Innovative Energy Technologies Program: 03-056
Quaternary Acid Gas Injection at Judy Creek BHL "A" Pool
2009 Annual Report

1.0 Report Abstract

A quaternary CO_2 EOR pilot is being conducted at the Judy Creek Beaverhill Lake "A" Pool, a middle Devonian age carbonate reservoir. The pilot pattern has previously undergone waterflood and hydrocarbon miscible flooding.

CO_2 injection in WAG mode began in February 2007. Acid gas injectant consists of waste CO_2 with a small percentage of H_2S from the Judy Creek Gas Plant, supplementing a pure CO_2 stream which is purchased and trucked. In April 2009, injection of CO_2 concluded at 26.2% HCPV. Water injection and production response monitoring continues through the end of the report period.

This report outlines production and operational data for the period ending December 31, 2009.

Overall pilot performance to date indicates encouraging results for incremental recovery of oil, hydrocarbon solvent and CO_2 breakthrough. CO_2 reproduction has been cyclic, lagging CO_2 injection, and peak reproduction periods which were somewhat predictable resulted in some operational downtime.

2.0 Summary

<u>2.1 Team Members</u>

Current Team Members

- Ray Pollock – Exploitation Engineer
- Norm Schultheis - Geologist
- Craig Johnson – Operations Superintendent
- Ken Suchan – Operations Foreman
- Al Myles – Well Servicing Coordinator
- Bruce Malcolm – Senior Royalty Coordinator
- Glenn Malcolm – Manager, Geophysics
- Ashok Singhal – Consulting Research Engineer

New Team Members

- Rohan Balkaran – Facilities Engineer
- David Fowler – Geophysicist
- Colin Muir – Exploitation Engineer

Former Team Members

- Mario Struik – Facilities Engineer
- Randy Sutherland – Construction Supervisor
- Rob Moriyama – Director, Exploitation Engineering
- Andrew Seto – Manager, Reservoir Studies

2.2 Activity Summary

Following is a point for summary of key activities associated with the Judy Creek acid gas injection pilot.

Q2 2006	10-02-064-11W5 producer acid fracture stimulation Injector 07-02-064-11W5 injection string upgrade
Q3 2006	Producer 02-02-064-11W5 flowline replacement Construct & install acid gas pipeline from 04-23-064-11W5 to injector 07-02-064-11W5 Wellhead upgrades at pilot producers
Q4 2006	Construction & installation of surface facilities at injector 07-02-064-11W5 Dec - Acquire baseline 3D seismic survey of pilot area
Q1 2007	Jan - ERCB D51 & D65 Approval Jan - Static pressure surveys Jan - Fluid sampling initiated Feb - Commence CO_2 injection (Purchased CO_2 only) Mar - CO_2 injection profile log
Q2 2007	Apr - Water injection profile log Apr - Supplement injection stream with acid gas Apr - Water tracer injection May - 02-02-064-11 ESP repair; install downhole pressure probes; Saturation (RST) log May - 06-02-064-11 ESP repair; install downhole pressure probes
Q4 2007	Nov - Water injection profile log Dec - 02-02-064-11W5 ESP repair & static pressure survey
Q1 2008	Mar - 07-02-064-11W5 Injection fall off test
Q2 2008	May - 06-02-064-11W5 ESP repair May - Static pressure surveys June – Alter target WAG ratios & injection schedule
Q3 2008	Sept – Static pressure surveys Nov – Judy Creek Gas Plant completes “jefftreat” upgrades
Q1 2009	Feb – Acquire 3D seismic survey of pilot area (4D)
Q2 2009	Apr – Manage CO_2 breakthrough Apr – Static pressure surveys Apr – Terminate CO_2 injection
Q3 2009	Aug – Injection profile
Q4 2009	Oct – Static pressure surveys Dec – Adjust water injection target

2.3 / 2.4 Production & Reserves Summary

Table 1 below outlines the injection and production results relative to the forecast provided with the project approval. Table 2 shows the ultimate reserves expectation of the pilot relative to the original project approval.

Table 1: 2009 Monthly and Calendar Year Production and Injection Data

	CURRENT DATA					IETP APPROVAL FORECAST			
	CO2 Inject. e3m3	Oil w/o 10-02 frac m3	Oil w/ 10-02 frac m3	Hydrocarb. Gas (Raw) e3m3	Acid Gas Prod. e3m3	CO2 Inject. E3m3	Oil m3	Hydrocarb Gas (Raw) e3m3	Acid Gas Prod. e3m3
2009 Monthly Data – Actual									
Jan-09	2,766	357	466	187	434	0	272	97	310
Feb-09	360	306	417	226	543	0	245	97	280
Mar-09	1,480	292	389	158	423	0	272	97	310
Apr-09	1,565	276	403	154	486	0	263	97	300
May-09	0	261	410	100	327	0	272	97	310
Jun-09	0	362	500	49	326	0	263	97	300
Jul-09	0	340	478	62	292	0	272	97	310
Aug-09	0	262	411	104	249	0	272	97	310
Sep-09	0	253	363	103	223	0	263	97	300
Oct-09	0	262	329	71	176	0	272	97	310
Nov-09	0	280	351	51	174	0	263	97	300
Dec-09	0	259	346	86	183	0	272	97	310
Calendar Year Data (Actual & Forecast)									
2006	0	0	749	0	0	0	0	0	0
2007	12,253	722	2,111	1,639	416	13,385	0	0	0
2008	16,007	3,073	4,221	2,406	2,736	13,385	2,848	580	1,825
2009	6,172	3,509	4,861	1,351	3,837	0	3,197	1,160	3,650
2010	0	2,315	2,944	686	1,456	0	1,478	1,160	3,650
2011	0	667	910	112	382	0	1,128	580	1,825
2012	0	204	256	6	92	0	550	0	0
2013	0	0	0	0	0	0	336	0	0
TOTAL	**34,431**	**10,490**	**16,053**	**6,200**	**8,918**	**26,770**	**9,538**	**3,481**	**10,951**

Table 2: FORECAST RESERVES @ YE 2009

	Oil (w/o frac) [e^3m^3]	Oil (w/ frac) [e^3m^3]	Sales Gas [e^6m^3]	Ethane [e^3m^3]	Propane [e^3m^3]	Butane [e^3m^3]	C5+ [e^3m^3]	MOE 6:1 (w/ frac)	BOE 6:1 (w/ frac)
Current	10.5	16.0	3.1	4.1	1.7	1.2	0.5	**24.1**	**166.1**
Approval	10.0	10.0	0.9	0.9	0.7	0.4	0.2	**12.4**	**82.5**

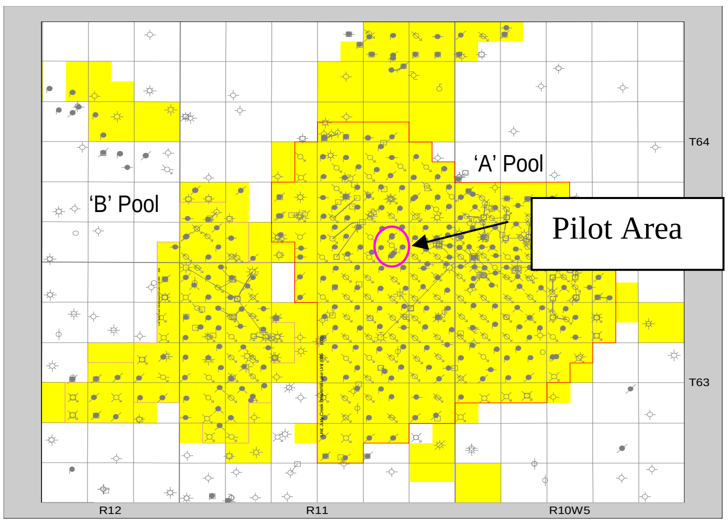
3.0 Well Information

3.1 Well Layout & Pattern Description

The pilot is located in an existing 80 acre pattern located within the Judy Creek Beaverhill Lake (BHL) "A" Pool (Figure 1). The pool spans portions of four townships in Central Alberta from 63-10W5 to 64-11W5, and is a carbonate reservoir of middle Devonian age, located at a depth of approximately 2400 m.

The pattern area is small relative to other "A" Pool patterns. The smaller pattern was selected to allow a higher percentage of the pattern pore volume to be flooded with a given volume of injectant and to provide timely pattern response.

