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October 11, 2011

Research and Technology Branch
Alberta Department of Energy
9th Floor, North Petroleum Plaza
9945 – 108 Street
Edmonton, AB
T5K 2G6

Attention: Geoffrey Pearson
Research and Technology Branch

Dear Mr. Pearson:

RE: Innovative Energy Technologies Regulation – Project Approval No. 03-059
Rainbow Keg River 0 Pool - Enhanced Gas Recovery

Husky Oil Operations Ltd. received ERCB approval for an Enhanced Gas Recovery Scheme (Approval #10668A) for Rainbow Keg River O Pool on March 12, 2007. Traditionally, gas reservoirs recover only 65–85 percent of the original gas in place before being considered “depleted” due to low reservoir pressure or water influx reducing productivity to uneconomic levels. Based on this theory, Husky Energy developed an innovative project to determine whether significant hydrocarbon gas volumes could be recovered through the injection of acid gas near the bottom of the reservoir in order to raise reservoir pressure and displace trapped hydrocarbon gas to the top of the reservoir, while sequestering large volumes of CO₂ and H₂S gas.

As this scheme used new technology, an application was made to the Innovative Energy Technologies Program through the Research and Technology Branch with the Alberta Department of Energy on May 30, 2007. On May 14, 2009 approval was granted through the Innovative Energy Technologies Regulation and the project was eligible to receive royalty credit adjustments for eligible costs of the project. All requirements were met throughout the course of the project and all operations were summarized in the required annual reports. In Oct 2010 a presentation was made in Edmonton, AB to the IETP committee outlining the progress of the project in its first year.

In February 2010 the premature breakthrough of acid gas jeopardized the success of the Enhanced Gas Recovery Scheme. After thorough investigation the scheme was terminated due to technical, safety and economic reasons.

As no relevant additional information is available (apart from acid gas injection volumes), another presentation in October 2011 does not seem to be warranted or valuable. All required information is documented in the attached Final IETP Report detailing all of the operations, findings and conclusions of the project.

On May 31, 2011 an application was made to the ERCB to rescind the Enhanced Gas Recovery Scheme and approval was received on August 9, 2011. The scheme has now been converted to an Acid Gas Disposal Scheme and approval for this new project was received on August 25, 2011.



If you have any questions or require additional information, please contact Julie Browne at (403) 513-7969 or Brian Hunter at (403)298-7401.

Yours truly,
HUSKY OIL OPERATIONS LIMITED

A handwritten signature in black ink that reads "Claire Galvin, P. Eng" followed by a horizontal line.

Claire Galvin, P. Eng.
District Manager, Rainbow Asset
Foothills/NW Plains

Rainbow Keg River O Pool

Enhanced Gas Recovery

Final IETP Report

October 11, 2011

**Prepared by
Julie Browne, E.I.T.**

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1.0 Report Abstract

This is the final report for the Enhanced Gas Recovery Scheme as it has been deemed unsuccessful and approval has been granted by the ERCB to rescind the scheme and convert it to an Acid Gas Disposal Project.

Traditionally, gas reservoirs recover only 65 – 85 percent of the original gas in place before being considered “depleted” due to low reservoir pressure or water influx reducing productivity to uneconomic levels. Based on this theory Husky Energy developed an innovative project to determine whether significant hydrocarbon gas volumes could be recovered through the injection of acid gas near the bottom of the reservoir in order to raise reservoir pressure and displace trapped hydrocarbon gas to the top of the reservoir, while sequestering large volumes of CO₂ and H₂S gas.

This report will detail the Rainbow Keg River O Pool Enhanced Gas Recovery Scheme throughout the life of the project and includes operation details, injection data, regulatory requirements, maps, and results.

2.0 Summary Project Status Report

2.1 Project Team Members

Brian Hunter – Reservoir Engineering Supervisor
Julie Browne – Reservoir Engineer
Randy Dotzler – Production Engineer

In the approved application Frank McIntyre, Brian Hunter, and Gord Robson were the key team members in developing this acid gas injection project. Frank McIntyre and Gord Robson have since retired; however, Brian Hunter continues to work on this project along with the current reservoir engineer (Julie Browne), production engineer (Randy Dotzler) and superintendent of field operations, Harold Norberg. Ivy Cheung was the production engineer for the 2008-2010 period of the project.

2.2 Project Activities and Operations

The following activities and operations have been conducted since the initiation of this project:

Date	Operation
February 2009 - May 2009	Acid gas injection commenced.
May 2009 – November 2009	Inline inspection of acid gas pipeline was conducted and determined valves needed replacing. Injection was suspended while waiting for valve replacements.
November 25, 2009	Acid gas injection resumed.
Nov 25, 2009 - Present	Continuous Injection
February 5, 2010	Production was initiated at 02-12 producer
February 17, 2010	Sample taken from producing stream; H ₂ S = 18.7%
March 1, 2010	Well loaded up and died
March 10, 2010	Second sample taken from 02-12 production well; H ₂ S = 23.3%
May 31, 2011	Submitted ERCB application to rescind EGR Scheme.
August 9, 2011	Received ERCB approval to rescind EGR Scheme.
June 2, 2011	Submitted ERCB application for Acid Gas Disposal Scheme.
August 25, 2011	Received ERCB approval for Acid Gas Disposal Scheme.

2.3 2010 Production

It was Husky's intent not to commence production in the 02-12 well (which watered out in 2008) until a significant volume of acid gas had been injected and the reservoir pressure had increased to a sufficient level to help "push" the oil-water contact down from the uppermost perforations and enable the well to flow on its own. Due to the suspension of acid gas injection from May to November in 2009, it was decided not to produce the 02-12 well until additional acid gas volumes were injected. Consequently, there was no production data for 2009.

However, after a cumulative acid gas injection of 19,967 E3m³ from the start of the project and a corresponding increase in pressure from 12,049 kPa to 13,462 kPa, it was decided to try and produce the 02-12-110-08W6 well. Accordingly on Feb 5, 2010, the well was brought on production. The well flowed initially with the production rate being restricted to less than 50 E3m³/d to prevent the chance of water coning and/or initiating acid gas breakthrough to the perforations at the top of the reef. On Feb 17, 2010 a gas sample was taken resulting in an unexpectedly high H₂S value of 18.7 mole%. The well then stopped flowing on Mar 1, 2010 (unable to lift water). A Tutweiler sample was performed on the non-flowing well on March 10, 2010 to confirm the high H₂S content, which was measured at 23 mole%. As the pipeline for this well is only rated at 3 mole%, Husky was in a position of non-compliance during the 02-12 production period. This non-compliance was the subject of a self-disclosure that was prepared and submitted to the ERCB Compliance and Surveillance Group on March 19, 2010. Although production was shut-in at that stage, acid gas injection continued.

2.4 Estimated Remaining Reserves

By injecting acid gas into the reservoir, Husky believed that based on previously documented experimental results in the petroleum literature that some 15-20% of the remaining lean gas could be swept to the 02-12 wellbore for production. This corresponds to estimated recoverable reserves of 35 E6m³. The major objective of this project was to prove up lean gas recovery volumes. With the premature breakthrough of the injected acid gas, and a thorough investigation of the source of breakthrough it was determined that this project was no longer feasible and that

the remaining reserves would be uneconomic to recover. Therefore these estimated reserves have been deemed uneconomic and have been removed from Husky's reserves booking system.

3.0 Well Information

3.1 Map

Figure 1 is a structure map of Keg River O Pool which can be used to reference the locations of the wells in the pool. 02-12 is the production well, 15-01 is the injection well, 16-01 is the Keg River pressure monitor. 08-12 is a Muskeg pressure monitor which is used to ensure there is no leakage or pressure changes between formations. All other wells in the pool have been abandoned.

3.2 Workovers

No new wells have been drilled or completed in this pool since the start of the project and no workovers have been completed. Below is a summary of the workovers that have been performed on the wells in the pool prior to the initiation of acid gas injection.

04-07-110-07W6	Jul-07	Well abandoned per ERCB requirements
10-01-110-08W6	Mar-07	Previously recompleted to Sulphur Point and Muskeg. Workover to abandon all zones (incl Keg River) to meet ERCB requirements.
14-01-110-08W6	May-07	Well abandoned per ERCB requirements
15-01-110-08W6	Jun-07	Well worked over (incl. nickel alloy tubulars) to set up for use as acid gas injection well.
16-01-110-08W6	Sept-07	Workover to equip well with downhole pressure monitor (Keg River) and abandon Keg River zone per ERCB requirements
03-12-110-08W6	May-07	Previously abandoned. Well abandoned to ERCB requirements
08-12-110-08W6	May-07	Keg River zone abandoned per ERCB requirements. Recompleted to Muskeg zone for use as Muskeg pressure monitoring well
02/08-12-110-08W6	May-07	Well abandoned per ERCB requirements
10-12-110-08W6	Dec. 06 – Jan. 07	Well abandoned per ERCB requirements
14-12-110-08W6	May-07	Well abandoned per ERCB requirements

Currently an abandonment of 02-12-110-08W6 is planned for Q4 2011. This is a critical sour well as it has experienced high H₂S production and is now part of an acid gas disposal scheme. Husky is working with the ERCB to safely abandon 02-12 in accordance with the Acid Gas Injection Scheme requirements. All abandonment programs have to be approved by the ERCB and a site specific emergency response plan has already been approved by the ERCB for the workover.

3.3 Well List

The chart below details all the wells in the pool and their current status.

Well	Status
04-07-110-07W6	Abandoned
10-01-110-08W6	Abandoned
14-01-110-08W6	Abandoned
02-12-110-08W6	Suspended
15-01-110-08W6	Injection Well
16-01-110-08W6	KR Pressure Monitor
03-12-110-08W6	Abandoned
08-12-110-08W6	Muskeg Pressure Monitor
02/08-12-110-08W6	Abandoned
10-12-110-08W6	Abandoned
14-12-110-08W6	Abandoned

3.4 Wellbore Schematics

For wellbore schematics please refer to **Appendix I**.

4.0 Production Performance

4.1 Injection and Production History

Acid gas injection into the 15-01-110-08W6 well has been continuous since Nov 24, 2009. A table detailing the injection volumes into 15-01-110-0W6 on a monthly basis since the start of the project until August 2011 can be found in **Table 1** of this report. Please note that from May 1 – August 31, 2011 injection volumes were significantly reduced due to the Plains Midstream pipeline break which occurred in May, 2011. If this incident had not occurred then production rates and volumes would have remained the same as in previous months.

As stated previously in the 2010 Production section, the 02-12 production well was brought online on February 5th, 2010. By March 1, 2010 the well ceased to produce as it was not capable of lifting the water being produced with the gas. When the results from the gas analysis identified the high H₂S values, it was decided that further production attempts would not be made until the source of the early H₂S breakthrough was evaluated.

The distribution of fluids within the reservoir at month-end August 2011 is shown on the following table.

CALCULATE RESERVOIR FLUIDS AT 2010/12 Reservoir pressure = 14,600 kPaa

Original conditions

Pr =	16688 kPaa
Bo =	1.489 resm3/stm3
Sw =	0.22 frac
Sg =	0 frac
HCPV =	8642.1 E3 resm3
Pore Space =	11079.6 E3 resm3
OOIP (C5+) =	5804.0 E3 stm3

At the end of Miscible Flood Dec 31, 2000

Pr =	17288 kPaa
Bo =	1.487 resm3/stm3
Bg =	6.18 resm3/E3Sm3
Sw =	0.22 frac

Cum chase gas inj	2,209,215 E3m3
Cum solvent inj	399,264 E3m3

Cum Chase gas pd	1,245,832 E3m3
Cum solvent pd	399,587 E3m3

Net gas in place	963,060 E3m3
	5,952 E3 resm3

Sg (avg)	0.54 frac
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Cum C5+ prod	4,001,252 m3
	5,949,862 res m3

Remaining C5+	1,802,710 m3
	2,680,630 res m3

So (avg)	0.24 frac
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At the end of 2011/08

Pr =	14600 kPaa
Bo =	1.473 resm3/stm3
Bg =	7.52 resm3/E3Sm3

Net gas in place (at Dec 31, 2000)	963,060 E3m3
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Gas prod (chs gas+liberated) (Jan 2001 - Dec 2009)	797,356 E3m3
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Chs Gas injected (Jan 2001 - Nov 2003)	15,555 E3m3
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Gas produced (Feb 2010)	1,374 E3m3
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Rem Hydrocarbon gas in place (at 2010/12)	179,886 E3m3
	1,352,740 resm3

Sg (avg)	0.12 frac
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Acid gas injected (Feb 2009 - Dec 2010)	76,462 E3m3
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C5+ prod (Jan 2001 - Dec 2009)	57,723.55
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Remaining C5+	1,744,987 m3
	2,570,365 res m3

So (avg)	0.23 frac
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C5+ Recovery factor	0.70 frac
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4.2 Gas Compositions

