	20.80	4.156	4.031	.7047	1.4190
*5	21.00	4.154	4.029	.7040	1.4204
*5	23.20	4.044	3.919	.6672	1.4987
*5	24.20	4.000	3.875	.6528	1.5319
*5½	13.00	5.044	4.919	1.0380	.9634
5½	14.00	5.012	4.887	1.0249	.9757
*5½	15.00	4.974	4.849	1.0094	.9907
5½	15.50	4.950	4.825	.9997	1.0003
5½	17.00	4.892	4.767	.9764	1.0242
5½	20.00	4.778	4.653	.9314	1.0736
5½	23.00	4.670	4.545	.8898	1.1238
*5½	26.00	4.548	4.423	.8439	1.1850
*5¾	14.00	5.290	5.165	1.1417	.8758
*5¾	17.00	5.190	5.065	1.0990	.9099
*5¾	19.50	5.090	4.965	1.0570	.9460
*5¾	22.50	4.990	4.865	1.0159	.9843
*6	15.00	5.524	5.399	1.2450	.8032
*6	16.00	5.500	5.375	1.2342	.8102
*6	17.00	5.450	5.325	1.2119	.8252
*6	18.00	5.424	5.299	1.2003	.8331
*6	20.00	5.352	5.227	1.1687	.8557
*6	23.00	5.240	5.115	1.1203	.8926
*6	26.00	5.140	5.015	1.0779	.9277
*6⅝	17.00	6.135	6.010	1.5356	.6512
6⅝	20.00	6.049	5.924	1.4929	.6698
*6⅝	22.00	5.989	5.864	1.4634	.6833
6⅝	24.00	5.921	5.796	1.4304	.6991
*6⅝	26.00	5.855	5.730	1.3987	.7150
6⅝	28.00	5.791	5.666	1.3683	.7309
*6⅝	29.00	5.761	5.636	1.3541	.7385
6⅝	32.00	5.675	5.550	1.3140	.7610
7	17.00	6.538	6.413	1.7440	.5734
7	20.00	6.456	6.331	1.7005	.5880
*7	22.00	6.398	6.273	1.6701	.5988
7	(23.00)	6.366	6.241	1.6535	.6048
*7	24.00	6.336	6.211	1.6379	.6105
7	26.00	6.276	6.151	1.6070	.6223
*7	28.00	6.214	6.089	1.5754	.6347
7	29.00	6.184	6.059	1.5603	.6409
*7	30.00	6.154	6.029	1.5452	.6472
7	32.00	6.094	5.969	1.5152	.6600
*7	33.70	6.048	5.923	1.4924	.6701
7	35.00	6.004	5.879	1.4708	.6799
7	38.00	5.920	5.795	1.4299	.6994
*7	40.00	5.836	5.711	1.3896	.7196

NO. 214

OF CASING

Barrels Per Lin. Ft.	Lin. Ft. Per Barrel	Cu. Ft. Per Lin. Ft.	Lin. Ft. Per Cu. Ft.	Wt. Per Ft. With Couplings Lb.	Size O. D. In.
.0162	61.54	.0912	10.960	9.50	4½
.0159	62.70	.0895	11.167	10.50	4½
.0155	64.34	.0872	11.459	11.60	4½
.0149	66.99	.0838	11.932	13.50	4½
.0142	70.32	.0798	12.525	15.10	4½
.0136	73.05	.0768	13.010	16.60	*4½
.0128	77.69	.0722	13.838	18.80	*4½
.0161	61.78	.0908	11.003	16.00	*4¾
.0202	49.51	.1134	8.817	11.50	5
.0196	50.97	.1101	9.078	13.00	5
.0188	52.98	.1059	9.436	15.00	5
.0177	56.30	.0997	10.028	18.00	5
.0170	58.80	.0954	10.473	20.30	*5
.0167	59.60	.0942	10.615	20.80	*5
.0167	59.66	.0941	10.625	21.00	*5
.0158	62.95	.0892	11.211	23.20	*5
.0155	64.34	.0872	11.459	24.20	*5
.0247	40.46	.1387	7.206	13.00	*5½
.0244	40.98	.1370	7.299	14.00	5½
.0240	41.61	.1349	7.411	15.00	*5½
.0238	42.01	.1336	7.483	15.50	5½
.0232	43.01	.1305	7.661	17.00	5½
.0221	45.09	.1245	8.031	20.00	5½
.0211	47.20	.1189	8.407	23.00	5½
.0200	49.77	.1128	8.864	26.00	*5½
.0271	36.79	.1526	6.552	14.00	*5¾
.0261	38.22	.1469	6.807	17.00	*5¾
.0251	39.73	.1413	7.077	19.50	*5¾
.0241	41.34	.1358	7.363	22.50	*5¾
.0296	33.74	.1664	6.008	15.00	*6
.0294	34.05	.1649	6.061	16.00	*6
.0288	34.66	.1620	6.173	17.00	*6
.0285	34.99	.1604	6.232	18.00	*6
.0278	35.94	.1562	6.401	20.00	*6
.0266	37.47	.1497	6.677	23.00	*6
.0256	38.96	.1441	6.940	26.00	*6
.0365	27.35	.2052	4.871	17.00	*6⅝
.0355	28.13	.1995	5.011	20.00	6⅝
.0348	28.70	.1956	5.112	22.00	*6⅝
.0340	29.36	.1912	5.230	24.00	6⅝
.0333	30.03	.1869	5.348	26.00	*6⅝
.0325	30.70	.1829	5.467	28.00	6⅝
.0322	31.02	.1810	5.524	29.00	*6⅝
.0312	31.96	.1756	5.693	32.00	6⅝
.0415	24.08	.2331	4.289	17.00	7
.0404	24.70	.2273	4.399	20.00	7
.0397	25.15	.2232	4.479	22.00	*7
(.0393)	25.40	.2210	4.524	23.00	7
.0390	25.64	.2189	4.567	24.00	*7
.0382	26.14	.2148	4.655	26.00	7
.0375	26.66	.2106	4.748	28.00	*7
.0371	26.92	.2085	4.794	29.00	7
.0367	27.18	.2065	4.841	30.00	*7
.0360	27.72	.2025	4.937	32.00	7
.0355	28.14	.1995	5.012	33.70	*7
.0350	28.56	.1966	5.086	35.00	7
.0340	29.37	.1911	5.232	38.00	7
.0330	30.22	.1857	5.383	40.00	*7

*Not API Standard. Shown for information only.

TABLE NO. 214

CAPACITY OF CASING

Size O. D. In.	Wt. Per Ft. With Couplings Lb.	Inside Diameter In.	Drift Diameter In.	Gallons Per Lin. Ft.	Lin. Ft. Per Gallon	Barrels Per Lin. Ft.	Lin. Ft. Per Barrel	Cu. Ft. Per Lin. Ft.	Lin. Ft. Per Cu. Ft.	Wt/Ft With Couplings Lb.	Size O. D. In.
*7 5/8	20.00	7.125	7.000	2.0712	.4828	.0493	20.28	.2768	3.612	20.00	*7 5/8
7 5/8	24.00	7.025	6.900	2.0135	.4966	.0479	20.86	.2691	3.715	24.00	7 5/8
7 5/8	26.40	6.969	6.844	1.9815	.5047	.0471	21.20	.2648	3.775	26.40	7 5/8
7 5/8	29.70	6.875	6.750	1.9284	.5186	.0459	21.78	.2577	3.879	29.70	7 5/8
7 5/8	33.70	6.765	6.640	1.8672	.5356	.0444	22.49	.2496	4.006	33.70	7 5/8
7 5/8	39.00	6.625	6.500	1.7907	.5584	.0426	23.45	.2393	4.177	39.00	7 5/8
*7 5/8	45.30	6.435	6.310	1.6895	.5919	.0402	24.86	.2258	4.428	45.30	*7 5/8
*7 3/4	45.30	6.560	6.500	1.7558	.5696	.0418	23.92	.2347	4.261	45.30	*7 3/4
*8	26.00	7.386	7.261	2.2258	.4493	.0529	18.87	.2975	3.361	26.00	*8
*8 1/8	28.00	7.485	7.360	2.2858	.4375	.0544	18.37	.3055	3.273	28.00	*8 1/8
*8 1/8	32.00	7.385	7.260	2.2252	.4494	.0529	18.88	.2974	3.362	32.00	*8 1/8
*8 1/8	35.50	7.285	7.160	2.1653	.4618	.0515	19.40	.2894	3.455	35.50	*8 1/8
*8 1/8	39.50	7.185	7.060	2.1063	.4748	.0501	19.94	.2815	3.552	39.50	*8 1/8
*8 5/8	20.00	8.191	8.066	2.7374	.3653	.0652	15.34	.3659	2.733	20.00	*8 5/8
*8 5/8	24.00	8.097	7.972	2.6749	.3738	.0636	15.70	.3575	2.797	24.00	*8 5/8
8 5/8	28.00	8.017	7.892	2.6223	.3813	.0624	16.02	.3505	2.853	28.00	8 5/8
8 5/8	32.00	7.921	7.796	2.5599	.3906	.0609	16.41	.3422	2.922	32.00	8 5/8
8 5/8	36.00	7.825	7.700	2.4982	.4003	.0594	16.81	.3339	2.994	36.00	8 5/8
*8 5/8	38.00	7.775	7.650	2.4664	.4055	.0587	17.03	.3297	3.033	38.00	*8 5/8
8 5/8	40.00	7.725	7.600	2.4348	.4107	.0579	17.25	.3254	3.072	40.00	8 5/8
*8 5/8	43.00	7.651	7.526	2.3883	.4187	.0568	17.59	.3192	3.132	43.00	*8 5/8
8 5/8	44.00	7.625	7.500	2.3721	.4216	.0564	17.71	.3171	3.154	44.00	8 5/8
8 5/8	49.00	7.511	7.386	2.3017	.4345	.0548	18.25	.3077	3.250	49.00	8 5/8
*9	34.00	8.290	8.134	2.8039	.3566	.0667	14.98	.3748	2.668	34.00	*9
*9	38.00	8.196	8.040	2.7407	.3649	.0653	15.32	.3664	2.729	38.00	*9
*9	40.00	8.150	7.994	2.7100	.3690	.0645	15.50	.3622	2.760	40.00	*9
*9	45.00	8.032	7.876	2.6321	.3799	.0626	15.96	.3518	2.842	45.00	*9
*9	55.00	7.812	7.656	2.4899	.4016	.0592	16.87	.3328	3.004	55.00	*9
*9 5/8	29.30	9.063	8.907	3.3512	.2984	.0797	12.53	.4479	2.232	29.30	*9 5/8
9 5/8	32.30	9.001	8.845	3.3055	.3025	.0787	12.71	.4418	2.263	32.30	9 5/8
9 5/8	36.00	8.921	8.765	3.2470	.3080	.0773	12.93	.4340	2.304	36.00	9 5/8
*9 5/8	38.00	8.885	8.760	3.2209	.3105	.0766	13.04	.4305	2.323	38.00	*9 5/8
9 5/8	40.00	8.835	8.679	3.1847	.3140	.0758	13.19	.4257	2.349	40.00	9 5/8
9 5/8	43.50	8.755	8.599	3.1273	.3198	.0744	13.43	.4180	2.392	43.50	9 5/8
9 5/8	47.00	8.681	8.525	3.0747	.3252	.0732	13.66	.4110	2.433	47.00	9 5/8
9 5/8	53.50	8.535	8.379	2.9721	.3365	.0707	14.13	.3973	2.517	53.50	9 5/8
*9 5/8	58.40	8.435	8.279	2.9029	.3445	.0691	14.47	.3880	2.577	58.40	*9 5/8
*9 5/8	61.10	8.375	8.219	2.8617	.3494	.0681	14.68	.3825	2.614	61.10	*9 5/8
*9 5/8	71.80	8.125	7.969	2.6934	.3713	.0641	15.59	.3600	2.777	71.80	*9 5/8
*10	33.00	9.384	9.228	3.5928	.2783	.0855	11.69	.4802	2.082	33.00	*10
10 3/4	32.75	10.192	10.036	4.2382	.2360	.1009	9.91	.5665	1.765	32.75	10 3/4
*10 3/4	35.75	10.136	9.980	4.1917	.2386	.0998	10.02	.5603	1.785	35.75	*10 3/4
10 3/4	40.50	10.050	9.894	4.1209	.2427	.0981	10.19	.5508	1.815	40.50	10 3/4
10 3/4	45.50	9.950	9.794	4.0393	.2476	.0961	10.40	.5399	1.852	45.50	10 3/4
10 3/4	51.00	9.850	9.694	3.9585	.2526	.0942	10.61	.5291	1.890	51.00	10 3/4
*10 3/4	54.00	9.784	9.628	3.9056	.2560	.0929	10.75	.5221	1.915	54.00	*10 3/4
10 3/4	55.50	9.760	9.604	3.8865	.2573	.0925	10.81	.5195	1.925	55.50	10 3/4
10 3/4	60.70	9.660	9.504	3.8073	.2627	.0906	11.03	.5089	1.965	60.70	10 3/4
10 3/4	65.70	9.560	9.404	3.7288	.2682	.0887	11.26	.4984	2.006	65.70	10 3/4
*10 3/4	71.10	9.450	9.294	3.6435	.2745	.0867	11.53	.4870	2.053	71.10	*10 3/4

