

BACKGROUND REPORT

**Summary of Carbon Dioxide
Enhanced Oil Recovery (CO₂EOR)
Injection Well Technology**

Supporting Information Provided by

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Nomenclature

BCF	-	billion (10^9) cubic feet of gas at standard conditions
BCFD	-	billion cubic feet of gas at standard conditions per day
bbl	-	barrel
BOPD	-	barrels of oil per day
°C	-	temperature, Celsius
CaCO ₃	-	calcium carbonate
Ca(HCO ₃) ₂	-	calcium bicarbonate
Ca(OH) ₂	-	calcium hydroxide
CO ₂ EOR	-	carbon dioxide enhanced oil recovery
CCS	-	carbon capture and storage
CO ₂	-	carbon dioxide, chemical symbol
CO ₂ EOR	-	carbon dioxide enhanced oil recovery
CRA	-	corrosion resistant alloy
CSH	-	calcium silicate hydrate
EOR	-	Enhanced oil recovery
GMT	-	giga (10^9) metric tons
HCO ₃ ⁻	-	bicarbonate ion
H ₂ CO ₃	-	carbonic acid
H ₂ S	-	hydrogen sulfide
HCl	-	hydrochloric acid
HCPV	-	hydrocarbon pore volume
MCF	-	thousand (10^3) cubic feet of gas at standard conditions
MMCF	-	million (10^6) cubic feet of gas at standard conditions
MMCFD	-	million cubic feet of gas at standard conditions per day
MMP	-	minimum miscibility pressure
MW	-	electric power, mega watt
MT	-	million (10^6) metric tons
OOIP	-	original oil in place
ppm	-	part per million
psia	-	pressure, pounds per square inch absolute
psig	-	pressure, pounds per square inch gauge
PV	-	pore volume
SO ₄ ⁻²	-	sulfate ion
STB	-	oil, stock tank barrel
°F	-	temperature, Fahrenheit
TCF	-	trillion (10^{12}) cubic feet of gas at standard conditions
TCFD	-	trillion cubic feet of gas at standard conditions per day
WAG	-	water alternating gas

Standard Conditions:

Pressure	14.7 psia
Temperature	60°F

Executive Summary

The purpose of this report is to identify the technologies and operating practices that have been developed by the oil and gas industry for injecting carbon dioxide (CO₂) for enhanced oil recovery (EOR). These technologies and practices have been developed specifically for use in CO₂ EOR; however, due to anticipated similarities in operating conditions, it is thought that the oil and gas industry's experiences and learnings may be of value in considering the injection of carbon dioxide for the purpose of geologic storage.

Capture and geologic storage of carbon dioxide (carbon capture and storage or CCS) is seen as a potentially viable near term approach for mitigating global carbon emissions provided significant legal, regulatory, and technical obstacles are addressed. Geologic storage involves injection of CO₂ into underground formations. Once placed there, the expectation is that the CO₂ will stay there indefinitely, thus removing it from the atmosphere.

Geologic storage on the scale that is thought to be necessary will require huge new investments in equipment and infrastructure. Some estimates suggest that the amount of infrastructure necessary to perform geologic storage on a meaningful level is equivalent to the existing worldwide infrastructure associated with current oil and gas production. This includes gas treatment facilities for CO₂ capture, pipelines and compression equipment for transportation, and more compression equipment, distribution lines, flowlines and wells for injection. Because of the magnitude of investment that may be made, it is also vitally important that any legal and regulatory infrastructure that is developed encourage safe, efficient, and environmentally sound geologic storage projects that balance costs and benefits.

The oil and gas industry has over 35 years of continuously developing experience in transporting and injecting CO₂ for enhanced oil recovery (EOR). While constantly evolving, the technology operating experience, and regulatory requirements that have been developed for EOR are extensive. In the United States alone, the oil and gas industry operates over 13,000 CO₂ EOR wells, over 3,500 miles of high pressure CO₂ pipelines, has injected over 600 million tons of CO₂ (11 trillion standard cubic feet) and produces about 245,000 barrels of oil per day from CO₂ EOR projects.

Clearly, the technology and operational practices used by the oil and gas industry in handling and injecting CO₂ can be considered a valuable resource in planning CCS projects. Among the numerous technological and engineering advances made over the past 35 years in CO₂ injection well design include:

- Corrosion resistant materials such as stainless and alloy steels (316 SS, nickel, Monel, CRA, etc.) for piping and metal component trim,

- Swell resistant elastomer materials such as Buna-N and Nitrile rubbers for downhole packers, and Teflon (PTFE) and Nylon for seals,
- Fiberglass lined (GRE) and internally plastic coated pipe (IPC) (phenolics, epoxies, urethanes and novolacs) tubing strings to retard corrosion,
- Acid resistant cements containing latex, pozzolan, alumina and other additives,
- Automatic control systems that not only regulate flows but also provide real-time monitoring capable of initiating well shutdowns should an unsafe condition be detected.

A summary of the materials of construction (MOC) commonly used for individual CO₂ injection well components is presented below:

Materials of Construction (MOC) for CO₂ Injection Wells

<u>Component</u>	<u>MOC</u>
Upstream Metering & Piping Runs	316 SS, Fiberglass
Christmas Tree (Trim)	316 SS, Nickel, Monel
Valve Packing and Seals	Teflon, Nylon
Wellhead (Trim)	316 SS, Nickel, Monel
Tubing Hanger	316 SS, Incoloy,
Tubing	GRE lined carbon steel, IPC carbon steel, CRA
Tubing Joint Seals	Seal ring (GRE), Coated threads and collars (IPC)
ON/OFF Tool, Profile Nipple	Nickel plated wetted parts, 316 SS
Packers	Internally coated hardened rubber of 80-90 durometer strength (Buna-N), Nickel plated wetted parts
Cements and Cement Additives	API cements and/or acid resistant specialty cements and additives in Appendix 2

Complementing the foregoing hardware innovations has been the development of operational and safety practices, including:

- Use of corrosion protection of the casing strings via impressed and passive currents and chemically inhibited (oxygen, biocide, corrosion inhibitor) fluid in the casing-tubing annulus,
- Use of special procedures for handling and installing the production tubing to provide gas tight seals between adjacent tubing joints and eliminate coating or liner damage,
- Use of tubing and casing leak detection methods and repair techniques, using both resin and cement squeeze technologies as well as insertion of fiberglass and steel liners,
- Formulation and implementation of criteria unique to siting wells in or near populated areas incorporating: fencing, monitoring and atmospheric dispersion monitoring elements to protect public safety.

Current industry experience shows that when these technologies and practices are used, EOR operators can expect wellbore integrity at levels equivalent to those seen for conventional oil and gas wells. Additionally, there are no indications from available information that geologic integrity of the receiving formations are at risk. Core samples recovered in 2002 from a 52 year old CO₂ injection well after 30 years of exposure to CO₂ flood conditions verify that near geologic (reservoir cap-rock) and cement sealing integrity has been maintained⁴⁸.

This report provides: an overview of CO₂ EOR operations, discusses technologies and operational practices mentioned above and identifies several key differences between CO₂ EOR operations and potential CO₂ CCS operations. The information offered in this report is presented with the intent of illustrating the types of technology and operational practices that have been developed for CO₂ EOR projects, which may be adaptable to CCS projects. The information offered here illustrates technologies and practices in use by the oil and gas industry for CO₂ EOR; however each project, whether EOR or CCS, should be designed to meet the site specific conditions applicable to that project.

The current state of CO₂ injection technology can best be summarized by the conclusions reached by MIT (Massachusetts Institute of Technology) in their, Environmental Assessment of Geological Storage of CO₂¹, namely that:

“The technologies and practices associated with geological CO₂ sequestration are all in current commercial operation, and have been so for a decade to several decades. Such commercial operations include: enhanced oil recovery, acid gas (CO₂) injection, natural gas storage and CO₂ pipeline transportation. No major “breakthrough” technological innovations appear to be required for large scale CO₂ transportation and storage.”

There are however, significant policy, legal and regulatory challenges that must be resolved before CCS is widely implemented. Those topics are well beyond the scope of this report.

History and Current Status of CO₂ in EOR Applications

1.a Development

During the life of a producing oil field, several production stages are encountered. Initially, when a field is brought into production, oil flows naturally to the surface due to existing reservoir pressure in the primary phase. As reservoir pressure drops, water is typically injected to boost the pressure to displace the oil in the secondary phase. Lastly, the remaining oil can be recovered by a variety of means such as CO₂ injection, natural gas miscible injection, and steam recovery in the final tertiary or enhanced oil recovery (EOR) phase.

Depending on the geological specifics, oil recovery estimates for each phase, when miscible CO₂ EOR is used as the tertiary phase, are as follows:

Table 1
Oil Recoveries by Recovery Mechanism as a Function of Original Oil in Place (OOIP) ²

<u>Mechanism</u>	<u>OOIP Recovery (%)</u>
Primary	6-15
Secondary	6-30
Miscible CO ₂ EOR	8-20
Remaining	80-35

Oil that is left behind after waterflooding is there because: either it has not been contacted by the injected fluid, or because of the capillary forces that exist between oil, water and the porous rock in the contacted portions that trap and retain it.

To capture this residual oil, the petroleum industry has devoted billions of dollars for research and development to develop enhanced oil recovery (EOR) technologies. One of the most promising technologies developed was that based on the use of CO₂ which, at high pressure and reservoir temperature, mixes with the oil to form a low viscosity, low surface tension fluid that can be more easily displaced. Additionally, CO₂ has the capability of invading zones not previously invaded by water, as well as releasing and reducing trapped oil ³. The first patent for CO₂ EOR technology was granted to Whorton, Brownscombe, and Dyes of the Atlantic Refining Company ⁴ in 1952.

In 1964, a field test was conducted at the Mead Strawn Field, which involved the injection of a large slug of CO₂ (25% of the hydrocarbon pore volume or HCPV) followed by carbonated water at reservoir conditions. Results indicated that 53 to 82 percent more oil was produced by the CO₂ flood than was produced by water in the best areas of the waterflood ^{5, 6}. Following this success, laboratory and pilot tests continued.

1.b SACROC and Fields

In January 1972, the first commercial CO₂ EOR injection project was initiated at SACROC (Scurry Area Canyon Reef Operators Committee) Unit of the Kelly-Snyder Field in Scurry County, West Texas and remains today the world's largest miscible flooding project⁷. Initially, 220 MMCFD of CO₂ was supplied from the Val Verde Gas Plant, where it is removed from gas generated during ammonia production and shipped via the Canyon Reef Carriers (CRC) System for injection at 2350 psig⁸. Current CO₂ supply sources include Bravo Dome in Colorado and McElmo Dome in New Mexico⁹. Numerous field developments and facility expansions have occurred over the last 3 decades, resulting in a current field gas handling capacity in excess of 0.60 BCFD. The field currently produces 29,300 of enhanced oil production per day¹⁰. To date, CO₂ injection has resulted in an incremental oil recovery of about 10% of the HCPV¹¹.

Since the initial SACROC commercial development, the number of CO₂ EOR projects has continued to grow steadily as illustrated by the oil production data in Figure 1 (page 4). The data in Table 2 provide an in-depth picture of a number of large miscible CO₂ projects in the United States in terms of geological, fluid and production parameters. Geographically, the data in Figure 2 represent the distribution of current CO₂ sources and EOR projects¹² throughout the continental U.S. On a daily basis, 2.14 BCF of CO₂ are injected and 245,000 of barrels of oil are produced via CO₂ EOR processes.

