FINAL REPORT

COMPLETION TECHNIQUES
FOR
GEOTHERMAL-GEOPRESSURED WELLS

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TABLE OF CONTENTS

	<u>Page</u>
INTRODUCTION	1
SUMMARY	2
Conclusions	4
Needed Research	5
OIL WELL COMPLETIONS	6
Tubing and Packers	7
Wellhead Equipment	11
Open Hole Completions	15
Liner Completions	17
Perforated Casing Completions	22
Casing Cementation	24
Liner Cementing	27
Bullet and Jet Perforating	31
Single-Zone Completions	46
Multiple-Zone Completions	48
Dual-Completion Procedures	50
Wireline Completion Equipment	56
Unloading the Well	63
WATER WELL COMPLETIONS	68
Water-Well Design	70
Gravel Packing and Formation Stabilization	73
Well Development	76
Gravel Placement Procedures	80
SAND CONTROL PROCEDURES	88
Reduction of Drag Forces	88
Mechanical Methods	90
Plastic Consolidation Methods	110
Comparison of Sand Control Methods	118
GEOPRESSURED OIL AND GAS WELLS	119
Completion Planning	124
Completion Operations	126
Perforating	130
Tubing and Packer	132
Producing Equipment	139
GEOPRESSURED WATER WELL COMPLETION	145
Wellhead Equipment	147
Casing and Tubing	152
Packer Arrangement	158
Perforating Procedure	159
REFERENCES	162

COMPLETION TECHNIQUES
FOR
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INTRODUCTION

Geological studies have established that geothermal-geopressured formations can be found at depths of 10,000 to 18,000 feet in the Gulf Coast area of Texas and Louisiana. Bottom hole pressures are in the range of 9,000 to 15,000 psig and temperatures 250-350°F. Test wells to tap these reservoirs can be drilled routinely, utilizing available equipment and methods. Electric logs, surveys, cores and production tests can be used to assess these resources and to evaluate their economic viability as primary sources of energy. But it will be necessary to complete the wells in such fashion that production of the high-pressured fluid can be obtained to deliver heat, mechanical energy and methane gas in economic quantities. This will require carefully considered completion techniques, involving pipe sizes and accessory equipment suitable for high volumes of fluid. Completion operations may include formation stimulation treatments and/or sand control measures to obtain optimum rates of flow with minimum sand influx. It appears that gravel-packed completions will be more feasible at this time than chemical consolidation treatments to control sand production because of high temperatures, thick producing intervals, and high-velocity flow rates. Flow rates up to 100 barrels per day per foot of perforations should be possible from consolidated formations without sand control treatments.

SUMMARY

Oil well completions may be quite simple, as cable-tool or air-drilled rotary wells which are allowed to produce after removal of the drilling tools, or very complex as a multi-zone producer which will involve setting casing, perforating, testing and running a string of tubing for each zone. Multi-zone wells will require careful cementation of the casing, perforating the several productive intervals, and special packers to segregate production from each zone. A single-zone completion may be as uncomplicated as a string of 2 7/8-inch pipe for a "tubingless" well, perforating, and removal of fluid in the casing to enable oil or gas to flow to the surface.

Pipe sizes and pressure ratings used to produce a well will be selected taking into account the expected fluid flow rates and pressures that might be obtained during the life of the well. If artificial lift is anticipated, casing and tubing sizes should be large enough to accommodate the downhole equipment that might be needed for pumping.

Completion equipment and methods employed may be quite variable, and are usually dependent on the kind of production to be obtained. If high pressure is anticipated and/or well depth is considerable, the best grades of pipe will be needed. Dual and triple-zone oil and gas wells are sometimes made where multiple reservoirs are present. The pipe sizes usually employed in oil or gas wells have much greater capacity than generally needed. Of course, factors other than oil or gas capacity and the desired producing rates must be considered when choosing pipe sizes for a well. Total fluid capacity must be considered when designing a producing well; wells that might have to handle a large amount of salt water along with the oil should be equipped with larger tubing than

needed for oil alone. Fluid production in the order of 5,000 barrels per day will require 3 1/2-inch or larger flow strings to handle the required volume without sizable pressure losses. Water production up to 40,000 barrels per day can be handled through 5 1/2-inch pipe; up to 60,000 b/d can be produced through 7-inch casing.

Water supply wells have progressed a long way from the hand-dug holes of yesteryear. Well bores then had to be large enough for a man to work on bottom. Stone and brick linings were succeeded by fire-hardened clay pipe. Later iron pipe was set for casing in small-diameter bored holes; finally, steel pipe with perforated sections were used for production. Three- or four-inch casing will suffice for artificial lift using sucker rods, but larger diameter casing is needed for high-capacity centrifugal pumps. Today, municipal water supply wells pumping rates sometimes exceed 10,000 gallons per minute; these wells are pumped through 16-inch production strings with screen liners and gravel packs to exclude sand. Carefully sized gravel is placed in underreamed holes to allow up to 6-inch thickness outside the screens.

Extreme pressured gas-condensate wells have been produced from geopressured formations in the Texas-Louisiana Gulf Coast for more than forty years. Deep wells in Iran and other locations around the world have produced from abnormally pressured carbonate reservoirs, but few geopressured wells have been reported from sandstone formations except in the United States. Deep, high-pressured wells in the Gulf Coast are always completed with perforated casing set through the productive interval. In most instances the production casing is set as a liner and subsequently extended to the surface. This facilitates getting the pipe to bottom and allows a full column of cement back to the wellhead.

Tubing head equipment suitable for 10,000-15,000 psi working pressure is usually installed. Tubing sizes from 2 3/8-inch to 4-inch may be employed; the larger sizes are necessary for the high flow rates frequently required. Variable flow rates will cause large temperature variations in the tubing and consequently its length. Movement of the tubing in the packer of twenty feet, or more, should be provided to minimize mechanical stress due to temperature changes.

Geothermal-geopressured wells will need large size casing and tubing to handle the required volumes of fluid. Perforated casing will probably allow the required fluid volume, though 4-8 holes per foot may be needed to lower the fluid velocity through each perforation. Prudence requires that a tubing string be provided for a safer and cleaner completion. Shut-in wellhead pressures may be 6,000-8,000 psig, depending on the amount of gas that breaks out of solution. Sand production may be a problem, depending on the mechanical strength of the productive rocks, fluid flow rates, and manner of completing.

Conclusions:

A geothermal-geopressured water well completion should include the following:

1. Wellhead equipment should be suitable for 10,000 psi pressure above the production casing hanger.
2. Intermediate casing, 10 3/4-inch or larger, should be suitable for 5000 psi pressure and cemented to the surface.
3. Production casing, 7 5/8-inch or larger, should be set as a liner through the productive zone with a liner hanger and packer bore receptacle for tie-back casing to the surface. The production casing should be cemented to the surface and tested to 10,000 psi.

4. For high flow rates, 5 1/2-inch or larger tubing should be installed with a packer bore receptacle to allow 20-foot travel. Tubing should be satisfactory for 10,000 psi pressure.
5. All porous and permeable intervals behind the production casing should be perforated, using 4-8 holes per foot, depending on the total footage of porosity. Perforating should be done using through-tubing procedures with minimum overbalance of formation pressure.
6. If sand-control is necessary, make an inside-casing gravel pack, using calcium chloride-bromide fluid to wash perforations and to place the gravel. An open-hole gravel pack with screen liner will be more effective than an inside casing gravel pack.

Needed Research:

1. An inert, solids-free, fluid having a specific gravity of 2.0 that can be used for gravel pack work. Calcium chloride-bromide mixtures are available up to 15.5 ppg (1.86 specific gravity) but these fluids are expensive and not always readily available. Heavier fluid may be required in many instances.
2. Proppants for 12,000 psi formation fracture work. Sintered bauxite has been used with good results to fracture reservoirs as deep as 16,000 ft, but fracture work in geopressured formations will be limited by the availability of suitable proppants.

OIL WELL COMPLETIONS

Early-day oil wells were drilled with cable tools in areas where the rock layers were consolidated and would not slough into the open hole. Casing was not usually provided except at the top of the well. If an oil-producing zone was encountered, oil would flow into the well immediately; if there was enough "rock" pressure, oil would flow to the surface and the well would be permitted to produce in that manner. If the oil had to be lifted, a small string of pipe (tubing), sucker rods and a rod pump would be used to raise the oil to the surface. If water-entry from up the hole became troublesome, a simple packer would be attached to the lower end of the tubing to seal against the wall of the hole to shut off water flow. Casing to shut off water from above was obviously an improvement to an open-hole packer on the tubing, thus it became general practice to provide a "water shut-off" string of pipe set just above the productive interval. The hole would then be deepened into the oil zone and the well allowed to produce from the open hole into the casing, i.e., the original "Open-Hole Completion."

If sand production from the producing formation became a problem, the well would be cleaned out and a "screen" liner placed in the hole to keep the sand in place. The original screens were made of small diameter pipe with drilled holes or saw-cut slots to hold back the sand. Later, more sophisticated wire-wrapped screens were developed. Screen liners, as well as blank liners, usually include friction-grip hangers to support the weight of the liner from the casing set above the open hole. A packer arrangement is frequently used to seal the annulus space between the top of the liner and casing. Blank liners are nearly always cemented

in open hole. Whether screen or blank liners are set, such wells are generally termed "Liner Completions."

The term "Perforated Casing Completion" is used to describe wells where hole is drilled through one or more productive intervals, casing set through the pay zones, and perforated for production. Most wells are completed as single-zone producers, but multi-zone completions, whereby two or more productive intervals are opened to the wellbore, are frequent. Special tools have been developed for perforating and other operations inside small diameter pipe, thus "tubingless completions" are now feasible, frequently employing 2 7/8-inch casing, without an inner string of pipe.

Tubing and Packers

Tubing, except when provided for pumping, was not set in newly completed wells until engineering studies showed that the flowing life of a well could be extended by means of tubing. Although well capacity was reduced by the use of tubing, it became regular practice by 1930 to install tubing because it made possible a safer and cleaner completion than bailing fluid from the hole and allowing the well to blow in as a "gusher". Tubing made it possible to circulate water to remove mud from the well, thus to reduce hydrostatic pressure at the bottom of the hole and allow formation pressure to cause the well to flow. If formation pressure — sometimes termed rock pressure — is not sufficient to overcome hydrostatic pressure, then fluid in the tubing can be removed by swabbing or using high pressure gas. Tubing in a well will allow circulation to obtain a fluid column of sufficient weight to "kill" well pressure if necessary for safety or repairs. A string of tubing that is plugged or damaged mechanically can be removed and repaired.

Tubing is nearly always provided with a packer to seal the annular space between the tubing and casing near the bottom of the tubing. Circulation is usually accomplished by raising the tubing string to release the packer from the casing or to open circulation ports. A circulation-port device in the tubing string may be opened by wireline methods.

A tubing string under changing conditions of temperature and pressure will have constantly changing length if the tubing is free to move. If the tubing is not free to move, varying stress levels will be imposed in the string. High flow rates will cause temperature increase that will tend to lengthen the string. Pressure applied internally because of fluid density and/or high pressure at the surface will swell tubing and cause the string to shorten. Pressure applied externally, tending to collapse the tubing, will lengthen the string. Calculations should be made to determine the net effect of these factors for a specific set of conditions.

Recent practice favors the employment of 3 1/2-in., 4-in., and larger tubing for high-volume producers with a full opening packer arrangement and provision for movement of the tubing relative to the packer. At the original bottom-hole pressure such wells can deliver a high volume of fluid or gas with the high wellhead pressure.

Casing

Drilling for oil, gas, or water involves two main objectives: (1) to bore a hole to an underground reservoir, and (2) to install a pipe from the reservoir to the surface, e.g., "casing." Casing has several important functions, including:

- (1) Prevent cavings from sloughing into the hole.

- (2) Prevent contamination of fresh water sands by fluids from lower zones.
- (3) Exclude extraneous fluid from the producing zone.
- (4) Provide means of controlling well pressure.

Figure 1 shows the several strings of pipe commonly installed in a producing well.

Conductor Pipe

Conductor pipe is the first string put in a well. Conductor pipe serves to protect the subsequent strings from corrosion and may be used to support some of the wellhead weight. Hole for the conductor may be drilled and cemented, as the other strings, but is often driven with a pile driver where the ground is soft or at an overwater location.

Surface Casing

The first string of any consequence that goes into a well is called surface casing. It is the starting point for the wellhead assembly. The setting depth may be 200 feet or so, but sometimes is several thousand feet. State regulations are quite specific as to the required depth of surface casing to protect fresh water formations. Surface casing must have sufficient strength to support a blowout preventer and to hold well pressures that may be encountered. Surface casing depth is sometimes established by the depth of salt or other mineral deposits that might be leached out or contaminated by the drilling fluid. Surface casing may be used to support part of the suspended weight on the wellhead; this is usually accomplished by cementing the surface casing from the bottom to the surface.

Figure 1 Casing Strings for an Oil or Gas Well

Intermediate Casing

Intermediate casing is a string of pipe run after the surface casing, but before the production casing. It is generally employed to seal off weak formations that might rupture with the heavy drilling fluid usually required when deepening a well. Sometimes an intermediate string is set to seal off older producing zones in order to drill for deeper production. It provides better protection against high well pressure than surface casing because it is usually stronger, higher grade pipe, and will not have been worn by abrasion of the drill string. The setting depth of intermediate casing should be deep enough to reach formations firm enough to hold the mud weight expected to be employed when drilling deeper.

Production Casing

This string of casing serves to isolate the underground reservoir from undesirable fluids from other zones penetrated by the wellbore. It is the protective housing for the tubing and other equipment used in a well. Tubing may be removed for inspection or repair, but production casing is cemented in place. Production casing is often the last casing set in a well, therefore it will be the longest, and is frequently the heaviest, string of pipe. This casing will be subjected to the maximum well pressures, thus it is generally the best pipe put into the well.

Wellhead Equipment

All bored wells must have some kind of wellhead equipment at the surface to which casing can be attached, tubing supported and pipe connected for flow of gas, oil, or water to receiving tanks or pits.

Most oil or gas producers will be equipped with two or more strings of casing that will be "landed" at the wellhead to make an assembly suitable for the pressures likely to be obtained. Besides pressure integrity, the wellhead must support all or most of the weight of casing run into the well after surface casing is set. A typical wellhead assembly is illustrated in Figure 2; note the manner of suspending the intermediate and inner casing strings. The final string of pipe in most oil or gas wells is the tubing through which produced fluid moves from the bottom of the well to the surface. The tubing string is supported by the tubing head; the tubing may be supported by a tubing hanger, as shown, or by attachment to a tubing head adapter. The aggregate weight of the tubing and casing supported by a wellhead may be a million pounds or more, depending on the size, unsupported length, and weight per foot of the pipe employed in the well. Individual strings of casing may be landed at the wellhead with five hundred thousand pounds, or more, supported by friction grip or threaded casing hangers.

The wellhead of a flowing well is topped by an array of valves and fittings, called the Christmas Tree as shown in Figure 3, which directs fluid flow through one or two wings to piping leading to separators, tanks, etc. High pressure throttling devices, chokes, are usually provided on each wing to regulate pressure and flow from the well. American Petroleum Institute (API) has established standards and pressure ratings for nearly all items of oil well producing equipment. Table 1 lists the pressure ratings of API wellhead equipment, as follows:

TYPICAL WELLHEAD ASSEMBLY

NOTE: Outlet connections for casing and tubing heads may be flanged, studded, or internally threaded.

NOTE: Intermediate and inner casing string may be cut off flush with the face of the flange of the bottom head or may extend above the face of the flange of the supporting head.

Figure 2. API Wellhead Assembly

Spec 6A: Wellhead Equipment

TYPICAL CHRISTMAS TREE

NOTE: Flow fitting may be a cross (as shown) or tee, and either flanged (as shown) or studded.

Figure 3. API Christmas Tree Assembly

TABLE 1

Wellhead Pressure Ratings <u>API Class</u>	Psi @ - 20° to 250°F <u>Working Pressure</u>
2M	2,000 psi
3M	3,000 psi
5M	5,000 psi
10M	10,000 psi
15M	15,000 psi
20M	20,000 psi

These ratings are lowered about 5% for each 100°F above 250°F temperature. Christmas Trees for 5000 psi pressure and higher usually are fitted with two master valves; sometimes two wing valves in series are provided for high pressure service.

Open Hole Completions

This type of completion is useful where there is only one productive zone and the interval of saturation is fairly thin. If sloughing shales are interbedded in the productive horizon, a perforated or screen liner may be placed in the open hole without cementing. Figure 4 shows the general configuration of an open-hole completion. The well can be tested as it is drilled, formation damage is minimum, the hole can be underreamed to obtain a larger bore for gravel pack, etc., or the well can be converted to a liner or perforated completion. Some of the disadvantages of an open-hole completion are that excessive gas or water production may be difficult to control, the productive interval cannot be selectively acidized or fractured, and frequent cleanouts may be needed.

Production casing can be set either before or after the productive interval is penetrated. If casing is set before, the fluid used to drill the pay zone can be oil or oil-base that will minimize formation

Figure 4. An Open-Hole Completion

damage, while the up-hole section of the well may have been drilled with more economical water-base mud. Open-hole completions are ideal in that all of the producing interval is exposed to the wellbore. No casing or cement sheath is present, as with other types of completions, to restrict fluid flow.

Open-hole completions are the simplest to make, but because of the problems outlined are rarely employed if other methods are possible. Gravel packing, in conjunction with a liner, is one alternative, but most gravel packs are made through casing. Sand consolidation treatments can be best performed through perforations.

Liner Completions

Liners are often used in open-hole completions as a means of supporting sloughing shale or to prevent shifting sand from entering the well bore. If the producing formation is loose and unconsolidated, specially prepared pipe, generally termed "screen pipe," will be set in the producing interval to hold back the sand that might otherwise enter the wellbore. Figure 5 shows a liner made of saw-slotted pipe; drilled holes can be used to accomplish the same purpose. Wirewrapped screen liners are more effective to hold back sand grains that might enter the well.

