COILED TUBING CO_2 GAS LIFT EVALUATED IN WEST TEXAS

Dean Sorrell
Altura Energy Ltd.

CO_2 floods impose a number of artificial lift challenges to an operator. Typically as a flood matures, a significant number of the producers are affected by the CO_2-water injection cycle. Producers swing through a broad range of producing characteristics. It is not unusual, depending on the injection cycle, for a producer to load up during the water cycle and then flow strongly during the CO_2 injection cycle. These wide swings cause troublesome failures, a loss in production, and lead to higher operating cost.

Since late 1995, Altura Energy has been testing two CO_2 gas lift installations in the Denver Unit San Andres CO_2 flood. Results have been mixed. One of the two has been converted to a flowing well. The other remains in operation. This paper presents an overview of CO_2 gas lift candidate selection, equipment and selection and performance results of the CO_2 gas lift test.

Candidate Selection

Denver Unit has about 60% wells on beam rod pumps, 20% on electric submersible centrifugal pumps, 18% flowing well and 2% on plunger lift. Increased production, reduced downtime and reduced pulling or repair expense are incentives behind a program to analyze well producing characteristics and to match the well's behavior to lift type. Wells that produce with high flowing bottomhole pressure (BHP), at high gross rates and with significant gas are good candidates for gas lift. Another candidate well type is producing at a high gross rate, plus high gas, and some solids such as asphaltines or fracture sand.

Specific producing characteristics favorable for gas lift in the Denver Unit are:

- Producing BHP exceeding 800 psig
- Gross rate of 500 bfpd or greater
- Gas-liquid ratio exceeding 500 scf/bbl and less than 1,500 scf/bbl
- Frequent pump gas locking, or asphaltine or solids failures.

Using these criteria will eliminate wells better served by other types of lift. A beam pump can attain a lower producing BHP when gas quantity is low. As gas quantity increases, pump performance deteriorates and reservoir-driven lift such as flow or plunger lift becomes more attractive. Gas lift fills the niche between beam and flow/plunger lift.

To identify those wells that met selection criteria, Denver Unit's 700+ producers were first categorized using well tests, production history, failure history, and workover history and lease operator input. Once categorized, the primary list of potential candidates was narrowed using bottomhole flowing and static gradient measurements and computer modeling. Current wellbore configuration, wellbore condition and distance and obstacles between the CO_2 source and candidates wellhead further narrowed the list.

The first well chosen, Denver Unit 3715, to evaluate CO_2 gas lift was a flowing well that would become weaker when the injection cycle was on water. As the two offsetting injectors alternated from a water-alternating-gas (WAG) cycle of 3 MMcfgd to 1,000 bwpd, production would swing from 60 bopd, 400 bwpd and 400 Mcfgd to nearly zero production. During the water injection cycle, the well was loading up and dying. Flow influenced by the WAG injection cycle, plus the benefit of greater production, made this flowing well a good gas lift candidate.

The second installation to evaluate CO_2 gas lift, Denver Unit 7604, was a recently sand fractured well. The sand fracture had greatly increased liquid and gas rates to 100 bopd, 930 bwpd and 1,030 Mcfgd. Post-frac sand production and gas interference were causing a high number of beam pump failures and a significant loss of production due to downtime. Reducing well failures and associated downtime while maintaining production made this a favorable gas lift candidate.

Gas Lift Equipment and Facilities

Several different mechanical configurations were considered. After numerous computer flow and economic modeling runs, the following configuration was settled upon as most effective for the two evaluation installations.

Well completion equipment consists of 2 7/8-in. production tubing (inside 5½-in. or 7-in. casing) with a 2-3/8-in. side pocket gas lift mandrel installed 90 ft above the packer, Fig 1. CO_2 gas lift gas is injected through a 1 ¼-in. coiled tubing string strapped to the outside of the tubing and connected to the side pocket mandrel. Gas will pass through a 1-in. orifice valve in the side pocket (valve has a ¼-in. orifice and a check assembly). Gas is isolated from casing to eliminate corrosion potential from the CO_2 and prevent undue pressure from being applied to the casing (some wells date from 1938).