Acid Gas Injection Volumes & Composition

Date	Injection Volume (E3m3/mth)	N2 mole frac	CO2 mole frac	H2S mole frac	C1 mole frac	C2 mole frac	C3 mole frac	IC4 mole frac	NC4 mole frac	IC5 mole frac	C5 mole frac	C6 mole frac	C7+ mole frac
February-09	1,647	0.0000	0.1905	0.8060	0.0013	0.0008	0.0009	0.0001	0.0002	0.0001	0.0000	0.0000	0.0001
March-09	4,532	0.0000	0.1905	0.8060	0.0013	0.0008	0.0009	0.0001	0.0002	0.0001	0.0000	0.0000	0.0001
April-09	3,906	0.0004	0.2156	0.7780	0.0013	0.0010	0.0012	0.0003	0.0006	0.0002	0.0003	0.0004	0.0007
May-09	1,184	0.0004	0.2156	0.7780	0.0013	0.0010	0.0012	0.0003	0.0006	0.0002	0.0003	0.0004	0.0007
June-09	0	0.0004	0.2156	0.7780	0.0013	0.0010	0.0012	0.0003	0.0006	0.0002	0.0003	0.0004	0.0007
July-09	0	0.0004	0.2156	0.7780	0.0013	0.0010	0.0012	0.0003	0.0006	0.0002	0.0003	0.0004	0.0007
August-09	0	0.0007	0.2181	0.7769	0.0009	0.0009	0.0008	0.0003	0.0003	0.0001	0.0001	0.0002	0.0007
September-09	0	0.0015	0.2290	0.7640	0.0027	0.0010	0.0008	0.0002	0.0003	0.0001	0.0001	0.0001	0.0002
October-09	0	0.0015	0.2290	0.7640	0.0027	0.0010	0.0008	0.0002	0.0003	0.0001	0.0001	0.0001	0.0002
November-09	1,036	0.0015	0.2185	0.7700	0.0033	0.0014	0.0017	0.0005	0.0009	0.0004	0.0004	0.0005	0.0010
December-09	4,143	0.0012	0.2002	0.7859	0.0030	0.0016	0.0031	0.0009	0.0017	0.0004	0.0004	0.0005	0.0012
total	16,448												

Acid Gas Injection Volumes & Composition

Date	Injection Volume (E3m3/mth)	N2 mole frac	CO2 mole frac	H2S mole frac	C1 mole frac	C2 mole frac	C3 mole frac	IC4 mole frac	nC4 mole frac	IC5 mole frac	nC5 mole frac	C6 mole frac	C7+ mole frac
January-10	3,519	0.0000	0.2203	0.7721	0.0034	0.0012	0.0012	0.0003	0.0005	0.0002	0.0002	0.0003	0.0005
February-10	3,221	0.0000	0.2366	0.7558	0.0032	0.0012	0.0012	0.0003	0.0005	0.0002	0.0002	0.0002	0.0006
March-10	2,662	0.0034	0.2356	0.7544	0.0027	0.0009	0.0009	0.0003	0.0004	0.0002	0.0002	0.0003	0.0007
April-10	2,853	0.0034	0.2356	0.7544	0.0027	0.0009	0.0009	0.0003	0.0004	0.0002	0.0002	0.0003	0.0007
May-10	3,326	0.0025	0.2322	0.7576	0.0034	0.0012	0.0015	0.0003	0.0006	0.0001	0.0001	0.0001	0.0003
June-10	3,076	0.0013	0.2374	0.7497	0.0031	0.0016	0.0029	0.0006	0.0014	0.0004	0.0004	0.0004	0.0007
July-10	3,728	0.0011	0.2480	0.7438	0.0035	0.0012	0.0013	0.0002	0.0004	0.0001	0.0001	0.0001	0.0003
August-10	4,110	0.0013	0.2619	0.7307	0.0032	0.0011	0.0010	0.0001	0.0003	0.0001	0.0001	0.0000	0.0003
September-10	3,702	0.0014	0.2614	0.7291	0.0032	0.0013	0.0016	0.0004	0.0007	0.0002	0.0002	0.0002	0.0005
October-10	3,283	0.0015	0.2552	0.7319	0.0038	0.0018	0.0027	0.0006	0.0012	0.0003	0.0003	0.0003	0.0005
November-10	3,357	0.0071	0.2353	0.7428	0.0039	0.0020	0.0036	0.0010	0.0019	0.0005	0.0005	0.0005	0.0010
December-10	3,216	0.0045	0.2642	0.7177	0.0040	0.0019	0.0032	0.0008	0.0015	0.0004	0.0004	0.0005	0.0009
total	40,054												

Acid Gas Injection Volumes & Composition

Date	Injection Volume (E3m3/mth)	N2 mole frac	CO2 mole frac	H2S mole frac	C1 mole frac	C2 mole frac	C3 mole frac	IC4 mole frac	nC4 mole frac	IC5 mole frac	nC5 mole frac	C6 mole frac	C7+ mole frac
January-11	2,912	0.0330	0.2372	0.7223	0.0033	0.0013	0.0015	0.0004	0.0005	0.0001	0.0001	0.0001	0.0003
February-11	2,678	0.0054	0.2573	0.7277	0.0037	0.0014	0.0018	0.0005	0.0008	0.0002	0.0002	0.0002	0.0008
March-11	3,067	0.0028	0.2523	0.7236	0.0049	0.0030	0.0062	0.0016	0.0029	0.0007	0.0006	0.0006	0.0008
April-11	2,997	0.0044	0.2545	0.7337	0.0033	0.0011	0.0013	0.0003	0.0004	0.0001	0.0001	0.0001	0.0006
May-11	1,616												
June-11	1,483												
July-11	2,589												
August-11	2,620	0.0060	0.2936	0.6878	0.0063	0.0022	0.0022	0.0005	0.0007	0.0002	0.0002	0.0001	0.0002
total	19,960												

Samples of the injected acid gas stream are taken monthly for analysis. Prior to being used for reservoir calculations (voidage, etc.) a qualitative review is performed on the analysis to ensure that the sample accurately represents the acid gas stream composition. The table below summarizes the acid gas sampling that was performed throughout the project. Please note that no samples were taken from May to July of 2011 due to the Plains Midstream pipeline break.

Over the course of the project, the average H₂S mole percent of the accepted samples was 75% while the CO₂ mole percent had an average of 24%; although slight variations were seen on the monthly analyses, there did not appear to be a trend in either increasing or decreasing major component concentrations.

4.3 Pressures

Pressure monitoring for this scheme requires surveillance of pressures in two formations, the Keg River in which the scheme is operated and the overlying Muskeg formation to ensure that the acid gas is not escaping from the Keg River zone.

The Keg River pressures may be obtained through a static gradient performed on the 02-12-110-08W6 production well, or from a pressure monitoring system installed on the 16-01-110-08W6 well prior to abandoning the Keg River zone. The pressure monitoring system on the 16-01 well consists of a sensor located in the Keg River formation at a depth of 1754 mKB. Pressure readings are sent to a readout located on the wellhead. Readings obtained must be corrected to adjust the pressure to Datum Depth pressure. The table below summarizes the pressures taken on the Keg River zone since August 2007, with 2 static gradients having been taken during 2010.

O Pool Pressure - Datum Pressure Calculations

Pool Datum = 1295.4 mss

<u>Test Date</u>	<u>Well UWI</u>	<u>KB Elev. (m)</u>	<u>Test Type</u>	<u>Run Depth (mKB)</u>	<u>Final Pressure (kPaA)</u>	<u>Final Gradient (kPa/m)</u>	<u>Datum Pressure (kPaA)</u>
4-Aug-07	15-01-110-08w6	562.8	SG	1800.0	10249.7	9.5	10802.6
2-Oct-07	16-01-110-08w6	547.1	Monitor	1754.0	10367.0	5.0	10809.5
13-Dec-07	16-01-110-08w6	547.1	Monitor	1754.0	10465.9	5.0	10908.4
20-Mar-08	16-01-110-08w6	547.1	Monitor	1754.0	10837.0	1.0	10925.5
3-Apr-08	02-12-110-08w6	550.5	SG	1802.3	10885.3	1.0	10928.9
7-Feb-09	02-12-110-08w6	550.5	SG	1798.0	11963.0	1.8	12049.2
1-Apr-09	16-01-110-08w6	547.1	Monitor	1754.0	10750.0	5.0	11192.5
16-May-09	02-12-110-08w6	550.5	SG	1798.0	12423.3	1.1	12476.7
26-Jan-10	02-12-110-08w6	550.5	SG	1798.0	13404.3	1.2	13462.9
19-Sep-10	02-12-110-08w6	550.5	SG	1798.0	14384.8	5.2	14632.6

Two points of interest should be noted with regard to these pressures.

Firstly, before the start of injection in Feb 2009, the pressure in the reservoir was continually rising. This is due to the fact that during blowdown, the gas was produced at high rates, drawing reservoir pressure down to approximately 9.0 MPa in 2004. Since production was reduced to very low levels, aquifer influx has been steadily rebuilding pressure within the reservoir.

Second, on March 20, 2008 a pressure reading taken on the 16-01 well was confirmed by running a static gradient on April 3, 2008 in the 02-12 well. The final gradient of 1.0 kPa/m was obtained from the 02-12 gradient and was used for both wells, giving good correlation of the pressures.

During 2010, there had been some instrumentation issues with the pressure monitor at 16-01 which are still under review. The display on the monitor is not working correctly and we are not able to read the pressure data. Consequently, we have relied solely on the static gradient measurement in the production well to monitor the reservoir pressure. On a go-forward, basis it will be necessary to have an independent reservoir pressure measurement from the 16-01 well.

Pressures for the uphole Muskeg zone are obtained by running static gradient tests on the 08-12-110-08W6 well, which was re-completed specifically to provide an observation well for Muskeg pressures. The table below summarizes the pressures obtained from this well, including the one measurement taken in 2010.

Muskeg Undefined Pressure - MPP Pressure Calculations

		MPP Depth = 1765 mKB		---	1214.7 mSS		
				Run	Final	Final	Datum
		KB Elev.	Test	Depth	Pressure	Gradient	Pressure
<u>Test Date</u>	<u>Well UWI</u>	<u>(m)</u>	<u>Type</u>	<u>(mKB)</u>	<u>(kPaA)</u>	<u>(kPa/m)</u>	<u>(kPaA)</u>
3-Apr-08	08-12-110-08w6/03	550.3	SG	1765.3	16050.6	10.4	16047.5
7-Feb-09	08-12-110-08w6/03	550.3	SG	1765	15997.7	10	15997.7
22-Mar-10	08-12-110-08w6/03	550.3	SG	1765	15968.3	10.4	15968.3
9-Jun-11	08-12-110-08w6/03	550.3	SG	1765	15910.9	10.4	15910.9

As can be seen, pressure in this zone is between 15910 and 16050 kPaa. This data should provide a good baseline for monitoring any potential pressure changes in this formation and demonstrates that the Muskeg and Keg River are not in pressure communication.

The injection wellhead pressure throughout the project is detailed in **Table 2**. It shows the WH injection pressure for each month of injection operations for the life of the project. **Figure 2** illustrates both the average wellhead injection pressure and the average reservoir pressure during injection of the acid gas.

5.0 Data

Aside from production and performance data, no additional data has been collected since the project commenced in Feb. 2009.

6.0 Economics

In 2010 the 02-12-110-08W6 producer was shut-in for the majority of the year. However we did produce 1,374 E3m³ during 3 weeks of production in February 2010.

In Q4 2010 Husky became the sole Working Interest owner in this project which previously had been 50/50 with Exxon Mobil.

The gross operating costs throughout 2009 and 2010 are shown below:

Gross Operating Costs	2009 (Gross)	2010 (Gross)
Fuel/Power	\$ 8,381	\$ 9,310
Treating	\$ 8,998	\$ 33,276
Servicing	\$ 14,293	\$ 23,730
Maintenance	\$ 12,973	\$ 28,003
Land Costs & Taxes	\$ 23,540	\$ 26,158
Labour	\$ 4,069	\$ 6,362
Processing & Gathering		
Overhead Recovery	\$ 13,026	\$ 20,411
Other Costs	\$ 52,540	\$ 63,108
Total Operating Costs	\$ 137,820	\$ 210,357

The following table shows the cumulative capital costs spent prior to the initiation of the project. This includes abandoning the Keg River zone in all KR O pool wells as well as constructing an acid gas pipeline.

Location	Description	Amount
03-12-110-08W6	Abandonment	\$1,064,585.00
10-12-110-08W6	Abandonment	\$245,637.00
10-01-110-08W6	Abandonment	\$1,059,666.00
14-01-110-08W6	Abandonment	\$238,189.00
15-01-110-08W6	Convert to Acid Gas Injector	\$677,616.00
14-12-110-08W6	Abandonment	\$127,220.00
02/08-12-110-08W6	Abandonment	\$475,182.00
08-12-110-08W6	Recomplete as a Muskeg Pressure Monitor	\$1,177,880.00
04-07-110-07W6	Abandonment	\$319,021.00
16-01-110-08W6	Recomplete as a Keg River Pressure Monitor	\$929,634.00
10-10-109-08W6 to 03-12-110-08W6	Acid Gas Pipeline	\$10,324,073.00
TOTAL CAPITAL COSTS		\$16,638,703.00

7.0 Facilities

7.1 Major Capital Items

No new facilities were constructed during the life of the project.