Figure 6 shows some of the types of wire-wrapped screens that are available; they may be flush-wrapped, as at left, or stand-off types as the other two examples. Round holes or rectangular slots may be provided in the pipe. Wire-wrapped screens provide less chance for plugging and the effective inlet area per foot of pipe is greater than plain pipe with either drilled holes or sawed slots.

Figure 5. Screen Liner Set in Open Hole to Control Entry of Unconsolidated Sand into the Wellbore

Figure 6. Wirewrapped Screen Liners

The most common liner completion is to set and cement blank pipe that is subsequently perforated. Special liner setting tools are available to facilitate washing the liner to the bottom of the well, cementing, hanging the liner to the prior casing, and sealing the space between the liner and the casing with a packer. Special equipment is available that will permit "tie-back" of the liner to another string of casing that extends to the surface. Extreme depth wells are often completed in this fashion as a means to facilitate drilling and permit installation of special completion equipment for handling large volumes of gas or fluid. Liner setting equipment to place a screen or blank liner in a well may be quite simple or complex for long liners that are cemented in a well. Slotted, perforated, or screen liners are usually run on tubing with a liner hanger and releasing device that will permit the run-in string to be detached after the liner is in place. This may be a simple "J-slot" arrangement, or a combination tool that will permit circulation through the liner, a packer arrangement, hanger device and a releasing device. Figure 7 shows a liner setting tool that permits circulation through the liner and provides means for cementing the liner. The setting tool permits circulation through the liner and provides means for cementing the liner. The setting tool and the liner assembly includes friction slips to support the liner, hold-down slips, packer, and releasing tool. A similar tool is used to set a screen liner; it does not include the cementing plug, but has a removable string of tubing inside the liner that extends to the shoe. Liner setting includes washing the liner to the proper depth in the well, hanging the liner at the desired depth with the required amount of weight on the packer, and, finally, releasing the run-in string from the liner. Often a liner packer is used above

Figure 7. General Arrangement of Liner, Hanger, Packer and Setting Tool

the hanger to prevent movement of gravel, for a gravel-pack job, or to make possible a reliable cement job. A packer provides a pressure seal between the casing and liner, but cement in the annular space of the liner overlap is the primary seal. An extension sleeve may be run at the top of the liner to provide a pressure-tight "tie-back" connection for extending the liner back to the surface. Liners in excess of 200 feet long are generally set with a hanger because a heavy liner may buckle or fail due to compressive loading if not suspended from the top.

Perforated Casing Completion

Because it is the most economical procedure and offers the best alternatives for subsequent well repair, formation stimulation, and sand control treatments, a perforated casing completion is by far the most popular method of finishing a well. The perforated casing method is suitable for testing several zones, or parts of zones penetrated in a well, and the method can be used for successive recompletions of higher intervals in a thick zone of oil saturation. Set-through procedures can be used for all types of formations, and various ways of finishing wells have been developed. Single-zone completions are the most common, but many multi-zone completions using set-through procedures are made every year. Small diameter perforating guns and logging devices developed for running through tubing have made it practical to employ 2 7/8-inch and smaller pipe for casing and dispense with tubing except when needed for artificial lift. Multiple strings of pipe may be cemented in a single borehole, and special devices are available to orient the perforator to insure perforation of only one string.

Perforated casing completions must rely on successful and complete cementation to insure isolation of productive intervals behind the

casing thus to obtain zone segregation. Near the casing shoe the pipe may be completely cemented in the open hole, but cementing difficulties due to voids and gaps in the cement sheath around the pipe will be found up the hole where mud contamination and cement channeling problems develop. In a set-through completion, squeeze cementing techniques can usually repair those defects.

Excessive gas or water production from an oil or gas zone can be controlled more easily in a perforated casing completion than in open hole. Electric logs, drill stem tests, cores and formation samples can be obtained prior to setting pipe in a set-through completion; this eliminates the cost of casing if the pay zone is non-productive. After setting casing, the hole can be deepened if necessary. Other advantages of a set-through completion include: (1) Sand control measures are feasible and both gravel-pack and sand-consolidation treatments can be made through perforations; and (2) Individual intervals of porosity within a productive zone can be stimulated using fracture or acidizing treatments.

Some of the disadvantages of set-through completions are: (1) Perforating long intervals may be expensive; (2) Zone evaluation using electric logs, DST's, cores, etc., before setting pipe can be critical. The hazard of poor interpretation of electric log information as to the ability of a well to produce cannot be completely eliminated. There is always the chance that a zone, though oil or gas is indicated, will not make enough hydrocarbons to pay for the completion attempt. Formation damage due to mud-plugging the porous zone or mud filtrate invasion of a permeable zone is always a real hazard of the set-through procedure that is almost impossible to eliminate.

Casing Cementation

Primary casing cementation is of the utmost importance to a successful perforated completion. Figure 8 illustrates the procedure, some details of equipment, and the method of cementing casing in a well. Dry cement is mixed with water and various additives to prepare a specific weight slurry that is then pumped into the casing, thence to the bottom of a well, and out of the casing to rise in the annulus as shown at right. Various accessory devices assure better distribution of the cement outside the casing.

Guide shoes are employed to guide the casing into the well and the drilling tools into the casing after cement or plastic material forming the nose is removed. Some guide shoes are provided with a float device, which is actually a back-pressure valve. Float collars serve several purposes. The back-pressure valve in these devices is closed by pressure of the outside fluid column, thereby preventing entry of the fluid as the pipe is lowered into the hole. If the casing is only partly full of fluid, then the string of pipe will literally float in the well. When the casing has been run to the desired depth, circulation is established through the casing and float collar; the valve in the collar serves as a check valve to prevent backflow of cement after being pumped outside the casing. This is important because the density of the cement slurry is often greater than the density of the mud. Thirdly, the float collar serves as a stop in the casing for the top plug when cement is displaced. Automatic fill-up shoes allow mud to enter the casing as pipe is run into the hole; after circulation is established the back-pressure valve is activated to work in the same fashion as the valve in a regular float collar.

Figure 8. Diagram of Primary Cementing Job

Casing centralizers, sometimes used in conjunction with scratchers, will (1) insure a reasonably uniform distribution of cement around the pipe, and (2) allow the cement to make a competent seal between the formation and casing. Engineering investigation has proven that casing cementation will be improved by the use of centralizers and turbulent flow in the annulus. Sometimes it is not possible to obtain turbulent flow in the annulus using conventional pumping equipment except by means of friction-reducing agents; reciprocation of the pipe (or rotation) will accomplish the same result. Centralizers hold the casing away from the wall of the hole and can prevent stuck pipe due to differential pressure. Centralizers may help remove mud cake from the wall of the well and prevent cement channels in the annulus. They must have sufficient strength to center the casing in the hole, thus to allow a concentric sheath of cement around the pipe.

Scratchers are mechanical wall-cleaning devices attached to casing that will abrade the wall of the hole when the pipe is worked by reciprocation (or rotation). Most operators will work the pipe when cement is being moved in the hole to create turbulence whether scratchers are provided or not. Casing that is equipped with reciprocating wall cleaners will be worked up and down for a distance of 5 to 35 feet, depending on the spacing of the devices on the pipe.

After the cementing plug has been pumped to the float collar and fluid pressure behind the plug increased, the next step is to bleed off pressure behind the plug in order to determine if the back-pressure valve is holding satisfactorily. Accepted procedure is to run up several hundred pounds after the plug stops moving; this pressure plus the imbalance of hydrostatic pressures inside and outside the casing may

total 1500 psig or more after pumping is stopped. This pressure will swell the pipe by an appreciable amount due to hoop expansion. If this pressure is held on the casing until the cement hardens, release of pressure will permit the pipe to contract to such an extent that the cement bond may be loosened. Cement waiting time before drilling out is usually 12-24 hours. Waiting-on-cement time is required for the cement to attain sufficient strength in order to: (1) Anchor the pipe and withstand the shocks of subsequent operations; and (2) Seal permeable zones to prevent movement of formation fluids behind the pipe.

If there is any question of the height that cement has risen in the annulus, the cement top should be checked. This can be done by running a temperature survey or cement bond log. A temperature survey will reflect the normal temperature gradient in the well; an abrupt change from this gradient will indicate the top of the cement in the annulus. Bond logs are usually employed to determine the quality of cement-to-pipe bond, the cement-to-formation bond, and the top of the cement. Generally, if a bond log shows a good bond, the primary cement job can be assessed as good.

Squeeze cementing is a secondary cementation method that is sometimes required due to failure of the primary cement job because of channeling, etc., and the consequent lack of a solid sheath of cement in the space between the casing and wall of the hole. Squeeze cementing normally involves running a squeeze tool, which is a special packer device, and setting it in the casing just above perforations through which cement is forced out to place cement in the annular space outside the casing.

Liner Cementing

Liner settings have several advantages. They provide a means of

testing a lower zone at less cost than a full string of casing. Because a liner can be run in shorter time than a full string, there is less danger of sticking the pipe off bottom. Liner strings are made up in the same manner as casing. When the liner pipe is made up, a liner hanger and releasing tool are attached to the upper end for lowering the liner into the hole on drill pipe. Hydraulic or mechanically-set hangers, as shown in Figure 9, are available. Both types depend on serrated-tooth slips to obtain a friction grip on the casing wall to support the weight of the liner. Hydraulic-set hangers are activated by fluid pressure inside the liner; mechanical types are set by manipulating the run-in string. After the liner hanger is set and the liner fully supported, the setting device is released by right-hand rotation, thus to disengage the liner from the run-in string. The setting tool is picked up a few feet to free a cup packer inside the top of the liner; this packer is used to circulate mud and cement through the liner. A small plug is pumped down the drill pipe immediately behind the cement slurry. The small plug seats in a female plug that is inside the liner; the larger plug is then released from the mandrel attached to the drill pipe and pumped down the liner as shown in Figure 10. Continued pumping displaces the cement in the liner to the shoe and up the annulus. When the plug reaches the bottom of the liner a pressure shutoff is obtained, indicating that the cement slurry has been pumped out of the liner. The cup packer attached to the drill pipe is then raised to clear the top of the liner; if a liner packer is employed, this movement releases the packer element which is then compressed by turning or lowering the run-in string. Cement slurry that may have been circulated above the top of the liner can then be pumped out of the hole, usually by reverse circulation.

Figure 9. Basic Liner Equipment: (A) Conventional Mechanical-Set Liner Hanger, (B) Hydraulic-Set Hanger, (C) Liner Receptacle, and (D) Seal Nipple

Figure 10. Conventional Method of Cementing Liners

Whether or not a packer is used, a satisfactory seal of the annulus can be obtained by cement, either by the primary job — the initial placement behind the liner — or by squeeze-cementing procedures after the initial cement job.

A liner may be converted to a full casing string by means of tie-back equipment also shown in Figure 9. Before running casing to complete the string back to the surface, a special milling tool is used to smooth out the inside of the receptacle to receive the tie-back seal nipple that is run on the lower end of the casing that is run into the well. The seal-nipple is fitted with seals to match the bore of the receptacle. After cement is placed outside the tie-back string of pipe, the seal-nipple is lowered into the receptacle and firmly seated.

Figure 11 shows a liner installation that allows two strings of protective casing to be set and a large "tubing" string to be employed for producing the well. In this instance, 10 3/4-inch casing, for example, would be set at 10,000 feet; the hole deepened to 14,000 feet where a 7 5/8-inch liner would be set. The hole could be deepened and a 5-inch liner set for production. The 7 5/8-inch liner would then be tied back to the surface. Note that 5 1/2-in. casing will be used as tubing from the top of the 5-inch liner to the surface. This procedure makes possible a large diameter tubing flow string and new 7 5/8-inch production casing that has not been weakened by drilling.

Bullet and Jet Perforating

Perforating is probably the most important of all completion procedures for cased hole completions. Adequate communication between the wellbore and all desired completion zones is essential to evaluate the formation and to obtain optimum production and recovery from each zone or reservoir.

Figure 11. Liner and Casing Arrangement Using Packer-Bore and Seal Nipple

Research⁽¹⁾ has developed the significance of (a) mud plugging of perforations, (b) plugging with shaped charge debris, (c) perforating with a pressure differential into wellbore, and (d) the effect of formation compressive strength on perforation hole size and penetration. This work led to the development of non-plugging shaped charges, through-tubing perforators, and improved bullet guns. About 98% of oil well perforating is with shaped-charge jet perforators.

Bullet Perforating

Bullet guns, 3-1/4 inches O.D. or larger, are applicable in cased-through formations having compressive strength less than about 6000 psi. Bullet perforators in the 3-1/4-inch or larger size range, may provide deeper penetration than jet guns in formations having less than about 2000 psi compressive strength.

Muzzle velocity of bullet guns is about 3,300 feet per second. The bullet loses velocity and energy when the gun-to-casing clearance exceeds 0.5 in. With zero clearance, penetration increases about 15% over 0.5 in. clearance. Loss in penetration with one-inch clearance is about 25% of penetration at 0.5-inch and at two-inch clearance, the loss is 30%. Bullet guns can be designed to fire shots selectively or simultaneously.

Jet Perforating

To fire the shaped charge, illustrated in Figure 12, an electrically-fired detonator starts a chain reaction which successively detonates the Primacord, the high velocity booster in the charge, and finally the main explosive. High pressure generated by the explosive causes the metal in the charge liner to flow. Continued pressure buildup on the liner causes a needle-like high speed jet with fine particles to spew from the

(1) Allen, T. O. and Worzel, H.C. (1956)

Figure 12. Jet Perforating Process

cone at a speed of about 30,000 feet per second at its tip with a pressure at this point estimated to be 5×10^6 psi. The outer shell of the liner collapses to form a slower moving metal stream, with a velocity between 1,500 and 3,000 feet per second. Jet-charge malfunction can result in an irregular or inadequate hole size and penetration or no hole at all. High temperature aging of explosive in the Primacord or charge may reduce charge effectiveness or, cause low order detonation.

Conventional retrievable hollow carrier steel guns normally provide adequate penetration without damaging the well casing. Guns are run in the hole with atmospheric pressure inside the gun carrier. Through-tubing jet perforators, including capsule-type guns, swing-jet guns, wire and strip carrier guns, and thin wall or expendable hollow carrier guns are available. Many of the through-tubing guns give inadequate penetration and/or hole size. The thin-wall hollow carrier or expendable hollow carrier gun eliminates debris and casing-splitting problems, and overcomes the gun clearance problem if the gun is properly decentralized but sacrifices some penetration.

Other Perforating Methods

Hydraulic perforators. Cutting action is obtained by jetting sand-laden fluid down tubing through an orifice against the casing. Penetration is greatly reduced as wellbore pressure is increased from zero to 300 psi. Nitrogen in the jet fluid stream appreciably increases penetration.

Mechanical cutters. Knives and milling tools have been used to open slots or windows to provide communication between the wellbore and the formation. Milling a window in the casing, under-reaming, and gravel packing are becoming routine for sand control in some areas.

Effect of Perforating in Various Fluids

Table 2 shows the results of Well Flow Index tests of jet and bullets in various fluids. Two types of tests were made with jet perforators in salt water, one test with a 200 psi differential into the wellbore and a second test with a 500 psi differential into the formation. Tests of bullet perforator were run with a 500 psi differential pressure from the wellbore to the formation.

Effect of Formation Strength on Perforator Performance

Simulated downhole tests have shown that perforator penetration (2) varies with formation compressive strength. In Figure 13, jets will penetrate deeper than bullets in hard formation. However, bullets may penetrate deeper than jets in low compressive strength formations, particularly if guns are fired at zero clearance.

If rock compressive strengths are obtained from applicable, properly cut and preserved cores, perforator penetration projections can be made for comparison with Berea sandstone test data or for comparison of different guns in the same formation on wells at any depth at any location by using Fig. 14. It may be possible to estimate strength based on cores from nearby wells.

Effect of Pressure Differential

1. Pressure differential into formation while perforating

- When perforating in mud, perforations are filled with a dense plug of mud solids, charge debris, and formation particles.
- Mud plugs are difficult to remove, often resulting in reduced well productivity and some permanent perforation plugging.
- When perforating in fluids such as water or oil, having

(2) Thompson, G.D. (1962)

Table 2

COMPARATIVE RESULTS WHEN PERFORATING IN VARIOUS FLUIDS

<u>Type Perforator, Well Fluid, and Differential Pressure</u>	<u>Perforation Data</u>		<u>Average</u>	<u>Avg. Flow Index</u>	<u>Condition of Perforation after Backflowing</u>
	<u>Penetration Inches</u>	<u>Hole Size Inches</u>	<u>to Initiate Flow, psi</u>		
<u>Jet Perforator</u>					
10-lb saltwater 200 psi into wellbore 500 psi into formation for 3 to 10 hours	6-1/2 - 8	1/4 - 1/2	0	1.00	Hole clean to total depth.
	6-1/2 - 8	1/4 - 1/2	0	0.61	Hole clean or partially filled with charge debris and sand.
10-lb caustic-quebracho mud 500 psi into formation	6-1/2 - 8	1/4 - 1/2	30	0.55	Partially or completely filled with mud and charge debris.
16-lb lime-base mud 500 psi into formation	6-1/2 - 8	1/4 - 1/2	100	0.41	Completely filled with mud, sand, and charge debris.
<u>Bullet Perforator</u>					
10-lb saltwater 500 psi into formation	3 - 3-1/2	1/2	0	0.61	Cleaned out or partially filled with sand.
10-lb caustic-quebracho mud 500 psi into formation	3 - 3-1/2	1/2	30	0.53	Filled with mud and sand.

After Allen and Worzel

Figure 13. Effect of Formation Compressive Strength
on Penetrating Efficiency of Bullet and Jet Perforators
After Thompson

Figure 14. Bullet, Jet, and Hydraulic Perforator Performance in Formations of Various Compressive Strength, After Thompson

high filtration rates, particles of charge debris, clay, or other fines may cause some plugging of perforations and deep damage in the formation.

2. Pressure differential into wellbore while perforating

Perforating with a differential pressure into the wellbore in clean fluids aids in perforation cleanout. This is the preferred method of perforating sandstone and some carbonate formations.

