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Geochemistry data from three oil shale intervals in unit 1, Red Head Rapids Formation (Upper Ordovician) on Southampton Island

S. Zhang

2011

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doi:10.4095/288109

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Recommended citation:
Zhang, S., 2011. Geochemistry data from three oil shale intervals in unit 1, Red Head Rapids Formation (Upper Ordovician) on Southampton Island. Geological Survey of Canada; Open File 6681, 23 p. doi:10.4095/288109

Publications in this series have not been edited; they are released as submitted by the author.

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1. INTRODUCTION

Upper Ordovician rocks on Southampton Island contain occurrences of oil shales (Nelson and Johnson, 1966; Sanford in Heywood and Sanford, 1976; Zhang, 2008). As part of the Southampton Island Integrated Geoscience Project, these oil shales were studied for their potential as hydrocarbon source rocks (Zhang, 2008). Discussions of the field setting of the oil shales, their age, distribution, regional stratigraphic position and significance are included in Zhang (2008; 2011).

In addition to previous geochemical studies (Zhang, 2008), six samples of oil shale from Southampton Island were analyzed for:

1) Vitrinite reflectance and visual kerogen assessment
2) Kerogen carbon isotope; whole extract carbon isotope, and carbon isotope of saturates and aromatics fractions
3) Soxhlet Extraction
4) Medium pressure liquid chromatography (MPLC)
5) Whole extract bulk composition by Iatroscan analysis
6) Thermal extract gas chromatography
7) High resolution gas chromatography

This Open File report contains the analytical data from these studies. Although the significance of the data is not discussed here, these data will be useful in determining the primary contributors to the organic matter in the oil shales, thermal maturity, and help to characterize the hydrocarbon source potential of these rocks. The analyses were completed at Geochemical Services Group**,** Weatherford Laboratories in Texas and at Newcastle University, Newcastle upon Tyne, UK. .

2. REGIONAL STRATIGRAPHY

The Paleozoic strata on Southampton Island include Upper Ordovician Bad Cache Rapids and Churchill River groups, and Red Head Rapids Formation, and Lower Silurian Severn River and Ekwan River/Attawapiskat formations. These units are exposed on land in the southern and western parts of Southampton Island, and at Cape Donovan along the northeast coast of the island (Fig. 1).

(1) Upper Ordovician

1) Bad Cache Rapids Group

The Bad Cache Rapids Group unconformably overlies Precambrian basement. It consists of dark grey or brownish grey fossiliferous dolomitic limestone with thin basal clastic rocks. It is rich in coral, gastropod, nautiloid, algae, crinoid and trace fossils. On Southampton Island, the total thickness of the group is about 65 m (Zhang, 2011). The group can be correlated to Edenian–Maysvillian Stage based on conodont data (Zhang, 2011).

2) Churchill River Group

The Churchill River Group conformably overlies the Bad Cache Rapids Group (Zhang, 2011); it consists of greenish grey or grayish brown argillaceous dolomitic

limestone. The total thickness of the formation is unknown on Southampton Island due to limited exposures. The group is correlative to lower Richmondian Stage based on conodont data (Zhang, 2011).

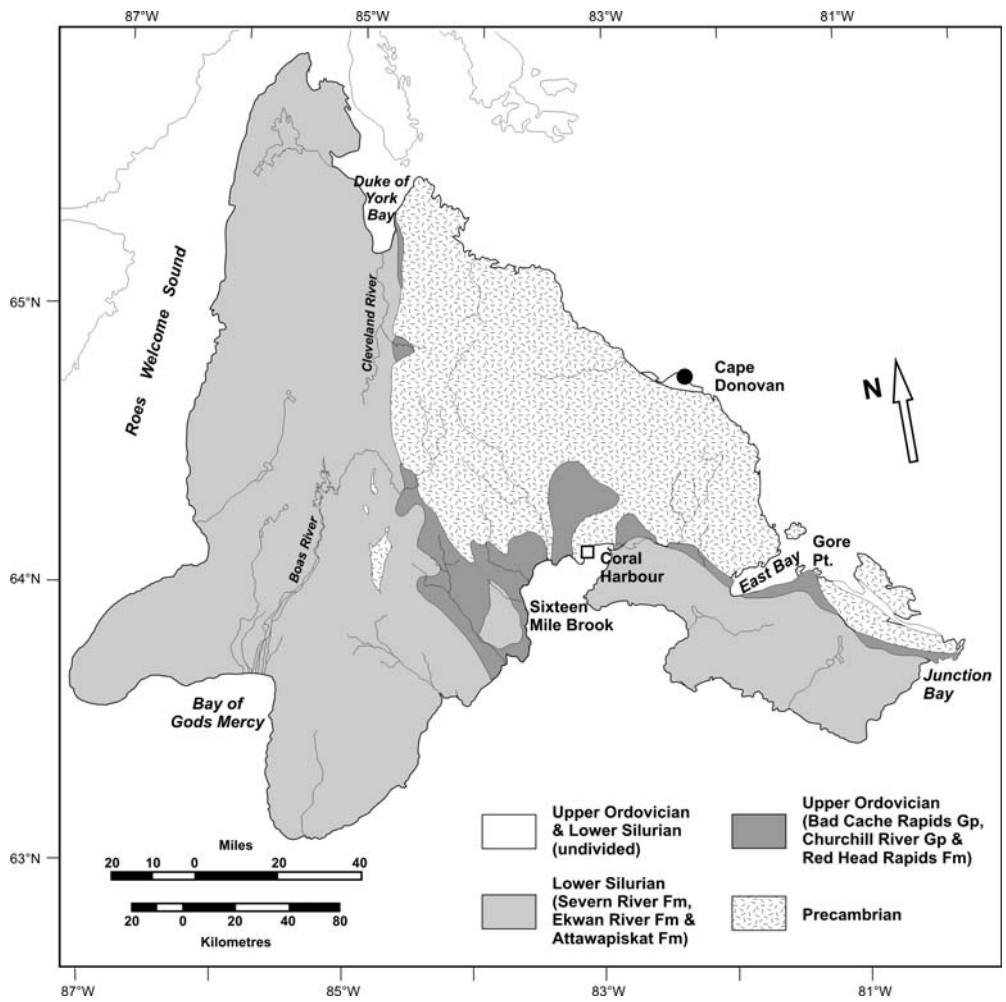


Figure 1. Simplified geological map of Southampton Island with sampling location in Cape Donovan area (modified from Heywood and Sanford, 1976 and Zhang, 2008)

3) Red Head Rapids Formation

The Red Head Rapids Formation conformably overlies the Churchill River Group; the contact between these two units is transitional. The Red Head Rapids Formation has a distinctive orange-tan color, and is mostly composed of dolostone, which is in striking contrast to the grey limestone-dominated Bad Cache Rapids and Churchill River groups. This formation is internally divided into the following four units (Zhang, 2008): (1) laminated beds; (2) breccia beds; (3) biostromal beds; and (4) biohermal beds. The total thickness of the formation on Southampton Island is > 61 m (Zhang, 2011). Conodonts indicate that the Red Head Rapids Formation is late Richmondian in age, with an uncertain Gamachian component (Zhang, 2011).