7.2 Capacity Limitation, Operational Issues, and Equipment Integrity

A new pipeline was built specifically to carry the acid gas to the 15-01-110-08W6 injection well. Following construction, an Ultrasonic Thickness Monitoring Survey was carried out to be used as baseline data for future surveys. In addition, the line was hydrostatically tested to ensure pipeline integrity prior to startup. Future testing will be carried out in accordance with the Husky Energy Acid Gas Injection Pipeline Integrity Plan as submitted to the ERCB and subsequently approved.

Throughout September - November of 2009, work was completed to increase the H₂S rating of an 800m pipeline from the 02-12 well to the satellite. A sample of the pipeline was recovered and tested to ensure that it would be possible to increase the rating. The testing was successful. Amendments to the pipeline license to increase the H₂S rating from 3,900ppm to 30,000ppm will be completed in Q1 2011.

Operational Issues

From a field operations perspective, the only significant downtime problems occur during the minimum daylight hours in the months of December to January. 6 out of 7 ESD sites are solar powered to run the radio and HMI controls at each site. During December to January, field operations experience weekly alarms/shutdowns due to low battery levels.

Our action item for 2011 was to decrease power level alarms by installing thermo electric generators (TEG's) at each site. The TEG's utilize small amounts of propane as fuel gas to generate enough current to keep the site batteries charged. We have since installed one TEG at the wellsite ESD resulting in 100% reliability. The other five sites will have propane TEG's installed by Q4 2011.

Since February 2009, when the acid gas pipeline was brought online, to December 2010 our two plant acid compressors have experienced a high rate of mechanical downtime. This downtime has been due to high vibration, frame misalignments and unreliable compressor valves which have contributed to run time rates of 93.6%.

In 2011, our run time rates have improved to 100%. This significant improvement in reliability can be attested to improved monitoring, new compressor valves and lower compressor loads. The lower loads are due to lower acid gas rates coming in to our plant inlet. The low rates are a result of sweet gas re-injection which is occurring in two of Rainbow's largest pools as a miscible flood scheme. The production from these pools accounts for over one half of the plant inlet volumes.

7.3 Process Flow and Site Diagram

A P&ID of the O Pool set up can be found in **Appendix 2**. This diagram depicts the 02-12 producing well and the 15-01 injection well and the associated piping and pipelines.

8.0 Environment, Regulatory and Compliance

8.1 Operational Failures

In the event of a failure of any operational equipment or safety devices, injection operations shall be suspended immediately.

In the event of a failure that could compromise environmental protection or the safe operation of the scheme, the ERCB field center will be notified immediately and a report will be submitted to the ERCB Well Operations group identifying the problem and any adverse effects.

Injection will not resume until the problem is fixed in a manner acceptable to the ERCB Well Operations group and when a written authorization is granted to resume injection.

8.2 Testing Requirements

Husky was in compliance with all of the daily, monthly and annual requirements as per the ERCB Approval 10668A. The wellhead injection pressure and pressure in the tubing/casing annulus are monitored on a daily basis and the ERCB will be notified if a tubing, casing or packer failure is suspected. H₂S and CO₂ concentrations in the injected and produced gas as well as the injected gas composition are also tested on a monthly basis.

The reservoir pressure is measured annually either through the bottomhole monitor in the 16-01 well, which is taken monthly for voidage calculations, or a static gradient conducted on either the 02-12 producer or 15-01 injector. Packer isolation tests are also required annually with the results submitted to ERCB within 45 days of test.

8.3 Emergency Response Plan

Husky Oil Operations currently has an EUB Approved ERP in place for the Rainbow Field. This plan was modified to include this scheme prior to commencing injection of acid gas.

The calculated EPZ for the 15-01-110-08W6 well, based on 95% H₂S, is 6.82 km and based on a constant flowing sandface pressure of 22,000 kPa. This is an H₂S release rate of 4.95 m³/sec up 60.3 mm OD tubing and is a Level 3 critical sour well. The calculated EPZ is a maximum value, based on a constant sandface pressure of 22,000 kPa at maximum rates (no drawdown) due to the expected high flow capacity from this horizontal well. Injection is into a zone of high water saturation that would likely kill the well or cause hydrates to form in the event of sudden backflow. The reservoir pressure used was also a maximum value that would occur only after the maximum re-pressurization of the reservoir was achieved by acid gas injection.

A notification radius of 8.8 km has been used based on the pipeline EPZ.

For notification and ERP purposes, an EPZ of 7.1 km has been utilized for the 15-01 injector, and also for the producing wells within the pool that have not been abandoned. The 7.1 km EPZ was calculated based on a lower reservoir pressure and larger tubing size than the final values shown

in this application. Public notification has been conducted in accordance with the requirements of Guide 71 Section 2.2.2.1.

All surface rights within a radius of 1.5 km of the 15-01-110-8W6 well are held by the Crown. There are no occupants within the 6.82 km EPZ radius for the wells.

The nearest urban center or public facility is located greater than 1.5 km from the wells. The town of Rainbow Lake boundary is 3.8 km beyond the 6.82 km well EPZ.

The 2 trappers in the area have been notified that a portion of their territory lies within the calculated EPZ of this acid gas disposal well, and the remaining wells producing from the Rainbow Keg River O Pool.

A number of additional parties were notified of this application for an acid gas disposal well. No objections to this application well were received.

8.4 Abandonment

Approval of the Acid Gas Disposal Scheme is on the basis that abandonment of the scheme will not proceed until the reservoir pressure is <16,688 kPaa (initial reservoir pressure) at the datum depth of -1295.4 mSS. Pressure tests will be performed on either the 16-01 observation well or the 15-01 injection well to determine the reservoir pressure on an annual basis.

The acid gas injection volume will be restricted to ensure no migration below the original oil-water contact and the disposal scheme will be abandoned prior to reaching the original reservoir pressure.

On May 31, 2011 an application was made to the ERCB asking for approval to terminate the Enhanced Gas Recovery Scheme in Rainbow's Keg River O Pool. Two days later on June 2, 2011 an application was submitted to the ERCB to convert the Enhanced Gas Recovery Scheme to an Acid Gas Disposal Scheme. Both applications were flagged as being dependant on each other in the ERCB's Resources Application online filing program.

Approval for the Enhanced Gas Termination Application was received on August 9, 2011. However this approval was granted before the approval of the Acid Gas Disposal Scheme and therefore at that time Husky was injecting acid gas outside of an approval. Husky filed a Voluntary Self Disclosure (VSD) on Aug 18, 2011 reporting the non-compliance of injecting acid gas without a scheme approval. While waiting for a response to Husky's VSD, approval was granted for the Acid Gas Disposal Application. Currently, Husky continues to inject under the Approval No. 11686 for an Acid Gas Disposal Scheme.

9.0 Future Operating Plan

As this project has been deemed unsuccessful, there will be no future operations pertaining to The Enhanced Gas Recovery Scheme, with the exception of the abandonment of the 02-12 producer and the continuous injection into the 15-01 injection well until a maximum acid gas injection volume, as stipulated by the ERCB, is in place.

10.0 Interpretations and Conclusions

Interpretations

The major objectives of the project were to:

1. Lower residual hydrocarbon gas saturation in the reservoir
2. Produce incremental gas
3. Justify implementation of this technology in other Alberta reservoirs
4. Demonstrate the successful and safe sequestration of large volumes of CO₂ and H₂S

Premature breakthrough of the injected acid gas resulted in early shut-in, with only marginal production of lean gas (1,374 E3m³).

The following theories comprise the explanation for the poor Enhanced Gas Recovery performance due to premature breakthrough of the injected acid gas.

Reservoir Complexity

Although acid gas is injected near the bottom of the reefal structure, high permeability streaks may provide a relatively direct flow-path for acid gases to migrate to the production well. Geologically, the Keg River O pool is characterized by large vugs and fractures; permeability from core is 50-60 mDs, but some flow tests show Darcy range permeability in some areas of the pool. The injection well is completed as an open-hole horizontal well – as such, there are no means currently in-place for controlling where the acid gas is injected. It is also possible that acid gas may be traveling through a high permeability streak along the reef edge, directly from the open-hole injector to the top production interval from 1795-1801 mKb in the 02-12 producer.

Husky was unable to confirm this theory by obtaining a fluid sample as access to a lower production interval in the 02-12 producer is restricted due to a plug stuck in the wellbore at 1819 mKb. Removal of the plug would require a major workover of the critical-sour well. The downhole diagram for the 02-12 producer can be seen in **Figure 3**. In addition, testing the acid gas concentration in the 16-01 pressure monitor was also not a viable option due to its current wellbore configuration. The pressure monitor is set up such that there is a capillary chamber located at 1754 mKb that was initially filled with helium and a capillary string to surface making it inaccessible to gather a fluid sample. The downhole diagram of the 16-01 pressure monitor can be seen in **Figure 4**. No intervention was possible in any other wellbore in the pool, due to the ERCB requirement to abandon the Keg River zone to prevent acid gas leakage to uphole formations.

Wellbore Isolation

Acid gas may be migrating behind casing to the productive interval, due to poor casing-formation cement bond (given the vintage of the well and the difficult formation conditions in which to place cement). Acid gas migration within the existing wellbore may also provide an explanation for the premature breakthrough observed; however, this is

thought to be extremely unlikely, given that the completion in 02-12 consists of a series of redundant packers, and the chance that all 7 packers are leaking must be considered very marginal.

A major workover of the critical-sour well would be necessary to test for and remediate against either behind casing migration or within wellbore communication (costs in excess of \$500,000 have been estimated specifically for this workover. Due to the limited proven developed reserves for the pool (~0.2 bcf), it would be uneconomical to proceed with this work.

Given the above, Husky concluded that it was not feasible to continue the EGR scheme due to technical, economical, and safety reasons. Accordingly, Husky filed the relevant application, on May 31, 2011 to terminate the existing scheme and ERCB approval to rescind the Enhanced Gas Recovery Scheme was received on August 9, 2011. Subsequently ERCB approved the continuation of acid gas injection into this pool as an Acid Gas Disposal Scheme.

This pilot project has been a large learning experience for the Husky team, technically and operationally. As this technology has never been applied in the industry before, many risks and concerns needed to be addressed before the project could be executed.

Due to the toxic nature of the H_2S , one of the largest difficulties throughout this project was ensuring that all safety measures were met, both operationally and environmentally. Extreme precautions and safeguarding were implemented to mitigate the risk of corrosion from the H_2S and CO_2 . The only operational issues encountered were due to sealing issues on the ESD valves. This issue was resolved by replacing the original metal-to-metal seat valves with soft seat valves.

This was primarily a pilot project, intended to test the theory and gain operational data and expertise. Observations on some of the uncertainties cited in the original IETP application were as follows:

- Does the injected acid gas plume disperse in the reservoir sweeping large pore space?
 - Early breakthrough indicates that a high volumetric sweep efficiency was not obtained. This could be a result of reservoir heterogeneity and/or wellbore isolation problems as discussed above. This behavior did not match the modeling of the acid gas plume which suggested much later breakthrough times.
- Does the acid gas channel through to the producing well quickly?
 - After only 7 months of injection, production was initiated and the injected acid gas was identified immediately in the production stream.
- Does the acid gas concentration in the production stream rise suddenly or gradually?
 - The first sample, after only 2 weeks of production, indicated 18.7 mole% H_2S . A subsequent sample 2 weeks later showed 23 mole%. No further samples were analyzed as production was shut in.

The results observed appear to be reservoir and/or wellbore specific in this case. There is no direct evidence to indicate that the mechanism involving lean gas displacement through acid gas injection is not successful. Application in a more homogenous reservoir with good wellbore isolation could potentially yield superior results.

Conclusions

1. The project was not successful in producing the targeted incremental trapped hydrocarbon gas volume. A small amount of lean gas was produced but early breakthrough of acid gas prevented sustained production and did not result in a significant lowering of the in-place hydrocarbon gas saturation.
2. The project was successful in safely sequestering large volumes of CO₂ and H₂S. Between February 19, 2009 and August 31, 2011 a total value of 76,462 E3m³ acid gas has successfully been injected and sequestered in the Rainbow Keg River O Pool. This volume will continue to increase up to the maximum volumes of 619 E6m³ or as stipulated in the ERCB Approval No.11686 for the acid gas disposal. The injected acid gas has been successfully contained in the Keg River formation as demonstrated by pressure monitoring in the adjacent up-hole Muskeg formation.
3. Husky has been successful in safely managing and operating the high pressure acid gas injection stream without any major incidents. Corrosion problems within the facilities have not been a major concern.
4. We are unable to conclude that this application may or may not be successful in other reservoirs. Upfront testing is recommended to ensure reservoir heterogeneity and wellbore isolation do not pose an issue prior to scheme implementation.

