EnCana requests that Husky:

1) Piezometer Data

1. When Husky has completed it's analysis of the piezometer data, give its views on EnCana's preliminary analysis.

Husky's Response: It is true that there is a period of stabilization after installation. We agree that the effects are most noticeable during the first couple of weeks. We also observe that within 3 months, 25 piezometers (81%) are stabilized and are reading actual pressures with established trends. 4 piezometers (13%) appear to have undersaturated casings with pressures mostly increasing during the stabilization period. It is also noted that this undersaturation effect appears to be diminishing with time as expected. Once these piezometers assume a uniform decline trend they can be assumed to be stabilized as well. 2 piezometers (6%) decline after the initial stabilization period and then slightly increase.

Two concerns that have been expressed in previous hearing with regards to piezometer reliability have been addressed by Husky and as expected majority of the measurements are reliable. The first concern that EUB expressed was related to problems with input voltage changes at the surface. The logger at the surface has a regulated 5-volt terminal, which is always at 5.000 volts which eliminates this problem. The second problem related to drift in the piezometer readings have been addressed by making sure that the minimum wire stress is below 13% of the yield (11.5% in this particular case) so that the long term drift is insignificant[1].

3-4-69-4W4

Husky's Interpretation: The latest datum corrected pressure difference between the piezometers at 491.5 m and 496.0 m is 109 kPa. Based on hydrostatic pressure gradient of 9.85 kPa/m, one would expect these pressures to be different by 44 kPa. Therefore, the additional 65 kPa pressure drop is due to the pressure transmission from the gas cap into the bitumen zone. Husky interprets the bottom of the gas zone to be at 493 m in this well. There is a tight streak at 493.5 m. The water saturation from the core can be below 50% within the bitumen zone in this 3 m interval which is close to the average for the whole development area. Therefore, the water saturation in the bitumen zone above the piezometer at 496 m is not particularly high. However, it is clear that within the 3 m vertical column below the gas cap, the pressure in the gas cap is transmitted without much difficulty. At this depth the pressure is 52.1 % below the highest observed pressure at the datum on Aug. 28, 2006 (assumed initial pressure).

It should be noted that there is thick shale rich zone from 498 m to 504 m in this well. Even below this zone, as one goes deeper into the bitumen zone, 16 m below the bottom of the gas zone the pressure decline is at 2.2% and 23 m below the bottom of the gas zone the pressure decline is at 0.8%. It is quite significant that these pressures 2.5 months earlier were 1.9% and 0.5% below the “initial” pressure, respectively. That is, although somewhat delayed, the pressure depletion is occurring at the bottom of the bitumen zone quite rapidly especially when compared with a time frame of bitumen recovery that can last many decades.

4-9-69-4W4

Husky’s Interpretation: The two shallower piezometers have taken a longer time to stabilize possibly due to the initial partial saturation of the protective casing. However, the saturation process appears to be coming to an end because the pressure increase has slowed down considerably. It is quite possible that the decline trend will be established in the near future based on the current behaviour. The deepest piezometer in this well declines steadily.

The piezometer at 470 m is interpreted to be in the gas cap and the piezometer at 474 m is in the bitumen zone that is fairly clean. The hole size is reasonably uniform between the piezometers and there are no obvious reasons to expect poor cement job in this hole. The pressure difference on Nov. 14 2006 between the two upper piezometers and the lower piezometer is 428 kPa. Based on a pressure gradient of 9.85 kPa/m, one would expect a pressure difference of 197 kPa, a pressure difference of 231 kPa. Therefore, it seems unlikely that there is behind pipe communication in this well. Rather, the two shallower piezometers seem to be taking a little longer to stabilize. Furthermore, it should be noted that the only pipe in the hole prior to cementing is the tubing which has a much smaller diameter than a casing.

16-7-69-4W4

Husky’s Interpretation: The two lowest piezometers appear to be still behaving in an unexpected manner. The pressure gauges are enclosed in a permeable protective casing. This casing is normally saturated with water during installation to provide capillary continuity between the reservoir and the recorder. The behaviour is suggestive of initially partially saturated protective casing which becomes more saturated with time. Husky’s investigation still continues. The formation at 466 m appears to have higher pressure than at 473. While investigation into the instrument malfunction continues, another explanation may be that these pressures reflect the hydraulic diffusivity of the lateral path that is traveled by the pressure transient to these particular piezometers. This path is reflective of the complex bedding of highly variable sands and shales .

