Deep Well Casing and Cementing for the Delaware Basin

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INTRODUCTION

Prior to 1957, exploration in the Delaware Basin was confined to the relatively shallow Delaware series. In 1959 deep drilling was still in its infancy when Phillips Petroleum Company drilled University EE #1, in Pecos County, Texas, to 25,340 ft as the deepest well in the world.

In the past few years new records have been made and broken in the Delaware Basin. In 1963 The Pure Oil Company completed W. C. Tyrrell #1 in Pecos County as the deepest producing well in the world. In 1964 Pure broke its own record with W. C. Tyrrell #2. Now in 1965, it appears Forest Oil Corporation will break Pure's records with its Walker #1 in the same area. All of these wells have been drilled below 21,000 ft.

With the advent of deep drilling, new drilling problems have emerged to challenge the industry. Major problems involve designing an adequate casing string, picking the proper setting depth, and successfully cementing the pipe. Failure to accomplish any of these, results in a well never reaching total depth, or a very expensive completion.

This paper discusses drilling problems encountered and outlines procedures used by The Pure Oil Company in designing and cementing casing for deep Delaware Basin wells.

CASING DESIGN

Deep well casing design practices are identical to conventional design except for a few extra considerations. The strings are usually larger, longer, heavier, and require higher grades of steel. Longer drilling periods are usually experienced through an intermediate casing string. Design safety factors in collapse, burst, and tension are usually 1-1/8, 1, and 2 respectively as in most conventional designs. At this point The Pure Oil Company may deviate from conventional practice by often deliberately introducing additional safety factors into a casing design. This is especially true where long periods of drilling will be done through a casing string. Normal drilling time inside an intermediate string may be six to eight months but can possibly be a year or more. Example casing designs are compared in Table 1.

With a long drilling period anticipated through a casing string, it is considered good operating practice to overdesign the string. The casing comparison in Table I shows that the single weight casing design costs $8500 more than the tapered string designed for well conditions. With a total casing string valuation of approximately $120,000, the additional expenditure is justified by minimization of future pipe failures. Relatively trouble free operation on Pure Oil Company deep wells supports the justification. Parted casing is usually not a problem.

A casing practice used by Pure, which some operators elect not to follow, is the installation of a tie-back casing string. If a deep, high pressure well is made, a casing string is installed from surface to the top of an intermediate liner prior to hanging a production liner. The new casing is present in the event high pressure gas communicates with the casing. Installation of the additional casing string is strongly recommended in high pressure wells. The tie-back string is considered one of the most important casing strings in the well.

TYPICAL DELAWARE BASIN CASING PROGRAM

The most important single factor in successfully drilling a deep Delaware Basin well is selecting good casing points. This one thing can mean the difference between success and failure or an

TABLE I

SAMPLE 10-3/4" CASING DESIGNS

CONVENTIONAL DESIGN

DEPTH	WEIGHT	GRADE	Thread	Tension S.F.	Burst S.F.	Collapse S. F.	Cost/Ft	Cost/Section
0' - 1,500'	60.7#/ft	P-110	HYD.T.S.	2.90	1.00	-	$11.64	$17,460
1,5000' - 3,000'	55.5#/ft	P-110	HYD.T.S.	3.05	0.99	3.230	10.81	16,215
3,000' - 6,400'	51.0#/ft	P-110	HYD.T.S.	3.24	0.99	1.161	10.03	34,102
6,400' - 8,600'	55.5#/ft	P-110	HYD.T.S.	6.24	1.25	1.127	10.81	23,782
8,600' -10,600'	60.7#/ft	P-110	HYD.T.S.		1.46	1.230	11.64	23,280
								$114,839

DESIGN WITH EXTRA SAFETY FACTOR

DEPTH	WEIGHT	GRADE	Thread	Tension S.F.	Burst S.F.	Collapse S. F.	Cost/Ft	Cost/Section
0' - 1,500'	60.7#/ft	P-110	HYD.T.S.	2.66	1.00	-	$11.64	$17,460
1,500' - 3,000'	60.7#/ft	P-110	HYD.T.S.	3.10	1.08	4.100	11.64	17,460
3,000' - 6,400'	60.7#/ft	P-110	HYD.T.S.	3.72	1.16	1.950	11.64	39,576
6,400' - 8,600'	60.7#/ft	P-110	HYD.T.S.	6.72	1.34	1.520	11.64	25,608
8,600' -10,600'	60.7#/ft	P-110	HYD.T.S.	-	1.46	1.230	11.64	23,280
								$123,384

extrerely expensive hole. Table II[1] is presented as an approximate guide to the mud weight one would expect Delaware Basin formations to hold. By knowing where high pressure gas is likely to occur and the approximate gas pressure to be expected, it is evident that certain zones must be cased before the higher pressure zones are penetrated.