(2) Lower Silurian

1) Severn River Formation

The Severn River Formation disconformably overlies Red Head Rapids Formation. It consists primarily of brown microcrystalline limestone and dolostone. The strata have been intensely dolomitized at a number of localities (Sanford in Heywood and Sanford, 1976). The thickness of the formation on Southampton Island is unknown. A Rhuddanian–early Telychian age is suggested by conodont data collected from Hudson Bay Lowland and offshore area (Zhang and Barnes, 2007).

2) Ekwan River/Attawapiskat formations

Ekwan River Formation conformably succeeds the Severn River Formation. It consists of well-bedded, skeletal and pelletoidal limestone and fine-grained dolostone. The upper part of the formation passes laterally into the Attawapiskat Formation consisting of a reef-bearing carbonate unit having algal and stromatoporoid bioherms. A late Telychian age is suggested by conodont data collected from Hudson Bay Lowland and offshore area (Zhang and Barnes, 2007).

3. OIL SHALE ON SOUTHAMPTON ISLAND

The organic-rich "Sixteen Mile Brook shale" (Nelson and Johnson, 1966) and "Boas River shale" (Sanford in Heywood and Sanford, 1976) were discovered in Upper Ordovician rocks on central and southern Southampton Island about 40 years ago. The recent discovery of oil shales in the Cape Donovan area on Southampton Island unequivocally demonstrated that: (1) the three oil shale intervals in the Cape Donovan area, informally named as lower, middle and upper oil shale intervals by Zhang (2008), are within the unit 1 of the Red Head Rapids Formation; and (2) the "Boas River shale" and "Sixteen Mile Brook shale" are stratigraphically correlative to the Cape Donovan lower and middle oil shale intervals, respectively (Zhang, 2008; 2011).

Detailed analysis of gamma-ray logs and bitumen and black shale particles in well cuttings from Hudson Bay offshore exploration wells led to the recognition of the three oil shale intervals in the lower Red Head Rapids Formation in the offshore area (Zhang, 2008). Recent Rock-Eval[6]/TOC analyses of 40 samples from three oil shale intervals in the Cape Donovan sections demonstrated Type I–Type II kerogen and hydrocarbon yields and TOC values much higher than those reported by Macauley (1986). The middle (0.4 m) and upper (0.5 m) oil shale intervals have, respectively, average and maximum yields of 136.5 kg HC/tonne and 230 kg HC/tonne and average and maximum TOC of 20% and 34%. The lower (>1 m) oil shale interval has mean and maximum yields of 58.5 kg HC/tonne and 112.5 kg HC/tonne, and mean and maximum TOC values of 9.8% and 17.3% (Zhang, 2008).

Previous studies (Macauley, 1986; Zhang, 2008) have suggested the shales are thermally immature. However, no studies have been done to determine character of primary contributor to the organic matter in the oil shales, and no methods have been used in evaluating the maturity of the shales other than the Rock-Eval pyrolysis.

4. ANALYZED SAMPLES

Units 1 to 3 of Red Head Rapids Formation are exposed near Cape Donovan, along a creek bed in a transect from 64°45'43.9"N, 82°22'37.9"W to 64˚45'42.7"N, 82˚22'31.3"W. A number of samples were collected along the creek transect, of which the following six were submitted to Weatherford Laboratories for analysis.

1) Two samples (07CYA-Z43-03 and 07CYA-Z43-04A) from the lower oil shale interval (Fig. 2) at 64°45'29.8"N, 82°22'06.7"W. The lower part of the lower oil shale interval is dark brown argillaceous limestone interbedded with black shale. Sample 07CYA-Z43-03 is from the interbedded black shale. There is a 10 cm bed of black sediments much more heavily eroded than the bed below and above in the mid-upper part of lower oil shale interval, where 07CYA-Z43-04A is from.

2) Two shale samples (07CYA-Z40-08 and 07CYA-Z40-10) from the lower and lower-middle parts of the middle oil shale interval, respectively, at 64°45'32.8"N, 82°22'10.0"W (Fig. 2).

3) Two shale samples (07CYA-Z44-10 and 07CYA-Z44-12) from the lower and middle parts of the upper oil shale interval, respectively, at 64°45'36.3"N, 82°22'25.5"W (Fig. 2).

