PREVENTING ESP FAILURES BY UTILIZING INTEGRATED CONTROL SYSTEMS IN THE SACROC CO_2 FLOOD

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ABSTRACT

Electric submersible pumps (ESP's) are difficult to operate in flumping wells. These flumping wells alternately or simultaneously flow up the casing annulus while pumping through the tubing. This is a common operating condition in CO2 floods. A flowing well simulates a no-load or gas locking condition at the surface. The motor controller then shuts the pump down as the under load parameters are exceeded. This repeated cycling is damaging to all components in the system.

An integrated control system utilizing a down hole sensor, surface controls and remote transmission unit (RTU) can been utilized to prevent unnecessary shutdowns and premature failures. This system bypasses the under load parameters but limits the motor operating temperature to a set degree. If a gas locking or pump off condition occurs, the motor temperature rises, the system shuts the unit down and then restarts once the temperatures normalize.

This application increases production and reduces system failures.

THE SACROC UNIT - HISTORY

The Kelly Snyder Field was discovered in November of 1948 in Scurry County, Texas. The Kelly Snyder Field is part of the Horseshoe Atoll, (**Figure 1**) one of the world's largest subsurface carbonate buildups. Following discovery, approximately 1200 Canyon Reef wells were drilled during the next four years. In 1953 the SACROC (Scurry Area Canyon Reef Operating Committee) Unit was formed to address the declining reservoir pressure, which had fallen from 3122 psia to 1650 psia (below bubble point). This was accomplished by initiating a secondary recovery operation.

Water injection was instigated in 1954 to try and increase reservoir pressure. Tertiary recovery efforts, in the form of carbon dioxide (CO2) injection began in 1972. Currently the SACROC Unit is an active miscible CO2 WAG (Water Alternating Gas) flood developed on 20/40 acre spacing and flooded with a combination of five, seven and nine spot patterns.

The injectors are switched from water to CO2 according to the hydrocarbon pore volume (HCPV) injected. The initial CO2 cycle is 15% of the HCPV in each flood pattern; this is followed by up to a 1% HCPV slug of water. The second CO2 Volume is 6% HCPV followed with up to a 2% HCPV slug of water. These alternating cycles are continued until the total CO2 volume injected is 35% HCPV at a minimum. The well is then placed on water injection until abandonment. Although the alternating of water and CO2 injection increases oil recovery, it causes unique problems in artificial lift because the two fluids act differently when produced.

Currently, the SACROC Unit produces 23,000 bbls oil, 423,000 bbls water, 18 MMCF hydrocarbon gas, and 160 MMCF CO2. There are 250 active producers consisting of 90 flowing and 160 artificial lift wells. ESP's are the lift mechanism in 95% of the non-flowing wells.

The formation is highly pressured with shut-in bottom hole pressures reaching in excess of 3000 psi. Kill fluids are usually required to work on these wells. Mud weights required to safely pull most wells range from 14.5 to 16 lbs/gal. Costs associated with failures are usually high.as mud is expensive and potentially damaging to the formation; therefore increased run life on artificial lift systems is imperative to the economics of the SACROC Unit.

Current well bore conditions include:

- Gas-liquid ratios (GLR) commonly over 2000 and as high as 6000, as measured in SCF/Bbl

- Gas content is over 80% CO_2.
- Reservoir temperature is 126 DEG F.
- Systems sized to 800 psi pump intake pressure (PIP)

EFFECTS OF CO2 ON ELECTRIC SUBMERSIBLE PUMPING SYSTEMS

CO_2 floods have historically presented operational problems for ESP's. CO_2 breaks out of solution as it reaches the wellbore drawdown radius. This increase in GLR causes the well to attempt to flow up the annulus and through the pump. When the well is flowing, the submersible pumping system begins to unload. The surface controller senses the under load condition as the underload parameters are exceeded, and the system shuts down. The well then quits flowing due to liquid loading. When the hydrostatic pressure is decreased enough to allow CO_2 to break out of the well, it starts flowing again, thus creating the phenomenon called "Flumping" or a simultaneous Flowing and Pumping of the well. (**Figure** 2)

The ESP will now continue to cycle as long as the producing fluid contains CO_2 and the under load settings are properly set.

