



Geochemical and Sedimentological Investigation of the Colorado Group for Shale Gas Potential: Initial Results

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Abstract

Alberta Geological Survey has started a project to quantify shale gas resources in the province by collecting 74 outcrop samples and 203 core samples from the Cretaceous Colorado Group. A series of ten analyses was run on selected samples, including isotherm, Rock Eval™ 6, total organic carbon, organic petrology, bulk mineralogy, clay mineralogy, permeametry, helium and mercury porosimetry, scanning electron microscopy, environmental scanning electron microscopy and thin section examination. Gas capacity has been calculated on a billion cubic feet per square mile (Bcf/sq. mi.) basis, assuming a base case of 100% desorption and a case assuming 25% free gas. A few thin sections and electron microscope descriptions are included, with the remainder becoming available when descriptions are complete.

1 Introduction

The rationale for this report is to introduce the reader to a shale gas sampling and analysis project that was completed in the spring of 2008, although we continue to test samples. The project involves sampling and analyzing the organic geochemistry and sedimentology of the shales of the Cretaceous Colorado Group and the Mississippian Banff and Exshaw formations; the Banff-Exshaw results are being released in a separate set of open files (Rokosh et al., 2008b; Beaton et al., 2008b; Pawlowicz et al., 2008b). The Colorado Group data are being released as individual open file reports for Rock Eval™, total organic carbon, isotherm and organic petrography (Beaton et al., 2008a) and for mineralogy, permeametry, mercury porosimetry and scanning electron microscope (SEM) imaging (Pawlowicz et al., 2008a), and will be available on the Alberta Geological Survey (AGS) website (<http://www.ags.gov.ab.ca>). The website is targeted for the public, government and industry, and will be expanded to include more data as it becomes available. The ultimate purpose of analyzing both the Colorado Group and the Banff and Exshaw formations is to assess their resource potential and discuss potential environmental difficulties, if merited. A companion document introducing the shale gas assessment project in Alberta (Rokosh et al., 2008a), targeted at the public, is also being released.

This report briefly reviews Colorado Group stratigraphy but stresses two points: 1) the present work is being done south of about Township 80; northern Alberta geochemistry and geology will be addressed in a separate project; 2) the stratigraphy published in this series of reports is a work in progress. Although we follow sequence stratigraphic principals in some of our correlations (e.g., top of the Cardium sand), our purpose is to package shale beds into a coherent assemblage that can be used for resource assessment; in some cases, therefore, our correlations are a mixture of sequence and lithostratigraphy (e.g., top of the Fish Scales Zone). The cross-sections are presently limited to the interval between the Base of the Fish Scales (BFS) and the top of the First White Speckled Shale (1WS); they are currently being expanded to include the top of the Mannville/Blairmore.

The stratigraphic summary in Section 2 is followed by a brief discussion of the methodology used in the analyses and a highlight of some of the geochemical and sedimentological results. The latter section includes a summary and discussion of adsorption analyses and a preliminary calculation of resources associated with each adsorption analysis. We assume two scenarios in the resource calculation: 1) adsorbed gas only with no free gas present; and 2) adsorbed gas plus 25% free gas. We will be expanding upon the highlights with a more comprehensive analysis of results in the immediate future and will publish these results as soon as possible. Lastly, a brief analysis of the location of some Colorado Group shale gas plays in Alberta is discussed.

2 Stratigraphy of the Colorado Group

This section reviews regional aspects of Colorado Group stratigraphy, largely from prior publications. We have included five cross-sections and four maps. The remainder of the cross-sections that are not included in this report are in the process of refinement and will be available when completed. A stratigraphic framework is constructed and there is a brief discussion of regional geological characteristics, within which shale sedimentology and geochemistry are assessed to determine shale gas assessment units and to evaluate the potential for shale gas resources. The ‘science’ of our discussion is necessarily brief and will be expanded as we apply data from this report and prior publications to regional mapping of shale geochemistry and geology.

2.1 Cretaceous Colorado Group Stratigraphy

Conventional sandstone reservoirs in the Colorado Group and equivalent formations are well studied; however, much less is known about shale stratigraphy (Figure 1), especially in the upper Colorado, and very little is known concerning reservoir characteristics of Colorado shale (Bloch et al., 1999), which is

one of our main areas of study. Over the last 20 years or so, a few reports have highlighted shale stratigraphy, sedimentology and/or geochemistry, dominantly in the lower Colorado (e.g., Bloch et al., 1993, 1999; de Caritat et al., 1994; Leckie et al., 1994; Schröder-Adams et al., 1996, 1998; Nielsen et al., 2003; Strancliffe and McIntyre, 2003; Tu et al., 2007; Tyagi et al., 2007), some of which contain geochemical data that can be used in future resource evaluations. The upper Colorado Group (Nielsen et al., 1993; Tyagi et al., 2007) is certainly much less studied than the lower Colorado Group, with the division defined by the BFS (Bloch et al., 1993).

PERIOD	EPOCH	STAGE	Southern Foothills	Central Foothills	Northwest Plains	Central Plains	Southern Plains	Bloch et al. 1999		
CRETACEOUS	LATE	Campanian	Belly River Fm.	Brazeau Formation	Puskwakua Fm.	Belly River Fm.	Belly River Fm.			
			84	First White Speckled Shale			Lea Park Fm.		Milk River Fm.	
		Santonian	87	Wapiabi Formation	Wapiabi Formation	Badheart Fm.	Medicine Hat Sandstone		Medicine Hat Sandstone	
						Muskiki Fm.				
		Conacian	89	Cardium Formation	Cardium Formation	Cardium Formation	Cardium Formation		Cardium Formation	
		Turonian	93	Blackstone Formation	Alberta Group	Smoky Group	Second White Speckled Shale		Jumping Pound Mbr	
							Opabin Member			
							Haven Member			
		Cenomanian	97-99	Blackstone Formation	Alberta Group	Smoky Group	Howard Ck. Mbr			
Pouce Coupee Mbr										
Doe Ck. Mbr										
Sunkay Member	Dunvegan Formation						Dunvegan Formation			
EARLY	Albian	Blairmore Group	Alberta Group	Smoky Group	Base of Fish Scales	Philips SS				
					Cruiser Formation					
					Goodrich Formation	Shaftsbury Formation				
					Hassler Formation					
					Boulder Creek Fm.					
					Hillcross Formation					
					Barons Sand					
					Viking Fm.	Bow Is. Fm.				
					Joli Fou Fm.	Joli Fou Fm.				
					Basal Colorado Sand	Basal Colorado Sand				
					Mannville Group	Mannville Group				
							Second White Specks Fm.			
							Belle Fourche Formation			
							Fish Scales Formation			
							Westgate Formation			

Figure 1. Stratigraphy of the Cretaceous Colorado Group (modified after Bloch et al., 1999).

Leckie et al. (1994) and Schröder-Adams et al. (1996) described the Cretaceous Colorado Group as resting unconformably on the Mannville/Blairmore Group and as conformably to disconformably overlain by the Milk River and Lea Park formations in the central and southern plains. In the northwestern plains, the upper Colorado Group correlates with the lower Puskwakua Shale of the Smokey Group (Leckie et

al., 1994). In the central and southern foothills, the Colorado Group is underlain unconformably by the Crowsnest volcanics and the Blairmore Group, with an upper contact that correlates with the upper portion of the Wapiabi Shale (Alberta Group). The Colorado Group is the first bedrock formation beneath glacial sediment throughout much of the province (Figure 2). The location of shale bedrock is important for resource evaluation, as these areas may contain Antrim-like shale gas resources that are associated with particular environmental issues (Rokosh and Beaton, 2006).

The shale formations of interest are displayed in Figure 1. Beginning in eastern Alberta (Central and Southern Plains, Figure 1) the main shale formations are Joli Fou, Westgate, Fish Scales Zone, Belle Fourche, Second White Speckled Shale (2WS), First White Speckled Shale (1WS; Bloch et al., 1999; Tyagi et al., 2007), and correlative formations to the west, north and south. Bloch et al. (1993, 1999) revised terminology and stratigraphy for the lower Colorado Group and this terminology is used here. We recognize the recent contribution to upper and lower Colorado Group stratigraphy by Tyagi et al. (2007) that suggests redefining the Belle Fourche–Second White Specks contact and, of additional importance to this report, the correlation of strata in the 1WS from the Deep Basin of Alberta to Saskatchewan. Nielsen et al. (1993) correlated 1WS equivalent strata in southeastern Alberta and Saskatchewan and proposed subdividing the 1WS into the Carlile and Niobrara formations.

Strictly speaking, our correlations, unlike the above-quoted publications, are informal. We are attempting to correlate areas where there are few publications in the public record, especially concerning the 1WS. For this report, we are not involving traditional methods of stratigraphic correlation, such as paleontology, palynology or magnetostratigraphy. More formal stratigraphy may be done by AGS in the future. The primary purpose of these cross-sections and maps is to aid division of the Colorado Group into assessment units in advance of a resource evaluation. From time to time, as stratigraphy is redefined by AGS or other authors, we will revisit and revise, if necessary, the stratigraphy and terminology we use.

The Colorado Group comprises relatively thick successions of marine mudstone and shale (Leckie et al., 1994) separated by periods of marine regression that resulted in deposition of coarser, mainly low-stand sandstone reservoirs of the following formations: Viking, Peace River, Cardium, Badheart and Dunvegan and equivalents (Figure 1). The BFS marker forms the contact between the upper and lower Colorado (Bloch et al., 1993, 1999). The Colorado Group has two depocentres in Alberta, indicated by thickening northwestward toward the Deep Basin to more than 1400 m (Figures 3–5; Leckie et al., 1994) and southeastward under the influence of the Williston Basin to about 500 m. The lower Colorado isopach (Figure 5) likewise is thickest in these two areas and thins over the central Alberta plains to about 80–120 m, while the upper Colorado (Figures 3, 4) is about 300 m thick over much of central Alberta. The Westgate Formation (Figure 6) is capped by a paraconformity (Stelck et al., 1958) and follows a pattern of thickness variations similar to that of the lower Colorado. The overlying upper Colorado 2WS to Fish Scales isopach (Figure 4) is thickest in the Deep Basin, but the influence of the subsiding Williston Basin on Colorado Group sedimentation appears less pronounced than during early Colorado time. The pattern of sedimentation changes slightly during 1WS time, being generally thickest along the deformation front, especially in the Deep Basin, and thinning to the northeast. Analysis of variations in the Joli Fou Formation is awaiting completion of the regional cross-sections.

The First and Second White Specks erosional edges (Figures 3, 4) underlying glacial cover are apparent across north-central Alberta; the precise locations of these edges is difficult to determine because the intervals are largely hidden behind surface casing. Recent changes to the Energy Resources Conservation Board (ERCB) regulations, requiring companies to log behind casing, will help delineate these edges.

Upper Colorado strata, such as the Cardium sand and Badheart sand (1WS ‘D’ on the cross-sections), thin eastward from the paleoshoreline and, where the shale packages are interlaminated with siltstone and sandstone, the ‘shale’ becomes a shale gas target with a reasonably high free gas content. In eastern Alberta, shale strata with more abundant laminae are a shale gas target and are currently producing, as

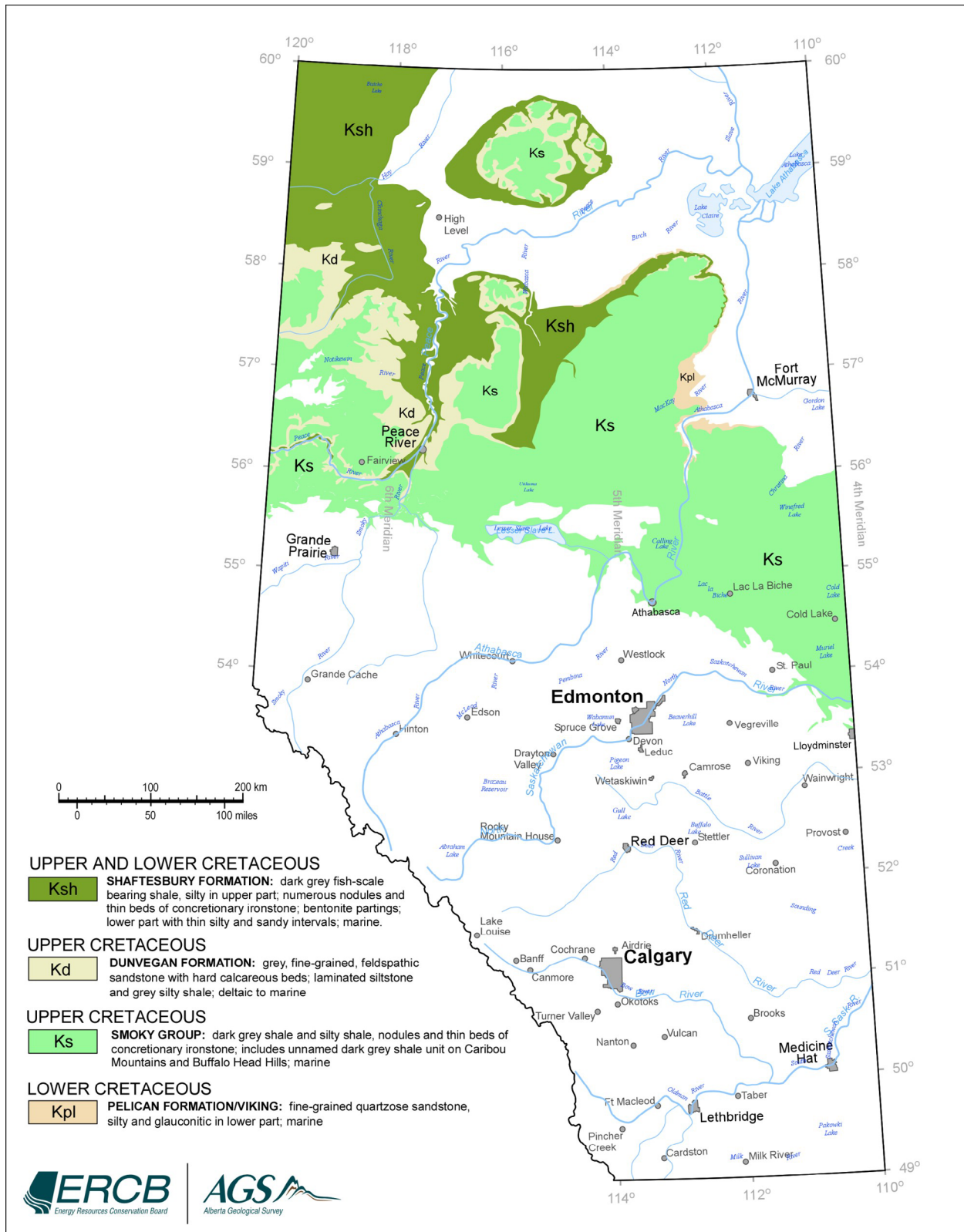


Figure 2. Bedrock geology of Alberta, showing the areas where the Colorado Group subcrops beneath glacial sediment (modified after Hamilton et al., 1999).

discussed in Section 5. The specific environment of deposition of the laminae awaits further research, as does the spatial distribution of the laminae. Porous laminae store free gas and may form a significant percentage of shale gas resources, along with both desorbed and free gas from organic shale. A few thin sections and SEM photos of the strata are discussed in Section 4.2.