TABLE II

APPROXIMATE FRACTURE GRADIENTS FOR DELAWARE BASIN FORMATIONS

Formation	Frac. Gradient (psi/ft)	Mud Column Formation Will Support
Rustler	0.90	17.3 PPG
Bell Canyon	0.55	10.6 PPG
Cherry Canyon	0.59	11.3 PPG
Brushy Canyon	0.60	11.5 PPG
Bone Spring	0.57	10.9 PPG
Wolfcamp	0.68	13.1 PPG
Wolfcamp Detriral	0.85	16.3 PPG
Penn. **Morrow**	0.91	17.5 PPG
Miss. **Lime**	0.73	14.0 PPG
Devonian	0.58	11.1 PPG
Ellenburger	0.62	11.9 PPG

In certain areas the Delaware Series contains slightly higher than normal pressure gradients. These may occur as deep as the Cherry Canyon zone. Below the Cherry Canyon down to the Wolfcamp formation, pressure should be normal. In the Wolfcamp, gas is usually encountered which may require 12.0 to 14.0 ppg mud to contain. Pennsylvanian zones may contain gas requiring 16.0 to 17.0 ppg mud. Below the Pennsylvanian, the pressure gradient is usually normal. The Devonian may be slightly abnormal.

The casing program for Pure's W. C. Tyrrell #1 in the Gomez Field is presented as a typical design for a wildcat well in an unknown area. Formation depths referred to in the discussion are those tabulated in Table III. The casing details are tabulated in Table IV.

One joint of 30 in. conductor pipe was set through the surface sand and caliche. A 26 in. hole was drilled through the upper cretaceous lime section to 725 ft. Twenty in. surface casing was set and cemented. In certain areas the surface casing might be set as deep as 2000 ft. Below the 20 in. casing, a 17-1/2 in. hole was drilled. When the anhydrite and reef sections above the Delaware sand were proved capable of supporting a 10.0 ppg drilling fluid, the hole was drilled on into the Delaware section. In certain areas the Rustler and the Capitan Reef are bad lost circulation zones. If lost circulation had been encountered, casing would have been set before drilling possible production in the Delaware. The hole was drilled through the Bell Canyon and Cherry Canyon zones of the Delaware Series. Thirteen and three eighths in. casing was set at 6034 ft in the Brushy Canyon.

By analyzing the expected fracture gradients tabulated in Table II, it is apparent that in all probability a casing string will be required before Wolfcamp gas is encountered. The Bone Spring is historically weak and has been found to support only 10.7 to 10.9 ppg fluid. If casing can be set approximately 1500 to 2000 feet into the Wolfcamp formation, the Wolfcamp will usually hold a drilling mud capable of drilling the Pennsylvanian zone. A good rule of thumb for the Delaware Basin is to be sure the Bone Spring and Upper Wolfcamp are cased before drilling high pressure zones.

A 12-1/4 in. hole was drilled below the 13-3/8 in. casing. With weak zones open, it was apparent that Wolfcamp gas could probably not be drilled without setting casing through the Bone Spring and Upper Wolfcamp. In nearly all cases, some "small" gas is encountered before the "big" gas is drilled in the Wolfcamp. In nearly every instance before high pressure gas formations are drilled, small amounts of trip gas will be seen up the hole. With a knowledge of formation characteristics, it was decided to drill until some gas was encountered or the Wolfcamp had been penetrated at least 2000 ft. An increase in formation gas and the inability to raise the mud weight above 10.9 ppg resulted in 10-3/4 in. casing being set. In some areas 9-5/8 in. casing is installed. In the Gomez Field Pure has elected to set 10-3/4 in.