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TABLE NO. 214
CAPACITY OF CASING

Size O. D. In.	Wt. Per Ft. With Couplings Lb.	Inside Diameter In.	Drift Diameter In.	Gallons Per Lin. Ft.	Lin. Ft. Per Gallon	Barrels Per Lin. Ft.	Lin. Ft. Per Barrel	Cu. Ft. Per Lin. Ft.	Lin. Ft. Per Cu. Ft.	Wt/Ft With Couplings Lb.	Size O. D. In.
*11¾	38.00	11.150	10.994	5.0723	.1971	.1207	8.28	.6780	1.475	38.00	*11¾
11¾	42.00	11.084	10.928	5.0125	.1995	.1193	8.38	.6700	1.492	42.00	11¾
11¾	47.00	11.000	10.844	4.9368	.2026	.1175	8.51	.6599	1.515	47.00	11¾
11¾	54.00	10.880	10.724	4.8297	.2071	.1149	8.70	.6456	1.549	54.00	11¾
11¾	60.00	10.772	10.616	4.7343	.2112	.1127	8.87	.6328	1.580	60.00	11¾
*11¾	65.00	10.682	10.526	4.6555	.2148	.1108	9.02	.6223	1.607	65.00	*11¾
*12	40.00	11.384	11.228	5.2875	.1891	.1258	7.94	.7068	1.415	40.00	*12
*13	40.00	12.438	12.282	6.3119	.1584	.1502	6.65	.8437	1.185	40.00	*13
*13	45.00	12.360	12.204	6.2330	.1604	.1484	6.74	.8332	1.200	45.00	*13
*13	50.00	12.282	12.126	6.1546	.1625	.1465	6.82	.8227	1.215	50.00	*13
*13	54.00	12.220	12.064	6.0926	.1641	.1450	6.89	.8144	1.228	54.00	*13
13⅜	48.00	12.715	12.559	6.5962	.1516	.1570	6.37	.8817	1.134	48.00	13⅜
13⅜	54.50	12.615	12.459	6.4928	.1540	.1545	6.47	.8679	1.152	54.50	13⅜
13⅜	61.00	12.515	12.359	6.3903	.1565	.1521	6.57	.8542	1.171	61.00	13⅜
13⅜	68.00	12.415	12.259	6.2886	.1590	.1497	6.68	.8406	1.190	68.00	13⅜
13⅜	72.00	12.347	12.191	6.2199	.1608	.1480	6.75	.8314	1.203	72.00	13⅜
*13⅜	77.00	12.275	12.119	6.1476	.1627	.1463	6.83	.8218	1.217	77.00	*13⅜
*13⅜	83.00	12.175	12.019	6.0478	.1653	.1440	6.94	.8084	1.237	83.00	*13⅜
*13⅜	85.00	12.159	12.003	6.0319	.1658	.1436	6.96	.8063	1.240	85.00	*13⅜
*13⅜	98.00	11.937	11.781	5.8137	.1720	.1384	7.22	.7771	1.287	98.00	*13⅜
*14	50.00	13.344	13.156	7.2649	.1376	.1729	5.78	.9711	1.030	50.00	*14
16	65.00	15.250	15.062	9.4885	.1054	.2259	4.43	1.2684	.788	65.00	16
*16	70.00	15.198	15.010	9.4239	.1061	.2241	4.46	1.2598	.794	70.00	*16
16	75.00	15.124	14.936	9.3324	.1072	.2222	4.50	1.2475	.802	75.00	16
16	84.00	15.010	14.822	9.1922	.1088	.2188	4.57	1.2288	.814	84.00	16
*16	109.00	14.688	14.500	8.8021	.1136	.2095	4.77	1.1766	.850	109.00	*16
*18⅝	78.00	17.855	17.667	13.0070	.0769	.3096	3.23	1.7387	.575	78.00	*18⅝
18⅝	87.50	17.755	17.567	12.8618	.0777	.3062	3.27	1.7193	.582	87.50	18⅝
*18⅝	96.50	17.655	17.467	12.7173	.0786	.3027	3.30	1.7000	.588	96.50	*18⅝
*20	90.00	19.166	18.978	14.9872	.0667	.3568	2.80	2.0035	.499	90.00	*20
20	94.00	19.124	18.936	14.9216	.0670	.3552	2.81	1.9947	.501	94.00	20
20	106.50	19.000	18.812	14.7288	.0679	.3506	2.85	1.9689	.508	106.50	20
20	133.00	18.730	18.542	14.3131	.0699	.3407	2.93	1.9133	.523	133.00	20
*21½	92.50	20.710	20.522	17.4992	.0571	.4166	2.40	2.3393	.427	92.50	*21½
*21½	103.00	20.610	20.422	17.3307	.0577	.4126	2.42	2.3167	.432	103.00	*21½
*21½	114.00	20.510	20.322	17.1629	.0583	.4086	2.45	2.2943	.436	114.00	*21½
*24½	100.50	23.750	23.562	23.0137	.0435	.5479	1.83	3.0764	.325	100.50	*24½
*24½	113.00	23.650	23.462	22.8203	.0438	.5433	1.84	3.0506	.328	113.00	*24½

*Not API Standard. Shown for information only.

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Inside Tubing
O.D. 1.050"
ONE STRING

TABLE VOLUME & HEIGHT

Outside Casing: Size O.D. In.	Outside Casing: Wt/Ft With Couplings Lb.	Outside Casing: I.D. In.	Gal. Per Lin. Ft.	Lin. Ft. Per Gallon	Barrels Per Lin. Ft.
4 1/2	9.50	4.090	.6375	1.5686	.0152
4 1/2	10.50	4.052	.6249	1.6003	.0149
4 1/2	11.60	4.000	.6078	1.6452	.0145
4 1/2	13.50	3.920	.5820	1.7183	.0139
*4 1/2	15.10	3.826	.5523	1.8107	.0131
*4 3/4	16.00	4.082	.6349	1.5752	.0151
5	11.50	4.560	.8034	1.2447	.0191
5	13.00	4.494	.7790	1.2837	.0185
5	15.00	4.408	.7478	1.3373	.0178
5	18.00	4.276	.7010	1.4265	.0167
*5	21.00	4.154	.6590	1.5173	.0157
*5 1/2	13.00	5.044	.9930	1.0070	.0236
5 1/2	14.00	5.012	.9799	1.0205	.0233
*5 1/2	15.00	4.974	.9644	1.0369	.0230
5 1/2	15.50	4.950	.9547	1.0474	.0227
5 1/2	17.00	4.892	.9314	1.0736	.0222
5 1/2	20.00	4.778	.8865	1.1281	.0211
5 1/2	23.00	4.670	.8448	1.1837	.0201
*5 3/4	14.00	5.290	1.0768	.9118	.0261
*5 3/4	17.00	5.190	1.0540	.9488	.0251
*5 3/4	19.50	5.090	1.0121	.9881	.0241
*5 3/4	22.50	4.990	.9709	1.0299	.0231
*6	15.00	5.524	1.2000	.8333	.0286
*6	16.00	5.500	1.1892	.8409	.0283
*6	17.00	5.450	1.1669	.8570	.0278
*6	18.00	5.424	1.1553	.8655	.0275
*6	20.00	5.352	1.1237	.8899	.0268
*6	23.00	5.240	1.0753	.9300	.0256
*6	26.00	5.132	1.0296	.9713	.0245
*6 5/8	17.00	6.135	1.4907	.6708	.0355
6 5/8	20.00	6.049	1.4479	.6907	.0345
*6 5/8	22.00	5.989	1.4184	.7050	.0338
6 5/8	24.00	5.921	1.3854	.7218	.0330
*6 5/8	26.00	5.855	1.3537	.7387	.0322
6 5/8	28.00	5.791	1.3233	.7557	.0315
*6 5/8	29.00	5.761	1.3091	.7639	.0312
6 5/8	32.00	5.675	1.2690	.7880	.0302
7	17.00	6.538	1.6990	.5886	.0405
7	20.00	6.456	1.6556	.6040	.0394
*7	22.00	6.398	1.6251	.6153	.0387
7	23.00	6.366	1.6085	.6217	.0383
*7	24.00	6.336	1.5929	.6278	.0379
7	26.00	6.276	1.5621	.6402	.0372
*7	28.00	6.214	1.5305	.6534	.0364
7	29.00	6.184	1.5153	.6599	.0361
*7	30.00	6.154	1.5002	.6666	.0357
7	32.00	6.094	1.4702	.6802	.0350
*7	34.00	6.040	1.4435	.6928	.0344
7	35.00	6.004	1.4258	.7014	.0339
7	38.00	5.920	1.3849	.7221	.0330
*7	40.00	5.836	1.3446	.7437	.0320
*7 5/8	20.00	7.125	2.0263	.4935	.0482
7 5/8	24.00	7.025	1.9685	.5080	.0469
7 5/8	26.40	6.969	1.9365	.5164	.0461
7 5/8	29.70	6.875	1.8835	.5309	.0448
7 5/8	33.70	6.765	1.8222	.5488	.0434
7 5/8	39.00	6.625	1.7458	.5728	.0416

*Not API Standard. Shown for information only.