Our initial investigation into the geochemical and sedimentological characteristics of the upper Colorado Group, especially the IWS in eastern Alberta, is revealing that shale in this interval is as geochemically and sedimentologically variable, both vertically and laterally, as the shale of the lower Colorado Group, as indicated by Bloch et al. (1999). Our correlations of the strata are in agreement with the regional correlations of Tyagi et al. (2007). Although our assertion of variable characteristics within the so-called 'shale' units may be obvious, the importance of estimating the proportions of 'non-shale' rock types in the unconventional shale gas plays for resource evaluation cannot be understated. Shale strata such as the IWS in eastern Alberta or thick successions like the Blackstone or Shaftsbury are not classical shale gas intervals with log characteristics that readily identify them as organic-rich black shale. Classical shale gas log properties viewed in many publications and on the Internet speak of a 'hot' elevated gamma-ray profile, with a high resistivity and perhaps a low density and high sonic transit time owing to elevated total organic carbon (TOC), all relative to 'background shale'. Indeed, Colorado shale has log characteristics that more resemble 'background shale' than classical shale gas intervals. Yet a lesson has been learned in eastern Alberta, where production is obtained from such strata (*see* Section 5), suggesting that 'background shale' may indeed be productive, especially when associated with porous laminae of siltstone and sandstone. These intervals are perhaps more economic to complete and produce (i.e., higher free gas content) than organic shale with no laminations. Furthermore, we are beginning to identify shale sedimentological characteristics, such as microfabric (*see* Section 4.2), that may be associated with enhanced permeability and themselves would be preferred completion targets (Davies et al., 1991; Davies and Vessel 2002). Thus, much of the shale gas potential in the upper Colorado Group appears similar in concept to the Lewis Shale of New Mexico (e.g., Frantz et al., 1999; Dube et al., 2000), where the TOC of productive Lewis Shale is as low as 0.5 wt. %. The Lewis Shale has an estimated $2746 \times 10^6 \text{ m}^3$ (~97 Tcf) of resources in the play area (Faraj et al., 2004).

It is important to delineate the variable lateral and vertical characteristics of these 'background shales' and identify the most productive intervals. This is no small task because the Colorado shale underlies a large part of Alberta. For example, the Westgate shale is described as a regressive or progradational unit exhibiting multiple cycles of coarsening-upward sediment (Bloch et al., 1999) that varies from noncalcareous, medium to dark grey to black, mudstone to siltstone (Bloch et al., 1993) with occasional lenticular sandstone (Buckley and Tyson, 2003). The Westgate shale contains relatively low TOC (<2.0 wt. %) of dominantly Type III organic matter (Bloch et al., 1999). Overlying the Westgate Formation is the Fish Scales Zone, generally described as a composite of less common or rare thin conglomerate or sandstone beds or laminae (Bloch et al., 1993; Leckie et al., 1994), underlying a silty, noncalcareous, organic-rich black shale with some thin lenticular sandstone interbeds (Buckley and Tyson, 2003). The Fish Scales Zone has a TOC content of up to 8 wt. %, with mixed Type II and III organic matter. The geochemical and sedimentological characteristics of the lower Colorado shale strata not only change through time (i.e., depth) but also laterally, and therefore vary across Alberta (Bloch et al., 1999; Buckley and Tyson 2003) due to changing depositional environments and increasing depth to the west (Bloch et al., 1999). Colorado Group shale becomes more mature as the strata deepen to the west than the shallow, immature shale to the east (Creaney et al., 1994; Bloch et al., 1999; Buckley and Tyson 2003). As stated earlier, perhaps no less variability should be expected in the thick 'background' shale of the upper Colorado.

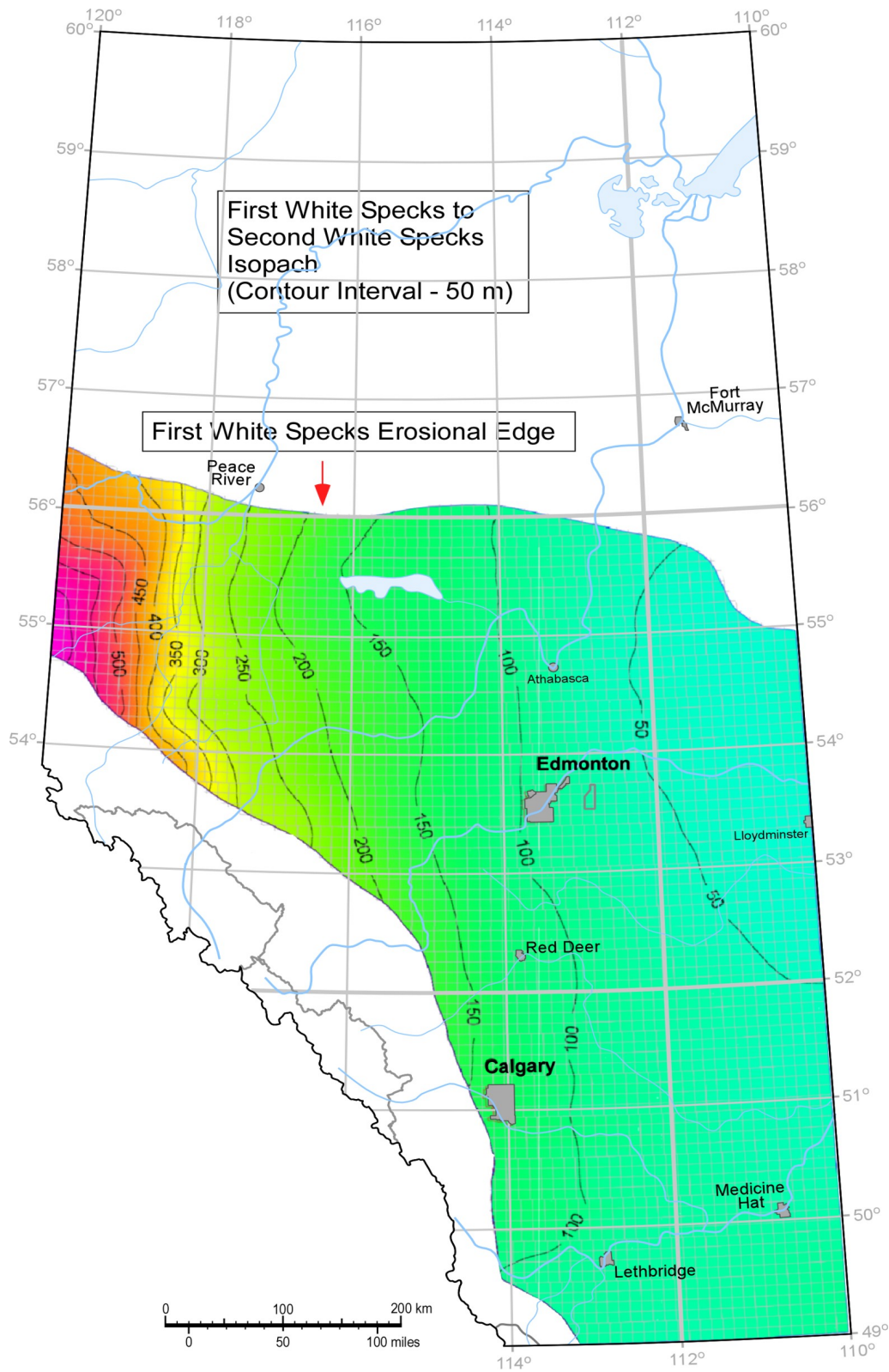


Figure 3. Isopach from the top of the First White Specks (1WS) to the top of the Second White Specks (2WS; *modified after* Leckie et al., 1994). The isopachs of Figures 3 and 4 are summed to determine the thickness of the upper Colorado Group.

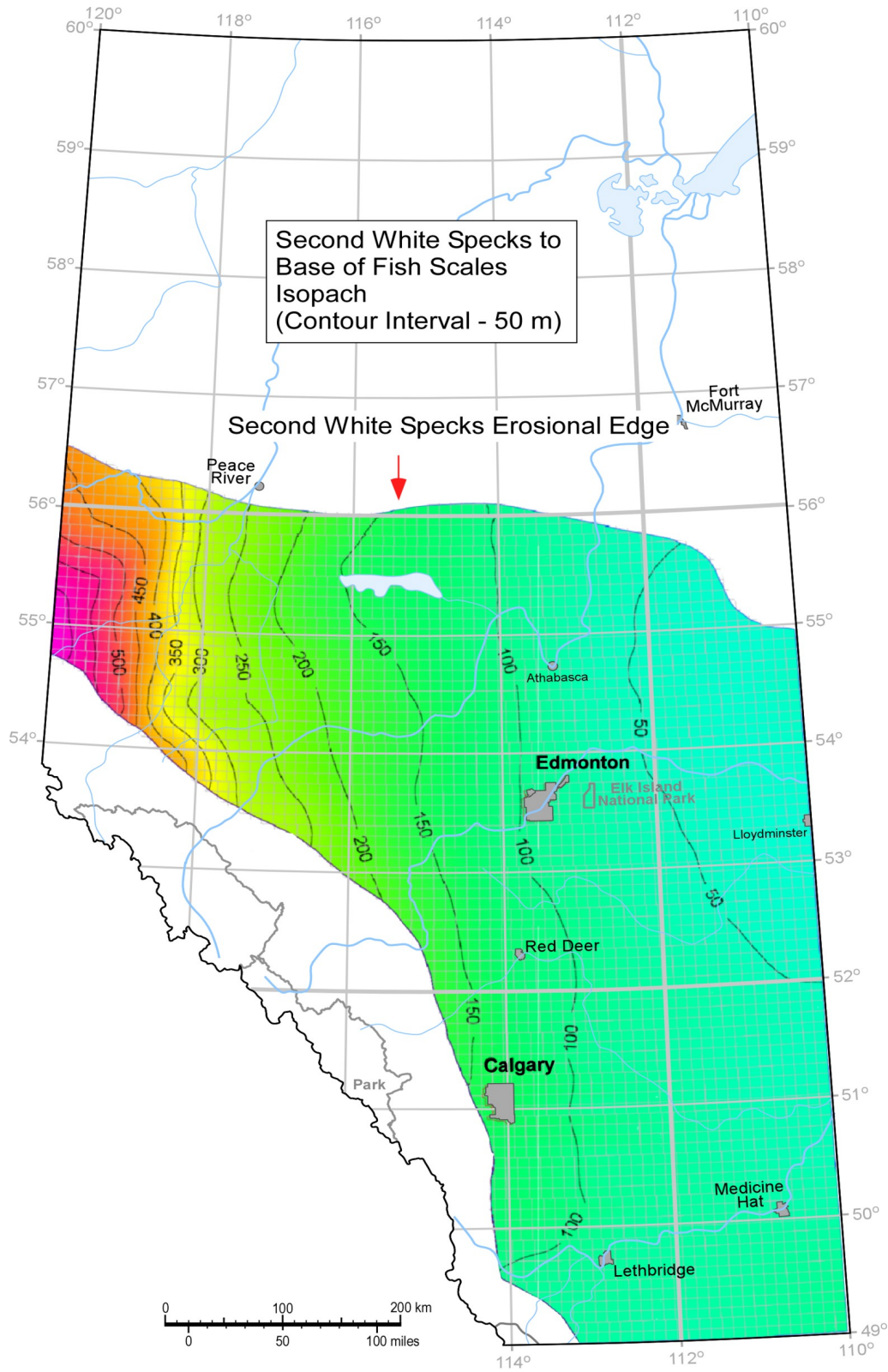


Figure 4. Isopach from the top of the Second White Specks (2WS) to the Base of Fish Scales (BFS) marker (modified after Leckie et al., 1994). The isopachs of Figures 3 and 4 are summed to determine the thickness of the upper Colorado Group.

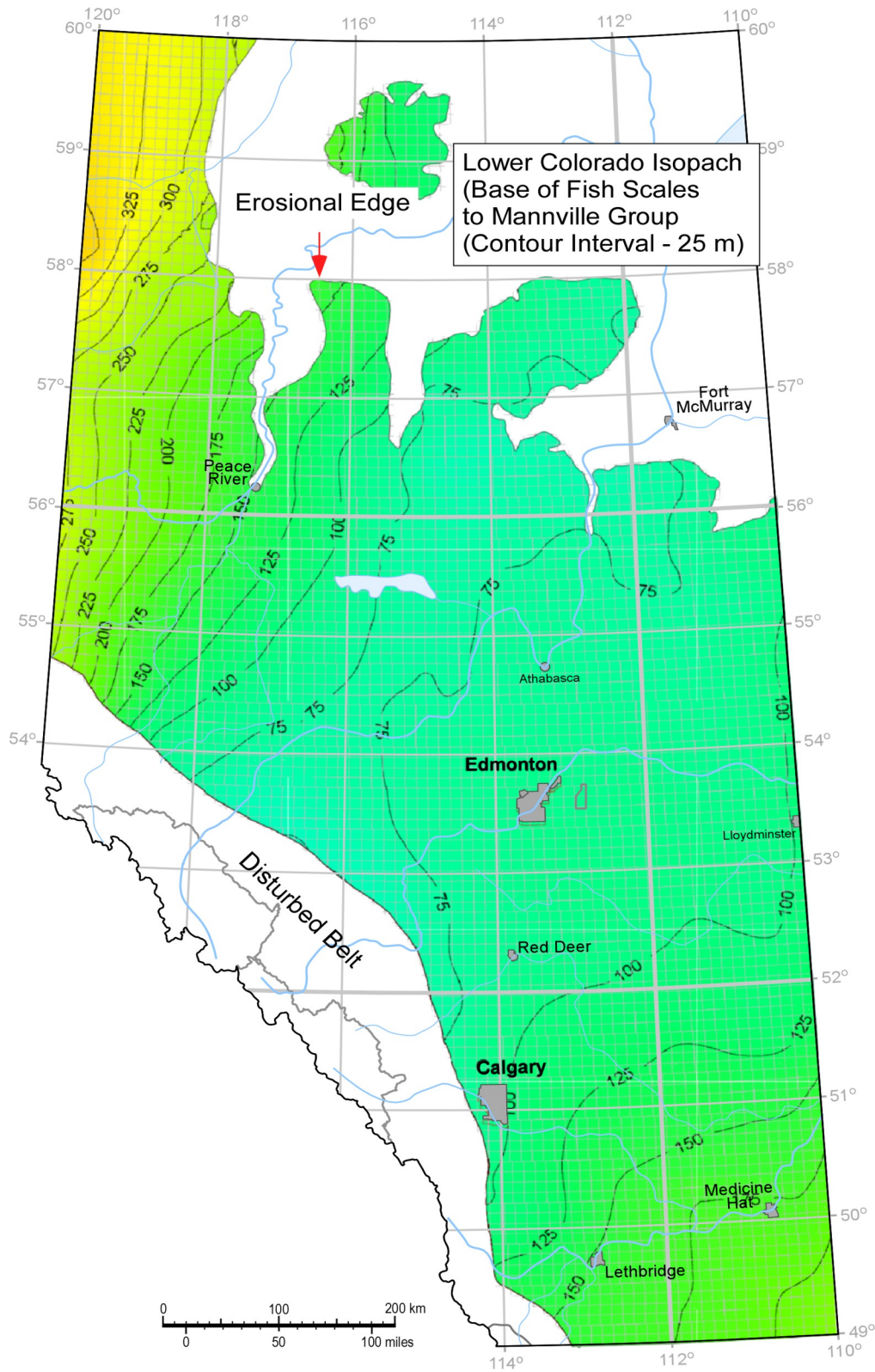


Figure 5. Isopach of the lower Colorado Group, from the Base of the Fish Scales (BFS) marker to the top of Mannville/Blairmore Group (modified after Leckie et al., 1994).

