CO_2 INJECTION AND PRODUCTION FIELD FACILITIES DESIGN EVALUATIONS AND CONSIDERATIONS*

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Introduction:

In November, 1984, Amoco Production Company commenced CO_2 injection into the Wasson ODC Unit (WODCU), the first of four CO_2 projects in West Texas. One month later, CO_2 injection was initiated in the three remaining projects, the Slaughter Estate Unit (SEU), the Central Mallet Unit (CMU), and the Frazier Unit. Figure No. 1 shows the location of these units, approximately 35 miles southwest of Lubbock, Texas.

The beginning of CO_2 injection marked the completion of over two and one-half years of engineering design and over 18 months of construction. The projects consisted of designing, specifying, and constructing more than 300 miles of 2 inch through 36 inch diameter steel, fiberglass, and polyethylene line pipe; 74 two and three phase production vessel installations; and approximately 400 CO_2 injection wellhead and bottomhole equipment changeouts. Figure No. 2 is a schematic of the CO_2 project facilities.

This paper discusses field facilities problems that were experienced during the initial construction and during the actual operations over the last two years. Furthermore, design and operational considerations and changes which have been made will be discussed for future CO_2 projects.

For the purpose of this paper, four areas of the CO_2 project facilities will be discussed: the CO_2 injection facilities, the field production facilities, the gas collection facilities, and the excess water handling facilities.

CO_2 Injection System

Piping System: CO_2 is provided to all four units from the Bravo Dome Unit through the Bravo Pipeline. The normal pipeline pressure of 1800 to 2000 psi is boosted to 2400 psi for the Slaughter Field units and reduced to approximately 1600 psi for the WODCU. CO_2 for the WODCU can also be provided from the Sheep Mountain and Cortez CO_2 Pipelines.

Each of the four projects utilized a trunkline piping system. Radial systems were investigated and were found to be more costly. The SEU, CMU, and FU systems were designed with a working pressure of 2500 psi, which required ANSI 1500# flanges and valves, and the WODCU system was designed with a 2000 psi working pressure, which required ANSI 900# flanges and valves.

Each project made use of X-grade and grade B internally bare, externally coated, carbon steel pipe, which was installed at a depth of

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four ft. All of the injected CO_2 is dry and is therefore noncorrosive in these bare carbon steel injection systems.

Valves used throughout the system are trunion mounted ball valves with bare carbon steel bodies and NACE trim. The design of the piping system was such as to allow all of the valves to normally operate in the open position. In places where a positive shutoff was required, a line blind was installed. This was done to minimize seat damage within the vales. Valves in the piping system which were four inches in diameter and larger were buried. Three inch and smaller valves were installed above ground. This was done based on the cost of installing each size valve. The larger valves were less expensive to bury, and the smaller valves were less expensive to install above ground.

Several minor problems have been noted in the piping system since the start-up of CO_2 injection. First, many of the below ground flanges were found to have small leaks due to the bolts not being sufficiently tight. As a result, dry ice blocks formed and pushed the connection and the surrounding earth upwards. In one instance, this phenomenon caused a weld on a four inch diameter, 45 degree ell to break. The solution to this problem is to have as many (if not all) flanged valves and tie-ins above ground as possible. This would allow for early leak detection and quick remedial action. This will cost a little more than burying the valves, but will more than pay for itself if any leaks do occur.

Another minor problem with the existing system is that many of the X-grade fittings are not readily available and can cause unreasonable delays for otherwise routine repairs. Consequently, it was necessary to order spares for those long delivery items. For future designs, it may be more economical to order pipe that would be compatible with "off the shelf" Sch. 80, Grade B fittings. The use of transition pipe spools may be another economical way of using X-grade pipe with Sch. 80 fittings. Both alternatives should be evaluated before ordering pipe.

<u>Valving</u>: The valves used in the CO_2 injection system were trunnion mounted ball valves with ring joint flanged connections. Generally speaking, these valves have worked very well, with only a few exceptions.

Many of the valves were ordered with standard EPDM O-rings in the bonnets and trunnions, which have failed. The failures appear to have been caused by both explosive decompression and material degradation. The decompression problem is due to the relative low density, or a low degree of crosslinking, of the elastomer (70-80 durometer), and the degradation problem is thought to be caused by the incompatibility between the oil based sealant and the EPDM material used to make the O-ring. Future valve orders for high pressure CO_2 service should specify either Buna-N or Viton 90 to 95 durometer O-rings or any other proven elastomers that are compatible with both CO_2 and oil based sealants.

Another minor problem with the CO_2 injection valves has been that of the sealant injection ports. CO_2 tends to dry the sealant in the ports, which causes the internal check to unseat and leak. To resolve this problem, sealant ports with threaded caps have been installed. With the new ports, CO_2 can not leak past the metal to metal seal formed by the caps.

Blowdown: The blowdowns installed in the CO_2 injection system piping basically consisted of a buried, flanged blowdown valve (ball valve), a blowdown stack; and a line blind (see Figure No. 3). In the normal operation of the blowdown, CO_2 pressure is exerted against the blind, and the flanged blowdown valve is open. When a blowdown is required, the blowdown valve is closed, the piping is depressurized through the bleeder valve (initially a 1/2" needle valve), the line blind is rotated open, and the blowdown valve is then opened.