Inside Tubing
O.D. 1.050"
ONE STRING

NO. 221-B BETWEEN TUBING & CASING**

Lin. Ft. Per Barrel	Cu. Ft. Per Lin. Ft.	Lin. Ft. Per Cu. Ft.	Outside Casing: Wt/Ft With Couplings Lb.	Outside Casing: Size O.D. In.
65.88	.0852	11.734	9.50	4 1/2
67.21	.0835	11.971	10.50	4 1/2
69.10	.0813	12.307	11.60	4 1/2
72.17	.0778	12.854	13.50	4 1/2
76.05	.0738	13.545	15.10	*4 1/2
66.16	.0849	11.783	16.00	*4 3/4
52.28	.1074	9.311	11.50	5
53.91	.1041	9.603	13.00	5
56.17	.1000	10.004	15.00	5
59.91	.0937	10.671	18.00	5
63.73	.0881	11.351	21.00	*5
42.29	.1328	7.533	13.00	*5 1/2
42.86	.1310	7.634	14.00	5 1/2
43.55	.1289	7.756	15.00	*5 1/2
43.99	.1276	7.835	15.50	5 1/2
45.09	.1245	8.031	17.00	5 1/2
47.38	.1185	8.439	20.00	5 1/2
49.71	.1129	8.855	23.00	5 1/2
38.39	.1466	6.821	14.00	*5 3/4
39.85	.1409	7.097	17.00	*5 3/4
41.50	.1353	7.391	19.50	*5 3/4
43.26	.1298	7.704	22.50	*5 3/4
35.00	.1604	6.234	15.00	*6
35.32	.1590	6.290	16.00	*6
35.99	.1560	6.411	17.00	*6
36.35	.1544	6.475	18.00	*6
37.38	.1502	6.657	20.00	*6
39.06	.1437	6.957	23.00	*6
40.79	.1376	7.266	26.00	*6
28.18	.1993	5.018	17.00	*6 5/8
29.01	.1936	5.167	20.00	6 5/8
29.61	.1896	5.274	22.00	*6 5/8
30.32	.1852	5.400	24.00	6 5/8
31.03	.1810	5.526	26.00	*6 5/8
31.74	.1769	5.653	28.00	6 5/8
32.08	.1750	5.714	29.00	*6 5/8
33.10	.1696	5.895	32.00	6 5/8
24.72	.2271	4.403	17.00	7
25.37	.2213	4.518	20.00	7
25.84	.2172	4.603	22.00	*7
26.11	.2150	4.651	23.00	7
26.37	.2129	4.696	24.00	*7
26.89	.2088	4.789	26.00	7
27.44	.2046	4.888	28.00	*7
27.72	.2026	4.937	29.00	7
28.00	.2005	4.986	30.00	*7
28.57	.1965	5.088	32.00	7
29.10	.1930	5.182	34.00	*7
29.46	.1906	5.247	35.00	7
30.33	.1851	5.402	38.00	7
31.24	.1797	5.563	40.00	*7
20.73	.2709	3.692	20.00	*7 5/8
21.34	.2632	3.800	24.00	7 5/8
21.69	.2589	3.863	26.40	7 5/8
22.30	.2518	3.972	29.70	7 5/8
23.05	.2436	4.105	33.70	7 5/8
24.06	.2334	4.285	39.00	7 5/8

**NOTE: No allowance made for couplings.

Inside Tubing
O.D. 1.315"
ONE STRING

TABLE VOLUME & HEIGHT

OUTSIDE CASING					
Size O. D. In.	Wt/Ft With Couplings Lb.	I. D. In.	Gal. Per Lin. Ft.	Lin. Ft. Per Gallon	Barrels Per Lin. Ft.
4½	9.50	4.090	.6120	1.6341	.0146
4½	10.50	4.052	.5993	1.6685	.0143
4½	11.60	4.000	.5822	1.7175	.0139
4½	13.50	3.920	.5564	1.7973	.0132
*4½	15.10	3.826	.5267	1.8987	.0125
*4¾	16.00	4.082	.6093	1.6413	.0145
5	11.50	4.560	.7778	1.2856	.0185
5	13.00	4.494	.7534	1.3272	.0179
5	15.00	4.408	.7222	1.3846	.0172
5	18.00	4.276	.6754	1.4805	.0161
*5	21.00	4.154	.6335	1.5786	.0151
*5½	13.00	5.044	.9675	1.0336	.0230
5½	14.00	5.012	.9543	1.0478	.0227
*5½	15.00	4.974	.9389	1.0651	.0224
5½	15.50	4.950	.9291	1.0763	.0221
5½	17.00	4.892	.9059	1.1039	.0216
5½	20.00	4.778	.8609	1.1616	.0205
5½	23.00	4.670	.8192	1.2206	.0195
*5¾	14.00	5.290	1.0712	.9335	.0255
*5¾	17.00	5.190	1.0284	.9723	.0245
*5¾	19.50	5.090	.9865	1.0137	.0235
*5¾	22.50	4.990	.9454	1.0578	.0225
*6	15.00	5.524	1.1744	.8515	.0280
*6	16.00	5.500	1.1636	.8594	.0277
*6	17.00	5.450	1.1413	.8762	.0272
*6	18.00	5.424	1.1298	.8851	.0269
*6	20.00	5.352	1.0981	.9106	.0261
*6	23.00	5.240	1.0497	.9526	.0250
*6	26.00	5.132	1.0040	.9960	.0239
*6⅝	17.00	6.135	1.4651	.6826	.0349
6⅝	20.00	6.049	1.4223	.7031	.0339
*6⅝	22.00	5.989	1.3929	.7179	.0332
6⅝	24.00	5.921	1.3598	.7354	.0324
*6⅝	26.00	5.855	1.3281	.7529	.0316
6⅝	28.00	5.791	1.2977	.7706	.0309
*6⅝	29.00	5.761	1.2836	.7791	.0306
6⅝	32.00	5.675	1.2434	.8042	.0296
7	17.00	6.538	1.6735	.5976	.0398
7	20.00	6.456	1.6300	.6135	.0388
*7	22.00	6.398	1.5996	.6252	.0381
7	23.00	6.366	1.5829	.6318	.0377
*7	24.00	6.336	1.5674	.6380	.0373
7	26.00	6.276	1.5365	.6508	.0366
*7	28.00	6.214	1.5049	.6645	.0358
7	29.00	6.184	1.4897	.6713	.0355
*7	30.00	6.154	1.4746	.6781	.0351
7	32.00	6.094	1.4446	.6922	.0344
*7	34.00	6.040	1.4179	.7053	.0338
7	35.00	6.004	1.4002	.7142	.0333
7	38.00	5.920	1.3593	.7357	.0324
*7	40.00	5.836	1.3190	.7581	.0314
*7⅝	20.00	7.125	2.0007	.4998	.0476
7⅝	24.00	7.025	1.9429	.5147	.0463
7⅝	26.40	6.969	1.9110	.5233	.0455
7⅝	29.70	6.875	1.8579	.5382	.0442
7⅝	33.70	6.765	1.7967	.5566	.0428
7⅝	39.00	6.625	1.7202	.5813	.0410

*Not API Standard. Shown for information only.

NO. 221-B

BETWEEN TUBING & CASING**

Inside Tubing
O.D. 1.315"
ONE STRING

			OUTSIDE CASING	
Lin. Ft. Per Barrel	Cu. Ft. Per Lin. Ft.	Lin. Ft. Per Cu. Ft.	Wt/Ft With Couplings Lb.	Size O. D. In.
68.63	.0818	12.224	9.50	4½
70.08	.0801	12.481	10.50	4½
72.13	.0778	12.848	11.60	4½
75.49	.0744	13.445	13.50	4½
79.74	.0704	14.203	15.10	*4½
68.93	.0814	12.278	16.00	*4¾
54.00	.1040	9.617	11.50	5
55.74	.1007	9.928	13.00	5
58.15	.0965	10.358	15.00	5
62.18	.0903	11.075	18.00	5
66.30	.0847	11.809	21.00	*5
43.41	.1293	7.732	13.00	*5½
44.01	.1276	7.838	14.00	5½
44.73	.1255	7.968	15.00	*5½
45.20	.1242	8.051	15.50	5½
46.36	.1211	8.258	17.00	5½
48.79	.1151	8.689	20.00	5½
51.27	.1095	9.131	23.00	5½
39.21	.1432	6.983	14.00	*5¾
40.84	.1375	7.274	17.00	*5¾
42.57	.1319	7.583	19.50	*5¾
44.43	.1264	7.913	22.50	*5¾
35.76	.1570	6.369	15.00	*6
36.09	.1556	6.429	16 00	*6
36.80	.1526	6.554	17.00	*6
37.18	.1510	6.621	18.00	*6
38.25	.1468	6.812	20.00	*6
40.01	.1403	7.126	23.00	*6
41.83	.1342	7.451	26.00	*6
28.67	.1959	5.106	17.00	*6⅝
29.53	.1901	5.259	20.00	6⅝
30.15	.1862	5.371	22.00	*6⅝
30.89	.1818	5.501	24.00	6⅝
31.62	.1775	5.632	26.00	*6⅝
32.36	.1735	5.764	28.00	6⅝
32.72	.1716	5.828	29.00	*6⅝
33.78	.1662	6.016	32.00	6⅝
25.10	.2237	4.470	17.00	7
25.77	.2179	4.589	20.00	7
26.26	.2138	4.677	22.00	*7
26.53	.2116	4.726	23.00	7
26.80	.2095	4.773	24.00	*7
27.34	.2054	4.869	26.00	7
27.91	.2012	4.971	28.00	*7
28.19	.1991	5.022	29.00	7
28.48	.1971	5.073	30.00	*7
29.07	.1931	5.178	32.00	7
29.62	.1895	5.276	34.00	*7
30.00	.1872	5.342	35.00	7
30.90	.1817	5.503	38.00	7
31.84	.1763	5.671	40.00	*7
20.99	.2675	3.739	20.00	*7⅝
21.62	.2597	3.850	24.00	7⅝
21.98	.2555	3.915	26.40	7⅝
22.61	.2484	4.026	29.70	7⅝
23.38	.2402	4.164	33.70	7⅝
24.42	.2300	4.349	39.00	7⅝

**NOTE: No allowance made for couplings.

Appendix: 10

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Presented at Short Course IX on Exploration for Geothermal Resources,
organized by UNU-GTP, GDC and KenGen, at Lake Bogoria and Lake Naivasha, Kenya, Nov. 2-23, 2014.