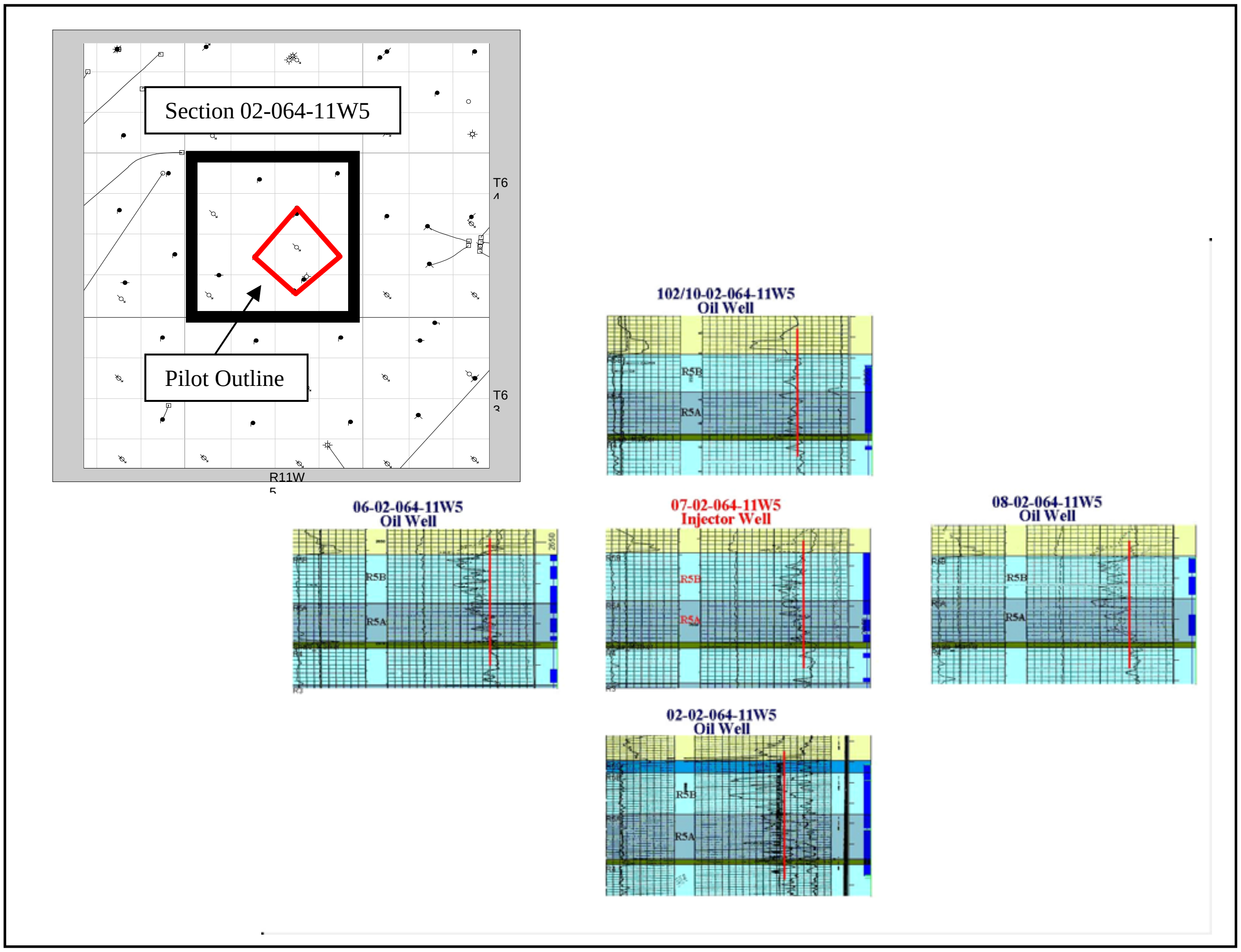
Figure 1: Judy Creek BHL "A" Pool



The pattern is centered on injector 07-02-064-11W5 (abbreviated 07-02), and includes four vertical oil producers. The pattern has historically undergone both waterflood and hydrocarbon miscible flood operations. Miscible operations were conducted between February 2002 and August 2003.

The montage shown in Figure 2 shows the pattern well layout within section 02-064-11W5. Also included are the open hole logs associated with each pattern well.

Figure 2: CO_2 Pilot Well Layout



3.2 2009 Drilling, Completion and Workover Operations

April 2009: 06-02-064-11W5 electrical submersible pump (ESP) repair after 12 month run life. Failure analysis found the cause to be a result of frequent startups and shutdowns. 06-02 was shut-in frequently during high CO_2 cycling periods due to CO_2 handling capacity at the Judy Creek Gas Conservation Plant. CO_2 corrosion was not observed during the replacement of this pump.

3.3 Well Operation

Well service factor has been satisfactory over the review period, with downtime events occurring mainly due to routine maintenance and pressure data acquisition. Producers were shut in to control CO_2 production in the early part of the year. This is discussed in later sections.

3.4 Well List and Status

Following is a listing of each of the pattern wells, and their function and status.

Well	Status and Function
00/07-02-064-11W5/0 (Abbreviated 07-02)	Operating water & acid gas injector
00/02-02-064-11W5/0 (Abbreviated 02-02)	Operating oil producer (ESP)
00/06-02-064-11W5/0 (Abbreviated 06-02)	Operating oil producer (ESP)
00/08-02-064-11W5/0 (Abbreviated 08-02)	Operating oil producer (ESP)
02/10-02-064-11W5/0 (Abbreviated 10-02)	Operating oil producer (rod pump)

3.5 Wellbore schematics

See Appendix I for wellbore schematics.

3.6 Spacing and Pattern

Discussed in section 3.1

4.0 Production performance

4.1 Injection & Production history

Figures 3a to 3d detail the daily injection & production history for each pattern well. Appendix II contains the monthly & daily plots & monthly tabular data associated with each producer.