Figures

Figure 1 – Structure Map

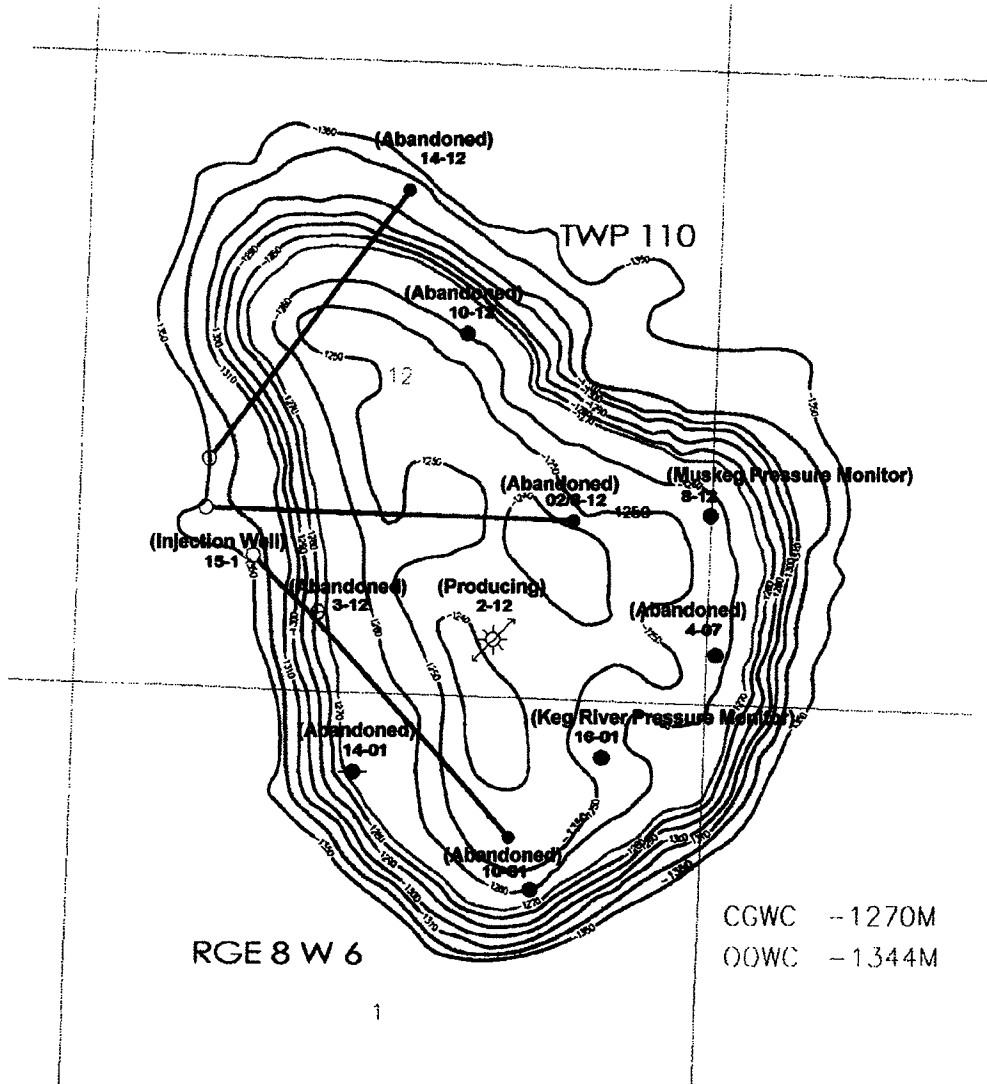
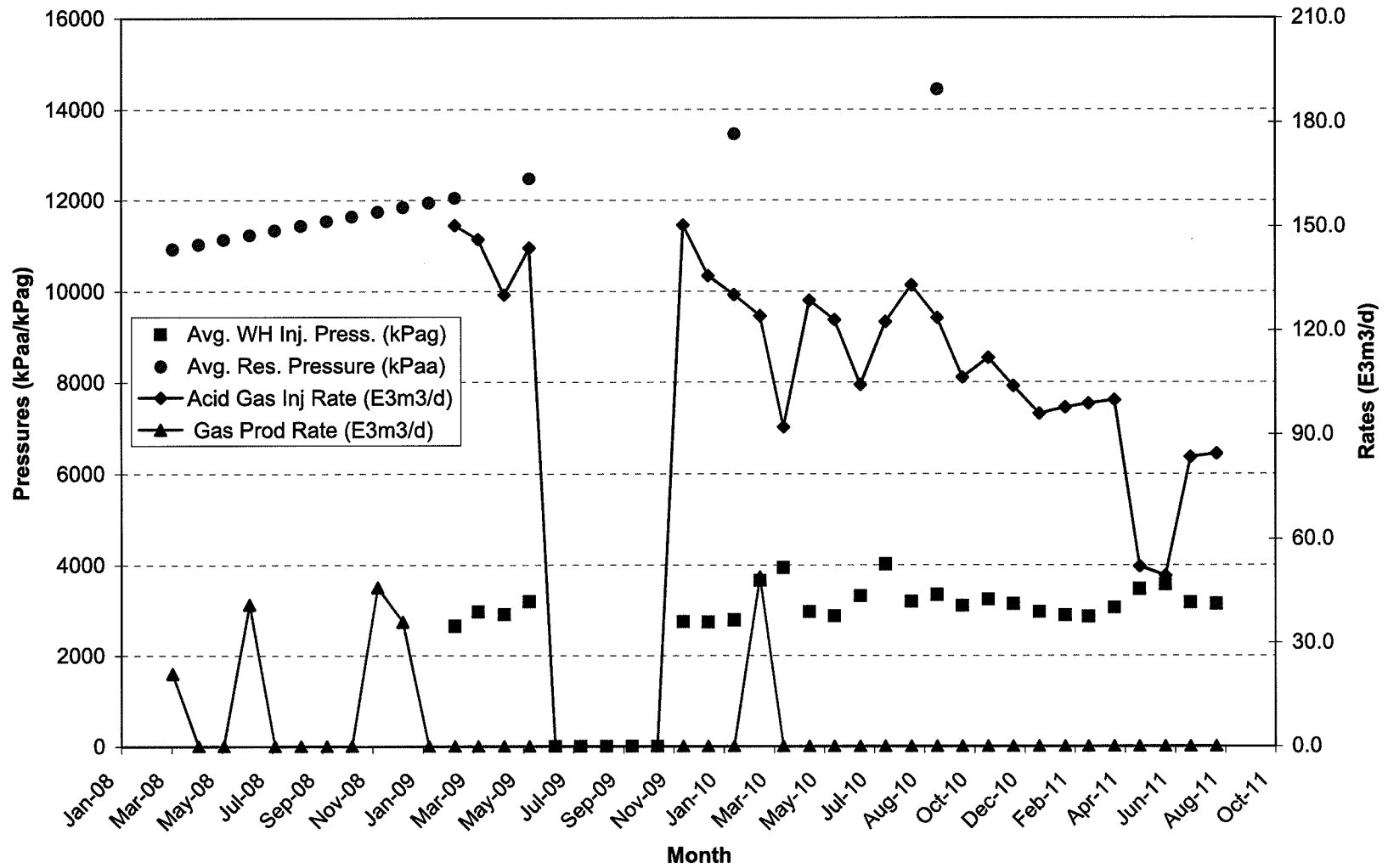


Figure 2



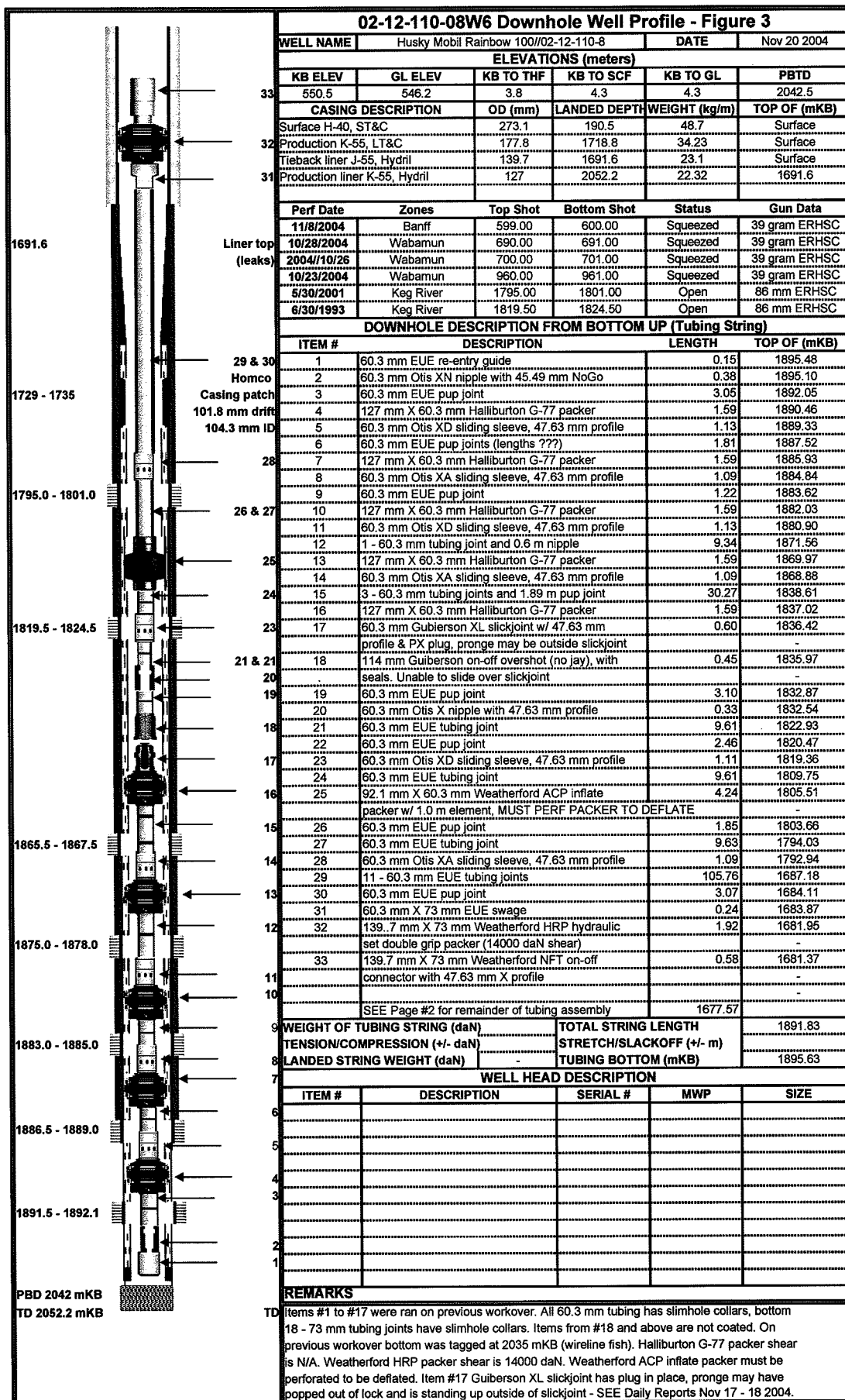


FIGURE 3



ALL DEPTHS ARE mKB

Surf. Csg.
186.0 m

Capillary tube

Liner Top @
1756.0 m

Int. Csg. @
1806.0 m

**TOP of flsh @
1816.4 mkb**

PBTD
Cement top @
1.884.6

Cmnt Perfs
1885.5 - 87.5 mkb
Fish @
1889.0 m

Original PBTD @
1893.0 m
Inner Landed @
1909.6 m

TD @ 1910.0 M

WELL DIAGRAM "Final"

WELL NAME: Husky Mobil Rain 100/16-01-110-08 W6

PREPARED BY: Mike Periard

DATE: 2007/09/18

ELEVATIONS (meters):

Licence No: 43773

TD	1,910.00	KB Elev.	547.10
PBTD	1,884.60	Ground Elev.	543.20

KB to CF Dist. H	3.90
KB to Ground	3.90

CASING/TUBING	SIZE (mm)	WEIGHT (Kg/m)	GRADE	DEPTHS (m)
---------------	-----------	---------------	-------	------------

Surface Casing	244.50	53.80	J-55 / LT&C	188.00
Int. Casing	177.80	34.20	K-55 / LT&C	CF - 1240.0
		29.80	K-55 / LT&C	1240.0 - 1808.0

Prod. Liner	114.30	17.26	J-55	1756.0 1909.6
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			ST&C	
--	--	--	------	--

Tubing	60.30	8.99	J-55, EUE	0 - 1746.57	181 Jts
			EUE	1746.57 - 1779.33	3 Jts

BOTTOM HOLE ASSEMBLY:

ITEM	DESCRIPTION	LENGTH (m)	Top at (m KB)
1	60.3 mm pump out plug, Incoloy 925, Hydril 533 thread, (OPEN)	0.21	1,785.75
2	1 - 60.3 mm pup joint, Incoloy 825, Hydril 563 thread	1.03	1,784.72
3	60.3 mm x 47.63 mm "XN" c/w 45.49 mm NoGo, Incoloy 925, Hydril 533	0.47	1,784.25
4	1 - 60.3 mm pup joint, Incoloy 825, Hydril 563 thread	2.82	1,781.43
5	114.3 mm Halliburton BWS permanent packer, Incoloy 925, Hydril 533	0.83	1,780.60
6	Rath Latch seal assembly, Incoloy 925, Hydril 533 thread	0.25	1,780.35
7	60.3 mm On/Off assembly c/w 47.63 mm "X" profile, Incoloy 925, Hydril 533	1.02	1,779.33
8	3 - 60.3 mm 6.99 kg/m, Incoloy 825, tubing joints, Hydril 533 thread	27.66	1,751.67
9	1 - 60.3 mm pup joint, Incoloy 825, Hydril 563 thread	1.03	1,750.64
10	141 mm Halliburton EZ gauge pressure chamber, Incoloy 925, Hydril 533	1.83	1,748.81
11	1 - 60.3 mm pup joint, Incoloy 825, Hydril 563 thread	1.90	1,746.91
12	60.3 mm x 47.63 mm "X" nipple, Incoloy 925, Hydril 533 (Plug in place)	0.34	1,746.57
13	1 - 60.3 mm pup joint, L-80, Hydril 563 thread	1.14	1,745.43
14	60.3 mm Hydril 533 x 60.3 mm EUE, L-80 crossover	0.16	1,745.27
15	180 - 60.3 mm 6.99 kg/m J-55, EUE tubing joints	1,732.84	12.43
16	2 - 60.3 mm 6.99 kg/m J-55, EUE pups (1 - 0.17 m / 1 - 0.23 m)	0.40	12.03
17	1 - 60.3 mm 6.99 kg/m J-55, EUE tubing joint	9.51	2.52
	Compression (2000 daNs)	-0.23	2.75
	Wireline correction	-0.81	3.56
18	60.3 mm Crown type CTC1AEN tubing hanger c/w BPV thread	0.16	3.40
			3.40
			3.40
			3.40
			3.40
			3.40
			3.40
			3.40
			3.40
			3.40
			3.40
			3.40
			3.40
			3.40
			3.40
			3.40
TALLY		1,782.56	
KB TO TUBING HEAD		3.40	
TUBING BOTTOM		1,785.96	

NOTE: All equipment below crossover is Incoloy with Hydрил threads.