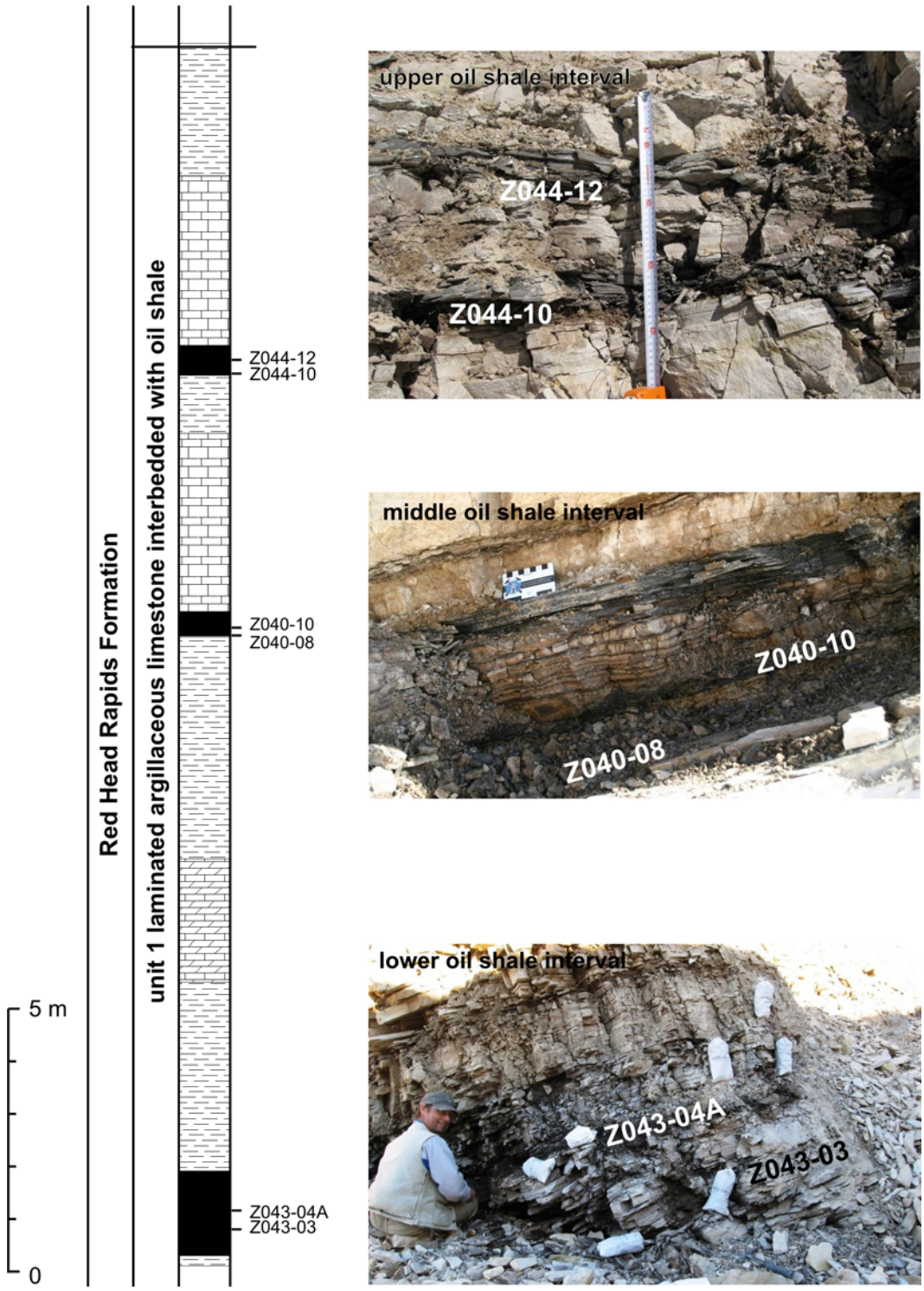


Figure 2. Stratigraphy of unit 1, Red Head Rapids Formation in the Cape Donovan area with photographs of the oil shale intervals. Sample locations are indicated.

5. GEOCHEMISTRY DATA

Samples were analyzed by the Geochemical Services Group at the Weatherford Laboratory (143 Vision Park Blvd , Shenandoah , Texas 77384; Phone: 1-281-681-2200, Fax: 1-281-681-0326). In addition, the Iatroscan analyses were carried out at the University of Newcastle (School of Civil Engineering and Geosciences, University of Newcastle, Newcastle upon Tyne, NE1 7RU, UK; Phone: +44 (0)191 222 8628). The data included in this report are in the original format as provided by the laboratories. Table 1 shows sample field number and Weatherford Laboratory ID. All samples are hand samples from outcrops, rather than core as showed in the original reports from Weatherford Laboratory.

Table 1. Field number and lab ID

Field number	Lab ID
07CYA-Z040-08	ADV000001
07CYA-Z040-10	ADV000002
07CYA-Z043-03	ADV000003
07CYA-Z043-04A	ADV000004
07CYA-Z044-10	ADV000005
07CYA-Z044-12	ADV000006

(1) Vitrinite Reflectance and Visual Kerogen Assessment

1) Experimental method (after Weatherford Geochemistry laboratory)

Visual kerogen assessments complement chemical assessments by recording information from the discrete particles (macerals) that make up the sedimentary organic matter. Vitrinite macerals are particles of sedimentary organic matter derived from wood, and their reflectance of incident light under oil immersion is used to assess the thermal maturity. Vitrinite reflectance (%R_0) increases with increased depth of burial (i.e., increased thermal exposure), and is an indication of the maximum temperature to which these particles have been exposed. The reflectance microscope measures the amount of reflected light relative to the incident light and expresses this ratio as a percentage. Vitrinite reflectance values range from about 0.25% (immature) to a high of about 5 or 6% (very mature). A population of vitrinite particles is found in almost all rocks of Devonian or younger age (older samples pre-date the evolution of land plants, the source of vitrinite). Selecting the appropriate vitrinite population for subsequent reflectance measurements is a somewhat subjective process. The *in situ* population must be identified, and must exclude vitrinite derived from cavings and reworked organic matter. Reworked vitrinite that was redeposited in the sediments may have higher reflectance that will skew the measurements towards higher R_0 values if not recognized and removed

from the average. In cuttings samples, cavings from overlying less mature sediments may skew the average towards lower values. Generally, when cavings are excluded, the lowest reflecting population is found to be indicative of the indigenous population, but this evaluation is made in combination with visual kerogen assessments, Rock-Eval Tmax measurements, and data for the extent of kerogen conversion. Vitrinite reflectance values are divided into the following stages of thermal maturity:

Stage Maturity	**Reflectance Range**
Immature	0.2% to 0.6%
Oil window maturity	0.6% to 1.1%
Condensate or wet-gas window	1.1% to 1.4%
Dry gas window	1.40% plus

Thermal alteration indices (TAI) are determined from the color of organic matter when viewed under transmitted light through a strewn slide mount of kerogen. Lighter colored organic matter is indicative of low maturity, whereas darker material is indicative of higher thermal maturity. Maceral composition is an assessment of the percentages of various organic particles found in kerogen samples. These particles are related to the oil and gas potential of the organic matter and are generally described as amorphous, exinitic, vitrinitic, inertinitic, or solid bitumen percentages. The former two macerals are primarily oil-prone particulate matter, whereas vitrinitic particles are indicative of gas-prone organic matter. Inertinitic matter is very hydrogen-poor and has no potential for generation of commercial quantities of hydrocarbons. The presence of solid bitumen is indicative of *in situ* generated hydrocarbons, migrated hydrocarbons, or contamination. Other observations from visual kerogen assessment include the quality of the organic matter (oxidized, well preserved), and the presence of palynomorphs (which can reveal key aspects of the depositional environment).

2) Results

See Fig. 3A–3F.