Effect of clean fluids — If a particular perforator will provide adequate hole size and penetration under given well conditions, high well productivities are indicated when perforating in clean oil or saltwater if pressure differential is into wellbore during perforating and until the well is cleaned.

Effect of compressive strength — Penetration and hole size of jet perforations are reduced as compressive strength of casing, cement, and formation rock is increased. Penetration of bullets is severely decreased with increases in strength of casing, cement, and formation rock.

Perforation Density — Shot density usually depends on the required production, formation permeability, and length of perforated interval. For high volume oil or gas wells, perforation density should be calculated to allow desired flow. Four shots per foot is the usual number in most areas. One or two shots per foot of perforated interval are generally adequate for most low volume wells in the U.S. In wells to be fractured, perforating is planned to allow communication with the desired zones. For sand consolidation, a minimum number of large diameter perforations is usually preferred. For gravel packing, a nominal number of very large diameter perforations is required.

Pressure and temperature limitations — As may be noted from Table 3, pressure and temperature ratings are available for all perforators.

Table 3

PRESSURE AND TEMPERATURE RATINGS
ON SELECTED PERFORATORS

<u>Gun Types</u>	<u>OD - Inches</u>	<u>Pressure Rating psi</u>	<u>Temp. Rating °F</u>
<u>Low Temperature Powder</u>			
Bullet	3-1/4, 3-3/8	15,000	250
Jet (Std. Hollow Carrier)	3-3/8, 4	20,000	340
Jet (Big Hole-Hollow Carrier)	4"	20,000	325
Jet (Thin Wall Hollow Carrier)	1-3/8, 1-11/16, 2-1/8, 2-7/8	15,000	340
Swing Jet (Expendable Thru Tubing)	1-11/16	12,000	300
Jet (Partially Expendable Thru Tubing)	1-11/16, 2-1/8	20,000	300
<u>High Temperature Powder</u>			
Jet (Std. Hollow Carrier)	3-3/8, 4	25,000	470
Jet (Thin Wall Hollow Carrier)	1-11/16, 2-1/8	25,000	470
Jet (Thin Wall Hollow Carrier)	1-9/16	25,000	600

Bottom hole pressure may impose limitations on some exposed charge guns. However, there are few wells where bottomhole pressure is a problem with most conventional hollow carrier casing-type guns.

Need for control of gun clearance — There is usually little problem with most large diameter conventional hollow carrier jet guns. Excessive gun clearance with any jet gun and especially with some through-tubing perforators, as illustrated in Figure 15, can result in inadequate penetration, inadequate hole size, and irregularly shaped or "keyed" holes. Bullet guns should usually be fired at zero - 0.5 in. clearance to avoid appreciable loss of penetration.

Clearance control can be achieved through spring-type deflectors, magnets, and other methods. Depending on charge and gun design, zero or one-half inch clearance for jet guns usually provides maximum penetration and hole size. In some hollow carrier casing-type guns, significant reduction of hole size can result when gun clearance is increased from zero to two inches. In such cases, centralization may produce satisfactory and more consistent hole size.

Depth measurements — A collar locator on the perforator correlating with a combination radioactivity and collar log is the accepted method of insuring accurate depth measurements for perforating. Radioactive tags can be inserted inside selected charges in a jet gun to assist in locating exact depth of perforations. Collar logs may show location of old or new perforations made with exposed charges such as those used in capsule guns. The collar log can record casing swelling or bulging from detonation of the exposed charges.

Figure 15. Control of Gun Clearance

Considerations Involved in Perforating

For most formations, perforating in a clean solids-free fluid with a differential pressure into wellbore will result in the highest well productivity without well stimulation, provided optimum hole size and penetration is obtained. The ideal method is to perforate with a through-tubing gun with zero gun clearance in clean fluids with a differential pressure into the wellbore. In many cases, however, because of tubing size limitations, available through-tubing guns do not provide adequate hole size and penetration. Also, there may be some question as to the effectiveness of some decentralizing devices required for zero gun clearance. Other possible means of optimizing perforating include:

1. One approach requires the use of a large diameter lubricator on the wellhead as depicted in Figure 16.

- Perforate with a full-sized casing gun in clean fluid with a differential pressure into wellbore and then retrieve the gun under well pressure. For normal pressure wells a differential pressure of 200 to 300 psi into the wellbore during perforating is quite adequate. Required differential is usually obtained by partially or completely filling the casing with KCl, NaCl, or CaCl_2 - water solutions or oil.

- A fullbore packer is then run under well pressure and set at the desired depth using an electric cable.

- After setting a packer equipped with a positive seal, pressure is bled off the casing above the packer to run the tubing.

2. A second approach would be to perforate casing with a conventional casing gun under pressure, and to produce the well without tubing. Producing wells without tubing has been the usual procedure for a number of years on many wells in Iran and other locations.

Figure 16. High Pressure Lubricator for Perforating Under Pressure

3. A third approach is to perforate with a conventional casing gun, with a pressure differential into wellbore. Pull the gun under full well pressure and snub tubing into the well.

Single-Zone Completions

About 90 percent of the oil and gas wells completed in the United States in recent years were finished as single-zone producers. Nearly all of these were single-zone perforated casing completions. Figure 17 shows the general arrangement of casing, tubing, and packer for a well that will flow naturally. A pumping well is equipped in much the same way but with a pump, sucker rods, pumping tee, and a polished rod stuffing box. Wells that are to be produced by gas lift are set up the same way as a flowing well, except that gas-lift valves are placed in the tubing string, and the lift gas is injected into the annulus above the packer. Hydraulic down-hole or submersible pumps generally are used with larger diameter tubing and casing than flowing wells or those produced by rod pumping.

Tubing plays an important part of any completion for several reasons. Its small diameter permits more efficient production of oil and gas than does casing, and it makes possible a safer completion because fluid may be circulated or swabbed if necessary to bring in the well. Conversely, fluid may be circulated to kill the well when the occasion arises, and tubing constitutes a string that can be pulled out if it becomes plugged or damaged. Tubing used in conjunction with a packer keeps well fluids away from the casing, affording protection against corrosion damage. Packers eliminate the hazard of well pressure on the casing and the chance of a casing leak that could develop into a blowout.

Figure 17. Single Zone Perforated Completion

After casing has been set, cemented, and landed at the wellhead, a tubing head and blowout preventers for tubing are installed. The usual program for a single-zone perforated casing completion includes procedures to clean out the casing to a specified depth, perforate, run tubing, circulate water to displace drilling fluid in the tubing, set the packer, land the tubing in the tubing head, and connect up the Christmas Tree. Sometimes there is enough formation pressure for the well to flow against the column of water in the tubing; if not, the tubing is swabbed to remove some of the water. The well is usually permitted to flow into a pit or tank until clean oil or gas appears. The well is then closed in for pressure observations prior to connection to an appropriate production facility. If the well is not expected to flow, alternative procedures would be to install gas-lift valves or pumping equipment. Modern completion practice favors the procedure of displacement of fluid inside the tubing by natural gas or nitrogen, but swabbing can be used to accomplish the same purpose. Generally the first completion choice, if other considerations do not conflict, will be the lowest possible producing zone in the well, because it is easier to plug back than to squeeze off and drill out an upper zone in order to reach a lower zone after depletion of the higher interval in the well.

Multiple-Zone Completions

Some 10 percent of the total wells completed in the United States annually are finished as multiple-zone producers. A multiple-zone completion is one in which two or more separate pay intervals are produced simultaneously through the same well bore without commingling the fluids. Zone separation is desirable for reservoir control but also is compulsory according to most state regulations. Multiple completions

have the obvious advantage of additional production from each zone where production is obtained. Two or more marginal zones that may not warrant separate wells can sometimes be economically produced. Field development can be accomplished more quickly because fewer wells need to be drilled. Multiple completions are particularly desirable for offshore locations where platforms may be very expensive and drilling costs are high.

The first multiples were dual completions using the annulus between the casing and tubing for producing the upper zone. This method is generally satisfactory, but producing through tubing is considered better because it is more dependable and permits swabbing, the running of bottom-hole pressure tests, and other operations. An individual tubing string for each zone is most often preferred. This is termed a "parallel string multiple completion." A triple- or quadruple-zone completion with parallel tubing strings is essentially the same as a dual, except for the additional tubing and packers. Many variations of casing and tubing sizes are possible, but popular combinations are as shown in Table 4.

TABLE 4

API CASING SIZE (Inches)	API TUBING SIZE (INCHES)		
	Dual	Triple	Quadruple
5 1/2	1 1/2*	-----	-----
7	2 3/8	2 1/16*	-----
7 5/8	2 7/8	2 3/8	-----
9 5/8	-----	2 7/8	2 3/8

* Non-API Tubing

Dual-Completion Procedures

After casing has been set through the productive intervals, the zones proposed for completion will be individually tested by DST methods to be sure of satisfactory production from each zone before the two strings of tubing and related equipment are run into the well. Formation tests will be made starting with the upper zone in order to avoid plugging the lower zone temporarily to test the upper zone. Drill pipe suitable for a work string will be picked up, the well cleaned out to the desired depth, and the drilling mud inside the casing displaced by salt water to be used as the completion fluid. Salt water is ideal for perforating, will hold most formation pressures, is often readily available, and generally will not cause formation damage.

The completion plan will usually include steps to run a perforating depth control log (gamma ray and collar), then to perforate the upper zone, and to run a formation test using a hookwall packer. This formation test should include shut-in pressures for reservoir evaluation, and the well may be flowed to a separator in order to obtain fluid and gas samples, determine the gas-oil ratio, and gauge the oil and gas volumes produced. The lower zone is then perforated and a DST taken in the same manner as the first. If either zone produces water, cement-squeeze repair or plug-back should be considered. If both zones prove acceptable for completion, the first step preparatory to running dual equipment is to run a bit and casing scraper to smooth the rough spots in the casing, particularly through the perforated intervals, in order to minimize damage to the packer that will be run. Although mechanical-set packers of various descriptions may be employed for multiple completions, equipment and procedures to be described here concern a nonretrievable

packer for the lower zone and a hydraulic-set, retrievable, dual packer for the upper position, as sketched in Figure 18.

The first step of the completion procedure is to run and set the lower packer. This may be any of several types, but a nonretrievable, or permanent, type is chosen in this instance. It may be set either by wireline or run on drill pipe. This packer is set about 30 ft. above the lower perforations. Figure 19 shows its general appearance in the well. The No. 1 string — the long string — with the tubing seal assembly seats in the lower packer. Other well equipment assembled in the order shown includes sufficient tubing to place the upper packer about 30 ft. above the upper perforations, with a specially protected "blast" joint opposite the perforations, a dual packer, a sliding-sleeve circulating valve and tubing to extend to the surface. The sliding sleeve nipple will be used to open ports to permit circulation between the tubing and casing. Figure 20 illustrates one type of hydraulic-set dual packer. When this string has been completely run, the tubing seal assembly is seated in the lower packer. Tubing nipples of various lengths are used to space out so that the string can be landed in the tubing hanger with the desired tension. Some of the details of a dual tubing head are shown by Figure 21. Sometimes both tubing strings are run simultaneously with the dual packer using special slips and elevators for handling the two strings of pipe at one time.

The No. 2 string is then assembled, starting with a latch nipple to seat and seal in the flow tube of the dual packer. Tubing to extend to the surface is picked up and the string spaced out and suspended at the tubing head in the same manner as the first string. Plugs are then placed in each tubing string at the hanger, the blowout preventers removed,

Figure 18. Diagram of Equipment of a Dual-Zone Completion

Figure 19. Permanent, or Drillable, Packer

Figure 20. Hydraulic-Set Dual Packer

Figure 21. Dual Tubing Head and Christmas Tree

and the Christmas Tree installed. The lowermost valve in this assembly controls flow through the No. 1 string, which produces the lower zone; the next valve controls the No. 2 string, which handles the flow from the upper zone. The wellhead fittings are pressure tested, all seals are checked for pressure tightness, and the tubing plugs are then removed. Fresh water is now pumped into the No. 2 string following a setting ball which seats in a catcher in the hydraulic-set packer; fluid circulation up to this point is around the upper packer and through the annulus to the surface. When the ball seats, hydraulic pressure is applied to set both the upper and lower slips of the upper packer and to compress the resilient sealing element. The setting ball is then flowed out of the string by well pressure. If formation pressure is sufficient, the well can be flowed through the short string to clean up the upper zone; otherwise, it will be necessary to swab this zone into production or to unload the tubing by opening the sliding sleeve and using gas to displace the fluid. If so desired, the long string can be swabbed to permit the lower zone to flow, or the sliding sleeve ports can be opened and load fluid displaced as described for the No. 2 string. The sliding sleeves must then be closed, using wireline tools, before permitting the zones to be cleaned up by flow to the pit.

Wireline Completion Equipment

Wireline completion devices are significant items for modern well completions, subsequent production, and workover procedures. The use of solid wirelines includes depth measurements, temperature and pressure surveys, paraffin removal, and similar employment. Bottom-hole chokes, regulators, plugs, safety valves, opening and closing of circulation ports, gas-lift valve changes, and other items for subsurface flow

control are regular features of wireline completion methods.

Some of the basic items of well equipment that can be run, set, or operated by wireline include:

1. Wellhead plug nipples should be placed below the tubing hanger in order to facilitate valve removal, flange repair, etc.
2. A retrievable collar or nipple stop should be placed near the bottom of each tubing string to prevent loss of tools or instruments out the bottom of the tubing.
3. Wells should be plugged with a tubing plug before the rig is moved off in case the wellhead is damaged.
4. Automatic safety equipment should be included for most flowing well completions. This may include tubing devices and/or surface valves that will shut off with excessive flow, release of pressure, etc.
5. Circulation ports in the tubing can be opened or closed by wireline equipment.
6. Bottomhole pressure surveys, samplers, etc., are usually run using wireline equipment.
7. Workovers by snubbing or wireline methods should be considered and planned for. This will eliminate killing the well and the possibility of formation damage by the kill fluid.
8. Remote, barge, or offshore locations and other hard to reach wells can generally be serviced at lower cost by wireline methods than by procedures which require a rig.

Wireline Units and Tools

Surface equipment for handling solid wirelines includes the following partial list. Power unit, measuring device, weight indicator, reels, pulleys, stuffing box, wireline valves, lubricator, and gin pole are the basic items of a wireline servicing rig. Figure 22 shows the several types of powered reel units for wireline service. Table 5 gives rated strengths of various diameter wirelines.

TABLE 5
STRENGTHS OF SOLID MEASURING LINES

Line Diameter, ins.	.066	.072	.082	.092
Minimum Strengths, lbs.	811	961	1239	1547
Maximum Strengths, lbs.	984	1166	1504	1877

As well depths increase and loads become greater, it is necessary to employ higher strength lines. The diameter of a measuring line should be kept to the minimum for the following reasons:

1. Enables minimum area exposed to pressure
2. Minimizes the load due to its own weight
3. Permits the use of small diameter sheaves and pulleys
4. Allows minimum reel and core diameters

Subsurface Well Equipment

The usual subsurface devices installed in the tubing for wireline completion procedures include items for immediate use to complete or produce the well. By anticipating future well conditions, equipment for servicing and workover can also be included.

Landing nipples, as shown in Figure 23, and similar devices, are

Air-Portable Wireline Service Unit

Skid-Mounted Wireline Service Unit

Trailer-Mounted Wireline Service Unit

Figure 22. Wireline Service Power Units

Figure 23. Tubing Landing Nipples

widely used for "known depth" seats in which various types of flow control devices can be located and landed. These nipples are available with different inside profiles and honed bores for pressure sealing. Special keys on the running mandrel will insure that only the specific nipple desired will accept the device. The No. 1 nipple should be run into the well at the lowermost position in the string when more than one nipple is used. The No. 2 position nipple should be run next, etc.

Sliding sleeve valve, Figure 24, is widely used to permit circulation between the tubing and casing annulus. It is opened by downward jarring and closed by upward jarring after engagement by a positioning tool.

Tubing safety valve, also called a "Storm Choke" by Otis,* is placed in the tubing of an oil or gas well to automatically shut in the well below the surface when the volume or velocity of flow exceeds a predetermined value. Alternative types include ball-type, bellows-type, and remote controlled units, the latter being operated by hydraulic pressure in small external lines. Safety valves for pipe sizes up to 7-inch casing are available.

Bottom-hole regulator is a removable valve and spring-loaded seat that is designed to reduce flowing pressure, as a bottom-hole choke, in the lower portion of the well bore. This allows the formation temperature to heat the flow stream before it reaches the surface and also serves to maintain a lower and safer pressure at the surface. Pressure reduction as much as 1500 psi can be taken across bottom-hole regulators.

*Otis Engineering, a Halliburton Company

Figure 24. Otis Engineering Sliding-Sleeve Valve

Plug-chokes are used to plug the tubing for:

1. Packer leakage tests
2. Removal of wellhead equipment
3. Tubing testing
4. Zone separation.

Some plugs will hold down pressure from either direction; others are designed to permit pumping down the tubing as a means of killing a well.

Unloading the Well

After the well is prepared by opening the producing formation to the well bore, the flow string — usually tubing — and the wellhead connections are ready for the expected fluid, the well will be allowed to produce by removing the column of fluid that was holding the oil or gas in check.

The rotary system requires that the well be full of fluid when formation pressure of any consequence is encountered. During the operations to complete the well, i.e., running casing, cleaning out, and installing tubing, the well will always be full of fluid of sufficient weight to hold down any formation pressure that may be exposed to the well bore. Perforating is sometimes performed without a full head of fluid in the well; but in that case, the wellhead will be "buttoned up" and ready to hold well pressure prior to perforating. When these operations are completed and everything is in readiness for the well to produce, the loading fluid will be removed by circulation, swabbing, or injecting gas. The final step is to permit formation pressure to push the loading fluid out of the well; artificial lift can be used to raise the fluid from a low-pressure well.