It is significant that the pressure declines in remaining piezometers, which have behaved as one would expect, reached 9.5% by Nov. 14, 2006. In the course of the 2.5 months prior to this date, these piezometers recorded pressures that continued to decline from, 6.5% to 7.3% (460 m), 5.7% to 6.0% (466 m), 9.1% to 9.5% (473 m) as shown in Table 1 of our response to the Board.

On Nov. 14, 2006, the pressure difference between the piezometers at 460 m and 473 m was 67 kPa. If there was hydraulic behind the pipe communication, one would expect a pressure difference of 128 kPa pressure difference. Consequently, behind pipe communication does not appear to be likely.

10-5-69-4W4

Husky's Interpretation: No gas zone is observed in the core, therefore, this well is not directly below the gas cap. The pressures are declining across all the piezometers in this well. In the last 2.5 months, the shallowest piezometer declined from 7.7% to 8.0% and the deepest from 4.3% to 4.4%.

The pressures in the 04-06 well that is 3 km away from the nearest producing gas cap have all declined and continue to decline as well. In this particular case, the highest observed pressure drop was 4.1% which itself declined by another 4.4% (from 3.9% to 4.1%) from Aug. 28 to Nov. 14, 2006.

The pressures in the 03-07 well that is 2 km away from the nearest producing gas cap have all declined and continue to decline. In this particular case, the highest observed pressure drop was 5.3% which itself declined by another 5.6% (from 5.0% to 5.3%) from Aug. 28 to Nov. 14, 2006.

3-7-69-4W4

Husky's Response: The pressures in this well increase with depth. Therefore, we do not understand what EnCana means by saying the apparent distribution by depth is "a little strange". These pressures behave as expected and they are as much as 5.3% below the highest pressure recorded in Aug. 28, 2006. The highest recorded pressure itself quite likely declined from the true virgin pressure. Thus, the word "virgin pressure" has to be used with caution.

It is unlikely that there is any residual impact from the steaming operations at the Caribou CSS pilot project from the early 1990s. The closet pilot wells such as A31 (0/04-7-69-4 W4M/0) or B25 (05/01-12-069-05W4/0) to the 3-7-4 W4M piezometer well are between 600 to 800 meters away and were last steamed in January 1992 over 14 years ago. These old pilot wells only received two small steam cycles, 4000 m^3 for the first cycle and 6000 m^3 for the second cycle in an area where the average net pay is 22 m. Any induced increase in local reservoir pressure due to the steam injection cycle is quickly depleted during the following production cycle since this is the primary drive mechanism for CSS. Consequently, it is highly unlikely that the pilot project has any influence on the currently observed pressures.

2. Provide piezometer data in digital form (or an update of the previously provided Excel workbooks) for the seven wells from the end of August to the

present time and provide monthly updates to the EUB and hearing participants.

Husky's Response: Latest data is attached. Husky will be pleased to respond to further requests for pressure data. Please let us know as you require them.

3. Provide any other non-public pressure data which is available for its area.

Husky's Response: There is none.

4. Provide any pressure data or any other non-public data or analysis it may have on the 1986 to 1992 pilot.

Husky's Response: There is none.

5. Provide any bitumen (oil) analysis data, including any core extract fluid that it has for its area.

Husky's Response:

Well	Depth m	Density kg/m^3	API @ 15 °C	Viscosity @ 15 °C mPa s
1AA/16-07-069-04W4M	461.15	981.7	12.51	54068
	469.25	984.1	12.16	91416
	476.33	987.0	11.74	185993
	483.30	991.0	11.16	353878
11AA/16-12-069-05W4M	453.95	982.0	12.47	103353
1AA/04-06-069-04W4M	473.88	991.3	11.12	333500
1AA/01-08-069-04W4M	494.80	990.0	11.30	164730
	500.80	993.0	10.87	347802
1AA/10-05-069-04W4M	483.53	985.1	12.01	93062
	490.35	986.6	11.80	129071
	496.85	987.2	11.71	136332
	503.95	992.4	10.96	223006
1AA/14-09-069-04W4M	491.60	987.4	11.68	108337
1AA/04-18-069-04W4M	448.25	984.2	12.15	56309
1AA/03-04-069-04W4M	515.73	985.1	12.01	81908
1AA/04-01-069-05W4M	471.30	983.6	12.23	20757
Average		987.0	11.74	155220
Maximum		993.0	12.51	353878
Minimum		981.7	10.87	20757

6. Comment on the variation of oil viscosity, oil density and solution gas oil ratio with depth in the Husky area and provide data from any studies Husky has conducted, including any oil characterization for reservoir simulation purposes.