Two minor design changes have been made to the CO_2 blowdowns. First, the buried, flanged valve should be changed to a weld neck valve to eliminate the buried flange connection. A flange leak on this valve at the blowdown on the 12 inch main CO_2 supply line caused the Slaughter Field projects to be shut-in while repairs were being made.

The second change that we would make in future CO_2 injection piping designs is the installation of a full port, 1/2 inch ball valve as a bleeder to depressure the blowdown stack in place of the originally designed 1/2 inch needle valve. With the needle valve, the time required to depressure the piping is about 45 minutes. With the full port ball valve installed, the time required for depressurizing the piping is reduced to 2-3 minutes. Additionally, the needle valves, in general, tend to freeze closed when venting high pressure CO_2.

Injection Wellheads: The CO_2 injection wellheads consist of two major components: the injection control skid and the Christmas tree (see Figure No. 4). The injection control skid is composed of a bare, carbon steel, junior orifice type meter run; a solar powered control valve; and solar powered instrumentation and microprocessor.

The Christmas trees were totally reconfigured from the master valve upward. All new, 9D aluminum bronze (AlBz) and 316 stainless steel ring joint flanged components were installed to minimize leaks. Because the WAG (water-alternating-gas) method of CO_2 injection is used in these projects, the exotic materials selected were required to be suitable for resistance to corrosion resulting from the occasional mixing of CO_2 and water in the wellhead when making well switches or during a flow back period. The high pressure CO_2 injected during the CO_2 half cycle is dry and is therefore noncorrosive unless mixed with water. The use of either AlBz or 316 SS was determined for each component based on component pricing.

The original CO_2 Christmas tree configuration included installing two AlBz tees above the master valve. One tee is used for CO_2 injection, and the other is used for water injection. Each branch consisted of a check valve, a line blind, and a ball valve. To allow for wireline work without interrupting either CO_2 or water injection, an AlBz gate valve was installed on top of the second tee.

Several repeated problems with both the injection control skid and Christmas tree have been encountered. Consequently, many design changes have been made.

The only major problem with the CO_2 injection control skid has been with low power pressure and temperature transducer failures caused by lightning. To eliminate this problem, isolating flange kits were installed between the control skids and the injection system piping, which was conducting transients into the skid. Additionally, all of the wellhead instrumentation and microprocessor components were commonly grounded to avoid creating a potential between instruments.

One problem common to both the control skid and Christmas tree, as with the CO_2 injection system valves, was that the 70 durometer EPDM and buna elastomers initially installed in the check valves, ball valves, and orifice fittings were improper for high pressure CO_2 service. As a replacement, and for future designs, 90 durometer Buna or Viton seals would be considered.

The problems encountered with the Christmas trees have required more extensive changes than those required for the control skid. First, the double tee arrangement resulted in a very tall and unstable wellhead. Special tie-down braces were later installed to provide a more rigid structure. Newer wellheads have incorporated a cross in place of the two tees. As a result of the lower profile, the wellheads are considerably more stable.

Early in the project, the AlBz tees, along with the AlBz check valves and the 316 SS line blinds, were found to be very susceptible to casting defects.

The components passed a standard hydrotest but failed in high pressure gas service. The initial specifications called for an industry standard casting (a level 3 casting), but were later changed to a more stringent level 2 casting, which requires radiographic inspection.

Another problem that has developed over the last several years involved the AlBz clappers in the check valves. These clappers have worn to the point of being inoperable. In general, the AlBz in this service has shown very poor wear resistance. These checks are being replaced with 316SS lift disc valves.

Finally, new casing valves were found to be required. Most of the pre-CO_2 valves were equipped with improper elastomers and were unable to withstand the high pressures associated with CO_2. Additionally, many of the 400 CO_2 injection wells were only equipped with one casing valve, and as discovered on the first blowout, two valves are required for proper well control. One valve is normally used as a blowdown valve while the other valve is being tied onto a kill truck. Additionally, if either of the valves become inoperable, the remaining valve can be used.

<u>Bottomhole CO_2 Injection Well Equipment</u>: The only new bottomhole equipment installed in each CO_2 injection well consisted of plastic

coated tubing and either a new or a reconditioned tension set type packer with 85-90 durometer perioxide cured nitrile CO_2 compatible elastomers.

The new tubing installed incorporated several design changes to the pin ends. First, the standard API sharp end, as shown in Figure No. 5, was rounded to allow for a smooth surface which could easily be plastic coated. The second change incorporated the extension of the standard upset length from four inches to six inches. This was done to allow the tubing to be rethreaded in the future if corrosion attack of the pin end persists.

Both thick film and thin film phenolic "plastic" coatings were used in the 350 miles of tubing installed. However, the thick film generally provides more consistently acceptable coating jobs, which were required to be 100 percent holiday free. With both coatings, quality control is essential. Our experience has shown that having a third party inspector or company inspector at the coating company to ensure an acceptable coating job is money well spent.