Figure 3a: 02-02-064-11W5 production and 07-02-064-11W5 Injection

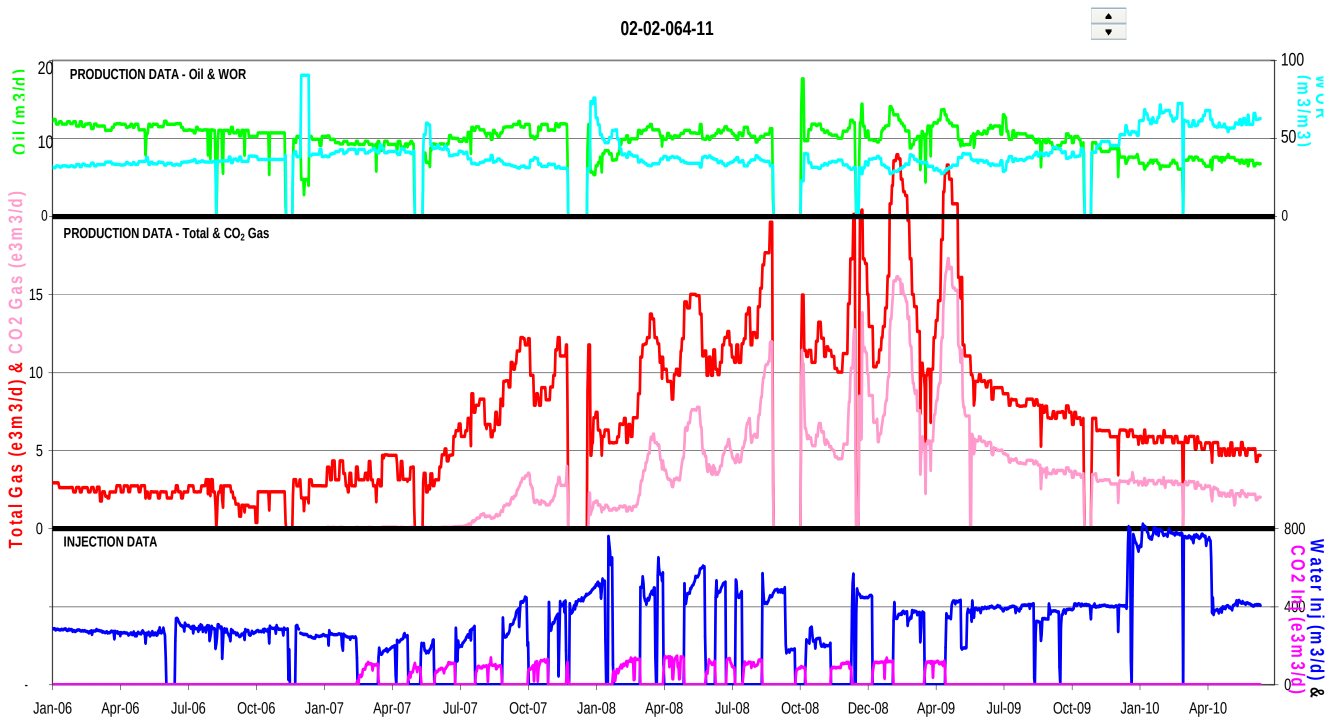


Figure 3b: 06-02-064-11W5 production and 07-02-064-11W5 Injection

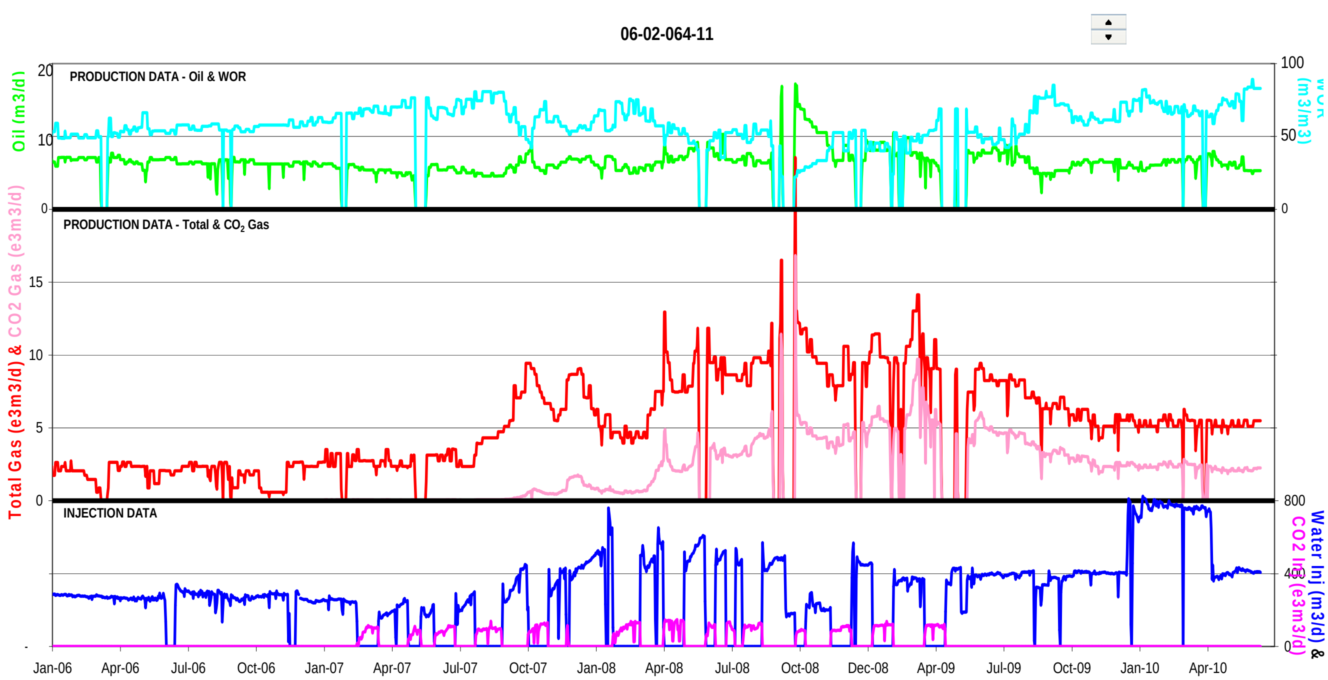


Figure 3c: 08-02-064-11W5 production and 07-02-064-11W5 Injection

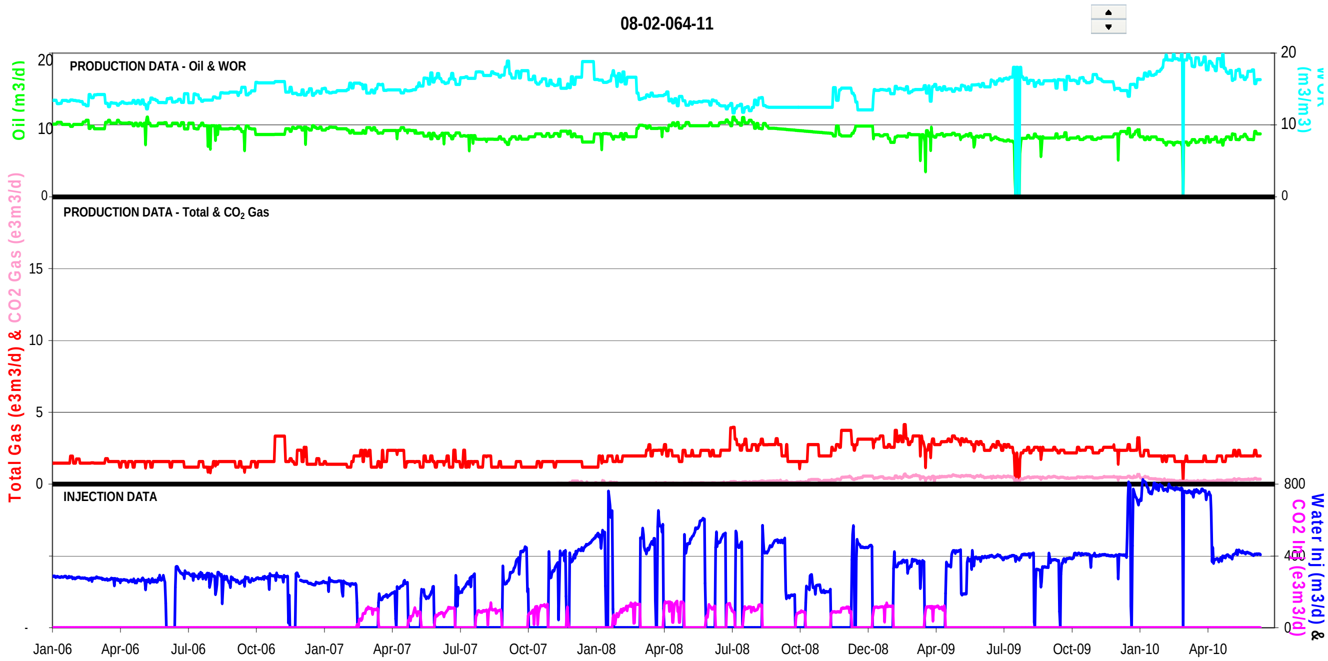
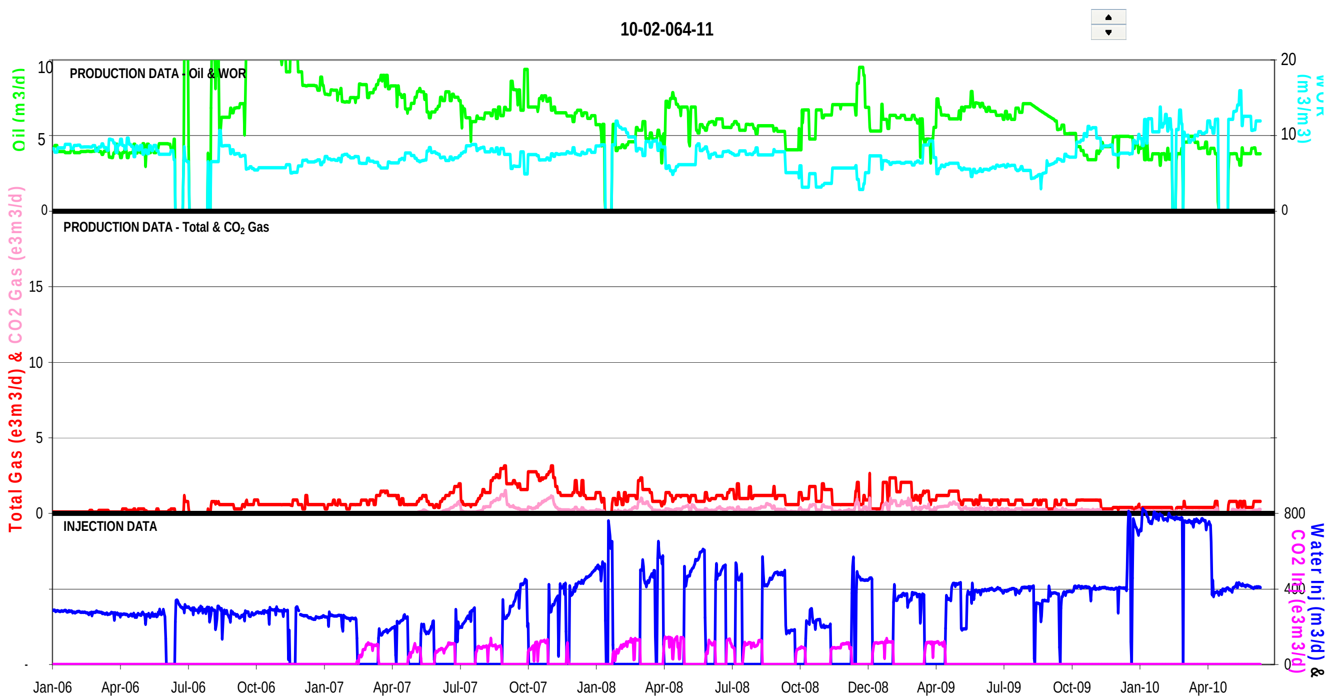