Husky's Response: The table above shows the variation of oil viscosity, density with depth in the Clearwater formation at Caribou area. This phenomenon was also addressed in the public literature[2]. There is no solution gas oil ratio variation study at available at present. However, GOR of 8 is a good approximation based on the generally available information in the Clearwater formation at Cold Lake area (7.5 m^3/m^3 was seen in SPE Paper 30276 *Numerical Study of the SAGD Process in the Burnt Lake Oil Sands Lease*). Although viscosity variation exists under the cold conditions, at the estimated operating temperature the variation will be diminished.

7. Provide data (as opposed to opinions) on the amount of gas that would evolve from bitumen in this area at pressures of 5% to 15% below virgin pressure and the potential for this gas to migrate through a bitumen zone of various water saturations (i.e. PVT data, relative permeability data, critical gas saturations etc.).

Husky's Response: The highest pressure observed on Aug. 28, 2006 is the closest pressure we have to the initial reservoir pressure. However, given the fact that even the piezometer that yielded this data point is in constant decline, this pressure has itself already declined from the initial pressure. This is because there has been gas production from the nearby gas pools for more than decade. Therefore, the term "virgin pressure" has to be used with caution.

The reservoir pressure decline is a clear indication that a significant pressure gradient has been established between Husky's bitumen reservoir and EnCana's depleted gas pools. Consequently, solution gas has evolved and will continue to evolve in the reservoir. There is a possibility that this gas will migrate through the bitumen zone within the water phase. Obviously, the rate of migration will be higher in areas with higher water saturation.

8. What effect on bitumen recovery factor has Husky calculated to result from a reduction in pressure 5% to 15% below virgin pressure? Show back up data, assumptions, use of analogues and calculations to support this answer.

Husky's Response: EnCana's assumption that the pressures has only declined by 5% to 15% is incorrect as explained above. Furthermore, the question assumes that the observed pressure declines have stabilized and that the adverse effects to bitumen recovery only need to be considered at these pressure levels. As it is evident by 25 piezometers, the bitumen pressures continue to decline. Even if the gas production was shut in today, these pressures would continue to decline for some time to come. What is worse is that the pressures in the gas pools continue to be depleted through gas production which means the effect of the imposed pressure transient will continue to increase with time under the current scenario.

Given the fact that pressures will continue to decline for a significant amount time, it is not know where they would be stabilizing in the reservoir with or without gas production. Husky relies on a Hybrid SAGD process which is mostly a SAGD operation which is initially accelerated through the application of CSS. Our simulation work continues to characterize our best estimate of harm that can be done to the bitumen recovery at depleted reservoir pressures. However, there are a number of risks associated with low pressure operations in SAGD operations such as adverse impact on the project economics, artificial lift problems, increase in residual oil saturation, etc. A commercially unproven process like the HSAGD is very likely to suffer from similar negative effects and probably other unknown risks that can not necessarily be characterized at this point in time until the field application commences.

Husky is concerned that continued pressure depletion and the existence of high water saturation zones in the reservoir will cause injected steam losses (resulting in higher steam oil ratios) through induced flow channels, poor distribution of steam in the reservoir, daily oil rate reduction and recovery reduction. As a result, our design choices will be severely limited and the project economics may suffer. Presently, Husky is establishing a generic Caribou gas-over-bitumen model to investigate the impact of gas pool depletion to adjacent HSAGD, SAGD and/or CSS operations. We are using the recently acquired piezometer data from Caribou to calibrate the flow properties of this model. Results and more details will be submitted as they become available.

2) Hydraulic Diffusivity

1. Does Husky have any information on pressure diffusivity in Clearwater zones of varying hydrocarbon saturation other than that presented by CNRL to this hearing and Husky's conclusion based on its interpretation of the 4-6-69-4W4 pressures that hydraulic diffusivity is "higher" in Husky's area.

Husky's Response: See below.

2. Can Husky provide any additional data, studies or references to support the theory that there is a "mobile water phase" that is continuous throughout the Clearwater formation. Please include any data Husky has on the migration of solution gas out of bitumen and through this "mobile water phase".