Several problems have occurred with the injection well downhole equipment since CO_2 injection commenced. First, the tension type packers that were initially installed have been found to be less than satisfactory. The tension packers have a depth limitation of about 5000 ft., and at the depth of these wells (4900 ft.), the packers are very sensitive to additional stresses caused by rapid temperature changes, as experienced during a water to CO_2 switch. In several instances, the packer shear pins sheared, which caused the packers to unseat and created blowouts. Additionally, on/off tools, which have proven to be very beneficial, can not be used with this packer. Currently, tension packers are being replaced with neutral set packers as wells are worked over, or at any other time the tubing is removed from the wellbore. In conjunction with changing the packers, profile nipples and on/off tools are being installed. With this new equipment, the wells are much easier to control, since in most cases, it is possible to control the well by setting a (wireline) profile plug before pulling or unlatching the tubing. Also, with neutral set packers, the circulation of the packer fluids and displacement of trapped, corrosive fluids is much more effective. Corrosive wellbore fluids, which flow into the annular space above the packer while a packer is being set, can be displaced by setting a profile plug, unlatching the on/off tool, and circulating inhibited water down the tubing. However, since on/off tools could not be used with tension packers, this procedure of displacing the trapped, corrosive fluids was not performed. As a result, several tubing failures due to external corrosion on the bottom tubing joints have occurred in wells equipped with these tension-set packers. With tension packers, costly, weighted mud must also be used in killing the well.

Field Production Facilities

Producing Well: No changes were made to either the artificial lift equipment or the wellhead equipment during the implementation of the CO_2 project facilities. Although modifications were anticipated to be required, none were initially made due to the potentially large investment and the uncertainty of design parameters for shut-in pressures and pumping conditions.

Modifications to the wellheads are presently being implemented on CO_2 breakthrough wells. They include: installing Schedule 80 nipples, 2000 psi rated ball valves on the tubing head, and new elastomers in both the secondary seal and tubing slips seal. For beam pumped wells, the blowout preventer elastomers are also changed. For electrical submersible pumps, the tubing valve is being replaced with a 2000 psi rated gate valve. Figure No. 6 illustrates all of the above changes.

Once completed, the modifications will allow for a maximum shut-in pressure of approximately 2000 psi. It should be noted that the majority of the production wells in the four CO_2 projects have casing which is more than 40 years of age and may not be capable of withstanding pressures in excess of 1000 psi. Consequently, the potential for casing repairs is expected to increase during the mature stages of the CO_2 floods.

Many equipment changes and tests are being conducted with respect to all artificial lift equipment. No significant conclusions about optimum artificial lift for CO_2 flooding can be made at this point in time. Undoubtedly, artificial lift equipment requirements for CO_2 floods will be the subject of numerous technical papers in the future.

Production Flowlines and Fluid Gathering Lines: The majority of the pre-CO_2 flood fluid gathering lines and individual well production flowlines were replaced with 150 psi cyclic pressure rated fiberglass pipe. The design operating pressure for the production flowlines is 50-55 psi, which is also the maximum desired back pressure at the wellheads. The fluid gathering lines, on the other hand, are sized to have a maximum operating pressure of 125 psi (with the exception of the remote header fluid gathering lines, which will operate at a maximum of 30-35 psi). In all instances, the replacement lines were installed to increase line capacity, and not for corrosion resistance. All totalled, more than 91 miles of 3, 4, and 6 inch diameter fiberglass production flowlines and more than 25 miles of 4 inch through 14 inch diameter fluid gathering lines were replaced.

No equipment failures have occurred in the fiberglass piping since the original pipeline construction was completed. However, due to the poor quality control that was discovered during the initial installations, stringent manufacturing specifications and inspections should always be included in major construction projects of this nature.

Remote Production Headers, Satellite Batteries, and Central Tank Batteries: The remote header, satellite battery, and central tank battery (CTB) installations are among the most important of the CO_2 flood production facilities.

The function of the remote headers and satellite battery headers is to collect, or centralize, production from numerous wells and to provide individual well test facilities for oil, water, hydrocarbon gas, and

CO_2 gas production. Operating pressures for the remote headers are in the range of 30 to 35 psi, while the satellite batteries' headers operate from 25 to 30 psi.

All of the remote and satellite battery headers in the projects (with the exception of the WODCU) existed prior to the initiation of the CO_2 flood. The WODCU facilities are all new, and larger, facilities. These were required in order to handle the expected high gas production rates (1 to 5 MMSCFD per well).

The only modifications made to the testing facilities were the inclusion of an automated, multiple orifice tube metering skid and an infrared CO_2 analyzer, which measures the percentage of CO_2 gas in the total volume of gas.

The main function of the satellite batteries is to remove the majority of the hydrocarbon and CO_2 gas from the produced fluids and to pump the remaining produced fluids through the fluid gathering system to the CTB. As a backup to the pumps, an automatic low pressure (70 psi) dump system was incorporated into each of the 46 new satellite battery production separators, which would allow for operation during a power outage or a pump malfunction. Additionally, a total production separator bypass system was installed at each satellite battery.