GDC Geothermal Development Company Powering the Vision
UNITED NATIONS UNIVERSITY UNU-GTP Geothermal Training Programme
KenGen Kenya Electricity Generating Co., Ltd.

INTRODUCTION TO GEOPHYSICAL WELL LOGGING AND FLOW TESTING

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ABSTRACT

Well logging is the practice of making a detailed record of the geologic formations penetrated by the well. The log may be either geological logs or geophysical logs. In geothermal, geophysical logging is done to identify location of fractures, the lithology and record the physical parameters like temperature and pressure. Important logs include temperature, pressure, gamma, neutron, cement bond log, calliper log, resistivity and directional surveying.

When the well has recovered sufficiently, a flow test is conducted by flowing the well to evaluate the total flow rate, enthalpy and chemical characteristics of the discharged fluids. A common method used in flow testing is the lip pressure method (Grant et al., 1982). The well is discharged under different throttle conditions to get the characteristic curve to be used in selecting operating conditions for the turbines in the power plant.

1. INTRODUCTION

Logging generally means to "make a record" of something. Well logging, also known as borehole logging is therefore, the practice of making a detailed record (a *well log*) of the geologic formations penetrated by a well. The log may be based either on visual inspection of samples brought to the surface (*geological* logs e.g. cuttings logs, core-logging or petro-physical logging) or on physical measurements made by instruments lowered into the hole (*geophysical* logs). Geophysical well logging was first developed for petroleum industry by Marcel and Conrad Schlumberger in 1927 (Schlumberger, 2000). They developed a resistivity tool to detect differences in the porosity of sandstones of oilfield at Merwiller-Pechelbronn in France. Since then, geophysical well logging has developed to become a key technology in petroleum, geotechnical, mineral, groundwater and geothermal industries. While geophysical logging in petroleum is done to determine porosity and hydrocarbon saturation, in geothermal, the main emphasis is on location of fractures and recording of physical parameters e.g. temperature and pressure. Well logging is done during all phases of geothermal development; drilling, completion, production and abandonment.

When the well has recovered from the effects of cooling during drilling, it is flow tested to evaluate its mass flow, enthalpy and chemical characteristics. This paper will attempt to give a short description of the more routine geophysical well logging methods used in the geothermal development as well as the method commonly used in flow testing of the geothermal wells.

2. GEOPHYSICAL WELL LOGGING

Knowledge of the subsurface comes primarily from drilling which is a very expensive process. Therefore, the number of holes to be drilled for studying the subsurface is limited. Geophysical logging offers an opportunity to determine the composition, variability and physical properties of the rocks around the well thereby enabling a proper understanding of the subsurface at a cheaper cost. The following are the common geophysical logging methods used in geothermal applications.

2.1 Caliper logging

A calliper tool is used to measure the diameter of a well and how it changes with depth. It works by using one or more spring loaded arms which are pressed against the well bore wall as the tool is raised from the bottom of the well. The arms move in and out from the bore wall and the motion is recorded electrically and transmitted to the surface recording equipment. Multi-arm tool gives a better resolution of the bore shape than a single arm tool.

The results of the caliper logs can be used by the drillers to calculate amount of cement to be used for cementing job if it is run in the open hole prior to cementing to identify the large cavities. Caliper logs are also used in addition to lithological logs when interpreting the well geology.

2.2 Cement bond logging

Cement Bond Logs (CBL) use sonic tools that work by transmitting a sound wave through the casing, cemented annulus into the rocks of the borehole wall. A basic sonic tool consists of two parts. One contains the transmitter and the other contains two or more receivers. The two parts are normally separated by a rubber connector to reduce direct transmission of acoustic energy along the tool from the transmitter to the receiver.

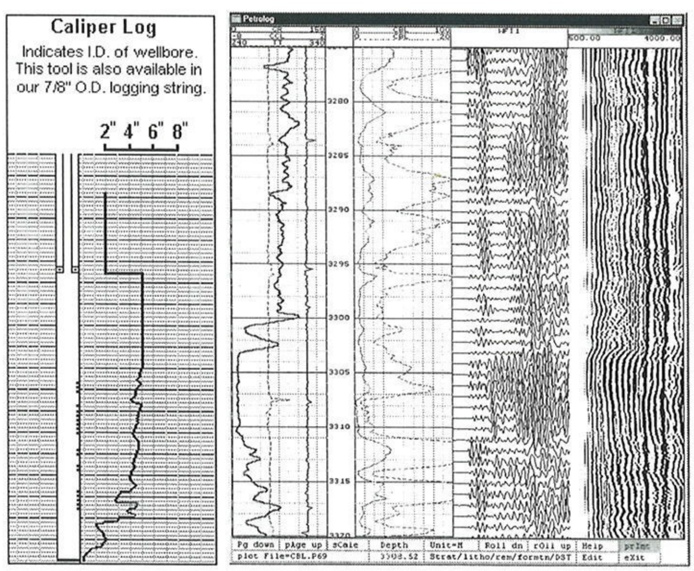

FIGURE 1: A Caliper and CBL log display (They are for different wells)

The transmitter injects a sinusoidal wave-train of acoustic energy into the formation. The detectors receive the signals whose arrival time will depend on the density of the media the signal has traversed. CBL is used for:

- Determining cement bond quality between cement and casing and also between cement and formation for zone isolation
- Correlating open hole logs to cased hole logs using the Casing Collar Locator (CCL) and Gamma Ray tool
- Indication of cement compressive strength. These tools can also measure casing thickness, micro annulus and cement channeling but do not measure cement bond to formation as well as the CBL

Once a well has been determined to be productive, casing is run in the open hole and cement is pumped to the outside of the casing to seal the casing to the borehole wall. A Cement Bond Log (CBL) is then run to inspect the integrity of the cement sealing to the casing and to the formation. This will ensure that undesired formation fluids will not flow into the well when on production or up or down the outside of the casing.

2.3 Lithological logging

Common lithological logging tools use either radioactive or resistivity methods. Principal radioactive emissions of interest in borehole geophysics are gamma rays and neutrons. Other radioactive products such as alpha particles and beta particles have low penetration capabilities and so are not useful for logging.

2.3.1 Natural gamma logging

This is the simplest geophysical well logging. These logging tools record the level of naturally occurring gamma ray emissions from rocks around the borehole. The signals comprise gamma ray emissions at different energy levels from the radioactive isotopes of Potassium (^{40}K), Thorium (^{232}Th) and Uranium (^{238}U) and their daughter products of the decay series. Distribution of K, Th and U varies widely in the crust and as a result, logging of the gamma ray signals emanating from the rocks around the borehole can provide considerable information about the geology of the borehole.

2.3.2 Neutron

Neutron-neutron and gamma ray tools are normally combined and run together. The neutron sensors measure the water content of the rock because the hydrogen atoms deflect neutron particles emitted from the tool. Porosity is a function of rock type and slow neutron count.

2.3.3 Resistivity logs

Resistance is impedance to flow of current and is a function of geometry and intrinsic resistivity of the material. Resistivity is the inverse of conductivity. Current flow in porous rock is mainly through the fluid filling the pore space and is affected by pore volume, pore connectivity and pore fluid composition, degree of alteration and mineralogy and temperature. Pore space character varies from formation to formation and for this reason, resistivity logs are often useful for exploring lithological units.

2.2.2 Self potential (SP) logs

SP method was developed by Schlumberger and measure small potential differences between the downhole movable electrode and the surface earth connection. The potentials arise from electrochemical and electrokinetic processes and are typically in the range of a few mV to a few tens of mV.

2.2.3 Induced polarisation (IP) logs

IP uses a transmitter loop to charge the ground with a high current. The transmitter loop is then turned off and the change in voltage with time is monitored using a secondary loop. In a well, the primary loop induces current flow in the rocks beyond the bore wall and the current leads to a charge build-up on conductive particles. The time dependent dissipation of this charge is then reflected as a decaying voltage. The IP can be used in detection of alteration zones.

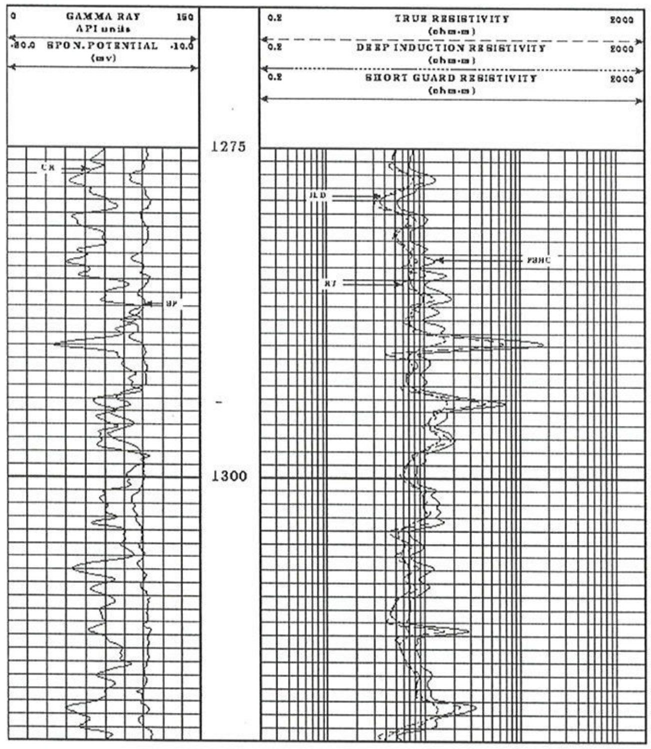

FIGURE 2: Gamma ray and resistivity logs

2.4 Temperature logging

Temperature Logs are the most important in geothermal applications. They are used to show how hot the well is and to locate aquifers. The information on aquifers is very useful in identifying the main inflow into the well for production purposes and also for cementing purposes where powerful aquifers have to be known so as to ensure good cementing jobs. Lithological tools and other electrical tools are very sensitive to temperature and so before running these tools, a temperature log would indicate whether it is safe.