Mandrel and Orifice Valve
The side pocket mandrel is the same as that used for gas lift offshore except that the pocket has an external connection, similar to a chemical injection mandrel, Fig 2. A tube from the gas lift mandrel is connected to 1 ¼-in. coiled tubing for passage of CO_2. Deflectors on the outside of the mandrel protect the tube and connection. Mandrel dimensional details are:

- Tubing connection = 2 3/8-in. API 8 rd EUE box by box
- Internal diameter = 1.995-in.
- Side pocket diameter = 1.0-in.
- Maximum diameter = 4.540-in. (diameter of circle with eccentric pocket and connection)
- Injection tube diameter = 0.75-in.
- Mandrel length = 6.3 ft
- Material = ASTM A519 4130 with internal coating of epoxy-phenolic IPC-400
- Manufacturer = Production Specialties Inc.

The internal side pocket is designed for a wireline retrievable valve and latch. The gas lift valve for this application has an orifice port, check assembly and a BK latch. The valve was pre-installed in the side pocket mandrel. The orifice port size is ¼-in. based on gas passage as calculated with the Thornhill-Craver equation.

Coiled Tubing and Strapping
Coiled tubing diameter was selected based on minimum friction losses for rates of 200-500 Mcfgd. CO_2 delivery pressure available permit injection rates 1 MMcfgd, even though friction loss will be a factor. In addition, high pressure enables the well to be easily unloaded with injection gas.

The mechanical detail for coiled tubing is:

- OD = 1.25-in.
- ID = 1.076-in.
- Wall = 0.087-in.
- Weight = 1.081 lb/ft.
- Yield Strength = 83,500 psi
- Material = ASTM A606 Type 4
- Thermal Expansion = $6.5 * 10^{-6}$ units/unit/°F
- Supplier = Quality Tubing (QT800)

Fig. 3 provides a chart of surface injection gas pressure, bottomhole gas pressure at 4,686 ft and rate. The data is based on the Shell Zabaras model and has a gas composition with a CO_2 content of 92%. Nominal rate is 200 Mcfgd, and pressures for gas lift injection are 1,800 psig at the control/metering skid, 800 psig at the wellhead (after choking at the skid) and 1,200 psig downhole (calculated) at the gas lift mandrel just upstream of the orifice valve.

Coiled tubing is strapped to the 2 7/8-in. with stainless steel ¾-in. bands, three per joint, and casing clearance permitting, with pinned wrap-around protectors. Ten wrap-around protectors were installed in the latest well that had 7-in. casing.

Wellhead and Hanger
The wellhead assembly is shown in Fig. 4. The components are:

- Lower tubing head with 71/16-in. flange
- Tubing spool to hold dual hanger
- Adapter flange with a 2 9/16-in. outlet on top for the production master valve with a 2 1/16-in. side outlet for the injection master valve
- Lower and upper 2-9/16-in. master valves – production
- A 2 9/16-in. tee and swab valve-production

- A 2 1/16-in. wing/emergency shut-down (ESD) valve – production
- A 2 1/16-in master valve – injection.

The tubing hanger is a dual hanger specially manufactured to accommodate 2 7/8-in. and 1 ¼-in. parallel strings inside the 5 ½-in., 17 lb./ft casing or 7-in., 23 lb./ft casing. The assembly consists of several components, Fig. 5. Dual hanger connections are made to accommodate, 1) 2 7/8 in. 8 rd EUE tubing and the slip and compression seal assembly for 1 ¼-in. coiled tubing on bottom and 2) on top, the hanger to adapter seal sub for 2 7/8-in. and the hanger to adapter seal sub for 1 ¼-in.