Table 2
Large Carbon Dioxide Miscible Projects in the U.S.¹⁰

Field	State	Start Date	Lithology	Depth (ft)	Oil API	Oil Production (B/D)		Injection Wells
						Total	Enhanced	
SACROC Unit	TX	January 1972	Limestone	6,700	39	31,200	29,300	414
Wasson (Denver Unit)	TX	April 1983	Dolomite	5,200	33	34,500	28,990	537
Seminole (Main Pay)	TX	July 1983	Dolomite	5,300	35	23,500	22,700	160
Rangely	CO	October 1986	Sandstone	6,000	35	15,300	11,600	262
Means (San Andres)	TX	November 1983	Dolomite	4,300	29	10,000	8,700	284
Wasson (ODC Unit)	TX	November 1984	D/L	5,100	34	9,230	8,440	165
North Hobbs	NM	March 2003	Dolomite	4,200	35	11,100	6,800	41
Salt Creek	TX	October 1986	Limestone	6,300	39	9,200	6,800	130
West Mallalieu	MS	1986	Sandstone	10,550	40	6,500	6,500	27
Anton Irish	TX	April 1997	Dolomite	5,800	28	5,850	5,400	75
Vacuum	NM	February 1981	Dolomite	4,500	38	6,200	5,200	103
Cogdell	TX	October 2001	Limestone	6,800	40	5,450	5,010	37
Postle	OK	November 1995	Sandstone	6,200	36	5,000	5,000	100
Slaughter Sundown	TX	January 1994	Dolomite	4,950	33	5,950	4,747	144
Lost Soldier	WY	May 1989	Sandstone	5,000	35	4,672	4,545	39
Wasson (Willard)	TX	January 1986	Dolomite	5,100	32	4,800	4,050	203
Salt Creek	WY	January 2004	Sandstone	1,900	37	3,900	3,900	83

Figure 1
U.S. Oil Production from CO₂ EOR Projects by Year¹⁰

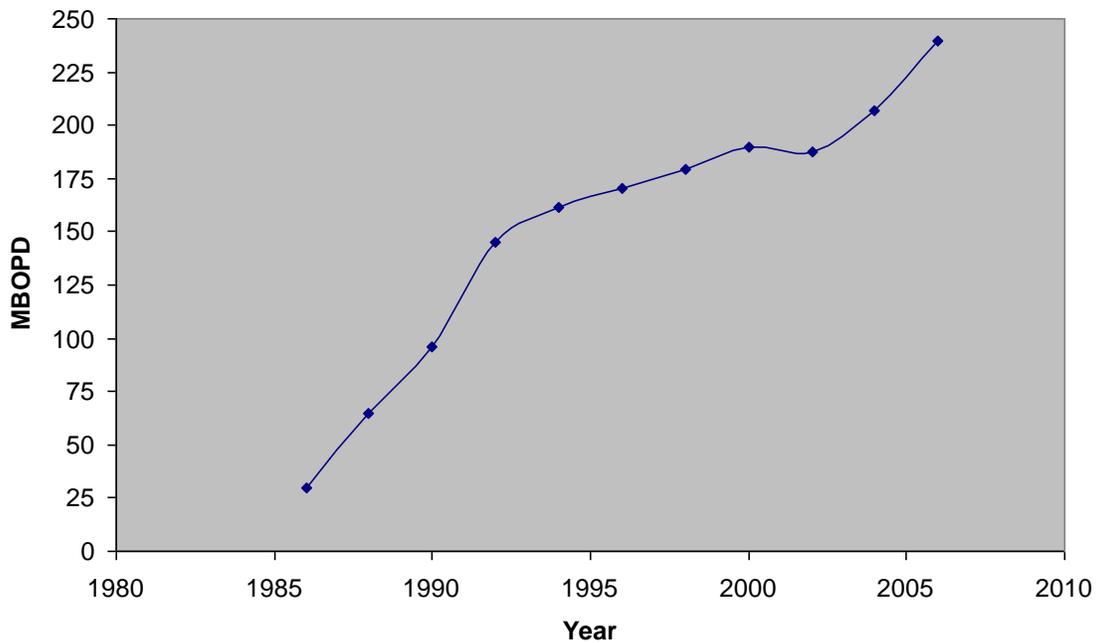


Figure 2
Carbon Dioxide Supply / EOR Production¹²

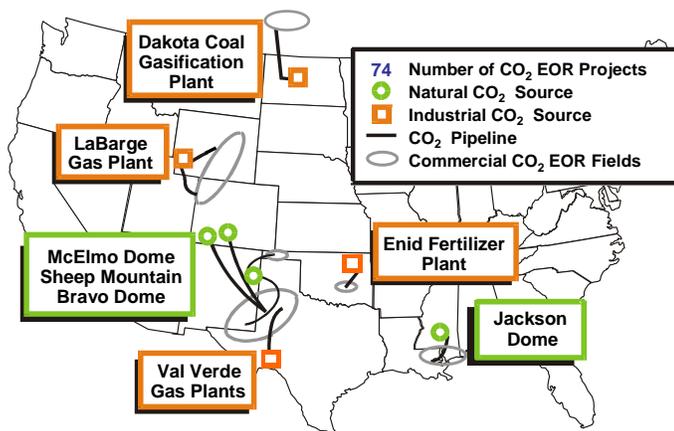


Table 3
CO₂ Injection Volumes and Associated Oil Production in the U.S. ¹³

<u>Source</u>	<u>CO₂ Injected</u> <u>BCFD</u>	<u>Oil Production</u> <u>BOPD</u>
Shute Creek Gas Plant	0.23	30,000
Permian (25 Industrial)	1.45	200,000
McElmo Dome (1.05)		
Sheep Mountain (0.04)		
Bravo Dome (0.30)		
Val Verde Gas Plant (0.06)		
Enid Fertilizer Plant	0.04	2,500
Jackson Dome (90 Industrial)	<u>0.42</u>	<u>12,500</u>
Total	2.14	245,000

Note:

0.044 GMT of CO₂ injected and 90 million barrels of oil produced per year

1.c Pipelines and Wells

More than 3,500 miles of high-pressure CO₂ pipelines have been constructed in the United States ¹⁴ to link remotely located, naturally occurring CO₂ sources¹⁵, such as those presented in Table 2, to oil fields in the Western United States (Figure 2). Additionally, in Texas alone, 9,419 CO₂ disposal and injection wells have been drilled and completed, as shown below, with the vast majority of these in the Permian Basin (Texas Railroad Commission Districts 8 and 8A).

Table 4
Number of CO₂ Disposal and Injection Wells
Permitted in Texas by District ¹⁶

<u>District</u>	Disposal Production Zone Secondary Recovery	
	<u>Type 2</u>	<u>Type 3</u>
1	0	1
3	4	29
4	1	5
5	0	0
6	0	1
7B	0	12
7C	0	5
8	122	2,846
8A	430	5,928
9	0	9
<u>10</u>	<u>16</u>	<u>10</u>
Total	573	8,846

1.d Summary

Since January 1972, when the world's first commercial CO₂ EOR project commenced operation in the SACROC Unit, the American oil and gas industry has:

- Drilled and completed 8,846 CO₂ injection wells in Texas alone, in multiple lithologies,
- Drilled and completed 573 CO₂ disposal wells in Texas alone, in multiple lithologies,
- Recently re-completed over 4,500 total wells for the Salt Creek, Wyoming CO₂ EOR flood, over half of which dated from the 1920's and approximately fifty percent were plugged and abandoned,
- Cumulatively injected over 10.8 TCF (0.6 GMT) into oil and gas reservoirs,
- Built over 3,500 miles of high-pressure interstate CO₂ pipelines, and,
- Spent billions of dollars for research and development to address the technical, engineering and safety issues related to CO₂ production, transport, injection and containment in naturally occurring geological formations.

Today, the petroleum industry:

- Operates CO₂ EOR projects in 74 fields and produces 245,000 barrels of incremental oil a day (BOPD); about 5% of total US production, and,
- Injects over 2.14 BCF of CO₂ per day.

This body of experience and success establishes that the oil and gas Industry has developed CO₂ handling, transportation and injection practices and technologies that should be considered when planning new CCS projects. These accomplishments reflect the underlying principle that durable, reliable and safe technology results in the most prudent stewardship of resources from both an economic and environmental point of view.

CO₂ EOR Technical Aspects

The oil and gas industry has invested billions of dollars on research and development of the CO₂ EOR process, which continues today. In the section below, a brief summary of the physics of the process, as currently understood, is presented. Additional information can be found in the numerous Society of Petroleum Engineers (SPE) technical papers that have been published over the past 50 years and precise summaries of which are presented in the monographs, Practical Aspects of CO₂ Flooding – Monograph Volume 22¹⁷ and CO₂ Flooding Report No. 51¹⁸.

2.a Miscibility

From a fundamental point of view, CO₂ EOR works on a very simple principle, namely, that given the right physical conditions, CO₂ will mix miscibly with oil, acting much like a thinning agent, much the same way that gasoline does with motor oil. After miscible mixing, the fluid is displaced by a chase phase, typically water.

In more scientific terminology, Holm¹⁹ describes miscibility as: “the ability of two or more substances to form a single homogeneous phase when mixed in all proportions. For petroleum reservoirs, miscibility is defined as that physical condition between two or more fluids that will permit them to mix in all proportions without the existence of an interface. If two fluid phases form after some amount of one fluid is added to others, the fluids are considered immiscible.”

Technically, the critical consideration is that in miscible displacements the residual oil saturation, that is, the oil left after being miscibly contacted with CO₂, is reduced nearly to zero. This leads to high oil recoveries and favorable project economics. This is in distinction to immiscible displacements where considerable residual oil saturations can remain, often leading to unfavorable project economics.

Flooding a reservoir with CO₂ can occur either miscibly or immiscibly. Miscible CO₂ displacement is only achieved under a specific combination of conditions, which are set by four variables: reservoir temperature, reservoir pressure, injected gas composition, and oil chemical composition²⁰. The test to determine whether a miscible or immiscible CO₂ displacement is described below.

2.b Minimum Miscibility Pressure (MMP)

“The most common method used to determine the conditions at which miscible displacement is achieved is known as a slim tube experiment. A long (40-80 ft), small diameter (1/4 in), high-pressure tube is packed with clean sand (or glass beads) to achieve a fluid permeability of 3 to 5 Darcies. It is then saturated with the reservoir oil of interest and the apparatus is maintained at

reservoir temperature. A series of floods are conducted at different pressures, while the exact composition of the displacing CO₂, (it may be either highly purified, >96% CO₂, or mixed with other hydrocarbon gases such as methane CH₄, ethane C₂H₆, propane C₃H₈, etc.), is injected. A correlation between oil recovery versus pressure is developed. Miscible displacement is achieved at the flooding pressure or minimum miscibility pressure (MMP) where about 95% of the oil in the tube is recovered after about 1.3 pore volumes of fluid have been injected. Below this pressure, oil recovery decreases dramatically¹⁹.”

2.c Reservoir Implications

2.c.1 Pressure

Geologically, reservoirs are physically huge in volume, well insulated from surface fluctuations in temperature and thus exhibit a constant temperature dictated by the local geothermal temperature gradient, nominally on the order of 1.5°F/100ft of depth²¹, with some variation locale to locale.

Reservoir pressure, on the other hand, is directly influenced by reservoir recovery practices. When hydrocarbons are withdrawn from a reservoir, its pressure declines. Depending on the results of the slim tube experiments described above, it is possible that reservoir pressure may be found to be below the MMP. If so, CO₂ can still be injected, but the efficiency of the recovery process is adversely impacted. Typically, this does not occur since, after primary depletion, water flooding operations commence which restore reservoir pressure to values above the MMP.

2.c.2 CO₂ Mobility and Reservoir Heterogeneity

In a CO₂ EOR flood, a variety of factors will influence process performance.

Because the viscosity of CO₂ at reservoir conditions is much lower than that of most oils, viscous instability will limit the sweep efficiency of the displacement and, therefore, oil recovery²². In addition, reservoir rock is extremely heterogeneous, exhibiting zones of high permeability in close proximity to those of low permeability. These permeability differences may be innate, that is caused by differences in pore structure at the time of geological deposition, or a product of fractures, natural or man-made.

Reservoir heterogeneity and the adverse effects of CO₂ viscosity must be contended with to optimize oil recovery. Two basic strategies have been developed by the petroleum industry to cope with these conditions, namely:

1. Alternately inject cycles of CO₂ and water in the so called WAG (water alternating gas)^{23, 24, 25}, process. This technique forms sequential banks of fluids in the reservoir rock: oil, CO₂ and water, that migrate from the injection to the production wells.

2. Add chemical agents, such as: ethoxylated and/or unethoxylated species, fluoroacrylate-styrene copolymers, lignosulfonates, etc, to CO₂ to form stable foams that increase its viscosity without compromising its efficacy
26, 27, 28, 29

These stiffened foams facilitate formation of oil and CO₂ banks, which migrate from injector to producer while suppressing adverse hydrodynamic instabilities, such as fingering, which lead to vertical fluid stratification and reduced oil recovery

In some form, WAG operation occurs in all CO₂ EOR floods, while field economics and reservoir heterogeneity dictate whether viscosifiers will be used.

2.c.3 CO₂ EOR Screening Criteria

As a result of the years of experience in CO₂ EOR laboratory, field pilot and full scale commercial operations, sufficient data has been obtained from which to develop technical screening criteria for potential CO₂ flood candidates. The results of these efforts, presented in Table 5 (below), were developed by Taber, Martin, and Seright of the New Mexico Petroleum Recovery Research Institute^{30, 31}. While not exclusive, the criteria provide an excellent framework with which to assess CO₂ EOR viability for a new field candidate.

Table 5
Technical Screening Guidelines for CO₂ Flooding³¹

	<u>Recommended</u>	<u>Current Projects Range</u>
Crude Oil		
Gravity, °API	>22	27 to 44
Viscosity, cp	<10	0.3 to 6
Composition	High percentage of intermediates (C ₅ to C ₁₂)	
Reservoir		
Oil Saturation	>40	15 to 70
Type of Formation	Relatively thin sandstone or carbonate unless dipping	
Permeability	Not critical if sufficient rates can be applied	
Depth/Temperature	For miscible displacement, depth must be great enough to allow injection pressures greater than the MMP, which increase with temperature and for heavier oils. Recommend depths of CO ₂ floods of typical Permian Basin oils is as follows:	
	<u>Gravity, °API</u>	<u>Depth Greater Than (ft)</u>
CO ₂ miscible	>40	2,500
	32 to 39.3	2,800
	28 to 31.9	3,300
	22 to 27.9	4,000
	<22	Fails CO ₂ Screening
CO ₂ immiscible	13 to 21.9	1,800
	<13	Fails CO ₂ Screening

2.c.4 CO₂ Utilization

For the first 10 years of field operation, CO₂ purchases are the single largest expense in CO₂ EOR floods, representing as much as 68% of total costs¹⁷. As such, optimal use of CO₂ resources is required to assure profitability.