Husky's Response: It is generally accepted that bitumen reservoirs are water wet. It is also well accepted that a wetting phase can flow at low saturations (be it at a significantly reduced relative permeability) in the reservoir through a continuous film that coats the grains of the porous medium. In fact, this has been shown to be the case for the two Clearwater cores from the well1 AA/03-07-069-04 W4M . Experiments conducted with preserved core indicate that there is finite mobility to water under cold reservoir conditions. The effective permeability to water was found to be 4.5 mD and 3.6 mD for these particular cores. The pressure drop applied at one end of the core was transmitted to the other end of a 15 cm long core in less than 10 seconds.

3) Bitumen Net Pay

With respect to Husky's Bitumen Net Pay Map (Figure 16) and the net pay intervals indicated on the logs on the recently submitted cross sections, EnCana requests that Husky provide an explanation of why the net pay values often exceed by significant amounts the intervals with bitumen saturations greater than 50% as reported in cores. For example in the well 16-8-69-4W4 Husky's net pay map indicates 23.9268 m of pay but the core only had 13.85 m over 50% bitumen saturation including some intervals that were not analyzed for oil saturation.

EnCana requests that Husky:

1. Explain the difference in the 16-8-69-4 W4 well.

Husky's Response: Husky uses log analysis to determine net pay. Log analysis samples data every 10cm, as opposed to irregularly spaced core analyses. Missing core intervals also require interpolation. (the log analysis method is summarized in the answer to Question 3.3).

2. If Husky has used the core data in determining net pay or a portion of net pay in cored wells please describe the methodology and provide a list by well of the core derived net pay compared to that determined from logs.
3. If Husky has used log data to determine net pays please give full details of all parameters and assumptions used in the calculation of shale percentage, porosity, mineralogy cutoffs and water saturation (including Rw, a, m, and n values)

Husky's Response: Husky uses log analysis data to determine net pay. Log analysis is done in the following manner:

- Porosity is calculated from the bulk density using a matrix density of 2620 kg/m^2 (the bulk density can be varied by well to match core porosity).
- Shale volume (Vsh) is calculated from the gamma ray curve by defining gamma ray clean and gamma ray shale uniquely for each well.
- Effective porosity is determined using the Vsh.
- Modified Simandoux shaly sand equation is used to determine water saturation.
- Rw = 0.2 (is varied to match core analysis Sw), a = 0.62, m = 2.5, n = 2.0

Log analysis results are matched to core analysis by varying matrix density for porosity and Rw for Sw.

Net pay is determined by using log cutoffs of: PHIE > 0.2, Sw < 0.5.

4) Shale Isopach

Husky has provided a shale isopach map as Figure IR3-1. This map shows shale thicknesses centered in T69R4 constrained with a clipping polygon. However, shale is present to the west of this polygon. For example, 11-33-68-5 W4 well has shale between the two sets of perfs (450.5-452.0 and 462.0-463.0) requested by Husky to be shut in. This situation occurs in several wells west of the clipping polygon.

1. Why has Husky chosen not to map this shale in the submission?
2. Please remap the shale isopach using all well data relevant to the submission.

<u>Husky's Response</u>: See response to AEUB IR 06.11.10 2c

5) Gas Reserves

In Husky's response to the most recent Board IR #7 a table of gas reserve estimates by pool is presented.

Please provide:

1. A table of net pay, porosity, and water saturation values by well.

<u>Husky's Response</u>: Pending

2. Full details of all log analysis parameters and assumptions used in the calculation of net pay, shale percentage, porosity, and water saturation (including Rw, a, m, and n values).

<u>Husky's Response</u>: The log analysis in gas zones is done using the same equations and procedures as detailed in the reply to Question 3.3, except for the porosity. In gas zones the gas effect on the density porosity and neutron porosity curves (crossover) is accounted for by:

$$Porosity = \sqrt{\frac{(Dphi)^2 + (Nphi)^2}{2}}$$

The shale volume (Vsh) from the Gamma Ray is applied to this value to determine effective porosity in the gas zone (PHIE).

Net pay in gas zones is determined by using cutoffs of: PHIE > 0.2, Sw < 0.5.

3. Please provide any seismic data used in determining pool areas.

<u>Husky's Response</u>: Husky has not made use of seismic data in determining pool areas.

6) HSAGD

In its explanation of the HSAGD process in response to the Board staff original information request #4 Husky states that "Husky's Caribou lease reservoir also has about 35 to 40% clay content with a 57% bitumen saturation and 34% porosity. The bitumen is 10 API and the insitu viscosity is about 100,000 cp."

