PLUNGER ENHANCED CHAMBER LIFT (PECL™)

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ABSTRACT
Many forms of artificial lift have been designed to deliquify gas wells. Plunger Lift is one form, utilizing the wells natural reservoir pressure as the prime energy source for removing the liquids from the bottom of the well bore. Intermittent operation of a motor valve installed on the tubing, allows fluid to be lifted to the surface, utilizing the free running plunger as an interface between liquids accumulated in the bottom of the well and the stored gas in the annulus. There are many variations of plunger lift employing multiple motor valves and many different sub-surface mechanical tubular arrangements. Chamber Lift is another form of artificial lift extending from Gas Lift. Combinations of Gas Lift and Plunger Lift have been used in the past and the technique described within is an extension of those methods.

INTRODUCTION
Gas wells cease efficient operations once the gas flow rate reaches critical velocity. At or below critical velocity, the gas flow rate cannot effectively remove the produced liquids from the wellbore. Liquids collect in the wellbore and add additional backpressure by virtue of the vertical liquid head. This liquid accumulation can amass and eventually shut down all flow from the formation.

The addition of an artificial lift method is an effort to remove the liquids and return the well to an improved producing state. Gas Lift is a method whereby gas is injected into the annulus of the wellbore, and through a series of valves in the tubing string, liquid is lifted to the surface, increasing the gas flow rate above critical velocity. This is accomplished by the use of high-pressure gas and can require the use of a compressor at the surface. Some field applications utilize a common pressure source from a centralized compression facility supplying multiple well applications.

GENERAL DISCUSSION
Chamber Lift is a form of Gas Lift that can be used in conjunction with long perforated interval reservoirs. In addition, low-pressure reservoirs can benefit from this type of lift. The wellbore annulus typically requires a packer or packers to be set for zonal isolation. Using a larger size pipe than the production tubing creates a chamber, typically located below the packer arrangement and through the perforated section. The chamber located at the bottom of the tubing string creates a larger void or chamber for the liquid to accumulate during the producing cycle. The liquid is dispersed over a larger cross-sectional area, creating less head or backpressure against the producing formation. Gas is injected into the annulus and displaces the fluid in the chamber into the production tubing. This process is intermittent and cyclical in nature and has a relatively high slippage of gas through the fluid slug. This inefficiency allows for liquid to "fallback" down the tubing and not be removed from the wellbore and produced at the surface. Liquid fallback is 5% per 1000 feet of vertical lift for chamber lift systems.

CONCENTRIC APPLICATION
With PECL™, a plunger is added to Chamber Lift to improve the efficiency of removing liquids and significantly reduce the liquid fallback from the intermittent cycle. Plunger Lift does this by creating a solid interface between the liquid slug above the plunger and gas energy below, effectively sweeping the tubing clean on the ascent to the surface of the well. Employing the idea of the concentric design mechanically isolates the down-hole tubing from the producing formation. Multiple motor valves arranged at the surface, control the complete operation and create the opportunity to produce the gas well at much lower pressures. Combining the technologies of intermittent Plunger Lift and Chamber Lift significantly improves the operating economics for well operations. The strategic advantage is the control of the surface motor valve and facility management. Redeploying the discharge gas from a compressor and utilizing this energy source as the prime mover of the plunger enhances operating performance of the complete system. Well inflow is maximized and energy management is completely utilized, all with low operating expenses.

The chamber can be created and incorporated in many different ways limited only by the well bore configuration and ingenuity. One such arrangement uses a concentric tubing design, incorporating coiled tubing as the inner production string and standard tubing as the outer string. By sealing off the two strings of tubing at the bottom of the well a secondary annulus or chamber is created. This conduit allows the transfer of injection gas to the bottom of the tubing and provides the necessary lift pressure for the plunger to ascend to the surface and remove the liquids from the wellbore.