Figure 3d: 10-02-064-11W5 production and 07-02-064-11W5 Injection



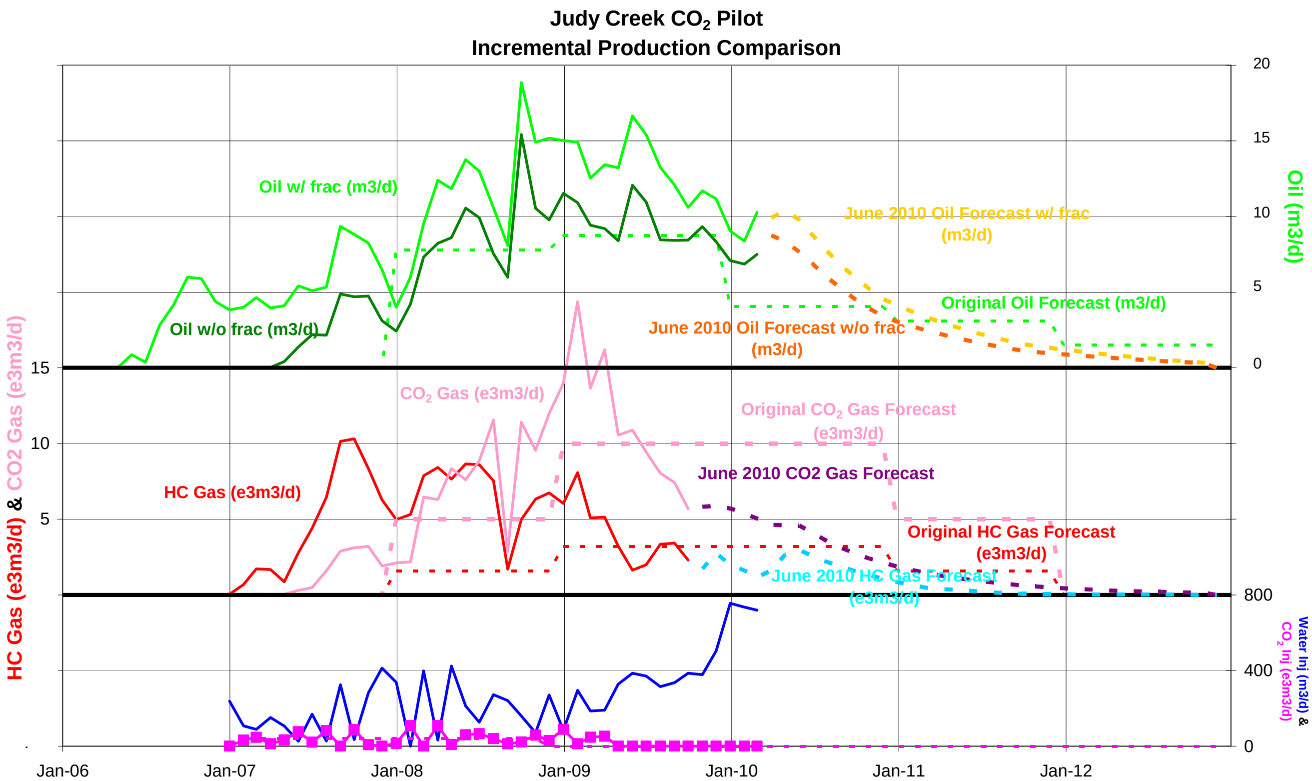
4.2 Composition of produced / injected fluids

Please reference Appendix II for composition tabular data.

4.3 Predicted vs. Actual Performance

Figure 4 provides a graphical comparison between actual pilot performance and the IETP Approval forecasts. The data is also provided in tabular form in Appendix III.

Figure 4: Pattern Production and Injection vs. Approval Forecast



Discussion

a) Injection

Initial CO_2 injection rates at 07-02 were lower than expected based on rates observed under hydrocarbon miscible flood. Over several months an increase in the injection rates of both water and CO_2 was observed. This is believed to be in part the result of increasing reservoir permeability caused by dissolution of reservoir rock from injected CO_2. In the latter portions of 2008, CO_2 injection rate was reduced to manage peak CO_2 production rates. CO_2 injection was terminated in April 2009 due to increased difficulties in handling CO_2 production at the Judy Creek Gas Conservation Plant. Water target rates were set to 400m^3/d to maintain voidage. The injection target was increased to 800m^3/d in Dec 2009 to observe production trends.

b) Production

In general, initial production response in terms of oil, hydrocarbon gas and CO_2 reproduction was seen earlier than had been predicted. The higher productivity producers 02-02 and 06-02 showed some response within the first six months of injection, compared to the predicted response time of 18 months.

Significant response began between 12 and 18 months. After 18 months of injection, peak oil and gas response to injection began to correlate strongly with injection events in a cyclic nature, with the magnitude of the peaks also increasing. Since terminating CO_2 injection gas production declined sharply, while oil production has been declining gradually.

Producer 10-02 experienced minor gas cycling after the first injection cycle. This was a direct result of an acid fracture stimulation which had been performed to improve communication with the 07-02 injector. In previous hydrocarbon miscible flood operations, 10-02 saw no response to solvent injection at 07-02. The acid fracture treatment improved oil production at this producer significantly. For the sake of clarity certain of the reported oil recovery values included in this report will show incremental oil production with and without the incremental oil associated with this workover. This is done so as not to combine impacts of the workover with direct CO_2 flood impacts (although a portion of this production can be attributed to the flood).

The magnitude of the peak acid gas reproduction rates began to impact gas plant operations in August 2008. This resulted in modification to the injection cycles and modifications to gas plant facilities. These will be discussed further in a later section.

Current estimates and actual 2009 recovery of hydrocarbon gas are higher than in the original forecast. This is the result of additional oil recovery (associated solution gas) from the 10-02 frac, and a higher volume of residual solvent within the pattern boundaries than was estimated in the original forecast.

4.4 Pressure Data

The following pressure data was collected from the Judy Creek CO_2 pilot:

- Static reservoir pressure
- Producer 02-02-064-11W5: flowing pressure data
- Producer 06-02-064-11W5: flowing pressure data
- Injector 07-02-064-11W5: tubing wellhead pressure

4.4.1 - Static Reservoir Pressure

To ensure miscibility of the acid gas solvent with the Judy Creek oil, reservoir pressure is maintained above 23.0 MPa. To monitor static reservoir pressure, pressure measurements are taken at two of the pattern producers annually. The static pressure measurements acquired for pilot producers are shown in Table 3 below. Note that 06-02 builds to 23.0MPa in ~7 days, while 02-02 takes ~21 days.

Table 3: Static Reservoir Pressure Data

Well	Shut-in Date	Survey Date	Shut in Days	Datum Pressure (MPa)
06-02-064-11	24-Jan-07	31-Jan-07	7	24.0
02-02-064-11	24-Nov-07	03-Dec-07	9	22.3
02-02-064-11	24-Nov-07	17-Dec-07	23	23.5
06-02-064-11	19-May-08	25-May-08	6	25.0
02-02-064-11	26-Aug-08	04-Sep-08	9	22.8
02-02-064-11	26-Aug-08	18-Sep-08	23	24.4
06-02-064-11	9-Apr-09	16-Apr-09	7	24.7
02-02-064-11	18-Oct-09	28-Oct-09	10	23.8
06-02-064-11	26-Mar-10	31-Mar-10	5	26.7

4.4.2 – Producer 02-02 & 06-02-064-11 Bottomhole Flowing Pressure

Producers 02-02 & 06-02 were equipped with downhole pressure sensors in conjunction with ESP replacements in May 2007. Both wells maintain a bottomhole flowing pressure (P_{wf}) of ~15 MPa. Periodic increases in P_{wf} are typically associated with downtime or gas cycling. (Figure 5a & 5b). The pressure sensor at 06-02 quit transmitting in Nov 2008, but was repaired during the ESP replacement in April 2009 and then failed again in March 2010. The pressure sensor at 02-02 failed in August 2009 and will be repaired during the pump replacement.