A 9-1/2 in. hole was drilled through the Wolfcamp and Pennsylvanian and into the Mississippian Lime. A mud weight of 16.0 ppg was required. The Mississippian Lime was penetrated 150 ft before a 7-5/8 in. liner was set at 16,199 ft. There was some question as to whether the entire Mississippian Lime section would support a 16.0 ppg drilling fluid.

After Wolfcamp and Pennsylvanian zones are cased, mud weight can be reduced. The Devonian will often require a slightly higher drilling fluid gradient than the Ellenburger, but both zones can usually be drilled without setting an additional string of casing. Even though the Devonian is usually normal, there are cases where 12.5 to 13.0 ppg mud has been required to control the zone. In such a well the Ellenburger formation should not be penetrated with the heavier mud since severe lost circulation will probably occur.

Below 7-5/8 in. casing in Tyrrell #1 a 6-5/8 in. hole was drilled to a total depth of 21,603 ft. A 10.8 ppg mud gradient was required to contain

TABLE III

FORMATION TOPS FOR W. C. TYRRELL #1

	Approximate Depth
Surface	0'
Rustler Anhydrite	1,683'
Tansil	2,763'
Yates	2,950'
Delaware Sand	4,845'
Brushy Canyon	5,740'
Bone Spring	7,120'
Wolfcamp	8,753'
Pennsylvanian	14,920'
Barnett Shale	15,596'
Mississippi Lime	16,048'
Woodford Shale	16,611'
Devonian	16,917'
Silurian	17,180'
Fusselman	17,313'
Montoya	17,326'
Simpson	17,853'
Ellenburger	19,826'
Cambrian Sand	21,458'
Granite Wash	21,538'
Total Depth	21,603'

TABLE IV

CASING FOR W. C. TYRRELL #1

SIZE	DEPTH	WEIGHT	GRADE	THREAD
20'	0' - 725'	94#	H-40	ST&C
13-3/8"	0' - 6,034'	61#,68#,72#	J-55, S-80, N-80	ST&C
10-3/4"	0' - 10,579'	60.7#	P-110	Triple Seal and Flush Joint
7-5/8" liner	10,202'-16,199'	33.7#	P-110	Triple Seal & Extreme Lime
7-5/8"tie-back	0'-10,202'	33.7#	P-110	Buttress
5" liner	15,806'-21,603'	18.0#	P-110	Triple Seal

the Devonian. This gradient has proved to be compatible with the Ellenburger. Upon reaching total depth, 7-5/8 in. casing was tied back to the surface. A 5 in. liner was hung from 15,806 ft to total depth.

The W. C. Tyrrell #1 casing program has been used to illustrate that by carefully selecting the right casing points and knowing roughly what to expect from a formation, a deep well can be drilled relatively trouble free. By placing casing in the proper place, many lost circulation problems are automatically eliminated. The importance of finding these casing points cannot be overstressed.

CEMENT

Cements used by The Pure Oil Company in its deep drilling program are Class A, Class C, Class E and an extremely fine grind light weight cement designed as Litewate, or a modified variation of these cements. On relatively shallow strings down to approximately 10,000 ft Litewate cement is used for its strength, light weight and economy. Below 10,000 ft Litewate is not recommended. Class C cement is usually used to tail-in around the shoe. Litewate cement mixed at 12.44 ppg will give 1150 psi compressive strength in 24 hours at 120°F.[3]

Class E cement is used to a maximum depth of approximately 17,000 ft. This cement is naturally retarded for use at temperatures up to approximately 275° F. Below this depth slurry weight is an important consideration. Class E cement mixes at approximately 16.4 ppg which usually eliminates its use below 17,000 ft.

A special cement formulation has been designed for cementing the production liner in the Gomez Field. Conditions require that the cement be light, be retarded, have good initial compressive strength and have no strength retrogression at extreme temperature. The cement selected is Class C cement with eight per cent gel, 30 per cent silica flour, 16 pounds per sack gilsonite and 7/10 per cent HR-12 retarder. This cement mixes at 12.4 ppg. Even though this cement has a pumping time of six to eight hours, excellent cement jobs have been experienced.