U-Tube Effect

The two columns of fluid in the tubing and annulus between the tubing and casing, when connected at the bottom, make a balanced pressure system that amounts to a U-tube. As shown in Figure 25, if the two columns are at rest, total static pressures on one leg of the U-tube will equal total pressures on the other. In the example, 10,000 ft. of 10 ppg mud — gradient pressure of 0.520 psi per foot — will produce 5200 psi at the bottom of the U-tube. The column of fresh water in the tubing has a gradient of 0.433 psi per foot that will be unbalanced against the other side unless 870 psi pressure is applied on top of the column. In this case, $4330 + 870 = 5200$ psi pressure will be obtained at the lower end of the left-hand column to exactly balance the heavier fluid of the annulus. The pressure of 5200 psi would hold down the 5000 psi formation pressure; but closing the circulation valve, as at right, would leave only the water "leg" of the U-tube — the tubing — to hold down the formation pressure. Release of the 870 psi on top of the water column in the tubing causes an unbalanced condition between formation pressure and the pressure of the water column — i.e., $5000 - 4330 = 670$ psi — and formation pressure will force the water to flow up and out of the tubing. Oil or gas is lighter than water, and there will be an even greater difference between formation and fluid column pressure when water is completely moved out of the tubing. Production tubing makes it possible to "unload" a well as a controlled operation.

A packer to shut off and isolate the fluid in the annulus or a circulation valve in the tubing string to serve the same purpose will also prevent contamination of well fluid in the tubing by fluid from the annulus. If the annulus is not shut off, then it will be necessary to

Figure 25. Fluid Columns in the Tubing and Annulus of a Well Are a Balanced Pressure System when Connected at the Bottom

lower the fluid in both the tubing and the annulus to reduce the fluid pressure "load" on the formation. This can be accomplished by circulation, usually down the casing and up the tubing. When heavy mud is "reversed" out in this manner using water or lighter mud pumped into the annulus, formation pressure will cause the well to flow as soon as fluid column pressure is reduced. Load fluid in a well can also be removed by swabbing, or by artificial lift methods.

Circulation

Circulation is the most common way to unload a well where formation pressure is high enough to flow the well and tubing when a circulation valve is installed. Using Figure 25, mud is displaced out of the tubing by pumping water into the tubing at the wellhead. Pump pressure using the lighter fluid will increase as the unbalance between fluid pressure at the bottom of the casing exceeds the pressure of the fluid column in the tubing. Using the well depth, mud weight, and water for displacement it will be seen that 870 psi will be needed on the tubing side, when the tubing is full of water and the annulus is full of mud, before the circulation valve is closed. When the tubing "leg" is full of water, the circulation valve is closed and pressure on the tubing can be released. Formation pressure, in this case, will overcome the fluid column pressure in the tubing, and the well will flow. If formation pressure is too low to overcome the head of a column of water, oil or gas instead of water can be injected into the tubing to lighten the column in the tubing.

Swabbing

Many wells are swabbed, either through the casing or more commonly through the tubing, to lower the fluid level so that the well can begin to produce. This is a mechanical operation whereby a swab cup arrangement picks up 400 ft. to 1200 ft. of fluid in the tubing and raises it to the surface by means of a continuous pull on a cable attached to a hoisting winch. A lubricator at top of the tubing with a stuffing box or "oil saver" will make it possible to divert the swabbed fluid to a flow tank or pit.

Gas Displacement

If gas under sufficient pressure is available, the best and easiest way to unload a well is by gas displacement. The usual procedure, where a packer or circulation valve is installed, is to inject high-pressure gas into the tubing, displacing fluid from the tubing into the annulus, up the casing, and out the well. When sufficient fluid has been moved out of the tubing so that the remaining fluid column pressure will be less than formation pressure, the packer will be seated to shut off the annulus, or the circulation valve will be closed. Gas injection can be stopped, the well permitted to flow, and the fluid column in the tubing pushed out of the well using formation pressure. This is the quickest, cleanest, and safest way to unload a high-pressure well.

WATER WELL COMPLETIONS

Water supply wells may be completed in the same manner as oil and gas wells, i.e., open hole, with screen liners (perforated or wire-wrapped), or as perforated casing completions.

Where the producing formations are consolidated and will not slough into the well, open-hole completions are the accepted norm and a great many water wells have been completed in that way. Bored wells are usually cased deep enough to prevent contamination of the producing zone from surface runoff or undesirable fluids from higher intervals in the well from reaching the lower part of the well.

Screen liners utilizing perforated or wire-wrapped screens, are the most common arrangement for industrial or municipal water supply wells. Gravel-packed screens are usual for such wells, which generally are rotary-drilled holes. Water shut-off casing is usually set just above the expected water-producing interval. The well is then deepened through the productive zone and underreamed to permit as much as 3-in. to 6-in. thickness of gravel. The screen liner is then run to bottom and gravel placed between the screen and underreamed hole. After placement of the gravel, with a liberal reserve for settlement, a packer to seal the annulus is set. The gravel behind the liner is then "developed" to flush the fine material from the gravel, to remove mudcake from the face of the productive formation, and to tighten the packed gravel. This is accomplished by means of a high-pressure water jet or surge device to wash water through the screen liner and flush the mass of gravel. Clean fluid under high pressure from the jetting nozzles flows through the screen into the gravel thence back through the screen and up the hole; air lift is often employed to raise the dirty fluid to the surface.

After the gravel pack is developed, a production string of casing is run into the well with a submersible pump — which may be electrical or shaft-driven.

Liner-type completions are sometimes made inside a set-through cased hole by milling out the casing through the productive interval, underreaming the open hole and setting a screen liner as described above. The actual completion is the same as a gravel-packed screen liner — which of course may be perforated pipe or wirewrapped screen.

Perforated casing water-well completions are made in the same fashion as oil or gas completions. Usually a rotary drilling rig is employed, drilling fluid is water-base mud, and the hole is drilled through the anticipated productive zone. Production casing is then lowered in the hole through the water-bearing strata, cemented in place, and the casing perforated for production. If the completion plan includes gravel packing through the perforations, the well will be prepared for gravel placement by washing the perforations, using a high-pressure perforation washing tool. This is a simple device that is fitted with opposing sets of packer cups on a mandrel which is run into the well to the perforated interval(s). Water or other solids-free fluid is then pumped through the perforations into the productive formation and back through the perforations above the upper packer cup. This will clean the formation and flush loose material from the "perforation tunnel" so that gravel can be forced to enter into the tunnel to create a filter arrangement. After the perforations have been washed, starting from the bottom and proceeding to the top of the perforated section of the casing, a gravel-pack crossover device and screen liner is run into the well. The liner is "washed" to the bottom of the well, usually plug-back

depth, and gravel is placed outside the screen liner by circulating down the tubing (or drill pipe) crossing over at the top of the liner, and then pumping the gravel down the annulus between the screen and the casing. Several types of cross-over tools are available. The annulus is filled with gravel and pressure applied to the top of the well to force gravel into the perforation tunnels outside of the casing-screen annulus.

Water-Well Design

A water well to be made in unconsolidated formations may be considered to have two main parts. The upper part, or cased section, serves as a housing for the pumping equipment and is a vertical conduit through which water is pumped from the aquifer to the surface. The upper section of the well is usually of water-tight construction and extends from the surface to an impervious formation immediately above the aquifer.

The lower, or intake section, of the well is that part where water from the aquifer enters the well. The intake section may be simply the lower end of the well casing, though this would be a very unsatisfactory arrangement in unconsolidated formations. It has several disadvantages, including: (1) a large diameter would be required for natural seepage into the well; and (2) the tendency for aquifer material to slough into the hole as the well is pumped. A well screen is usually set to permit higher rates of water flow into the well and to support the face of the producing formation and to prevent sloughing of this material into the well.

Cased Section

The selection of the well casing diameter is usually fixed by the

type and size of the pump that will be required for the desired yield or potential production of the well. The well casing must be large enough to accommodate the pump with sufficient clearance for easy installation and efficient operation. For larger wells, such as those for municipal or industrial purposes, the casing should be two nominal sizes larger than the pump selected. This assumes the use of a deep-well or submersible electric type of pump.

In larger and deeper wells, it is sometimes an advantage for economic or other reasons to reduce the casing diameter below the lowest anticipated pump setting depth. This saves the cost of extending the large diameter casing all the way to the aquifer when the smaller size of pipe is sufficient to accommodate the anticipated flow from the aquifer with reasonable loss of pressure head.

Intake Section

The single greatest influence on the performance of a water well is the design and construction of the well screen. A properly designed screen combines a high percentage of open area for relatively unobstructed flow of fluid into the well and sufficient strength to resist the mechanical forces to which the screen will be subjected both during and after installation in the well. The screen openings should preferably be shaped to facilitate flow into the well and to make it difficult for small particles of sand to become lodged in the opening, thus to lessen or plug fluid flow.

The continuous-slot type of well screen shown in Figure 26 is made of cold-drawn wire, approximately triangular in cross section, wound spirally around an array of longitudinal rods. The wire is welded to the rods at all points where they cross. The resultant cylindrical

Figure 26. Open-Construction Well Screen

well screen becomes a one-piece rigid unit. The stronger the material used, the smaller will be the dimensions of the wire and rods and hence the greater the ratio of open area to solid area of the screen surface. Such screens are available of metals such as galvanized iron or steel, stainless steel and various types of brass.

Along with the maximum open area in a well screen, the design should also be such that the openings do not become plugged by sand particles after the screen is placed in the well. This is achieved by the use of V-shaped openings formed by the triangular shaped wire as shown in Figure 27. The V-shaped opening is particularly important when developing the well, as the flushing process is based on the smaller particles of sand passing through the screen for removal from the well. Continuous-slot screens are made with practically any width openings from 0.006 inch and larger.

The pipe-base well screen is also in general usage. It consists of a slotted or drilled pipe around which triangular-shaped wire is wrapped. Alternatively the wire may be wound over a series of longitudinal rods spaced at intervals around the circumference of the pipe. The latter construction is a more efficient screen as the rods hold the wire away from the pipe surface, thus reducing blockage of the openings in the pipe.

Gravel Packing and Formation Stabilization

Drilling by the rotary method through an unconsolidated water-bearing formation will produce a hole somewhat larger than the outside diameter of the well screen. This provides the necessary clearance for lowering the screen to the bottom of the hole without interference.

Gravel packing or formation stabilization will fill the annular space

Figure 27. V-Shaped Openings in Well Screens

around the screen, at least partially, to prevent silt and clay materials above the aquifer from caving or slumping when the well is developed.

Gravel packing is to artificially provide graded gravel or coarser sand that may be missing from the natural formation. There are at least two conditions in unconsolidated formations that tend to favor gravel-pack construction. Fine uniform sand will require a screen with very small slot openings and the development process, which has the objective of forming sand grain bridges to hold back the sand grains that tend to move with the fluid, would not be very satisfactory. Screens with very small slot openings have low percentages of open area because of the relative thickness of the wires that must be used to provide strength. By gravel packing such wells with larger grains of gravel than the fine formation sand, screens with larger slot openings may be used, thus larger areas for fluid drainage into the well bore. The second condition favoring gravel packing is an aquifer that consists of thin, alternating layers of fine, medium and coarse sand. The use of gravel packing reduces the chance of error that could come about from developing the natural material of the aquifer. In other words, if a screen-slot size was selected that the fine formation material would plug, then that part of the screen would be useless. The selection of the gravel-pack material size is usually based on the finest material in the aquifer. The gravel-pack material should be of such size to hold 4-6 times the majority of the finest sand grains and the gravel/sand uniformity coefficient in the range of 3-5. The uniformity coefficient is the number expressing the ratio of the 40% size material to its 90% size, i.e., percentage retained on given sieves of sieve-analysis. Gravel-pack material should consist of clean, well-rounded, smooth grains. Quartz and other silica-based

rocks are preferable. Gravel-pack thicknesses are usually 3-6 inches thick. Tests have shown that only a fraction of an inch will satisfactorily retain formation sand, but greater thicknesses are usually made in order to insure that the well screen is completely surrounded by the gravel-pack material.

Formation stabilization is where the development is a natural process, with the graded coarse material coming from the aquifer itself and not from added gravel. Formation stabilization material should be adequate to fill the annular space around the screen and as far above the screen as practical. This should allow for settlement and losses of the material through the screen during the development process. Figure 28 shows a screen setting where formation stabilization was used instead of gravel packing. Note that all material finer than the screen openings has been washed out near the screen and that the remaining material grades from coarser to finer sizes with distance from the screen. Many shallow water wells are completed in this fashion.

Well Development

Well development is the process required to insure a good yield of clean fluid from the well by removal of silt, fine sand, and filter cake from the face of the aquifer exposed to the borehole. If development is done properly larger passages through the gravel pack or stabilized formation will result through which water can flow more freely towards the well. Well development also grades the material in the water-bearing formation around the screen, as described previously, and tends to wash off or flush away the filter cake deposited on the porous formation exposed to the well when the hole was drilled. It is generally conceded

Figure 28. Highly Permeable Developed Zone Around Well Screen.
All Material Finer Than the Screen Openings Has Been Removed.

that gravel packs thicker than six inches prevent effective removal of filter cake by well development.

The well development process, usually by means of high-pressure jetting or fluid surging through the screen, must cause reversal of fluid flow through the screen openings and the gravel or formation material immediately outside the screen. High velocity jetting, as illustrated in Figure 29, is the preferred procedure. Jetting is done with an assembly of three or more jet nozzles attached to the tubing or drill pipe string lowered into the hole after the screen is set and the well has been gravel packed. Fluid pressure of several hundred psi is applied to the run-in string which is held at a specific level while the string is rotated to turn the jetting streams around the inside of the screen. Jetting is the most effective development method because the energy of the jets is concentrated over small areas and every part of the screen can be selectively treated. The method is relatively simple to apply and not likely to cause trouble because of over-application. Surging is the name given to the mechanical development method whereby a plunger is worked up and down in the casing like a piston in a cylinder. This action causes fluid to surge into and out of the screen to flush the well. The surging process can also be accomplished by high speed bailing or swabbing to pull fluid out of the well and alternatively allowing the fluid level to fall back, thus to cause fluid to wash back and forth through the screen. Where formation pressure is sufficient to cause fluid to flow into the well, surging flow can be accomplished by means of a quick-opening valve on the flowline from the well. Rapid closing and opening of this valve can cause the fluid stream from the well to surge through the packed gravel or stabilized formation thus to flush fine sand and/or wall cake from the well.

Figure 29. Continuous Slot Screens Permit Very Effective Development of Gravel Pack Behind the Screen Using High-Velocity Jets

Development of gravel-packed wells is aimed at removing the thin layer of filter cake that was plastered on the wall of the hole when the well was drilled. The presence of the gravel sheath outside the well screen causes some difficulty when developing the well, depending on the thickness of the gravel pack and other factors. The jetting method is usually more effective than other methods; the thinner the gravel pack the more likely the removal of fine sand and silt from the pack as well as filter cake from the face of the aquifer. The use of mud thinners such as polyphosphates, lignosulfonates, etc., will effectively assist in the loosening of silt and clay in the pack. These chemicals will work more effectively when mixed with the flushing fluid and allowed to stand for an hour or two before starting development operations.

Gravel Placement Procedures

Figure 30 illustrates the simplest method of placing gravel in a well after the screen and casing have been run. By this system water is circulated from the surface outside the casing down the annulus to the bottom of the hole. Fluid will enter the screen and rise inside the casing where it can be picked up by the suction of the pump for recirculation. Gravel is simply poured down the annulus outside the casing and allowed to fall to the bottom of the well. This method is probably the poorest way to gravel pack a well. The main problem is that the gravel will tend to form bridges in the annulus, thus the open hole will appear to be full but gaps and channels will be present in the mass of gravel at the well bottom. It is satisfactory only for very shallow wells.

Figure 31 depicts the tremie-tube method of introducing gravel to the bottom of the well. Fluid flow is the same as the first method but

Figure 30. Simple Gravel-Pack Method

Figure 31. Tremie-Tube Method of Gravel

the velocity of the fluid-gravel mixture going down the tube is much faster than it would be in the annulus without the tube. The tremie-tube will be raised as the gravel outside the screen accumulates and the top becomes higher between the screen and borehole. The tremie-tube can be worked up and down to break up bridges that might form outside the screen and by this means the top of the gravel outside the screen can be determined. This method is satisfactory for wells of moderate depth.

Figure 32 outlines a more elaborate method of placing gravel in open hole outside a well screen and liner arrangement. Note that the screen-liner was run with a setting tool on drill pipe and that the screen-liner is attached to the drill pipe while the gravel is placed outside the screen. A blowout preventer is closed at the surface around the drill pipe to force fluid introduced from the gravel source and pumped into the annulus to circulate down the annulus as shown. Fluid circulated outside the drill pipe with the screen-liner in place will carry the gravel to the bottom of the borehole where it will accumulate outside the screen. Cleaned fluid will pass through the screen and go to the bottom of the "stinger" pipe which is attached to the drill pipe. Pressure applied to the fluid at the surface will force the fluid up the stinger and drill pipe to the surface where it can be flowed to a pit or tank to be picked up by a pump for recirculation. The screen section of the assembly may be some distance below the top of the liner, thus a "tattle-tale" screen will be used as an indicator that gravel placed in the annulus has risen to the desired height. After placement of the gravel, the setting tool is released from the screen liner, usually by right hand rotation of the run-in string to unscrew a left-hand thread at the top of the liner. This will permit the drill pipe and attached

Figure 32. Pressure-Pack Method of Placing Gravel

stinger pipe to be removed so a pump and production string of pipe can be run into the well. The pumping method using reverse circulation requires proper organization, an experienced crew, and reliable equipment to be effectively employed.

An even more elaborate method, shown in Figure 33, makes use of a "cross-over" device. This permits gravel-laden fluid to be circulated down the drill pipe, instead of in the annulus, to the cross-over tool where the fluid and gravel mixture is turned outside the drill pipe and the cleaned fluid rising inside the screen assembly is crossed to the annulus. This makes it possible to use the drill pipe for the fluid under high pressure and the annulus between the drill pipe and casing for the low-pressured fluid to return to the surface. High fluid velocity in the drill pipe can be maintained at lower-pumping rates than when circulating the fluid and gravel mixture in the annulus. Return flow of fluid in the annulus using the cross-over tool can be at slow velocity because the gravel has been removed by the screen. Most open hole and inside casing gravel packs are performed using cross-over devices. Considerable pressure is usually required on the gravel-fluid mixture to pump it into the well and move it to the bottom of the hole.