For field scale miscible CO₂ EOR floods, projected incremental recoveries range from 7 to 23% of the original oil in place (OOIP) and the net (purchased) amount of CO₂ required is estimated to be between 2.5 to 11 MCF/STB of incremental recovery with an average value of 6 to 7 MCF/STB³².

From the data available on immiscible floods, actual incremental oil recovery has been on the order of 9 to 19% of the original oil in place with net CO₂ requirements of 5 to 12 MCF/STB³³.

Because of the inherently higher utilization efficiency of CO₂ in miscible systems, virtually all worldwide CO₂ EOR projects are miscible in nature. In the U.S., enhanced oil production from miscible CO₂ floods is reported to be on the order of 245,000 BOPD, while enhanced oil production from immiscible floods is reported to be on the order of 2,700 BOPD¹⁰.

Well Design and Mechanical Integrity

3.a Design Standards and Recommended Practices

Oil and gas wells have existed for almost 150 years, since the time of Drake's first efforts in Pennsylvania in 1859. As well technology has evolved over the decades, trade and professional organizations such as the American Petroleum Institute (API), the American Society of Mechanical Engineers (ASME), the National Association of Corrosion Engineers (NACE), and others, have and continue to evaluate and catalogue the technical requirements and associated best design and operational practices into formal engineering standards and recommended practices.

For well technology and field piping, the following documents are a sampling of those currently in use, on a day-to-day basis:

Table 6
API Specifications and Recommended Practices for
Well and Field Piping⁴⁰

Spec 5/CT ISO 11960	Specifications for Casing and Tubing
Bull 5C2	Performance Properties of Casing Tubing and Drill Pipe
Spec 5L	Specification for Line Pipe
Spec 5LD	CRA or Lined Steel Pipe
Spec 6A	Specifications for Wellhead and Christmas Tree Equipment
Spec 6D/ISO 14313	Specifications for Pipeline Valves
Bull 6J	Testing of Oilfield Elastomers
RP 10B-2 through 5	Testing Well Cements
Spec 10A/ISO 10426-1	Specifications for Cements and Materials for Well Cementing
TR 10TR1	Cement Sheath Evaluation
RP65 Part 1	Cementing Shallow Water Flows in Deep Water Wells
Spec 11D1/ISO 14310	Petroleum and Natural Gas Industries – Downhole Equipment – Packers and Bridge Plugs
Spec 15HR	High Pressure Fiberglass Line Pipe
Spec 15LR	Low Pressure Fiberglass Line Pipe
RP 15TL4	Care and Use of Fiberglass Tubulars
RP 90	Annular Casing Pressure Management for Offshore Wells

Supplementing these documents are those related to corrosion control (NACE), mechanical properties of materials (ASME), and the design experience of a vast cadre of professionals.

From a design point of view, a well is characterized as consisting of two basic elements, namely:

1. The wellbore, that is, the penetration into the earth consisting of casing, cement, and wellhead whose purpose is containment of reservoir pressure and isolation of groundwater resources from contamination, and,
2. The mechanical completion equipment consisting of valves, tubulars and packers used to inject fluids into or to produce fluids from a formation.

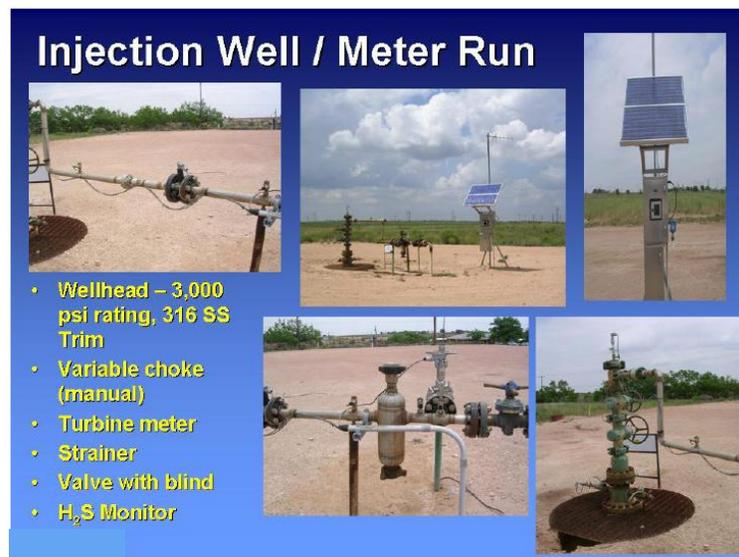
To assure clarity, precise definitions of the major physical elements that comprise the wellbore and mechanical completion of a CO₂ injection well are presented below.

3.b Definitions

1. *Upstream Metering and Piping Runs.* This section runs from the individual water and CO₂ field distribution systems to the well. It contains: control valves, pressure sensors, metering equipment, and both check and isolation valves and blinds. Depending on operator preference, separate CO₂ and water meter/piping runs may be used, each connecting individually to flanges on the Christmas tree, or the lines may be commoned and a single metering/piping run used with a single connection to the Christmas tree. Figure 4 illustrates a CO₂ injection well piping / meter run in use by a major West Texas CO₂ EOR operator which uses a single piping/metering run.
2. *Christmas Tree.* The assembly of valves, spools, pressure gauges and chokes fitted to the wellhead of a completed well to control production. Christmas trees are available in a wide range of sizes and configurations, such as low or high pressure capacity and single or multiple completion capacity⁴¹.
3. *Wellhead.* The surface termination of a wellbore that incorporates facilities for installing casing hangers during the well construction phase. The wellhead also incorporates a means of hanging the production (and injection) tubing and installing the Christmas tree and surface flow control facilities in preparation for the production phase of the well⁴¹.
4. *Casing.* Steel pipe cemented in place during the construction process to stabilize the wellbore. The casing forms a major structural component of the wellbore and serves several important functions: preventing the formation wall from caving into the wellbore, isolating the different formations to prevent the flow or crossflow of formation fluids, and providing a means of maintaining control of formation fluids and pressure as the well is drilled. The casing string provides a means of securing surface pressure control equipment and downhole production equipment, such as the drilling blowout preventer (BOP) or production packer. Casing is available in a range of sizes and material grades⁴¹.

5. *Tubing.*
 - a. Production. A **wellbore** tubular used to produce **reservoir** fluids. **Production** tubing is assembled with other **completion** components to make up the **production** string. The **production** tubing selected for any **completion** should be compatible with the **wellbore** geometry, **reservoir production** characteristics and the **reservoir** fluids ⁴¹.
 - b. Injection. A **wellbore** tubular used to inject fluid in the reservoir. **Injection** tubing is assembled with other **completion** components to make up the **injection** string. The **injection** tubing selected for any **completion** should be compatible with the **wellbore** geometry, **reservoir production** characteristics and the **reservoir** fluids ⁴¹.
6. *Liner.* Any string of **casing** in which the top does not extend to the surface but instead is suspended from inside the previous **casing** string. Many conventional well designs include a **production** liner set across the **reservoir** interval. This reduces the cost of completing the well and allows some flexibility in the design of the **completion** in the upper **wellbore**, such as when the fluid characteristics make it beneficial to increase the diameter of the conduit and components ⁴¹.
7. *Packer.* A downhole device used in almost every **completion** to isolate the **annulus** from the **production** conduit, enabling controlled **production**, injection or treatment. A typical packer assembly incorporates a means of securing the packer against the **casing** or **liner** wall, such as a **slip** arrangement, and a means of creating a reliable hydraulic **seal** to isolate the **annulus**, typically by means of an expandable elastomeric element. Packers are classified by application, setting method and retrievability ⁴¹.
8. *Kill a Well.* To stop a well from flowing or having the ability to flow into the **wellbore** ⁴¹.

Figure 4
Typical CO₂ Injection Well / Meter Run ⁹



Courtesy of Kinder Morgan ⁹

3.c CO₂ Injection Wellhead Conditions

When CO₂ is supplied by pipeline to EOR projects, it is of high purity (>95% by volume) and in a supercritical dense-phase state. A characteristic delivery composition would be one similar to that supplied from the Sheep Mountain Reservoir presented below:

Table 7
Sheep Mountain Reservoir CO₂ Composition and
Field Delivery Conditions⁴²

<u>Component</u>	<u>Volume %</u>
CO ₂	97.0
N ₂	0.6
CH ₄	1.7
CH ₄ ⁺	0.7
H ₂ O	Trace

Delivery Conditions at Plant Gate

Pressure	1400 psig
Temperature	<75 °F
Density	53 lbm/ft ³

At the wellhead, injected CO₂ is typically composed of a mixture of fresh pipeline supply and recycle from gas plant operations. Depending on the particular process used to recover CO₂ from plant operations, recycle composition can vary. Generally, the injected CO₂ content is in the range 92 to 97%.

For fields in the Permian Basin of West Texas, boost compression is used to raise the injection pressure to between 2,200 and 2,400 psig⁸ prior to distribution to an individual well via the gas distribution system. Injection rates vary well per well, depending on reservoir characteristics and EOR strategy. As an example, in the Slaughter Sundown Unit⁴³, 94 MMCFD of CO₂ is injected in 85 wells or 1.11 MMCFD per well.

In general, the pressure required to inject CO₂ at a given rate is a function of reservoir parameters, such as permeability and zone thickness and the bottom-hole pressure exerted by the column of CO₂ in the wellbore. Because water is denser than CO₂, water injection pressures on the order of 1,600 to 1,800 psig are common in the Permian Basin. When changing from CO₂ injection to water injection, a pressure differential needs to be overcome. To do so, the water supply header operates at a pressure in excess of the CO₂ supply header pressure. This allows water to be throttled into the well, its pressure declining to the appropriate value once the CO₂ is displaced from the wellbore.

3.d Wellbore

Depending upon circumstances, CO₂ EOR injection wells may be either drilled as new wells or, as is quite common in existing fields, re-completed by converting an existing producing well or a water injection well to a CO₂ injector.

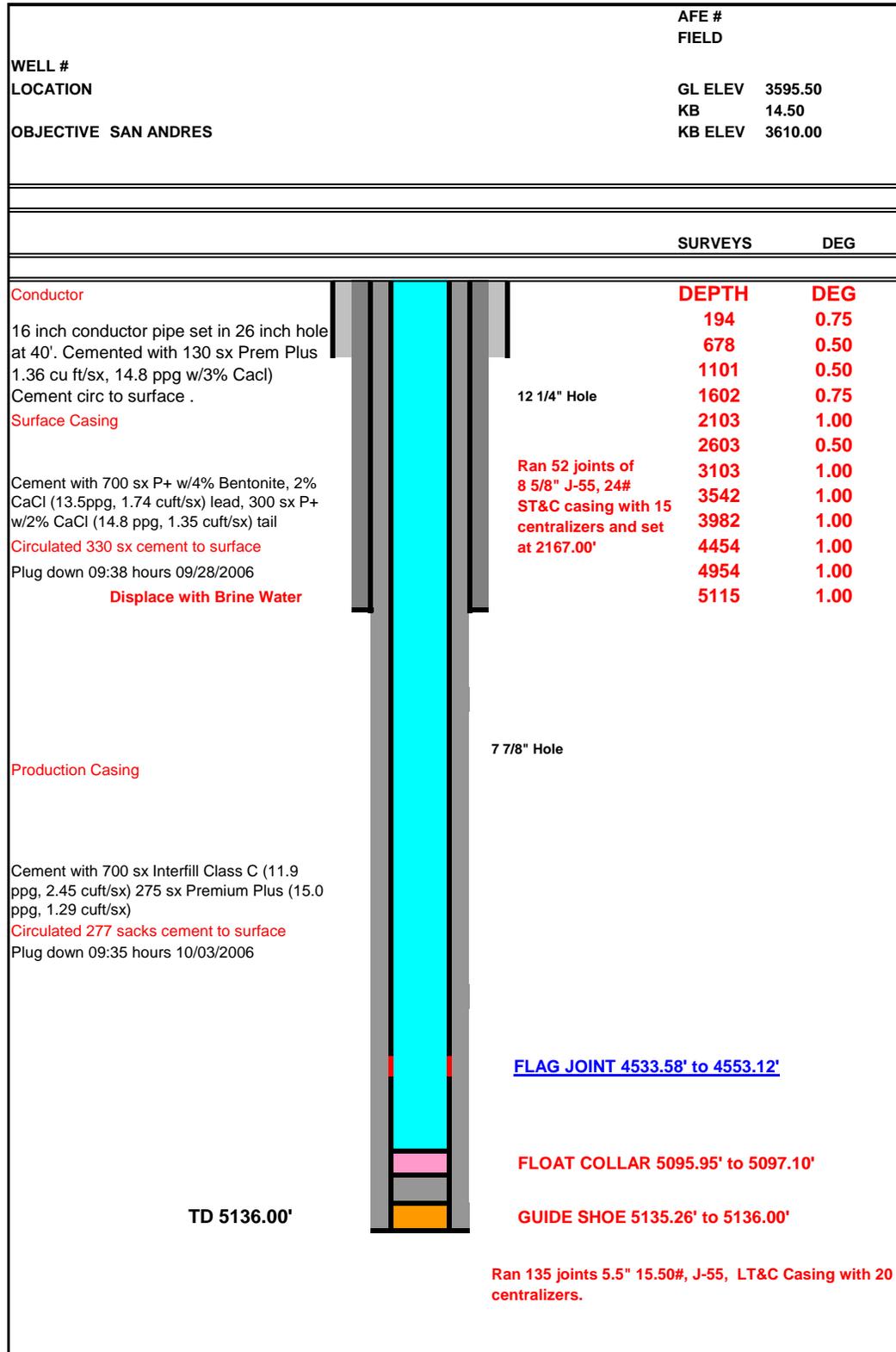
3.d.1 New Construction

3.d.1.1 Design

Typical wellbore designs for new wells are presented in Figures 5 and 6, (both from major CO₂ operators in the Permian Basin.) As expected, the well designs are similar in both cases, consisting of: surface casing and production casing. Multiple casing strings are used for a variety of reasons, the principle of which is isolation of groundwater resources from potential sources of contamination and maintaining the integrity of the wellbore from collapse.