Where long shale sections are to be cemented, it is suggested that saturated salt cement be used for better bonding if formation conditions will allow it. Saturated salt cement has two disadvantages. Normally, excess salt will retard a cement which may not be desirable at lower temperatures. Saturated salt cement normally weighs at least 1/2 ppg more than a comparable cement mixed with fresh water. In areas of lost circulation this is a big disadvantage. In fact, prevention of lost circulation may eliminate the use of saurated salt cement where it could perform well.

PIPE INSPECTION

On any deep well it is recommended that an adequate casing inspection program be followed. It is suggested that every joint of pipe used in a deep well be thoroughly inspected. There is little logic in designing an adequate casing string and then assuming the risk of running a defective joint without inspection. Experience has shown that casing is sometimes shipped from the mills with extreme damage which is often visually evident. An example of this is shown in Fig. 1.

Figure 1. Photograph of casing defect

A pipe inspection program considered adequate for deep well drilling is recommended. A magnetic particle inspection should be performed on the exterior of the pipe body and the ends to detect longitudinally oriented defects. An internal optical inspection will locate visible internal defects. When electrical resistance weld casing is used, an internal magnetic particle inspection is recommended to detect any flaws in the welded seam. On any type of integral joint pipe, the ends should be sand blasted and a special end area inspection performed. Longitudinal and circumferential magnetic fields will be induced into the end areas of the pipe to inspect for internal and external transverse and longitudinal defects. Casing should be drifted on location during the inspection procedure. Hydrostatic testing of casing is not recommended as part of an inspection program. This proposed pipe inspection program is considered adequate for deep wells. Individual operators may prefer more or less inspection depending upon expected well conditions.

A typical pipe defect often encountered is an overlapping seam which can be ground out of the pipe. Defects shallower than 12-1/2 per cent of the pipe wall are within API specifications and are usually used in a string. Pipe of this classification is placed adjacent to the next weaker group of casing in a design. In special cases where air or gas drilling is to be done, all defects, regardless of severity, are rejected from the pipe string. When a defect is ground out of the pipe, the edges of the ground area are tapered smoothly into the pipe body to reduce stress concentration.

CEMENTING DEEP CASING STRINGS

Deep casing cement jobs are similar to conventional jobs except for additional problems which arise to challenge the operator. A few of these are high temperature, high pressure, extreme lost circulation conditions, small annular flow areas, large cement volumes, slow pump rates and long pumping time. Cementing casing through extremely small annular flow areas is becoming quite common.

The Pure Oil Company follows a basic set of rules for deep well cementing which is considered good operating procedure. A list is compiled below which, if followed, should provide a good cement job.

(1) Always have the hole in shape before running casing.

(2) Run casing at the slowest possible rate.

(3) Use down-jet float shoe with holes in the the side.

(4) Support a small part of the casing weight on the bottom of the hole while cementing to minimize the chance of parting the string.

(5) Circulate hole after landing casing. Never cement without at least pumping the casing volume.

(6) Keep cement composition as simple as possible.

(7) If neat cement fails to meet temperature requirements, "tailor make" cement with retarder to desired pumping time.

(8) Check cement pumping time in laboratory several days before job.

(9) Take actual cement samples from location, mix with rig water, and check cement pumping time.

(10) Keep cement as light as possible.

(11) If feasible, allow cement to be at least two ppg heavier than mud.

(12) Pump at least 20 bbls water ahead of cement.

(13) Treat lead slurry with friction reducer to allow at least a 10 min contact time with formaion under turbulent flow.

(14) Never run a cement plug ahead of cement containing lost circulation material.

(15) If cement weight is not critical, use saturated salt cement across shales.

(16) Leave tub full of cement at end of mixing operation to eliminate water under plug.

(17) Cement around shoe with Class C or E neat cement.

(18) Place float collar at least two joints above shoe.

(19) When plug bumps float collar, release pressure to zero.

Pure has used some or all of the procedures in each cement job performed in its deep well drilling program with a high degree of success.