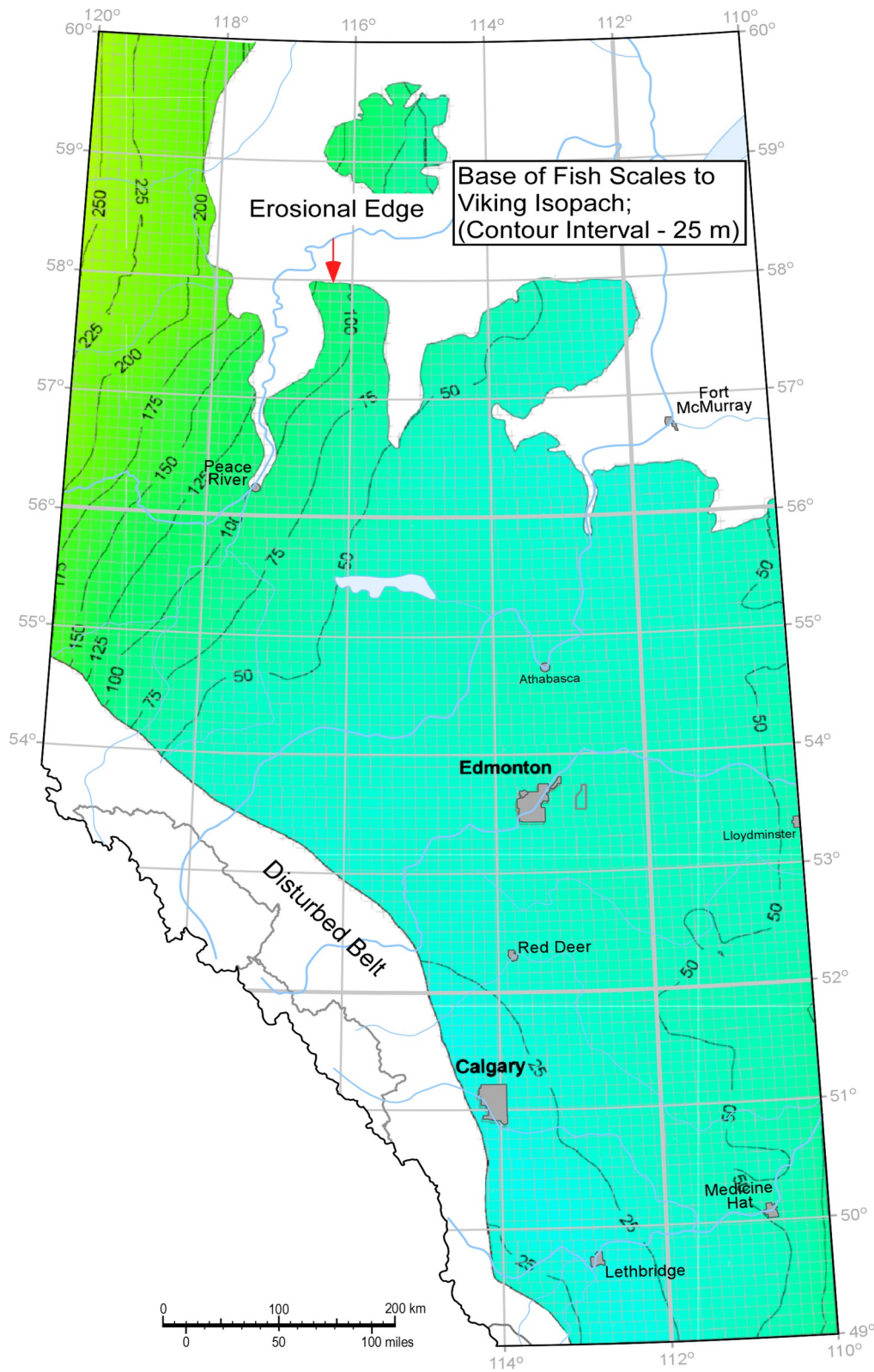


Figure 6. Isopach of the Base of the Fish Scales (BFS) marker to the top of the Viking sand. We are using this map as a mirror for the isopach of the Westgate Formation (*modified after* Leckie et al., 1994) until further mapping is complete.

2.1.1 Colorado Group Stratigraphic Cross-Sections

The locations of cross-sections discussed in this section are shown in Figure 7.

2.1.1.1 Colorado Group Stratigraphic Cross-Section C12 (T45, R13W5 to T70, R1W4)

This is the more northerly of the two southwest to northeast stratigraphic cross-sections (Figures 7 and 8), beginning west of the Cardium Pembina field and ending near the Alberta-Saskatchewan border. The section displays the dip direction and eastward progradation of the upper Colorado Group, especially the 1WS shale. From southwest to northeast, the slope of the correlations is reasonably steep to about 15-10-57-18W4 and then flattens out eastward, with perhaps an increase in slope again at the east end of the section. Future mapping and cross-sections will help determine how closely this section parallels depositional dip.

The 1WS decreases in thickness from about 800 m in the west to less than 100 m in the east over a distance of about 500 km. Thinner strata in the east reflect starved sedimentation in the deeper parts of basin relative to the subsiding foreland basin in the lee of the mountains during 1WS time (Leckie et al., 1994). Sand deposition in the 1WS was dominantly during Cardium and Badheart (i.e., 1WS 'D') time in the west nearer to shore. Nonetheless, Colorado 'shale' would seem to make up more than 95% of the 800 m interval in the west and nearly the entire interval in the east. As discussed earlier, some of the shale in the 1WS–Blackstone interval, both east and west, will consist of laminated shale and sandstone/siltstone where the sandstone and siltstone laminations are too thin to be 'seen' on well logs. These are key intervals of interest that we have yet to fully study.

Some of the correlations within the 1WS are difficult to follow as the strata thin eastward. The lines of correlations were stopped where we could not be certain of the correlation, such as the 1WS 'C' near 15-10-57-18W4. An increase in the density of wells used in the cross-section may help continue the lines of correlation. Downlapping of correlations is evident; for example, 1WS 'A' appears to downlap the 2WS top at about 10-25-58-16W4, and perhaps the 1WS 'B' (Cardium-equivalent zone) marker downlaps the Cardium sand near 11-02-59-13W4.

The 2WS to BFS interval decreases in thickness from about 400 m in the west to less than 50 m in the east. Strata within the interval have been well correlated by other authors (Nielsen et al., 2003; Tyagi et al., 2007). Generally, there is a larger isopach of sand in the west than the east (compare the resistivity logs west and east), although not necessarily a greater percentage of sand relative to the 2WS to BFS interval.

2.1.1.2 Colorado Group Stratigraphic Cross-Sections C6 (T27, R13W5 to T45, R2W4) and C11 (T36, R6W5 to T53, R1W4)

Both sections C6 (Figure 9) and C11 (Figure 10) exhibit stratigraphic profiles in the upper Colorado Group similar to that of section C12. From west to east, the 1WS stratum in C6 decreases in thickness from about 900 to 175 m, and from 750 to 160 m in section C11. The sections are tied by the two cross-sections discussed below and indicate continuity of the strata in the area between the sections. All other comments for section C12 regarding the presence, or lack thereof, of laminations and the difficulty in continuing some of the correlations applies equally to these two sections. Located at the east end of section C11 is the Cardium-equivalent shale gas field (e.g., 12-11-48-10W4) that will be discussed briefly in Section 5. Furthermore, there are now a considerable number of Fish Scales, Westgate and 2WS shale gas wells in various parts of eastern Alberta. For example, near the extreme east end of section C6 in T44–45, R1–2, W4, there are no less than about 23 Fish Scales Zone and Westgate shale gas wells producing about 50 to 1800 m³/d from organic shale with siltstone/sandstone laminations.

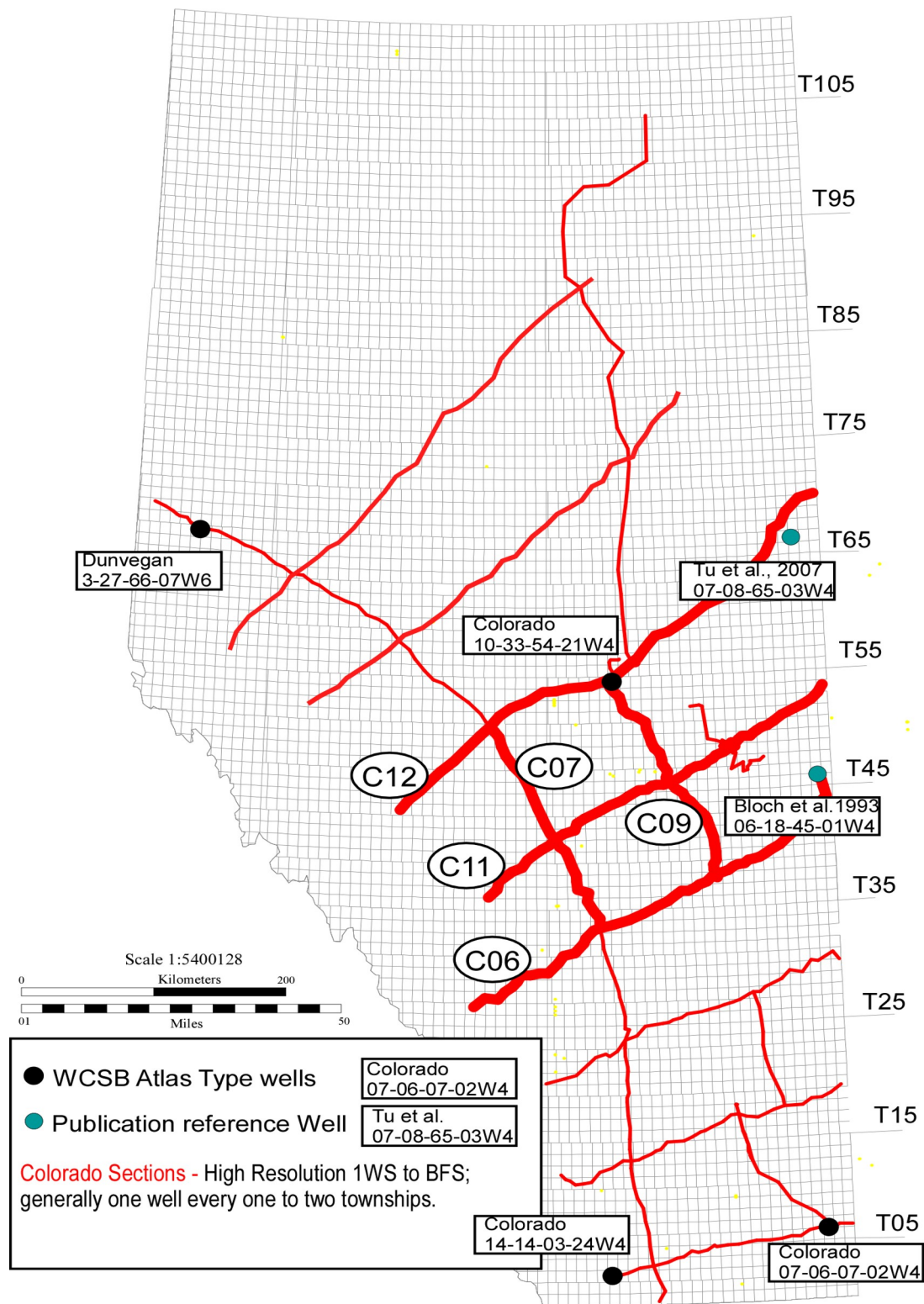


Figure 7. Locations of stratigraphic cross-sections of the Colorado Group. Cross-sections in bold lines have been included in this report. All cross-sections not included are being refined and will be available when complete.

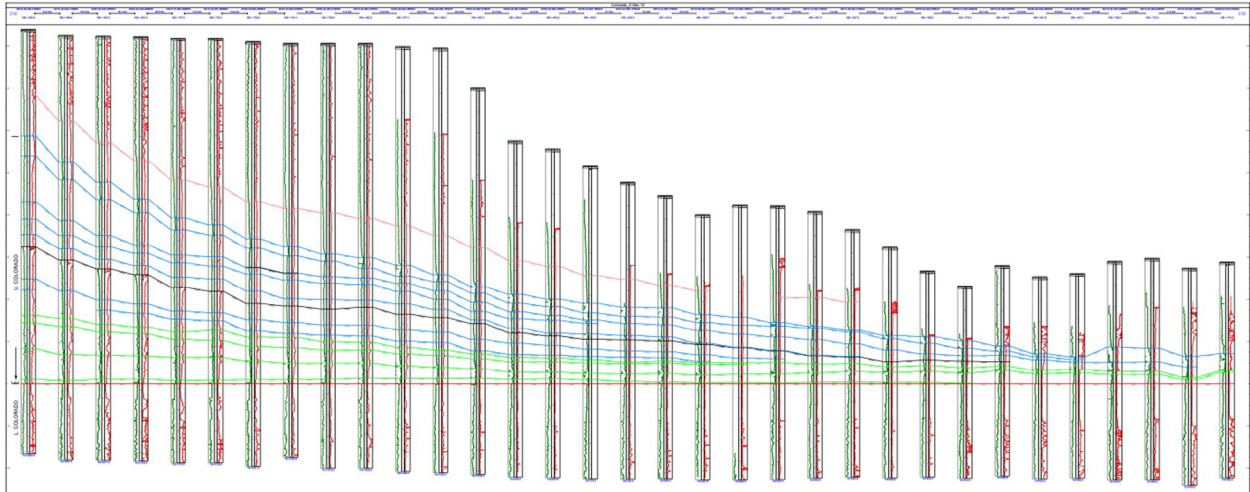


Figure 8. Stratigraphic cross-section C12. See Appendix 1 for a larger version.