EFFECTS OF CYCLING ON ELECTRIC SUBMERSIBLE PUMPING SYSTEMS

Excessive cycling of ESP's usually leads to shorter run times and premature failures. This type of operation induces excessive mechanical stress on the ESP components, contamination of the systems protector/seal sections, and electrical stresses on the motor and flat cable. (**Figure** 3) (**Figure** 4)
System observations and analysis conclude that:

- Cycling caused by shutdowns are not necessarily related to gas locking
- System shutdowns result in reduced production rates
- Frequent cycling can lead to contamination and destruction of seal section components
- Shafts and coupling breaks can occur due to frequent start ups
- Cycling can cause heat stress in motors and motor flat cables

SOLUTION

Existing installations in CO_2 floods have proven that ESP's will operate when a well is flowing, if the underload settings are set below idle current and a gas lock or pump off condition does not occur. However, if a gas lock or pump off condition does occur and no underload parameters are set, then the result will surely be a catastrophic failure. To solve the problem, an integrated control system utilizing a down hole sensor, surface controls and RTU was installed. The systems are set to over-ride underload parameters by limiting the motor operating temperature to 200 DEG F. If a gas lock or pump off condition occurs, the temperature will rise and the surface controller will trip and shut the unit down. This motor temperature increase is caused by the reduction of liquid (due to the increase of gas breakout) passing by the motor not allowing the heat to dissipate normally. (ESP's are landed above the pay zone because of the blast jet-like or erosional effect of CO_2 entering the wellbore upon equipment.). The controls can be set to restart after a preset delay or can be locked out requiring a technician to clear and restart the unit.

With the down hole sensor installed and system control parameters set:

- Allows the system to continue producing in a no load condition
- During gas locking conditions, the motor temperature will reach the predetermined setting, the RTU will shut-down the unit, allowing the gas to migrate out of the pump and the motor time to cool
- The well can now cycle on and off automatically based on acceptable motor temperature settings
- Motor temperature, well bore temperature, intake pressure, motor amps and voltages are measured and recorded, then monitored remotely via a SCADA (supervisory control and data acquisition) system or downloaded via a lap-top computer.

CURRENT INSTALLATIONS

The down hole sensor is currently installed in three wells in SACROC. Well data for these wells are shown in (**Table 1**). The production tests for these wells are shown in (**Table 2**). Injection patterns for these wells are shown in (**Figure 5**) and (**Figure 6)** respectively. Injection tests for offset injectors are shown in
(**Table 3**).

DATA AQUIRED

The down hole sensors measure the following:

- Current Time
- Pump Intake Pressure
- Pump Intake Fluid Temperature
- Motor Temperature
- Amperage
- Voltage

DATA ANALYSIS

The data is downloaded into a text file. This file is uploaded into MS Access. The hourly averages for all data are calculated and compared to individual data points. An exception report is generated showing all downtime and potentially bad data points.

POSSIBLE DISCOVERIES

To validate the sensor data, the pump intake pressures calculated from the fluid level shots with a model E Echometer and a Lufkin Ventawave are consistent with pump intake pressures taken from two of the sensors. One sensor seemed to be recording a much higher pump intake pressure but it is also supporting a higher column of fluid and a higher GLR. Does this mean that the pump intake pressures that have been used as a tool to size pumps in the higher GLR applications have been inaccurate? Is the CO_2 in the casing causing erroneous pump intake pressure readings?

Continual monitoring of the pump intake pressure allows the operator to determine the volumes of CO_2 that is being produced up the tubing and casing annulus. This volume can be used to possibly help resize the pumps, to allow for this phenomenon.