Since casing is often installed in a relatively tight hole, very few centralizers and no scratchers are used on deep Pure Oil Company casing jobs. Usually the bottom three or four joints as well as multiple stage tools are centralized. When 10-3/4 in. integral joint casing with an 11-1/4 in. coupling is installed in a 12-1/4 in. hole, no centralizers are used. Fear of failing to get casing to bottom dictates that very few centralizers be used. In most cases getting pipe to bottom has not been a problem.

Casing is not rotated or reciprocated during a cementing operation. Usually a long string of casing will weigh from 1/2 to 3/4 million lbs. It is considered inadvisable to move a heavy string which may be loading up inside with heavy cement. There are cases where pipe has actually parted during a cement job because it was hanging off bottom, increasing in weight, and pulsating with each pump stroke. Down jet float shoes are used on most of Pure's long, heavy casing strings. The casing is set on bottom so the additional cement weight can be transferred to the bottom of the hole.

In the Delaware Basin, cementing temperatures are usually less than those published in the API schedule. Laboratory testing of cements in this area is done at a corrected circulating temperature derived from the following Formula.[3]

$$BHCT_{Test} = ST + \left[BHCT_{API} - ST\right] \cdot \left[\frac{BHST_{Test} - ST_{Test}}{BHST_{API} - ST_{API}}\right]$$

BHCT= Bottom hole circulating temperature

BHST = Bottom hole static temperature

ST= Surface temperature

Turbulent flow is usually attempted in the lead slurry. If required, sufficient friction reducers are added to the lead slurry to allow a mimimum of 10 min contact time with formation in turbulent flow. Remainder of the slurry is not treated for friction reduction. Equations for calculating effective velocity and critical rates are shown below[4]

$$QC = \frac{Z\left[D_H + D_P\right]}{d}\left[n + \sqrt{n^2 + \frac{\left[D_H - D_P\right]^2 ty\ d}{M}}\right]$$

$$V_P = \frac{17.15 Q_C}{D_{IP}^{\ 2}} \qquad V_A = \frac{17.15\ Q_C}{D_H^{\ 2} - D_P^{\ 2}}$$

Q_C = Critical Flow Rate

Q_{CT} = Critical Flow Rate for Turbulent Flow, BPM - Reynolds No. 3000

Q_{CUL} = Critical Flow Rate for Upper Laminar Flow, BPM - Reynolds No. 2000

V_P = Effective velocity inside pipe, ft/sec

V_A = Effective velocity in annulus, ft/sec

D_H = Diameter in hole, inches

D_P = Outside diameter of pipe, inches

D_{IP} = Inside diameter of pipe, inches

d = Slurry weight, lb/gal

n = Coefficient of rigidity, lb/sec-ft

ty = Yield value, lb/sq. ft

Z = 140 for turbulent flow

Z = 93 1/3 for upper laminar flow

M = 2690 for turbulent flow

M = 179 1/3 for upper laminar flow

CEMENTING DEEP LINERS

Some of Pure's more complex cement jobs have been performed on deep liners. Where no high pressure gas has been present, success ratio on liner jobs has been extremely high. In the presence of high pressure gas where cement weight has been practically the same as mud weight, cementing success has been quite low. In most cases squeeze jobs have been required on the top of liners which case high pressure gas.

Pure's normal pattern for installing a liner is to hang the liner, circulate the mud to condition the hole, and then release the drill pipe from the liner hanger. The liner is then cemented with the drill pipe released and weight setting on the hanger. After cement is circulated and the excess is in place above the liner, the drill pipe and setting tool seals are retrieved. In most cases, a packer is not installed on the hanger assembly and cement is not reversed out.

One liner cementing problem not anticipated was cement failing to set at the top of a liner. Green cement has been circulated off the top of deep liners 24 to 36 hrs after placement. This apparent phenomenon has a simple explanation. The cement was engineered for six to eight hrs pumping time at the extreme bottom hole temperature. On a long liner the cement would come to rest, perhaps, 6000 to 7000 ft above the bottom at a substantially lower temperature. Mud contamination retards setting. Ferrochrome lignosulfonate thinners in deep hole muds further retard setting. Some of the commercial cementing retarders are actually calcium lignosulfonate. With all this retardation of a cement, in addition to possible high pressure gas movement up through the slurry, the net result is cement that sets much slower than anticipated.