Figure 5a: 02-02-064-11 Flowing Bottomhole Pressure

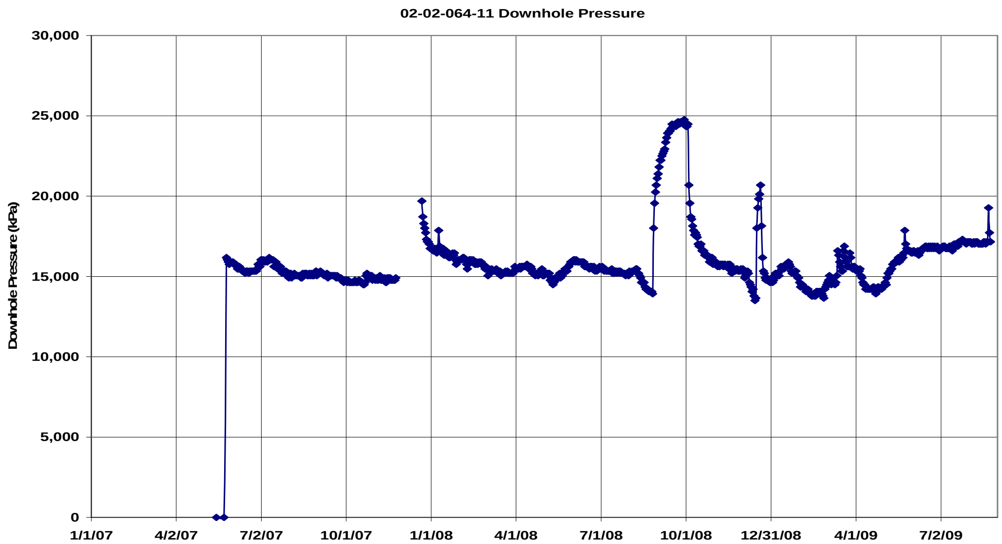
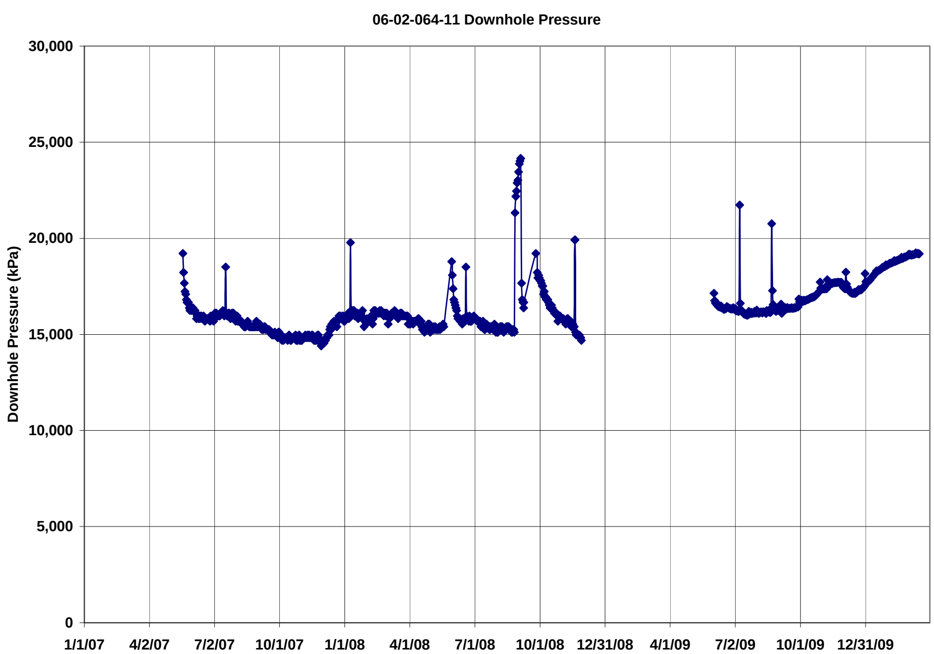


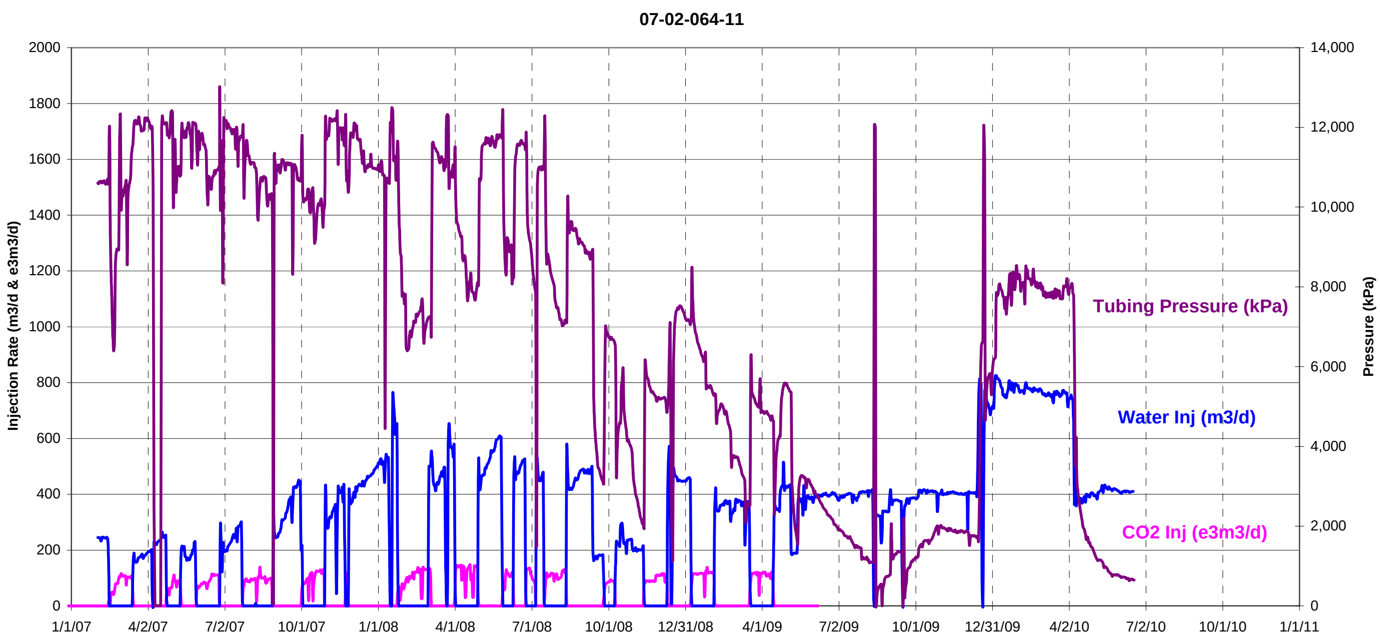
Figure 5b: 06-02-064-11 Flowing Bottomhole Pressure



4.4.3 - Injector 07-02-064-11 Tubing Wellhead Pressure

Tubing pressure data is collected at injector 07-02. Figure 6 displays this tubing pressure data with water and CO_2 injection rate data. Water injection rates began to increase in Q3 2007. A choke was installed in Q3 2008 to manage voidage replacement VRR and WAG ratio. Water injection target was set to 400m^3/d, which resulted in wellhead pressure to continue to decline to 1000kPa. The target was increased to 800m^3/d from Dec 2009 to Apr 2010 to observe production changes. Production observations are still ongoing and will be discussed in the 2010 annual report.

Figure 6: 07-02 Injection Pressure Data and Injection Rates



5.0 Pilot Data

<u>5.1 Other Data (geology, geophysical, lab studies, simulation, PVT, other)</u>

5.1.1 - Pilot Performance History Match Using Streamline-based Model

To supplement existing forecasts, based on compositional simulation results and analog analysis, a screening level streamline based model was employed to generate forecasts of ultimate oil and CO_2 recovery from the pilot. The software was developed by Texaco Exploration and Production Technology Department in the mid-1990s. It is a relatively fast and simple screening tool and can be used to simulate waterflood and various modes of CO_2 flooding (e.g. WAG, Immiscible).

Based on the early history match of pilot performance, the model forecasted an ultimate incremental oil recovery of 2.3% OOIP and recovery of 25% of the injected CO_2 (CO_2 bank size: 30% HCPV). Prior to terminating CO_2 injection, this coincided with our previous forecasts (2.5-3.0% OOIP recovery).

However, oil rates have not declined as severely as predicted and our updated forecasts indicate 3.0-3.5% OOIP and 25-35% CO_2 recovery. The streamline model will be updated at the end of the pilot. See Figures 7a and b for a comparison of the model history match and forecast.