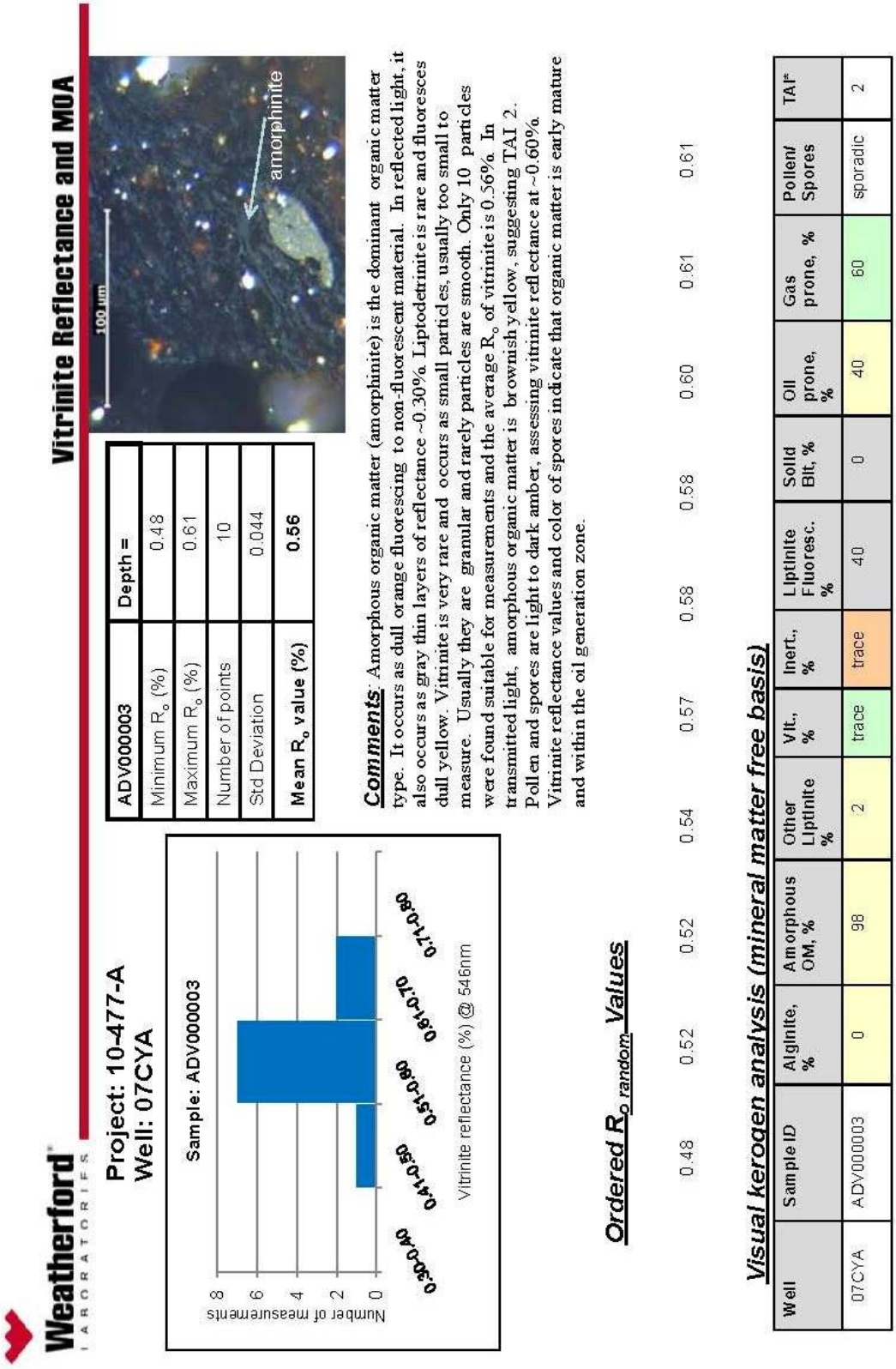


Figure 3A. Vitrinite Reflectance and Visual Kerogen Assessment for sample 07CYA-Z043-03 from lower oil shale interval.

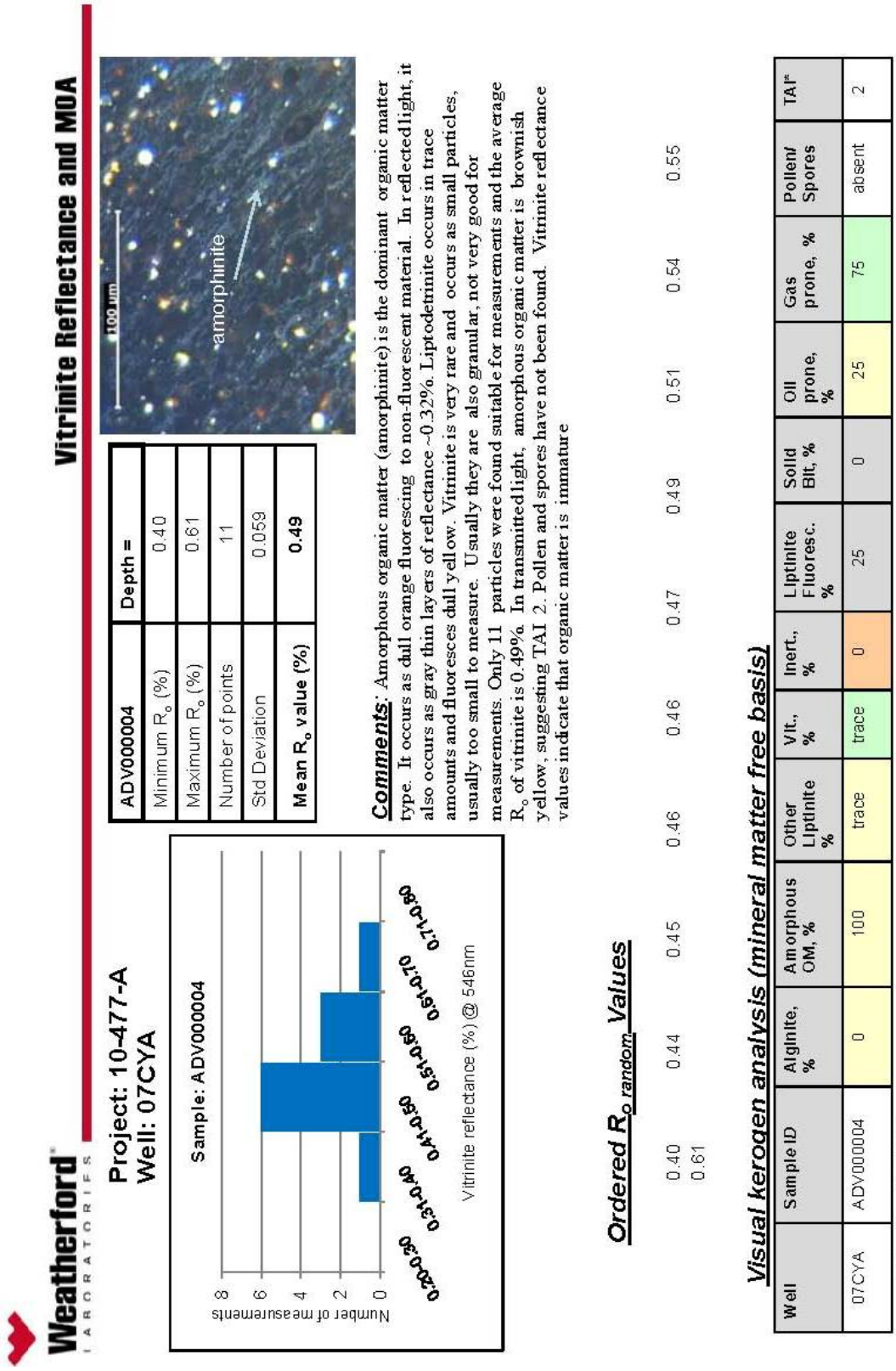


Figure 3B. Vitrinite Reflectance and Visual Kerogen Assessment for sample 07CYA-Z043-04A from lower oil shale interval.