Capillary tube is strapped to tubing with protectors @ each connection.

Annulus & tubing circulated to inhibited fresh water & topped off with diesel

PUMP AND ROD ASSEMBLY

Perforation Intervals	BHA cut off and left below	LENGTH	TOP @ mkb
1885.5 - 1887.5 mkb - Cemented	60.3 mm wireline re-entry guide	0.15	1,882.76
1880.6 - 1883.1 mkb - Open	60.3 mm x 47.65 mm "XN" nipple (plug in)	0.38	1,882.38
1873.8 - 1878.7 mkb - Open	1 - 60.3 mm pup it	1.90	1,880.48
1863.5 - 1867.1 mkb - Open	114.3 mm x 60.3 mm Halliburton G-77 Pkg	1.56	1,878.92
1851.7 - 1859.8 mkb - Squeezed	60.3 mm x 47.63 mm "XA" SSD (closed)	1.09	1,877.83
1810.5 - 1816.0 mkb - Open	4 - 60.3 mm pups (2 x 3.30, 0.67, 0.22 m)	6.95	1,870.88
1803.1 - 1806.2 mkb - Open	114.3 mm x 60.3 mm Halliburton G-77 Pkg	1.56	1,869.32
	60.3 mm x 47.63 mm "XD" SSD (closed)	1.13	1,868.19
	3 - 60.3 mm pup (3.02, 2.43, 0.33 m)	5.78	1,862.41
	114.3 mm x 60.3 mm Halliburton G-77 Pkg	1.56	1,860.85
	1 - 60.3 mm pup it	1.87	1,858.98
	4 - 60.3 mm tbq its	38.20	1,820.78
	114.3 mm x 60.3 mm Halliburton G-77 Pkg	1.56	1,819.22
	60.3 mm x 47.63 mm "XA" SSD (open)	1.09	1,818.13
	Tbq cut off above SSD.	1.75	1,816.40

NOTE: SITE selective tool lost & was pushed to 1893.0 mkb

Tables

TABLE 1

Monthly Injection Volumes

Month	Acid Gas Injected (E3m3)	Cumulative Acid Gas Injected (E3m3)	Acid Gas F.V.F. (Rm3/E3m3)	Acid Gas Injected (Rm3)	Mole Fraction H2S (fraction)	H2S Injected (E3m3)	Cumulative H2S Injected (E3m3)	Mole Fraction CO2 (fraction)	CO2 Injected (E3m3)	Cumulative CO2 Injected (E3m3)
Jan-09	0	0	3.17	0	0.8060	0.0	0	0.1905	0.0	0.0
Feb-09	1,647	1,647	3.15	5,186	0.8060	1327.0	1,327	0.1905	313.7	313.7
Mar-09	4,532	6,178	3.15	14,276	0.8060	3652.5	4,980	0.2523	1143.4	1457.1
Apr-09	3,906	10,084	3.04	11,874	0.7780	3038.8	8,018	0.2160	843.7	2300.8
May-09	1,184	11,269	3.04	3,600	0.7780	921.3	8,940	0.2160	255.8	2556.6
Jun-09	0	11,269	3.04	0	0.7780	0.0	8,940	0.2160	0.0	2556.6
Jul-09	0	11,269	3.04	0	0.7780	0.0	8,940	0.2160	0.0	2556.6
Aug-09	0	11,269	3.05	0	0.7770	0.0	8,940	0.2180	0.0	2556.6
Sep-09	0	11,269	3.12	0	0.7640	0.0	8,940	0.2290	0.0	2556.6
Oct-09	0	11,269	3.12	0	0.7640	0.0	8,940	0.2290	0.0	2556.6
Nov-09	1,036	12,305	3.09	3,203	0.7700	798.0	9,738	0.2190	227.0	2783.6
Dec-09	4,143	16,448	3.03	12,553	0.7860	3256.3	12,994	0.2000	828.6	3612.1
Jan-10	3,519	19,967	3.08	10,840	0.7721	2717.4	15,711	0.2203	775.3	4242.4
Feb-10	3,221	23,188	3.14	10,114	0.7558	2434.5	18,146	0.2366	762.1	5004.6
Mar-10	2,662	25,850	3.11	8,279	0.7544	2008.4	3,335	0.2356	627.1	940.8
Apr-10	2,853	28,703	3.11	8,873	0.7544	2152.4	5,488	0.2356	672.1	1612.9
May-10	3,326	32,030	3.09	10,279	0.7576	2520.1	8,008	0.2322	772.5	2385.4
Jun-10	3,076	35,106	3.08	9,474	0.7497	2306.2	10,314	0.2374	730.4	3115.7
Jul-10	3,728	38,834	3.09	11,520	0.7438	2773.1	13,087	0.2480	924.6	4040.4
Aug-10	4,110	42,943	3.12	12,822	0.7307	3002.9	16,090	0.2619	1076.1	5116.5
Sep-10	3,702	46,645	3.11	11,513	0.7291	2698.9	18,789	0.2614	967.5	6084.0
Oct-10	3,283	49,928	3.08	10,112	0.7319	2403.1	21,192	0.2552	837.8	6921.7
Nov-10	3,357	53,285	3.05	10,237	0.7428	2493.2	23,685	0.2353	789.8	7711.6
Dec-10	3,216	56,501	3.11	10,003	0.7177	2308.4	25,994	0.2642	849.8	8561.3
Jan-11	2,912	59,414	3.30	9,611	0.7223	2103.5	28,097	0.2372	690.9	9252.2
Feb-11	2,678	62,091	3.05	8,167	0.7277	1948.7	30,046	0.2573	688.9	9941.1
Mar-11	3,067	65,158	3.20	9,823	0.7236	2219.3	32,265	0.2523	773.8	10714.9
Apr-11	2,997	68,155	3.21	9,613	0.7337	2198.5	34,464	0.2545	762.6	11477.5
May-11	1,616	69,770	3.21	5,191	0.7337	1185.3	35,649	0.2545	411.1	11888.6
Jun-11	1,483	71,253	3.22	4,771	0.7337	1087.7	36,737	0.2545	377.3	12265.9
Jul-11	2,589	73,842	3.22	8,346	0.7337	1899.6	38,636	0.2545	658.9	12924.8
Aug-11	2,620	76,462	3.23	8,458	0.6878	1801.9	40,438	0.2936	769.3	13694.1

Note: Highlighted values are those for which analysis taken was rejected.
Previous month analysis was used for reservoir calculations.

TABLE 2**Monthly Injection Data**

Month	Hours On Injection (hrs)	Acid Gas Injected (E3m3)	Avg Daily Inj Rate (E3m3/d)	Max Daily Inj Rate (E3m3/d)	Conditions at Maximum WHIP				Avg WH Inj Press (kPag)	Avg WH Inj Temp (deg C)
					WH Inj Press (kPag)	WH Inj Temp (deg C)	WH Inj Rate (E3m3/d)	Calc. BH Inj Press (kPaa)		
Jan-09	0	0	0	0	0	0	0	0	0	0
Feb-09	263	1646.5	150.3	167.6	2778	7.6	146	17601	2655	7.3
Mar-09	744	4532	146.2	159.8	3513	9.3	145	18332	2968	13.0
Apr-09	720	3906	130.2	150.3	3318	9.3	105	18137	2908	12.5
May-09	198	1184	143.7	152.3	5740	0.9	135	20559	3192	12.5
Jun-09	0	0	0	0.0	0	0.0	0	0	0	0.0
Jul-09	0	0	0	0.0	0	0.0	0	0	0	0.0
Aug-09	0	0	0	0.0	0	0.0	0	0	0	0.0
Sep-09	0	0	0	0.0	0	0.0	0	0	0	0.0
Oct-09	0	0	0	0.0	0	0.0	0	0	0	0.0
Nov-09	165	1036	150.4	156.9	3136	2.3	161	17955	2751	11.1
Dec-09	732	4143	135.8	153.8	3661	8.7	109	18480	2741	9.5
Jan-10	656	3563	130.3	157.9	4030	6.8	143	18849	2782	8.2
Feb-10	623	3221	124.2	149.0	4327	5.9	151	19146	3657	5.5
Mar-10	693	2662	92.1	293.3	4894	3.3	119	19713	3939	4.4
Apr-10	532	2853	128.6	215.5	3359	8.9	186	17863	2967	9.2
May-10	649	3326	123.1	204.3	3044	17.0	204	17863	2871	13.8
Jun-10	708	3076	104.3	204.8	4121	17.5	112	18940	3315	16.6
Jul-10	731	3728	122.5	219.9	4631	11.6	217	19450	4017	11.9
Aug-10	741	4110	133.1	220.7	3787	13.5	217	18606	3189	13.5
Sep-10	719	3702	123.6	217.3	3941	11.7	200	18760	3342	11.7
Oct-10	741	3283	106.4	194.5	4203	10.5	188	19022	3103	10.3
Nov-10	719	3357	112.0	203.7	3540	8.3	190	18359	3238	8.4
Dec-10	743	3216	103.9	181.5	3350	7.1	160	18169	3140	7.4
Jan-11	728	2912	96.0	176.5	3313	9.0	176	18132	2965	10.9
Feb-11	657	2678	97.8	169.7	3119	7.2	168	17938	2889	8.6
Mar-11	743	3067	98.9	119.7	3199	6.8	109	18018	2857	7.4
Apr-11	719	2997	99.9	116.1	3741	7.8	15	18560	3060	8.2
May-11	744	1616	52.1	76.4	4856	5.7	62	19675	3467	5.8
Jun-11	630	1483	49.4	93.9	4167	6.8	62	18986	3563	8.0
Jul-11	732	2589	83.5	92.7	3644	9.7	82	18463	3171	8.5
Aug-11	744	2620	84.5	91.3	3481	9.6	91	18300	3138	10.1

note:

Well depth from wellhead to TD TVD = 1904.76

Static Gradient = 7.78 kPa/m

Appendices

Downhole Well Profile

WELL NAME: Husky Mobil Rainbow 15-1-110-08 W6			DATE: June 7/07		
ELEVATIONS (meters)					
KB ELEV:	GL ELEV:	KB TO THP:	KB TO SCF:	KB TO GL:	PBTD:
564.45	558.85	5.6			2715
CASING DESCRIPTION:		QD (mm):	LANDED DEPTH WEIGHT (kg/m):		TOP OF (mKB):
Surface Casing		339.7	355 81.1		0
Intermediate Casing		244.5	2065 53.6, 59.5		
			64.7		0

Perf Date:	Zones:	Top Shot:	Bottom Shot:	Status:	Gun Data:
	Keg River Open hole	2065.00	2715.00	Open	

DOWNHOLE DESCRIPTION FROM BOTTOM UP (Tubing String)

ITEM #	DESCRIPTION	LENGTH	TOP OF (mKB)
1	Incoloy 925 wireline re-entry guide	0.23	2016.06
2	Halliburton XN nipple c/w 47.6 & 45.4mm profile	0.38	2015.68
3	1- 60.3mm Hydril 533, Incology pup	2.86	2012.82
4	Halliburton X nipple c/w 47.6mm profile	0.44	2012.38
5	1- 60.3mm Hydril 533 Incology pup	5.29	2007.09
6	Halliburton 244.5mm BWS Permanent Packer c/w Incology Ratch Latch seal assembly	1.40	2005.69
7	Halliburton Incoloy XXL on-off tool 47.6mm profile	1.11	2004.58
8	1- 60.3mm Hydril 533 Incology pup	2.94	2001.64
9	27- Joints 60.3mm 533 L-80 Hydril tubing	256.83	1744.81
10	Halliburton 60.3mm Incology X nipple c/w 47.6mm pro	0.35	1744.46
11	1- 60.3mm Hydril 533 Incology pup	2.95	1741.51
12	182- Joints 60.3mm 533 L-80 Hydril tubing	1730.54	10.97
13	4- 60.3mm 533 L80 pup joints	6.26	4.71
	2.96, .43, 2.35, .52m Pups not buried		
	60.3mm 533 Hydril & 73mm eue pin crossover	0.26	4.45
15	Crown 244.5 & 73mm eue Crown tubing hanger c/w B. P. Threads.	0.26	4.19
	Tubing to tally correction	-1.11	
	Tubing string landed in compression	-0.30	
	Rotate 7- turns w/ slight tension to sting out of the permanent packer. To come off the on-off put tubing in slight compression and 1/4 turn to left.		