CONCLUSION

This installation will reduce production losses resulting from excessive cycling, and should reduce system failures due to detrimental wear of components suffering from extended operation under no-load conditions. The installation of downhole monitoring devices will allow engineers to more accurately predict the amount of fluids the pumps have available to produce.

Table 1
Installation Data for Downhole Sensors

Well #	124-4	124-6	170-6
Date Installed	09/20/2003	9/22/2003	11/26/2003
Pump Size	TD 1750	TD 1750	TD 850
Stages	208	200	211
Setting Depth	6515	6509	6582
Tubing Size	2 7/8” T.K. Lined	2 7/8” T.K. Lined	2 7/8” T.K. Lined
Casing Size	7” 24#	7” 26#	5.5” 15.5#
Top of Perfs	6609	6596	6700 (Open Hole)

Table 2
Well Test for Wells with Downhole Sensors Installed

Well	Test Date	Oil	Water	Gas	Ptb	Pcs
124-4	12/15/2003	74	1312	442	520	500
	11/14/2003	56	1317	110	400	250
	11/5/2003	74	1302	180	360	250
	10/25/2003	39	1420	148	350	250
	9/25/2003	48	1916	10	320	230
	9/21/2003	40	2140	325	500	240
124-6	12/10/2003	210	1746	1140	600	340
	11/29/2003	157	1847	279	600	340
	11/7/2003	63	1877	144	850	300
	10/26/2003	6	1659	1410	850	300
	10/14/2003	9	1738	44	600	250
170-6	12/18/2003	239	667	1060	360	
	12/17/2003	235	641	1042	350	
	12/16/2003	244	654	1021	340	
	12/15/2003	229	656	1023	340	
	12/14/2003	221	669	1002	340	
	12/13/2003	209	680	966	360	
	12/11/2003	213	690	966	340	
	12/8/2003	209	720	918	340	
	11/27/2003	86	901	327	320	
	11/14/2003	254	668	1393	790	
	10/15/2003	271	1180	3422	380	
	10/6/2003	686	1059	2774	350	
	9/30/2003	562	780	2095	32	720
	9/22/2003	458	854	1577	710	300

Table 3
Injection Tests on Wells Offset to Installed Sensors

Producer	Injector	Factor	Date	Fluid	W	CO2	Wall	CO2all	Ptb
124-4	124-12	31.6%	12/15/2003	CI		3721		1176	1890
			11/19/2003	CI		3723		1177	1965
			10/28/2003	CI		3180		1005	2025
			10/24/2003	WI	5920		1872		1675
			10/7/2003	WI	1858		587		1800
			10/1/2003	CI		1673		529	1856
	124-13	11.2%	12/15/2003	CI		3067		344	1871
			11/19/2003	CI		2981		334	1955
			10/28/2003	CI		2605		292	2000
	124-7	42.2%	12/15/2003	CI		400		169	1976
			11/12/2003	CI		2364		997	1966
			10/7/2003	CI		3206		1353	1925
	75-7	23.8%	12/18/2003	CI		2278		541	1880
			11/30/2003	CI		2121		504	1837
			10/31/2003	CI		2284		543	1958
			9/30/2003	CI		1760		418	1783
124-6	124-12	17.1%	12/15/2003	CI		3721		637	1890
			11/19/2003	CI		3723		638	1965
			10/28/2003	CI		3180		545	2025
			10/24/2003	WI	5920		1014		1675
			10/7/2003	WI	1858		318		1800
			10/1/2003	CI		1673		286	1856
	124-13	12.8%	12/15/2003	CI		3067		392	1871
			11/19/2003	CI		2981		381	1955
			10/28/2003	CI		2605		333	2000
	124-15	13.1%	12/15/2003	CI		1128		147	1990
			11/19/2003	CI		895		117	2055
			10/7/2003	CI		830		108	2000
			9/23/2003	WI	831		109		1735
170-6	170-1	13.5%	12/18/2003	CI		4438		599	1682
			12/8/2003	CI		4774		645	1755
			11/30/2003	CI		4036		545	1606
	170-2	25.0%	12/15/2003	CI		4223		1056	1484
			12/6/2003	CI		4537		1135	1521
			11/27/2003	CI		3876		970	1500