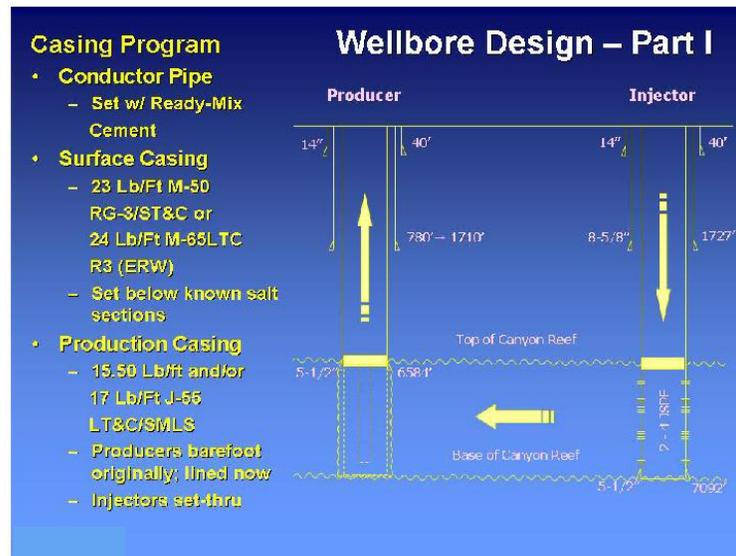
Mechanically, casing string specifications, that is their thickness and weight, are based on maximum potential burst and collapse pressures plus appropriate safety factors, which are a function of injection and production pressures, well depth, and reservoir conditions. For wells 10,000 ft or less in depth, carbon steel casing is typically used with J-55 and K-55 grades being common. In deep, high pressure, high-temperature environments, higher strength grades may be used and corrosion resistant alloys (CRA) are used in wells susceptible to H₂S and CO₂ attack⁴⁴.

**Figure 5
WELL BORE SKETCH**



Courtesy of a CO₂ operator in the Permian Basin

Figure 6
Typical Wellbore Design ⁹



Courtesy of Kinder Morgan ⁹

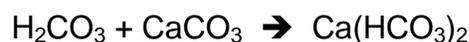
3.d.1.2 Cased-Hole and Open-Hole Completions

For new construction, almost all wells are cased-hole completions. In isolated cases, depending on reservoir conditions, open-hole completions are still used, but are rare ^{9, 36, 37}. Since cased-hole completions are amenable to a larger variety of profile management techniques (mechanical isolation, chemicals, squeeze cementing, etc.) than open-hole completions, they are the more common completion strategy.

3.d.1.3 Cement Technology

Cementing is critical to the mechanical performance and integrity of a wellbore both in terms of its method of placement and cement formulation used.

Chemically, the degradation of Portland based cements by carbonic acid (H_2CO_3) is well known and documented ^{45, 46}. The basic chemical mechanism is described below ⁴⁷:



In the foregoing reactions, calcium-silica-hydrate, C-S-H, compounds are major components in Portland cements, whereas free lime, $\text{Ca}(\text{OH})_2$ constitutes about 20% of the cement composition in set Portland cements.

Because CO_2 corrosion of cement is thermodynamically favored and cannot be entirely prevented, various solutions have been developed to limit CO_2 attack on the cement sheath. Most of these approaches involve substituting materials such as fly ash, silica fume or other non-affected filler or other cementitious materials for a portion of the Portland cement. The water ratio of the cement slurry is designed to be low to reduce the permeability of the set cement. The permeability of the set cement may be further lowered through the addition of materials such as latex (styrene butadiene) to the design

Recently, investigators⁴⁸ took samples from a 52 year old SACROC well with conventional, Portland-based well cement exposed to CO_2 for 30 years and found limited evidence of cement degradation. Preliminary evaluation suggests that the mixture of gelled and solid-particulate, (CO_2 and cement), reaction products sealed the cement permeability pore throats to significantly delay or prevent further CO_2 migration. While the evidence is limited, significant wellbore failure as indicated by over pressurization of over-lying formations and leakage to the surface has not been observed.

Non-Portland solutions, marketed as specialty cements, have not been widely used in CO_2 EOR applications, most likely due to the observed adequate performance of current formulations, as well as the higher cost and logistic issues associated with such systems. However, in some cases, these systems have been applied to resist very severe acid gas (CO_2 and H_2S) and highly corrosive geothermal brine exposure conditions, in place of conventional systems.

Descriptions of commonly used well cements, as well as specialty cements, are presented in Appendix 2.

3.d.1.4 Corrosion Control

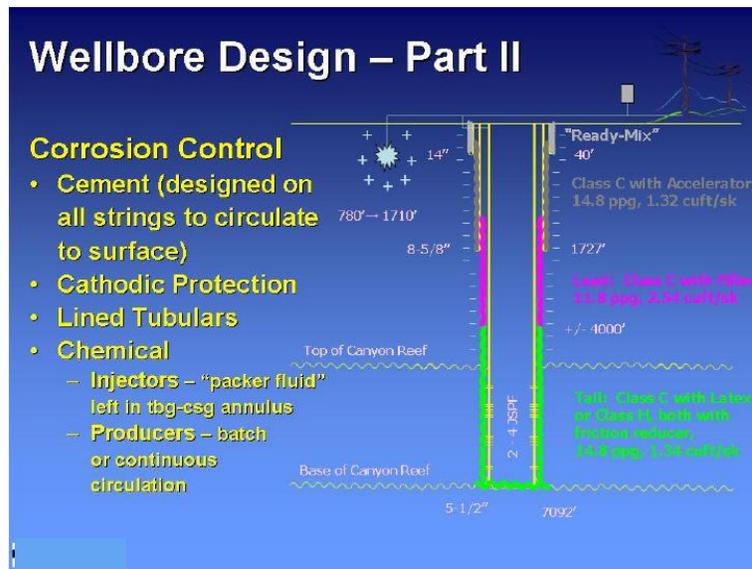
Carbon steel casing is used for CO_2 EOR injection wells and as such, it is susceptible to corrosion. To mitigate corrosion, several techniques are typically used as illustrated in Figure 7, including:

1. Correct cement placement. To minimize contact between carbonic acid and the steel casing, great care is used to assure that the cement, used to bond it to the formation, is adequately distributed along its entire axis. This requires:
 - a. Careful removal of residual drilling mud from the hole,
 - b. Use of centralizers to center the casing string in the bore hole, and,
 - c. Full circulation of the cement returns to the surface.

With a well formed cement sheath in place, the rate of permeation of corrosive material is greatly reduced.

2. Placement of acid resistant cements in zones susceptible to cement carbonation. As appropriate, operators will incorporate specialty cements or specialty slurry designs adjacent to and above the CO₂ injection zone. These cements are more resistant to CO₂ attack and hence dramatically reduce the rate of CO₂ degradation.
3. Cathodic protection of the casing string. Operators employ both impressed and passive current techniques on the casing string to counteract naturally occurring galvanic action, which leads to corrosion. Both methods are used widely in many industrial applications.
4. After completing the well, a biocide/corrosion inhibitor laden fluid is placed in the annular space between the casing and tubing string to further suppress any corrosive tendency.

Figure 7
Typical Wellbore Corrosion Control⁹



Courtesy of Kinder Morgan⁹

3.d.2 Re-Completion of Existing Wellbores

Since the inception of CO₂ EOR operations, a number of existing oil producing and water injection wells have been re-completed, that is converted, to CO₂ injection wells. Excellent reviews of major field redevelopment efforts have been presented by Folger and Goulet⁴³, Power et al⁴⁹, and Bowser et al⁵⁰.

More recently, the 100 year old Salt Creek Field in Wyoming has been converted to a CO₂ EOR development in which over 4,500 wells were re-completed. To do so, the following re-completion process was used:

1. Where they existed, cement bond logs were examined to ascertain the condition of individual wellbores with regard to bonding between the casing and the adjoining formation.

2. For wells that were plugged and abandoned, a pulling unit was set up and the wellbore drilled, from the top of the surface conductor to the bottom of the target formation to remove any accumulated debris (cement, bridge plugs, tree stumps, etc).
3. For those wells with cement bond logs, if insufficient or inadequate bonding was detected, a squeeze cement procedure was used to place cement behind the casing and the cement bond log rerun to validate successful wellbore remediation.
4. For every well, a casing mechanical integrity test was run. This required pressurizing the wellbore and monitoring it, to see if any pressure falloff occurred. If not, the wellbore was competent.
5. When pressure fall off was observed, it was indicative of casing leaks. The leaking section of casing was first identified and then re-sealed by squeeze cementing. In extreme cases, it was necessary to install a liner over the leaking section.

Use of squeeze cement techniques and installation of liners is common oil field practice. A detailed description of both squeeze cementing and liner installation procedures for re-completed CO₂ injection wells in the Maljamar Unit has been presented by Bowser et al ⁵⁰. An excellent review of the complete procedures with specifics for converting mature wells to CO₂ injectors can be found in the work of Power et al ⁴⁹ for the North Ward Estes Field.

In the Sundown Slaughter Unit in West Texas ⁴³, water injection wells, in service since the 1930's, needed significant upgrading for CO₂ injection beyond that described above. This included replacement of 10-25 ft of surface casing onto which a new wellhead was welded and new Christmas tree attached. In general, this procedure does not appear to be routine practice for most CO₂ injection well re-completions.

3.d.3 Performance Observations

All injection wells must pass current mechanical integrity tests (MIT) as dictated by appropriate regulatory bodies, state or federal. Results from the Salt Creek Field, as well as many others, validate the robustness of current re-completion and MIT practices.

For wells completed with modern completion techniques, casing failures have been observed to be rare ^{36, 37}.

3.e Mechanical Completion

Because of the corrosive effects of carbonic acid, H₂CO₃, on metal components, induced by the alternating water and gas (WAG) injection cycles during CO₂ EOR operation, a significant fraction of scientific and technical work has been devoted to developing robust solutions to corrosion problems. Supplemental work has also been done on identifying and developing elastomeric materials for packers and seals that can withstand the solvent effects of supercritical CO₂ that induce swelling and degradation. Throughout this

process, the underlying strategy of the industry has been to select materials based on their durability and corrosion resistance. As a result of these efforts, tubular components can be expected to have a service life of 20 to 25 years before replacement^{36, 37}.

3.e.1 Materials of Construction

3.e.1.1 Evolution – SACROC Experience

An excellent example of the evolution in materials technology for CO₂ injection systems has been presented by Newton^{51, 52} for the SACROC Unit.

For the dry side of the CO₂ supply system, corrosion has been minimal, as expected, since it contains less than 50 ppm H₂O. (Dry side, here, refers to the CO₂ field gas distribution system upstream of any piping exposed to both CO₂ and water flows). On the wet side, however, that is for those parts exposed to both CO₂ and water, this has not been the case as discussed below:

- Meter runs, initially constructed of plastic coated carbon steel piping and valves with plastic coated carbon steel bodies with 316 SS trim, were subject to severe corrosion at any point of coating damage, particularly at flange faces. Where 316 SS was used, no corrosion was observed. Meter runs are now constructed entirely of 316 SS pipe and valving.
- Initially, injection wellheads were equipped with 410 SS wellheads and 410 SS valves. They were subject to severe pitting type corrosion that occurred primarily under deposits from settled suspended matter contained in the injection water. Plastic coating the 410 SS wellheads and valve bodies and changing the gates and seats to 316 SS prolonged the life of many of the wellheads. A replacement program using all 316 SS wellheads was eventually undertaken.
- Injection wells were initially equipped using primarily 2 7/8 inch and 2 3/8 inch J-55 plastic coated tubing set on plastic coated double set packers. The plastic coating used was a thin film epoxy modified phenolic type. Up to 25% of the injection wells had tubing pulled and inspected each year due to tubing leaks or for workover purposes. The primary cause of failure was identified as mechanical damage occurring during: hauling, running and pulling of the tubing⁵². Handling and installation procedures were modified to circumvent these problems.
- With regard to internal coatings, SACROC experimented with different coating types. Powder applied epoxy-phenolics, 8-16 mil in thickness, exhibited improved resistance to mechanical damage and not subject to blistering. Tubing with this coating is now in use⁵¹.