WEIGHT OF TUBING STRING (daN)	12,000	TOTAL STRING LENGTH	2010.69
TENSION/COMPRESSION (+/- daN)	-4,500	STRETCH/SLACKOFF (+/- m)	
LANDED STRING WEIGHT (daN)		TUBING BOTTOM (mKB)	2016.29

Casing shoe 2065mKb

215mm packer c/w fishneck

Note:
Csgs
Inhibit
w/oil .

Halliburton 244.5mm BWS Permanent Packer , Incology 925
1- pup joint, 47.6mm X nipple, pup joint, 47.6mm XN nipple, wireline entry.

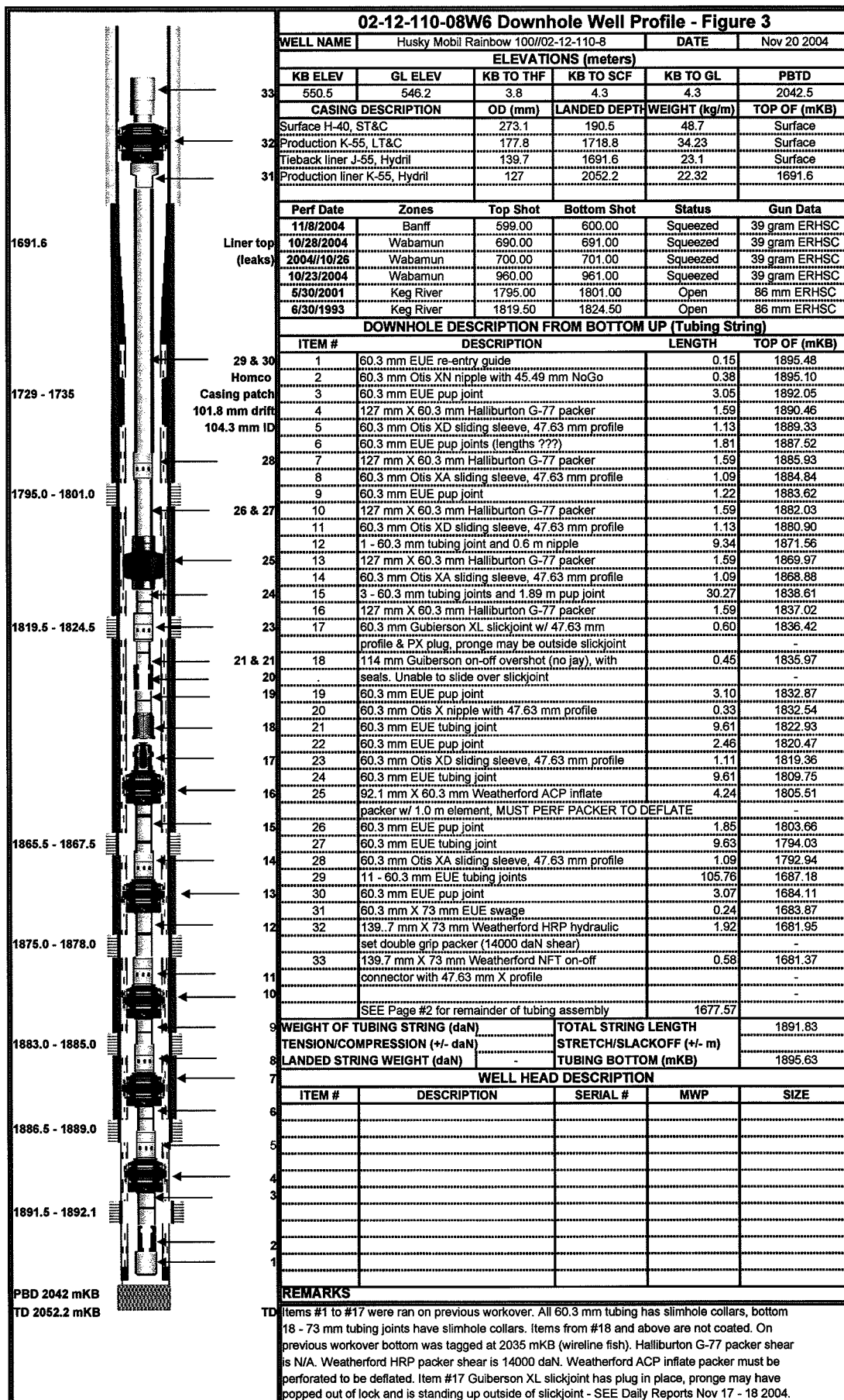
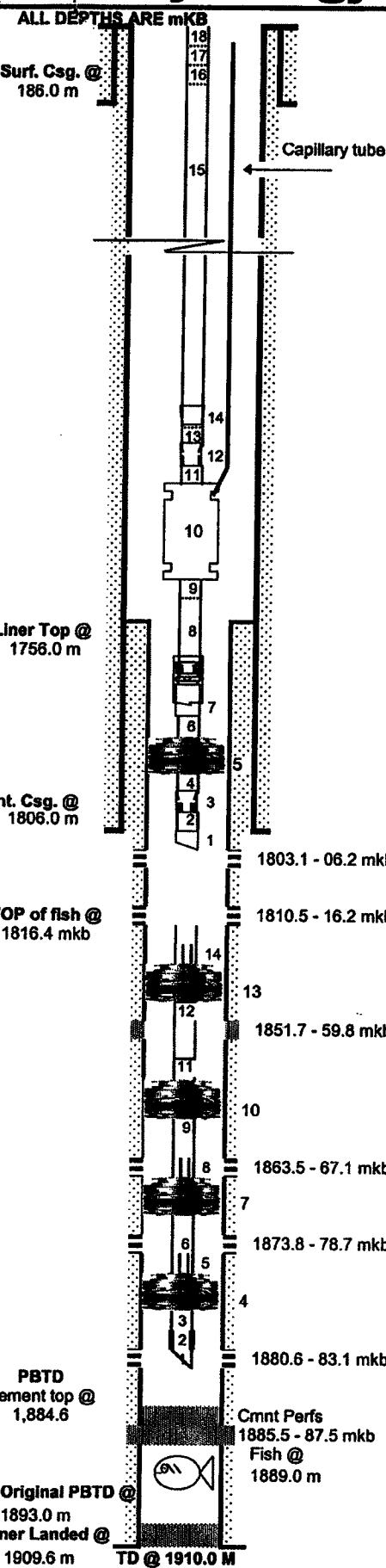


FIGURE 3



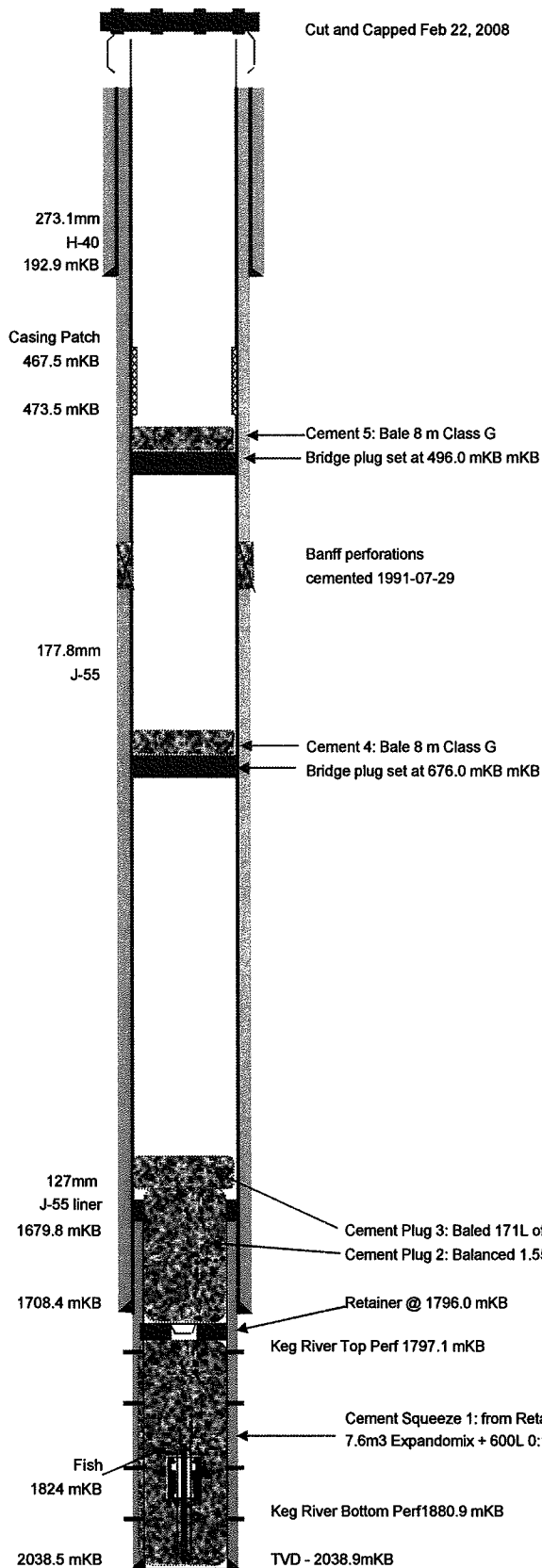
WELL NAME: Husky Mobil Rain 100/16-01-110-08 W6		DATE: 2007/09/18	
PREPARED BY: Mike Perlard		Licence No: 43773	
ELEVATIONS (meters):			
TD	1,910.00	KB Elev.	547.10
PBTD	1,884.60	Ground Elev.	543.20
		KB to CF Dist. H	3.90
		KB to Ground	3.90
CASING/TUBING	SIZE (mm)	WEIGHT (Kg/m)	GRADE
Surface Casing	244.50	53.60	J-55 / LT&C
			188.00
Int. Casing	177.80	34.20	K-55 / LT&C
		29.80	K-55 / LT&C
			CF - 1240.0
			1240.0 - 1808.0
Prod. Liner	114.30	17.26	J-55
			1758.0 1909.6
			ST&C
Tubing	60.30	8.99	J-55, EUE
			0 - 1748.57 181 Jts
			1748.57 - 1779.33 (3 Jts
			EUE

ITEM	DESCRIPTION	LENGTH (m)	Top at (m KB)
1	60.3 mm pump out plug, Incoloy 925, Hydril 533 thread, (OPEN)	0.21	1,785.75
2	1 - 60.3 mm pup joint, Incoloy 825, Hydril 563 thread	1.03	1,784.72
3	60.3 mm x 47.63 mm "XN" c/w 45.49 mm NoGo, Incoloy 925, Hydril 533	0.47	1,784.25
4	1 - 60.3 mm pup joint, Incoloy 825, Hydril 563 thread	2.82	1,781.43
5	114.3 mm Halliburton BWS permanent packer, Incoloy 925, Hydril 533	0.83	1,780.60
6	Rath Latch seal assembly, Incoloy 925, Hydril 533 thread	0.25	1,780.35
7	60.3 mm On/Off assembly c/w 47.63 mm "X" profile, Incoloy 925, Hydril 533	1.02	1,779.33
8	3 - 60.3 mm 6.99 kg/m, Incoloy 825, tubing joints, Hydril 533 thread	27.66	1,751.67
9	1 - 60.3 mm pup joint, Incoloy 825, Hydril 563 thread	1.03	1,750.64
10	141 mm Halliburton EZ gauge pressure chamber, Incoloy 925, Hydril 533	1.83	1,748.81
11	1 - 60.3 mm pup joint, Incoloy 825, Hydril 563 thread	1.90	1,746.91
12	60.3 mm x 47.63 mm "X" nipple, Incoloy 925, Hydril 533 (Plug in place)	0.34	1,746.57
13	1 - 60.3 mm pup joint, L-80, Hydril 563 thread	1.14	1,745.43
14	60.3 mm Hydril 533 x 60.3 mm EUE, L-80 crossover	0.16	1,745.27
15	180 - 60.3 mm 6.99 kg/m J-55, EUE tubing joints	1,732.84	12.43
16	2 - 60.3 mm 6.99 kg/m J-55, EUE pups (1 - 0.17 m / 1 - 0.23 m)	0.40	12.03
17	1 - 60.3 mm 6.99 kg/m J-55, EUE tubing joint	9.51	2.52
	Compression (2000 daNs)	-0.23	2.75
	Wireline correction	-0.81	3.56
18	60.3 mm Crown type CTC/AEN tubing hanger c/w BPV thread	0.16	3.40
			3.40
			3.40
			3.40
			3.40
			3.40
			3.40
			3.40
			3.40
			3.40
			3.40
			3.40
			3.40
			3.40
			3.40
			3.40
			3.40
			3.40
TALLY		1,782.56	
KB TO TUBING HEAD			3.40
TUBING BOTTOM			1,785.96