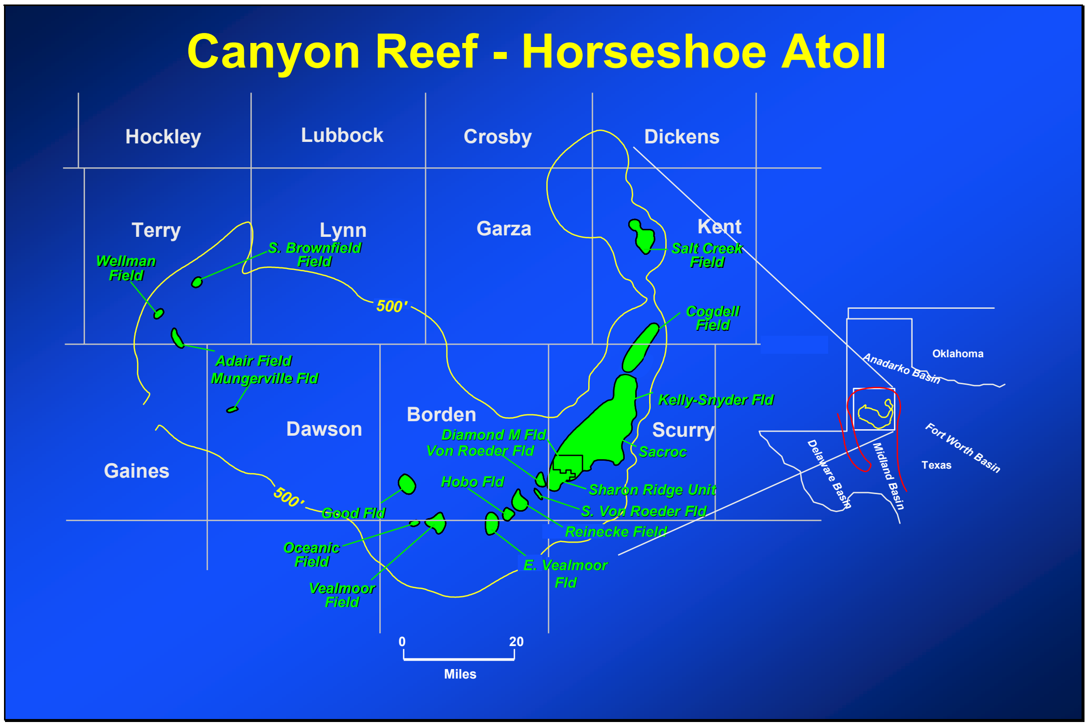

Figure 1 – The Horseshoe Atoll

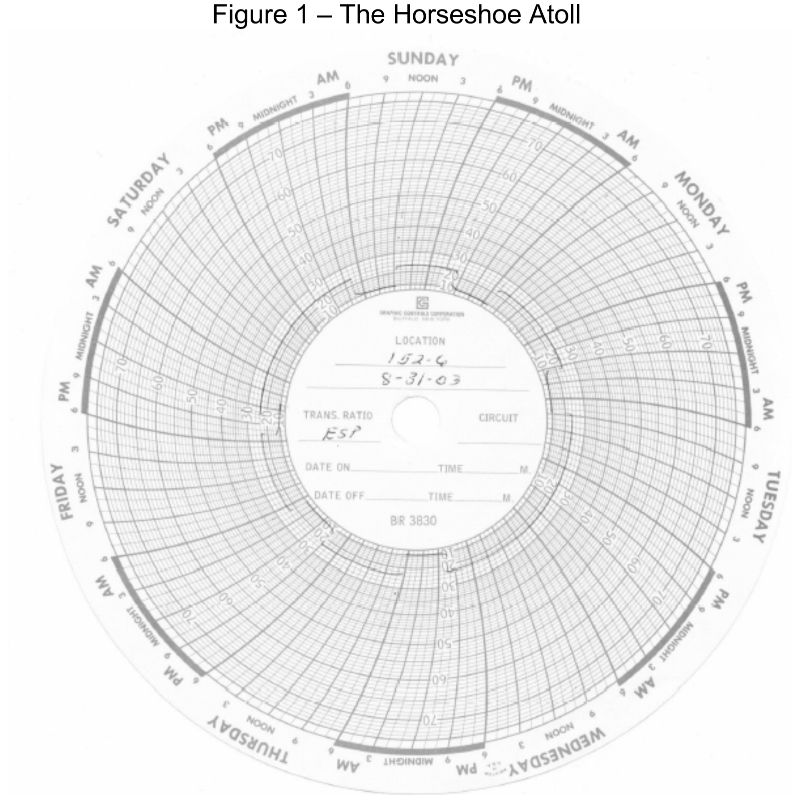

Figure 2 - Example of Amp Chart