Today, the material improvements presented in Table 8 below, as well as the use of special tubing handling and installation techniques, enable operators to routinely expect a tubular service life on the order of 20 to 25 years^{36, 37}.

3.e.1.2 Corrosion Control and Elastomers

As a result of using corrosion resistant materials in a WAG injection well and associated piping and invoking operational practices to isolate CO₂ sources during water injection cycles, no additional corrosion control measures, such as corrosion inhibitor injection, are used in current CO₂ EOR field operations.

Additionally, by choosing appropriate elastomeric materials for packers and seals, such as internally coated hardened rubber (80-90 durometer^{9, 36, 37}) for packers and Teflon or nylon for seals, swelling has been circumvented.

3.e.1.3 Operator Experience

A survey of operator experience by the New Mexico Petroleum Recovery⁵³ Research Center has shown that in CO₂ EOR floods, because of the suite of corrosion control measures used, corrosion and surface facility problems that were anticipated prior to project startup, were essentially absent. Other field experience also supports this same conclusion⁵⁴.

3.e.2 Typical Designs

Figure 8 presents a design supplied by a major Permian Basin CO₂ EOR operator of a typical CO₂ injection well, Christmas tree / wellhead combination, in use today. Depending on supplier and operator preference, slight design variations exist, but the basic functional elements remain the same. They include:

1. A lubricator valve at the top to access the injection tubing string for running wireline tools, such as a tracer / gamma ray combination used for injection profile management,
2. A CO₂ / water supply valve,
3. Master valves to permit isolation of the injection tubing string from the CO₂ / water supply sources,
4. Casing head valves to permit monitoring of the pressure in the annulus between the production casing and the injection tubing string to assure the mechanical integrity of the well, and,
5. A Bradenhead valve to permit monitoring of the pressure between the production casing and the surface casing strings.

The tubing and casing hangars are integral to the wellhead design.

Below the wellhead, within the production casing, lies:

1. The tubing string,
2. At the end of which is an ON/OFF tool used to withdraw the tubing sting from the formation while leaving the packer in place,
3. A profile nipple used for seating a plug to isolate the wellbore from the formation which allows the tubing string to be withdrawn without having to kill the well,

4. A mechanical packer, also at the end, which creates a seal between the injection tubing and the production casing, as illustrated in Figure 9.

The data in Table 8 summarize the major mechanical completion components of a CO₂ injection well and the current preferred materials of construction (MOC).

Table 8
Materials of Construction (MOC) for
CO₂ Injection Well Components

<u>Component</u>	<u>MOC</u>
Upstream Metering & Piping Runs	316 SS, Fiberglass
Christmas Tree (Trim)	316 SS, Nickel, Monel
Valve Packing and Seals	Teflon, Nylon
Wellhead (Trim)	316 SS, Nickel, Monel
Tubing Hanger	316 SS, Incoloy
Tubing	GRE lined carbon steel, IPC carbon steel, CRA
Tubing Joint Seals	Seal ring (GRE), Coated threads and collars (IPC)
ON/OFF Tool, Profile Nipple	Nickel plated wetted parts, 316 SS
Packers	Internally coated hardened rubber of 80-90 durometer strength (Buna-N), Nickel plated wetted parts
Cements and Cement Additives	API cements and/or acid resistant specialty cements and additives in Appendix 2

Figure 8
Typical CO₂ Injection Wellhead

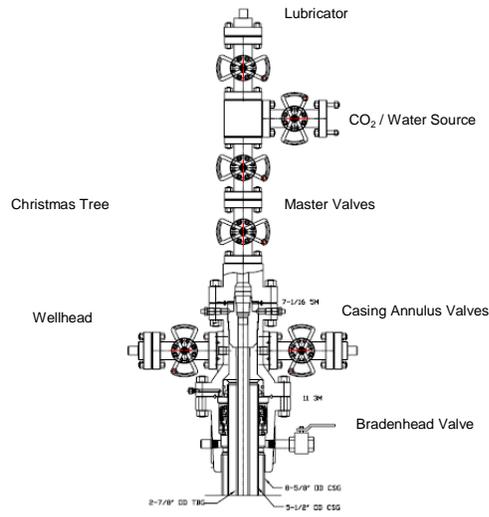


Figure 9
Typical CO₂ Injection Well Tubing String⁵⁵

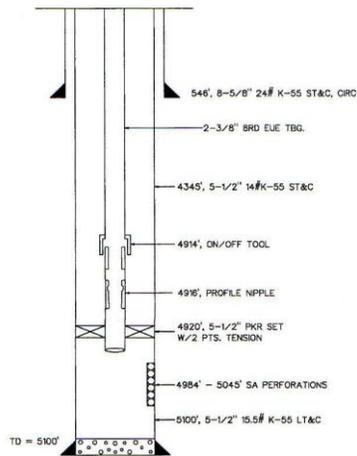


Figure 8 and 9 Courtesy of W.S. Sides III⁵⁵

The key points of the information in Table 8 are as follows:

1. In any wetted region, 316 SS is the metal of choice for valve trim, metal piping, etc. The corrosion resistant properties of stainless steels have been known for decades and their adaptation to oilfield use for CO₂ injection wells has largely been a matter of implementing existing technology. In selected cases, operators use fiberglass piping in upstream metering/piping runs.
2. The same is true with elastomer and seal materials. Buna-N and Nitrile rubbers with an 80-90 durometer reading are widely used for packers, with Teflon and Nylon used for seals.
3. Considerable effort has been devoted to the development of lined and coated tubing strings, illustrated in Figure 10. Currently, both are used. Glass reinforced epoxy (GRE) lined tubing is composed of an internal fiberglass liner, or sleeve, bonded to the inside of a steel pipe. Internally plastic coated (IPC) tubing⁵⁶ consists of a sprayed coating (phenolics, epoxies, urethanes or novolacs) to the inside of a steel pipe. Cement lined tubing⁴³ has been tried but experienced collar (joint) leaks and was replaced with GRE lined tubing. The choice of tubing type appears to be dictated by operator experience and success in a given area.

Figure 10
Glass Reinforced Epoxy Lined Tubing (GRE)⁹



Courtesy of Kinder Morgan⁹

4. Tubing collar leaks have been one of the most common problems associated with WAG injection^{39, 57}. Seal rings are commonly used for making up GRE lined tubing joints and the vendor is typically on-site during installation to assure quality. For IPC tubing, the coating typically extends over the threaded end of the joint and internally coated collars are used. For very large re-completion situations, such as the Wyoming field

described above, field personnel have been trained to properly makeup tubing joints.

Special procedures have been developed for handling, running, pressure-testing and installing the tubing to protect the internal coatings and connections^{49, 58}. Helium test methods have proved quite successful⁵⁸ for leak detection.

5. In the tubing string metal parts such as the profile nipple and ON/OFF tool are nickel plated.
6. For packers, nickel plating is used on all wetted parts and internally coated hardened rubber elastomers of 80-90 durometer strength (Buna-N) are used to circumvent CO₂ permeation.

3.f Workovers

As described earlier, once a CO₂ injection well is put into service, profile management is the most common workover activity, with the following options available:

1. Change WAG flow rates and cycle times,
2. Use mechanical isolation by setting packers, casing patches, etc.
3. Isolate zones by squeeze cementing and/or in combination with polymer gels or chemical squeezes alone
4. Set liners, and, lastly,
5. Sidetrack the well^{9, 36, 37},

as illustrated in Figure 3. Steps 2 through 5 require intervention into the wellbore. All of the above are routine oilfield activities handled on a day-to-day basis, independent of the field production mechanism (primary depletion, waterflood, CO₂ EOR, etc), and have been so for decades.

3.g Safety and Environment

3.g.1 Automatic Control Systems

Automated control systems are commonly used to continuously control and monitor CO₂ injection operations to assure both their performance and the mechanical integrity^{36, 37}. These systems provide real-time information from which immediate corrective action can be taken, if required. The principle components of these control systems include:

1. Meter(s),
2. Control valve(s), and,
3. Pressure sensors for both the tubing and the casing head.

Automated control systems provide real-time information on the state of the system and thus can provide a timely means for detection and response to any potential problem before it becomes a serious issue.

Additionally, check valves, isolation valves, blinds and bleeds/nipples are incorporated into the surface piping configuration to prevent backflow and facilitate servicing⁵⁹. These features are common oilfield piping practice.

3.g.2 Flow Isolation

While CO₂ EOR operations require CO₂ and water flows, they occur sequentially rather than simultaneously for extended periods of time. As an additional safety practice, operators insert a blind flange in the line of the non-flowing phase to assure its complete isolation. This procedure assures that, should a valve, (check or isolation) not seat properly, no back flow can occur which could induce corrosion and over-pressurization.

3.g.3 Populated Area Wells

For wells in populated areas special measures can be taken to protect the public from a potential accidental CO₂ release. The entire well location can be fenced and monitored 24 hours a day via computer assisted alarms. Atmospheric dispersion models can also be done to verify that CO₂ releases in the area pose no danger at maximum anticipated rates.

3.g.4 Well Control / Blowouts

3.g.4.1 Drilling Operations

Well blowouts are rare in oilfield operations. Both human factors and unforeseen reservoir conditions can contribute to their occurrence, and safety procedures, in-depth personnel training and specialized equipment are used to minimize their likelihood. Unlike oil and gas blowouts, where fire is the major concern, in CO₂ blowouts asphyxiation is the major concern, since CO₂ is heavier than air. Depending on the level of potential risk, it may be appropriate to have self contained breathing apparatus (SCBA) on-site and available during CO₂ injection well drilling or intervention procedures.

On March 17, 1982, CO₂ production well 4-15H blew out in the Sheep Mountain CO₂ field in Huerfano County, Colorado while it was being drilled. Because of the reservoir pressure and the limitations posed by the diameter of the drill pipe, conventional kill techniques using weighted mud proved unsuccessful. After several attempts, the well was dynamically killed on April 3, 1982⁶⁰. Dynamic killing uses frictional pressure losses to supplement the hydrostatic pressure of a light weight kill fluid injected at high rate at or near the bottom of the well. Well 4-15H was successfully contained using drag-reduced calcium chloride (CaCl₂) brine as the kill fluid followed by weighted mud loaded with lost-circulation material to rebuild the filter cake in the producing zone. After killing the well, it was plugged and abandoned.

Depending on circumstances, new wells can also be killed using conventional weighted mud techniques by bull heading it down the drill pipe, reservoir and fluid mechanical conditions permitting.

3.g.4.2 Workover Operations

For completed wells, weighted mud or brine can be bull headed down the tubing string to kill a well.

3.g.5 Plug and Abandonment

As reservoirs or zones are depleted, wells need to be plugged and abandoned. State and federal regulatory agencies specify the exact requirements for doing so. However, in general terms, the procedure involves:

1. Setting the ON/OFF plug in the tubing string to the OFF position,
2. Pulling the string,
3. Setting a cement retainer or bridge plug,
4. Placing sufficient cement to isolate the producing formation (squeezing through the cement retainer or placing a cement plug on top of a bridge plug), and,
5. Depending on the number of horizons in the well, repeating steps 3 and 4 for each.
6. Positive and/or negative pressure tests to verify the integrity of the cement and mechanical plugs.

A bridge plug is a downhole tool that is located and set to isolate the lower part of the [wellbore](#). [Bridge](#) plugs may be permanent or retrievable, enabling the lower [wellbore](#) to be permanently sealed from [production](#) or temporarily isolated from a treatment conducted on an upper [zone](#)⁴¹. Cement retainers are similar except that they are designed to allow cement to be pumped below the tool.

The foregoing plug and abandonment procedure is used to isolate the production/injection formation from other formations and to protect ground water resources from potential contamination.

3.h Mechanical Integrity

4.h.1 Testing

State regulatory agencies such as the Texas Railroad Commission and U.S. Environmental Protection Agency specify the technical requirements of the mechanical integrity test (MIT) for CO₂ EOR and when it is required, as shown in Appendix 1. For Texas, MITs are required:

1. Prior to putting a new well into service,
2. After any workover (squeeze cementing, placement of liners, fracturing, etc.), and,
3. Every five (5) years at a minimum.

Similar requirements exist for other states and regulatory bodies.

Regulatory MIT's can be done several ways however they typically involve pressurizing the tubing and monitoring the casing head pressure for a set period of time and observing whether or not it changes. If so, the cause of the change must be identified and remedied.