Gravel-fluid mixtures can be pumped into a well by the use of pressure "pots" in which the gravel is loaded prior to being mixed with the fluid under pressure from the pump. Figure 34 shows a double pot gravel mixing unit; the pressure vessels, into which the gravel is placed, are rated at 3000 psig working pressure. Manipulation of the valves equalizes the pressure inside the pots above and below the gravel, thus it can move into fluid stream being pumped into the well. The dual arrangement allows continuous movement of gravel into the well.

Figure 33. Sketch of Principal Components Used When Gravel-Packing by the Cross-Over Method

Figure 34. Double Pot Unit for Mixing Gravel and Fluid Prior to Pumping into a Well

SAND CONTROL PROCEDURES

Sand production is one of the oldest problems for oil or water wells. It is usually associated with shallow formations in unconsolidated rocks but in some areas sand problems may be encountered at depths of 14,000 feet or greater. Sand production may be a minor problem until a certain rate of flow is exceeded; fluid production above the critical flow rate will result in increasing sand production. Wells can "sand up" and shut off production, abrade the well head fittings or other surface equipment, accumulate in tanks or pipe lines, or cause casing collapse in the well. Sand production can be reduced by lowering the "drag" forces of the produced fluid, primarily by reducing fluid flow velocity, by bridging the sand grains of the producing formation mechanically, or by increasing the strength of the formation using sand consolidation measures. Flow rate reduction is the best means of sand control in most cases. Mechanical means of sand control involve sand screens, which may be perforated, slotted, or wire-wrapped pipe, and tightly packed gravel between the screen and face of the producing formation. Sand consolidation treatments consist of epoxy or resinous material that is forced between the sand grains to actually "glue" them together to form a stable and porous mass.

Reduction of Drag Forces

Reducing the drag or frictional forces between the fluid flowing in a sandstone matrix and the grains of sand is often the most effective and is certainly the simplest means of controlling sand production. Fluid production must be considered as a rate of flow (velocity) per unit area of permeable formation open to the wellbore.

For a fixed production rate, flow velocity per unit area may be reduced by: (1) clean, large perforations through the producing interval, (2) increasing the density of perforations, (3) increasing the length of the perforated interval, and (4) creating flow paths from the reservoir by gravel-packed fractures. Good completion practices, including a solid cement sheath around the casing, clean fluid in the well when perforating to lessen plugged perforations, and selection of perforating charges for clean holes not plugged with jet-gun debris, etc., can lessen the problem of serious sand influx.

Where the size of the reservoir and the requirement for high fluid volume justify, the critical producing rate above which sand production becomes "excessive" can be an important economic question. In the U. S. Gulf Coast the practical limit on sand production is often assumed to be 0.1% (600 pounds per 1000 barrels of fluid) as measured in a centrifuge graduated tube. For coarse formation sands, as in Nigeria, much lower limits are considered desirable, mainly because very high fluid production rates are involved. In Indonesia, where the wells are shallow and the production methods are sometimes rather primitive, 0.5-1.0% sand-to-fluid ratios have been observed.

In some sand-producing areas it appears possible, for a given zone, to establish for untreated wells a maximum producing rate without significant sand production that is proportional to the length of the producing zone or perforated interval. Maximum fluid production rate without excessive sand appears to be related to three important factors:

- Productivity Index (Barrels per day/Psi drawdown)
- Length of the Productive Interval
- Formation Strength

Frequently sand entry is detected in the separators, pipe fittings, etc., before excessive quantities are produced. A flowline probe, or erosion tube made of thin material, will cut out and show if sand is being produced; it can be connected to pressure actuated equipment to close in a well before the surface fittings are destroyed. A sonic device is available that can be installed in a flowline to "hear" sand impinging on the detector.

Some sand will always be produced, even when effective sand control treatments are made. Moveable fine material will continue to be flushed from the pore space of the formation, depending on the flow rate of the well. At very low rates the amount of this material may be almost imperceptible; at higher rates greater amounts of fine sand may be produced. Moveable fines should be moved out of the formation, through the gravel pack or consolidated section, and the screen to prevent plugging the well.

Mechanical Methods

Mechanical methods of sand control may involve:

1. A screen arrangement to retain sand without gravel.
2. Packed gravel to hold formation sand in place with a screen arrangement to retain the gravel.

The basic problem is to control formation sand entry into the wellbore without excessive reduction of well productivity. Basic design parameters include:

- Optimum screen slot width to retain the formation sand or artificially placed gravel.
- Optimum gravel size in relation to formation sand size.
- Effective placement techniques.

Screen Liner Considerations

Slotted or drilled-hole perforated pipe is the lowest cost type of screen available. Slotted plastic pipe is less expensive than steel pipe but is not as mechanically strong as steel. Saw-slotted pipe, as illustrated in Figure 35 is more commonly used than drilled perforations because very narrow slots can be made — .015-inch slot width is the practical lower limit. Slot plugging is almost a certainty when formation grain size variation is small and is probably the end result even when particle size variation is large. Parallel-side slots are easier to plug than the tapered openings of wirewrapped screens. Slot plugging promotes high velocities through the slots thus abrasion and enlargement of the slots, and failure to control sand entry will likely take place. Metal corrosion will likely occur to the slot corners due to saltwater or acid etching, thereby creating a funnel shape which will accelerate plugging. Saw-slotted liners can be obtained for about \$5/foot (1976) plus the cost of the pipe.

Flush wire-wrapped screens have keystone shaped slots. Slot area of a flush wire-wrapped screen is about twice that of a parallel-sided screen, therefore fluid velocity is lower and abrasion is less than for a slotted liner. If the metal of the pipe and the wire are not the same, bimetallic coupling will cause accelerated corrosion of the pipe. The best wire-wrapped screens use stainless steel for both the pipe and wrapping wire. Wire-wrapped screen pipe can be obtained with slot sizes as low as .006-inch wide. In 1976, wire-wrapped screen liners cost \$30/foot, plus the price of the pipe.

Figure 35. Saw-Slotted Liner Pipe

Stand-off wire-wrapped screens have keystone shaped slots, Figure 36 that will minimize slot-plugging. Slot area is about four times the area of flush wire-wrapped screens and eight times the area of a parallel-side slotted pipe. This provides maximum inlet area, lowest velocities, and the least abrasion. Bi-metallic corrosion can be minimized by plastic coating the inner pipe, though the best arrangement is to use stainless steel for both the pipe and wrapping wire.

Rod-base, wire-wrapped screens as shown in Figure 37 have nearly twice the open area as the wire-wrapped rib-type screen but cost about twice as much. Note the very great difference of effective inlet areas between slotted pipe and wire-wrapped screens.

Liner-casing size ratios are usually as shown in Table 6.

Formation Sand Size Analysis

Sand grain size distribution often varies through a particular sand body and will certainly vary from one geological zone to another. For a representative sieve measurement a number of samples are needed:

- Full-diameter cores are best.
- Sidewall cores are good. Some of the larger sand grains will be crushed and solid particles from the drilling mud are usually found.
- Formation sand particles from perforation washing or back-surfing are acceptable, if better samples are not available. Will generally be too fine.
- Produced, or bailed, sand-grain samples are better than nothing. Usually, these are too coarse.

For most oil field work, the U. S. Standard Sieve Series (ASTM E1170) is used and the sieve analysis is reported in inches or millimeters.

Figure 36. Stand-off Wire-wrapped Screen Pipe

Figure 37. Wire-Wrapped Rod-Base Screen

Table 6

Casing and Liner Sizes

Casing Size (Inches)	Inside Csg. Pack Liner Size	Open Hole Pack Liner Size
5-1/2	2-7/8	3-1/2
6-5/8	3-1/2	4-1/4
7	3-1/2	5
7-5/8	4	5-1/2
8-5/8	4-1/2	6-5/8
9-5/8	5	7

- Liner must be centralized inside casing or in open hole.
- A liner packer is required to prevent flow of fluids and gravel upward around the outside of the liner.

In some areas Tyler Mesh designations are used. Figure 38 shows a typical sand analysis distribution. Ten percentile sand size is defined as the point on the distribution scale where 10% by weight of the sand is of larger size and 90% smaller size. Grain-size distribution varies considerably around the world, both in average size, as shown in Figure 39, and in uniformity.

Ideally, sand screen slot width should be as large as possible to retain the sand grains but not to restrict flow of fluids and fine material. For retaining uniform formation sands where the grains are more difficult to bridge, or where changes in flow velocity occur, experience dictates screen slot width equal to the 10 percentile sand. Since it is imperative that all gravel be tightly placed and retained behind the screen, screen slots for a gravel pack must be slightly smaller than the smallest gravel grain size.

Early work by Coberly (3) in defining gravel/sand size ratios considered only the problem of sand entering the well bore, and not the permeability of the gravel pack. This led to rather large gravel-to-sand ratios. Later it became clear that the sand must be stopped at the outer edge of the gravel pack; if sand bridges took place within the gravel pack, permeability would be significantly lowered. The point is made by recent investigators that the coarsest parts of the sand should be bridged at the outer edge of the gravel pack and the fine material allowed to pass through the pack. The ratio of 5 or 6:1 gravel to sand size (4) should be employed for both uniform and non-uniform sands. In lab experiments it will be found that a gravel pack thickness of 4 or 5 gravel diameters will control sand; in practice much thicker packs are needed. Three-inch thickness of gravel may be considered

(3) Coberly, C. J. (1937)

(4) Schwartz, David H. (1969)

Fig.38 - Typical Sieve Analysis

Fig.39 - Variations in Sand Size Distributions

Figure 39. Variations in Sand Size Distributions

as minimum; six inch thickness is considered the maximum that can be developed by high-pressure fluid jets. Thicker gravel packs permit higher production rates within acceptable sand production limits.

High production rates can be obtained and maintained from unconsolidated sand formations by gravel packing with small size gravel. The key is to pack the gravel so that sand movement is completely stopped and in such fashion that the gravel retains its naturally high permeability.

Gravel should be within 10% of its specified range, neither too large nor too small, and must not contain dirt or unwanted material. The hole must be kept clean throughout the gravel packing operation. The screen must be checked to be sure the openings are properly sized; the screen must be centralized in the hole, and care must be taken that it is not damaged while being handled or run into the hole.

The smallest size gravel determined from sieve analyses of the formation sand should be used. A high concentration of gravel should be used in a viscous fluid (viscous oil or gelled saltwater) to reduce the amount of fluid lost to the formation and to minimize the possibility of mixing the gravel and sand from the formation.

Practical Considerations in Gravel Packing

The keys to successful gravel packing are:

- Select gravel of proper size and quality
- Place the gravel without contamination, at the proper location, as tightly as possible.

The solution of the problem is to control the load-bearing solids without losing too much productivity. Where the reservoir will sustain

high production rates, special effort must be made to maximize productivity and reduce flow velocity per unit area. As mentioned before, this can be accomplished by a longer perforated interval, more perforations per foot, larger perforations, or, ideally, an open-hole gravel pack with a wire-wrapped, rib-type, screen to hold the gravel. The much greater area open to flow of fluids into the well of an open-hole gravel pack, and the corresponding reduction in flow velocity, allows more margin for error, i.e., "poor practices," etc., compared to an inside casing gravel pack.

Gravel Packing Fluids

It is absolutely necessary that solid-particle filter cake not remain on the formation face of an open-hole gravel pack, or in the perforations or cavity of an inside casing gravel pack. Saltwater, crude oil, diesel fuel, or hydrochloric acid fluids are satisfactory for gravel placement, provided:

- They do not affect clay or shale wettability
- They are clean — filtered through a 2-micron filter — or non-gravel solids that can be degraded by acid or oil.

Gravel concentrations of 1/2 to 1 pound per gallon can be carried with pump rates up to 5 barrels per minute. Squeezing low viscosity fluids into the formation may make a tighter gravel pack.

When underreaming the hole for an openhole gravel pack, a desilter should be used to clean the drilling fluid as well as a filter to remove the fine material. Minimum safe hydrostatic overbalance of formation pressure should be used. If fluid density greater than 10.0 pounds per gallon is required to hold formation pressure, fluid costs and complications become greater. Calcium chloride can be used for fluid density up

to 11.5 ppg; calcium chloride plus calcium bromide fluids are available up to 15.1 ppg but are very expensive.

Recent work in the Gulf Coast for short gravel pack zones where sand has been produced, or where a cavity can be established outside casing by perforation washing, gravel can be effectively displaced using a high viscosity (gel) fluid⁽⁵⁾. The combination of high viscosity fluid, high sand concentration and low injection rate will carry gravel through perforations and will minimize mixing of formation sand with the gravel. High viscosity fluid will reduce fluid loss into the permeable formation. Water-base fluids up to 100 centipoise viscosity at 180°F are now being used for gravel packs. These fluids make possible:

- Fairly low pump pressures when displacing the gravel outside the casing.
- Gel-breaker can be used to aid removal of the gelled fluid after displacement.
- Gravel can be effectively made water wet.
- Hydrochloric acid can be used to remove acid-soluble material such as calcium carbonate.

Inside Casing Gravel Packs

Most oil well gravel packs are done where perforated casing completions have been made. Inside casing packs are used where there is need for zone isolation, where downhole repairs may be needed at a later date, where there may be problems of water or gas production along with oil, where lost circulation and/or formation fracture may take place, and, finally, if the operator is willing to accept the somewhat lower productivity of an inside casing compared to an open-hole gravel pack.

(5) Bruist, E. H. (1974)

Everything possible must be done to insure large diameter, clean perforations for a successful inside gravel pack. Gravel cannot be carried into a perforation that does not accept fluid readily. Even though clean fluid is present when the well is perforated, the "perforation tunnel" may be partially or completely plugged by metal particles from the jet charge and crushed formation material. Perforation tunnel plugging is particularly severe when perforating is done with differential between formation pressure and hydrostatic pressure towards the formation. Hollow-carrier jet perforators are preferred because less gun debris is left in the hole. Even with optimum standoff and centralization, perforations using jet charges may be too small for effective gravel packing, i.e. 3/8-inch entrance holes. Increased perforation density is one approach, but casing damage may result unless carrier-type guns are employed. In low-compressive strength formations (less than 2,000 psi), 1/2-inch bullet perforations are preferable to small-hole jets. The best compromise between entrance hole diameter and perforation depth may be the so-called "Big Hole" jet charges. These perforators, as shown in Figure 40, make perforation tunnels of 3/4 to 7/8-inch diameters with 0.91-inch entrance holes. Four to eight shots per foot using a hollow-carrier gun, should be considered if high producing rates are desired.

Cup-type perforation washing tools are usefully employed to flush and wash the perforations, using clean, solids-free fluid, as depicted in Figure 41. Perforation washing can create a cavity behind the casing to permit a greater thickness of gravel and can effectively clean and perhaps to break away some of the cement behind the casing, thus to reduce the length of the perforation tunnels. In short (<25 ft).

Figure 40. 4-inch Big Hole Perforation

Entrance Hole:	0.91 in.
Core Flow Efficiency:	0.73 in.
Total Core Penetration:	3.36 in.
Eff. Core Penetration:	2.47 in.

RUNNING IN

Circulating washer is made up on work string. Sleeve valve is positioned in open (but not locked) position and tool is run in hole. Valve will remain open while running in.

WASHING PERFORATIONS

Upon reaching perforations to be washed tool is lowered below perforations and picked up a minimum of 18 inches to close sleeve valve. Perforations are then washed from bottom up. When washing from bottom up it is not necessary to lock sleeve valve closed.

Figure 41. Baker Model B Perforation Washer

intervals, special equipment to back-surge the perforations before gravel packing has significantly increased productivity in Gulf Coast oil wells.⁽⁵⁾ It appears that abnormally pressured wells can be allowed to flow to clean up wallcake on the face of the productive formation or to open the perforations that may be plugged. For the latter purpose means of isolating the individual holes or short perforated section will have to be employed. Other means to clean out perforation tunnels include the use of acid washes to remove metallic particles and crushed formation material.

The perforation tunnels must be filled with gravel when making an inside gravel pack to prevent their being filled with formation sand. It has been shown by Saucier⁽⁶⁾ that a perforation tunnel filled with high permeability sand will be effectively plugged. Gravel must be placed in the perforation tunnel through the casing, cement sheath, and outside the casing for an effective job. Several procedures can be employed to place gravel in the perforation tunnels and outside the casing. The double crossover tool method can be used for long zones (300 feet or more), as illustrated in Figure 42. Clear fluid is employed to place the gravel and squeeze pressures are used to force the gravel outside the casing. Ball sealers or degradable diverting agents may be used to insure that a high percentage of the perforations accept gravel. Variations of the method include means to wash the liner to bottom and/or reverse circulation through the bottom of the liner instead of through the screen. Clear fluids up to 15.1 ppg can be obtained. Heavier fluids utilizing calcium carbonate solids for weighting material may be used; acid treatment after the gravel pack will chemically dissolve some of the plugging that will likely take place in the screen and perforations.

(5) Bruist, E. H. (1974)

(6) Saucier, R. J. (1972)

Figure 42. Gravel Packing Procedure Using Crossover Tool

Open Hole Gravel Packs

The much higher area open to fluids entering the well bore makes the open hole gravel pack the preferred treatment for sand control compared to inside casing packs. A moderate reduction of permeability in an open hole gravel pack caused by dirty completion fluid or partial plugging of the screen openings to the well bore may cause only a minor reduction of flow capacity. Inside-casing packs, on the other hand, can be completely plugged if formation sand fills the perforation tunnels. Alternatively, high velocity flow from a few perforations can cut out the well screen so badly that an inside casing pack can be ruined in a few days.

Open hole gravel packs are not always the favored method. Costs may be very high, particularly for deep geopressured formations or the upper zones of multiple completions. Open hole packs are simple to make in vertical shallow holes with normal hydropressures, but become difficult for deeper formations that may require expensive and unusual fluids. Directionally drilled wells present particular problems for open hole gravel packs. Workovers and cleanouts are difficult for open hole gravel packs; recompletions or even a new gravel pack will require cleanout of all the gravel and screen assembly that was previously placed in the well. Perforated casing gravel packs are much simpler to clean out and/or repair.