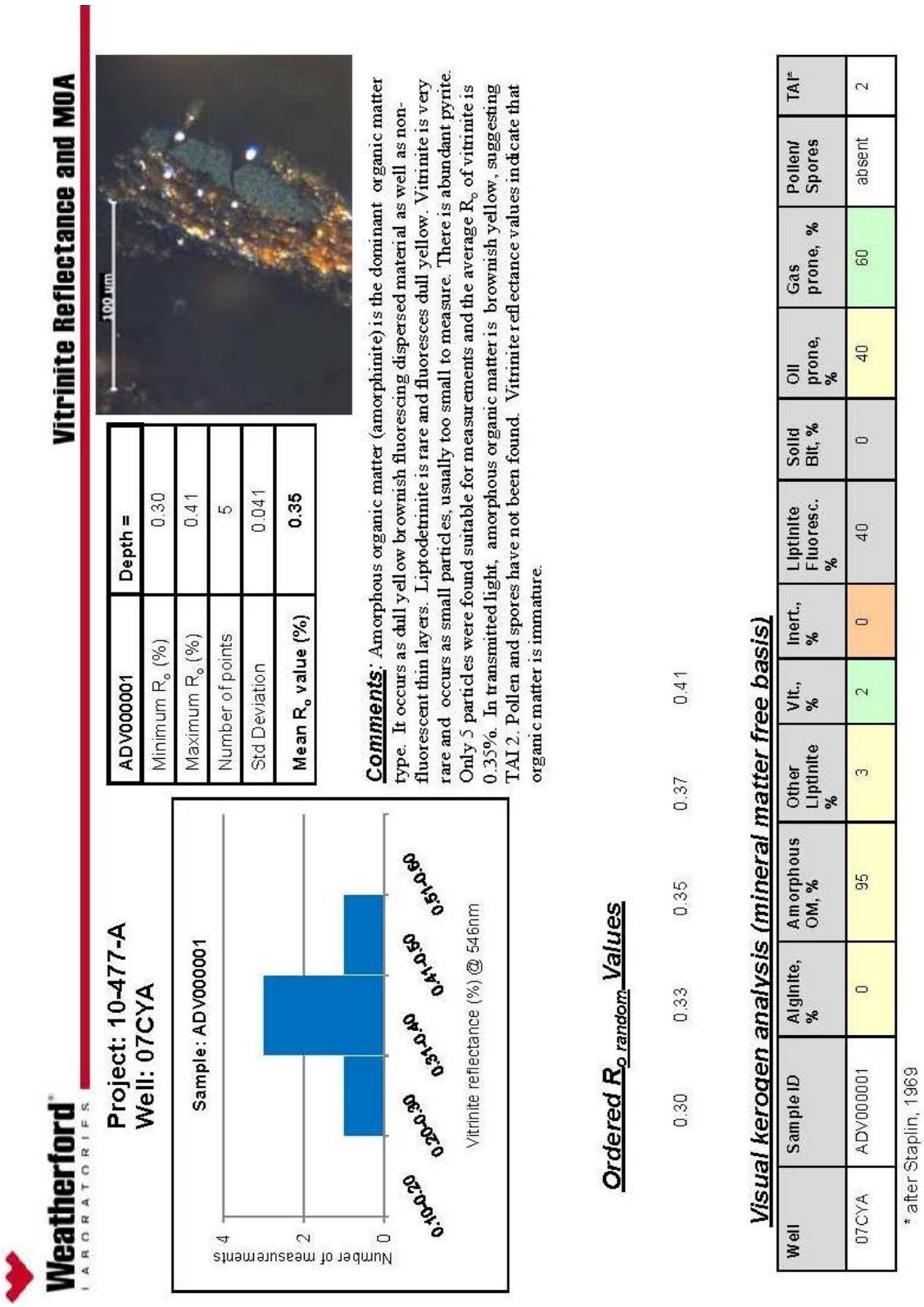
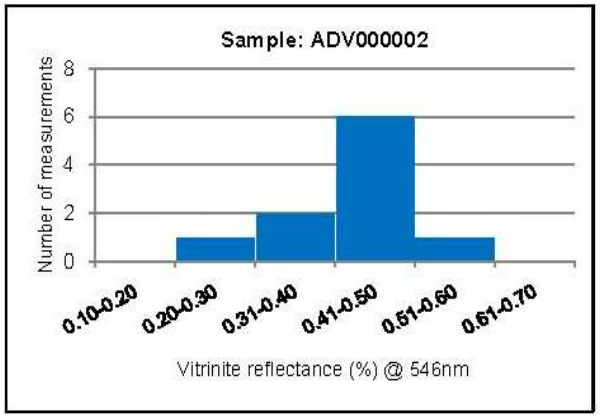


Figure 3C. Vitrinite Reflectance and Visual Kerogen Assessment for sample 07CYA-Z040-08 from middle oil shale interval.

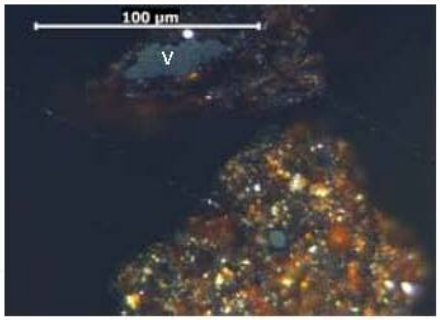
Weatherford LABORATORIES

Vitrinite Reflectance and MOA

Project: 10-477-A
Well: 07CYA



ADV000002	Depth =
Minimum R_o (%)	0.30
Maximum R_o (%)	0.51
Number of points	10
Std Deviation	0.075
Mean R_o value (%)	**0.43**



Comments: Amorphous organic matter (amorphinite) is the dominant organic matter type. It occurs as dull orange fluorescing to non-fluorescent material. In reflected light, it also occurs as gray thin layers of reflectance ~0.25%. Liptodetrinite is rare and fluoresces dull yellow. Vitrinite (v) is very rare and occurs as small particles, usually too small to measure. Only 10 particles were found suitable for measurements and the average R_o of vitrinite is 0.43%. In transmitted light, amorphous organic matter is brownish yellow, suggesting TAI 2. Pollen and spores are light amber, assessing vitrinite reflectance at ~0.50%, higher than the measured value. Vitrinite reflectance values and color of spores indicate that organic matter is immature.

Ordered $R_{o\ random}$ Values

0.30 0.33 0.36 0.41 0.42 0.45 0.49 0.49 0.50 0.51

Visual kerogen analysis (mineral matter free basis)

Well	Sample ID	Alginite, %	Amorphous OM, %	Other Liptinite %	Vit., %	Inert., %	Liptinite Fluoresc. %	Solid Bit, %	Oil prone, %	Gas prone, %	Pollen/ Spores	TAI*
07CYA	ADV000002	0	98	2	trace	trace	40	0	40	60	sporadic	2

* after Staplin, 1969

Figure 3D. Vitrinite Reflectance and Visual Kerogen Assessment for sample 07CYA-Z040-10 from middle oil shale interval.