Injection Pipeline and Control Skid

The injection pipeline links CO_2 gas supply to the control skid from a tie-in connection point located about 700 ft from each well. The pipeline data is:
Length = 700 ft
Diameter = 2.375 in. OD (1.939 in. ID, 0.218 wall) Sch 80 (X heavy) pipe
Rating = 2,488 psig with ANSI/ASME B31.3
Material = Grade B
Charpy test = 13 ft-lb. minimum average and 10 ft-lb. minimum valve at –20°F

The control and metering skid for two test installations were from existing injection equipment in the Denver Unit operation, Fig. 6. Located at the wellhead area, its function is to provide, 1) shut off from injection line, 2) rate control with the choke/actuator and 3) metering of the CO_2 gas lift injection gas. The short pipeline from the skid connects to the 2 1/16-in., 3,000 psig master valve on the well. A check valve is installed on piping adjacent to the wellhead, since none is on the skid.

Cost

Cost of complete installation ranged between $65,000 and $75,000. Target cost for each installation was $50,000, Fig. 7. The first installation took longer than expected because of workover crew unfamiliarity with equipment and operations. Severe cold weather and a mechanical failure of the downhole blanking plug hampered the second, requiring equipment to be pulled and rerun. Cost of future installations is expected to decrease as rig crew proficiency improves. However, distance to a CO_2 source and availability of surplus equipment greatly influences the final cost of an installation.

Gas Lift Results

Gas lift in the initial well, Denver Unit 3715, has performed worse than forecast. Production dropped rather than increase as forecast. Total liquids dropped from 460 bfpd gross (50 bopd) prior to installation to approximately 370 bfpd gross (70 bopd), with 200 Mcfgd injection, Fig. 8. This is less than the 650 bfpd gross (100 bopd) expected. The lower production was attributed to the change in offset injection philosophy and rates. In mid-1997, the tubing plugged off with paraffin/asphatines due to a surveillance glitch. During the workover to remove the plug, it was decided to remove the gas-lift equipment. The well had been a strong flower for a considerable time prior to the pull without the assistance of lift gas. The well continues to flow strong during the second leg of the second alternating injection cycle. Well performance will be monitored during the remaining 6 months of the water cycle. CO_2 gas lift was installed 2 years prior to converting back to flow.

The second installation, Denver Unit 7604, is still in operation. This well dies when lift gas is shut off. Current lift gas has been optimized to 200 Mcfgd. Total oil, water and gas production has declined constantly since installation in late-1995, Fig. 9. The 7604's lower than expected performance is also attributed to offset injection. This well has not yet completed a full alternating injection cycle. Since installation, no lift failures have occurred. Before being converted from beam to gas lift, the 7604 had failed three times in the prior six months at a cost of $34,000.

Findings

Pressure and temperature surveys run in both installations found reasonable matches to the Shell Zabaras CO_2 multiphase correlation and the Hagedorn-Brown multiphase correlation. Injected CO_2 gas does, as expected, exhibit cooling during expansion. However, the minimum temperature of 85°F does not pose a threat of downhole freezing.

Chemical-related problems are the biggest technical problem gas lift faces. A stable emulsion complicated production testing on the first installation. A gas dispersible demulsifier was injected into the gas stream for downhole mixing, which partially broke the emulsion given sufficient time and temperature. Interesting, no trace of an emulsion has been detected in the second installation, but early on, asphaltine plugged the gas lift mandrel. Since beginning injection of gas dispersible asphaltine solvent into the gas stream, asphaltine plugging has not been a problem. The failure to continue injection into the Denver Unit 3715 led to its tubing being plugged. Corrosion coupons installed in both wells display a normal metal-loss rate.

Economic viability of CO_2 gas lift is still in question. Long-term performance over several WAG cycles is currently underway. Typical WAG cycles are six to 12 months in duration. Complete evaluation may take one to two more years. Production performance and operating costs of beam pumped, electric submersible pumped, natural flow and the two gas lift wells will be monitored and compared during this time period to determine the most economic solution to the CO_2 flood lift solution.