All of the production stream, dump system, bypass system, and gas piping was bare carbon steel. The theory used in this original design was that the corrosion inhibitor flushed into the production wells would be produced and would create a protective film in all of these surface facilities. Due to the reduced fluid velocity and increased residence time in the production separators, sludge and solids can accumulate and impair the creation and regeneration of a protective film. An internal plastic coating was therefore applied.

The only modification to any of the eight central tank batteries in the four units was the addition of a 10 ft. x 30 ft. three phase production separator, which serves to provide for a second stage of gas separation during normal operation and as a backup if one of the satellite batteries is operating in a bypass or pressurized dump mode.

Many minor problems have occurred with the CTBs, the satellite batteries, and the gas testing facilities since the production facilities were put into service more than three years ago. First, numerous piping failures caused by corrosion have been reported, especially in the Wasson ODC Unit satellite and central tank battery facilities. All of these failures have been in locations where stagnant produced fluid has lain dormant in the bare steel for several months. These locations include the test side of each well header leg, the production separator bypasses, and the emergency dump valves and piping.

The below ground steel piping has been replaced with either fiberglass or coated steel piping, and the above ground valves and piping have been replaced with coated steel components. Future designs would include fiberglass piping and coated steel components wherever possible. The cost to repair several failures would more than offset the initial cost of installing fiberglass pipe or coating the steel components.

Finally, with respect to the gas measurement skids, only one failure and one operational change have occurred. The only failure occurred when a pinhole leak, due to corrosion, developed in a weld. The one major operational change made was due to the relatively high (and unexpected) volume of condensate that was found to accumulate in the measurement skids. To eliminate this problem, drip pots were installed on each skid. New skids being installed are fitted with a plastic coated drip header and an automatic blowdown system to drain the gas skid header (see Drawing No. 7).

Gas Collection System

Piping System: The gas collection systems begin at the Mallet and Wasson CO_2 Removal Plants at an inlet pressure of 5 psig. The gas gathering systems are polyethylene trunkline systems, which range in size from 10 inches to 36 inches in diameter and span outward to the satellite and central tank batteries to collect the produced gas. The systems were designed to have the satellites and the CTBs operate at a maximum of 25 psig during peak CO_2 gas production periods. Due to the burial load requirements, an SDR 21 pipe was used, which yields a 48 psi working pressure (based on rating factors). It should be noted that fiberglass pipe was bid and evaluated for installation, but was found to be cost prohibitive. The evaluation included installation cost, pipe and fitting cost, and the cost of gas loss associated with the permeability of the polyethylene pipe. Gas loss, although possible, is generally insignificant.

The fittings used in the piping system were all prefabricated, SDR 17, polyethylene. With the use of these fittings, special chamfers had to be made on fittings adjacent to the high performance butterfly valves in order for the valve disks to have ample clearance.

The valves used were buried, carbon steel valves with 316 SS disks and stems. As a special design feature, the valves were oriented so that the stems and disks were mounted in the horizonal position. This was done to allow debris to flow through the valve without getting into the bearing areas (see Figure No. 8).

One major problem that has persisted during construction and during initial operations has been with the prefabricated polyethylene fittings. Seams on fittings 24 inches and larger in diameter have frequently split. Repairs thus far have been performed by using plastic coated steel fittings. Upon investigation, it was discovered that the installed cost of steel fittings was actually less than the polyethylene counterparts. Additionally, the delivery of the steel fittings is generally a fraction of the time required for the polyethylene fittings. Consequently, steel fittings, especially in the larger sizes, will be evaluated for use in future projects.

Drips: The drips installed were fabricated from 3 ft. x 30 ft. fiberglass pipe sections and were strategically placed on the upslope sides of the elevation changes directly below the polyethylene pipe. At this point in the line the slug is at its lowest velocity, and is therefore less likely to flow over the drip without being caught.

Several failures have been experienced in the drips. Two of the failures were due to settling of the polyethylene gas gathering line pipe, which caused the fiberglass flanged nozzle (located on the top of the drip) to be pushed through the surrounding fiberglass drip body. The third failure occurred in a fiberglass drip body seam. An inspection of the failure showed that the seam had a wall thickness which was less than specified. However, the settling or improper bedding of the drip also contributed to the failure. The drip appeared to be in a bind at the location of the seam.

One alternative to the current design, which will reduce these problems, would be to install an internally and externally coated steel drip located two to three feet off center from, but parallel to and deeper than, the polyethylene pipeline. The connection between the top of the drip and the bottom of the pipe could be made using a non-rigid connection (i.e. hose). Although this design has not been tested, we feel that it would work satisfactorily.

Lease Custody Meter: The new lease metering facilities incorporate the use of multiple orifice type meter runs. They were sized to work individually at lower produced gas rates initially and eventually in unison at higher gas rates.

No failures have occurred in any of the installations; however, one major operational change has occurred. Gas samples prior to CO_2 flooding were taken quarterly and showed very little, if any, compositional changes from period to period. But with the breakthrough of CO_2 and heavier hydrocarbon gas, compositional changes are occurring more frequently. Consequently, gas samples may be required more often. Additionally, several continuous gas samplers are being tested for future use.