The open hole to be gravel packed should be underreamed 6 to 8 inches larger diameter than the casing size in order to provide the needed thickness of 3 to 4 inches outside the screen liner to be set. Drilled solids and mud cake from the face of underreamed hole should be

cleaned from the drilling fluid as the operation proceeds. A caliper survey may be needed to calculate the amount of gravel required to pack the well. Equipment and gravel placement technique for an open hole gravel pack is essentially the same as illustrated for the crossover reverse circulation method shown for the inside casing pack. If the open hole "accepts" significantly less than the calculated amount of gravel, then gravel bridging in the annulus may be suspected. An acoustic log is sometimes useful in detecting an open section within the pack.

Screen Liner Without Gravel Pack

Screen liners without gravel packing have been used in many oil wells, particularly where low production rates per foot of open section are involved. The wirewrapped screens or slotted pipe should have slot widths twice the 10% percentile sand size of the sieve analysis when the sand-size distribution is non-uniform. With uniform sand size distribution, screen slot width should not be greater than the 10 percentile sand size. Screen liners without gravel pack frequently plug in a short time.

When screens are set in open hole without gravel packing, the screen diameter should be as large as possible to prevent caving of shale ledges in the hole. Underreaming the hole in this instance is not desirable. The use of wash pipe inside the screen permits washing the screen to the bottom of the hole and flushing outside the screen but will not effectively remove mud cake from the wall of the hole. Water well screens, as mentioned earlier, are nearly always set in open hole. If the sand particles are large and approach gravel sizes, gravel packing will not be necessary, though it will be desirable to develop the formation

in order to flush out the fine material, tighten the natural gravel, and grade the particles from coarse to fine away from the screen.

Screen Inside Casing Without Gravel Pack

Screens set inside casing, without gravel packing the perforation tunnels and forcing gravel outside the casing, will usually fail because fine sand moving through the perforations will fill the space between the screen and casing and finally fill the perforation tunnels. Multiple-layer screens have been used in the belief that several screens should be better than a single screen. These screens failed by cutting out where flow velocity was high and/or plugging with fine material.

Putting the Well on Production

After gravel packing, or an open hole screen setting without gravel, the manner in which the well is put on production is quite important.

The following points should be considered:

- The formation pore space around the well is filled with fine material carried into the formation by the fluid used to place the gravel and by inherent fine material in the formation made moveable by the gravel packing fluid.
- Moveable fines in the pore space around the well should be started back towards the well bore as soon as possible, but at a low velocity to minimize plugging the screen slots.
- To promote bridging of formation sand on the face of the packed gravel, gradually increase production rates instead of opening the well quickly. Start with a low rate, gradually increasing the production rate to the desired figure over a period of days.

Plastic Consolidation Methods

The basic purpose of plastic sand consolidation is to increase the strength of the formation around the well bore to the extent that the sand grains are not loosened and moved by the drag forces of fluid flowing through the pores. Sand consolidation is accomplished by the precipitation of resin uniformly in the sand matrix near the well bore. Resin, attracted to the contact points between the sand grains, hardens to form a consolidated mass that will have a compressive strength in the order of 3,000 psi. Sand control by consolidation treatment is often preferred to mechanical measures because the sand grains may be immobilized some distance from the well bore. Inability of plastic material to retain the sand grains under high flow rates and/or elevated temperatures limits the use of plastic and epoxy resins for sand retention. Formation permeability is reduced because the resin has to occupy a part of the original pore space.

Plastic consolidation has certain advantages over mechanical sand control measures:

- Suitable for through-tubing applications
- Leaves full open bore casing
- Suitable for multiple zone completions
- Works well in fine sands that are difficult to control with gravel

Sand consolidation disadvantages are: (1) Usually limited to short intervals because of the high cost, ranging up to \$1000/foot for chemicals alone. (2) Plugged perforations will not receive the treating materials and this will result in poor sand control. (3) The curing reaction is dependent on temperature, and special curing-time accelerators, or retarders must be used to fit different temperatures. (4) The systems

do not work in wells having excess bottom-hole temperatures because the cured plastics are subject to thermal degradation and decomposition.

Sand consolidation has been under development since the mid-1930's. At first, the only readily available plastic was phenol-formaldehyde (Bakelite), which is still in use to some extent. It is an unpredictable material under reservoir conditions, it either works or completely plugs the well, and is a risky, inferior process. In the past thirty years, many polymer systems — often rather loosely termed "plastics" — have been developed. Numerous epoxy resins have been linked with a wide variety of curing agents to provide a whole series of high-strength, dense materials for downhole consolidation treatments. Some of the systems fail to provide good results in formations containing more than 10% clay, but an alternative system for that purpose has been developed.

Resin Consolidation Systems

Two types of resin consolidation systems are used. The phase-separation system consists of 15-25% active resin that will harden to form consolidation between sand grains when properly attracted to the grain contact points. Inert material fills the remaining pore space between the grains to insure that permeability is retained. Curing agents are added, the amount dependent on formation temperature. The overflush system makes use of a resin solution that contains a high percentage of active material. In the initial step, active resin occupies most of the pore space in the matrix of the rock. Formation permeability must be re-established by displacing the resinous material further away from the well bore. This will leave residual resin saturation at the sand-grain contact points. The resin curing agent is usually contained in the overflush fluid, but it is sometimes added to the

original resin solution. Accurate displacement is critical, for all sections not overflushed will be plugged.

Resin-Sand Pack

For wells where sand production has occurred — or where a cavity can be made by washing through perforations — the resin-sand pack has application. The system is much like gravel packing. Gravel that is sized to control formation sand is coated with resin on the surface. The coated gravel is then injected into the perforations until the gravel fills the perforations and "sand-out" is achieved. If an external curing agent is used, the resin-coated gravel is washed out of the casing and the gravel remaining in the perforations and in the cavity behind the casing is consolidated by injecting the reagent. With an internal reagent system, the resin-coated gravel is allowed time to consolidate, then drilled out of the casing. A wirewrapped or slotted liner is not required, but is sometimes used for supplementary sand control.

Sand-Consolidating Plastics Commercially Available:

1. Phase-Separation Systems

- Eposand 9 — Epoxy process developed by Shell Chemical Co.
(Similar to Eposand 10, 20 & 30)
- Sanset — Phenolic process developed by Exxon Company

2. Overflush Systems

- Eposand 112 — Epoxy process developed by Shell Chemical Co.
(Internal Reagent)
- Sanfix — Furanic process developed by Halliburton Services
(External Reagent)

- K-200 — Phenolic process developed by Dowell Division
(External Reagent)

3. Resin Sand-Pack Systems

- Conpac I — Furanic resin system using low viscosity oil carrying fluid and external reagent (Halliburton)*
- Sandlock III — Epoxy or phenolic resin system using low viscosity oil carrying fluid and internal or external reagents.
(Dowell)**
- Sandlock IV — Internally-reacted resin coated sand carried at high concentration (15 lbs/gal) in a high viscosity fluid (50 cp @ BHC) (Dowell)
- Conpac II — Furanic resin system with internal reagent using high viscosity carrying fluid and high sand concentration (Halliburton)

Some Representative Systems:

1. Eposand 9 Process (Eposand 20 & 30 are similar)

- Reagent is mixed with resin components on the surface.
Formulation is dependent on bottom hole temperature.
- Contact between resin and formation fluids must be prevented by preflush. Formation oil is displaced with diesel, and formation water with Isopropyl Alcohol.
- Overflush is very undesirable.
- Pumping time: 1 to 3 hours
- Formation temperature limits: 100° to 200° F
- Permeability retention: 85%
- Well shut-in time: 8 hours before circulating

24 hours before production

* Halliburton Services Company

**Dowell Division, Dow Chemical Company

2. Sanfix Process (Overflush System-External Reagent)

- Diesel preflush
- Resin injected into formation first, followed with the curing agent; mixing occurs in formation.
- Pumping time: No limit
- Formation temperature limit: 300°F
- Permeability retention: 90% in clean sand
- Well shut-in time: 1 hour before circulating

4 to 24 hours before production

3. Sandlock IV Process (Resin Sand Pack System)

- Diesel preflush (50 gal/ft)
- Gravel sized to control formation sand is mixed in 10 bbl batches with a high viscosity (50 cp @ BHT) refined oil at concentration of 15 lbs/gal. An internally reacted resin is added in low concentrations (1 gallon per 100 lbs) to coat the gravel.
- Viscous slurry is injected at low rates (1.0 BPM) until sand out. Injection pressure is high due to viscous oil. Additional batches may be required.
- Pumping time: 2-4 hours
- After hardening, material inside casing is drilled out.
- Temperature limit: 180°F
- Variations of Sandlock IV substitute viscous water or acid-base fluid for the viscous oil to lower injection pressure and improve "clean up" after the job.

Placement Techniques

Although a number of plastic systems are available and many improvements have been made since plastic consolidation was first introduced, it should be recognized that well completion and workover methods, placement techniques, and job supervision and performance are usually more important than the specific plastic system used.

1. Well Preparation

a. Primary Cement Job Important

A good primary cement job is very important. If any possibility of mud filled channels exists, a low fluid-loss low-pressure squeeze cement job should be done. Perforating several holes above and below the zone to be consolidated, circulating fluid between these perforations, then using a low fluid-loss circulation squeeze cementing technique is ideal in this case.

b. Perforations

- Well must be perforated in clean, no-solids fluid. Shaley zones should not be perforated.
- Perforation density is significant — four holes per foot should be used to improve plastic distribution and reduce drawdown.
- Length of perforated zone should be short. Ten feet is maximum that can be treated in one stage.
- Perforations should be cleaned by flow into well bore. Any debris left in the perforations will be "glued" in place by the resin.

c. Super Clean Fluid System

- Workover rig tanks must be scrubbed. Filter system should be used (2 micron filter).

- All fluids should be injected through 2 micron filters.
- Work string must be cleaned. Circulating sequestered HCl to bottom of tubing string then reversing or flowing it back out is one method of removing rust, pipe dope and scale from tubing.
- Service company tanks should be plastic coated or stainless steel, and should only be used for sand consolidation work.

d. Workover Fluids

- Brine fluid (1% KCl) is usually satisfactory. A denser brine (9.5 lbs/gal) placed below the perforations and a lighter brine or diesel placed above the perforations aid in preventing mixing of well fluids with resin materials (density 8.8 lbs/gal) during placement.
- Fluids containing starch should not be used with Isopropyl Alcohol since an insoluble precipitate is formed. Isopropyl Alcohol may also precipitate salt out of highly concentrated brine.

e. Stimulation

- An injectivity test showing less than 1.0 BPM at below frac pressure indicates stimulation is needed.
- In dirty sands a preflush stimulation treatment designed to increase permeability may be required to improve uniformity or resin placement, and to provide needed productivity following consolidation.
- HCl-HF treatment is preferred. HCl may be sufficient in clean sands to clear perforating charge debris.

- Hydroxy Aluminum may be used to recement clay particles in place.

2. Preflush the Perforated Section

Objective of preflushing is to:

- Remove reservoir fluids which might contaminate the resin. (Water is particularly bad with epoxy resins).
- Oil wet sand grain surfaces so resin will form continuous coating.

A multistage preflush must be used. First, diesel oil to displace the reservoir oil. Second, Isopropyl Alcohol to remove the formation water. Finally, a spacer fluid is required to prevent contact of IPA with the resin. All these fluids must be essentially water free when epoxy resins are used.

3. Resin Mixing and Injection

Each resin system has its own peculiarities and requires expert service company supervision. Formation temperature at the time of injection must be known to select the basic resin material in some cases, and the amount of accelerator in other cases. With internal reagents, time is a very important factor; both injection time for the resin, and (with the overflush systems) the overflush time.

Injection of all solutions must be done at low rates (1.0 gal/perforation) to promote uniform coverage; and at below fracture pressure.

4. Displacement

Careful control of displacement volume is required with the Phase Separation systems so that fluid is displaced to, but not beyond, the perforations.

Comparison of Sand Control Methods

1. Reduction of Drag Forces should be given first consideration.
 - Increase flow area if possible.
 - Good well completion practices are paramount.
2. Gravel Packing, offers the only practical sand control for long zones. Gravel packing may also be most practical for short zones — but remedial work, multiple completion, small hole diameter, and abnormal pressure, increase difficulty and cost.
 - Open Hole Gravel Pack should always be used on single completions where water or gas shut-off or other change of completion interval is not anticipated.
 - Inside Casing Gravel Pack restricts productivity — but productivity may be maximized by a sufficient number of large clean perforations and effective placement of the gravel — perhaps to the point of approaching the productivity of an open hole gravel pack.
3. Resin Consolidation has application in short zones where for one reason or another a gravel pack cannot be used.
 - Small pipe diameter
 - Top zone of a dual completion
 - Offshore or isolated location where tubing hoist is not available.
 - Abnormal formation pressures make through tubing work advisable. High temperatures may prohibit.
4. Resin Sand-Pack has most of the same problems and advantages of the inside casing gravel pack.

GEOPRESSURED OIL AND GAS WELLS

Oil and gas wells have been completed in geopressured formations in the United States since the mid-1930s. The first wells were to depths of 10,000 feet, but by the 1950s 15,000-foot wells were being made in Coastal Texas and Louisiana. Geopressured formations are now being tapped at depths of 20,000 feet and greater in Mississippi, Oklahoma, Texas and Louisiana. Most of the deep wells in West Texas have encountered "normal" pressures at final depth, though geopressured shales are penetrated at intermediate levels. The deepest hole, drilled in Western Oklahoma, penetrated a zone containing molten sulfur at the final depth of 31,441 feet. Geopressured hydrocarbon producers generally are deep holes, usually in the range of 15,000-20,000 feet, and surface pressures will be high, often exceeding 10,000 psi. Figure 43 shows shut-in tubing pressure of 11,400 psi on a geopressured well completed in Coastal Louisiana. Some recently drilled wells have shut-in pressures exceeding 15,000 psi. Flowing pressures will be high, depending on the flow rates, tubing sizes, and type of fluids. Most geopressured wells produce gas and gas-condensate liquids.⁽⁷⁾ Figure 44 illustrates this fact, and shows that pressure gradients and temperatures are generally high where high formation pressures are encountered in the Gulf Coast.

Most high-pressured gas will contain acid compounds which will corrode steel, even though only small quantities of CO, CO₂ and H₂S are present. For this reason, geopressured gas wells will be provided with some means to mitigate corrosion. This may be accomplished by internal plastic-coated tubing, chemical injection, and dual strings of tubing so anti-corrosion chemicals can be introduced near the bottom of the well. Wellhead valves and fittings are often made of stainless steel for the

(7) Timko, D. J. and Fertl, W. H. (1971)

Figure 43. Geopressured Wells Have Extremely High Pressure

Figure 44. Most Geopressured Wells Produce Gas-Condensate
After Timko and Fertl, 1971

same reason. High-pressure or low-pressure safety shut-off valves are usually installed in the wellhead train of equipment for safe operation in case of plugged or broken lines. Temperatures of the produced fluids will usually exceed 200°F at the wellhead before expansion through pressure reduction fittings. Producing equipment, besides the usual requirement of pressure regulation, must provide heating to prevent freezing of hydrates and conditioning the gas to acceptable pipeline specifications. The latter includes separation of liquid hydrocarbons from the gas, dehydration of the gas to meet the pipeline requirement of 5-10 pounds of water per thousand cubic feet (MCF), and in some cases warming the gas stream to a temperature higher than 32°F.

Figure 45 shows a geopressured gas well drilled in the 1960s; four strings of casing were set (20-inch, 13 3/8-inch, 9 5/8-inch, and 5 1/2-inch) and the well is produced through 2 7/8-inch tubing. The Christmas Tree valves and fittings are rated at 15,000 psi working pressure. Note the indirect heater on the flowline used to heat the well effluent, thus to melt frozen hydrates that would otherwise plug the downstream producing equipment. Not shown are the separators and gas dehydration vessels that remove condensed liquids and condition the gas prior to its being metered for sale to a transmission pipeline company. Liquid production is stored in tanks for sale to a crude oil purchasing company.

About 150 geopressured gas/condensate producers are being completed in the U. S. annually. At maximum depth, drilling and production conditions of pressure and temperature are near the limits of modern technology. One well recently completed in Mississippi had a shut-in tubing pressure of 17,000 psi; bottomhole pressure was more than 20,000 psi.

Figure 45. Wellhead Equipment for a Geopressured Gas Well

The world's deepest hole, Bertha Rogers No. 1 in Western Oklahoma, was not completed at final depth; bottomhole formation pressure probably exceeded 30,000 psi. Wellhead equipment for 20,000 psi working pressure is available and special order valves and fittings for 30,000 psi can be obtained. Casing and tubing to withstand the tensile, burst, and collapse loadings such wells involve are available. Cement slurry for downhole temperatures in excess of 500°F can be prepared and circulated to the desired depths. Casing is usually set through the productive interval as a liner suspended from the intermediate pipe. In most cases the production liner is extended to the surface by a tieback string of casing. Shaped-charge jet perforating equipment suitable for bottomhole temperatures exceeding 340°F is readily available; perforating gun sizes range from 1 9/16-inch to 4-inch diameters and pressure ratings 15,000-25,000 psi. Tubing and threaded connections, packers, and accessories suitable for the pressures and temperatures of geopressured reservoirs are readily available.