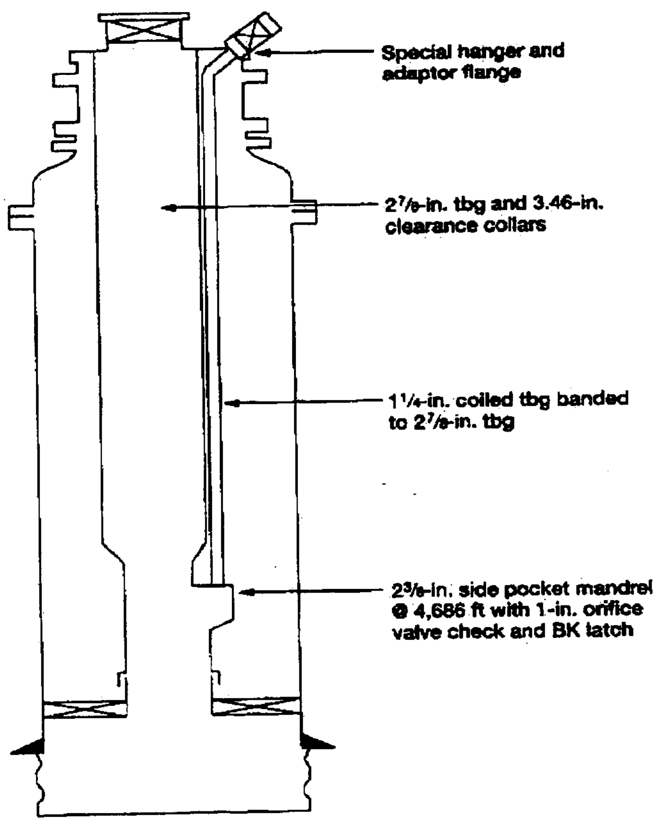

Figure 1 - Well Completion Equipment

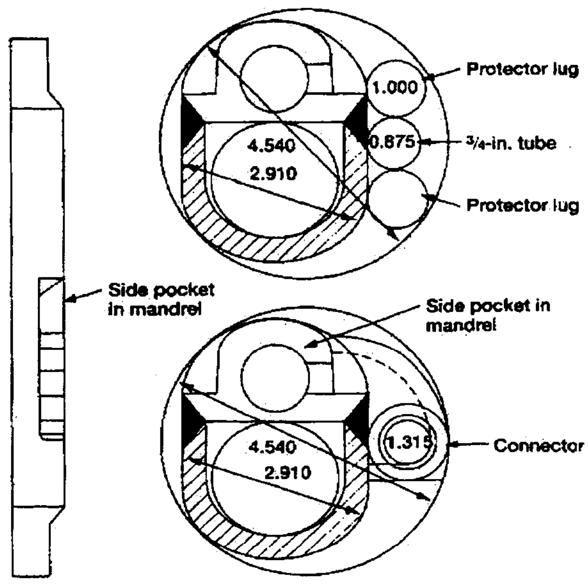

Figure 2 - Side Pocket Mandrel with External Connection

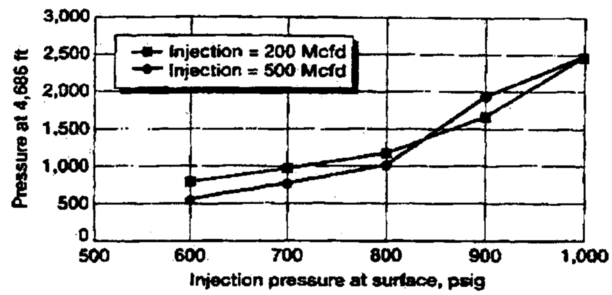

Figure 3 - CO2 Injection Pressure, 1 1/4 in. Coiled Tubing (ID = 1,078 in.)