Production is improved by cycling the well more frequently by not having to wait on natural pressure build-up from the reservoir. Managing the fluid slug size is important. Frequent cycles will ensure the lowest fluid level in the production tubing and minimize the lift gas pressure requirements. The application can require very little lift pressure as can be seen in Figure 1. Figure 1 is a 10-hour trend of operating performance on an actual PECL™ installation. Notice in Figure 2 that the Injection pressure (InjP PSIG) is approximately 90 PSIG, and Casing pressure (CasP PSIG) is approximately 11 PSIG. CasP is a direct measurement of the wellhead casing pressure that is piped and connected to the surface production equipment. The primary casing annulus offers the path of least resistance to flow and will result in the lowest operating pressure at the sand face. Tubing pressure (TubP PSIG) is the pressure of the coiled tubing string recorded at the wellhead during the lift cycles and can be seen to have no effect on the casing pressure during the cycle. **As** can be seen from Figure 3, the casing and tubing are commingled at the wellhead and piped to the surface production equipment. Small liquid slugs are removed frequently (approximately 25 cycles shown for the 10 hour period in Figure 1) without disturbing the system pressure. The plunger offers several significant features: 1) directly indicates overall system performance from the formation to the sales line 2) controls the surface motor valve sequencing and thus minimizing injection gas volume 3) cleans the tubing, 4) acting as a solid interface between the liquid slug and the lift gas.

PECL™ OPERATING TECHNIQUE

The following steps (included in the attachments) indicate the general operating principle behind PECL™.

STEP 1: PRECHARGE CYCLE – Permits the gas to be removed from the primary annulus and injected into the secondary annulus (between the concentric tubing strings). Some of the fluid will be transferred from the secondary annulus to the coiled tubing during this operation. The tubing motor valve is closed during this process. The injection motor valve is closed after this step is complete.
STEP 2: PURGE ON CYCLE – The tubing motor valve is opened and allowed to relieve pressure for a short period of time (i.e. 1 minute) to completely displace all fluid from the secondary annulus into the coiled string. The tubing motor valve is closed after this step is complete.
STEP 3: PURGE OFF CYCLE – The plunger falls back through the fluid to reestablish position under the complete fluid slug.
STEP 4: ON CYCLE – The tubing motor valve is opened concurrently with the injection motor valve. The plunger is lifted to the surface removing the fluid slug from the tubing. The standing valve does not permit pressure to be transmitted to the casing perorations.
STEP 5: AFTEFLOW CYCLE – The plunger is detected at the surface switching the injection motor valve to be closed. The secondary annulus is subsequently equalized with the tubing and casing at the wellhead to allow fluid entry into the down-hole tubing. Notice at this point that the fluid is displaced across the largest cross-sectional area, thus minimizing the liquid head pressure.
STEP 6: CLOSED CYCLE – The tubing motor valve is closed and as a result the plunger is returned to the bottom of the tubing string. Notice that the secondary annulus is continually open during this period allowing fluid entry and equalization of surface pressure with the casing.

Return to **STEP 1** to repeat the process.

The primary casing is open 24 hours per day therefore permitting continuous flow through the path of least resistance minimizing flowing bottom hole pressure.

CONCLUSIONS

Production enhancement and/or reservoir decline stabilization was achieved in all applications tested. Coal seam production was especially challenging due to the coal tines encountered during the drawdown process. The application proved to be mechanically successful in maximizing the gas flow and redeploying energy at the surface facility.

KEY BENEFITS OF PECL™ ARE AS FOLLOWS:

1) **ACHIEVE CONTINUOUS FLOW**

Maximize gas and liquid production from low bottom hole pressure / high productivity index wells efficiently removing liquid and producing at the lowest possible bottom hole pressure. Create the lowest sand-face pressure by producing the formation gas from the primary casingltubing annulus 24 hours per day.

2) **PRODUCE LONG PERFORATED INTERVALS WITH LOW BOTTOM HOLE PRESSURE**

The chamber allows long perforated pay intervals to be produced at minimum pressure ensuring fluid storage with a minimum amount of head pressure. Isolate injection gas from the formation by creating a closed chamber system. Reduce the pressure build-up time normally required by adding the injection pressure source gas. Artificially creating this pressure improves cycle frequency and accomplishes maximum drawdown on the reservoir.

3) **REDUCE FRICTION THROUGH ANNULAR FLOW**

Minimize the dynamic gas friction by producing through the larger conduit (i.e. the primary annulus) as opposed to the smaller production tubing to improve inflow performance. Maximize the pressure drawdown by removing the liquids from the wellbore and distributing across the largest cross-sectional area (i.e. casingltubing annulus). The tubing can be set low in the well bore creating maximum draw down of pressure as liquid is removed. Traditional plunger lift requires the tubing to be set higher in the well bore.