Figure 7a: Model History Match & Forecast: Oil Recovery

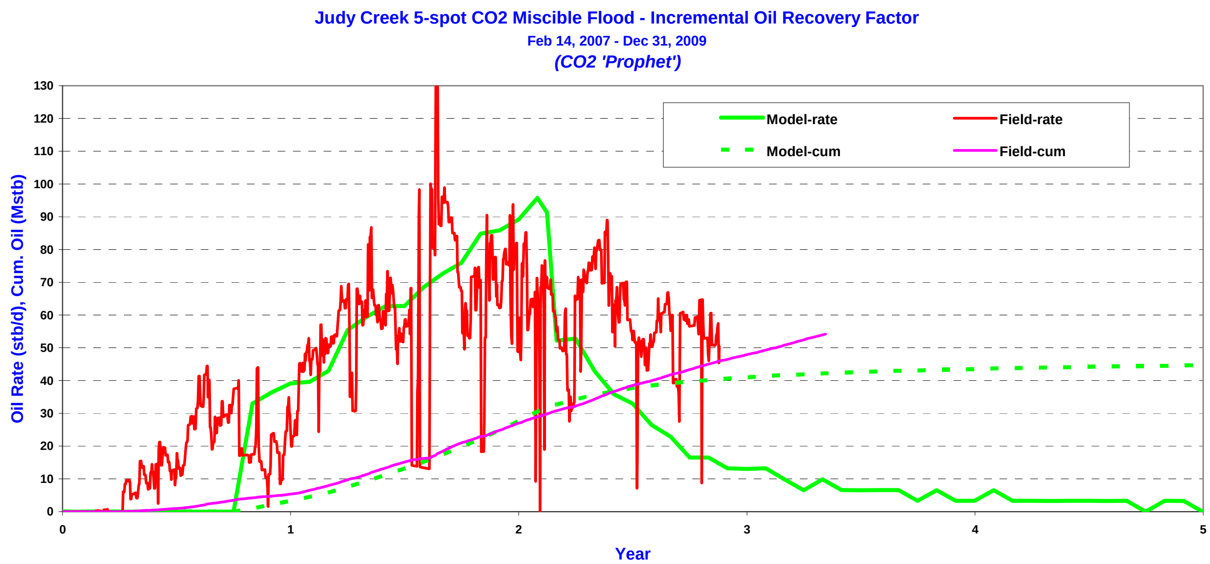
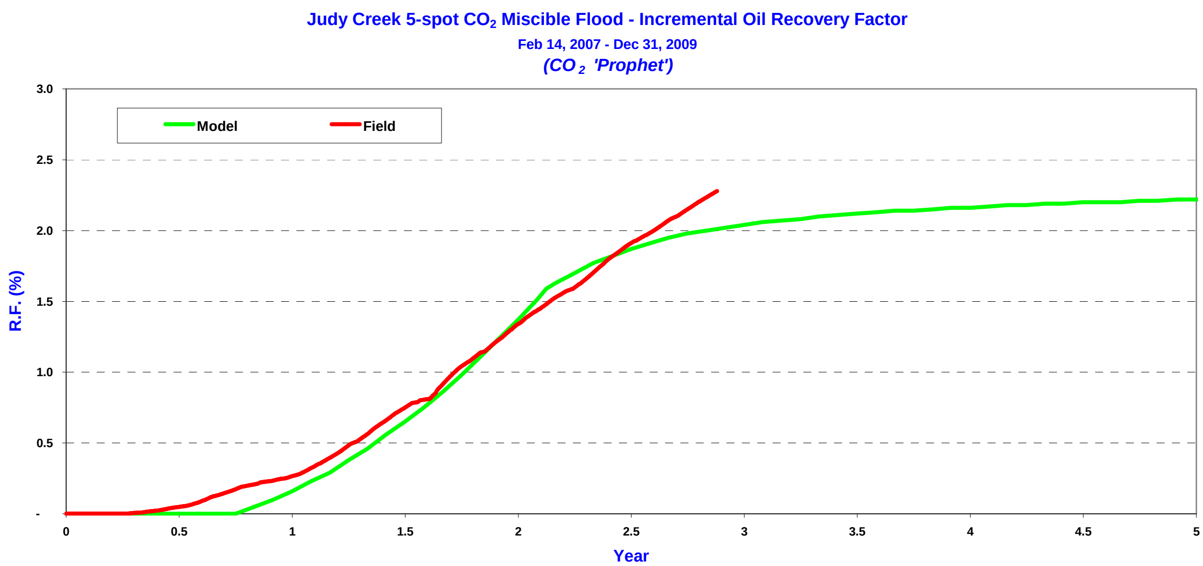


Figure 7b: Model Forecast and History Match: Oil Recovery Factor



5.1.2 - Isolation Testing

In Q4 2007 an increase in the water injection rate at the 07-02 injector was noted. Likely causes of this increase were:

a) Loss of isolation between the target R5 zones and lower zones. The lower zones in the wellbore had been shut off with a bridge plug in preparation for the pilot, and/or
b) Reservoir permeability increase due to CO_2 injection, yielding carbonic acid.

An injection profile log & temperature log were run in November 2007 and an injection fall off test was performed in March 2008 in an attempt to confirm isolation.

Given the short interval between the R5 perforations and the top of the bridge plug (0.3 m), the injection/temperature log was inconclusive, since the lowermost portion of the interval could not be logged. However, since the injection profile was essentially the same as the original profile run in April 2007, it was rationalized that permeability was increasing and isolation was intact.

The fall off test indicated that either the well had fractured (unlikely since injection is below fracture pressure), that permeability had increased or that isolation was lost to the lower zones.

It was concluded that an increase in reservoir permeability was being observed. This conclusion was supported given:

- Sustained reservoir pressure (static & flowing), and
- Consistent voidage replacement, calculated assuming full injection into the R5
- Similar response at the Swan Hills Unit 1 CO_2 pilot
- Ongoing miscible response to all pattern producers

An additional injection profile log was performed in Aug 2009 to help validate this conclusion. Profiles were measured at 2 injection rates (400 & 1000m^3/d). Both spinner surveys indicate that at least 88-92% of injectant is entering the target R5 perforations. The static flow check was once again inconclusive at the bridge plug, due to the potential for fill & potential offdepth measurement (~0.1m). After consulting with Weatherford we concluded that the bridge plug was holding.

After discussions with service companies, a temperature log was determined to more accurately show isolation of the bridge plug rather than a spinner survey. A logging program was devised to confirm depth (Run 1 GR-CCL) and then a temperature log (Run 2 Temp-GR-CCL), with the temperature logging tool on the bottom of the stack. During the initial run in Dec 2009, it was determined that fill was on top of the bridge plug and that future logs would continue to be inconclusive unless the fill was remove. Considerations were given to cleanout the fill, but due to the low ID of the XN-Nipple our well servicing department advised that it would be a low chance of success to cleanout to the bridge plug.

Due to the reasons mentioned above, we maintain our original conclusions that injectivity is increasing due to enhanced permeability.

The injection profiles, interpretations and proposed temperature log program for 2009 are provided in appendix IV.

5.1.3 - Water Tracer Analysis

A non-radioactive tracer was injected with the water phase after the first CO_2 injection cycle in 2007. Water samples have been taken quarterly through 2007, monthly in 2008 and quarterly in 2009. The tracer study was undertaken to determine if CO_2 injection was sweeping in markedly different pathways than the water injection. Since CO_2 acts as its own tracer, only the water phase was traced. To date results have shown water tracer arriving at all pattern producers. Below are the early conclusions that were reached with the Alberta Research Council.

- Tracer returns helped quantify distribution of the injected water towards the four producers.

- Water tracer returns indicate the strongest communication between the injector 07-02 and 06-02, whereas returns of oil, CO_2 and ethane suggest strongest communication between the injector and well 02-02, with somewhat less direct communication with well 06-02.

- There is thus some persuasive evidence that injected water and CO_2 travel towards the four producing wells via different paths and that WAG is only partially effective.

- There exist relatively high quality permeability 'streaks' between the injector and well 08-02 but their aerial extents are much smaller than those between the injector and wells 02-02 and 06-02.

- Flow towards well 10-02 was dominated by the hydraulic fracture. It possibly extends in the NW direction towards well 16-02.

- Flow of water tracer and CO_2 via hydraulic fracture around well 10-02 is episodic, suggesting it may be opening and closing depending upon pressure gradients.

Data collection and analysis is ongoing. The results from the tracer surveys to date are supplied in Appendix V.

5.1.4 - Corrosion Monitoring

Operational and equipment issues resulted in delays in the implementation of the corrosion monitoring and mitigation program and some loss of collected data.

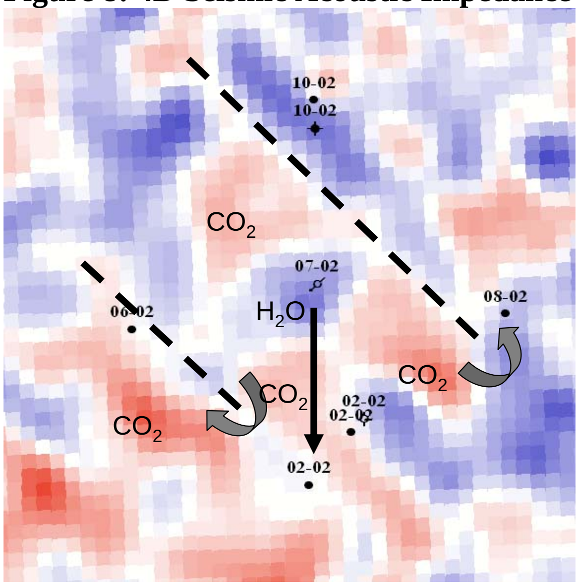
Corrosion inhibitor batch treatments were started after CO_2 breakthrough occurred. Corrosion rate data collected prior to the startup of the pilot was supplemented with manual readings after pilot operation was underway.