PUMP AND ROD ASSEMBLY

Perforation Intervals	BHA cut off and left below	LENGTH	TOP @ mkb
1885.5 - 1887.5 mkb - Cemented	60.3 mm wireline re-entry guide	0.15	1,882.76
1880.6 - 1883.1 mkb - Open	60.3 mm x 47.65 mm "XN" nipple (plug in	0.38	1,882.38
1873.8 - 1878.7 mkb - Open	1 - 60.3 mm pup it	1.90	1,880.48
1863.5 - 1867.1 mkb - Open	114.3 mm x 60.3 mm Halliburton G-77 Pkr	1.56	1878.92
1851.7 - 1859.8 mkb - Squeezed	60.3 mm x 47.63 mm "XA" SSD (closed)	1.09	1,877.83
1810.5 - 1816.0 mkb - Open	4 - 60.3 mm pups (2 x 3.30, 0.67, 0.22 m	6.95	1,870.88
1803.1 - 1806.2 mkb - Open	114.3 mm x 60.3 mm Halliburton G-77 Pkr	1.56	1,869.32
	60.3 mm x 47.63 mm "XD" SSD (closed)	1.13	1,868.19
	3 - 60.3 mm pup (3.02, 2.43, 0.33 m)	5.78	1,862.41
	114.3 mm x 60.3 mm Halliburton G-77 Pkr	1.56	1,860.85
	1 - 60.3 mm pup it	1.87	1858.98
	4 - 60.3 mm tbq its	38.20	1820.78
	114.3 mm x 60.3 mm Halliburton G-77 Pkr	1.56	1819.22
	60.3 mm x 47.63 mm "XA" SSD (open)	1.09	1818.13
	Tbq cut off above SSD.	1.75	1816.40

NOTE: SITE selective tool lost & was pushed to 1893.0 mkb



Cut and Capped Feb 22, 2008

Downhole Well Profile

WELL NAME	HUSKY RAINBOW 04-07-110-07W6	SPUD	Feb 3, 1967
License	31675 - abandoned	Current	Feb 22, 2008

ELEVATIONS (meters)

KB ELEV	GL ELEV	KB TO GL	BGWP	PBTD	TD
541 m	537.7 m	3.3 m	100 mKB	2024.80	2038.90

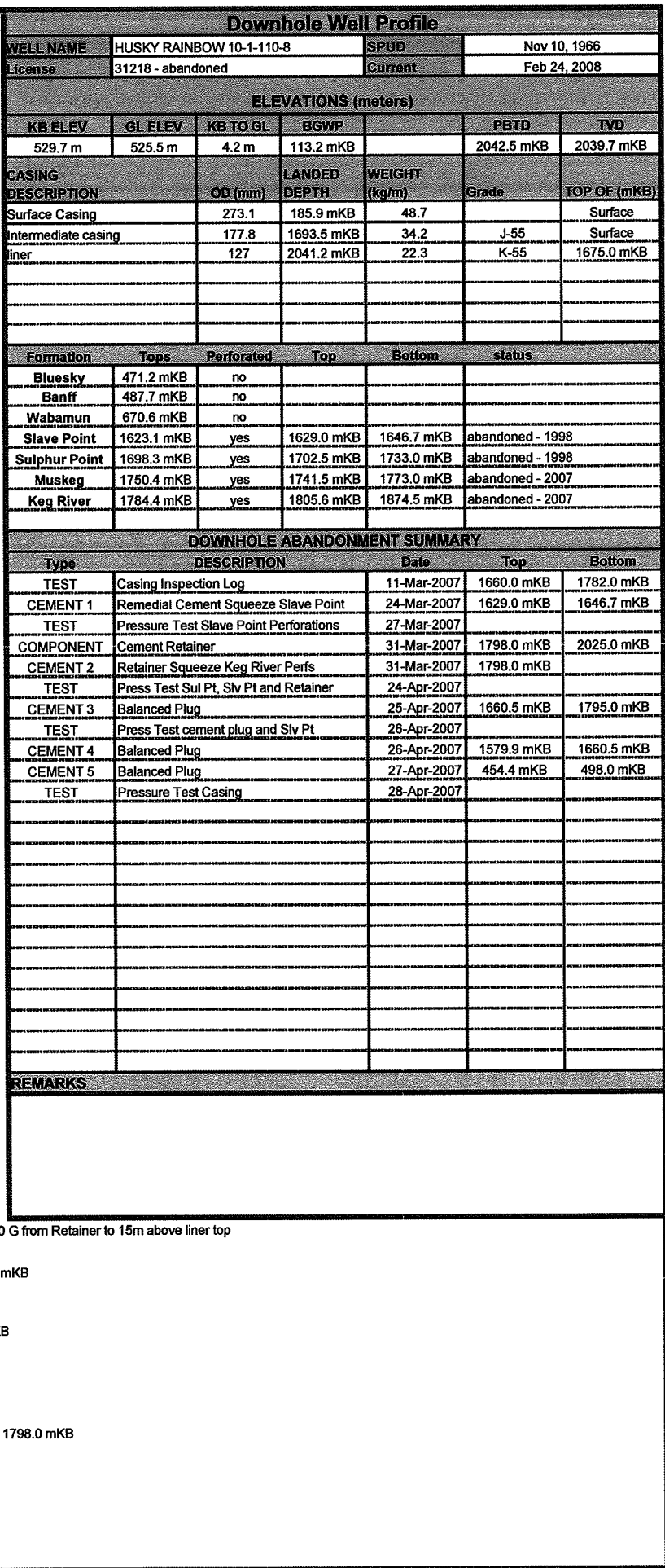
CASING DESCRIPTION	OD (mm)	LANDED DEPTH	WEIGHT (kg/m)	Grade	TOP OF (mKB)
Surface Casing	273.1	192.9 mKB	48.1	H-40	Surface
Intermediate casing	177.8	1708.4 mKB	34.2	J-55	Surface
liner	127	2038.5 mKB	22.3	K-55	1679.8 mKB

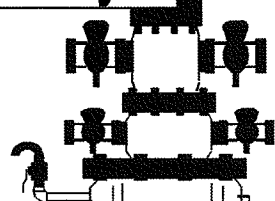
Formation	Tops	Perforated	Top	Bottom	status
Bluesky	483	no			
Banff	500	yes	565 mKB	566 mKB	cemented
Wabamun	681	no			
Slave Point	1634	no			
Sulphur Point	1714	no			
Muskeg	1745	no			
Keg River	1767	yes	1797.1 mKB	1880.9 mKB	abandoned

DOWNHOLE ABANDONMENT SUMMARY

Type	DESCRIPTION	Date	Top	Bottom
TEST	Press test annulus and casing patch	09-Jul-2007		
COMPONENT	Set Retainer	11-Jul-2007	1795.66 mKB	
CEMENT 1	Cement Squeeze Keg River	12-Jul-2007	1795.66 mKB	TD
TEST	Casing Inspection Log	13-Jul-2007	surface	1795 mKB
CEMENT 2	Set Cement Plug from Retainer to 1660	15-Jul-2007	1673.6 mKB	1795.66 mKB
CEMENT 3	Dump Bale extra cement	16-Jul-2007	1663.8 mKB	1673.6 mKB
TEST	Pressure Test Cement plug to 7 Mpa	17-Jul-2007		
COMPONENT	Set Bridge Plug at 676.0	18-Jul-2007	676.0 mKB	
TEST	Pressure Test Bridge Plug	18-Jul-2007		
CEMENT 4	Dump Bale 8 linear meters onver Plug	18-Jul-2007	668.0 mKB	676.0 mKB
COMPONENT	Set Bridge Plug at 496.0	18-Jul-2007	496.0 mKB	
TEST	Pressure Test Bridge Plug	18-Jul-2007		
CEMENT 5	Dump Bale 8 linear meters onver Plug	18-Jul-2007	488.0 mKB	496.0 mKB

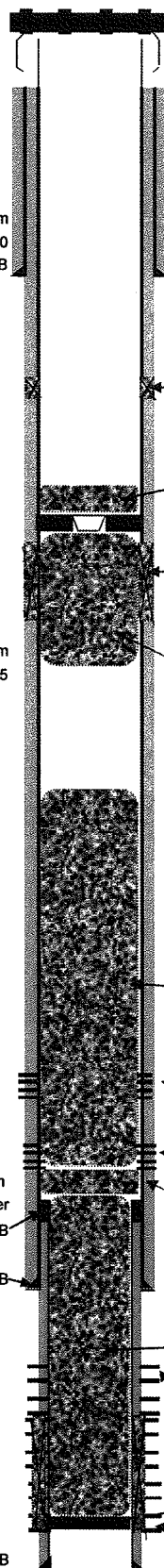
REMARKS





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[illegible]



Keg River Perfs

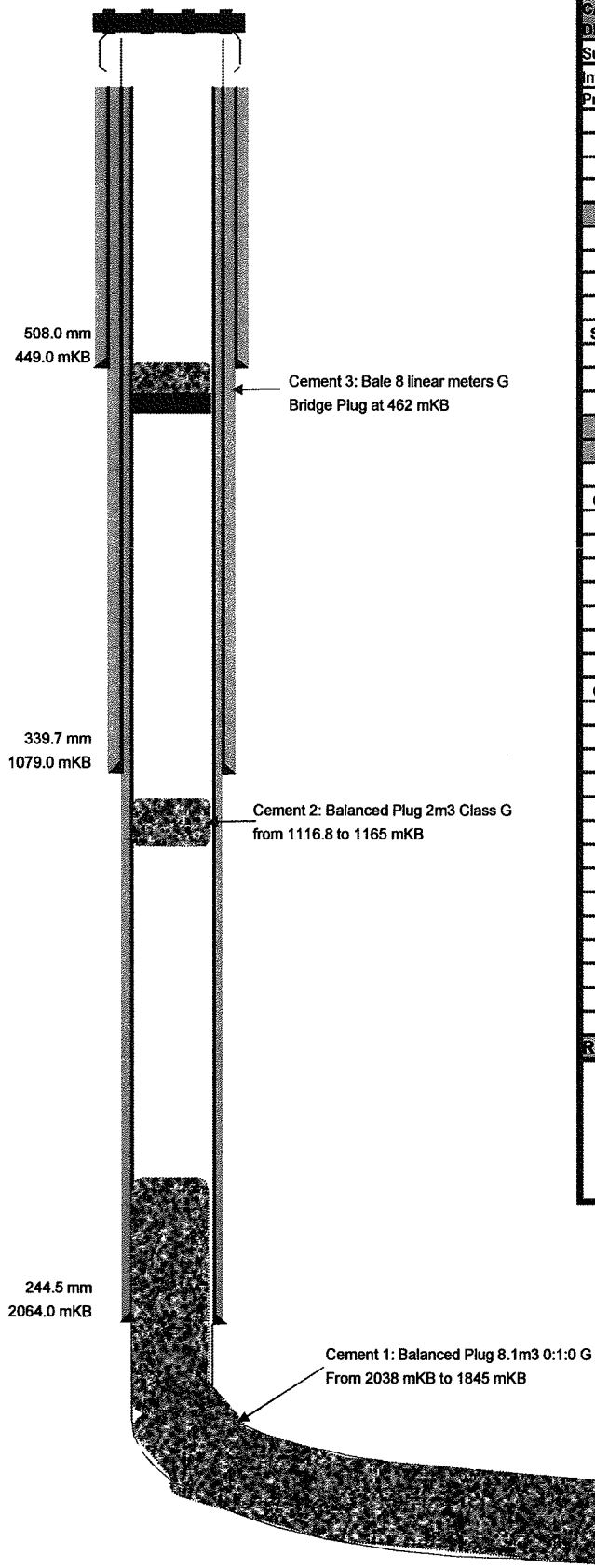
REPORT BY: Randy Dotzler

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Horizontal from 5-12 Surface

102/8-12 is a re-entry kicked off from the 7-12 horizontal well. Both legs were in the open hole section