3.h.2 Observations on Component Integrity

As industry experience has matured, the integrity of CO₂ injection well components have improved correspondingly. For new wells that use completion techniques and mechanical components with appropriately chosen materials of construction, current experience suggests that integrity lives on the order of 20 to 25 years for tubulars and well beyond for wellbores can be expected.

3.h.3 Leak Detection and Well Repair Methods

If a CO₂ injection well has failed a mechanical integrity test, the operator must take it out of service, identify and remedy the problem and then retest the well before putting it back in service.

3.h.3.1 Tubing Leaks

During the mechanical integrity test procedure, tubing leaks are typically indicated by increases in casing head pressure. The following is an example of how an operator might repair a tubing leak.

1. Initially, the operator sets a blanking plug in the profile nipple at the bottom of the tubing string to establish a seal between the wellbore and the producing formation.
2. Then the tubing is pressurized. If the pressure holds, the tubing is competent and the problem lies with the casing. Nonetheless, the tubing string must be removed from the well.
3. If the pressure does not hold, then a leak exists in either the tubing string or in the seal of the ON/OFF tool at the bottom of it. It is necessary to kill the well and remove the tubing string from the well.
4. To kill the well, the operator perforates the tubing string just above the ON/OFF tool and circulates kill fluid (weighted brine) to the surface. This displaces the chemically treated water in the casing/tubing annulus.
5. The Christmas tree is removed from the well, a blow out preventer (BOP) is installed and the tubing is removed.
6. After removal of the tubing, the ON/OFF tool manufacturer checks the integrity of its seal. As appropriate, it is either replaced or reinstalled.
7. Then the tubing is run in the well and hydrotested for leaks. When a leak is found, the failed tubing joint is replaced and re-hydrotested. If no leaks are detected, this usually indicates that a failure occurred in a collar which was remedied as the tubing was rerun.
8. When the entire tubing string has been run into the well the,
 - a. BOP stack is removed,
 - b. Christmas tree replaced,
 - c. Kill fluid displaced from the hole,
 - d. Tubing re-engaged on the ON/OFF tool, and,
 - e. Blanking plug removed.
9. Finally, a mechanical integrity test is rerun and the well returned to service.

3 h.3.2 Casing and Packer Leaks

If the tubing has been shown to be competent, inspection and remedy of casing leaks must now be addressed. The following is an example of how to repair a casing leak:

1. The operator inserts a temporary test packer on tubing into the well within a short distance above the injection packer.
2. The system is pressurized and observed. If the pressure falls, the injection packer requires replacement.
3. If the pressure holds, then the leak is in the casing above the injection packer. To find the leak's location, the test packer is successively moved up the wellbore, reset, and pressure tests performed, until its location is isolated. Frequently, leaks occur at the collars between adjacent casing joints.
4. Once the location of the casing leak has been found, the operator can remedy it in several ways, including:
 - a. Squeeze cementing^{49, 50}, chemical sealant squeezes, or,
 - b. Insertion of a new liner (fiberglass^{50, 61} or steel) over the leaking section.

The choice of techniques is dictated by the severity of the situation, the geometry and state of the wellbore and operator experience.

5. Once a casing leak has been repaired, the well is mechanically reassembled, as per the steps given above, and a mechanical integrity test performed.

This procedure for detecting tubing and casing leaks is indicative of that used in CO₂ EOR operations in the Permian Basin. Leak detection methods are a constantly evolving part of oilfield technology that use sophisticated wireline tools based on the principles of radioactive, acoustical, or thermal phenomena. With regard to the latter, the work of Johns, et al⁶² is illustrative of research and development efforts to identify cost effective methods for identifying small tubing and casing leaks typical of those commonly encountered in CO₂ injection wells.

It should be remembered that, in CO₂ injection wells, coated or lined tubing is normally used. Thus, use of wireline tools to detect a tubing leak could have the undesired effect of damaging the coating which can lead to further damage to the tubing. This consideration is a principle factor for using the test procedure described above. For CO₂ storage wells, however, where dry CO₂ would be injected and thus uncoated or unlined metal tubulars could be used, wireline methods offer a viable and cost effective means for tubing leak detection.

3.i Cement Concerns – SACROC Experience

For CO₂ storage, a central concern has been wellbore integrity measured not in terms of decades but in terms of millennia. Active research programs such as those summarized in the recent wellbore integrity workshops^{63, 64} highlight the

body of scientific work currently being undertaken by academic, government and industrial institutions to address the issue.

Recently, cement core samples have been recovered from well 49-6 of the SACROC Field after 30 years of CO₂ injection^{48, 65}. The specifics are as follows:

Table 9
SACROC Cement Samples⁴⁸

<u>Parameter</u>	<u>Value</u>
Drilled and Completed Service	1950 10 years as producer 7 years as injector
Start of CO ₂ Exposure	1972
Years of CO ₂ Exposure	30
Cement above Formation	Portland (Neat)
Sample #1 Depth	6,550 ft
Sample #2 Depth	5,160 ft
Reservoir Temperature	120 °F
Reservoir Pressure	2,610 psig

The following observations⁴⁸ were made regarding the samples:

1. Both cement samples retained their ability to prevent significant CO₂ flow having air permeabilites in the tenth of a miliDarcy range.
2. For sample #1, located 10-12 feet above the formation, some CO₂ migration had occurred along the casing-cement and casing-shale interfaces. No evidence of CO₂ migration was found through the matrix permeability of the cement itself. No similar evidence of migration was observed for sample #2, located 1400 feet above the formation.

In light of foregoing results and current well completion practices, the following conclusions can be drawn:

1. In spite of not being formulated for acid resistivity, the 50 year old neat Portland cement has held up remarkably well under its service conditions and 30 years exposure to CO₂. Such performance bodes well for all CO₂ EOR wells.
2. Nothing can be said definitively about the rate of CO₂ migration further up the wellbore other than, after 30 years of CO₂ exposure, it migrated at least 12 feet. However, the ~0.1 mD measured permeability, structural integrity, etc. of the CO₂ altered (including the degraded layer) cement “indicates the cement retained its capacity to prevent significant transport of fluid (CO₂) through the cement matrix.”⁴⁸

The cement degradation deposits adjacent to the well bore were at most 0.125 inch thick, while those adjacent to the shale were 0.25 inch thick. It has been suggested⁴⁸ that the cement degradation found at the cement-

shale interface may have resulted from the presence of shale fragments (filter cake) which provided a fluid pathway.

3. Specially formulated acid resistant cements, some containing latex additives, are used for CO₂ injection well completions today in severe CO₂ environments. More information on acid resistant cements is provided in Appendix 2.

The best appraisal of the performance of well 49-6 can be found in the SACROC cement report itself, namely that: "The most basic observation of the SACROC core is that at well 49-6 Portland cement survived and retained its structural integrity after 30 years in a CO₂ environment. While the cement permeability determined by air permeability is greater than pristine Portland cement, it would still provide protection against significant movement of CO₂ through the cement matrix. The location of a sample at only 10-12 feet above the reservoir contact suggests that the majority of the cement forming the wellbore seal has survived and would provide a barrier to fluid migration⁴⁸."

Acknowledgements

In developing this report two approaches were used: first, a thorough review of the available technical literature and, second, contact and discussion with current industry practitioners of carbon dioxide, CO₂, injection well technology.

With regard to the first avenue, the available literature is significant in both volume and technical depth. A large fraction of this material has been compiled by the Society of Petroleum Engineers (SPE), over the past four decades, in the form of conference proceedings, technical papers and journal articles. More recently, publications by investigators at the Los Alamos National Laboratory and the E.O. Lawrence National Laboratory, together with other DOE/SPE and international consortia, have made significant contributions, particularly in the area of CO₂ storage.

With regard to the second avenue, the insight and the experience of the following individuals, into the technology of CO₂ injection well design and operation, has been invaluable:

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APPENDIX 1

Texas Rail Road Commission Well Mechanical Integrity Test Regulations

Texas Administrative Code

<u>TITLE 16</u>	ECONOMIC REGULATION
<u>PART 1</u>	RAILROAD COMMISSION OF TEXAS
<u>CHAPTER 3</u>	OIL AND GAS DIVISION
RULE §3.46	Fluid Injection into Productive Reservoirs

(a) Permit Required. Any person who engages in fluid injection operations in reservoirs productive of oil, gas, or geothermal resources must obtain a permit from the commission. Permits may be issued when the injection will not endanger oil, gas, or geothermal resources or cause the pollution of freshwater strata unproductive of oil, gas, or geothermal resources. Permits from the commission issued before the effective date of this section shall continue in effect until revoked, modified, or suspended by the commission.

(b) Filing of Application.

(1) Application. An application to conduct fluid injection operations in a reservoir productive of oil, gas, or geothermal resources shall be filed in Austin on the form prescribed by the commission accompanied by the prescribed fee. On the same date, one copy shall be filed with the appropriate district office. The form shall be executed by a party having knowledge of the facts entered on the form. The applicant shall file the freshwater injection data form if fresh water is to be injected.

(2) Commercial disposal well. An applicant for a permit to dispose of oil and gas waste in a commercial disposal well shall clearly indicate on the application and in the notice of application that the application is for a commercial disposal well permit. For the purposes of this rule, "commercial disposal well" means a well whose owner or operator receives compensation from others for the disposal of oil field fluids or oil and gas wastes that are wholly or partially trucked or hauled to the well, and the primary business purpose for the well is to provide these services for compensation.

(c) Notice and Opportunity for Hearing.

(1) The applicant shall give notice by mailing or delivering a copy of the application to affected persons who include the owner of record of the surface tract on which the well is located; each commission-designated operator of any well located within one half mile of the proposed injection well; the county clerk of the county in which the well is located; and the city clerk or other appropriate city official of any city where the well is located within the corporate limits of the city, on or before the date the application is mailed to or filed with the commission. For the purposes of this section, the

term "of record" means recorded in the real property or probate records of the county in which the property is located.

- (2) In addition to the requirements of subsection (c)(1), a commercial disposal well permit applicant shall give notice to owners of record of each surface tract that adjoins the proposed injection tract by mailing or delivering a copy of the application to each such surface owner.
 - (3) If, in connection with a particular application, the commission or its delegate determines that another class of persons should receive notice of the application, the commission or its delegate may require the applicant to mail or deliver a copy of the application to members of that class. Such classes of persons could include adjacent surface owners or underground water conservation districts.
 - (4) In order to give notice to other local governments, interested, or affected persons, notice of the application shall be published once by the applicant in a newspaper of general circulation for the county where the well will be located in a form approved by the commission or its delegate. The applicant shall file with the commission in Austin proof of publication prior to the hearing or administrative approval.
 - (5) **Protested applications:**
 - (A) If a protest from an affected person or local government is made to the commission within 15 days of receipt of the application or of publication, whichever is later, or if the commission or its delegate determines that a hearing is in the public interest, then a hearing will be held on the application after the commission provides notice of hearing to all affected persons, local governments, or other persons, who express an interest, in writing, in the application.
 - (B) For purposes of this section, "affected person" means a person who has suffered or will suffer actual injury or economic damage other than as a member of the general public or as a competitor, and includes surface owners of property on which the well is located and commission-designated operators of wells located within one-half mile of the proposed disposal well.
 - (6) If no protest from an affected person is received by the commission, the commission's delegate may administratively approve the application. If the commission's delegate denies administrative approval, the applicant shall have a right to a hearing upon request. After hearing, the examiner shall recommend a final action by the commission.
- (d) Subsequent Commission Action.
- (1) An injection well permit may be modified, suspended, or terminated by the commission for just cause after notice and opportunity for hearing, if:
 - (A) A material change of conditions occurs in the operation or completion of the injection well, or there are material changes in the information originally furnished;
 - (B) Fresh water is likely to be polluted as a result of continued operation of the well;
 - (C) There are substantial violations of the terms and provisions of the permit or of commission rules;
 - (D) The applicant has misrepresented any material facts during the permit issuance process;