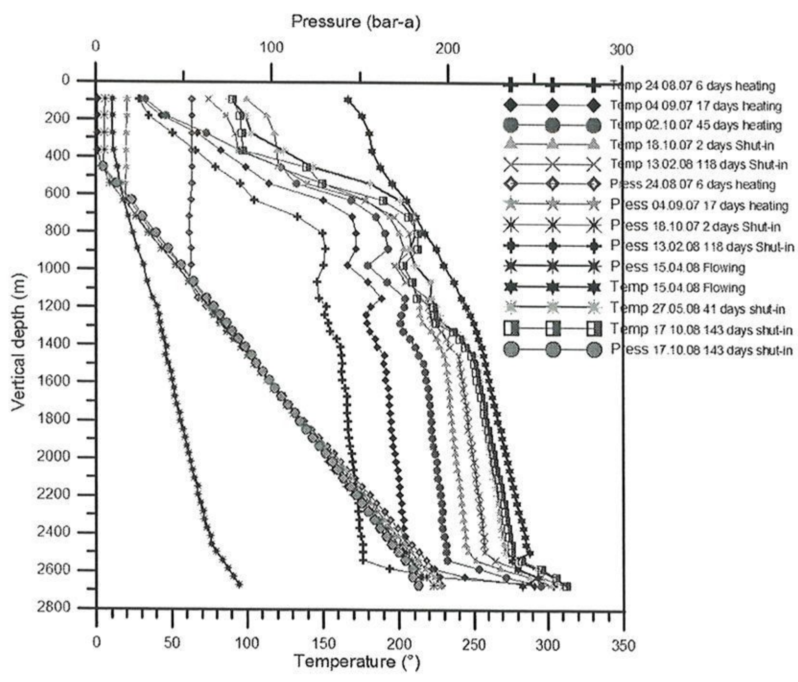

FIGURE 3: Pressure and temperature logs from one of the wells in Olkaria

2.5 Pressure logging

In most cases, pressure logs are done when the well has been drilled to the final depth. Transient pressure tests are done to estimate well injectivity index and hydraulic properties of the prominent aquifers. The injectivity index gives an idea of the well productivity. Pressure logs also indicate the type of fluids contained in the reservoir whether liquid or gas/steam as well as where the well is best connected to the reservoir.

2.6 Directional surveying

Directional drilling has gained importance in geothermal drilling in the recent past. To this effect, tools that can indicate the direction of the well profile as well as depth and azimuth are now available. Two types of directional tools are in operation i.e single-shot and multi-shot magnetic or gyro tool. Magnetic Single-Shot records one measurement, usually near the bottom of the well. It is comprised of a precision floating compass, a device to superimpose concentric circles (calibrated in degrees) with a plumb-bob type indicator, and a camera that photographs the plumb-bob and compass face to record both drift and direction. It cannot record compass directions inside regular drill collars or casing because steel pipe blanks off the Earth's magnetic lines of force. Thus, it is used only in open hole or inside non-magnetic drill collars. Magnetic Multi-Shot records multiple measurements of borehole drift and azimuth on a single run into the hole. It consists of a modified magnetic single-shot instrument with the single frame camera replaced by a multi-frame camera. It also has incorporated timing devices, including a motion sensor, and is used for multi-depth drift and direction measurements. Like the single-shot, It must be in an open hole or inside non-magnetic drill collars to measure compass directions.

Gyroscopes are impervious to magnetic interference and can be used to survey in cased wells or orient directional equipment for re-entry wells. The photographic gyroscope is used primarily to survey wellbores that have already been cased. This instrument can run in casing, tubing or drillstring, using a wireline.

The latest high precision tool is multi-shot true north seeking tool by Stockholm Precision Tools (SPT). The SPT system uses the gyro-compassing method to find direction. As it is a north-seeking gyro, all measurements are in reference to geographic north. Unlike other downhole survey or magnetic tools, the GyroTracer is not affected by magnetic interference. It can be run inside casing, tubing, drill pipe and magnetically disturbed ground. It can be run either as wire-line SRO (surface read out) or in memory mode via slickline.

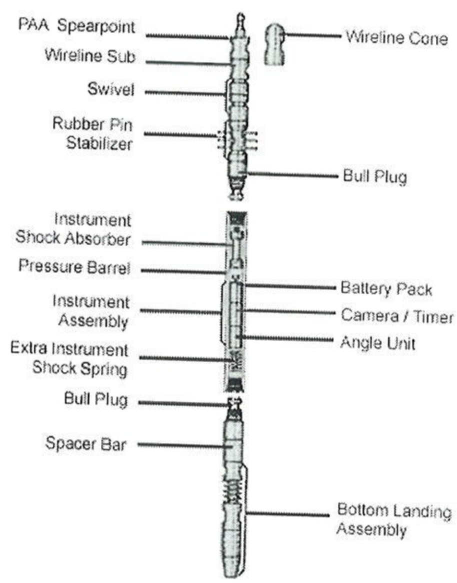

FIGURE 4: Multi-shot magnetic tool

3. FLOW TESTING

During recovery or warm up period, the water level in the well gradually rises and if there is boiling or accumulation of gas, the well will eventually build wellhead pressure above atmospheric for artesian flow. If not, the discharge can be initiated by compression, gas lift or swabbing. When the well has built up sufficient wellhead pressure and the well has recovered sufficiently, a flow test is then conducted by flowing the well through an orifice. Measurements are taken to evaluate the total flow rate, enthalpy and chemical characteristics of the discharged fluids. The lip pressure method (Grant et al., 1982) or a separator can be used to determine the total flow rate and enthalpy with a simple weir being used to measure separated water flow. By repeating the flow tests with different sized orifices, the well productivity as a function of wellhead pressure can be determined. This is the characteristic curve for the well that can be used in selecting operating conditions for the turbines in the power plant.

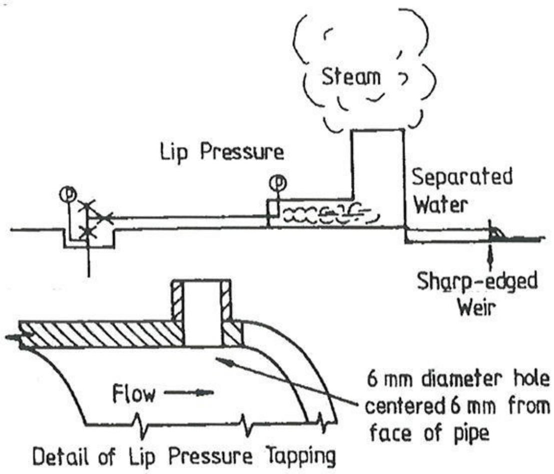

FIGURE 5: Schematic of Lip pressure method

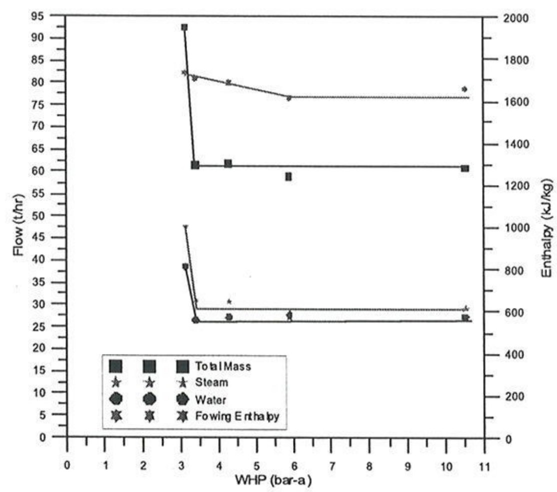

FIGURE 6: Characteristic curves of one of the Olkaria wells

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Appendix: 11

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Paper #2-25

PLUGGING AND ABANDONMENT OF OIL AND GAS WELLS

Prepared by the Technology Subgroup
of the
Operations & Environment Task Group

On September 15, 2011, The National Petroleum Council (NPC) in approving its report, *Prudent Development: Realizing the Potential of North America's Abundant Natural Gas and Oil Resources*, also approved the making available of certain materials used in the study process, including detailed, specific subject matter papers prepared or used by the study's Task Groups and/or Subgroups. These Topic and White Papers were working documents that were part of the analyses that led to development of the summary results presented in the report's Executive Summary and Chapters.

These Topic and White Papers represent the views and conclusions of the authors. The National Petroleum Council has not endorsed or approved the statements and conclusions contained in these documents, but approved the publication of these materials as part of the study process.

The NPC believes that these papers will be of interest to the readers of the report and will help them better understand the results. These materials are being made available in the interest of transparency.

The attached paper is one of 57 such working documents used in the study analyses. Also included is a roster of the Subgroup that developed or submitted this paper. Appendix C of the final NPC report provides a complete list of the 57 Topic and White Papers and an abstract for each. The full papers can be viewed and downloaded from the report section of the NPC website (www.npc.org).

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* Individual has since retired but was employed by the specified company while participating in the study.

** Individual has since retired but was employed by the specified company while participating in the study.

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EXECUTIVE SUMMARY

Modern regulatory standards in all US jurisdictions require specific provisions for plugging and documenting oil and natural gas wells before they are abandoned. Plugging and abandonment (P&A) regulations vary to some degree among states but all state regulations prescribe the depth intervals which must be cemented as well as the materials that are allowable in plugging practices

The basic technologies associated with the plugging and abandoning of wells has not changed significantly since the 1970s. Water-based slurries of cement and drilling mud are still the basic materials used to plug most wells although progress has been made in use of additives to customize the cements and muds for specific types of wells.

Recent shale-gas developments have rediscovered some P&A issues in the forms of older oil or gas wells which never were adequately plugged but which now pose possible cross-contamination or leakage risks. Furthermore, eventual retirement of uneconomical shale-gas wells must address P&A practices that are specific to issues affecting gas wells and especially horizontal gas wells.

The lack of progress in P&A practices is attributable to absence of a long-term vision, and inattention to corresponding research, that recognizes the benefits of P&A to oil and gas development projects. Specific findings are that:

- Benefits from reduced operational costs and/or increased production, especially in redeveloped, older fields, generally has been underappreciated.
- By plugging wells correctly, future environmental issues, related to fluid or gas leakage, can be avoided and thereby preserve savings otherwise eroded by remediation or litigation costs.
- Research has lagged on materials and methods for plugging wells although advances in technologies for drilling and completion should be applicable to practices in plugging and abandonment.

INTRODUCTION

The plugging and abandoning (P&A) of oil and gas wells that are no longer economically viable for production, or which have wellbore issues that require closure, has historically been conducted as an afterthought in the oil and gas production business. Production wells that can no longer be used must be plugged to prevent the oil and gas reservoir fluids from migrating uphole over time and possibly contaminating other formations and or fresh water aquifers. A well is plugged by setting mechanical or cement plugs in the wellbore at specific intervals to prevent fluid flow. The plugging process usually requires a workover rig and cement pumped into the wellbore. The plugging process can take two days to a week, depending on the number of plugs to be set in the well. The P&A work takes capital to complete and provides no return on the investment for the oil companies. Most wells are plugged at the lowest cost possible following the minimum requirements set forth by the oil and gas regulating agencies.

As older oil and gas fields are re-entered to exploit bypassed reserves or to develop reserves deemed uneconomical in the past, the plugged and abandoned wells within the fields become a potential problem as new technologies are applied to old fields. In many of the older fields previously abandoned, many of the wells were potentially left unplugged and their locations not properly documented (Pennsylvania DEP, 2000). As these old fields are reentered to apply newer technologies such as solvent or CO_2 flooding, the reservoir pressure is increased due to the injection of fluids for oil recovery. When this higher pressure is applied to unplugged or poorly plugged wells, there is a chance that the formation fluids will bypass the plugging materials and migrate uphole. This can cause problems with the fresh water aquifers in the area by allowing gas, oil or salt water to contaminate the fresh water.