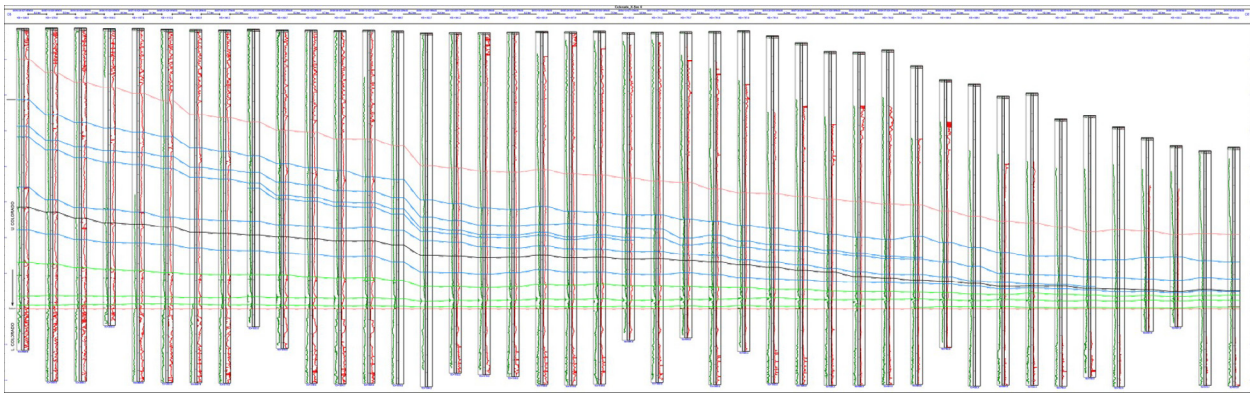


Figure 9. Stratigraphic cross-section C6. See Appendix 1 for a larger version.

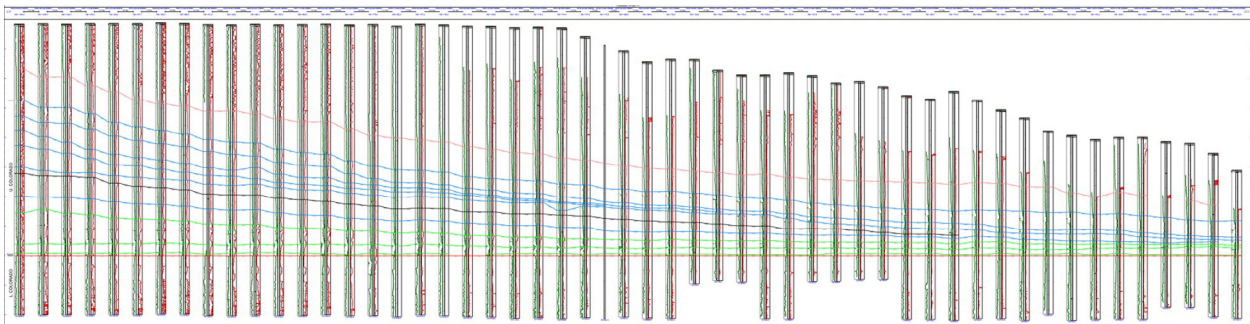


Figure 10. Stratigraphic cross-section C11. See Appendix 1 for a larger version.

2.1.1.3 Colorado Group Stratigraphic Cross-Section C7 (T50, R6W5 to T33, R24W4)

This northwest to southeast section (Figure 11) ties the southwest to northeast sections (C6, C11 and C12) together in western Alberta (Figure 7). Notice the flat-lying correlations of the 1WS that suggest the cross-section traverses depositional strike. The strike of the continental slope appears to have remained remarkably steady during deposition of the 1WS in this area. The 2WS strata above the 2WS 'B' line of correlation show a slight thickening northward, likely representing a slight increase in subsidence toward the Deep Basin of Alberta.

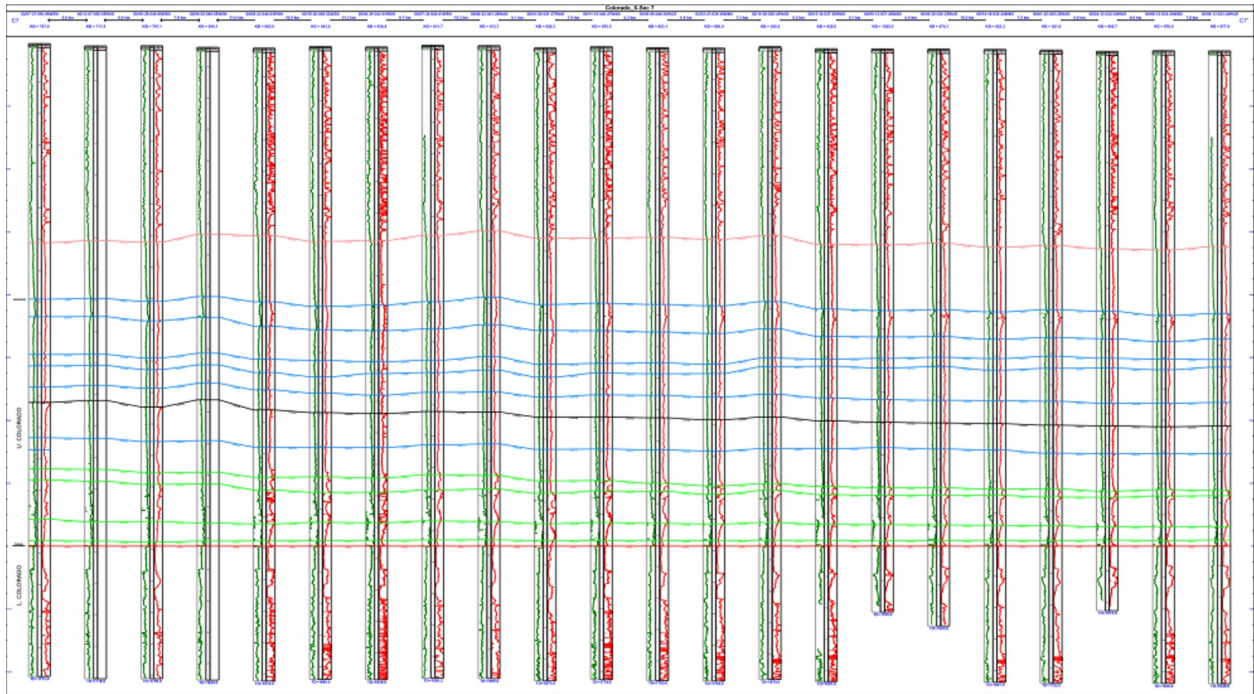


Figure 11. Stratigraphic cross-section C7. See Appendix 1 for a larger version.

2.1.1.4 Colorado Group Stratigraphic Cross-Section C9 (T54, R22W4 to T37, R12W4)

This northwest to southeast section (Figure 12) ties the southwest to northeast sections (C6, C11 and C12) together in eastern Alberta (Figure 7). Notice again the flat-lying correlations of the 1WS, suggesting that this section also traverses along depositional strike and that the strike and dip of the continental slope remained remarkably steady during deposition of the 1WS. Likewise, there is little change in thickness of the 2WS. The thickness of both the 1WS and 2WS is less than half that of the same formations in the other connecting section, C7. The decrease in thickness represents a decrease in subsidence and reduced sedimentation to the east (i.e., basinward) from the subsiding foreland basin during the time of deposition (Leckie et al., 1994).

The main point of this brief review is that there are numerous 'packages' of shale strata within the upper and lower Colorado Group. There are enough hints of vertical and lateral variability in geochemical and sedimentological characteristics in both the upper and lower Colorado Group that each shale stratum must be evaluated separately for its shale gas resource potential. The lack of shale gas potential within a single shale stratum or 'package' in one area does not reflect on its potential in other areas of the province.

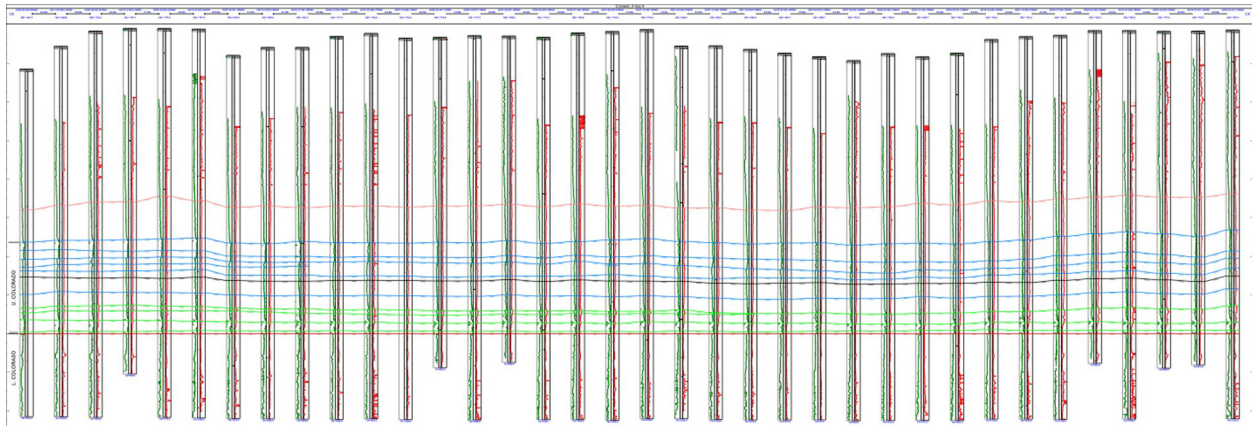


Figure 12. Stratigraphic cross-section C9. See Appendix 1 for a larger version.

3 Methodology of Sampling and Testing

Samples were selected for analysis from outcrop and core (Figure 13). Outcrop samples were selected near Birch Mountain ('Asphalt Creek' and 'Greystone Creek') and Cadomin (Figures 14a–c). Section descriptions for Asphalt and Greystone are in Appendix 2. Single samples were taken from an additional four sites at Greystone Creek (Table 2, sites C39–C42). Subsurface core and outcrop were selected to determine vertical and spatial geochemical and sedimentological characteristics. Our approach to sampling and description of core is to spend a maximum amount of time and effort in sampling the core and preparing a brief description, at the expense of a full core description. Although the lack of a full description is a shortcoming in geological analysis, we feel that maximum benefit at this early stage of shale gas evaluation in Alberta will be obtained by sampling and testing of core. As stated by Schieber and Zimmerle (1998), such a small amount of research has been done on shale, let alone shale as a reservoir, that everyone is on a very steep learning curve. In our case, fully describing more than 36 cores would have greatly reduced the time and money available for sampling and analysis. Furthermore, the core is available at the ERCB Core Research Centre in Calgary, so all interested parties can view it at their leisure. From time to time, we may return to describe the core and will make this information available.

Our sampling strategy in outcrop is to select 1) at least one sample for each facies or lithological change, or 2) if the lithology was vertically congruent over a few metres, enough samples to give a reasonable vertical and, if possible, lateral distribution of characteristics. Where permitted, approximately 30–60 cm (1–2 feet) of surface material was unearthed in order to obtain samples that may be less affected by surficial weathering. If the outcrop face was well indurated, then a surface sample was selected. Subsurface core selection is primarily guided by the availability of core rather than strategic selection of samples, as there is a relative paucity of shale core in the Western Canada Sedimentary Basin. A key issue related to core sampling is that the amount of sample selected from each core is limited, which restricts the number and types of tests that can be performed. The size and number of samples selected from each core was approved by ERCB personnel at the Core Research Centre. Although it would be ideal to be able to subject all samples to every analysis, this could not be done. We have attempted to obtain a reasonable temporal and spatial distribution of characteristics in both formations and have tried not to test core on which the same analyses have been performed at a similar depth, as indicated in published reports (e.g., Bloch et al., 1999; Tu et al., 2007). An important point concerning the core samples is that all sample depths are recorded as core depth rather than being converted to log depths.

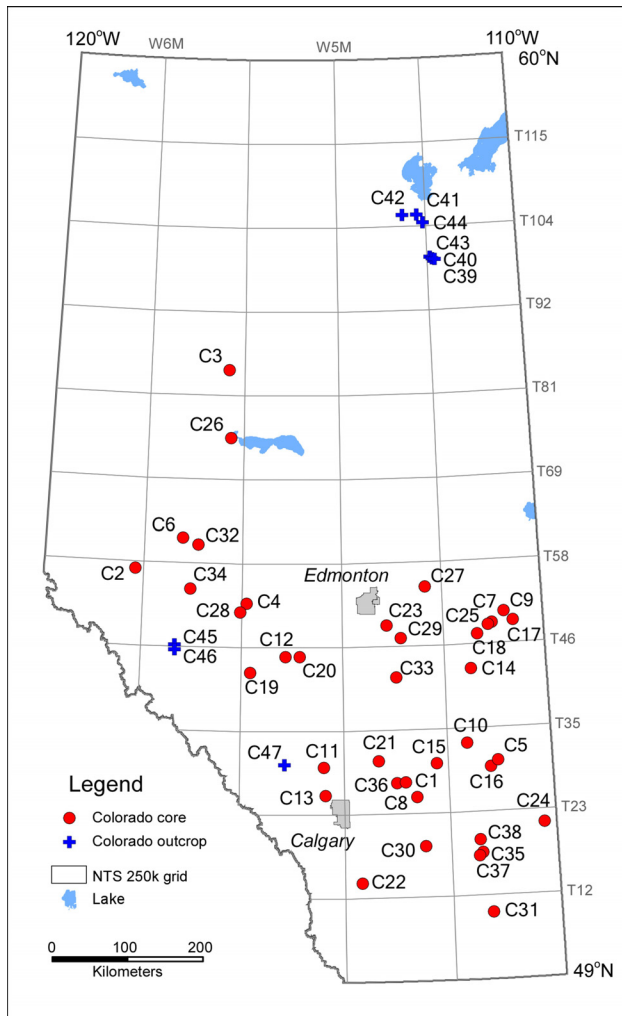


Figure 13. Locations of outcrop and subsurface core samples from the Colorado Group.

Our experience in unconventional gas resource analysis, conversations with industry and background research led to the selection of more than 10 geochemical and geological analyses for outcrop and subsurface samples (Table 3). This suite of analyses has been performed on many low-permeability and organic-rich samples, as indicated in a variety of public reports. Only a brief description of each type of analysis and the rationale for its selection is given here. We will not discuss the assumptions or errors inherent in each analysis. Errors and assumptions, if any, are discussed in the references listed in Table 3. For a more detailed description of each analytical method, we urge the reader to navigate to the publication or website given in Table 3 for a better understanding of the methodology and potential errors involved.

3.1 Rock Eval™ 6 and Total Organic Carbon

A fundamental property of shale gas reservoirs is organic richness. A higher organic content (total organic content or TOC) is preferred in shale gas plays because more gas may be generated, all other factors being equal. Rock Eval™ (Rock Eval is a registered trademark of Institut français du pétrole) is a test of maturity of the organic matter.