4) **REDUCE FORMATION AND COMPRESSION SURGE**

Compression surge is mitigated by continuous production from the casingltubing annulus. Significantly improve the formation pressure surge by producing the casingltubing annulus 24 hours per day. Reducing the pressure cycle on the formation mitigates sand and solids production. Solids removal is better accomplished by the high frequency of plunger cycles, thus not allowing solids to settle and accumulate in the bottom of the tubing.

5) **TOTAL GAS SYSTEM MANAGEMENT**

Minimize the “make –up” gas requirements by utilizing a semi-closed single well intermittent rotative system. Maximize the use of injection gas when using a gas injection system (i.e. high pressure, clean dry gas). The control theory allows for modification to the injection cycle time based on plunger performance and there fore adjusts the volume of gas injected for the amount of fluid that is being produced. Minimize gas and liquid production loss utilizing the concentric tubing concept. Well equipment can be installed and implemented without having to kill the well. This technique will minimize the potential of damaging the reservoir and will improve the speed at which the application will be returned to a producing status.

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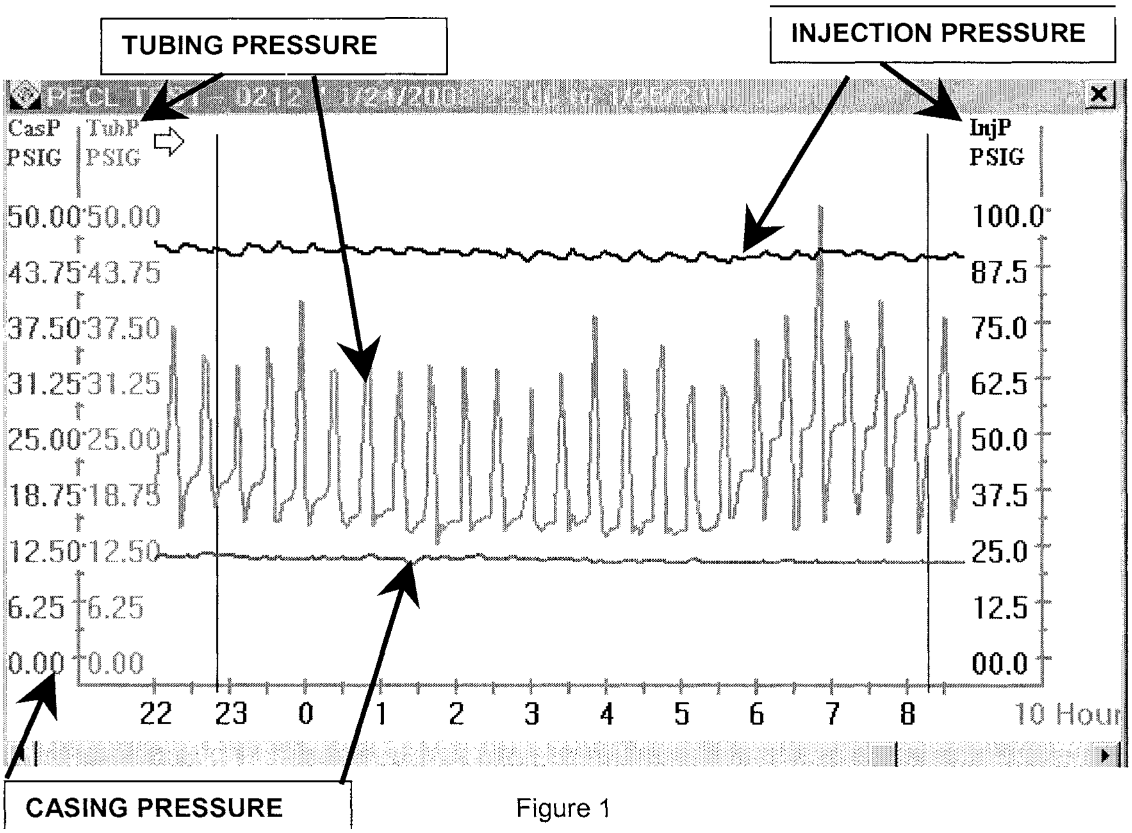