Past liner cement failures have been due to gas cutting of green cement. To solve the problem cement must be made to set before the gas can migrate through it. Past failures are attributed to inadequate hydrostatic head and slow set cement. These failures have occurred principally because adequate hydrostatic head has not been used for fear of creating lost circulation. With this poor experience in deep, hot, high pressure liner cementing, Pure is now prepared to approach the problem differently.

The first step in solving the problem is to raise the mud weight until gas quits feeding in. Extremely slow setting cement will not be used. The tentative plans are to use heavier cement with faster setting properties. Class E cement will be densified and "tailored" to give an adequate pumping time with a fair margin of safety. Actual cement samples from the location mixed with rig water will be pumped in the laboratory at simulated well conditions. Sufficient excess cement will be used to adequately remove mud contamination from behind the liner. Normally 35 to 40 per cent excess is used. Sufficient friction reducers will be added to lead slurry to allow 10 min contact time with the formation at turbulent flow. Tail-in slurry across the troublesome high pressure gas zone will be heavier than the lead slurry and will have a pumping time of approximately two hrs.

Liner cementing under the best conditions is a hazardous operation. Add to this extreme temperature, depth and high pressure and here is a combination which makes perfect liner cement jobs very rare.

LOST CIRCULATION

Loss of circulation in the presence of high pressure gas zones can be one of the most dangerous and expensive problems encountered in deep drilling. When lost circulation does occur and a normal amount of lost circulation material and mud is used without success, it is suggested that a wireline survey be made to determine the thief zone. In most cases there is only a minimum amount of danger in making a trip with lost circulation occurring if drilling mud is available on location. It is then only a matter of removing the bit to allow a wireline to be run out into open hole. Very little expense is involved in making a radioactive or temperature survey since mud is being pumped into the well anyway. If the loss zone can be located, the problem is already partially under control. A plan of action can then be efficiently formulated. Expediting the survey can often save as much as $50,000 to $100,000 on a single circulation job.

If a well is near a casing point when lost circulation occurs, it is often wise to run and cement casing without regaining circulation. The savings can sometimes be substantial. The decision must be based on a knowledge of where the loss is occurring. If the loss is at the bottom of the hole, the loss must be repaired before a pipe is run. If the loss is high in the hole, then casing should probably be run. In any event a survey to pinpoint the thief zone is an invaluable tool in helping to make these decisions. The point to be stressed is that early location of a thief zone can save an operator large sums of money.

An example where cementing without circulation has paid off handsomely is in Pure's Brininstool Deep Unit #1 in Lea County, New Mexico. Circulation was lost while running 10-3/4 in. integral joint casing in a 12-1/4 in. hole to approximately 12,700 ft. Since upper Delaware zones below the last casing string are usually weak, it was probable that mud was being lost fairly high in the hole. When the casing reached bottom, cementing operations were commenced immediately without any preliminary circulation. A temperature survey later revealed the cement top 5,000 ft above the shoe.

In another well, logging was completed at 14,480 ft prior to running casing. Upon running to bottom with drill pipe to condition the hole, it was discovered that lost circulation had been created. Lost circulation material failed to plug the thief zone and high pressure gas from an upper zone was attempting to blowout. Four days and $60,000 worth of mud were expended before it finally became apparent that lost circulation material would not cure the problem. Mud was pumped into the hole and drill pipe was pulled. A temperature survey revealed the mud loss was at 8,800 ft, approximately 400 ft below the last string of casing. Drill pipe was worked to bottom to check for bridges and was then pulled. A full string of 7-5/8 in. casing was run to total depth. When the well attempted to "kick", mud was pumped into the well. The well was cemented without any returns. Mud was pumped into the annulus continuously throughout the cement job to maintain the hydrostatic head on the high pressure gas zone. A temperature survey revealed that cement extended up into the previous casing string. Pressure applied to the annulus confirmed the temperature survey. The hole was drilled below 14,480 ft with air with no more gas from the potential blowout zone.

In most lost circulation and attempted blowout conditions an operator has a problem which must be solved regardless of cost. The examples are cited to stress the point that early location of a thief zone can substantially reduce the over-all cost of the loss. In most cases, the condition can be completely eliminated by proper placement of the casing.

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