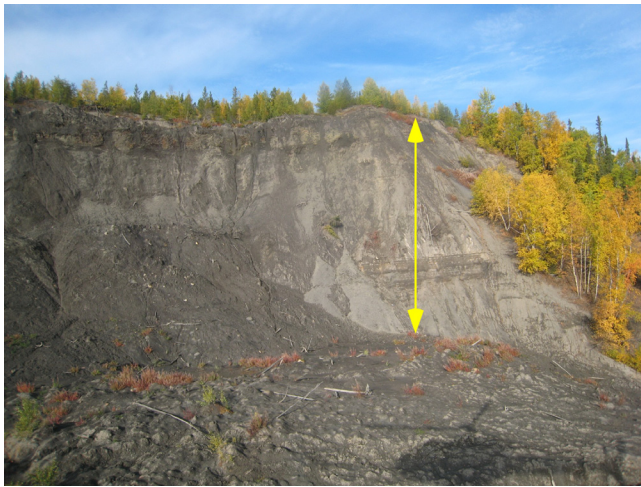


Figure 14. a) Colorado Group section at Asphalt Creek, Birch Mountains. Distance between arrowheads is ~1 m. See Figure 13 for outcrop location, and Appendix 2 for outcrop section descriptions. b) Colorado Group section at Greystone Creek, Birch Mountains. See Figure 13 for the location of the outcrop section, and Appendix 2 for outcrop section descriptions. Distance between the arrowheads is approximately 25 m. c) Colorado Group (Blackstone Formation) section near Cadomin. See Figure 13 for the location of the outcrop section and Appendix 2 for the sample sites.

Table 1. Colorado Group core locations. See also Figure 13.

Site No.	Unique Well Identifier	Latitude (NAD83)	Longitude (NAD83)	Year Drilled	No. of Samples	Group
C01	100/04-11-028-22W4/00	51.375371	-113.000011	2002	6	Colorado
C02	100/04-13-057-02W6/00	53.921709	-118.170803	1962	4	Colorado
C03	100/04-29-084-15W5/00	56.306578	-116.343167	1952	6	Colorado
C04	100/04-31-052-13W5/00	53.530131	-115.912450	2002	2	Colorado
C05	100/05-03-030-09W4/00	51.537186	-111.196063	1946	4	Colorado
C06	100/05-27-061-22W5/00	54.301586	-117.223691	1997	4	Colorado
C07	100/05-30-049-07W4/00	53.252497	-111.024094	2005	2	Colorado
C08	100/06-08-026-19W4/00	51.202794	-112.626775	1980	15	Colorado
C09	100/06-11-051-06W4/00	53.385156	-110.785097	2006	2	Colorado
C10	100/06-15-033-12W4/00	51.827959	-111.624249	1980	6	Colorado
C11	100/06-17-030-03W5/00	51.568035	-114.390524	1982	7	Colorado
C12	100/06-20-045-08W5/00	52.892068	-115.129927	1979	2	Colorado
C13	100/06-21-026-03W5/00	51.233362	-114.365477	1983	6	Colorado
C14	100/06-23-043-11W4/00	52.716098	-111.492145	2004	8	Colorado
C15	100/06-29-030-16W4/00	51.595231	-112.225340	1969	5	Colorado
C16	100/06-34-030-08W4/00	51.609735	-111.052456	1969	6	Colorado
C17	100/06-36-049-05W4/00	53.268492	-110.606221	2004	3	Colorado
C18	100/07-12-048-10W4/00	53.124039	-111.332969	2004	7	Colorado
C19	100/07-16-043-13W5/00	52.703956	-115.824539	2006	3	Colorado
C20	100/07-19-045-06W5/00	52.892373	-114.854086	1979	16	Colorado
C21	100/08-09-031-24W4/00	51.639470	-113.338736	1952	2	Colorado
C22	100/08-24-014-28W4/00	50.184105	-113.687534	1998	4	Colorado
C23	100/08-27-049-22W4/00	53.254931	-113.128424	2004	4	Colorado
C24	100/09-05-022-02W4/00	50.844880	-110.240286	2004	1	Colorado
C25	100/09-16-049-08W4/00	53.229438	-111.107681	2005	6	Colorado
C26	100/12-16-075-15W5/00	55.499583	-116.274312	1950	7	Colorado
C27	100/12-32-054-16W4/00	53.709219	-112.332668	2004	9	Colorado
C28	100/13-20-051-14W5/00	53.421052	-116.035361	2003	6	Colorado
C29	100/13-34-047-20W4/00	53.102458	-112.853229	2005	4	Colorado
C30	100/14-18-019-18W4/00	50.612334	-112.488539	2004	6	Colorado
C31	100/15-03-010-10W4/00	49.798865	-111.277533	1949	3	Colorado
C32	100/15-27-060-20W5/00	54.221784	-116.911727	1982	4	Colorado
C33	100/16-21-042-21W4/00	52.634819	-112.960441	1979	10	Colorado
C34	100/16-29-054-21W5/00	53.697805	-117.053719	1980	5	Colorado
C35	102/03-14-018-11W4/00	50.515811	-111.418574	2004	4	Colorado
C36	102/10-12-028-21W4/00	51.381280	-112.830199	2004	2	Colorado
C37	102/11-32-017-11W4/00	50.480595	-111.484723	2003	8	Colorado
C38	102/13-03-020-11W4/00	50.670811	-111.457734	2004	4	Colorado

3.2 Organic Petrology

Organic petrology examines organic macerals and determines the source of the organic matter (i.e., marine or terrestrial). Macerals in organic petrology are akin to minerals in sedimentology. Furthermore, during gas desorption, the shape and morphology of organic matter may contribute to permeability and influence gas diffusion rates (although this is a relatively new area of research).

3.3 Isotherm (Adsorption) Analysis

Adsorption analysis will identify the maximum amount of gas that a shale sample can hold. The maximum capacity, however, may not represent the present state of storage in the reservoir.

Table 2. Colorado Group outcrop locations. See also Figure 13.

Site No.	Datum	UTM			Site Location Name	No. of Samples	Group
		Zone	Easting	Northing			
C39	NAD83	12	446778	6385401	Birch Mountains – NTS 84I	1	Colorado
C40	NAD83	12	449178	6384521	Birch Mountains – NTS 84I	1	Colorado
C41	NAD83	12	429162	6444821	Birch Mountains – NTS 84I	1	Colorado
C42	NAD83	12	410496	6444999	Birch Mountains – NTS 84I	3	Colorado
C43	NAD83	12	443512	6387776	Birch Mountains – Asphalt Creek	16	Colorado
C44	NAD83	12	436680	6434329	Birch Mountains – Greystone Creek	22	Colorado – Shaftesbury
C45	NAD83	11	478167	5875014	Cadomin – railroad section	30	Colorado – Blackstone

3.4 X-ray Powder Diffraction (XRD): Whole-Rock and Clay Mineralogy

X-ray powder diffraction (XRD) will identify the mineralogy of a sample whereby an electromagnetic beam (x-ray) on a crystal yields a characteristic scattering or diffraction pattern.

X-ray diffraction analysis and interpretation, and x-ray fluorescence spectroscopy (XRF) on core samples was done by SGS Minerals Services Ltd. (<http://www.ca.sgs.com/home.htm>), while CBM Solutions Ltd. (<http://www.cbmsolutions.com>) performed XRD analysis and interpretation on outcrop samples. A detailed summary of sample preparation procedures and scan conditions for XRD and XRF will be provided upon request.

SGS Minerals uses a Siemens D5000 diffractometer with cobalt radiation and Siemens search-match software for peak identification. Mineral proportions are based on relative peak heights and can be strongly influenced by crystallinity, structural group or preferred orientations (H. Zhou, SGS Minerals Services Ltd., pers. comm., 2008). The calculation of mineral abundances from both bulk mineral analysis and clay mineral separates is based on relative peak intensity and is reconciled with a whole-rock analysis by XRF. The detection limit of minerals is approximately 0.5–2.0 wt. % according to SGS Minerals but can be as high as 3–5 wt. % (<http://www.xrd.us>). However, amorphous compounds are not detected by XRD.

CBM Solutions uses a Siemens D5000 or D500 with copper or cobalt x-ray tube with search-match software for peak identification. X-ray diffraction patterns were analyzed using a commercial Rietveld program for quantification of the mineralogy. The accuracy of the Rietveld analyses is considered to be $\pm 3\%$ in minerals with fixed cell dimensions. In samples with substantial disordered clay minerals, the total percentage of clay was determined by Rietveld fitting and then the relative abundances of the clay

species were quantified by integrating the areas under the 001 peak. The Lorentz and polarization contributions to the x-ray intensity in this study were corrected following the procedures of Pecharsky and Zavalij (2003, p. 192). As a result of the presence of disordered phases and the need for a combination of methodologies, the accuracy of the results varies sample by sample. For samples in which substantial montmorillonite, random mixed-layer clay minerals and/or degraded illite are present, the percentage mineralogy reported here is best considered semiquantitative (*summarized from CBM Solutions Ltd., 2008*).

3.5 Petrographic Analysis (Thin Section)

Thin sections, cut by Vancouver Petrographics Ltd. (<http://www.vanpetro.com>), were used to analyze mineralogy, texture, fracturing, microfabric and microstratigraphy. Not all thin sections contain an upper glass cover. Most of the samples were cut by saw using water as a cooling/lubricant liquid; in some cases, however, a limited amount of kerosene was used during the preparation due to the presence of swelling smectite that would have caused excessive swelling of the sample in the presence of water. Once the samples were completed, the polished surfaces were cleaned with acetone. All thin sections were impregnated with Petropoxy™ 154 (<http://burnhampetrographics.com/petropoxy/ppp.php#154>). A few thin sections have been described in Section 4.2.2; the remaining thin sections descriptions will be released after they have been completed.

Table 3. Analyses performed on shale samples, including references for the methodologies.

Type of Analysis	Company/Analyst	Notes and Reference
Isotherm	Schlumberger Limited; CBM Solutions Ltd.	References available upon request
Mercury porosimetry and envelope and helium pycnometry	Department of Physics, University of Alberta (D. Schmitt)	Analytical Methods in Fine Particle Technology Webb and Orr (1997)
Permeametry	Department of Earth and Atmospheric Sciences, University of Alberta (M. Gingras)	Gingras et al. (2004)
Rock Eval™ 6 /TOC	Geological Survey of Canada; Schlumberger Limited; CBM Solutions Ltd.	Peters (1986), Peters and Cassa (1994), Lafargue et al. (1996)
Organic petrography	Geological Survey of Canada	Organic petrology (Taylor et al., 1998)
Petrographic analysis (thin section)	Vancouver Petrographics Ltd.; CBM Solutions Ltd.	
Scanning electron microscope (SEM) with energy-dispersive x-ray (EDX)	Department of Earth and Atmospheric Sciences, University of Alberta (G. Braybrook)	http://easweb.eas.ualberta.ca/page/29
Environmental scanning electron microscope	Department of Biology, University of Alberta (R. Bhatnagar)	http://www.biology.ualberta.ca/facilities/microscopy/?Page=2146
X-ray diffraction (bulk and clay mineral)	SGS Minerals Services Ltd. (H. Zhou); CBM Solutions Ltd.	Klein (2002)

3.6 Permeametry

Permeability is one of the critical parameters characterizing potential shale gas reservoirs; furthermore, the identification of shale seals or lack of permeability is an equally important parameter in shale gas exploration and pool delineation. Spot permeametry analysis will determine the permeability to gas (nitrogen in our case) of the selected samples. Note that the diameter of a nitrogen molecule is about 0.15 nanometre (nm; 1.5 ångströms), while the diameter of a methane molecule is about 0.4 nm (4.0 ångströms). Spot permeametry was performed at the University of Alberta, under the guidance of M.K. Gingras, under ambient conditions on a portable probe permeameter (CoreLabs model PP-250) with

nitrogen as the pore fluid. Optimal accuracy of the model is between about 0.01 and 3000 millidarcies (mD; $\pm 1\%$). Five or six measurements were made on each sample. The highest and lowest values were excluded and an average taken of the remainder; however, all measurements are included in the data release. No corrections were applied to the data.

3.7 Mercury Porosimetry and Helium Pycnometry

Mercury porosimetry and helium pycnometry are techniques for quantifying intrusion pore diameter, total pore volume, surface area, and envelope and skeletal densities of the sample. A helium gas molecule is smaller than a methane molecule, whereas mercury is larger than a methane molecule; hence, the pore characteristics of the samples are relatively well described although not accurate relative to a methane molecule, and the methods provide detailed information on the micro-, meso- and macroporosity and/or seal characteristics of the samples. Porosimetry and pycnometry analyses were done at the University of Alberta under the direction of D. Schmitt. Some of the samples desorbed gas; hence, the samples were put under vacuum in a cold oven prior to analysis.

3.8 Scanning Electron Microscopy (SEM) and Environmental Scanning Electron Microscopy (ESEM)

Both of these instruments are being used to characterize the microfabric of the samples, and the morphology, size and distribution of the pores. The scanning electron microscope (SEM) can also provide a mineralogical analysis (energy-dispersive x-ray, EDX), as well as backscattered images on selected samples. All samples are coated with gold prior to analysis.

Samples viewed with the environmental scanning electron microscope (ESEM) were examined in high vacuum mode using a secondary electron detector operating at 15–20 kV with a Philips/FEI XL 30 ESEM. The ESEM equipment has a resolution of 2.5 nm and a magnification of up to 200 000 \times . The SEM is a JEOL 6301F (field-emission scanning electron microscope) with magnification ranging from 20 to 250 000 \times . Semiquantitative elemental analysis (EDX) is available via a PGT x-ray analysis system. The resolution of EDX mineralogical analysis is ~ 1 μm diameter.

4 Shale Gas Data Analysis

Seventy-four outcrop samples and 203 core samples from the Colorado Group were selected for analyses (*see* Figure 13, Tables 1, 2). A copy of the well log, core depth and type of analysis for each core is provided in Appendix 3. The selection of all subsurface core samples received the approval of the ERCB Core Research Centre. Energy Resources Conservation Board rules state that a copy of all data from core must be sent to the Core Research Centre. This section examines a few of the analytical techniques and highlights specific aspects of the formations that reflect on their potential, or lack thereof, for shale gas resources. Any further analysis of the results will be published in journals or as AGS open file reports. All data will be made available on the AGS website (www.ags.gov.ab.ca).

4.1 Geochemistry Results

Tabulated data and photographic images for the organic petrography are available in Beaton et al. (2008a).

4.1.1 Organic Geochemistry as an Indicator of Shale Gas Potential

Geological evidence overwhelmingly indicates that the majority of economic hydrocarbon (oil and gas) deposits originated from the breakdown of organic matter, such as marine and lacustrine phytoplankton and terrestrial vegetation. Marine settings are favourable for the accumulation of large amounts of sediments and organic matter. Some terrestrial environments are also well suited to preserving organic matter (peat and coal). Preserved organic matter can be subsequently incorporated into lithified sediment

and undergo thermal maturation with burial. Maturation causes physical and chemical changes in the organic matter, generating and releasing hydrocarbons, the nature of which is determined by the original organic matter. Furthermore, microbial activity can contribute significant amounts of gas (biogenic methane) in sediments.

Hydrogen is the key element in determining petroleum potential of sediment. Marine-type organic material (plankton, algae) has high ratios of hydrogen to carbon, whereas terrestrial material (trees, vegetation, etc) has higher oxygen to carbon ratios. When these compounds break down, they are likely to produce (initially) more oil and gas, respectively.