Saltwater Disposal (SWD) System

The SWD systems constructed in the four CO_2 floods utilize either low pressure transfer of produced water (at 100 psi) or high pressure disposal (at 1000 psi with a design maximum of 1800 psi) into disposal wells. In the CMU, a low pressure system was used to transfer excess produced water to another Amoco operated property requiring makeup injection water for waterflooding, while the remaining three units made use of high pressure systems which transported pressurized water from the waterflood injection stations to deep (12,000 ft.) disposal wells by means of plastic coated high pressure trunkline systems.

Numerous operational problems, equipment failures, and design changes have occurred in the high pressure WODCU, SEU, and Frazier Unit SWD systems. However, the CMU low pressure transfer system has worked extremely well. Therefore, the following will apply only to the high pressure systems.

Piping: The piping system functions to transport excess produced water from the existing waterflood injection stations to the disposal wells. In all cases, a trunkline layout was less expensive than a radial layout. Consequently, trunkline systems were installed.

The piping used was Sch. 60 and Sch. 80, Grade B, internally plastic coated and was connected with a proprietary interference fit coupling. Additionally, ANSI 900# ring joint flanges were used at the tie-ins and valve locations.

Numerous corrosion caused failures have occurred in the high pressure piping. Two of these failures were caused when tightening of RTJ flange bolts caused the metal ring gasket to crack the internal plastic coating. We believe that the remaining failures were due to a set screw being loose in the machine used to hydraulically press the six inch diameter pipe into the six inch interference fit couplings. Our conclusion as to the cause of these failures is based on the failure locations, which were 18 inches from the couplings and concentrated in one area of the piping system. Also, the manufacturer had one of the failures analyzed and found a partial imprint of the set screw.

Since these original SWD systems were installed, new, tougher coatings and new internal pipe liners have become available. Future high pressure SWD system design evaluations will consider these new products. Additionally, ANSI 900# or 1500# raised face flanges, instead of the RTJ flanges, should be used for internally plastic coated systems.

As with the CO_2 injection system flanged connections, the SWD system flanged connections were buried and have been found to leak. In several of the units, the valves have been excavated and raised above ground level. Future systems will be designed with above ground valves and flanged connections.

The valves used in the SWD system were remanufactured, carbon steel, trunnion mounted ball valves with 316 SS trim. The remanufactured valves were used due to the lack of availability of new valves at the time the systems were designed and constructed. Many of these valves were found to have improper trim components and undersized gear reducers. As a result, many of them were sent back to the supplier for repairs. Most of the reported problems are associated with the failure of the valves to produce a positive seal when closed. Other problems with the valves, such as gear reducers breaking, grease fittings breaking, and lubrication line leaks, have also been reported.

It is recommended that reconditioned valves not be purchased for critical service projects. Inspecting reconditioned valves, such as these, before purchase is not of appreciable benefit unless the inspection is performed by an original manufacturer's representative who knows the acceptable tolerances and other performance and manufacturing criteria of the valves.

System Operations: Two major design changes have been instituted on the three high pressure disposal systems. The first, which applied to all three systems, is a new method of maintaining suction tank levels at the water injection stations (see Figure No. 9). The original design incorporated the use of a low tank level switch with a SWD control valve which regulated the volume of water pumped from the water station header to the SWD system. When the low level switch was activated, the SWD control valve would close. By regulating the volume of water transferred to the SWD system, this valve also controlled the injection header pressure. When this valve closed, as a result of low suction tank level, it caused the water injection pump bypass valves to open (in order to maintain the set header pressure) and to circulate water back to the suction tanks. This design did function, but the header pressure fluctuated, because the movement of the bypass valves from the closed to the open position was appreciably slower than the movement of the SWD system control valve from the open to the closed position. As a result, it was decided that the SWD system control valve should only control header pressure and not tank level. A bypass loop from the SWD line back to the suction tanks was installed downstream of the control valve, which, in this location, would not affect the header pressure. An actuated ball valve, which would open when the low level switch was energized, was installed on this throwback line. With this new design, the suction tanks can be filled using the water in the disposal system when required.

The second operational change, which was not part of the initial design, is that the SEU and Frazier Units' SWD Systems have been modified to dispose water at low pressure (150 psi). The modifications included the installation of at least one centrifugal pump at each water injection station, new taps into the SWD system, and a high level switch (located on the suction tanks) which activates the pumps.

This option of water disposal at low pressure was not a part of the original design, since wellhead pressures of the disposal wells in the SEU and Frazier Units were expected to be about 1600 psi for peak disposal rates. However, due to a more phased implementation schedule, the actual SWD rates and pressures required are somewhat lower than the original design criteria.

The result of disposing at low pressure, rather than at high pressure, is that significantly less electrical horsepower is required. Additionally, it is a safer system to operate. Future high pressure saltwater disposal systems which are connected to the water injection stations will be designed to operate on low pressure when it is possible.