Please provide:

1. An explanation of how all of these averages were derived.

Husky's Response: Bitumen and porosity averages were determined using available core analysis data. Bitumen properties reported in response to Question 5.

2. Provide any studies Husky has conducted on the types and amounts of clays present.

Husky's Response: See attached XRD analysis.

3. A discussion of how the clays are distributed throughout the reservoir (i.e. dispersed, in layers, etc.) in a few representative wells.

Husky's Response: Pending

4. An explanation of how the clays were handled in the net pay determination for individual wells (if not already covered in Husky's reply to Item 2)

Husky's Response: see response to Question 5, above (Vshale correction).

5. A review of work Husky has done to examine the effect of steam injection on the clays, including effects of temperature, pressure and swelling.

Husky's Response: See answer to 7-4 below.

6. Examples of other reservoirs of this quality where SAGD or CSS have produced viable commercial projects.

Husky's Response: The following table shows two other commercial projects in reservoirs of similar quality to Husky's proposed Caribou Lake Project. All the projects are in the Clearwater trend and display similar reservoir characteristics. The Shell (Blackrock Ventures) Orion Project is an approved but not yet built commercial SAGD project in 64-3-W4M. The existing CNRL Primrose North and South projects are existing commercial CSS projects operating immediately south of Husky's Caribou lease also in the same reservoir trend.

Project	**Hilda (Orion)** (Approved Commercial SAGD Project)	**Caribou** (Averages over proposed development area)	**CNRL CSS Primrose North And South Projects** (typical properties)
Depth (m)	425	465	500
Gross Pay Thickness (m)	20 - 35	20-30	8-20
Porosity (%)	36	34	32
Oil Saturation (%)	61	55	60
Horizontal Permeability (MD)	3500	2445	2700
Vertical Permeability (MD)	500	1187	500 – 1500
Dead Oil Viscosity @ Reservoir T	75000	20000 - 350000	> 100000
Oil Gravity (API)	10.5	10 – 12	10.5
GOR (m3/m3)	8.0	8.0	7.5
Reservoir T (C)	16	15	13
Reservoir P (kPa)	3100	1200-2800	3100

7. A detailed description of the preliminary model referred to in the HSAGD discussion and a description of how Husky has incorporated the pressure depletion that it believes is taking place in its area.

Husky's Response: This work is still in progress, therefore, this discussion is premature at present. Results and description will be submitted shortly.

7) Bitumen Reserves

1. In light of the data provided in your answer to 6) above please provide details on the source of Husky's "conservative estimate for the bitumen recovery in the primary development area" of 27% "with a potential to go as high as 50%". Were the results of the old pilot project in sections 7-69-4 and 12-69-5W4 considered in these estimates?

Husky's Response: Please see Husky's response to Board's Question 2f (Nov.10, 2006)

2. In its discussion of the pressure data in 3-4-69-4W4 Husky has stated that it "considers the entire zone to be prospective for HSAGD operations". Does Husky consider that there are commercially viable bitumen reserves in the zone between Husky's picks of the base of gas at 493m and top of shale at 497.5m? If so please provide the pay cutoffs (both core and log) it is currently using for bitumen directly under gas caps and a discussion of the method it expects to use to exploit these reserves:

Husky's Response: Pending

3. Please identify all the areas on Husky lands where Husky believes there are commercially viable bitumen reserves that are below gas and above the top of the Clearwater Shale mapped by Husky (Figure IR 3-1) and provide detailed estimates of these bitumen reserves for each gas pool where Husky believes that continued gas production will affect bitumen recovery.

Husky's Response: Pending

4. Has Husky done any work to correlate bitumen recovery to sand quality and bitumen saturation? Please provide the summary and conclusions to this work.

Husky's Response: Husky conducted two steam flood tests with plugs taken from cores containing approximately 20% and 40% clay content at 471-475 m and 489-492 m depths in the well 1AA/03-07-069-04 W4M. It was observed that water permeability is increases as the temperature increases. Minor fresh water sensitivity was observed when switching from saline formation brine to steam condensate at 230 °C but this was insignificant. That is, swelling effect of clay is not an issue. The total recoveries in the swept zone of oil from the 20% and 40% clay content cores were 80% and 90%, respectively.