Overwhelmingly, the shale samples contain marine plankton and algae as the dominant organic component. Mature samples show evidence of thermal breakdown of organic matter, suggesting that hydrocarbons have been generated by the samples. The presence of marine organic matter and degraded organic matter suggests that the samples have hydrocarbon potential.

These geological processes may result in shale that contains small amounts of organic matter derived from different sources. The subsequent processes of deposition, decomposition and burial, accompanied by increasing heat and pressure, cause the organic matter to undergo physical and geochemical changes that include a progressive loss of oxygen and a generation of hydrocarbon from the partial breakdown of the remaining organic material, or kerogen. This promotes a large reduction in the H/C ratio as the kerogen becomes increasingly aromatic, and the resultant hydrocarbon is released. This stage of hydrocarbon generation reflects oil generation within the 'oil window' and, with increasing depth of burial and temperature, the processes continue, subsequently causing further breakdown of the kerogen and the production of gas. Furthermore, previously generated oils may now be broken down into gas. The physical and geochemical changes experienced by organic matter as it goes through deposition, preservation, burial and breakdown are referred to as 'maturation'. The degree of maturation indicates whether organic matter has passed through the oil or gas window, and is used as an exploration tool. The geochemistry of organic matter, including the relative amounts of H and O associated with organic matter in the rocks, can also be used to indicate the original type of organic matter in the rock and the respective hydrocarbon potential, as different organic materials have different hydrocarbon potentials.

A common method for evaluating the hydrocarbon potential of a source rock is the Rock Eval™ analysis. This method involves combusting a small amount of sample (100 mg) in a controlled environment and analyzing the produced gas. The sample is heated to 300°C in an oxygen-purged environment. This temperature volatilizes the in-place hydrocarbon, known as the 'S1' hydrocarbon. The temperature of the Rock Eval apparatus is then slowly increased to a final temperature of approximately 600°C. During this time, the remaining kerogen starts to break down, resulting in generation and release of hydrocarbons. This is referred to as the 'S2' hydrocarbon and represents the total remaining hydrocarbon potential of the source rock. The total source-rock potential is determined as the sum of S1 and S2. The temperature at which the maximum amount of S2 hydrocarbon is generated is referred to as T_{max} (maximum temperature), which has been correlated with other maturation parameters (such as vitrinite reflectance) and is considered a good maturation indicator. A T_{max} between 435°C and 450°C indicates that the sample is in the oil window; temperatures below or above these represent immature or gas prone rocks, respectively.

The Rock Eval process also records evolved CO₂ derived from the volatilization of hydrocarbons throughout the analysis to determine the oxygen content of the organic matter. Subsequently, the sample is combusted in the presence of air at 600°C. Evolved CO₂ is determined and added to the volatilized hydrocarbon CO₂ to determine total organic carbon (carbonate carbon does not break down at this temperature, but siderite, if present, may partially break down).

Key indicators of shale gas potential include the amount of organic matter within a potential source rock, the level of maturation or ‘cooking’ of the organic matter and the type of organic matter.

A greater total amount of organic matter will increase the hydrocarbon potential of a source rock. Total organic matter is indicated by the total organic carbon (TOC) value. Shale with TOC values as low as 0.5–1 wt. %, and carbonate rocks with as little as 0.5 wt. % TOC, can act as a source rock. Source rocks from Canada range from 1.5 to 25% TOC, with most in the range 3–7%.

Organic matter derived from marine sediments can include plankton, marine algae, bacteria and lipid-rich components of higher plants (spores, waxes, etc). These materials are hydrogen rich (hydrogen/carbon ratios of 1.4–1.6, hydrogen index >700) and are oil prone. Organic matter derived from plant material is hydrogen poor (H/C ratio 1.3–1.5) and is more gas prone.

The PI (production index) is calculated using $S1/(S1+S2)$ and indicates the amount of hydrocarbon that has been produced relative to the total amount that can be produced.

4.1.2 Results of the Analysis

This study tested a wide variety of samples, including outcrop and core, to obtain an overview of lateral and vertical compositional characteristics of shale-bearing intervals from the Colorado strata. Within each section or core sample, lithological variations were sampled to include not only black shale but also grey shale, siltstone and some sandstone. Samples were analyzed using Rock Eval 6 pyrolysis to determine hydrocarbon potential. Isotherms are available in Beaton et al. (2008a).

The 1WS had TOC values ranging from 0.6 to 6.8 wt.% . The samples were typically dark grey shale, with TOC values typically in the 1.3–3 wt. % range. These TOC values suggest a moderate source-rock potential. Maturation based on T_{max} suggests that the 1WS, where sampled, is in the early stage of the oil window to slightly immature, based on T_{max} values ranging from 415°C to 430°C.

The 2WS contained more black shale than the 1WS, and this is reflected by TOC values in the typical range 2–5 wt. %. The grey shale sampled had lower TOC values (1.5–2 wt. %). It is noteworthy that some black shale samples contained in the order of 5–8 wt. % TOC. The T_{max} values are typically in the 430°C–450°C range, indicating that the samples are within the upper limits of the oil window and therefore may have produced early gas. These results suggest very favourable gas potential for the 2WS.

The Belle Fourche formation (*see* Figure 1) had TOC and T_{max} values similar to those of the 2WS, and therefore a similar gas potential is expected.

The Blackstone and Cardium formations and the Cardium-equivalent shale had variable TOC, but contents were typically low (1–2 wt. %) for most of these dark grey mudstones and siltstones; however, isolated black shale intervals did have TOC as high as 6 wt. %. The T_{max} values ranged from 410°C to 460°C, suggesting that the samples were scattered throughout the oil window, depending on depth of burial. Overall low TOC and T_{max} values indicate limited shale gas potential for the samples analyzed unless associated with intervals that have an abundance of siltstone and sandstone laminae and therefore a relatively high free gas content.

The Fish Scales Zone of the Colorado Group showed elevated TOC values, typically 2–3.5 wt. %. The T_{max} values were typically 425°C –440°C, indicating that the Fish Scales Zone is in the upper part of the oil window and may have seen initial gas production; therefore, the shale gas potential of this member is considered favourable.

Samples from the Medicine Hat Sandstone and Milk River Formation returned low TOC and T_{max} values (<2.5 wt. % and <425°C, respectively). Shaftesbury Formation shale samples returned low TOC (1.1

wt. %) but higher T_{\max} (445°C). Shale gas potential of the Shaftesbury still needs further examination owing to limited sampling. Westgate shale had a similar low TOC value (1.5 wt. %.), with T_{\max} values in the 430°C–400°C range, suggesting low to moderate shale gas generation potential in the samples analyzed unless associated with a high abundance of siltstone and sandstone laminae and a high free gas content.

4.1.3 Shale Gas Capacity as Inferred from Selected Alberta Shale Samples

4.1.3.1 Overview

Gas content results for shale in Alberta are very limited and often not clearly identified as to the producing horizon, or whether shale and associated silt and sand are being coproduced. An alternative approach to determining gas content in shale is to evaluate gas-holding capacity and draw inferences on content potential. Gas capacity can be determined using adsorption isotherms. In this procedure, a sample is crushed and subsequently equilibrated to maximum adsorptive capacity with the gas of choice (in this case methane). The sample is allowed to slowly adsorb as much gas as possible at a given temperature, over a range of pressures, to mimic reservoir conditions. The experimental data from the adsorption is modelled using Langmuir equations relating equilibrium pressure and volume of gas adsorbed experimentally to anticipated reservoir pressure. The results allow a prediction of the maximum gas capacity of the sample at reservoir conditions.

Organic matter has a great capacity to adsorb gas owing to a relatively large surface area derived from its microporous nature, not unlike that of activated charcoal. Gas can be held on the surface of organic matter by physical or chemical forces. Gas capacity will therefore be related to the amount of organic matter present (as indicated by TOC). Furthermore, gas adsorption capacity increases with increasing maturity of the organic matter, but capacity decreases with increasing reservoir temperature. Adsorption capacity is dictated primarily by the large surface area of organic matter; illite and smectite also have a high surface area relative to kaolinite and quartz, and can add to the adsorption capacity of shale.

As is the case with coal, organic matter tends to generate more gas than it can retain via adsorption; therefore, the maximum holding capacity of the shale is a fair proxy for anticipated gas in the sample (if the sample is assumed to be at saturation). Furthermore, it has been demonstrated that pore spaces and fractures in gas shale typically contain free gas, which is gas derived, and perhaps subsequently expelled, from the organic matter. This gas is thought to represent anywhere from 25% to 50% of gas produced in a shale gas well, so the maximum gas content of a shale determined by an adsorption isotherm analysis may under-represent the total gas available for production in a shale play.

4.1.3.2 Results

The results of adsorption analysis are summarized in Table 4. Maximum gas capacity is within the range 0.2–1.0 cubic centimetres of gas/gram (cc/g) that is typical of shale; however, the shallow samples from the Colorado shale in the Birch Mountains have somewhat higher capacities, in the range 1.1–1.8 cc/g. These higher values may indicate increased potential gas capacity for the shallower samples in northwestern Alberta.

Variations in mineralogy, total organic carbon, lithology, thickness, depth and maturation within a shale formation prevent extrapolation of a few maximum gas capacity estimates from approximately 20 wells and outcrop to a basin-wide, regional scale. Here, calculations of gas capacity are presented for the individual wells and extrapolated to a maximum gas content on a Bcf/square mile basis.

Using typical shale thickness, as observed in the sample wells, the gas capacity was determined using Langmuir isotherm analysis. Average shale density of 2.5 g/cc was used in the calculations. Two sets of results are presented, the maximum capacity and the maximum capacity plus 25% of capacity to account

Table 4. Gas capacity data (as-received basis).

Sample	Depth (m) ¹	Analysis Temperature (°C)	Average Thickness of Shale (m)	Moisture (wt. %)	Langmuir Pressure (MPa)	Langmuir Volume (standard cubic cm/g)	Density (g/cc)	Geological Unit	T _{max} (°C)	TOC (%)	Calculated Reservoir Pressure (MPa)	Calculated Gas Volume at Reservoir Pressure (cc/g)	Gas Capacity (Bcf/sq. mi.)	
													Max. Capacity on Organic Matter	Max. Capacity + 25% (for Free Gas)
Core samples														
8524/25	548.9	25	300	2.3	5.81	2.3	2.5	1WS	412	5.18	5.37922	1.1	75.8	94.8
8606/07	2319.7	50	10	0.51	9.09	0.6	2.5	FSZ	441	1.75	22.73306	0.4	1.0	1.2
8615/16	2319.1	60	150	0.74	7.32	0.8	2.5	blackstone	453	1.73	22.72718	0.6	20.8	25.9
8618/19	2485.0	60	50	0.82	6.96	1.4	2.5	belle f	455	3.2	24.353	1.1	12.4	15.6
8650/51	1816.6	50	50	0.75	7.71	1.3	2.5	2WS	449	2.92	17.80268	0.9	10.4	13.0
Outcrop samples														
7257	2100	33	100	3.32	6.29	0.68	2.615	blackstone	427	1.4	20.58	0.5	12.5	15.6
7286	2100	38	100	1.29	9.78	0.23	2.589	blackstone	513	0.68	20.58	0.2	3.7	4.6
7318	500	33	10	9.83	6.84	2.64	2.116	bmtns asp	411	11.9	4.9	1.1	2.1	2.7
7327	500	33	10	4.3	15.86	6.47	2.559	bmtns asp	426	1.31	4.9	1.5	3.6	4.5
7338	500	33	50	3.72	8.44	3.15	2.463	bmtns grey	422	2.14	4.9	1.2	13.0	16.3
7343	500	33	50	4.8	10.93	6.02	2.463	bmtns grey	420	1.82	4.9	1.9	21.0	26.2
7251	500	33	50	4.57	3.28	1.01	2.46	bmtns grey	447	0.83	4.9	0.6	6.8	8.5
Core samples				Outcrop samples										
1WS	First White Specks (00/06-23-043-11W4/00)			blackstone	7257: silty grey-brown shale; Blackstone at Cadomin; sample above Fish Scales Sandstone									
FSZ	Fish Scales Zone (00/06-17-030-03W5/00)			blackstone	7286: silty grey-brown shale; Blackstone at Cadomin; sample at top of Blackstone below the Cardium sandstone									
blackstone	Blackstone (00/16-29-054-21W5/00)			bmtns asp	7318: black to dark brown-grey shale; Asphalt Creek section, Birch Mountains; Belle Fourche/Second White Specks equivalent									
belle f	Belle Fourche (00/16-29-054-21W5/00)			bmtns asp	7327: reddish brown, clayey mudstone; Asphalt Creek section, Birch Mountains; Belle Fourche/Second White Specks equivalent									
2WS	Second White Specks (00/07-18-045-06W5/00)			bmtns grey	7338: grey-brown slightly fissile shaly mudstone; Greystone Creek section, Birch Mountains; Fish Scales Zone equivalent									
				bmtns grey	7343: medium brown-grey, very slightly fissile, silty mudstone; Greystone Creek section, Birch Mountains; Westgate equivalent									
				bmtns grey	7251: black to grey sandy mudstone; Greystone Creek section, Birch Mountains; Joli Fou equivalent									

¹ for core samples, depth in the core; for outcrop samples, projected average depth below surface

Other abbreviations: scc, standard cubic centimetres T_{max}, temperature at which the maximum amount of S2 hydrocarbon is generated; TOC, total organic carbon

for potential free gas in the system. The results assume saturation to the capacity of the shale matrix. These results are very preliminary and additional analyses are needed to validate the predictions of gas capacity.

Maximum gas capacity (cc/g shale) is greatest for the Colorado Group samples tested from the Birch Mountains at Greystone Creek (1.9 cc/g) and Asphalt Creek (1.5 cc/g), although there are also samples from these locations that have a lower gas capacity. Shale samples from the 1WS and the Belle Fourche members of the Colorado Group also have high gas capacities, at 1.1 cc/g in each case. Samples from the 2WS, Blackstone and Fish Scales zones of the Colorado have lower capacity, in the range 0.2–0.9 cc/g.

Total gas capacity (Bcf/sq. mi.) is determined by the thickness of the shale package as well as the unit gas capacity of the shale package. Table 4 indicates average thickness for the given unit across Alberta. Although shale gas capacity is rather low, the thickness of shale units can make a play feasible. This is highlighted by the high total gas capacity within the 300 m thick 1WS of the Colorado Group. Shale units have varying TOC values within a given formation, which is reflected in the gas capacity of the sample.

The 1WS has the greatest total gas capacity, resulting from a thick cumulative shale package (300 m) and high gas capacity per unit, in the order of 75 Bcf/sq. mi. (potentially up to 94 Bcf/sq. mi. assuming 25% additional free gas).

It should be noted that the thicknesses indicated in Table 4 and used for the calculations are averaged. Across Alberta, the thickness of shale packages, as well as total organic content (TOC) and maturation (T_{max}), are extremely variable; therefore, it is important to obtain a large number of data points to capture the variability before making gas capacity estimates and inferring resource potential.