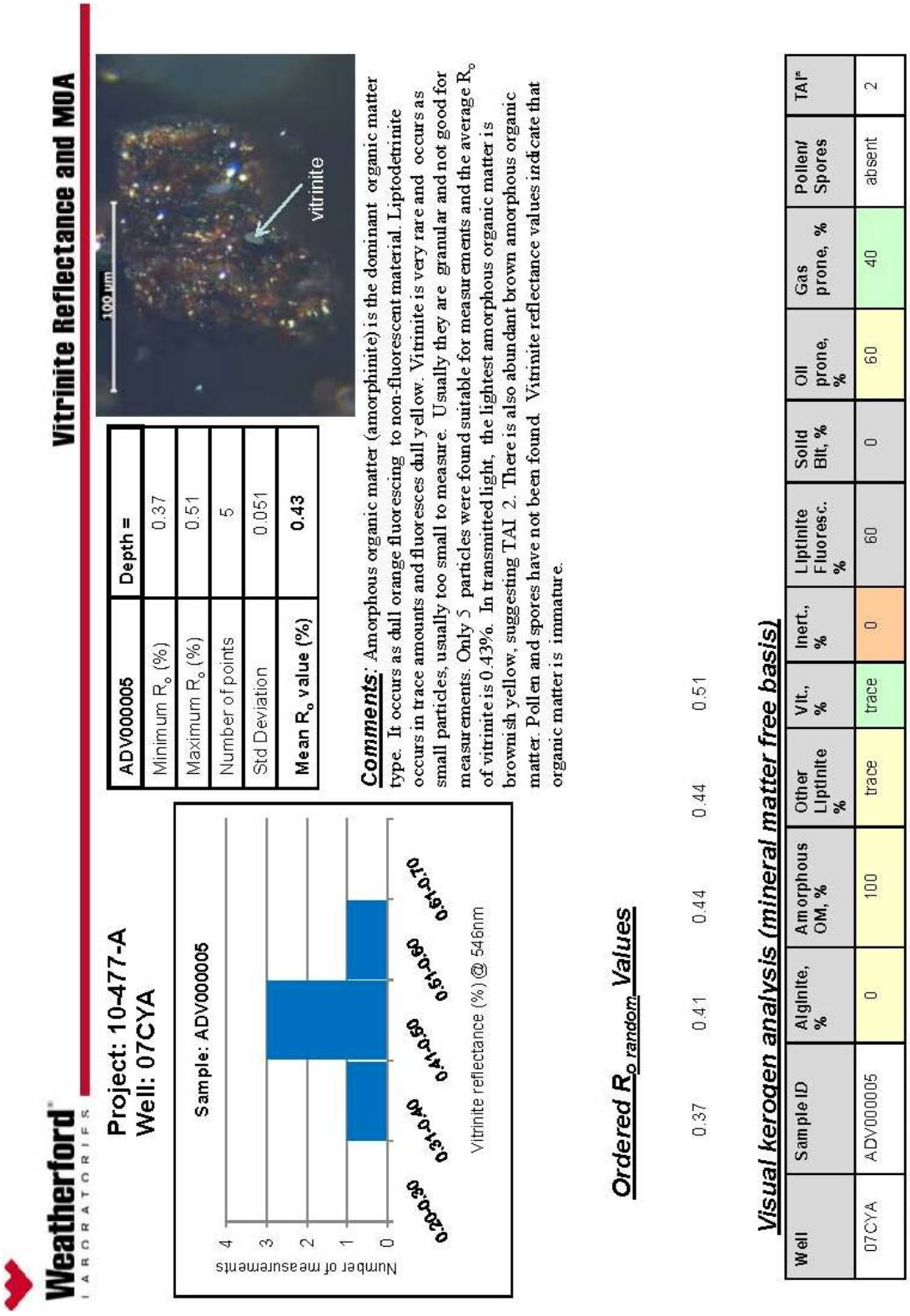


Figure 3E. Vitrinite Reflectance and Visual Kerogen Assessment for sample 07CYA-Z044-10 from upper oil shale interval.

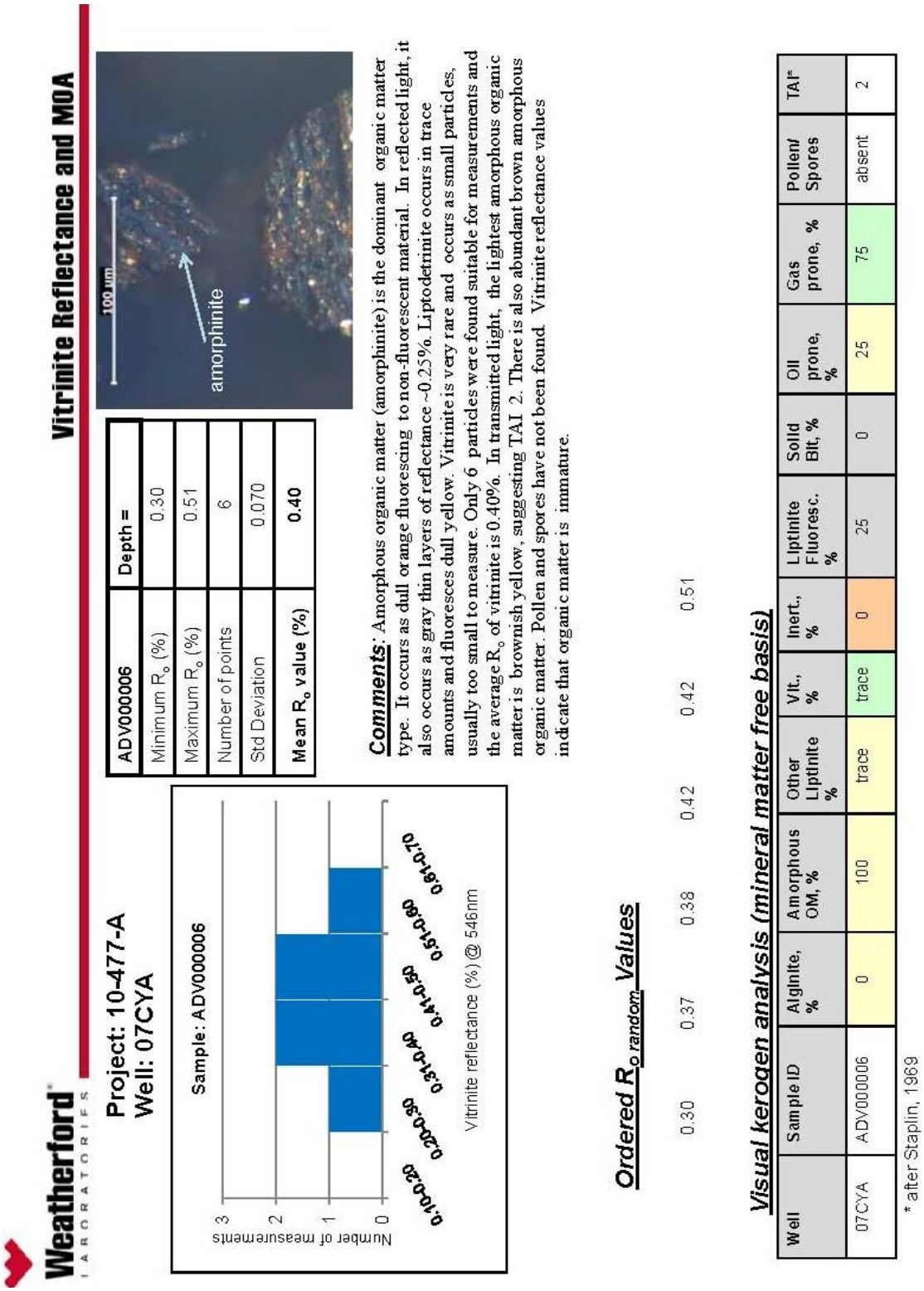


Figure 3F. Vitrinite Reflectance and Visual Kerogen Assessment for sample 07CYA-Z044-12 from upper oil shale interval.