- (E) Injected fluids are escaping from the permitted injection zone; or
 - (F) Waste of oil, gas, or geothermal resources is occurring or is likely to occur as a result of the permitted operations.
- (2) An injection well permit may be transferred from one operator to another operator provided that the commission's delegate does not notify the present permit holder of an objection to the transfer prior to the date the lease is transferred on commission records.
- (3) Voluntary permit suspension.
- (A) An operator may apply to temporarily suspend its injection authority by filing a written request for permit suspension with the commission in Austin, and attaching to the written request the results of an MIT test performed during the previous three-month period in accordance with the provisions of subsection (j)(4) of this section. The provisions of this paragraph shall not apply to any well that is permitted as a commercial injection well.
 - (B) The commission or its delegate may grant the permit suspension upon determining that the results of the MIT test submitted under subparagraph (A) of this paragraph indicate that the well meets the performance standards of subsection (j)(4) of this section.
 - (C) During the period of permit suspension, the operator shall not use the well for injection or disposal purposes.
 - (D) During the period of permit suspension, the operator shall comply with all applicable well testing requirements of §3.14 of this title (relating to plugging, and commonly referred to as Statewide Rule 14) but need not perform the MIT test that would otherwise be required under the provisions of subsection (j)(4) of this section or the permit. Further, during the period of permit suspension, the provisions of subsection (i)(1) - (3) of this section shall not apply.
 - (E) The operator may reinstate injection authority under a suspended permit by filing a written notification with the commission in Austin. The written notification shall be accompanied by an MIT test performed during the three-month period prior to the date notice of reinstatement is filed. The MIT test shall have been performed in accordance with the provisions and standards of subsection (j)(4) of this section.
- (e) Area of Review.
- (1) Except as otherwise provided in this subsection, the applicant shall review the data of public record for wells that penetrate the proposed disposal zone within a 1/4 mile radius of the proposed disposal well to determine if all abandoned wells have been plugged in a manner that will prevent the movement of fluids from the disposal zone into freshwater strata. The applicant shall identify in the application any wells which appear from such review of public records to be unplugged or improperly plugged and any other unplugged or improperly plugged wells of which the applicant has actual knowledge.
 - (2) The commission or its delegate may grant a variance from the area-of-review requirements of paragraph (1) of this subsection upon proof that the variance will not result in a material increase in the risk of fluid movement into freshwater strata or to the surface. Such a variance may be granted for an area defined both vertically and laterally (such as a field) or for an

individual well. An application for an areal variance need not be filed in conjunction with an individual permit application or application for permit amendment. Factors that may be considered by the commission or its delegate in granting a variance include:

- (A) The area affected by pressure increases resulting from injection operations;
 - (B) The presence of local geological conditions that preclude movement of fluid that could endanger freshwater strata or the surface; or
 - (C) Other compelling evidence that the variance will not result in a material increase in the risk of fluid movement into freshwater strata or to the surface.
- (3) Persons applying for a variance from the area-of-review requirements of paragraph (1) of this subsection on the basis of factors set out in paragraph (2)(B) or (C) of this subsection for an individual well shall provide notice of the application to those persons given notice under the provisions of subsection (c)(1) of this section. The provisions of subsection (c) of this section shall apply in the case of an application for a variance from the area-of-review requirements for an individual well.
- (4) Notice of an application for an areal variance from the area-of-review requirements under paragraph (1) of this subsection shall be given on or before the date the application is filed with the commission:
- (A) By publication once in a newspaper having general circulation in each county, or portion thereof, where the variance would apply. Such notice shall be in a form approved by the commission or its delegate prior to publication and must be at least three inches by five inches in size. The notice shall state that protests to the application may be filed with the commission during the 15-day period following the date of publication. The notice shall appear in a section of the newspaper containing state or local news items;
 - (B) By mailing or delivering a copy of the application, along with a statement that any protest to the application should be filed with the commission within 15 days of the date the application is filed with the commission, to the following:
 - (i) The manager of each underground water conservation district in which the variance would apply, if any;
 - (ii) The city clerk or other appropriate official of each incorporated city in which the variance would apply, if any;
 - (iii) The county clerk of each county in which the variance would apply; and
 - (iv) Any other person or persons that the commission or its delegate determines should receive notice of the application.
- (5) If a protest to an application for an areal variance is made to the commission by an affected person, local government, underground water conservation district, or other state agency within 15 days of receipt of the application or of publication, whichever is later, or if the commission's delegate determines that a hearing on the application is in the public interest, then a hearing will be held on the application after the commission provides notice of the hearing to all local governments, underground water conservation districts, state agencies, or other persons, who express an interest, in writing, in the application. If no protest from an affected person is received by the

commission, the commission's delegate may administratively approve the application. If the application is denied administratively, the person(s) filing the application shall have a right to hearing upon request. After hearing, the examiner shall recommend a final action by the commission.

- (6) An areal variance granted under the provisions of this subsection may be modified, terminated, or suspended by the commission after notice and opportunity for hearing is provided to each person shown on commission records to operate an oil or gas lease in the area in which the proposed modification, termination, or suspension would apply. If a hearing on a proposal to modify, terminate, or suspend an areal variance is held, any applications filed subsequent to the date notice of hearing is given must include the area-of-review information required under paragraph (1) of this subsection pending issuance of a final order.
- (f) Casing. Injection wells shall be cased and the casing cemented in compliance with §3.13 of this title (relating to Casing, Cementing, Drilling, and Completion Requirements) in such a manner that the injected fluids will not endanger oil, gas, or geothermal resources and will not endanger freshwater formations not productive of oil, gas, or geothermal resources.
- (g) Special Equipment.
 - (1) *Tubing and packer*. Wells drilled or converted for injection shall be equipped with tubing set on a mechanical packer. Packers shall be set no higher than 200 feet below the known top of cement behind the long string casing but in no case higher than 150 feet below the base of usable quality water. For purposes of this section, the term "tubing" refers to a string of pipe through which injection may occur and which is neither wholly nor partially cemented in place. A string of pipe that is wholly or partially cemented in place is considered casing for purposes of this section.
 - (2) *Pressure valve*. The wellhead shall be equipped with a pressure observation valve on the tubing and for each annulus of the well.
 - (3) *Exceptions*. The commission or its delegate may grant an exception to any provision of this paragraph upon proof of good cause. If the commission or its delegate denies an exception, the operator shall have a right to a hearing upon request. After hearing, the examiner shall recommend a final action by the commission.
- (h) Well Record. Within 30 days after the completion or conversion of an injection well, the operator shall file in duplicate in the district office a complete record of the well on the appropriate form which shows the current completion.
- (i) Monitoring and Reporting.
 - (1) The operator shall monitor the injection pressure and injection rate of each injection well on at least a monthly basis.
 - (2) The results of the monitoring shall be reported annually to the commission on the prescribed form.
 - (3) All monitoring records shall be retained by the operator for at least five years.
 - (4) The operator shall report to the appropriate District Office within 24 hours any significant pressure changes or other monitoring data indicating the presence of leaks in the well.
- (j) Testing.

- (1) *Purpose.* The mechanical integrity of an injection well shall be evaluated by conducting pressure tests to determine whether the well tubing, packer, or casing have sufficient mechanical integrity to meet the performance standards of this rule, or by alternative testing methods under paragraph (5) of this subsection.
- (2) *Applicability.* Mechanical integrity of each injection well shall be demonstrated in accordance with provisions of paragraphs (4) and (5) of this subsection prior to initial use. In addition, mechanical integrity shall be tested periodically thereafter as described in paragraph (3) of this subsection.
- (3) *Frequency.*
 - (A) Each injection well completed with surface casing set and cemented through the entire interval of protected usable-quality water shall be tested for mechanical integrity at least once every five years.
 - (B) In addition to testing required under subparagraph (A), each injection well shall be tested for mechanical integrity after every workover of the well.
 - (C) An injection well that is completed without surface casing set and cemented through the entire interval of protected usable-quality ground water shall be tested at the frequency prescribed in the injection permit.
 - (D) The commission or its delegate may prescribe a schedule and mail notification to operators to allow for orderly and timely compliance with the requirements in subparagraph (A) and subparagraph (B) of this paragraph. Such testing schedule shall not apply to an injection well for which an injection well permit has been issued but the well has not been drilled or converted to injection.
- (4) *Pressure Tests.*
 - (A) Test pressure.
 - (i) The test pressure for wells equipped to inject through tubing and packer shall equal the maximum authorized injection pressure or 500 psig, whichever is less, but shall be at least 200 psig.
 - (ii) The test pressure for wells that are permitted for injection through casing shall equal the maximum permitted injection pressure or 200 psig, whichever is greater.
 - (B) Pressure stabilization. The test pressure shall stabilize within 10% of the test pressure required in subparagraph (A) of this paragraph prior to commencement of the test.
 - (C) Pressure differential. A pressure differential of at least 200 psig shall be maintained between the test pressure on the tubing-casing annulus and the tubing pressure.
 - (D) Test duration. A pressure test shall be conducted for a duration of 30 minutes when the test medium is liquid or for 60 minutes when the test medium is air or gas.
 - (E) Pressure recorder. Except for tests witnessed by a commission representative or wells permitted for injection through casing, a pressure recorder shall be used to monitor and record the tubing-casing annulus pressure during the test. The recorder clock shall not exceed 24 hours. The recorder scale shall be set so that the test pressure is 30 to 70% of full scale, unless otherwise authorized by the commission or its delegate.
 - (F) Test fluid.

- (i) The tubing-casing annulus fluid used in a pressure test shall be liquid for wells that inject liquid unless the commission or its delegate authorizes use of a different test fluid for good cause.
- (ii) The tubing-casing annulus fluid used in a pressure test shall contain no additives that may affect the sensitivity or otherwise reduce the effectiveness of the test.
- (G) Pressure test results. The commission or its delegate will consider, in evaluating the results of a test, the level of pollution risk that loss of well integrity would cause. Factors that may be taken into account in assessing pollution risk include injection pressure, frequency of testing and monitoring, and whether there is sufficient surface casing to cover all zones containing usable-quality water. A pressure test may be rejected by the commission or its delegate after consideration of the following factors:
 - (i) The degree of pressure change during the test, if any;
 - (ii) The level of risk to usable-quality water if mechanical integrity of the well is lost; and
 - (iii) Whether circumstances surrounding the administration of the test make the test inconclusive.
- (5) *Alternative Testing Methods.*
 - (A) As an alternative to the testing required in paragraph (2) of this subsection, the tubing-casing annulus pressure may be monitored and included on the annual monitoring report required by subsection (i) of this section, with the authorization of the commission or its delegate and provided that there is no indication of problems with the well. Wells that are approved for tubing-casing annulus monitoring under this paragraph shall be tested in the manner provided under paragraph (3) of this subsection at least once every ten years after January 1, 1990.
 - (B) The commission or its delegate grant an exception for viable alternative tests or surveys or may require alternative tests or surveys as a permit condition.
- (6) The operator shall notify the appropriate district office at least 48 hours prior to the testing. Testing shall not commence before the end of the 48-hour period unless authorized by the district office.
- (7) A complete record of all tests shall be filed in duplicate in the district office within 30 days after the testing.
- (8) In the case of permits issued under this section prior to the effective date of this amendment which require pressure testing more frequently than once every five years, the commission's delegate may, by letter of authorization, reduce the required frequency of pressure tests, provided that such tests are required at least once every three years. The commission shall consider the permit to have been amended to require pressure tests at the frequency specified in the letter of authorization.

Source Note: The provisions of this §3.46 adopted to be effective January 1, 1976; amended to be effective April 1, 1982, 7 TexReg 655; amended to be effective January 1, 1994, 18 TexReg 8871; amended to be effective December 4, 1996, 21 TexReg 11361; amended to be effective April 7, 1998, 23 TexReg 3432; amended to be effective August 4, 1998, 23 TexReg 7768; amended to be

effective December 28, 1999, 24 TexReg 11711; amended to be effective November 24, 2004, 29 TexReg 10728

APPENDIX 2

Descriptions of API Cements and Specialty Cements

API Cements

The oil industry purchases cements manufactured predominantly in accordance with API classifications as published in API Standards 10A, Specifications for Cements and Materials for Well Cementing. These standards have been published annually by the American Petroleum Institute since 1954, when the first national standards on cements for use in wells were issued. These specifications are reviewed annually and revised according to the needs of the oil industry. The different classes of cements covered by API standards (referred to as *API cements*) for use at downhole temperatures and pressures are defined in the following list.

Class A. The product is obtained by grinding Portland cement clinker, consisting essentially of hydraulic calcium silicates, usually containing one or more of the forms of calcium sulfate as an interground material. At the option of the manufacturer, processing additions may be used in the manufacture of the cement, provided such materials in the amounts used have been shown to meet the requirements of ASTM C 465. This product is intended for use when special properties are not required and is available only in ordinary (O) Grade (similar to ASTM C 150, Type I).

Class B. The product is obtained by grinding Portland cement clinker, consisting essentially of hydraulic calcium silicates, usually containing one or more of the forms of calcium sulfate as an interground material. At the option of the manufacturer, processing additions may be used in the manufacture of the cement, provided such materials in the amounts used have been shown to meet the requirements of ASTM C 465. This product is intended for use when conditions require moderate or high sulfate resistance and available in both moderate sulfate-resistant (MSR) and high sulfate-resistant (HSR) grades (similar to ASTM C 150, Type II).

Class C. The product is obtained by grinding Portland cement clinker, consisting essentially of hydraulic calcium silicates, usually containing one or more of the forms of calcium sulfate as an interground material. At the option of the manufacturer, processing additions may be used in the manufacture of the cement, provided such materials in the amounts used have been shown to meet the requirements of ASTM C 465. This product is intended for use when conditions require high early strength. Available in ordinary (O), moderate sulfate-resistant (MSR), and high sulfate-resistant (HSR) grades (similar to ASTM C 150, Type III).