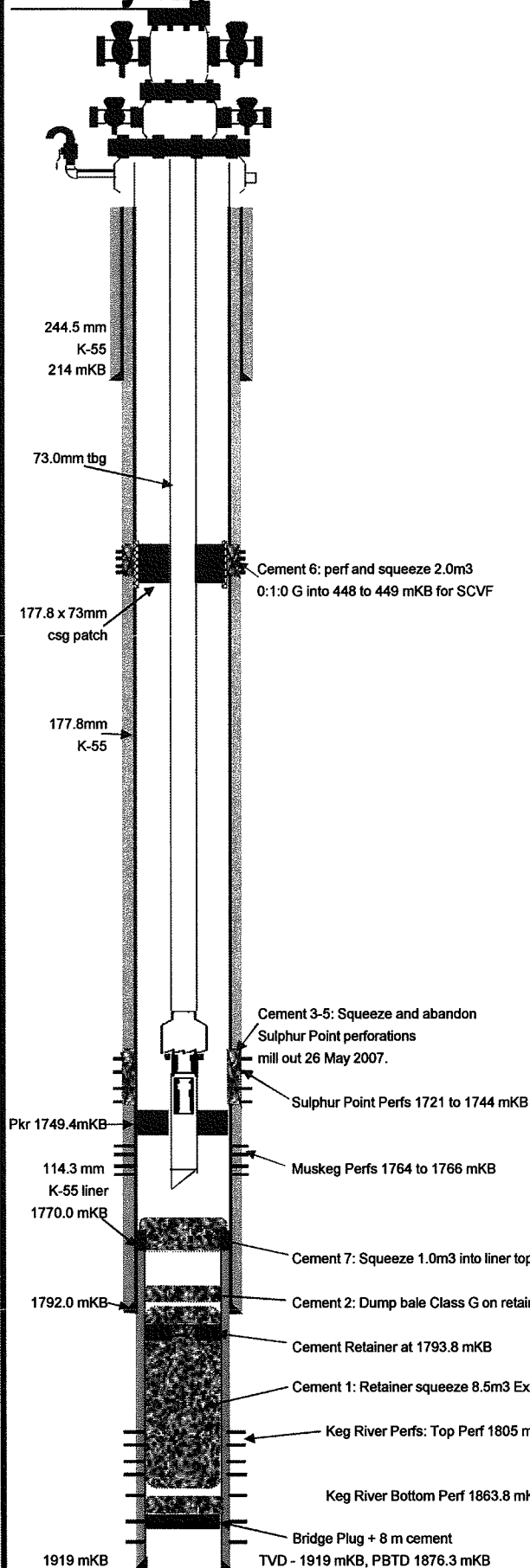
Cut and Capped Feb 25, 08



Downhole Well Profile

WELL NAME	HUSKY 102 RAINBOW 8-12-110-8	SPUD	Dec 15, 1990
License	146792 - abandoned	Current	Feb 25, 2008
ELEVATIONS (meters)			
KB ELEV	GL ELEV	KB TO GL	BGWP
565.9 m	561.0 m	4.9 m	93.7 mKB
CASING DESCRIPTION		LANDED DEPTH	WEIGHT
		OD (mm)	(kg/m)
Surface Casing		508.0	449.0 mKB
Intermediate Casing		339.7	1079.0 mKB
Production Casing		244.5	2064.0 mKB
		Grade	TOP OF (mKB)
		K55, J55, H40	Surface
		L80, K55, J55	Surface
		L-80, K55	Surface
Formation	Tops	Perforated	Top
Banff	524.5 mKB	no	
Wabamun	709.5 mKB	no	
Slave Point	1673.0 mKB	no	
Sulphur Point	1755.0 mKB	no	
Muskeg	1792.7 mKB	no	
Keg River	2039.0 mKB	Open Hole	2064.0 mKB
DOWNHOLE RE-ABANDONMENT SUMMARY			
Type	DESCRIPTION	Date	Top
NOTE	Well was abandoned in 2003 with bridge plugs, top at 2036.5 mKB and cement		Bottom
COMPONENT	Fish - 2 old bridge plugs chased down	26-May-2007	2038.5 mKB
TEST	Packer at 2005 mKB Press Test Casing	26-May-2007	
TEST	Cement Bond Logging	27-May-2007	Surface
TEST	Cement Bond Logging	28-May-2007	1650.0 mKB
TEST	Casing Inspection Logging	28-May-2007	Surface
CEMENT 1	Balanced Cement Plug	29-May-2007	1845.0 mKB
CEMENT 2	Balanced Cement Plug	30-May-2007	116.8 mKB
TEST	Pressure Test Cement and Casing	31-May-2007	1165.0 mKB
COMPONENT	Bridge Plug	31-May-2007	462.0 mKB
TEST	Pressure Test Bridge Plug	31-May-2007	
CEMENT 3	Dump Bale 8 linear meters cement	31-May-2007	454.0 mKB
REMARKS			

[illegible]



REPORT BY: Randy Dotzler

Downhole Well Profile

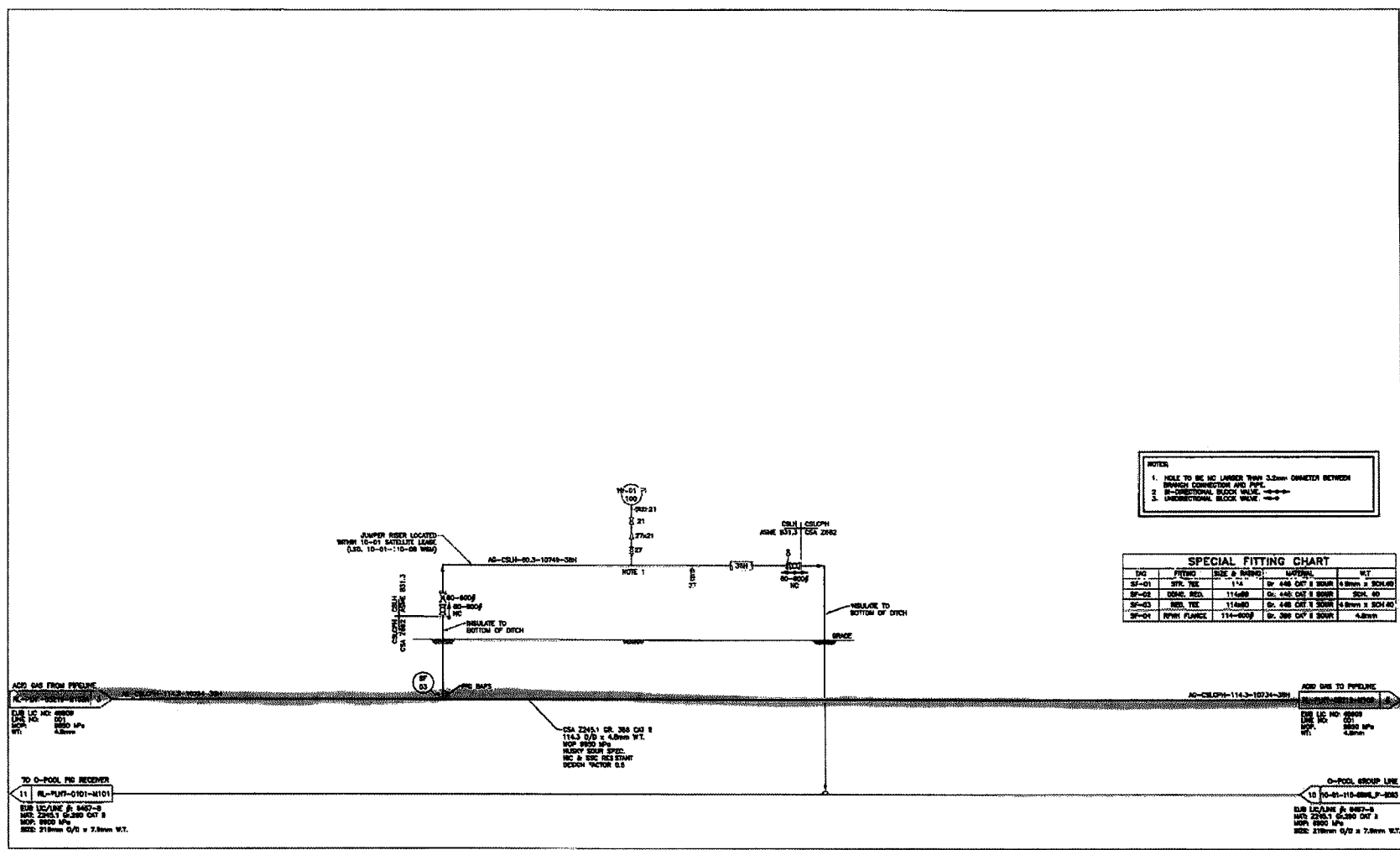
WELL NAME	HUSKY RAINBOW 8-12-110-8	SPUD	Aug 25, 1980
License	84627 - KR abandon, Mskg Observtn	Current	Sept 20, 2007
ELEVATIONS (meters)			
KB ELEV	GL ELEV	KB TO GL	BGWP
550.0 m	545.0 m	5.0 m	77.8 mKB
PBD			
TVD			
1919.0 mKB			
CASING DESCRIPTION	OD (mm)	LANDED DEPTH	WEIGHT (kg/m)
Surface Casing	244.5	214.0 mKB	53.6
Intermediate casing	177.8	1792.0 mKB	29.8
Liner	114.3	1919.0 mKB	14.1
Grade			
TOP OF (mKB)			
Surface			
Surface			
1770.0 mKB			
Formation	Tops	Perforated	Top Bottom status
Banff	510.0 mKB	no	
Wabamun	692.0 mKB	no	
Slave Point	1644.0 mKB	no	
Sulphur Point	1699.6 mKB	yes	1721.0 mKB 1744.0 mKB Abandoned - 2007
Muskeg	1752.9 mKB	yes	1764.0 mKB 1766.0 mKB Observation zone
Keg River	1795.5 mKB	yes	1805.0 mKB 1868.3 mKB Abandoned - 2007

KEG RIVER ABANDONMENT SUMMARY

Type	DESCRIPTION	Date	Top	Bottom
COMPONENT	Bridge Plug + Cement	28-Jun-1994	1868.3 mKB	
COMPONENT	Cement Retainer	20-May-2007	1793.8 mKB	
CEMENT 1	Retainer Squeeze Keg River	21-May-2007	1787.8 mKB	1895.0 mKB
TEST	Pressure Test Cement and Casing	22-May-2007		
CEMENT 2	Dump Bale 8 linear meters on retainer	24-May-2007	1785.2 mKB	1787.8 mKB
CEMENT 3	Retainer Squeeze Sulphur Point, fail	25-May-2007	1721.0 mKB	1744.0 mKB
CEMENT 4	Braidenhead Squeeze Sul Pt, fail	30-May-2007	1721.0 mKB	1744.0 mKB
CEMENT 5	Braidenhead Squeeze Sul Pt, fail	03-Jun-2007	1721.0 mKB	1744.0 mKB
TEST	Pressure Test Sulphur Point and Csg	07-Jun-2007		
TEST	Cement Bond Log	08-Jun-2007	1600.0 mKB	1770.0 mKB
TEST	Casing Inspection Log	08-Jun-2007	Surface	1770.0 mKB
PERFORATE	Perf casing to repair SCVF	13-Jun-2007	448.0 mKB	449.0 mKB
CEMENT 6	Remedial Cement for SCVF	14-Jun-2007	448.0 mKB	449.0 mKB
CEMENT 7	Squeeze Liner top	25-Jun-2007	1778.0 mKB	1779.0 mKB
TEST	Pressure Test Liner Top	28-Jun-2007		
TEST	Pressure Test Casing	01-Jul-2007		

REMARKS

Tubing String from bottoms up:
 73.0mm Re-Entry Guide 1760 mKB
 177.8mm x 73.0mm Packer 1749.4 mKB
 73.0mm X Profile Nipple 1746.7 mKB
 On/Off Connector
 73.0mm tubing (1290 m) to 449 mKB
 177.8 x 73mm Innicor casing patch
 73.0mm casing to surface



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- INSTALLATION
- LUBRICATING
- INSULATION ENGINEERING

NO.	DATE	DESCRIPTION	BY	APPROVED
1	08.05.18	AS-BUILT ACID GAS PIPELINE	ALN	JSD
2	08.05.18	AS-BUILT ACID GAS PIPELINE	ALN	JSD
3	08.05.18	AS-BUILT ACID GAS PIPELINE	ALN	JSD
4	08.05.18	AS-BUILT ACID GAS PIPELINE	ALN	JSD
5	08.05.18	AS-BUILT ACID GAS PIPELINE	ALN	JSD
6	08.05.18	AS-BUILT ACID GAS PIPELINE	ALN	JSD
7	08.05.18	AS-BUILT ACID GAS PIPELINE	ALN	JSD
8	08.05.18	AS-BUILT ACID GAS PIPELINE	ALN	JSD
9	08.05.18	AS-BUILT ACID GAS PIPELINE	ALN	JSD
10	08.05.18	AS-BUILT ACID GAS PIPELINE	ALN	JSD
11	08.05.18	AS-BUILT ACID GAS PIPELINE	ALN	JSD
12	08.05.18	AS-BUILT ACID GAS PIPELINE	ALN	JSD
13	08.05.18	AS-BUILT ACID GAS PIPELINE	ALN	JSD
14	08.05.18	AS-BUILT ACID GAS PIPELINE	ALN	JSD
15	08.05.18	AS-BUILT ACID GAS PIPELINE	ALN	JSD
16	08.05.18	AS-BUILT ACID GAS PIPELINE	ALN	JSD
17	08.05.18	AS-BUILT ACID GAS PIPELINE	ALN	JSD
18	08.05.18	AS-BUILT ACID GAS PIPELINE	ALN	JSD
19	08.05.18	AS-BUILT ACID GAS PIPELINE	ALN	JSD
20	08.05.18	AS-BUILT ACID GAS PIPELINE	ALN	JSD

HUSKY OIL OPERATIONS LTD.
PRODUCTION DIVISION

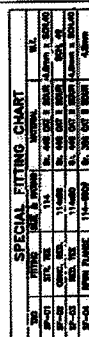
RAINBOW LAKE PROCESS PLANT
BLOWDOWN JUMPER LINE
03-12 ACID GAS INJECTION PIPELINE
PIPING & INSTRUMENTATION DIAGRAM

Job No. 03219
Drawn By JSD
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Approved By JSD
Designing Dept. GAS LIQUIDS ENG. LTD.

Revisions

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Date 08.10.17
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Rev. 2
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