The main separator at the Judy Creek Production Complex & the test separator at the 08-02-064-11 satellite are scheduled for inspections in 2010.

5.1.4 – 4D Seismic

A baseline 3D seismic was obtained in Dec 2006 prior to commencing CO_2 injection. In Feb 2009 a second set of 3D seismic was shot to observe any changes in pathways & saturations. Figure 8 illustrates the change in acoustic impedance.

Figure 8: 4D Seismic Acoustic Impedance (2009 minus 2006)



A negative change in acoustic impedance (Blue) indicates water swept pathways, while a positive change in acoustic impedance (Red) indicates CO_2 swept pathways. Interpretation of pathways is consistent with; production history to 02-02 & 06-02, geology to 08-02 & 10-02 and pattern tracer response. While the technology assists in interpreting pilot response, it is not likely viable for commercial application.

5.2 Interpretation of pilot data

Production response is being seen to some degree at all pattern producers. Early comparisons between CO_2 response and water tracer response might suggest a variation in sweep between CO_2 and water, but a final conclusion awaits additional data collection and analysis.

A discussion of the performance of each of the pattern wells follows.

Producer 10-02 was acid fracture stimulated in June 2006. 10-02 was the first well to respond to 07-02, as it cycled minor amounts of gas during the first few CO_2 injection cycles. Typically this would not be an encouraging response, however, since 10-02 is a low rate producing well that did not respond to historical hydrocarbon miscible floods (HCMF) the results can be viewed as encouraging. Further, such an acid treatment on a larger spacing pattern might yield more muted or delayed response. Cyclic gas response has reduced over the duration of the pilot. This acid fracture stimulation has identified opportunities to optimize future miscible patterns.

Producer 02-02 oil and gas response began in Q2 2007. The response sequence was as expected with an oil response followed by hydrocarbon gas (methane & ethane). CO_2 response did not begin until Q3 2007. 02-02 has maintained a steady oil production of ~10m^3/d, which is a modest increment from the base decline. Significant CO_2 breakthrough in August 2008 resulted in 02-02 and 06-02 being shut-in until late September 2008 (see sections 9 & 10 for operation details). The reproduction of injected acid gas at 02-02 is cyclic and highly correlated with 07-02 injection. This has been shown to make the gas response predictable and to some extent controllable by managing CO_2 injection rates and WAG ratio. Since completing CO_2 injection, 02-02 oil production has steadily been declining.

Producer 06-02 gas response began in July 2007 and oil response in Sept 2007. Gas response was primarily methane and ethane until April 2008. As noted above, 06-02 had significant CO_2 breakthrough in August 2008 and was shut-in until late Sept 2008. 06-02 cyclic response is offset in time from 02-02 response, which allows for additional flexibility in managing CO_2 breakthrough response. 06-02 continued to be shut-in periodically to handle peak CO_2 production in early 2009. 06-02 production has declined steadily since completing CO_2 injection.

As producer 08-02 did not respond to miscible injection at 07-02, predicted response under acid gas injection was likewise fairly small. 08-02 began subtle oil and gas response in Feb 2008. 08-02 had about a 2 m^3/d oil increment and <1e^3m^3/d increment of methane & ethane. CO_2 recycling has also been limited to <1e^3m^3/d. The results are encouraging that CO_2 has contacted new reservoir. 08-02 will be considered for an acid fracture stimulation after monitoring of production is complete.

07-02 injectivity was initially lower than anticipated but began to increase in Q3 2007. This resulted in modifying WAG ratio targets and CO_2 injection schedule. A water injection choke was installed in June 2008 to manage voidage and WAG ratios. The injection schedule was modified in June 2008 to lower WAG ratios, with shorter injection cycles. This potentially resulted in CO_2 breakthrough in August 2008. The injection cycles were modified again while the Judy Creek Gas Plant completed work on the acid gas handling facilities. 07-02 remained choked at 400m^3/d to manage voidage replacement. The rate was increased to 800m^3/d in December 2009 to observe any production changes which are still ongoing.

6.0 Pilot Economics

6.1 Sales volumes of natural gas and by-products.
See Appendix VI

6.2 Revenue.
See Appendix VI

6.3 Capital costs (include a listing of items with installed cost greater than $10,000).
Table 5 shows the expenditures since the inception of the project. 2009 capital was primarily expended on CO_2 purchases, skid rental, sampling & 3D seismic.

Table 5: Capital Expenditures to data

	IETP ($M)	2006 ($M)	2007 ($M)	2008 ($M)	2009 ($M)	2010 ($M)	TOTAL ($M)
Pipeline & Surface Piping	2,931.7	2,430.0	357.8	0.0	0.0	0.0	2,787.8
Downhole Work	975.0	890.8	53.1	6.1	0.0	0.0	950.0
Other	45.5	0.0	22.7	0.0	0.0	0.0	22.7
Sampling	284.2	0.0	70.0	105.0	105.0	105.0	385.0
CO2 Purchases & Skid Rental	4,118.1	0.0	2,369.6	2,655.2	1,339.6	140.0	6,504.3
3D Seismic (3 surveys)	1,160.0	353.3	25.7	0.0	247.5	5.6	632.1
07-02 Isolation Testing	0.0	0.0	0.0	0.0	0.0	500.0	500.0
TOTALS	9514.5	3,674.1	2,898.8	2,766.3	1,692.1	750.7	**11,781.9**

6.4 Direct and indirect operating costs by category (e.g. fuel, injectant costs, electricity).
See Appendix VI

6.5 Crown royalties, applicable freehold royalties, and taxes.
See Appendix VI

6.6 Cash flow.
See Appendix VI

6.7 Cumulative project costs and net revenue.
See Appendix VI

6.8 Explanation of material deviations from budgeted costs
As per the table in section 6.3, the major deviations from budgeted costs are: Sampling, CO_2 purchases & skid rental and 3D seismic. The sampling & CO_2 purchases increased due to the change in scope of the project to inject CO_2 to 30% HCPV instead of the original 20% HCPV (50% increase). The 3D seismic cost was reduced with only 2 surveys shot, while up to three were provided for in the plan.

7.0 Facilities

7.1 Major capital items incurred in 2009

As noted in section 6.3, key capital expenses in 2009 were associated with 3D seismic, CO_2 purchases, skid rental & sampling ($1,692.1M).

7.2 Capacity limitation, operational issues & equipment integrity

Acid Gas System

The acid gas portion of the injectant is sourced from the Judy Creek Gas Conservation Plant, and includes CO_2 and H_2S removed from produced gas streams prior to sale.

Acid gas is removed from the produced gas stream using an amine based “Jefftreat” system. The design capacity of the Jefftreat System is 90 e^3m^3/d of CO_2 removal, based on an assumed inlet flow rate of 2000 e^3m^3/d with a maximum CO_2 composition of 4.63 mole%. The system has performed as predicted.

The integrity and reliability of the acid gas compressor has been satisfactory over the review period. Minor operational issues have been experienced with the lubricating and cooling systems.

Praxair CO_2 Skid

The Praxair CO_2 skid has a 400 tonne bullet and pump at 02-02-064-11. CO_2 is pumped to the 07-02-064-11 injection site. During the initial injection cycles, the CO_2 injection rate was lower than expected. New plungers were installed in the pump to optimize the equipment. As the injectivity began to increase over time, the plungers were again modified. Although after 12 months the pump was still undersized for the potential injectivity, the pump capacity was set at ~110e^3m^3/d. This would delay the rate of peak CO_2 breakthrough and the attendant operational issues, which ultimately occurred in August 2008. The integrity and reliability of the acid gas compressor has been satisfactory over the review period.

7.3 Process flow and site diagram

See appendix VII for process flow diagrams.

8.0 Environmental/Regulatory/Compliance

8.1 Summary of project regulatory requirements & compliance

8.1.1 - Regulatory Compliance

The Judy Creek Pilot is governed under ERCB EOR approval number 10269. The pilot is operating with 100% compliance to the requirements of this approval. Highlights of these requirements include:

ERCB EOR Approval 10269 Highlights (see appendix VIII)

- Miscible injectant fluid at least 0.970 mole fraction H_2S & CO_2 and not greater than 7% H_2S
- Inject at least 15% HCPV
- Maintain reservoir pressure above 23.0 MPa & complete two pressure surveys per year
- Monitor molar composition of injection & production gas
- Complete 2 part annual reporting process (annual presentation to ERCB and data submission)

8.1.2 - Environmental Procedures

Emergency Response Procedures
If a release should occur Pengrowth would implement the First Hour Response and the Emergency Response Plan (ERP), if required.