This paper presents an overview of the methods and materials used to plug and abandon wells along with a discussion on the environmental and economic benefits of proper well plugging. The discussion includes a synopsis of P&A research and the issues that impede the progress of the research.

HISTORY OF WELL-PLUGGING PRACTICES AND REGULATIONS

When oil and gas drilling began in Pennsylvania in 1859, there was no regulation regarding the treatment of a well at the end of its useful life (Pennsylvania DEP, 2000). Those early wells could simply be abandoned as gaping holes in the ground. In the 1890s, when Pennsylvania started regulating that wells should be plugged, the requirements were designed to protect the production zones from flooding by fresh water (Pennsylvania DEP, 2000). Much of the regulation of the oil and gas industry in the early days was driven by the need to protect the oil and gas resources and not the environment. The promulgation of plugging and abandonment regulations trailed behind advancements in drilling and production practices because the adverse environmental and safety implications of improperly abandoned wells had not yet been revealed. As more and more dry holes were abandoned, other states began recognizing the need to institute a set of standards associated with plugging oil and gas wells.

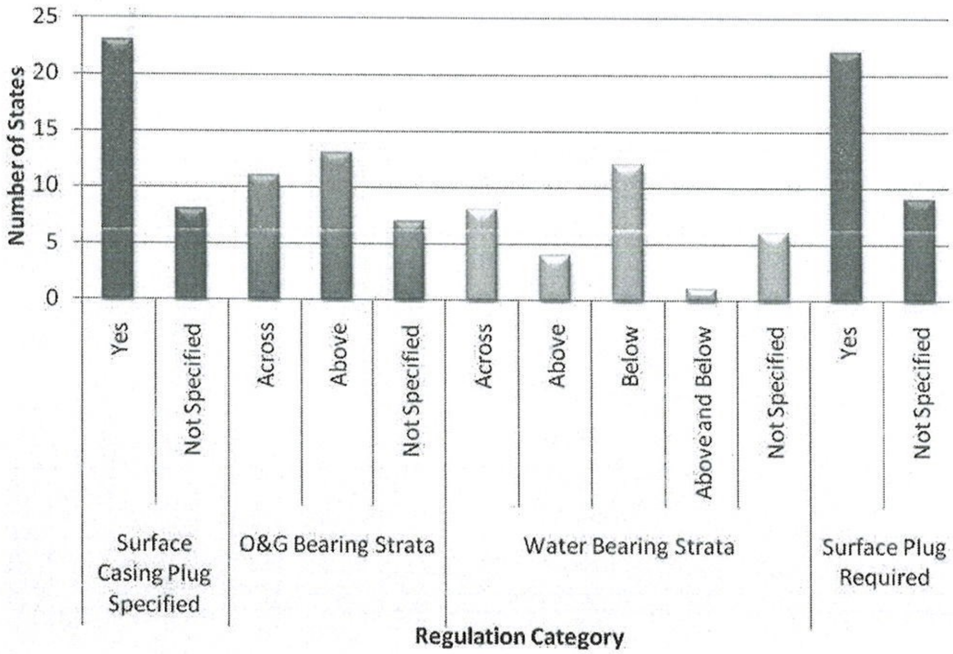
For instance, in Texas, the first well was drilled in 1893 although it was not until 1919 that the Texas Railroad Commission (RRC) gained authority to regulate well plugging (Texas RRC, 2000). By that time, thousands of wells had been drilled with little to no information recorded on the location or construction of the wells. In 1919, Article 3 of the RRC regulations laid out general requirements by stating that "dry or abandoned wells be plugged in such a way as to confine oil, gas, and water in the strata in which they are found and prevent them from escaping into other strata" (Texas RRC, 2000). Like most regulations at the time, the rules were designed to protect the loss of oil and gas to other strata, not to protect the environment. As the oil and gas industry progressed, the RRC continued to update their plugging regulations by issuing specific cementing instructions in 1934 and then requiring the plugging of fresh water strata in 1957 (Texas RRC, 2000).

Plugging regulations in many other states progressed similarly, and as a consequence, thousands of wells prior to the 1950s either were not plugged at all or plugged with very little cement in them. Additionally, when cement was required, the regulations was so vague that wells were plugged with brush, wood, rocks, paper and linen sacks, or a variety of other handy items that would serve to hold a sack of cement (Ide et al., 2006). As states began to regulate the oil and gas wells more closely starting in the 1950s, cement became a required material for sealing the producing intervals and the top of the wellbore. Over time, plugging regulations have progressed to describe the specific intervals at which cement should be placed and the types of materials allowed between the cement plugs (Texas RRC, 2000; Ide et al., 2006).

The regulations for the oil industry started changing significantly in the 1970s when environmental protection became a bigger driver in the regulation of the oil and gas industry. Congress passed the Safe Drinking Water Act (SDWA) in 1974 which increased the requirements for fresh water protection. As a result, many state regulations were updated to include stricter requirements for protection of the fresh water zones and for minimizing the flow of fluids between formations (GWPC, 2009). Currently, state regulations specify the intervals to be cemented, such as above or through producing and water-bearing zones, inside and outside of casing below fresh water aquifers, and at specified distances from the surface. Figure 1 provides a comparison of the plugging requirements in different states with focus on key elements of plugging the oil and gas strata, plugging the fresh water zone, and surface casing plugging.

As an example of how individual state regulations have evolved into specific details, California's plugging regulations require cement plugs to be placed at the following locations: a 200-foot plug straddling the surface casing shoe, a plug across oil and gas bearing strata that extends 100 feet above the strata, a plug extending from 50 feet below to 50 feet above the base of water-bearing strata, and a 50-foot plug at the surface of the wellbore (State of California, 2007).

Figure 1. Elements of State Well-Plugging Regulations



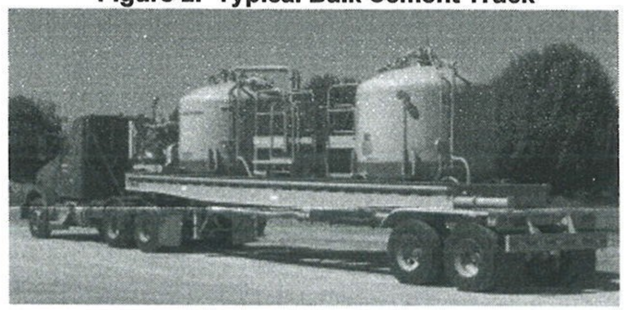
Source: Ground Water Protection Council

Additionally, most State regulations typically permit the placement of the following materials within the wellbore: cement, drilling mud, gels, mechanical plugs, and other non-porous materials such as clays. In recognition of its strength and low permeability, cement typically is used to create a seal between formations or to seal off the surface of the wellbore. Other materials which do not offer the same strength or durability as cement, including drilling mud, gel, and clay, are used to fill in the spaces between cement plugs. Additionally, many states allow the use of mechanical bridge plugs in lieu of a large cement plug since the bridge plug is extremely strong and nearly completely impermeable. However, mechanical plugs are susceptible to corrosion, and therefore the regulations typically require the bridge plugs to be capped by a specified amount of cement.

WELL-PLUGGING METHODS AND MATERIALS

A. General Methods

Figure 2. Typical Bulk Cement Truck



Source: Photo courtesy of Halliburton.

The plugging methods employed on oil and gas wells have improved over time as regulators required better well plugging plans and as operators began to see the benefits of sealing the abandoned wells more securely. When cement was first being used to plug wells, the cement tended to not set up correctly and was often contaminated by the drilling mud and wellbore fluids. Through the implementation of cementing standards by the American Petroleum Institute (API) and more standardized plugging programs, the cement plugs became more uniform (Ide et al., 2006).

When wells were plugged in the late 1800s and early 1900s, cement was often emplaced in the well by pouring the cement from the surface. The wells were shallow and this method was somewhat effective. As the wells became deeper, cement was pumped down tubing to place the cement at the desired depth. To be able to pump cement down hole, oilfield cement companies developed specialized equipment that could transport the dry cement to a well site and then blend the cement mix while pumping it down the hole. Figure 2 shows a bulk cement truck that brings the dry cement blend to a well site for pumping. The dry cement is pumped into a cement pumping truck which adds the water at the desired blending rate and then pumps the liquid cement down the well.

As operators started pumping cement downhole for cementing operations, they initially did not understand the need for hole cleaning prior to cementing. Therefore, many of the early plugs did not harden as desired. After the passage of the SDWA a new technique for placing cement in the well was researched and improved, now being known as the displacement method or the balance plug method (Ide et al., 2006). The displacement method minimizes the contamination of the cement by use of a cement that has good hole-cleaning characteristics and can displace leftover drilling mud. First, tubing is run into the well to the depth desired for the bottom of the cement plug where the cement is then placed into the well by pumping down the tubing. The cement goes out the bottom of the tubing and then flows back up the outside of the tubing. Second, after the desired amount of cement is pumped, water is pumped behind the cement to displace the cement in the tubing to a predetermined depth. At that point the tubing is pulled out of the well and when done correctly, the cement in the tubing fills the space the tubing occupied in the well which leaves a good solid section of clean cement. When using the displacement method, operators can fairly accurately place the cement in the well at the desired depth and thereby prevent flow in the wellbore from the targeted depth intervals.

The types of materials used for plugging abandoned wells have not changed significantly over the last 100 years. While cement is the most common plugging material used to seal the abandoned wells, drilling mud, bentonite and mechanical plugs also are used frequently in conjunction with cement. In wells plugged prior to the more modern regulations and standards set in the 1950s and onward, many wells were abandoned with plugs consisting of brush, wood, paper sacks, linen or any other material that could be pushed into a well to form a basis for the dumping of one or two sacks of cement to "plug" the well (Ide et al., 2006). While that use of sundry materials was fairly common in the early days of the oil field, current procedures are significantly more disciplined and have higher success ratios of providing seals adequate to prevent future contamination issues.

B. Cement

A basic and widely used plugging material is formulated as a slurry of water and Portland cement that is compositionally managed in terms of gallons (gal) of water or pounds (lb) of additives per 94-lb sack (sk) of cement. Cement used in plugging of oil and gas wells has improved significantly over the past few decades. The cement composition in the early days of the oil industry is similar to what is used today, but today's cement uses a number of additives that enhance the sealing of the cement in the wellbore (Ide et al., 2006). With the advances in well drilling technology and the types of wells being drilled and completed, the cementing technology has improved to allow for cementing of horizontal wells, high-pressure wells, high-temperature wells, low-temperature wells, CO_2 wells, and other specialty applications. Those same cement technologies can be used in the plugging of abandoned wells.