on Well with Cycling Electric Submersible Pump

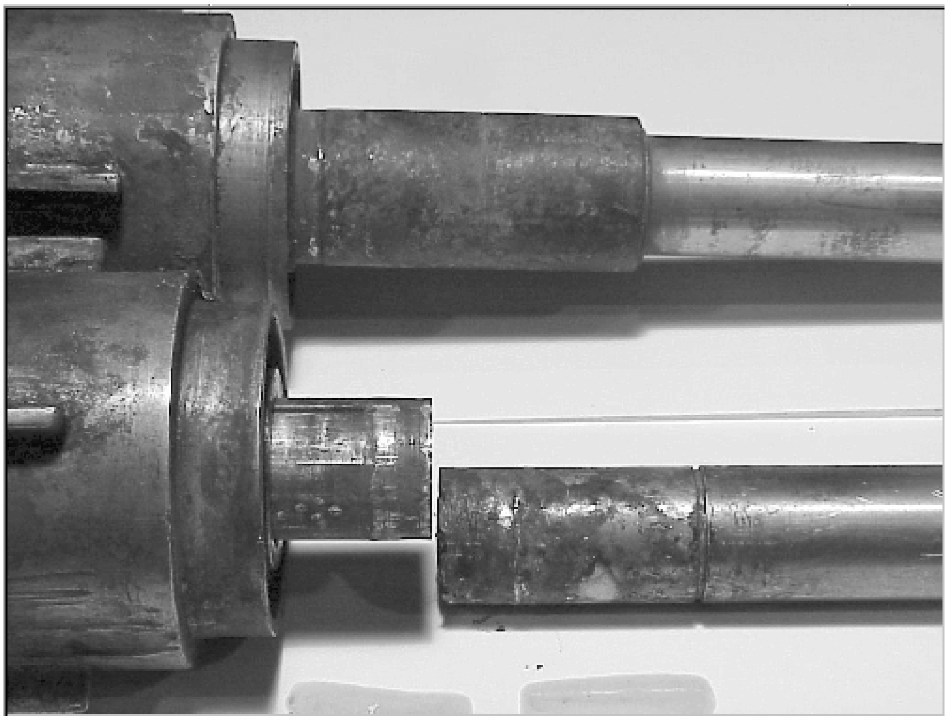

Figure 3 – Shaft Failure Due to Excessive Cycling of