Conclusion

In conclusion, no insurmountable operational problems or equipment failures have occurred in the four CO_2 projects since the commencement of CO_2 injection in late 1984. Problems have been encountered, but none which could not be addressed quickly with prompt, cooperative engineering and operations efforts. Furthermore, design modifications and recommendations have been implemented that will help reduce future problems.

Overall, the original designs have worked exceptionally well. This is due to the excellent coordination and communication that has existed between all offices and groups involved during the initial design stages, construction phases, and operational stages of the CO_2 floods.

Acknowledgements

I am grateful to Amoco Production Company management for allowing me to be involved in the original design, implementation, and operation of the West Texas CO_2 Floods and for permission to publish this paper. Additionally, many thanks to all of the engineers involved in the original design and implementation of the CO_2 floods.

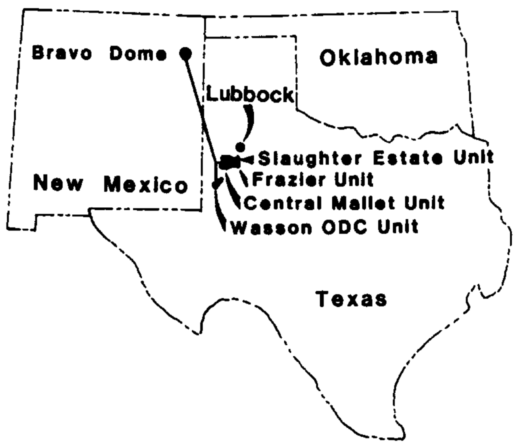

Figure 1 - Amoco's CO_2 projects

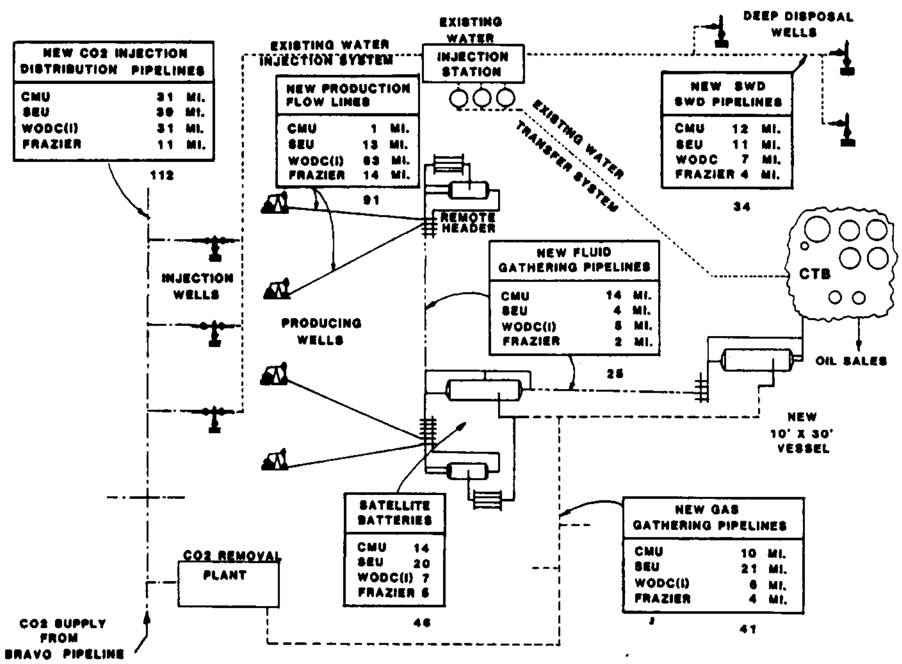