Class G. The product is obtained by grinding Portland cement clinker, consisting essentially of hydraulic calcium silicates, usually containing one or more of the forms of calcium sulfate as an interground addition. No additions

other than calcium sulfate or water, or both, shall be interground or blended with the clinker during manufacture of Class G well cement. This product is intended for use as a basic well-cement and available in moderate sulfate-resistant (MSR) and high sulfate-resistant (HSR) grades.

Class H. The product is obtained by grinding Portland cement clinker, consisting essentially of hydraulic calcium silicates, usually containing one or more of the forms of calcium sulfate as an interground addition. No additions other than calcium sulfate or water, or both, shall be interground or blended with the clinker during manufacture of Class H well cement. This product is intended for use as basic well cement and is available in moderate sulfate-resistant (MSR) and high sulfate-resistant (HSR) grades.

Note: One of the main differences between Class G and Class H cements is that Class G is often ground to a finer particle size than Class H. The average size of all the particles is typically determined by laboratory test measurement of the cement powder's surface area. Surface areas based on the Blaine test method for Class G and Class H cements typically lie in the range of 300 to 400 and 220 to 330 m²/kg, respectively.

Specialty Cements

A number of cementitious materials that have been used very effectively for cementing wells do not fall into any specific API or ASTM classification. Some 'Specialty Cements' are dry blended with API or ASTM cements and additives for well applications in primary or remedial cementing operations. While these materials may or may not be sold under a recognized specification, their quality and uniformity are generally controlled by the supplier. These materials include:

- Pozzolanic-Portland cements
- Pozzolan-lime cements
- Resin or plastic cements
- Gypsum cements
- Microfine cements
- Expanding cements
- Refractory cement
- Latex cements
- Sorel cements

Pozzolanic-Portland Cement: Pozzolanic materials are often dry blended with Portland cements including API or ASTM cements to produce "lightweight" (low density) slurries for well cementing applications. Pozzolanic materials include any natural or industrial siliceous or silica-aluminous material, which, though not cementitious in itself, will combine with lime in the presence of water at ambient temperatures to produce strength-developing insoluble compounds similar to those formed from hydration of Portland cement. Typically, pozzolanic materials are categorized as natural or artificial, and can be either processed or unprocessed. The most common sources of natural pozzolanic materials are volcanic materials and diatomaceous earths. Diatomaceous earths are composed of diatom fossil remains consisting of opaline silica. Artificial pozzolanic materials are produced by partially calcining natural materials such as clays, shales, and certain siliceous rocks, or are more usually obtained as an industrial byproduct. Artificial pozzolanic materials include metakaolin, fly ash, microsilica (silica fume), and ground granulated blast-furnace slag.

The addition of pozzolanic materials to API or ASTM cements reduces permeability and may minimize chemical attack from some types of corrosive formation waters. In most cases, pozzolanic materials can also reduce the effect of sulfate attack, though this is somewhat dependent on the slurry design.

Pozzolan-Lime Cement: Pozzolan-lime or silica-lime cements are usually blends of fly ash (silica), hydrated lime, and small quantities of calcium chloride. These products hydrate with water to produce calcium silicate hydrates, calcium aluminate hydrates, and calcium aluminosilicate hydrates. The pozzolanic activity of such cements depends on the maximum amount of lime that the pozzolan can react with and the rate of the reaction. The nature and content of the active phase, the lime/pozzolan ratio, length of curing, water-to-solids-mix ratio, and temperature all impact on the pozzolanic activity of the pozzolan-lime cement. At low temperatures, the initial reactions of these cements are slower than similar reactions in Portland cements. Therefore, they are generally recommended for

primary cementing at temperatures above 140°F (60°C). Fly ash is composed primarily of an amorphous silicate or calcium aluminosilicate glass containing a small amount of crystalline minerals. This glass dissolves in highly alkaline solutions produced from the hydrated lime and precipitates on reaction with Ca^{2+} derived from both the fly ash and the lime to produce the hydration products. The merits of this type of cement are ease of retardation, light weight, economy, and strength stability at high temperatures.

Gypsum Cement: Gypsum cement is blended cement composed of API Class A, C, G or H cement and the hemi-hydrate form of gypsum ($\text{CaSO}_4 \cdot 0.5\text{H}_2\text{O}$). In practice, the term “gypsum cements” normally indicates blends containing 20% or more gypsum. Gypsum cements are commonly used in low-temperature applications for primary casing or remedial cementing work. This combination is particularly useful in shallow wells to minimize fall-back after placement. The unique properties of gypsum cement are its capacity to set rapidly, its high early strength, and its positive expansion (approximately 2.0 %). This is caused by the “plaster of Paris” reaction where the hemi-hydrate re-hydrates to form gypsum.

Cement with high gypsum content has increased ductility and acid solubility and because of these characteristics are not considered appropriate for use in CO_2 service. It is usually used in situations of high lateral stress or in temporary plugging applications. A 50:50 gypsum cement is frequently used in fighting lost circulation, to form a permanent insoluble plug. These blends should be used cautiously because they have very rapid setting properties and could set prematurely during placement. A limitation of gypsum cements is that they are non-hydraulic and they are not stable in contact with external water sources including corrosive formation waters.

Microfine Cement: Microfine cements are composed of very finely ground (1) sulfate-resisting Portland cements, (2) Portland cement blends with ground granulated blast furnace slag and (3) alkali-activated ground granulated blast furnace slag. Specific surface area for microfine cements is 500 to 1,000 m^2/kg and sometimes higher. Microfine cements have an average particle size of 4 to 6 microns, and a maximum particle size of 15 microns. They hydrate in the same manner as normal Portland cements, though at a significantly faster rate because of the greater surface area. The blends of Portland cement and ground granulated blast furnace slag cement are equivalent to a finely ground pozzolanic cement, resulting in a faster hydration reaction. Such cements have a high penetrability and ultra-rapid hardening. Applications for such cements include consolidation of unsound formations and repair of casing leaks in squeeze operations, particularly “tight” leaks that are inaccessible by conventional cement slurries because of their penetrability.

Expanding Cements: Expansive cements are available primarily for improving the bond of cement to pipe and formation. If expansion is properly restrained, its magnitude will be reduced and a pre-stress will develop. Expansion can also be used to compensate for shrinkage in neat Portland cement. Expansive cements were developed in the 1950's and 1960's that are hydraulic in nature and have controlled expansion that occurs just after setting.

These cements were based on either the formation of considerable quantities of ettringite ($C_6A_3\bar{S}_3H_{32}$) after set, or on hydration of anhydrous polyvalent metal oxides such as MgO or hard-burnt CaO. In the late 1970's, in-situ gas-generating additives were developed. These additives produce micro-size gas bubbles that cause the cement to expand while still in the plastic state.

ASTM C845-96 covers three types of ettringite-expansive cement: Type K, Type S, and Type M. Type S and Type M are no longer commercially produced in the United States. Type O cement, not covered by ASTM specifications, is a hard-burnt CaO expansive cement, originally produced in Japan.

Type K cement contains the anhydrous calcium sulfoaluminate $C_4A_3\bar{S}$, which can be formed in the rotary kiln as an integral part of the cement or formed separately and then blended with Portland cement and anhydrite $C\bar{S}$. Most Type K cements also contain some uncombined CaO to change the early rate of expansion.

Type S cement is a Portland cement that is similar to API Class A, but has a very high C_3A content (approximately 20%). The cement also contains 10 to 15% gypsum. Expansion characteristics are similar to those of Type K cement, though the reaction is somewhat different:

Type M cement is obtained by adding small quantities of refractory cement (with calcium aluminate as the principal compound) and additional calcium sulfate to Portland cement to produce expansive forces.

Type O cement derives its expansion properties from the delayed hydration of the hard-burnt CaO.

Other formulations of expanding cement include the following:

- API Class A or H (Portland cement) containing 5 to 10% of the hemi-hydrate forms of gypsum.
- API Class A, G, or H cements containing sodium chloride in concentrations ranging from 5% to saturation.
- Cement additives that create in-situ gas generation within the cement matrix based primarily on the reaction of finely ground alumina powder with the alkalis present in the cement aqueous solution to produce hydrogen gas. Although alumina powder is the most commonly used additive, zinc, magnesium, and iron powders are potential alternatives.

At this time, the API standards contain no test procedure or specifications for measuring the expansion forces in cement. There is, however, an API Technical Report (API 10TR2, Shrinkage and Expansion in Oilwell Cements) that describes some of the test procedures used for expansion. Hydraulic bonding tests have also been used to evaluate cement expansion.

Calcium Aluminate Cement: High-alumina cement (HAC) was first developed for industrial use as a solution to degradation of mortars and concretes in ground containing large quantities of sulfate. Today, these cements are primarily used in refractory concretes, but they are also widely used in construction for rapid setting and controlled expansion or shrinkage compensation. In well-cementing operations, they are used at both temperature extremes in permafrost zones with temperatures at 32°F or below; in-situ

combustion wells (fireflood) where temperatures may range from 750 to 2,000° F, and thermal recovery wells where temperatures can exceed 1,300°F and fluctuate dramatically.

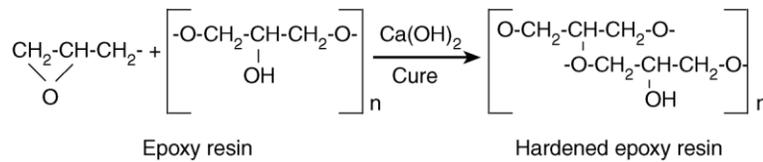
Several high-alumina cements have been developed with alumina contents of 35 to 90 percent, and there is a move to term these collectively as calcium aluminate cements (CAC) because the reactive phase in all cases is calcium aluminate. Calcium aluminate cement is manufactured by blending bauxite (aluminum ore) and limestone and heating the mixture above 2640°F in reverberatory open hearth furnaces until it is liquefied. The molten clinker is continuously removed through a tap hole, collected in molds, cooled, and ground in ball mills. The setting time for calcium aluminate cement is controlled by the composition and no materials are added during grinding.

The manufacturer usually controls standards for calcium aluminate cements because few national standards address these cements. It is the standard type that is most commonly used in well cementing. These cements can be accelerated or retarded to fit individual well conditions, however, the retardation characteristics differ from those of Portland cements. The addition of Portland cement to a refractory cement will cause a flash set; therefore, when both are handled in the field, they must be stored separately.

The Brookhaven National Laboratory reported that calcium aluminate phosphate cement blended with a few additives produce cements that are highly resistant to the corrosive conditions found in wells exposed to naturally occurring “wet” CO₂ gas or the injection of CO₂ for enhanced oil recovery applications.

Latex Cement: Latex cement, although sometimes identified as a special cement, is actually a blend of API Class A, G, or H with latex. Latex is a colloidal suspension of polymer in water. Latex in latex cements are generally copolymer systems that incorporate more than one type of polymer to optimize film formation and flexibility. The copolymers are based on polyvinyl acetate, polyvinylidene chloride-polyvinyl chloride, polyacrylate copolymers or styrene-butadiene, and are spherical with diameters of 0.01 to 1.0 micrometers. In general, a latex emulsion contains only 50 % by weight of solids and is usually stabilized by an emulsifying surface-active agent. The latex particles coalesce to form a continuous film around the cement hydration products in the set cement and effectively coat the walls of the capillary pores. A well distributed latex film may protect the cement from chemical attack by some types of corrosive conditions such as formation waters containing carbonic acid. Latex also imparts elasticity to the set cement and improves the bonding strength and filtration control of the cement slurry.

Resin or Plastic Cements. Resin and plastic cements are specialty materials used for selectively plugging open holes, squeezing perforations, and the primary cementing of waste disposal wells, especially in highly aggressive, acidic environments. These cements may be composed of resins and catalysts alone or contain fillers such as silica sand. Other systems are mixtures of water, liquid resins, and a catalyst blended with API Class A, B, G, or H cement. For example:



A unique property of these cements is their capability to be squeezed under applied pressure into a permeable zone to form a seal within the formation. These specialty cements are used in relatively small volumes, and are generally effective at temperatures from 60 to 200°F (15 to 93°C). Some types of resin cements can be applied in wells with higher temperature conditions.

Sorel Cement: Sorel cement is magnesium-oxychloride cement used as a temporary plugging material in well cementing. The cement is made by mixing powdered magnesium oxide with a concentrated solution of magnesium chloride. The complex hydration reactions include at least eight different primary reactions. Carbonates are generally incorporated into the formulation to reduce the solubility of the magnesium hydroxide chloride hydrates that are normally formed by producing carbonated hydrates. The main phases formed are $\text{Mg}_2\text{OHClCO}_3 \cdot 3\text{H}_2\text{O}$ and $\text{Mg}_3(\text{OH})_2(\text{CO}_3)_4 \cdot 4\text{H}_2\text{O}$. Sorel cements have been used on occasion in the CIS for cementing oil wells at temperatures up to 1400°F (752°C). Acid-soluble magnesia cement that reacts as a complex Sorel cement has been set across production perforations as a temporary abandonment plug and used to protect water injection zones during workover operations. The same system has been used to squeeze lost circulation zones during drilling operations. A more finely ground version is available for applications requiring short cement times.