The American Petroleum Institute (API) first developed a classification system for oilfield cements in 1952. The API cements are all Portland cement-based with similar ingredients but are mixed in different proportions. The different classifications are ground to a different fineness and have different water requirements for mixing (Petrochem, 2002). Table 1 summarizes the different API classifications of cement.

When using the API cement for cementing a well or for plugging, various additives are blended into the cement for specific purposes. Each cementing company uses additives and blends cement based on the customer's specific cementing plan. Most companies have proprietary additives for specific applications along with the standard additives such as barite and bentonite. Some of the additives commonly used are:

- Retarder. A retarder is added to slow down the setting time to allow for longer pump times and/or the removal of the tubing used to place the cement.
- Accelerator. Accelerators are used to shorten the setting time. These are used in wells to allow the cement to set up faster to prevent gas or fluid channeling, to prevent backflow in the tubing and when plugging the additive can shorten the wait time between plugs.
- Pozmix. Pozmix™ (a Halliburton Co. product), which includes pozzaline (a mixture of lime and volcanic ash), is added to Portland cement to achieve a more durable calcium

silicate cement mixture. The use of pozzaline also reduces the amount of Portland cement in the mixture which reduces the overall cost of the cement.

- Lost Circulation Material. Selected materials are added to cement to reduce the loss of cement to the formation prior to hardening. Materials such as walnut shells, cottonseed hulls, fibers, flaked cellophane (including Flocele™, a Halliburton Co. product), diesel oil, and other proprietary mixtures are used to reduce the loss of circulation.
- Density-Increasing or Weighting Additives. Materials are added to the cement to increase its weight to combat higher formation pressures. Materials such as barite, sand, and other proprietary mixtures are used as weighting materials.
- Light-Weight Additives. These materials are added to cement to reduce the cement density and thereby lessen the chances of losing cement to high-permeability or low-fracture-gradient formations. Materials such as Pozmix™, gel, foam, and other proprietary mixtures are used to "lighten" cement mixtures.
- Water-Loss Additives. Water-loss additives are combined with the cement mixture to reduce the rate of water loss from the cement mixture. By reducing water loss prior to setting, the cement can harden properly and avoid premature drying which can reduce the strength of the cement (Halliburton, 1981).

Table 1. API Cement Classifications

API Classification	Depths (Ft)	Water Requirement (gal / sk)	Slurry Density (lb / gal)	Description
Class A	0 to 6,000	5.2	15.6	Common or regular cement
Class B	0 to 6,000	5.2	15.6	Moderate to high sulfate resistance.
Class C	0 to 6,000	6.3	14.8	High-Early Cement. Fine grind, good availability
Class D	6,000 to 10,000	4.3	Varies	For Moderate Temperature and Pressure. Coarse grind plus retarder
Class E	10,000 to 14,000	4.3	Varies	High pressure, high temperature. All depths with retarders
Class F	10,000 to 16,000	4.3	Varies	Use for extremely high temperature and pressure
Class G & H	0 to 8,000	G -5.0 H – 4.3	G - 15.8 H – 16.4	Basic cement. Used at all depths with retarders.

Source: Halliburton Company, *Halliburton Cementing Tables, Technical Data Oil Well Cements and Cement Additives* (Duncan, OK: Halliburton, 1981).

Specialty Cements. While most wells can be cemented with standard cements, there are situations that can require a special cement blend to create the best seal in the well. Some of the well types that require a specialized blend of cement include moderate to high-pressure gas wells, horizontal wells, wells completed through salt zones, high temperature wells, and wells that are very deep (below 15,000 ft.) (Salehi and Paiaman, 2009). Plugging such wells with conventional systems can be done in many instances but there is a risk of channeling or mud contamination from gas or fluids that can create a pathway for fluids to migrate out of the zones being plugged. The following paragraphs discuss the types of wells and situations that require specially cement blends.

- Moderate to high pressure gas wells. Cementing of natural gas wells to prevent the flow of gas outside the casing has plagued the oil and gas industry for years. As the demand for gas increases, this issue becomes larger as more wells are drilled and the gas migration causes casing pressure problems and gas leaking into other formations and the fresh water. The cements used for these wells require that the cement be designed to reduce the gas migration while the cement is curing. Many cementing companies have developed additives that can reduce the gas cutting through the cement.
- Horizontal wells. The horizontal orientations introduce different gravitational effects compared with vertical wells. In a typical vertical well, where there is a large column of cement, some migration of the solids downward or the water upward does not cause a significant change in the cement properties. In a horizontal well, the solids migrating to the bottom of the section and the water migrating to the top can provide areas of the well that do not have a complete seal. If the water in the cement separates from the mixture before the cement is set, it can migrate to the top of the wellbore and form a channel along the top of the wellbore which can allow migration of formation fluids. If the solids in the cement mixture settle to the bottom of the cement before the cement can harden, the solids can cause the cement to not set up correctly and the weakened area along the bottom of the wellbore can fail under pressure during stimulation activities (Salehi and Paiaman, 2009).
- Salt zones. Salt mixed into cement functions as an accelerator of solidification. If a well is drilled through a natural salt zone and the cement mixture is not adjusted for the salt, the cement can set up prematurely. When cementing wells that have been drilled through a salt layer, special precautions must be taken to prevent contamination of the cement by the salt. Special additives must be used to prevent the premature setting of the cement caused by salt entering the cement mixture as the mixture it is pumped past the natural salt layer.
- Deep wells. Cementing of deep wells requires long pump times to get cement pumped to the bottom of the well and displaced upward. With long pump times there is a chance that the cement could harden prematurely and cause pumping problems. Special cement retarders are used to allow for adequate pumping time to place the cement where desired. In addition, with the long stands of pipe to pump through, friction becomes an issue and friction reducers may be required to make pumping the cement easier.

C. Bentonite and Drilling Mud

In many of the wells currently being plugged, drilling mud and bentonite are still being used to fill those portions of the well that are not cemented. Bentonite, which is a natural material rich in swelling clays, is used commonly to form the base of most drilling muds. Bentonite powder is mixed with water to form a fluid that has the ability to lift cuttings from a well and suspend them at times when the mud pumps are shut down. Drilling mud has historically been used to plug most wells in the United States. A review of historical well records will show that most wells were filled with heavy mud, or drilling mud at the time of plugging. In California, records from wells in Los Angeles County that were drilled and plugged in the 1930s through the 1950s in many cases had a small cement plug at the top of the production zone and then were filled with mud that ranged from 9.1 pounds per gallon (ppg) to over 12 ppg depending on the depth (State of California, 2004).

The use of drilling mud for well plugging relies on the characteristics of mud weight and gel strength to prevent upward flow of reservoir fluids. For upward flow of fluids to occur, the formation fluids must overcome the downward pressure exerted by the weight and gel strength of the mud column in the wellbore. The gel strength of mud is the resistance to shear that develops when the mud is not moving. When mud is being pumped (moving) it has gel strength of less than one pound per one-hundred square feet (1 lb/100 sq. ft) but once the mud stops moving the gel strength increases by up to 100%. A study of the pressure effects of the static mud column in abandoned wells, found that over time the gel effect is reduced slightly due to the mud drying out, but that the gel strength should still be calculated at around 25 lb/100 sq. ft (Johnston and Knape, 1986). Gel strength increases the pressure required to start fluid moving uphole in a mud-filled well.

Bentonite plugging of wells is still used in some areas. In the Bakersfield and Coalinga Districts of California bentonite is approved as an alternative to cement to plug wells. The bentonite must be in a compressed form and can only be used in wells that are larger in diameter than 2-7/8 inches. The bentonite must be hydrated for 24 hours and, if the plug is to go across the fresh water zone, the surface casing must be cemented through the fresh water interval. The rules state that bentonite may not be used when there is a 500 pounds per square inch (psi) pressure differential between zones of a wellbore (State of California, 2004).

Bentonite, when placed as a compressed solid and then hydrated, will form a dense and low-permeability solid mass in the wellbore based on its character as a clay material that swells when water is added. Bentonite clay is often used in surface applications where low-permeability clay is needed to prevent migration of liquids such as the liner for a landfill or pond.

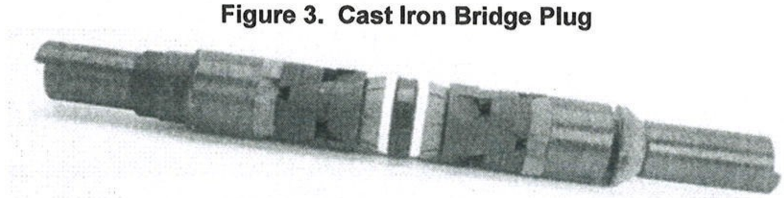
D. Mechanical Plugs

Mechanical plugs are used in some wells to reduce the amount of cement required to plug a well or to provide additional protection from formation pressure in the well. Two types of mechanical plugs utilized to plug and abandon wells are a bridge plug or a cement retainer. The choice of which plug type to use is based on whether cement needs to be pumped below the plug to seal the perforations (squeeze cementing). If cementing below the plug is not required, or if a balanced cement plug was installed below the mechanical plug setting depth, a bridge plug can be used. Mechanical plugs can be set in the well using workstring tubing, coiled tubing, or with a wireline. When working in wells with pressure, the use of tubing and or coiled tubing is typically required.

The mechanical plugs consist of four major parts: 1) the body of the plug which can be made of steel, cast iron and composite material; 2) the slips which are metal parts that grab the casing to hold the plug in place; 3) the packing material which is a rubber or nylon ring that is squeezed outward when the plug is set in the well; and 4) the on/off tool that allows the plug to be set and then released to pull the tubing or wireline out of the well after setting (Baker Hughes, 2011). Setting the tool downhole is accomplished in a number of ways depending on the specific manufacturer's design. Typically the tool is lowered to the desired location and then rotated to release the slips that will grab the casing to hold the plug. Then the plug is raised or lowered (depending on the specific application) to expand the sealing element against the casing. Once the desired tension on the tool is applied, either the tool is set and can be released, or, if required, it is rotated to release a secondary set of slips that will keep the tool expanded and set prior to release. In the case of a wireline set tool, some versions use explosives or hydraulic systems to set the slips and packing element prior to release.

- Bridge Plugs. Bridge plugs are a mechanical plug that is used to provide a solid seal within a wellbore for plugging. Some bridge plugs are designed to be easily drillable in case the well is desired to be reentered at a later date. Bridge plugs are typically made of cast iron with duel slips with a sealing element between the slips. The plug is designed to be set in a wellbore and then have cement set on top to provide a complete seal of the reservoir below. In cases where there is a potential for moderate or high pressure gas to be flowing from the area below the setting depth, a bridge plug can be set to seal the wellbore prior to cementing to reduce the chances of the pressurized water or gas to contaminate the cement. Figure 3 shows a typical cast iron bridge plug used to plug and abandon wells.