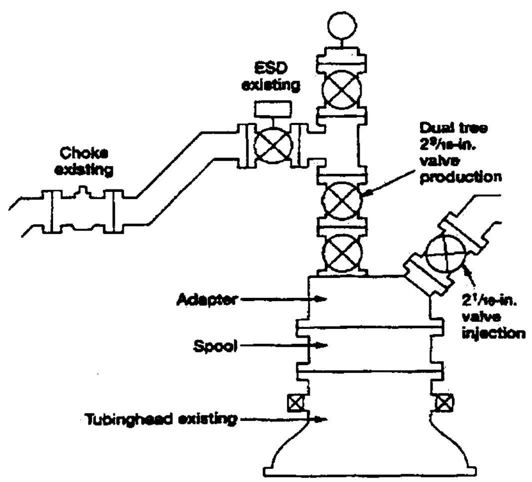

Figure 4 - Wellhead Assembly

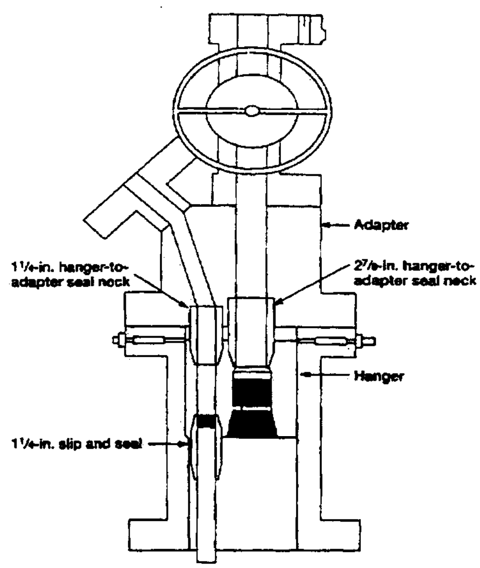

Figure 5 - Components of the Tubing Hangar

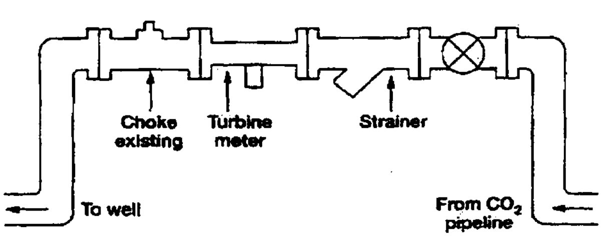