Figure 1

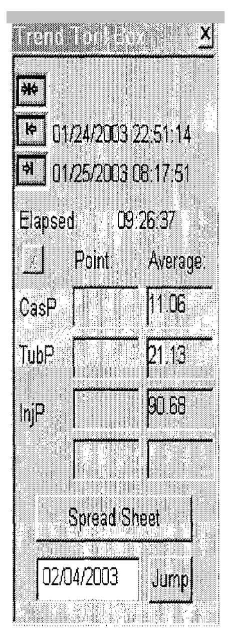


Figure 2

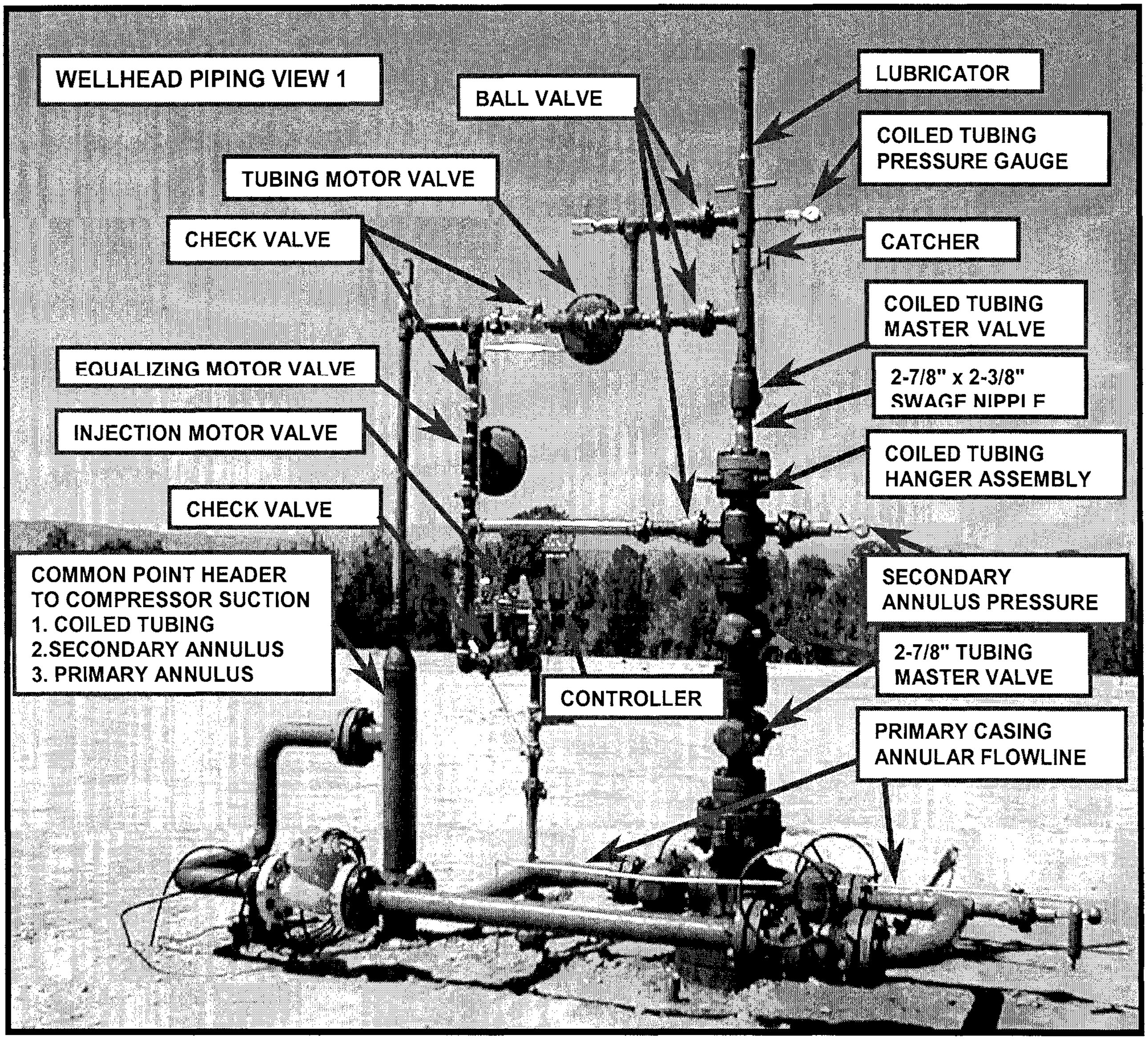