The First Hour Response manual outlines initial critical facts and procedures when dealing with an emergency. Pengrowth, regulatory and service company contacts are listed to assist in the initial stages of an emergency. This document is used in conjunction with the ERP.

The ERP outlines the details of responding to various emergency situations.

Environmental Procedures
Pengrowth demonstrates its commitment to environmental principles through involvement at all levels of the Environmental Management System (EMS). The EMS contains Pengrowth's Environmental Policy & six Operating Practices (OP). These OPs outline Pengrowth's expectation of employees and contractors and ensure compliance with applicable legislation. The six OPs are listed as follows with a brief explanation:

Environmental Incident Reporting
This OP outlines the process followed to identify reporting requirements (Internal vs. regulatory office notification) for environmental incidents. All releases or environmental incidents are reported to the Field Environmental Coordinator to assist with determining the reporting requirements.

Spill Prevention and Clean-up
This OP outlines Pengrowth's expectation and standard for preventing releases to the environment. If a release should occur this practice guides in the clean-up and control of the release event. Depending on the severity of the release, this practice is used in conjunction with the ERP.

General Housekeeping
This OP outlines Pengrowth's expectation to keep worksites clean and free of hazards or pollution.

Surface Water Run-Off Management
This OP outlines Pengrowth's expectation to minimize pollution or damage caused by surface water from rainfall or snow melt. Within this practice the regulatory release limits are outlined.

Production Waste Management
This OP provides guidance in minimizing, effectively managing & properly disposing of wastes generated from production operations. All waste generated by Pengrowth is the responsibility of Pengrowth and is handled according to provincial and federal regulations.

Vegetation Management
This OP outlines Pengrowth's expectation to effectively manage vegetation and minimize problem or noxious weeds. Within this practice various control methods and a restricted pesticide list are identified

9.0 Future Operating Plan

9.1 Project Schedule Update

CO2 Quaternary Pilot Milestones

October 2005:	Approval-in-principle for the quaternary flood concept
January 2006:	Laboratory testing and Compositional Simulation initiated
March 2006:	Management approval for Pilot: $8.5 million
April 2006:	Laboratory and simulation work completed
May 2006:	Application filed with EUB for scheme approval
December 2006:	Baseline 3-D seismic data obtained
January 2007:	Well re-completion, facility upgrade, pipeline construction completed
January 2007:	ERCB Scheme approval is granted
February 2007:	First CO2 injection
April 2007:	Acid gas injection begins in the WAG mode
August 2008 **(April 2009)**:	Acid gas injection completed and straight water injection resumes
August 2008 **(February 2009)**:	Follow-up 3-D seismic survey
August 2009 **(December 2010)**:	Monitoring and Evaluation of the Pilot completed

Milestones pushed out from 2008-2009 to 2009-2010 due to increased target banksize.

9.2 Changes in pilot operation & optimization strategies

Water Injection Rate
As mentioned in section 5.1, with the increasing water injection rate, a surface choke was installed at the 07-02-064-11W5 injector to control water injection rates and thereby maintain voidage replacement and WAG ratio.

ESP Failures
02-02 & 06-02-064-11W5 failed in May 2007. Both wells had older vintage equipment and were expected to fail during the CO_2 pilot. 02-02 failed again in December 2007 and 06-02 in May 2008. Failure analysis indicated that both failures resulted from a manufacturer error and not from operation in the CO_2 pilot. There were similar failures in other parts of Judy Creek and other Pengrowth operated properties. 06-02 failed in May 2009. There were no signs of corrosion and the pump condition was similar to units from non-CO_2 portions of the field.

Acid Gas Handling (injection changes, shut-in production)
Acid gas handling issues were anticipated when the target total injection volume was increased above 20% HCPV. The original acid gas handling system was designed to accommodate peak rates associated with a 20% HCPV injection target. Modifications to the acid gas handling systems were executed to handle the incremental CO_2.

In August 2008 the Judy Creek Gas Plant began experiencing acid gas handling problems as 02-02 & 06-02 began to breakthrough CO_2 gas. Both wells were shut-in and CO_2 injection was deferred while the upgrades to the acid gas handling system (Jeff treat) were undertaken. The water injection rate into the pilot was reduced to prevent an escalating WAG ratio and pressure buildup. In late September 2008, both wells were re-started and CO_2 injection resumed. To manage the peak CO_2 reproduction, the CO_2 injection cycle time was reduced from 28 to 14 days and the CO_2 injection rate was reduced.

In November 2008, the JCGP completed work on the Jeff treat system. The JCGP was able to handle the additional acid gas, but struggled during peak periods of gas production at 02-02 & 06-02. During December 2008 & April 2009, 06-02 was shut in during peak CO_2 production periods at 02-02.

<u>9.3 Salvage Update</u>
Inasmuch as the pattern injector and producers will continue operation after the conclusion of the pilot, salvage opportunities are limited to the CO_2 injection facilities (CO_2 bullet and pipeline). Praxair Canada removed the CO_2 skid in Q1 2010.

Pengrowth purged all acid gas & CO_2 lines upon completion of injection to reduce any environmental impact in the event of a flowline failure. All lines remain in place for future acid gas injection.

10. Interpretations and Conclusions

<u>10.1 Overall Pilot Performance</u>

Lessons learned & difficulties encountered

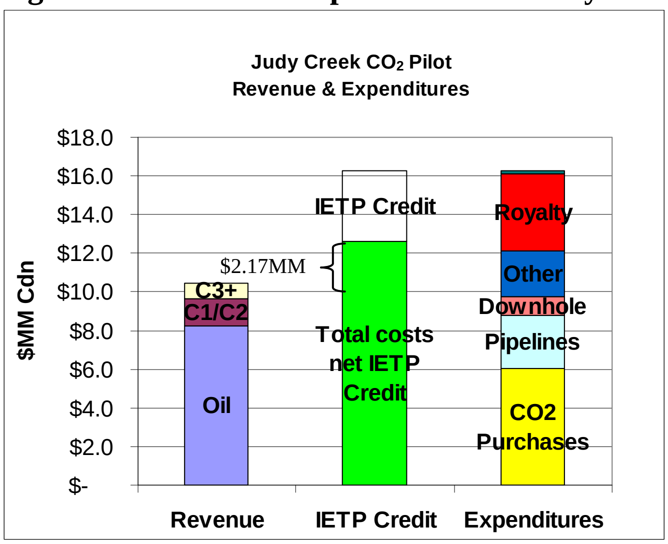
Increasing injectivity over time is thought to be at least partly the result of increasing reservoir permeability through dissolution of reservoir rock from CO_2 & water injection (carbonic acid). This resulted in installing a choke during water injection to manage VRR and WAG ratio, and multiple diagnostics to assess downhole isolation. Constraints on diagnostics existed based on the selection of isolation techniques (isolation with bridge plug) and downhole equipment, most notably the permanent packer. While alternate techniques may have increased flexibility for diagnostics, they would have also increased the risk of loss of isolation, in the case of a zonal isolation using only cementing and costs.

As expected, acid gas handling limitations were experienced when the injection target was increased above 20% HCPV. Modifications to the amine system and installing larger coolers helped to improve removal of acid gas, but some disruptions to pilot and gas plant operation were still experienced.

Technical & Economic Viability

The Judy Creek CO_2 pilot can be deemed technically successful as it has resulted in incremental oil production & hydrocarbon solvent (methane & ethane) from all pattern producers. As well, the ability to handle and inject a waste acid gas stream combined with purchased CO_2 has been demonstrated. As expected, due to the high cost of infrastructure and CO_2 purchases, the pilot will not generate positive economics, but will guide the design and forecasts for commercial scale development. See figure 9 for a breakdown of revenue & expenditures for the CO_2 Pilot.

Figure 9: Revenue & Expenditures for Judy Creek CO_2 Pilot



Overall Effect on Oil & Gas Recovery

The expected oil recovery from the pilot is ~3.3% OOIP (10,500m^3). In addition 45-50% of previously injected hydrocarbon solvent will be recovered. Target recoveries were 3.0% OOIP & 40% of previously injected hydrocarbon solvent.

Assessment of Commercial Field Application and Discussion of Reasons

Data to date is being used to update both simulation and analytical models for other reservoir types within Judy Creek such that full field commercial production forecasts can be updated. Operational data is also being used to advance engineering work in facility design.

Pengrowth is also working with, and sharing pilot results with, other Swan Hills Area operators to assess joint venture facilities and common CO_2 supply, to optimize capital investment in any future commercial development.

The economics of a commercial scale CO_2 scheme at Judy Creek continue to be updated, and the range of possible outcomes remains wide. Key drivers for the project remain CO_2 delivered costs and oil recovery & price. Multiple development scenarios have now been formulated that account for: Reservoir quality (impacts on oil and solvent recovery), banksize, development pace, joint facilities, and joint CO_2 supply.