Electric Submersible Pump

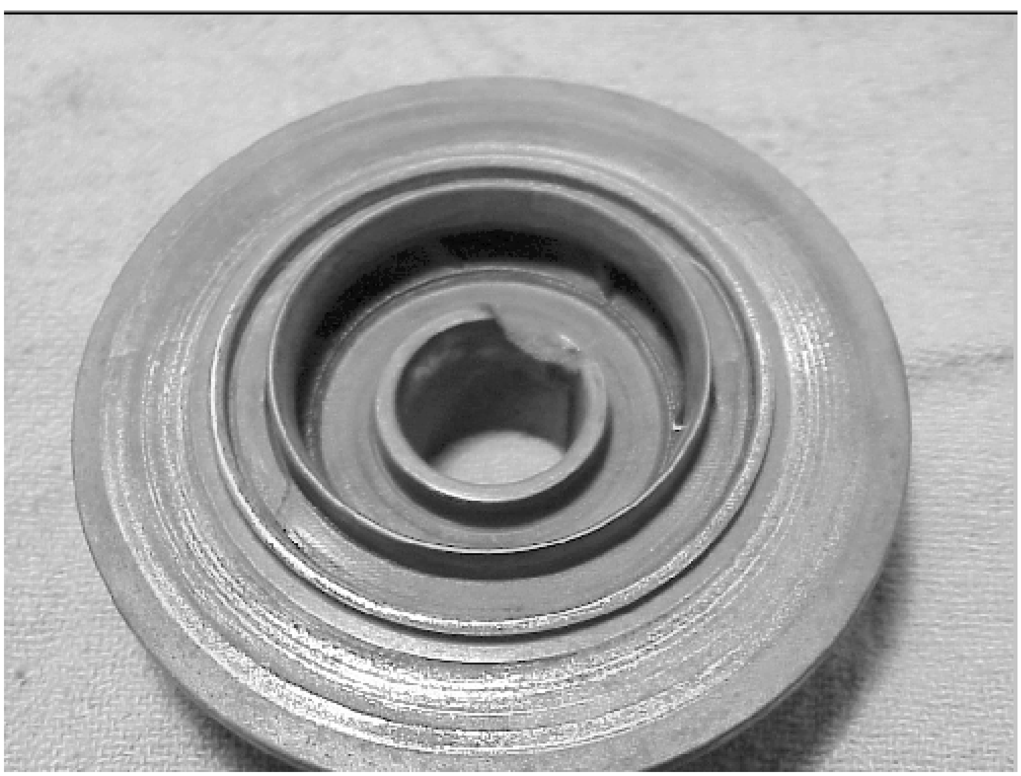

Figure 4 - Example of Pump Failure Due to Excessive Downthrust (Under Load)