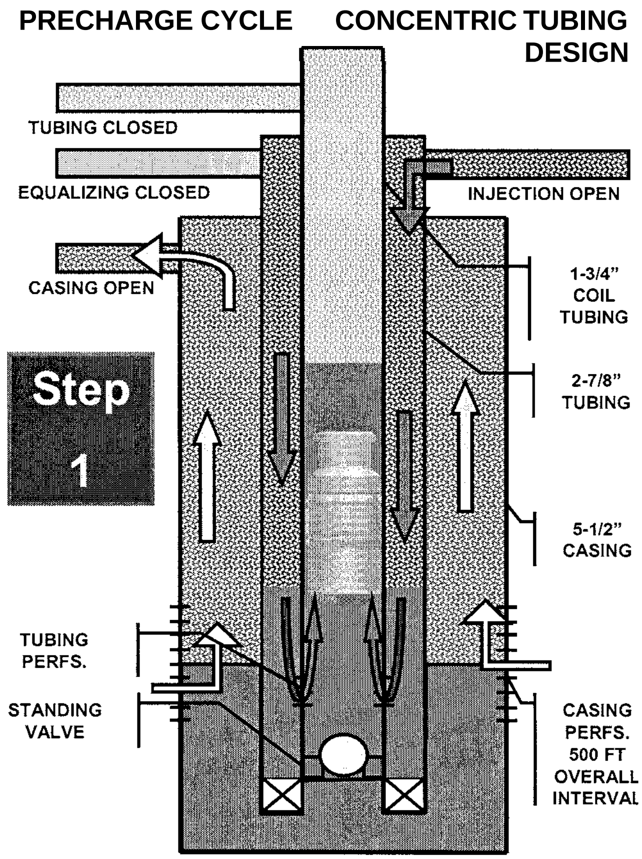
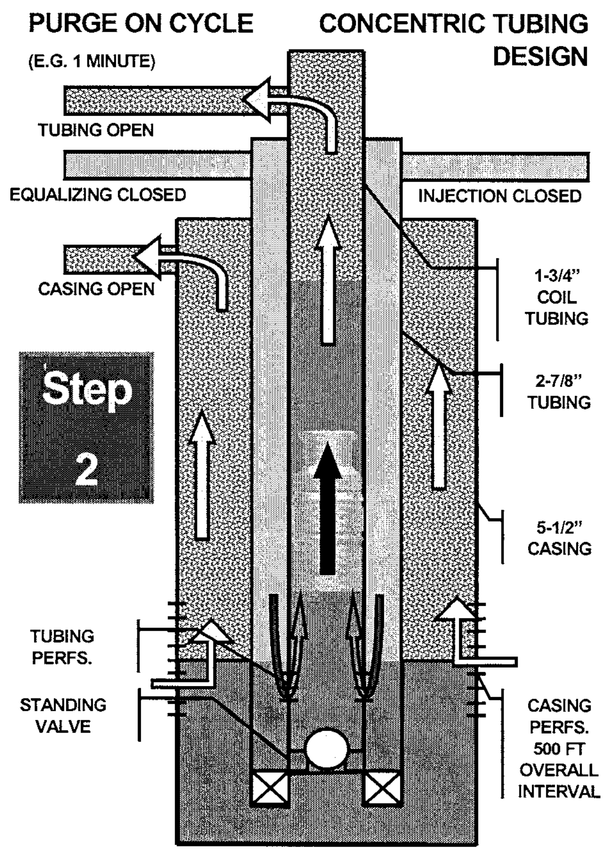