Completion Planning

Notwithstanding that drilling of a well progresses from the surface to the bottom, engineered deep well planning is the reverse process, i.e., it starts at the bottom of the hole. After curves for both pore pressure and fracture gradient versus depth have been established, an ideal mud-weight curve can be plotted. Geological, technical, safety and economic considerations will influence the size, setting depth, and design factors (burst, collapse, and tension) for the production string that will be set in a geopressured formation. Related problems that must be considered are corrosive fluid conditions, tubing leaks, liner cementing problems, etc. The production string, of course, must be large enough to accommodate the production tubing with reasonable

clearance. The diameter of the production casing will determine the hole diameter at final depth, drill pipe size, hoisting loads, and other mechanical factors of drilling. The diameter and setting depth of the intermediate casing must be suitable for the final string of casing and satisfactory for the mud weight required to reach the projected final depth. Likewise, the diameter and setting depth of the surface casing must be appropriate for the intermediate string and the mud weight needed to reach the depth at which intermediate casing will be set. Conductor pipe size must be large enough to accommodate the surface casing, but its diameter and wall thickness may be controlled by the requirement of a freestanding, unsupported column, as at an offshore location, or the column loads of a deep well at a land location. Finally, the foundation for the wellhead assembly must take into consideration the weight of the pipe loads that will be landed at the surface. This may be more than one million pounds, depending on the size and weight of casing that will be suspended at the wellhead. Weight of casing and tubing suspended at the wellhead will be one value under static conditions when the pipe string is at normal earth temperatures and quite another when high temperature fluids from the producing formation are flowed to the surface. If the tubing string is fixed both top and bottom severe buckling or tension stresses may develop with temperature variation. Unless the casing strings are solidly cemented bottom to top, increased temperatures will tend to lengthen the pipe and may cause the wellhead to rise; conversely lowered temperature could cause the pipe strings to shorten and thus impose tension stress at wellhead which may exceed tensile strength of the pipe and/or threaded joints.

Completion Operations

A geopressured well completion, after the hole is drilled, logged and tested to total depth, will commence with preparations to set and cement the production casing or liner. The usual first step is to clean out the open hole, condition the drilling fluid, and make sure that casing can be run to the bottom of the hole. If hole-casing clearance is not at least one inch on the diameter, the hole should be underreamed. The drilling fluid should be conditioned to a fairly low filtrate loss to prevent deposition of a thick wall cake and filtrate invasion of the permeable intervals. Mud density should be high enough to provide about 300 psi overbalance of the highest formation pressure exposed to the wellbore. Deep wells, where time off bottom may be excessive and fluid pressure fairly high opposite the lower pressured intervals, can be cased best by means of a liner. This procedure will insure minimum exposure time to high differentials that may stick the pipe. For the same reason, the liner should be equipped with centralizers to hold the pipe away from the wall of the hole; centralizers will center the pipe in the hole thus to obtain a concentric sheath of cement between the liner and wall of the hole. Some operators favor the employment of no-wall-stick (NWS) grooves on the liner to lessen the hazard of stuck pipe due to differential pressure. A combination liner hanger, cementing device, and releasing tool at the top of the liner will permit the use of drill pipe to run and set the liner. The liner hanger-releasing tool will include a polished-bore receptacle to accept a seal nipple run on the tieback string. After cementing the liner, with a calculated excess of cement to fill the annular space behind the liner, the liner hanger should be set, the run-in string released, and pulled clear of

the top of the liner. After the cement has hardened, cement on top of the liner should be checked and pressure tested. If necessary the top of the liner may be recemented, cleaned out and the liner receptacle made ready to accept the tieback seal nipple. The tieback string of casing — generally extended to the surface — is run with a tieback seal nipple to the top of the liner. The tieback string may be cemented all the way to the surface to insure a solidly cemented production string. Liner "splices" cemented in this manner are generally stronger than the casing. Cement to the surface will be desirable on wells where extreme variations of temperature may take place; this will minimize vertical movement of the wellhead and stress on the casing anchored at the wellhead.

The cement-to-hole and cement-to-pipe bonding should be checked by means of a cement bond log, thus to determine the effectiveness of the cement in the casing-formation annulus. A bond log is an acoustic device which will show the quality of the cement behind the casing, where gaps and channels in the cement sheath may exist, and the top of the cement in the annulus. Cement bond logs are usually run in conjunction with a gamma ray logging device that will record the lithology and depths of formations behind the casing. This will permit depth correlation with a similar log when perforating the casing. If necessary, cement gaps and/or channels behind the liner will be squeeze cemented to insure good cement bond between the liner and wall of the hole.

When the liner is satisfactorily cemented in the well and pressure tested, the liner will be cleaned out to the desired depth opposite the interval(s) to be perforated. Completion operations can then proceed to make the well ready as a producer. Successive steps to complete

the well — not necessarily in the following sequence — will include perforating, running tubing and packer, displacing the old mud in the annulus with a specially prepared packer (completion) fluid, installation of tubing accessories, assembly of the tubing head, landing the tubing, and unloading the well. Liner sizes may be 5-inch, 5 1/2-inch, or 7-inch; tubing is commonly 2 3/8-inch or 2 7/8-inch sizes.

Earlier practice was to perforate the well with the casing full of drilling mud to hold down formation pressure while recovering the perforating tools and running tubing. Large diameter, casing-size, bullet or jet perforators were employed. After perforating the productive interval, tubing and packer were run, the tubing head attached to the casing head assembly, and the well brought into production by lightening the fluid column in the tubing. Usually, nearly all the perforations were plugged with mud. Modern practice favors perforating the pay zone with hydrostatic pressure in the wellbore less than formation pressure. This requires cleaning out the wellbore to the productive interval to be perforated and replacing the drilling mud with fluid that will cause less damage to the formation. Salt water is often used as a perforating fluid, but if formation pressure is considerable heavy-weight solids-free fluid such as calcium chloride or calcium bromide may be employed. After "spotting" special fluid at the interval to be perforated, the work string of pipe will be removed and a production packer set about thirty feet above the place in the casing that will be perforated. Tubing with a 20-foot long assembly of seal nipples to fit the packer bore will be run. Since pressure as high as 12,000 psi may be anticipated, special precautions will be taken to obtain absolutely "bubble-tight" tubing joints. Modern high-pressure tubing connections

— usually integral joint — feature metal-to-metal pressure seals, an elastometer as an extra precaution, and a shouldered closure to insure proper thread makeup. Threads are carefully lubricated and tightened to specific torque. The seal nipple is seated in the packer and spaced out at the tubing head to allow about 20-foot movement of the lower end as the string lengthens due to thermal expansion when hot fluids are flowed to the surface. The average temperature of the tubing string in a geopressured gas producer may vary as much as 150°F. This can cause 16-foot variation of tubing length in a 15,000-foot well with consequent stress on the threaded connections if the string is anchored at top and bottom. After the tubing is landed at the tubing head and the Christmas Tree attached, the assembly is pressure tested to full working pressure. When these preparations are completed, a high-pressure, full-bore perforating lubricator is installed and the well is then ready for "Through Tubing" perforating.

Hydrostatic pressure at perforating depth will be lowered to about 500 psi less than formation pressure. This can be accomplished in several ways, but for a geopressured completion the most convenient means will be to displace some of the fluid in the tubing. This will require opening a sliding-sleeve valve in the tubing string, circulating salt water down the tubing to obtain the desired hydrostatic pressure at the interval to be perforated. The sliding-sleeve valve is then closed. If necessary, additional pressure will be obtained at the wellhead by pump pressure. The perforating gun assembly is then run to the desired depth while holding pressure on the tubing. When depth correlations are adjusted and the operator is certain that the perforator is at the correct depth — as outlined below — the gun charges will be fired

to perforate the casing. Formation pressure, less hydrostatic pressure at the perforations, will appear at the wellhead.

Perforating

The usual "Through Tubing" perforating system, as outlined above, involves running tubing, and sealing the annulus with a packer. After the packer is set the hydrostatic pressure at perforating depth is lowered by removing enough of the fluid column to reduce the hydrostatic to less than formation pressure. The perforating gun assembly is then run to the top of the interval to be perforated. If a combination gun and gamma ray tool is used, depth control and perforating can be obtained on a single trip. Figure 46 shows how an IES electric log (SP, Resistivity and Induction Curves) can be correlated with gamma ray and casing collar logs. The gamma ray instrument measures the variations in natural radioactivity of the formations. Since shales are generally more radioactive than sands, the gamma ray log often closely resembles the SP log, thus it will provide a log for correlating lithology, bed thickness and depth with other logs. The collar log will enable another check for absolute depth control relative to the objective formation when perforating.

Shaped-charge jet perforators are preferred to bullets for geopressured reservoirs because the depth of the formations will mean that compressive loads exceed 10,000 psi, based on 1 psi per foot of depth, therefore compressive strength will be high. Bullets will not penetrate very far in formations exceeding 6,000 psi compressive strength. Jet perforators are also favored because most tubing sizes are too small to pass bullet guns. If 2 7/8-inch tubing, drift 2.43 inch, is employed,

Figure 46. Correlation of SP and Resistivity Logs with a Gamma Ray Log for Depth Control

a 2 1/8-inch jet perforator may be used. A hollow-carrier gun offers the advantage of maximum perforator performance, leaves no gun debris in the well, and will not damage the casing. A through-tubing, hollow-carrier, jet perforator 2 1/8-inch size will penetrate up to 10 inches and produce a 0.32 inch opening in the casing. Up to 4 holes per foot can be made, phased at 0° or 180°. Jet perforator assemblies are suitable for bottomhole temperatures up to 470°F and as much as 25,000 psi pressure. If run inside large diameter casing it may be desirable to use 0° phase loads and provide magnetic means to face the jets against the casing, thus to obtain minimum gun-casing clearance and maximum penetration. Gun lengths are random; shot loadings can be arranged for any desired pattern of interval coverage. Only the permeable sections of the productive interval should be perforated.

Tubing and Packer

Geopressured oil or gas well completions will include tubing and a packer because of the very high pressures involved, the desire to keep high pressure from the casing, and to facilitate unloading the well. A tubing string will make it possible to circulate mud in the well to reduce well pressure and to inject chemicals to mitigate corrosion. The latter functions are usually accomplished by means of a separate "kill" string of tubing which is frequently set inside the regular production tubing. Production tubing in a geopressured well is used in conjunction with a packer in order to seal the annulus between the casing and tubing, thus to prevent well fluids and pressure from reaching the casing. A packer can be opened — or by opening ports in the tubing string — thereby to permit circulation to lighten the fluid column in the tubing, and thus to allow the well to start flowing gradually. If it becomes

necessary to pump fluid into the tubing to kill well pressure, circulation ports can be opened and fluid circulated down the tubing and up the annulus. The usual production packer is often run and retrieved on regular tubing but in a geopressured well a drillable or retainer-type is generally employed. To pump between the tubing and annulus, circulation ports that can be opened by wireline methods are usually employed. Tubing accessories will include a sliding-sleeve circulation valve placed in the string near the packer, one or two landing nipples in which plugs and/or other flow devices may be set, and a tubing safety valve about two thousand feet below the wellhead. Most of these devices are set and pulled by wireline methods. Ball-type, pressure activated safety valves are frequently installed instead of velocity type units. Tubing used in a geopressured gas/condensate producer will often be plastic coated internally to mitigate the effects of corrosion. Special attention should be given to protect the threads that will be exposed in the coupling boxes below the pins. If a kill string is provided, chemicals may be injected to counter the effects of corrosion. A retainer-type packer can be arranged to permit the lower end of the tubing to move vertically in the packer bore as temperature changes varies the length of the tubing string. In a 15,000-foot well with a bottomhole temperature of 325°F, the average temperature of the string may vary 150°F. This can lengthen the string 16 feet from minimum to maximum conditions. This will require that the tubing stop be placed about 18 feet above the packer when the string is "cold" as it is landed at the wellhead.

Geopressured gas/condensate producing wells will have very high pressures at the wellhead, frequently exceeding 10,000 psi. Prudent operators do not want to maintain such pressure on the production casing

because a small leak could quickly develop into a major break that could be catastrophic, with no immediate recourse. But with tubing installed, the casing would provide reserve protection in case of tubing failure. Preventive measures can be taken to lessen the chance of tubing failure. This will include special threaded joints, careful tightening procedures, and full pressure testing as the pipe is run into the well. As a further precaution that excessive pressure will not be imposed on the casing in case of tubing failure, weighted fluid of sufficient density to kill the formation pressure is placed in the annulus above the packer. With a sliding-sleeve valve in the tubing string, circulation ports can be opened in the tubing string to permit fluid circulation to kill the well. If circulation cannot be established, it will still be possible to fill the tubing with heavy fluid by pumping into the formation, thus to kill the well pressure. A tubing string in the well will permit circulation when completing the well; low density fluid in the tubing will permit the well to be brought into production gradually.

A packer must be employed when tubing is used if it is desired to keep well pressure away from the casing. Packers are constructed in various configurations, but basically all types include a ring of elastometer material that can be compressed, thus to increase its diameter and seal the annulus between the tubing and casing. Most packers include serrated-teeth slips which can be activated to engage the casing by a friction grip, thus to support the sealing element(s) when it is desired to "set" the packer. Retrievable packers are permanently attached to the tubing string; when tubing is run into the well to the desired depth, the slips on the packer are released by manipulation of the tubing string. Further lowering the tubing activates

the slips to set the packer. Tubing is then lowered to impose weight on the packer; weight expands the elastometer to seal the annular space. Retainer-type packers can be run on tubing, but are usually run into the well on a wireline and set by detonating an explosive charge. Retainer packers have two sets of opposed slips that are set when the lower slips are expanded and obtain an initial friction grip on the casing. This action effectively locks a retainer packer in place when it is set, as illustrated in Figure 47. The elastometer sealing material is compressed at the same time to seal the annulus, though tubing fitted with seals can be worked through the smooth bore of the packer as shown in the illustration.

Tubing accessories may include tubing plug(s), a sliding-sleeve valve, safety shut-off and other devices that can be placed in the string by the use of friction slips or by seating in landing nipples placed in the string. Tubing plugs are frequently employed when pressure testing tubing or to facilitate removal of wellhead equipment under pressure. Sliding-sleeve valves, opened by wireline methods, can be employed to circulate the well. Safety valves, usually seated in landing nipples, can be used to shut off excessive flow in case of damage to the surface control equipment. These valves may be activated by high velocity flow or by pilot pressure from controls on the surface.

Packer fluid, usually the regular mud used to circulate the well but sometimes specially prepared solids-free fluid, is placed in the annulus above the packer to prevent formation pressure reaching the casing. This fluid nearly always has sufficient density to overbalance formation pressure. Packer fluid heavy enough to kill formation pressure can be considered as "insurance" in case the packer leaks or the tubing

Figure 47. Baker Retrievable Retainer Packer

parts near the packer. Solids-free packer fluid is preferred because weighted mud behind the tubing may gel, stiffen, or harden, thus to freeze the string in the well.

A kill string inside the production tubing is desirable for a geopressured gas/condensate well since it makes it possible to kill well pressure in an emergency, because displacement of heavy fluid to control the well can be quickly performed, and because chemicals to mitigate corrosion can be injected continuously, an easier process than pumping a "slug" down the production tubing with the well closed in. On the other hand, a kill string of pipe inside the production tubing can severely restrict flow if maximum well performance is expected. Wear and the effects of corrosion can cause a kill string to part, thus to partially plug the well. Kill strings will prohibit the employment of plugs and safety valves in the production tubing. This is the main reason kill strings are not usually employed in modern, high pressure wells. Figure 48 shows a parallel tubing string arrangement for a single zone completion recently made in South Louisiana. This well features 7-in. O.D. casing at T.D. with parallel strings of 2 3/8-in. tubing set in a dual packer just above the perforated interval. This arrangement provides increased well control, because less time is required to kill the well or bring it in because the operator does not have to pump into the formation. Chemicals for corrosion control may be pumped down one string. Both strings may be produced if desired, or one side may be employed for production while the other is reserved for a kill string. Landing nipples are placed at various depths to accommodate shut-off valves or tubing plugs.

NOTE:
All "R" Nipples
Have 1.71" I.D.

Figure 48. Parallel Tubing Strings for Single Zone Completion

Producing Equipment

A geopressured hydrocarbon well will generally be a high ratio gas-condensate producer, sometimes with considerable salt water production. Well pressure will be high, usually exceeding 10,000 psi, thus several stages of pressure reduction will be needed to lower the gas pressure to a figure acceptable for a gas transmission line. Besides pressure reduction, the liquid hydrocarbon will have to be removed, and water vapor content of the gas must be lowered to transmission pipeline specifications. Heating of the well effluent will be necessary to prevent formation of hydrates that could plug lines and pressure vessels. Corrosion is usually a problem, thus chemicals are injected into the well and surface lines to lessen the corrosive affects of the natural gas.

Figure 49 shows a 3 1/2-inch, 15,000 psi, wellhead installed on a geopressured gas-condensate producer. Shut-in pressure on this well originally was in excess of 11,000 psi; flowing pressure at that time was 7,000 - 10,000 psi, depending on the size choke employed. Note the pressure operated safety shut-off valve on the flow wing of the Christmas Tree leading to the flowline; this valve is operated by gas pressure from a pilot system that may be triggered by high or low-pressure on the downstream producing equipment. Note the chemical pump at lower right in the photograph; this pump is used to inject chemical in the flowline for protection against corrosion. Downhole corrosion is treated by periodically closing in the well and pumping a slug of chemical to the perforations, thereby coating the tubing to lessen the corrosive action.

Figure 49. Geopressured Gas/Condensate Producing Well

Figure 50 depicts a water-bath, gas-fired heater to counter the chilling effect of pressure reductions at the wellhead and intermediate points before the gas stream reaches the separators. Figure 51 shows a freewater separation unit between the heater and main separator, which is shown in Figure 52. This unit incorporates a pressure reducing valve to chill the incoming gas-condensate, thus to form hydrates of the water in the gas stream, which is then heated to melt the solidified hydrates to form free water that can be turned to waste. The gas will then be essentially water free. The liquid hydrocarbon, condensate, is dumped from the separator to storage. Not shown is the meter for measuring the gas which goes to a transmission line or the tanks for storing the liquid production.