Figure 6 - Control and Metering Skid

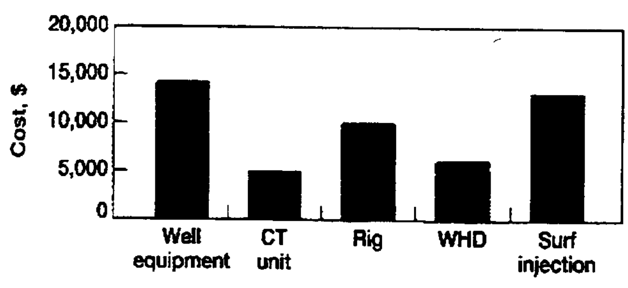

Figure 7 - Equipment and Installation Costs

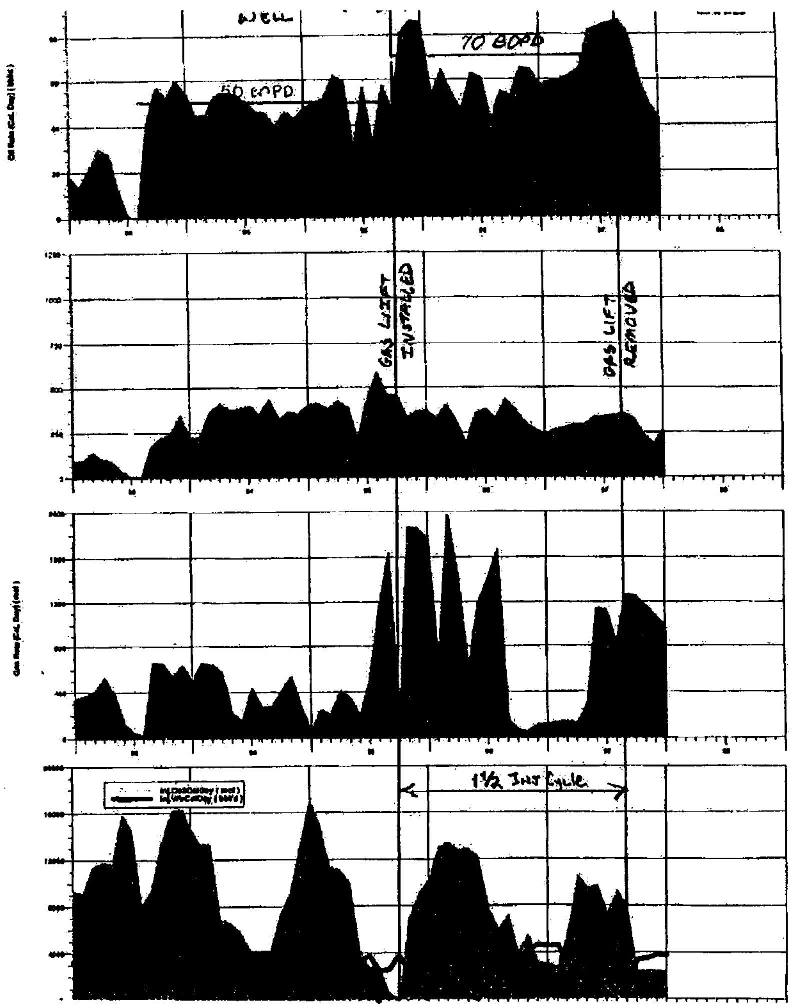

Figure 8

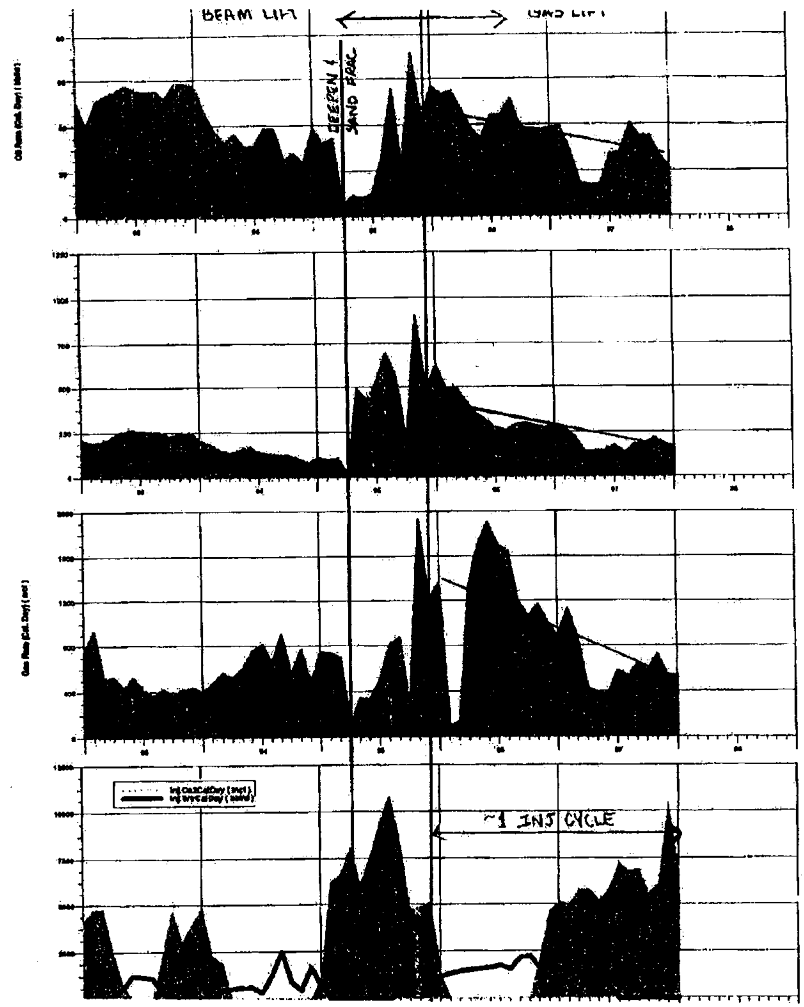

Figure 9