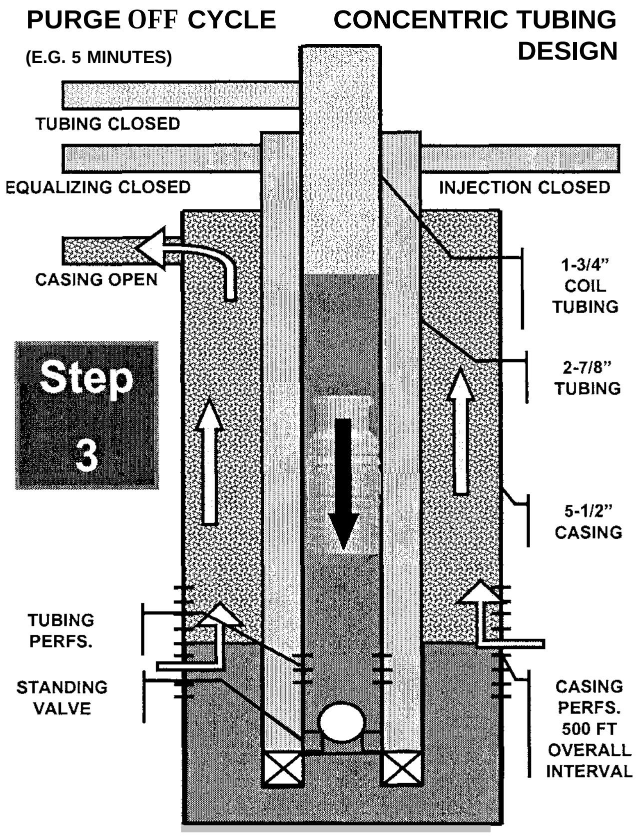
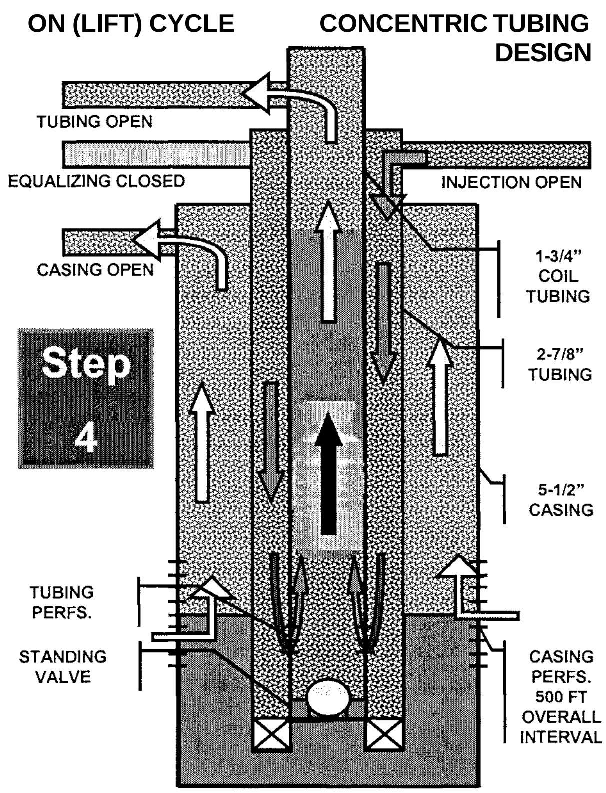