(2) Bulk Isotope Analysis

1) Experimental method (after Weatherford Geochemistry laboratory)

Bulk Isotope Analysis Stable carbon isotope ratios of bulk petroleum samples (whole oil, SARA fractions, kerogens, etc) are measured using a Eurovector elemental analyzer connected to a GV Isoprime continuous flow isotope ratio mass spectrometer (EA-CF-IRMS). The purposes of the elemental analyzer is to quantitatively combust the sample and convert the carbon it contains into CO_2 gas, and then introduce this gas into the mass spectrometer for analysis. 50-60ug samples are placed in clean tin capsules and then dropped into an oxidation furnace maintained at 1000 °C where they are combusted in the presence of added oxygen. The combustion gases are then swept in a helium stream over a combustion catalyst (Cr_2O_3), CuO wires (to oxidize hydrocarbons), and silver wool to remove sulphur and halides. The remaining gases, N_2, NOx, H_2O, O_2, and are then swept through a reduction stage of pure copper wires held at 600 deg. C. This step removes oxygen and converts NOx to N_2. Water is removed by a magnesium perchlorate. Nitrogen and carbon dioxide are then separated by a packed column gas chromatograph held at a constant temperature. The resultant CO_2 peak enters the ion source of the IRMS where masses 44, 45, and 46 are collected and the ratio C_{13} to C_{12} measured. Samples are analyzed in duplicate and calibrated against the international oil standard NBS22 for which the accepted value of -29.73 per mil is used. Manufacturers precision specifications for stable carbon isotopes using the Eurovector interface are + or - 0.15 per mil.

2) Results

See Table 2.

Table 2. Results of Isotope Analysis for six samples from three oil shale intervals of unit 1, Red Head Rapids Formation

ISOTOPES

Company: CANADA-NUNAVUT GEOSCIENCE OFFICE **Project #: 10-477-A/BH-46889**

Client ID	Lab ID	Prep	$\delta^{13}C$ Saturate	$\delta^{13}C$ Whole Oil	$\delta^{13}C$ Aromatic	$\delta^{13}C$ Resin	$\delta^{13}C$ Asph	$\delta^{13}C$ Extract	$\delta^{13}C$ Kerogen
07CYA-Z040-08	ADV000001	EXT	-31.3		-30.7			-30.0	
07CYA-Z040-08	ADV000001	NOPR							-29.6
07CYA-Z040-10	ADV000002	EXT	-31.5		-30.6			-29.5	
07CYA-Z040-10	ADV000002	NOPR							-29.4
07CYA-Z043-03	ADV000003	EXT	-31.1		-30.2			-28.8	
07CYA-Z043-03	ADV000003	NOPR							-29.5
07CYA-Z043-04A	ADV000004	EXT	-32.4		-30.9			-29.5	
07CYA-Z043-04A	ADV000004	NOPR							-29.6
07CYA-Z044-10	ADV000005	EXT	-31.4		-31.0			-30.1	
07CYA-Z044-10	ADV000005	NOPR							-29.8
07CYA-Z044-12	ADV000006	EXT	-31.2		-30.2			-29.5	
07CYA-Z044-12	ADV000006	NOPR							-29.5

(3) Soxhlet Extraction

1) Experimental method (after Weatherford Geochemistry laboratory)

Soxhlet extraction is generally performed on a rock sample (outcrop, side-wall core, cuttings, cores, etc.) for the purposes of quantifying the amount of extractable organic matter (EOM) present in the rock, and also to provide a sample of the soluble organic material, also called bitumen, for further geochemical analysis. Soxhlet extraction may also be used to prepare the rock sample for further analysis, such as the removal of contamination from cuttings prior to RE and TOC, or for the removal of bitumen prior to pyrolysis GC of residual kerogen. Generally, about 50g of rock, if available, is ground to -60 mesh, weighed, placed in a cellulose soxhlet thimble and then extracted with dichloromethane using soxhlet apparatus. Both the soxhlet thimble and apparatus are run through the extraction process before the addition of the sample to make sure no contamination is present within the extraction system. Freshly activated copper metal is added to the refluxing solvent at the beginning of the extraction process for the removal of any elemental sulfur that may be extracted along with the bitumen. Removal of elemental sulfur is necessary since it interferes with subsequent tests that are performed on the bitumen, and because it would artificially inflate the EOM value that is measured. The extraction is allowed to continue until no additional color is observed leaching from the sample (typically overnight). At this point the extraction is stopped and the extract filtered through a pre-extracted Whatman #40 filter paper. Solvent is then carefully evaporated from the filtrate and the amount of EOM obtained by transferring it to a pre-weighed sample vial.

2) Results

See Table 3.

Table 3. Results of Soxhlet Extraction for six samples from three oil shale intervals of unit 1, Red Head Rapids Formation

SOXHLET

Company: CANADA-NUNAVUT GEOSCIENCE OFFICE **Project #: 10-477-A/BH-46889**

Client ID	Lab ID	Rock Weight (g)	Net Extract Weight (g)	% Extract	EOM (ppm)
07CYA-Z040-08	ADV000001	11.9840	0.2014	1.68	16806
07CYA-Z040-10	ADV000002	11.1155	0.1699	1.53	15285
07CYA-Z043-03	ADV000003	13.3967	0.1011	0.75	7547
07CYA-Z043-04A	ADV000004	11.6120	0.0409	0.35	3522
07CYA-Z044-10	ADV000005	15.2363	0.4264	2.80	27986
07CYA-Z044-12	ADV000006	11.0770	0.2002	1.81	18073

(4) Medium pressure liquid chromatography (MPLC)

1) Experimental method (after Weatherford Geochemistry laboratory)

Medium pressure liquid chromatography (MPLC) is a preparative separation technique used to isolate saturate, aromatic and resin compound class fractions from de-asphaltened crude oils, rock extracts or other petroleum samples. These fractions are typically analyzed further by GCMS and GC-MSMS for biomarkers, as well as stable carbon isotopes, gas chromatography and occasionally, compound specific – Isotope Ratio Mass Spectromety (IRMS). The weights of these fractions, together with that of the precipitated asphaltenes, can also be used for a bulk compositional analysis similar to that of a traditional SARA analysis. Depending on the characteristics of the sample and the needs of the client, oils and extracts are lightly topped, de-asphaltened, and/or passed through a Sep-Pak Plus CN cartridge before being introduced into the sample injection loops. Once injected the sample passes through a deactivated silica pre-column which retains the resin fraction. The combined saturate and aromatic fractions are not retained in the pre-column and pass into the main column. Again the saturates are not significantly retained but the aromatics are held near the head of the main column. Once the saturates have eluted and been collected by an automated fraction collector, the flow of hexane is reversed to the main column and the aromatics are back-flushed into separation fraction collector tubes. Both refractive index and uv absorption detectors are used to measure the elution of the fractions. The resin fraction is eluted from the pre-column with a 50:50 mix of dichloromethane/methanol using a separate pump. The saturate, aromatic and polar fractions, together with any precipitated asphaltenes are weighed.