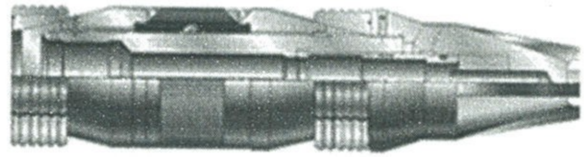
Figure 3. Cast Iron Bridge Plug



Source: Photo Courtesy of Baker Hughes.

- Cement Retainer. A cement retainer is a mechanical plug that can be set above a zone to be cemented. This type of plug is especially useful when plugging higher pressured zones that need to be squeeze-cemented prior to plugging. Cement retainers are usually built from drillable material so will yield to later re-entry of the reservoir as needed. The cement retainer is set in the well in a method similar to that used for a bridge plug. Once the tool is set in the well, cement can be pumped through the plug to squeeze cement through the perforations or open-hole area below the retainer. Pressure can be applied to the area below the retainer without a concern for cement traveling uphole past the cement retainer. The application of pressure to squeeze the cement through the perforations provides a good method of sealing the well at plugging. Once the desired amount of cement is squeezed below the retainer, the tubing is pulled upward out of the retainer and a mechanical flap closes the hole to effectively seal the cement below the cement retainer. Cement is then typically placed on top of the cement retainer to provide a more complete seal of the reservoir. Figure 4 shows a typical cement retainer.

Figure 4. Cement Retainer



Source: Diagram Courtesy of International Completion Solutions, LLC.

RESEARCH ON ALTERNATIVE METHODS AND MATERIALS

The technology associated with the P&A of wells has not changed significantly for more than 100 years. Cement and drilling mud is still the basic material used to plug many of the wells plugged by operators. While the plugging of wells has become more reliable over time due to advances in cementing materials and volumes placed in a well, the overall methods for plugging remain similar as to what was used during the early oilfield days.

The use of cement as a plugging material was the first major change in the plugging of wells, followed by the requirement to place cement below and across the fresh water zones (Pennsylvania DEP, 2000; Texas RRC, 2000). As regulations became more stringent, operators were required to place cement plugs above the productive zones and below the fresh water zones. Some areas began to allow the use of mechanical plugs to seal of portions of wells, but in most cases cement was required to be placed on top of the mechanical plug if it was for permanent abandonment (GWPC, 2009).

Most research into cements and tools for use in oil and gas wells historically has been associated with the completion of the wells and not the plugging of the wells (Bruffatto et al., 2003). As such, little actual research has been done on the materials and procedures for plugging oil and gas wells.

A research project conducted in 2000-2001 looked into the use of fly ash as a cementing material to plug wells in Oklahoma. The two-phase project gathered fly ash samples from five coal-fired power plants in Oklahoma and tested each of them to determine if they could be used as a plugging material for shallow wells (Shah and Sublette, 2004). First, each sample was tested in a laboratory to determine the optimum grout formulation for plugging wells. Pumpability tests were also conducted to verify that the grout formulations could be pumped through coiled tubing and straight pipe. The results for Phase 1 showed that an optimum fly ash grout formulation could be found and that it had a compressive strength of over 500 psi which meets the minimum strength criteria for P&A. The pumpability test showed that the cement / fly-ash grout can be pumped through coiled tubing which allows wells to be plugged without a conventional rig on the site (Shah and Sublette, 2004).

Phase 2 of the study involved testing the fly ash grout in a test well situation to determine the bond strength and gas permeability. This testing showed that the fly ash grout had low permeability and adhesion properties and that the grout provided a good seal to the casing , meaning that the fly-ash grout should be effective in preventing fluids or gas from migrating upward. Ultimately, the testing showed that the fly ash grout performed similarly to Class H cement and could be used to plug wells at depths up to 6,000 feet (Shah and Sublette, 2004).

ENVIRONMENTAL BENEFITS OF WELL PLUGGING

Unplugged or poorly plugged wells are an environmental hazard as they provide potential conduits for fluids to migrate between formations and potentially into the fresh water zones. Poorly plugged wells also might provide pathways for natural gas to seep to the surface and potentially cause fire or be a health hazards. An abandoned well's potential for causing a potential hazard is largely dependent on the original use of the well. Oil wells that have been pumped for years will typically be very low pressure and the risk of contamination is low while a gas well that is flowing at a rate that is non-economical can still posses enough pressure to be a risk to the environment.

As oil prices rise to high levels, many abandoned oil fields are re-entered with new technologies meant to produce oil that was not economical to produce in years past. With the new activity in the oilfield, any idle or unplugged wells not targeted for re-development must be plugged to prevent the escape of gas and oil from the reservoir. In areas where CO_2 is being injected as a tertiary recovery project, well plugging becomes an issue due to the high pressure of the CO_2 flood in the reservoir. Old wells that are not being used to inject or produce the oil must be plugged in a manner that also protects the fresh water from the high formation pressures. The ability of these plugs to seal the well from the migration of CO_2 gas will protect the fresh water sources from potentially becoming contaminated with CO_2 or the produced fluids (Ide et al., 2006). As old fields are revitalized, failure of older plugging jobs will be an issue due to the increased pressure created during re-development of the reservoir (Ide, Friedmann, and Herzog, 2006). The risks presented by older P&A wells must be quantified by operators and the wells properly monitored to reduce any impacts to the environment.

In areas where shale-gas reservoirs are being newly developed, plugging of older wells has become an issue due to the potential for stray gas to migrate from the shale formation to other formations that are open to the old wells in the area. The old wells can transmit gas from the formation to the fresh water or even the surface, thereby posing an environmental risk to the local area. Older wells are a risk if they are poorly plugged or not plugged across the shale production zone. Even if the older well has casing, the casing might not be adequately cemented across the shale production zones.

Even the newly developed shale-gas wells eventually will become uneconomical and must be plugged. The P&A of those wells must be designed to minimize the future risk of gas migration that might pose environmental hazards.

The proper plugging of wells provides a great environmental benefit by protecting the environment from potential contamination from oil and gas. Properly plugged wells prevent the movement of fluids between formations which reduces the chance of oil or gas getting into a formation that may be connected through an old, unplugged well nearby. Properly plugged wells also prevent contamination of the drinking water aquifers. In areas where groundwater use is important, protecting those water sources from oil and gas wells must include well-planned and implemented P&A programs for oil and gas wells.

ECONOMIC BENEFITS OF ADVANCES IN WELL-PLUGGING TECHNOLOGY

Well plugging is often seen by some operators as a cost that provides little benefit to the company bottom line. While in some instances that may be true, properly plugged wells can save the operators substantially through avoidance of lost production from fields that are candidates for high-technology recovery projects (NETL, 2010). Properly plugged wells can prevent cross-contamination from other zones in a production field. Proper well plugs can also prevent the loss of pressure in pressure maintenance water floods and CO_2 floods. Both of those merits can result in higher oil and or gas production from the targeted reservoir.

Technological changes have been made in the areas of cementing and downhole equipment for oil and gas well construction and production operations and at least some of those advancements should be beneficial to P&A practices. With the development of deep high-pressure gas projects and shale gas projects, the advances in well cementing technology, along with new mechanical systems, can potentially be applied to plugging of gas wells. By advancing the technology of plugging wells, the overall cost of plugging can decrease. In addition, the newer plugging materials and methods can reduce the plugging failures along with the problems associated with leaking well plugs.

For CO_2 flood projects, the application of cement that can prevent the loss of CO_2 and gas pressure could potentially increase the ultimate recovery of oil while reducing the overall cost of the CO_2 project (NETL, 2010). Operators would spend less over the life of the project in CO_2 purchases as well as less spent on remedial projects dealing with leaking wells.

With the current development of numerous shale-gas basins in the US, the eventual plugging of all of those new gas wells is a concern. Most of those shale-gas wells are horizontal completions, which can pose an issue for plugging operations due to gas channeling and solids settling. If those wells are not plugged correctly, gas channeling can occur and the well could become a potential liability from gas leaking into the upper fresh water zones. Improved P&A practices in the shale-gas basin developments should allow more economical and sustainable development of US gas production. It can also increase the density of the development as wells can be installed closer together if the abandoned wells are properly plugged to withstand the potential impact of fracturing treatments nearby.

BARRIERS TO PROGRESS

Some of the barriers to advancing the science of plugging and abandoning wells can be attributed to the lack of research and the lack of a clear vision of the role that plugging and abandonment can play in the production cycle of the oil field.

- Lack of Research. The science of well P&A has not been the focus of research in the oilfield. Most relevant research is focused toward maximizing the production of oil and gas or reducing the cost of finding and producing the oil and gas. P&A has typically been seen as a waste of capital dollars and has only been done when required; then, the work is done as cheaply as possible. Most operators have historically not see the benefit of properly closing wells. As a result, there are many wells in the oil field that are poorly plugged or have been left in an unplugged status for years. As operators have been reentering old oil fields to apply new production technologies, these poorly abandoned wells have become a liability. To continue the application of the newer production technologies in the fields, these old wells are being reentered and replugged. As these wells are being plugged, the newer, higher-tech plugging processes are not being used; instead, the wells are being plugged using traditional methods. If operators had newer methods and materials that would make the plugs stronger, less prone to contamination, and less expensive to install, the new production technologies would be more cost-effective and would reduce potential environmental issues.
- Lack of Long-term Vision. The long-term vision of P&A's importance to the oil production program is not readily seen in the oil and gas production arena. The traditional view of P&A is that it is a necessary evil and should be done as cheaply as possible. As a result, many wells are poorly plugged and over time these poor plugging jobs may result in significant environmental problems. This is especially true in the gas well area. Cementing of gas wells is a constant issue due to gas channeling. If operators plan poorly for the cementing of a gas well and try to cut costs by using cheaper materials and methods, those gas wells could potentially become a hazard due to gas leaking through the plugs. Implementation of new regulations, training, or an industry outreach program to bring the issue to the forefront could reduce the potential problems in the future.

FINDINGS

The plugging and abandonment of oil and gas wells has not changed significantly over the past 100 years. There has been improvement in the quality of the materials and changes to the methods used to plug wells, but there has not been a specific change that has elevated the technology of plugging wells.

Most wells are still plugged with cement using methods and materials developed in the 1970s. Cement additives have improved, but gas channeling and contaminated cement jobs are still operational issues.

Plugging wells is still regarded by some operators as a requirement with little or no corresponding benefit. Benefits from reduced operational costs and/or increased production, especially in redeveloped, older fields, generally has been underappreciated. Accordingly, the true benefits of quality plugging jobs has not been realized in most areas.

By plugging wells correctly, future environmental issues, related to fluid or gas leakage, can be avoided and thereby preserve savings otherwise eroded by remediation or litigation costs.

Research has lagged on materials and methods for plugging wells although advances in technologies for drilling and completion, taken in proper context, should be applicable to practices in plugging and abandonment.

By doing research and educating operators to the benefits of proper well plugging, the science of well plugging will be advanced and the environment will benefit from better protection.

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