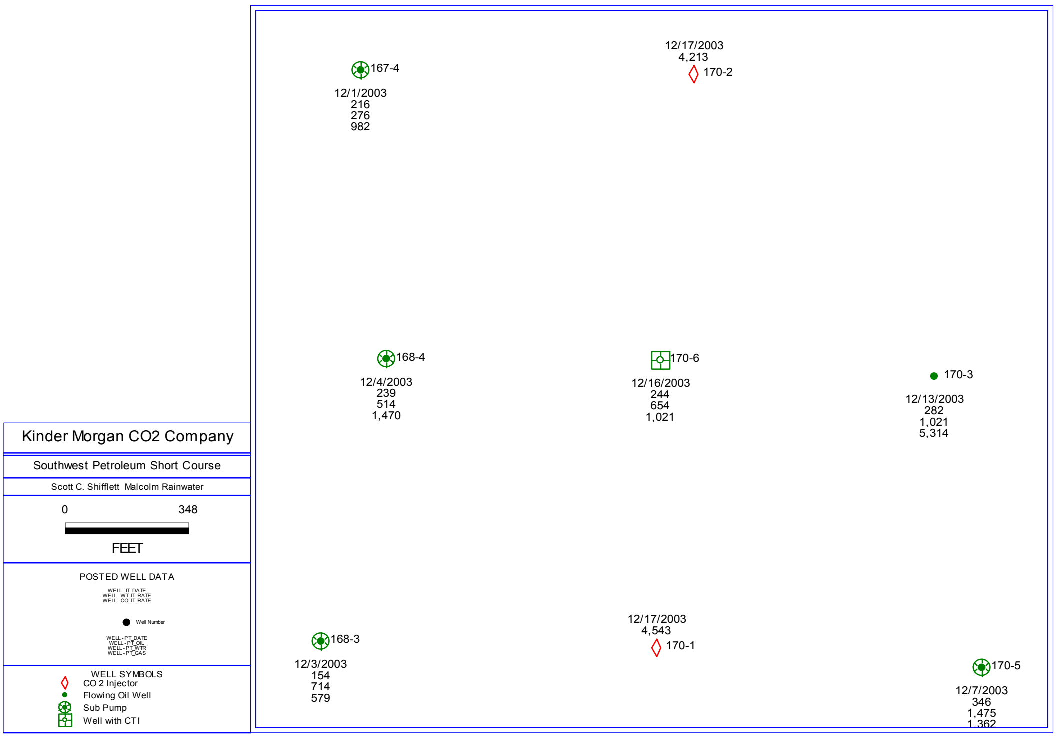

Figure 5 – Map of the 170-6 and Surrounding Area

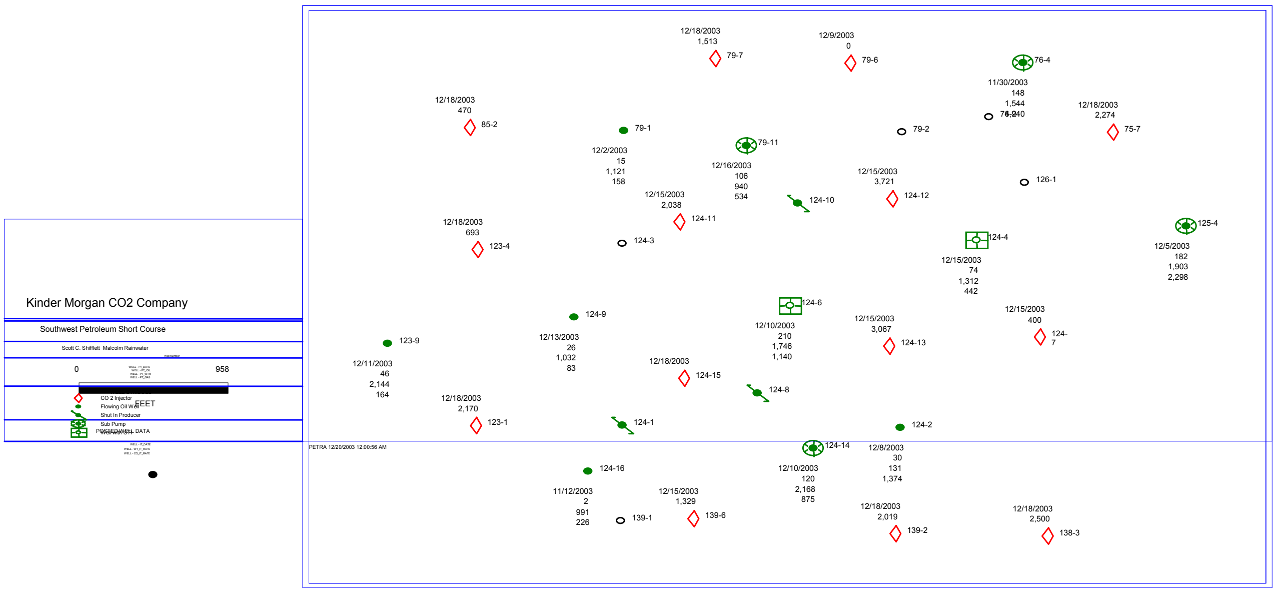

Figure 6 - Map of the 124-4, 124-6 and Surrounding Area