2) Results

See Table 4.

Table 4. Results of MPLC for six samples from three oil shale intervals of unit 1, Red Head Rapids Formation

MPLC

Company: CANADA-NUNAVUT GEOSCIENCE OFFICE **Project #: BH-46889 / 10-477-A**

Client ID	Lab ID	Sample Weight	SAT Weight	ARO Weight	NSO Weight	ASPH Weight	% SAT	% ARO	% NSO	% ASPH	% evap loss
07CYA-Z040-08	ADV000001	0.0811	0.0042	0.0064	0.0506	0.0166	5.18	7.89	62.39	20.47	4.07
07CYA-Z040-10	ADV000002	0.0808	0.0023	0.0045	0.0393	0.0251	2.85	5.57	48.64	31.06	11.88
07CYA-Z043-03	ADV000003	0.0629	0.0035	0.0064	0.0415	0.0082	5.56	10.18	65.98	13.04	5.25
07CYA-Z043-04A	ADV000004	0.0270	0.0008	0.0029	0.0166	0.0054	2.96	10.74	61.48	20.00	4.81
07CYA-Z044-10	ADV000005	0.0749	0.0041	0.0073	0.0465	0.0136	5.47	9.75	62.08	18.16	4.54
07CYA-Z044-12	ADV000006	0.0763	0.0029	0.0064	0.0443	0.0213	3.80	8.39	58.06	27.92	1.84

(5) Iatroscan analysis

1) Experimental method (after Karlsen and Larter, 1991)

An Iatroscan TH-10, Mk IV (Iatron Labs Inc., Tokyo), equipped with a flame ionization detector (FID) interfaced with an electronic integrator (Perkin-Elmer LCI-100), was used for rod scanning and quantification, Silica rods, type Chromarod-S III (pore diameter 60 Å, particle size 5µm) and Chromarod type A (alumina, pore diameter 150 Å) were used. Pure grade hydrogen (190 ml/min) and air (2.1 l/min) supplied by a pump were used for the detector. Dichloromethane: methanol (DCM:MeOH 73:7 vol%) was used for extracting rock samples. N-Hexane, cyclohexane and toluene were used as mobile phases for the Chromarods. DCM:MeOH 95:5 vol% was used to separate "resins" from "asphaltenes".

2) Results

See Table 5.

Table 5. Results of Iatroscan analysis for six samples from three oil shale intervals of unit 1, Red Head Rapids Formation

IATROSCAN SARA

Company: CANADA-NUNAVUT GEOSCIENCE OFFICE **Project #: 10-477/BH-46889**

Client ID	Lab ID	Sample type	% Saturates	% Aromatics	% Resins	% Asphaltenes
07CYA-Z040-08	ADV000001	core	13.9	29.7	52.1	4.2
07CYA-Z040-10	ADV000002	core	13.5	29.2	54.5	2.8
07CYA-Z043-03	ADV000003	core	8.1	45.8	41.5	4.7
07CYA-Z043-04A	ADV000004	core	14.6	48.7	31.4	5.3
07CYA-Z044-10	ADV000005	core	16.8	48.3	32.8	2.1
07CYA-Z044-12	ADV000006	core	12.2	24.6	59.8	3.4

(6) Thermal Extract Gas Chromatography

1) Experimental method (after Weatherford laboratory)

Thermal Extract Gas Chromatography (TE-GC) may be completed on potential source rocks to examine source specific molecular distributions or on potential reservoir rocks to characterize and fingerprint liquid hydrocarbon components. Samples to be analyzed are typically rinsed to remove drilling mud contaminants and are sometimes hand picked to recover representative cuttings fragments for analyses. Approximately 10-50 mg of rock sample are placed in a metal crucible and inserted into the specially designed inlet system. The samples are thermally extracted at 300°C for 2.45 min. with a split portion of the volatile hydrocarbons trapped onto the front of the analytical column using a liquid nitrogen trapping system. Gas chromatography is performed using HP 6890 Series GC System with 50m high-resolution column. The GC is temperature programmed from 35°C (8 min. hold) to 50°C at 1.5°C/min. and then to 330°C at 8°C/min. with a final hold time of 40 min. Light hydrocarbons, isoprenoids and normal paraffins are identified when they are present in the sample. The GC method is specifically designed to separate light hydrocarbons and allows identification of higher molecular weight hydrocarbons out to C_{42}.

2) Result

See Appendix 1.

(7) High Resolution Gas Chromatography

1) Experimental method (after Weatherford laboratory)

High resolution gas chromatography is an analytical technique employed in the organic geochemistry laboratory for the evaluation of the detailed molecular composition "fingerprint" of a crude oil or other petroleum sample. It is most often used to determine the range of hydrocarbons present in a sample and via the monitoring of specific compounds, oil and source rock characteristics such as biodegradation, water washing, source facies, thermal maturity and depositional environment, can often be inferred. Additionally, the technique can be used for oil-oil correlations as may be part of a reservoir continuity or production allocation study. Generally a (0.1ul to 1.0ul) sample of is introduced by syringe into a split/split-less injector of an Agilent 6890N gas chromatograph (GC) held at a temperature of 275°C. From there the sample passes through a 60m, 0.25mm I.D. Agilent DB-1 column using a constant pressure of helium as the carrier gas. The column oven is programmed to hold at 30°C for 5 minutes but then to increase to 320°C at 3°C/min at which point it is held at this final temperature for 20 minutes. Components eluting the column are detected by a flame ionization detector (FID) held at 350°C. The addition of an internal standard prior to injection allows these components can be quantified. Under these chromatographic conditions compounds from nC_4 to nC_{42} are observed, with n-alkanes, key isoprenoids, key aromatic compounds and the lighter hydrocarbons (part of which are used in C_7 analysis) are reported. Oils standards are run periodically to check retention times and other chromatographic performance criteria.

2) Result

See Appendix 2.

6. ACKNOWLEDGEMENTS

This project was financially supported by Canada-Nunavut Geoscience Office. All the data provided by this report were collected by Weatherford Laboratories, Taxes and University of Newcastle, UK. M. Obermajer reviewed the report.

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