WELLHEAD PIPING VIEW 1
BALL VALVE
LUBRICATOR
COILED TUBING
PRESSURE GAUGE
TUBING MOTOR VALVE
CHECK VALVE
CATCHER
COILED TUBING
MASTER VALVE
EQUALIZING MOTOR VALVE
2-7/8" x 2-3/8"
SWAGE NIPPLE
INJECTION MOTOR VALVE
COILED TUBING
HANGER ASSEMBLY
CHECK VALVE
COMMON POINT HEADER
TO COMPRESSOR SUCTION
1. COILED TUBING
2.SECONDARY ANNULUS
3. PRIMARY ANNULUS
SECONDARY
ANNULUS PRESSURE
2-7/8" TUBING
MASTER VALVE
CONTROLLER
PRIMARY CASING
ANNULAR FLOWLINE

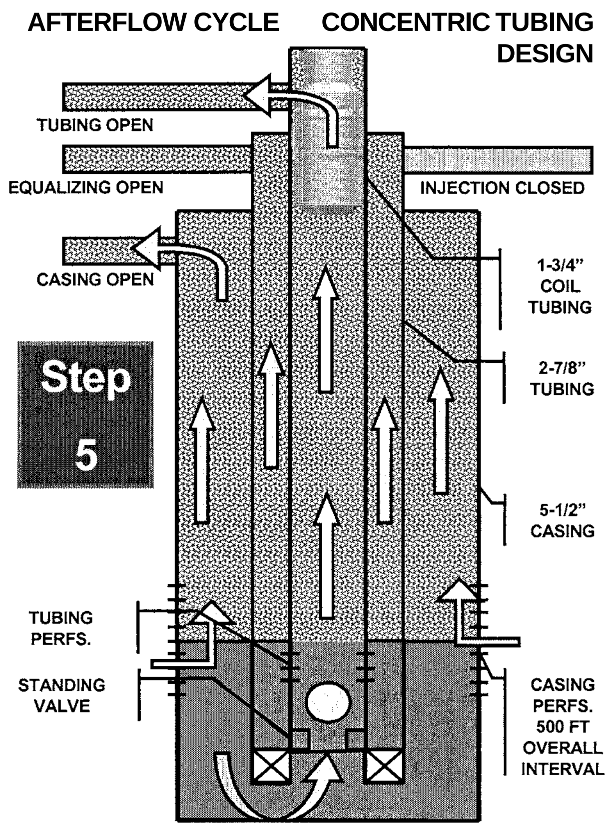
Figure 3

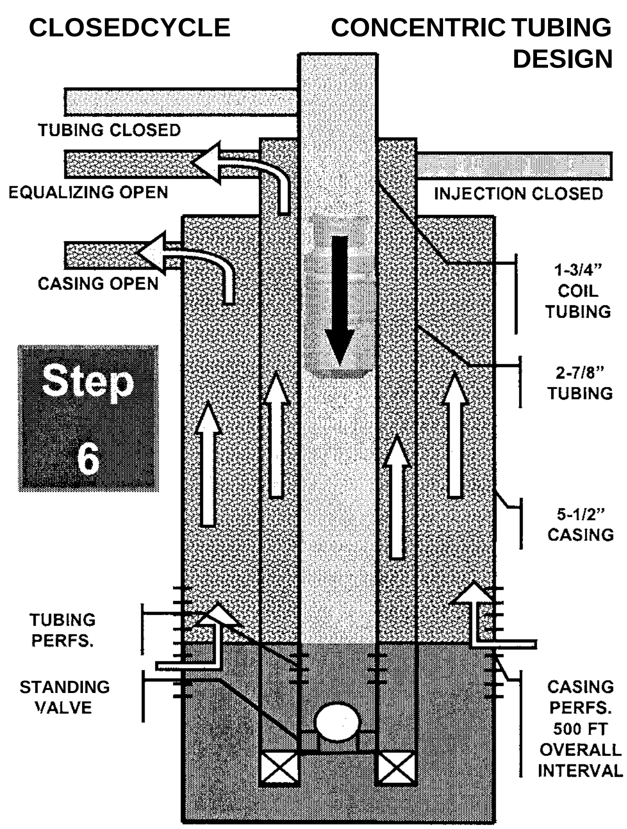

PRECHARGE CYCLE
CONCENTRIC TUBING DESIGN
TUBING CLOSED
EQUALIZING CLOSED
INJECTION OPEN
CASING OPEN
1-3/4" COIL TUBING
2-7/8" TUBING
Step 1
5-1/2" CASING
TUBING PERFS.
STANDING VALVE
CASING PERFS. 500 FT OVERALL INTERVAL


PURGE ON CYCLE
(E.G. 1 MINUTE)
CONCENTRIC TUBING DESIGN
TUBING OPEN
EQUALIZING CLOSED
INJECTION CLOSED
CASING OPEN
1-3/4" COIL TUBING
2-7/8" TUBING
Step 2
5-1/2" CASING
TUBING PERFS.
STANDING VALVE
CASING PERFS. 500 FT OVERALL INTERVAL


PURGE OFF CYCLE
(E.G. 5 MINUTES)
CONCENTRIC TUBING DESIGN
TUBING CLOSED
EQUALIZING CLOSED
INJECTION CLOSED
CASING OPEN
1-3/4" COIL TUBING
Step 3
2-7/8" TUBING
5-1/2" CASING
TUBING PERFS.
STANDING VALVE
CASING PERFS. 500 FT OVERALL INTERVAL


ON (LIFT) CYCLE
CONCENTRIC TUBING DESIGN
TUBING OPEN
EQUALIZING CLOSED
INJECTION OPEN
CASING OPEN
1-3/4" COIL TUBING
Step 4
2-7/8" TUBING
5-1/2" CASING
TUBING PERFS.
STANDING VALVE
CASING PERFS. 500 FT OVERALL INTERVAL


AFTERFLOW CYCLE
CONCENTRIC TUBING DESIGN
TUBING OPEN
EQUALIZING OPEN
INJECTION CLOSED
CASING OPEN
1-3/4" COIL TUBING
Step 5
2-7/8" TUBING
5-1/2" CASING
TUBING PERFS.
STANDING VALVE
CASING PERFS. 500 FT OVERALL INTERVAL


CLOSEDCYCLE
CONCENTRIC TUBING DESIGN
TUBING CLOSED
EQUALIZING OPEN
INJECTION CLOSED
CASING OPEN
1-3/4" COIL TUBING
Step 6
2-7/8" TUBING
5-1/2" CASING
TUBING PERFS.
STANDING VALVE
CASING PERFS. 500 FT OVERALL INTERVAL