Figure 2 - Amoco's CO_2 projects

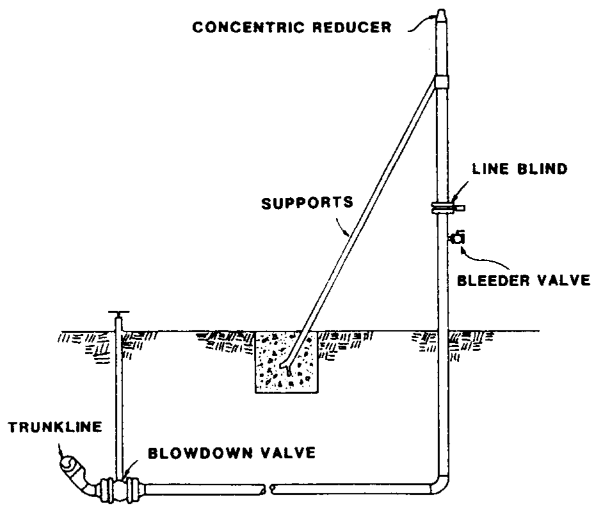

Figure 3 - CO_2 trunkline blowdown station

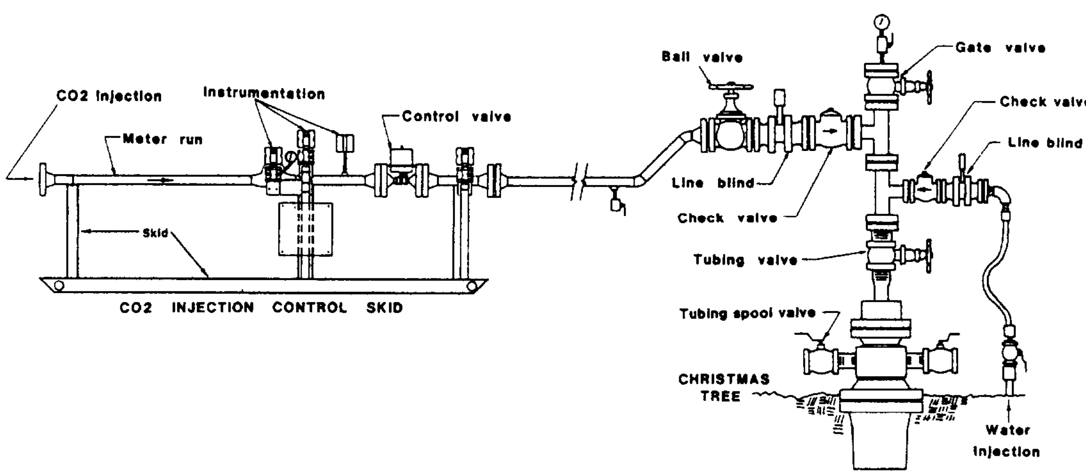

Figure 4 - CO_2 injection wellhead

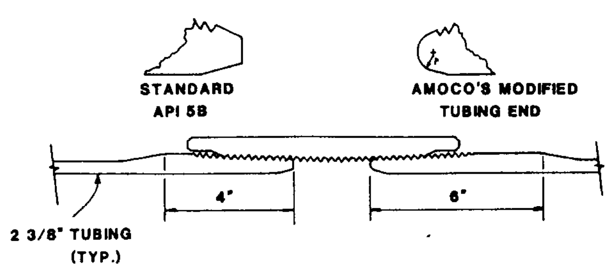

Figure 5 - Modified API tubing ends

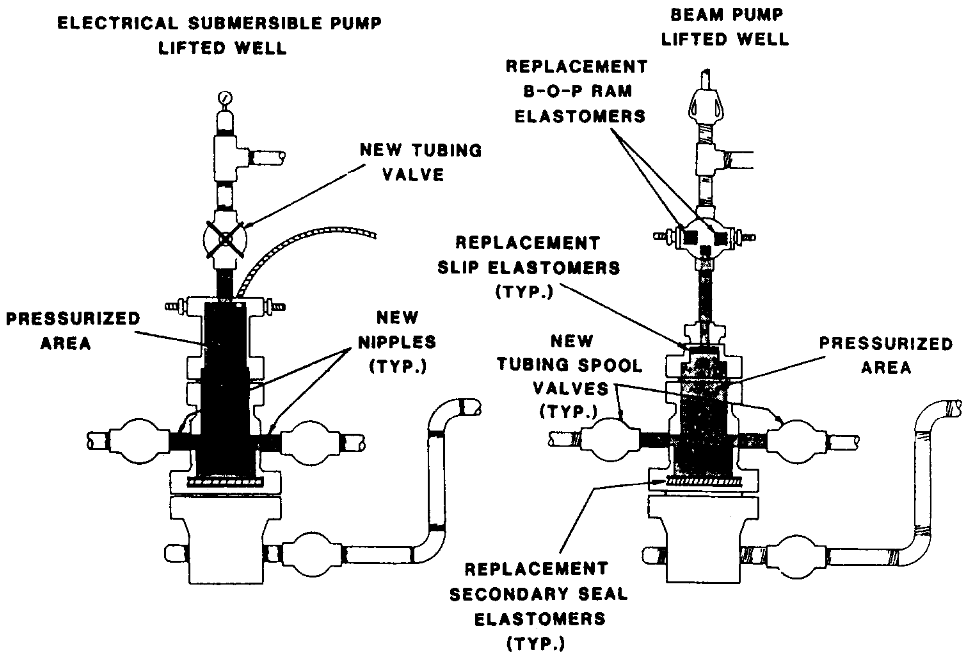

Figure 6 - CO_2 production wellhead modifications

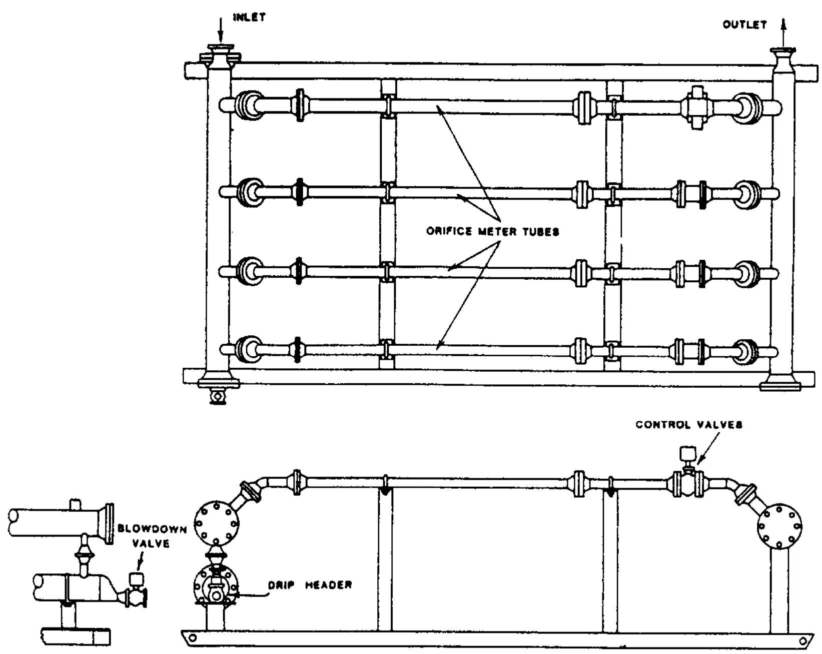

Figure 7 - Gas measurement skid

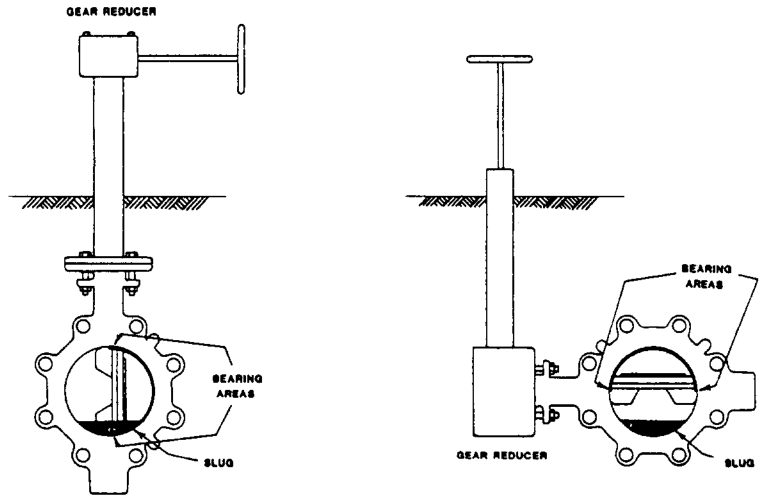

Figure 8 - Buried valve installations

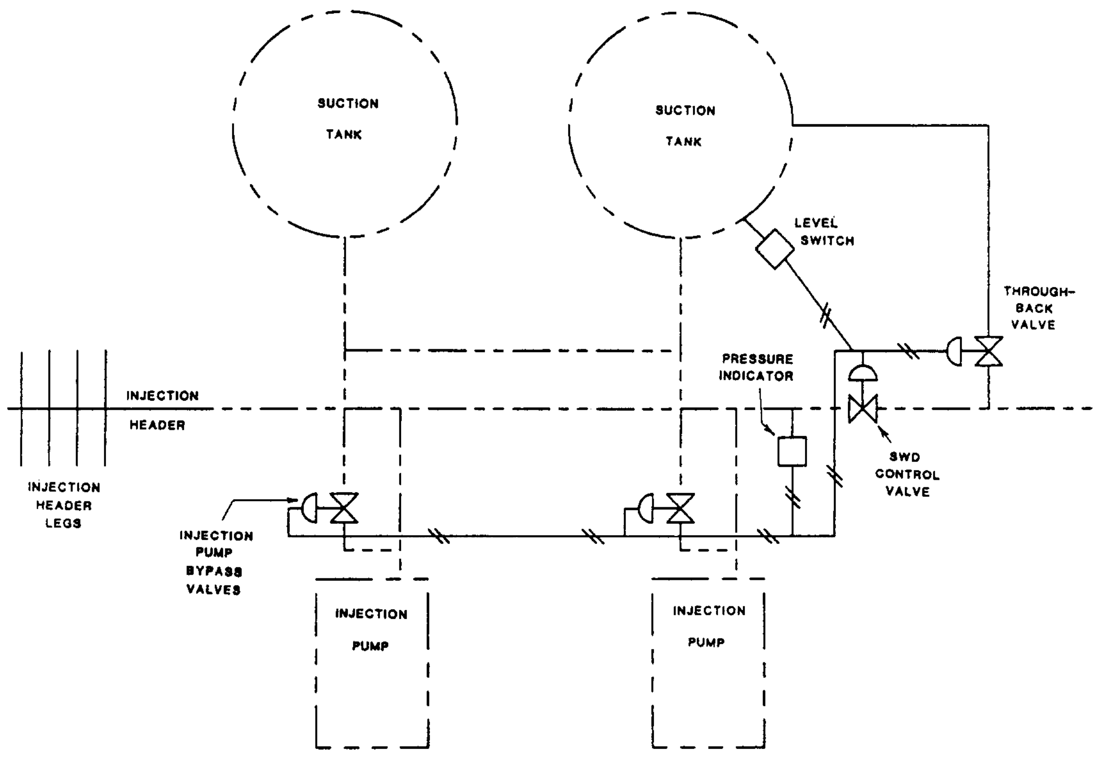

Figure 9 - SWD system control schematic