4.2 X-Ray Diffraction, Petrographic Analysis and Electron Microscope Results

Four techniques were used to determine mineralogy and microfabric in the samples: x-ray diffraction (XRD), scanning electron microscopy (SEM), energy dispersive x-ray analysis (EDX) and petrographic analysis (thin section). This section briefly summarizes some key observations from three of our methods of analysis. The XRD data are available in Pawlowicz et al. (2008a).

4.2.1 XRD Observations of the Colorado Group

The top two minerals in nearly all the subsurface Colorado Group samples are quartz (19–45 wt. %) and muscovite (9–26 wt. %), with the clay minerals illite, clinocllore, kaolinite or montmorillonite (combined clay mineralogy ranging from 9 to 29 wt. %) as the third major mineral, depending on the sample. However, samples from the 2WS often show calcite (6–31 wt. %) as the third major component. Pyrite is the dominant minor component, ranging from 5 to 8 wt. % in all samples except the Cardium-equivalent zone, which has ~1 wt. %.

Colorado Group outcrop samples were taken from two sites (Birch Mountains in northeastern Alberta and Cadomin in the southern Cordilleran mountains). The 2WS, Fish Scales Zone and Westgate mineralogy were analyzed from the Birch Mountain site, while the Blackstone Formation was analyzed from the Cadomin site. Mineralogy of the 2WS shows that all samples contain quartz (6–45 wt. %), kaolinite (1–17 wt. %), albite (2–12 wt. %), and orthoclase (2–12 wt. %), with gypsum as a minor component. Other minerals present are montmorillonite (0–35 wt. %) and illite (0–21 wt. %). Fish Scales Zone samples contain a high percentage of montmorillonite or random mixed-layered clays (30–68 wt. %) and quartz (16–36 wt. %), with minor albite (2–7 wt. %). The top three minerals in the Blackstone shale are quartz (26–83 wt. %), illite (0–34 wt. %) and kaolinite (1–18 wt. %). Minor minerals include albite (2–13 wt. %) and orthoclase (1–6 wt. %). Westgate shale samples contain only three notable minerals: montmorillonite (37–64 wt. %), quartz (16–43 wt. %) and albite (2–12 wt. %). In general, clay minerals are more prevalent

in outcrop samples than equivalent subsurface samples, likely due to muscovite alteration to clay minerals.

4.2.2 Thin Section Description of the Colorado Group

Twenty-five thin sections were prepared from Colorado Group core. In this report, only two thin sections will be described. All other thin-section photos and descriptions will be released in a separate ERCB/AGS open file report and will be available on the AGS web site (<http://www.ags.gov.ab.ca>) when complete.

Slide preparation included cutting the samples with a saw. Most of the samples were cut using water as a lubricant, which caused various amounts of swelling in the samples (ranging from no swelling to complete destruction of the sample). To counter this effect, a small amount of kerosene was added to the lubricant. In addition, all sections were polished using a small amount of acetone. The preparation process may cause fracturing and staining of the samples. All sample depths are recorded as core depth.

The thin sections were analyzed for structure and mineralogy. Although microporosity is very important in shale samples where gas may be adsorbed or housed, the average grain size of our samples does not allow us to visually estimate porosity. In conventional reservoirs, identification of epoxy in a thin section generally indicates porosity. However, the epoxy is not able to penetrate micropores, so the absence of epoxy-filled cavities in our thin sections does not mean the absence of porosity.

4.2.2.1 Sample 8552 – Cardium-Equivalent Zone, 100/09-16-049-08W4/00

Sample 8552 was taken at a core depth of 462.5 m from well 100/09-16-049-08W4/00. It consists of moderately sorted, silt-sized grains in a clay matrix. Lithology ranges from silty mudstone to muddy siltstone (grain supported to matrix supported). Silt grains are angular to subangular and show no sign of preferred orientation. The grains are composed mainly of quartz with some feldspar, rock fragments and organic detritus.

Magnification 2.5x: At this magnification (Figure 15a), microfractures can be seen throughout the sample, but some of the fractures were created or enhanced due to core retrieval and sample preparation. With the insertion of the quartz plate at this magnification (Figure 15a), there appears to be no apparent crystallographic orientation within the clay matrix or the larger grains.

Magnification 20.0x: At higher magnifications (Figure 15b), the microfractures are observed to be cutting through grains (Figure 15b, left photo), which would indicate that these fractures are natural unless the grain fractures are pre-existing; core unloading may have enhanced the length and opened existing fractures. The crystallographic orientation of the silt grains and clay matrix is random (indicated by the nonuniform birefringence of grains [Figure 15a, right photo] and matrix [Figure 15c] in the presence of a quartz plate). This random morphology of grains and clay may reflect a somewhat chaotic microfabric that could be a key parameter for obtaining sufficient microporosity and permeability, as discussed in the SEM summary and in Section 4.2.3.

4.2.2.2 Sample 8566 – First White Speckled Shale

Sample 8566, taken at a core depth of 417.25 m from well 100/12-32-054-16W4/00, is composed mainly of clay-sized grains with subrounded, moderately sorted, silt- and sand-sized grains. The silt- and sand-sized grains are randomly distributed throughout the sample (Figure 16a). There is a weak fabric defined by clay and elongated organic debris (organic material or detritus appears as dark or black in Figure 16b and c) and is oriented parallel to bedding. The larger grains are composed mostly of quartz with some feldspar, rock fragments and fossil shell or bone debris.

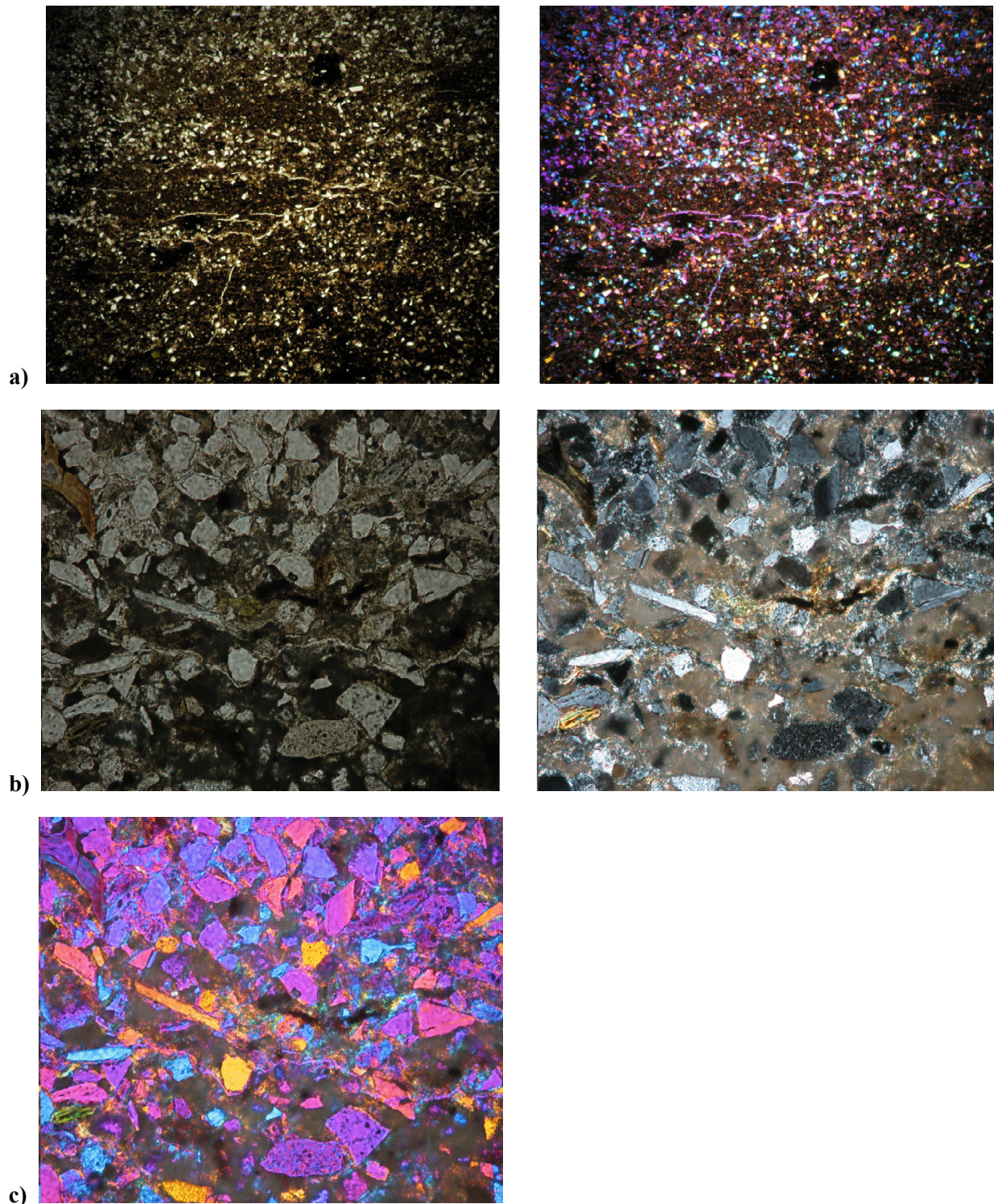


Figure 15. a) Left photo: sample 8552, Cardium-equivalent zone, Tx_8552_07 (plane-polarized light, mag. 2.5x). Right photo: sample 8522, Cardium-equivalent zone, Tx_8552_09 (quartz plate inserted, mag. 2.5x). b) Left photo: sample 8552, Cardium-equivalent zone, Tx_8552_10 (plane-polarized light, mag. 20.0x). Right photo: sample 8522, Cardium-equivalent zone, Tx_8552_11 (cross-polarized light, mag: 20.0x). c) Sample 8522, Cardium-equivalent zone, Tx_8552_12 (quartz plate inserted, mag. 20.0x).

Magnification 2.5×: Microfractures are present parallel to bedding (Figure 16a) but are likely due to core retrieval and sample preparation, as the hand sample showed signs of swelling after preparation. Under crossed polars (Figure 16a, right photo), crystallographic alignment of the clays is indicated by the uniform birefringence of clay-sized grains, as seen in Figure 16a (left photo). This would suggest secondary recrystallization of the clay minerals. The sand- and silt-sized grains show no preferred crystallographic orientation.

Magnification 20.0×: At higher magnification (Figure 16b, c), organic detritus and clay-sized particles maintain a preferred orientation that is parallel to bedding (i.e., northwest-southeast in the photos). Some of the more rounded dark or opaque matter (Figure 16b) could be framboidal pyrite (based on morphology) and may preferentially form within organic detritus as secondary mineralization. With the quartz plate inserted (Figure 16c), distinct clay stringers can be seen. These stringers are formed from recrystallization of clay minerals into flat, laterally extensive sheets in these thin sections.

4.2.3 SEM/ESEM Descriptions of the Colorado Group

Samples were observed using the scanning electron microscope (SEM) and the environmental scanning electron microscope (ESEM) to examine the texture, microfabric and mineralogy of the clay and other constituent minerals. The high magnification capability of the electron microscope allows for examination of grains down to the nanometre scale. All sample depths are recorded as core depth. Just one sample is discussed here. The remainder of the SEM descriptions are presented in Pawlowicz et al. (2008a).

4.2.3.1 Sample 8542 – Cardium-Equivalent Zone

Sample 8542 (Figure 17) was taken at a core depth of 410.0 m from well 100/06-36-49-05W4/00. The sample is dominantly clay minerals with silt-sized grains distributed both randomly in the matrix and as laterally continuous and discontinuous laminae, as seen in the right-hand photo. The clay layers are somewhat randomly orientated, as indicated by the arrows that follow along the clay sheets. The clay sheets compact around grains, as indicated by the rounded nature of the top of the clay sheets. The large pore in the middle right of the left image may be due to a plucked silt grain, around which clay sheets are draping.

Porosity in both images is viewed as dark areas between clay sheets and ranges from less than 1 μm to perhaps 5 μm (excluding, in the left image, the site of the plucked grain). The lower end of the pore diameter scale (up to about 5 μm) is associated with porosity between clay sheets or clay domains. The image on the right side of Figure 17 identifies a lamina, approximately 150–200 μm thick (0.15–0.2 mm), of poorly cemented silt grains with pore diameters up to 50 μm , representing the upper end of the porosity scale in these images. Ultra-thin layers cannot be ‘seen’ on well logs (and are very difficult to view with the naked eye in core), yet the presence of these laminations in shale will contribute a small amount to free gas storage and production and, importantly, act as a conduit for gas diffusion from the shale matrix to the well bore. The long axes of some of the silt grains are up to 50–60 μm , which corresponds to coarse silt.

The grains are moderately well sorted, subangular to subrounded with poor sphericity, and appear to be coated with secondary cement (quartz overgrowth and clay). Energy-dispersive x-ray mineralogical analysis indicates that the clay mineralogy is a mixture of smectite/illite and a small amount of authigenic kaolinite. The silt grains are composed primarily of quartz with some sodium feldspar. There is also secondary mineralization of pyrite in the form of framboids (ball-shaped clusters of crystals).