Table 1 - Summary of XRD Analysis

Company: Husky Energy Inc. — Work Order No. A12250

Location: Husky Primrose 3-7-69' 1AA/03-07-069-04W4M/00 — June, 2006

SAMPLE ID.	TYPE OF ANALYSIS	WEIGHT %	Qtz	Plag	K-Feld	Cal	Dol	Anhy	Pyr	Hal	Bar	Sider	Kaol (CLAYS)	Chl (CLAYS)	Ill (CLAYS)	ML (CLAYS)	Smec (CLAYS)	Total Clay
	BULK FRACTION:	96.68	53	17	7	0	0	0	0	0	0	0	13	10	0	0	0	23
1	CLAY FRACTION:	3.32	2	2	0	0	0	0	0	0	0	0	46	26	20	0	0	92
471.1m	BULK & CLAY	100	51	17	7	0	0	0	0	0	0	0	14	10	1	0	0	25
	BULK FRACTION:	97.39	49	24	9	0	0	0	0	0	0	0	14	4	0	0	0	18
2	CLAY FRACTION:	2.61	4	0	2	0	0	0	0	0	0	0	50	10	27	7	0	94
475m	BULK & CLAY	100	48	24	9	0	0	0	0	0	0	0	15	4	1	TR	0	20
	BULK FRACTION:	95.50	43	19	12	0	0	0	0	0	0	0	14	4	8	0	0	33
3	CLAY FRACTION:	4.50	5	3	0	0	0	0	0	0	0	0	33	20	32	8	0	92
478.65m	BULK & CLAY	100	41	18	12	0	0	0	0	0	0	0	15	12	8	TR	0	35
	BULK FRACTION:	65.47	35	9	0	3	0	0	0	0	0	0	25	14	22	0	0	57
4	CLAY FRACTION:	34.53	11	0	0	0	0	0	0	0	0	0	25	10	40	15	0	90
479.45m	BULK & CLAY	100	23	4	0	2	0	0	0	0	0	0	25	13	28	5	0	71
	BULK FRACTION:	95.10	38	16	7	0	0	0	0	0	0	0	16	11	12	0	0	39
5	CLAY FRACTION:	4.90	0	0	0	0	0	0	0	0	0	0	48	15	28	10	0	100
481.70m	BULK & CLAY	100	37	15	7	0	0	0	0	0	0	0	17	11	13	TR	0	41
	BULK FRACTION:	95.37	35	20	10	0	0	0	0	0	0	0	19	9	7	0	0	35
6	CLAY FRACTION:	4.63	3	3	2	0	0	0	0	0	0	0	42	16	28	5	0	91
486.1m	BULK & CLAY	100	34	19	10	0	0	0	0	0	0	0	20	9	8	TR	0	37
	BULK FRACTION:	95.36	44	20	8	0	0	0	0	0	0	0	13	6	9	0	0	29
7	CLAY FRACTION:	4.64	1	2	0	0	0	0	0	0	0	0	37	13	24	0	25	96
488.40m	BULK & CLAY	100	42	18	7	0	0	0	0	0	0	0	14	8	10	0	1	33
	BULK FRACTION:	95.96	41	17	7	0	0	0	0	0	0	0	18	4	13	0	0	35
8	CLAY FRACTION:	4.04	4	1	0	0	0	0	0	0	0	0	43	17	18	14	0	95
489.9m	BULK & CLAY	100	39	16	7	0	0	0	0	0	0	0	19	10	13	TR	0	40
	BULK FRACTION:	95.20	28	28	5	0	0	0	0	0	0	0	21	9	9	0	0	39
9	CLAY FRACTION:	4.80	2	0	1	0	0	0	0	0	0	0	51	25	17	4	0	97
492.0m	BULK & CLAY	100	27	27	5	0	0	0	0	0	0	0	22	10	9	TR	0	41
	BULK FRACTION:	96.41	44	14	7	0	0	0	0	0	0	0	20	8	7	0	0	35
10	CLAY FRACTION:	3.59	2	1	0	0	0	0	0	0	0	0	31	13	47	5	0	97
492.75m	BULK & CLAY	100	43	13	7	0	0	0	0	0	0	0	20	9	8	TR	0	37
	BULK FRACTION:	80.05	27	12	5	0	0	0	0	0	0	0	25	14	6	0	12	56
11	CLAY FRACTION:	19.95	3	0	1	0	0	0	0	0	0	0	11	6	19	0	59	96
494.95m	BULK & CLAY	100	22	9	4	0	0	0	0	0	0	0	22	12	8	0	22	65