Figure 50. Water-Bath, Gas-Fired Flowline Heater

Figure 51. Freewater Separator for a Geopressured Well

Figure 52. Refrigeration-type Separator and Gas Conditioning Unit

GEOPRESSURED WATER WELL COMPLETION

Though few have been made specifically for the purpose, a geopressured water producer will generally have the same conditions and characteristics as oil and gas wells completed in geopressured formations. The holes will be deep, generally in the order of 15,000 feet, bottom hole pressure may be 12,000 psi or greater, and formation temperature 300°F or more. Pressure at the surface will not likely exceed 10,000 psi because a column of hot brine (gradient pressure of ± 0.440 psi per foot) will lessen shut-in pressure and fluid friction losses will lower flowing pressures. Temperature in the order of 300°F at the wellhead will require special valves to insure positive closure at high pressure. High volume producers will require large diameter tubing and accessories to permit flow of large quantities of fluid without excessive pressure draw down. Table 7 shows expected pressures at the wellhead for various sizes of tubing and flow rates with a given formation pressure and permeability. Actual wellhead pressures will depend on formation pressure, porosity, permeability, footage of perforations, and rate of flow. Sand production will relate to unit flow velocity through the perforations, productivity index, or flow rate per day per foot of perforated interval.

Table 7

**FLOWING WELLHEAD PRESSURES
VARIOUS SIZE TUBING**

13,000 FT. Depth; 11,700 Psi Pressure, 5000 md Permeability

<u>Flow Rate</u> <u>Barrels/Day</u>	<u>Tubing Head Pressures (Psi)</u>		
	<u>4 1/2-In Tbg</u>	<u>5 1/2-In Tbg.</u>	<u>7-In Tbg.</u>
10,000	5800	6200	6290
20,000	4640	5550	5900
40,000	450	3600	4900
60,000	----	1000	3730

If both tubing and 7 5/8 x 5 1/2 annulus are produced simultaneously, up to 70,000 b/d could be produced with wellhead pressure over 3000 psi under the conditions listed.

Since sand production must be negligible or zero for a viable geothermal-geopressured producer, regular wellhead equipment may be used, though this will not preclude downhole sand control procedures or sand detection equipment in the surface facility.

Geopressured water wells must be completed using large diameter, unobstructed casing and tubing to minimize fluid pressure losses at high rates of flow. This will preclude downhole velocity-operated shut-off (safety) valves in the tubing string. Downhole, ball-type, safety valves that are activated from the surface may be employed, but reliability and trouble-free operation must be assured for the large diameter equipment that will be employed.

Most geopressured gas wells produce corrosive fluids that must be countered chemically to minimize the effects on the flow strings and/or surface equipment. The effects of corrosion can be estimated by "iron counts" of the produced waters that accompany gas/condensate production. Downhole chemicals can be injected to mitigate the effects of gas corrosion, monitored by the amounts of iron that appear in the water that is produced with the gas. High volume water producers cannot be treated effectively with chemicals because of dilution, even if chemicals could be injected near the bottom of the hole. Iron counts, for the same reason, cannot be employed to measure the relative amount of corrosion.

Wellhead Equipment

The wellhead for the suggested geopressured water well completion will be a 20" x 16" x 10 3/4" x 7 5/8" x 5 1/2", 10,000 psi working pressure assembly, generally as depicted in Figure 53. The assembly

Figure 53. 20" x 16" x 10 3/4" x 7 5/8" x 5 1/2" Wellhead Assembly

will be built up from a 28" baseplate that will rest on the cut-off stub of the conductor pipe and will then be cemented in a shallow cellar, some three feet below the general surface of the ground. This will place the 20" flange about level with the surface of the ground.

The 16 3/4" casing string will be cemented to the surface and landed at the 20" casing hanger with full tension. This will anchor the 16 3/4" to prevent movement later when it is heated to 300°F, or more, by hot fluids from the geopressed formations. It would be desirable to cement the 10 3/4-inch string to the surface, but formation breakdown with high weight cement slurry will prohibit this procedure. The 7 5/8-in. string — which will be run as a liner with a tie-back casing to the surface — will be cemented all the way back, utilizing 12.0 ppg slurry for the upper string. The 5 1/2-in. tubing string will be suspended at the wellhead by means of a tubing hanger. Both the 5 1/2" and 7 5/8" strings will be tested to 10,000 psi pressure after being assembled. The Christmas Tree assembly will be satisfactory for 10,000 psi working pressure.

A 24" diverter will be attached to the conductor pipe when drilling the hole for the 1000 feet of 20" surface casing. It may be necessary to underream the hole to obtain enough clearance for the 20" casing. This string will be cemented to the surface, using a small pipe to fill the annulus if cement returns are not obtained.

The blowout preventer assembly for the 20" casing will consist of two ram-type and one annulus preventer, suitable for 3000 psi working pressure. Hole will be drilled to about 8,000 feet where 16" casing will be set. It may be necessary to underream this section of hole to obtain sufficient clearance for the 16" casing. A multistage cementing collar will be placed in the string at 3000 feet. Slurry for the first

stage should bring cement in the annulus to the approximate depth of the stage collar. The second stage should bring the cement slurry from 3000 feet to the surface.

The BOP assembly on the 16" casing will consist of two ram-type and one annular-type preventer, suitable for 5000 psi maximum pressure. A 13 1/2" hole will be drilled to 13,600 feet, where 10 3/4" casing will be set. This string will be cemented back to about 10,000 feet.

The blowout preventers for the 10 3/4" casing string will be two ram-type and one annular preventer suitable for 5,000 psi working pressure. Hole diameter will be 9 1/2" and drilled to 16,000 feet, or deeper, where 7 5/8" production casing will be set. The lower part of this string will be run as a liner and cemented back to lap inside the 10 3/4" casing about 200 feet. After the liner top is cemented inside the 10 3/4" intermediate casing, the 7 5/8" tie-back casing to the surface will be run and cemented, using 12.0 ppg slurry weight and appropriate retarders for actual bottomhole temperatures. This string will be tested to 10,000 psi pressure.

Blowout preventers for the 7 5/8" casing will be two ram-type and one annular preventer suitable for 10,000 psi working pressure. This assembly will be used when cleaning out and testing the 7 5/8" casing string and running 5 1/2" tubing.

The 5 1/16" bore Christmas Tree will be flanged to the tubing head after the 5 1/2" tubing is landed and tested to 10,000 psi pressure. The well will be perforated after the Christmas Tree is assembled and tested.

Figure 54 shows one way the 6" flowline could be arranged from the wellhead to the ground. This line should be solidly anchored at ground

Figure 54. Flowline Arrangement for 10,000 psi Wellhead

level near the base of the wellhead to prevent stress on the wellhead due to movement of the flowline due to thermal expansion.

Casing and Tubing

A geopressured water well completion will include intermediate casing set into the top of the geopressured shale. For the purpose of illustration, Figure 55 shows an Induction-Electric Survey (I-ES) of a well that penetrated the geopressured zone and was subsequently drilled to 15,200 feet. The geothermal-geopressured interval was topped at 13,450 feet, which is clearly depicted on the electric log by the sharply lowered resistivity and increased conductivity in the shale section below that depth.

Intermediate casing, 10 3/4-inch for the example to be discussed, could be set at any point below 13,600 as shown on the electric log. It would be desirable to set this string somewhat deeper, in order that the hole would support heavier drilling fluid without rupture, but since the operator would not know the exact depth of the uppermost geopressured sand, prudence would dictate that casing be set as soon as the geopressured zone was penetrated. The intermediate casing should be designed for a burst pressure exceeding 5000 psi at 80% yield strength of the material, with satisfactory tensile and collapse strength. The design factor in tension for the casing in 12.0 ppg mud should be 2:1; collapse design factor may be less than 1:1 with 12.0 ppg mud outside that pipe and the string half full of mud because the intermediate casing would never be completely empty. The usual design program for long strings of casing is to have several weights and grades — often 3-5 sections — in the string for economic reasons. Since this string will be set at an intermediate depth and drilling through it may proceed for an indefinite

Figure 55. Induction-Electric Survey (I-ES) of a Geopressed Well

period, an unknown amount of internal wear may occur caused by drill pipe abrasion. For this reason, one weight and grade of casing should be used top to bottom, designed strong enough in burst at 80% yield strength to withstand the stress of 18.0 ppg mud inside the pipe and 12.0 ppg mud outside at 12,000 feet, using a design factor of 1.5:1. These considerations for 10 3/4" casing require S-95 grade, 55.5 lb per foot pipe, with API Short Thread and Coupling, topped with Buttress Thread joints at the surface. String weight in 12.0 ppg mud will be 620,000 pounds. Two thousand feet of the intermediate casing should be equipped with centralizers, placed at each coupling, on the bottom ten joints and every 90 feet above that point. Cement slurry volume should be calculated to fill 4,000 feet of the annulus. Slurry weight for the upper 3000 feet of this column should be mixed to 12.0 ppg, using 10% bentonite plus 5% salt, and suitably retarded for the actual bottomhole temperature. The final 25% of cement should be mixed to weight 16.0 ppg.

After the hole is drilled to the projected depth of 15,000 feet, or greater, logged, and open-hole tests of the geopressured sands completed, the recommended 7 5/8-inch production casing will be set and cemented. Mud weight as much as 18.0 ppg may be involved, thus the final string should be set as a liner that will subsequently be extended to the surface with a tie-back string of pipe. Production casing should be set as a liner for the following reasons:

- (1) It can be run to total depth quicker if set as a liner, thus to lessen the chance of sticking before reaching the bottom of the hole.

- (2) To enable a full column of cement to be placed from the top of the liner to the surface.

The liner will be run with centralizers placed on every length of casing in open hole to lessen the hazard of stuck pipe and to make possible a concentric sheath of cement between the pipe and wall of the hole. The liner will be run on drill pipe using a combination liner hanger, cementing tool and releasing device for attachment to the drill pipe. Liners as long as 10,000 feet have been set in deep holes using this procedure. The liner hanger and releasing assembly will include a polished-bore receptacle for a seal nipple on the bottom of the tie-back string. The 7 5/8-inch liner should be designed for 18.0 ppg mud outside and salt water inside; design factor in collapse at 15,000 ft. may be 1.1:1, based on 80% minimum yield strength. Using these factors, 39.00 lb/ft., S-95 grade material will be satisfactory.

The liner should be cemented, using slurry weight the same as the drilling fluid in the hole. Additives suitable to retard setting time for the actual bottom-hole temperatures involved should be employed. Slurry volume can be based on the caliper-size at the hole, plus 50% excess, in order to be assured of filling the annular space behind the liner. After the liner hanger is set and the run-in string released, the liner setting tool can be pulled clear of the liner and the cement allowed to set. When the cement has hardened, cement on top of the liner drilled out and the overlap of the 7 5/8 inch - 10 3/4 inch casing should be pressure tested. If necessary the top of the liner will be squeezed. The tie-back receptacle on top of the liner can then be cleaned out and made ready to receive the tie-back seal nipple.

The tie-back string of casing will be run into the hole with the seal nipple on bottom and no float equipment in order to allow placement of cement slurry in the annulus by reverse circulation. Slurry weight will be mixed to equal the weight of the fluid in the casing and with retardants "tailored" to the earth temperatures at various levels in the well. Cement outside the production string will be desirable to prevent its movement due to thermal expansion when high temperature fluids are produced. The production string should be landed at the wellhead with the same weight on the casing hanger as the hook load when the string was seated in the tie-back receptacle.

After the tie-back string is run and cemented, the 5,000 psi BOP's will be removed and 10,000 psi working pressure preventers installed and pressure tested. The 7 5/8-inch production casing will be cleaned out to the tie-back splice and pressure-tested to the full 10,000 psi to ensure that the joint has pressure integrity. If satisfactory, the liner will be cleaned out to the desired plug-back depth, completely through the geopressured interval to be perforated and tested.

The cement bond between the casing and the formation behind the liner should be checked by running a cement bond log. If necessary, gaps and channels in the cement outside the liner should be squeeze cemented to obtain a good bond between the pipe and wall of the hole. When the liner is satisfactorily cemented, completion operations can proceed to make the well ready as a producer. This will include running tubing and a packer arrangement, perforating, and allowing the well to flow.

A 5 1/2-inch tubing string will be used for production. This size pipe has a bore of about 4.6 inches, thus 4-inch O.D. perforating guns may be employed, and flow rates up to 40,000 b/d can be obtained without excessive pressure loss due to fluid friction. Tubing for the recommended completion will consist of 5 1/2-inch, S-95 grade, 20.0 lb/foot pipe suitable for 8700 psi burst pressure at 80% yield strength. This casing will be threaded for Hydril Type CS-CB, or equivalent, type connections. These joints have metal-to-metal seals, an elastometer, and a shouldered closure to insure proper make up. The tubing joints will be carefully made up to the recommended torque and pressure tested, using an external tester, as the string is run into the well. The seal nipple, to match the packer-bore receptacle will be run on the lower end of the tubing. An Otis sliding-sleeve circulation valve will be run in the string immediately above the 6.5-inch O.D. Seal Mandrel Shoulder. The circulation valve will be run in the open position. Landing nipples will be placed at desired intervals in the tubing string to accommodate plugs, safety valves, or other accessories. The seal nipple assembly will be 20 feet long to permit + 15 foot expansion of the string as the temperature increases. The seal nipple assembly will include a 6.5-inch "No-Go" shoulder to land on the 6.250-inch I.D. Packer Bore Receptacle (PBR). After the no-go shoulder is seated on the receptacle, the string will be pulled up a measured distance to allow for thermal expansion, corrected for internal pressure, that will lengthen the tubing string under maximum temperature change. This will occur when the whole tubing string is heated to the maximum observed bottom hole temperature. The

tubing string will be landed at the tubing head with full tension when the no-go shoulder of the seal mandrel is located the calculated distance above the PBR with mud temperature minimum. The blowout preventers will be removed and the 5 1/16-inch Christmas Tree assembled on the tubing head and tested to 10,000 psi pressure. Salt water will be circulated down the annulus and up the tubing to displace the mud in the system. This will lower the static hydrostatic head at perforating depth to the equivalent of a column of salt water. After salt water is circulated, the sliding sleeve circulating valve will be closed, using a plain nonconductor wireline and an appropriate tool to engage the sliding sleeve valve. The annulus will then be pressure tested to 10,000 psi to insure that the sliding sleeve valve is closed. The well will be ready to perforate when other preparations are made.

Packer Arrangement

The 7 5/8-inch production casing will be S-95, 39.00 lb/foot pipe suitable for 10,000 psi internal pressure at the surface. The design factor of 2:1 should be employed for tension, 1.1:1 in collapse, and 1:1 for burst. Collapse strength is critical at 13,000 feet considering 18.0 ppg mud outside the casing and saltwater (0.440 psi per foot gradient) inside, even though a full column of cement will be placed between the production and intermediate strings. A 7.750-inch O.D. by 6.250-inch ID Packer Bore Receptacle will be run in the lower part of the 7 5/8-inch production string to accommodate a seal assembly on the 5 1/2-inch tubing string. The receptacle will be placed in the

7 5/8-inch string above the uppermost zone of porosity, at the same depth where a packer would be landed. The receptacle and seal assembly on the tubing will eliminate a production packer and expansion joint, and permit a full bore through which to pass perforating tools, etc.

Perforating Procedure

A high pressure lubricator will be rigged up on the swabbing valve of the Christmas Tree. The lubricator will be long enough to accommodate the maximum length perforating gun, with a hydraulic packing gland to lessen leakage around the perforating conductor cable, and a fitting for control fluid injection to seal pressure on the cable. The lubricator with gun assembly inside will be pressure-tested to 10,000 psi pressure before the gun is lowered into the well.

The perforating gun will be run with a collar-locator and gamma ray instruments for positive depth control relative to the zone of porosity to be perforated. The perforator should be a 4-inch O.D. Hollow Carrier Jet gun, loaded four shaped-charges per foot, and fitted with spring-type deflectors to insure centralization of the gun inside the casing. Regular charges for 3 3/8-in. and 4-in. hollow-carrier guns are suitable for 20,000 psi bottom hole pressure and 340°F temperature. If needed, high temperature powder can be obtained for 25,000 psi and 470°F, gun length will be limited by the weight of the assembly and the lubricator length available. The gun should be loaded in such manner to perforate only the best intervals of porosity on the electric log.

Prior to firing the perforating charges, the tubing and lubricator should be raised to sufficient pressure, using salt water, to obtain an equivalent hydrostatic pressure at perforating depth about 500 psi less than formation pressure. For example, assuming 14,900-foot perforating depth with a full column of salt water in the well, hydrostatic pressure due to the salt water only will be 6556 psi at perforating depth. To raise this pressure to 11,000 psi — on the assumption that formation pressure is 11,500 psi — 4444 psi will be applied at the surface thus to obtain the desired pressure at perforating depth. If penetration is obtained when the perforating charges are detonated there will be an immediate pressure increase at the surface, i.e., to 4944 psi. If this pressure is obtained, the perforating gun can be recovered and preparations made to perforate additional footage, or flow test the well, as may be in order. If more holes are needed, successive runs should be made with the perforator in the same manner. Fluid production for a given pressure drawdown will depend on the permeability of the same and its thickness, i.e., or permeability-foot, usually expressed as millidarcy-feet. Fluid velocity through the perforations, as described below, will depend on the number of holes per foot (density) the net feet of perforated interval.

Perforating should be started at the lowest sand in the well and proceed upwards. This will enable successive perforating runs to be made at shallower depths. Since the well is ready to flow as soon as perforations are made, production tests can be made at any time after the first zone is opened to the well bore. When enough holes have been made to allow sufficient productive capacity, the well can be tested

for fluid volume, drawdown pressure at the tubing head, and evidence of sand entry. If needed, additional holes per foot or added internal can be perforated without changing the tubing setting. This may be necessary to increase the rate of flow, to obtain higher pressure at the wellhead at maximum flow rate, or to reduce sand production caused by high velocity flow through the perforations. In general, fluid production should not exceed 100 barrels per day per foot of perforations. This volume can be obtained with flow velocity through each perforation not greatly exceeding one foot per second. Lower velocity can be obtained by opening more holes per foot or by perforators that make larger openings in the casing. For example, 8 shots per foot, using shaped charges that make 3/8-inch holes, will enable 1.1 ft/sec. velocity through the perforations at 100 b/d flow rate. "Big-Hole" perforators, which create 0.90-inch holes, will have 0.38 ft./sec. velocity through four holes per foot for the same 100 b/d production per foot of perforations.

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