Sample 8518 (Figure 18) was taken at a core depth of 407.5 m from well 102/03-14-018-11W4. The sample is composed of clay-sized material with silt-sized grains randomly distributed throughout the sample. The clay minerals have a sheet-like morphology, as seen in the left-hand photo (10 μm scale),

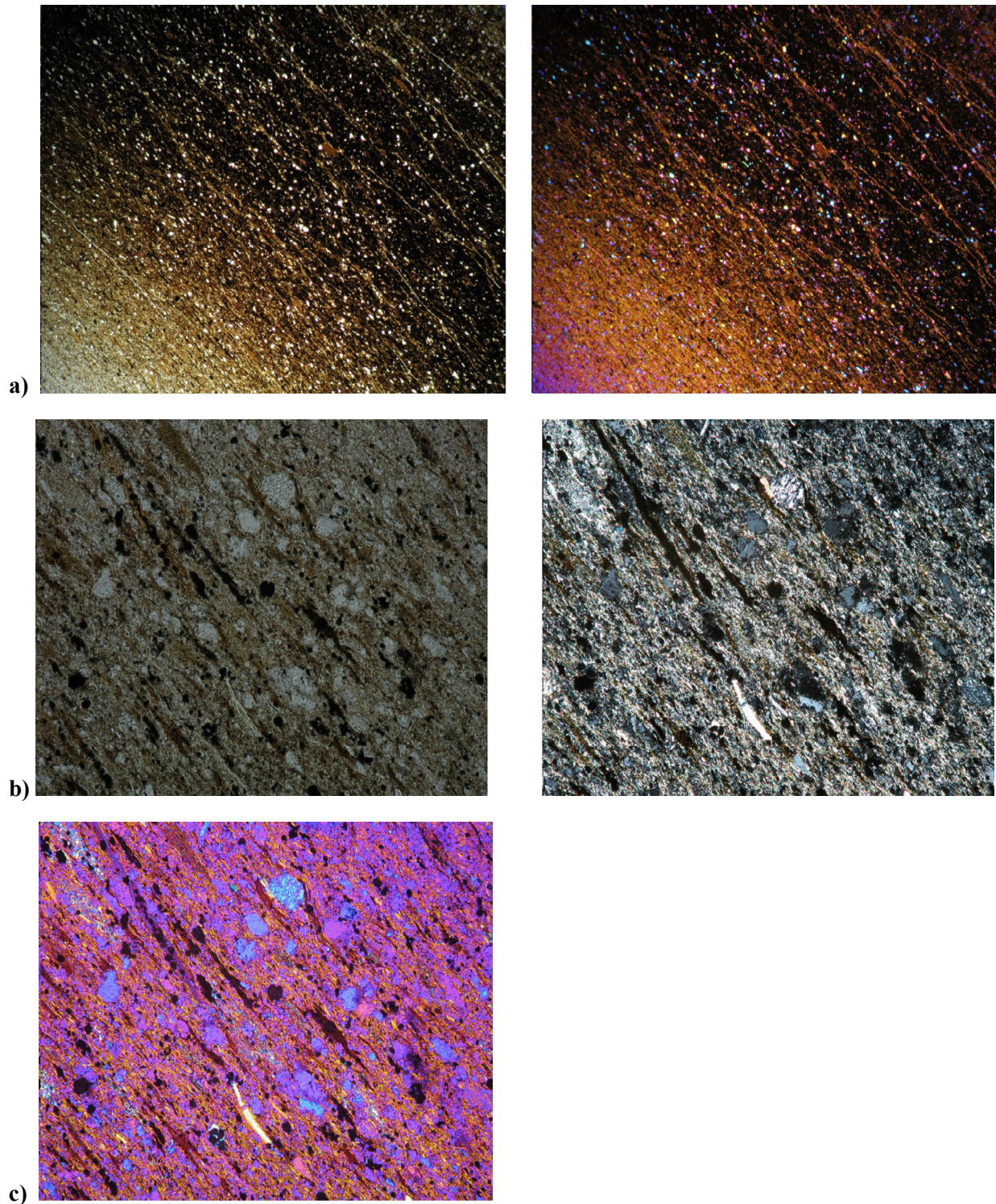


Figure 16. a) Left photo: sample 8566, First White Speckled Shale, Tx_8566_01 (plane-polarized light, mag. 2.5x). Right photo: sample 8566, First White Speckled Shale, Tx_8566_03 (quartz plate inserted). b) Left photo: sample 8566, First White Speckled Shale, Tx_8566_07 (plane-polarized light, mag. 20.0x). Right photo: sample 8566, First White Speckled Shale, Tx_8566_08 (cross-polarized light, mag. 20.0x). c) Sample 8566, First White Speckled Shale, Tx_8566_09 (quartz plate inserted, mag. 20.0x).

although the distribution of clay sheets appears to be disrupted near the bottom right (i.e., near the 5 μm diameter plucked grain?). Some of the rolling morphology of the clay sheets may be due to draping over silt grains. There is porosity between the sheets, identified by the dark areas in the image, with the largest pore ranging up to 5 μm in diameter. The tops of the sheets (e.g., bottom left) exhibit little porosity at this scale of observation, so vertical fluid migration may be limited in favour of lateral migration. The sample appears to exhibit a lower permeability relative to the microfabric of sample 8542. The image on the right (1 μm scale) is a close-up of quartz overgrowth that has cemented porous areas between silty(?) clay sheets, thus occluding much of the porosity. Nonetheless, there is still some porosity (dark areas) seen in the image. Energy-dispersive x-ray mineralogical analysis indicates that smectite is the dominant clay mineral, and that the silt-sized grains are mostly quartz with some potassium feldspar and aluminum silicate (muscovite?).

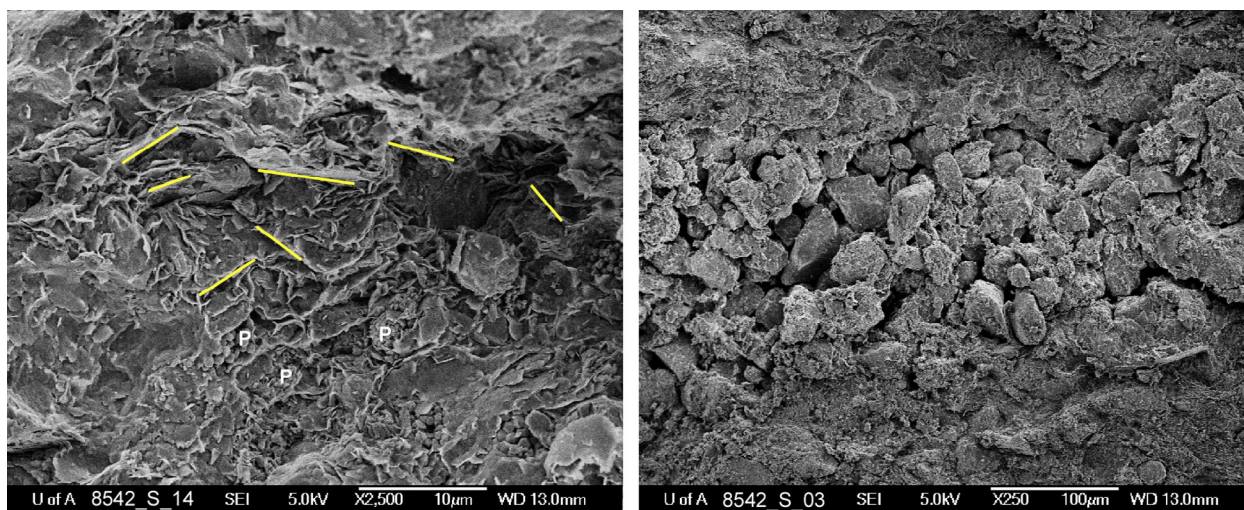


Figure 17. Left photo: sample 8542, Cardium-equivalent zone, SEM image 8542_S_14; yellow lines identify the trend of the horizontal plane of a few clay sheets; white letter 'P' in left photo identifies the presence of pyrite. Right photo: Sample 8518, First White Speckled Shale, SEM image 8542_S_03.

4.3 Permeametry Results

The permeametry results are very encouraging and, in fact, some of the numbers are quite spectacular. The data are summarized in Table 5 and, along with the raw data, are available in Pawlowicz et al. (2008a). However, all of the single-phase measurements were done at ambient conditions and no corrections were applied, so results at reservoir conditions may differ considerably (Miller et al., 2007). Samples were carefully chosen to exclude fractured sediment, although microfractures may still be present. Bustin (2007) suggested that the minimum permeability in a shale gas reservoir should exceed 0.00001 mD ($= 10^{-8}$ darcies) and, in fact, all the results exceed this value. These results are also consistent with the quoted permeability from producing shale gas reservoirs (e.g., Davies and Vessell, 2002 for Ohio Shale and Lewis Shale; *see also* Bustin, 2007) and, from that point of view, are very encouraging.

The Colorado values range from a low of ~ 0.007 mD to a high value of 6.94 mD. Samples were taken in shale from the 1WS, 2WS, Fish Scales Zone, Belle Fourche Formation and Cardium-equivalent zone. A sample was also taken in the lower Milk River Formation, immediately above the Colorado Group.

Shale is heterogeneous on the micro scale, so variations in vertical and horizontal permeability are expected. Furthermore, it is difficult to detect microfractures in a sample that may form after the shale is brought to surface (i.e., unloading fractures), although natural microfractures that have developed in the

subsurface can open up when the rock is brought to the surface (*see* thin section Figures 15 and 16 in Section 4.2.2). Unloading fractures, if present, may considerably enhance permeability results, thus making them spurious.

The high values in the Colorado Group are similar to those seen in tight-sand or low-porosity conventional plays, so the values are quite impressive. According to Davies and Vessel (2002), high-permeability zones in shale may result from chaotic microfabric and are a preferred completion interval. High microfabric permeability is also associated with higher recovery factors (all other variables being equal) and hence more economical reserves (Bustin et al., 2008). Thus, shale that is thinner than an arbitrary cut-off (say 50 m) but with high permeability may be a favourable completion target.

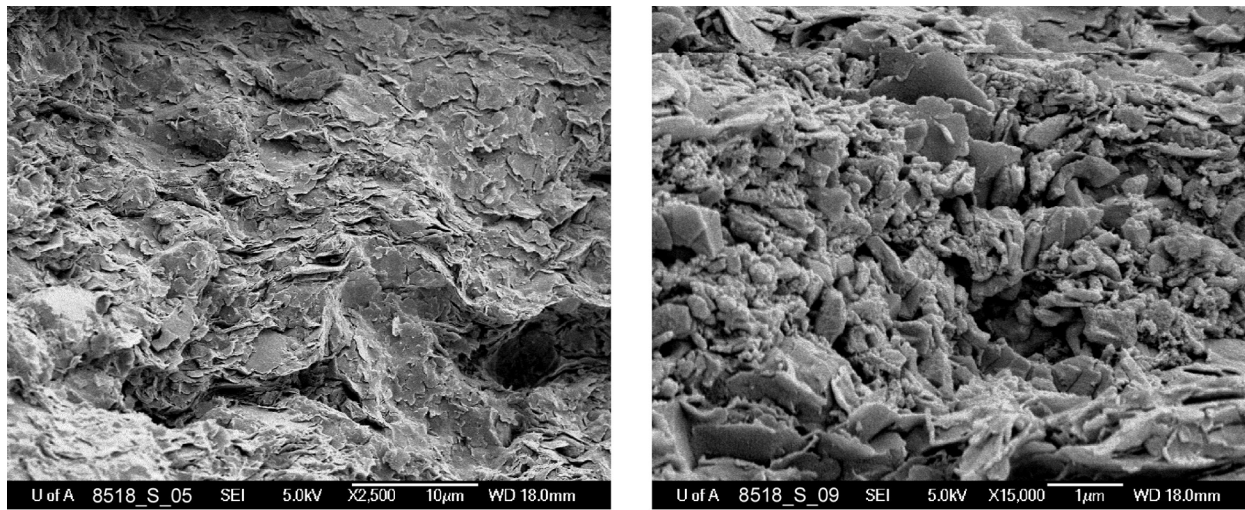


Figure 18. Left photo: sample 8518, First White Speckled Shale, SEM image 8518_S_05. Right photo: sample 8518, First White Speckled Shale, SEM image 8518_S_09.

Any discussion of the minipermeability data must be tempered with the realization that the numbers quoted in Table 5 were determined from small pieces of shale (no less than 1 cm³) and therefore do not necessarily represent regional permeability trends. What is not determined here is both the vertical and lateral extent of the enhanced shale permeability zones and the silt laminae, provided the values are still ‘enhanced’ at reservoir conditions. These high permeability zones appear to be thin enough to be hidden on well logs and would appear to be below minimum log resolution. Nevertheless, there may be more than one thin, highly permeable zone in a 50 m shale package, for example; therefore, identifying and determining the number and lateral extent of these zones may be important to resource assessment.

4.4 Mercury Porosimetry Results

A brief analysis of two of the samples is presented here; a complete tabulation of the data is available in Pawlowicz et al. (2008a). Here, mercury porosimetry is used to determine the macropore throat diameter (>50 nm or 0.05 µm) of a sample and a large portion of the mesopore throat diameter range (2–50 nm or 0.002–0.05 µm), but cannot determine micropore throat diameters (<2 nm; Bustin 2007; www.iupac.org). For reference, a molecule of gas is about 0.38 nm in diameter, which is an order of magnitude below the capability of mercury porosimetry (~2–3 nm or 0.02–0.03 µm). Figures 19 and 20 are from upper and lower Colorado Group samples, respectively. We have included all the data points in these graphs, even though a few data points on each side of the graph are artifacts of the testing procedure and may not identify the diameter of real pore throats.

Table 5. Summary of permeametry results.

AGS Sample No.	Core Depth (m)	Unique Well Identifier	Formation	N	Average Permeability (mD) ¹	Average permeability (mD)
8027	701.6–702.15	102/13-03-020-11W4/00	2WSPKS/Belle Fourche	4	0.0544	
8031	2017.5	100/13-20-051-14W5/00	2WSPKS	5	0.0243667	
8596	805.1	100/16-21-042-21W4/00	Milk River	4	2.75	
8669	2589.1	100/04-13-057-02W6/00	Cardium-equivalent one	5	0.023467	
7292	2120	100/08-24-014-28W4/00	Fish Scales	6	0.013303 (sand)	0.002475 (mud)
8516	630	100/14-18-019-18W4/00	1WSPKS	4	6.94	
8634	1740.2	100/15-27-060-20W5/00	2WSPKS	4	0.007535	
8656	1836.1	100/07-19-045-06W5/00	2WSPKS	5	0.159	

¹ Average permeability (K) for each sample is calculated by removing the high and low recorded values, then averaging the remaining values. Raw permeametry data is available upon request and will be published on the AGS website.

The upper Colorado Group sample (Figure 19) is from the informally named ‘Cardium-equivalent zone’ that is producing in eastern Alberta; in fact, this particular well is producing gas from perforations apparently located immediately above and below the sample interval (perforation at 451.5–453.5 m and 460.0–461.0 m log depth; sample interval 457.0 m core depth). The lithology of the sample is laminated silty, dark brown shale with siltstone laminations. The graph reveals a multimodal distribution with a peak at about 0.02 μm (20 nm), perhaps representing pores between single-domain clay sheets or multidomain clay minerals (*see* Section 4.2.3.1). A second peak is at about 0.4 μm , a third peak is at about 10 μm , and lastly, a peak at about 95 μm is likely a surface pore and an artifact of the testing procedure. The second peak may also be associated with clay minerals, while the third peak may result from porosity associated with silt layers (*see* SEM discussion in Section 4.2.3.1) or perhaps is a function of chaotic multidomain clay particles, in the manner of Davies et al. (1991) and Davies and Vessell (2002). The presence of large pores is quite significant and suggests a larger gas storage capacity for the sample than is normally associated with shale, in addition to enhancing permeability. Questions we now ask are “are the larger pores associated with silt layers, as seen in Section 4.2.3.1?”; “are the silt layers of limited areal extent or more areally extensive?”; and “how many of these layers are present, and how can we detect these zones on well logs?”

Figure 20 displays a bimodal distribution of the Westgate shale sample. The large peak at 100 μm is an artifact of testing. The peak at approximately 0.02 μm is likely associated with clay minerals, while the 10 μm peak may be associated with silt grains.

4.5 Discussion of Analytical Results

It is clear from this short analysis of the data and cross-sections that the Colorado Group may contain many of the different types of shale gas plays. Classic organic-rich black shale can be found in the Fish Scales Zone and some intervals in the 2WS, both of which are present in the foothills (Barnett-type play) and shallow areas of eastern Alberta (Appalachian-type play). Intervals in the 1WS, Blackstone, Shaftsbury, Joli Fou and Westgate that exhibit ‘background’ shale characteristics are more amenable to a Lewis Shale-type play, where the lithological target is laminated siltstone and organic-rich shale. An Antrim-like play could be found in north-central Alberta near the erosional edge of the 1WS and 2WS, where both of these formations underlie glacial till, although this type of play requires a hydrogeological recharge zone and microbes to generate biogenic gas (Rokosh and Beaton, 2006). We urge caution in our initial analysis because the results are preliminary and in no way suggest that there are reserves in these

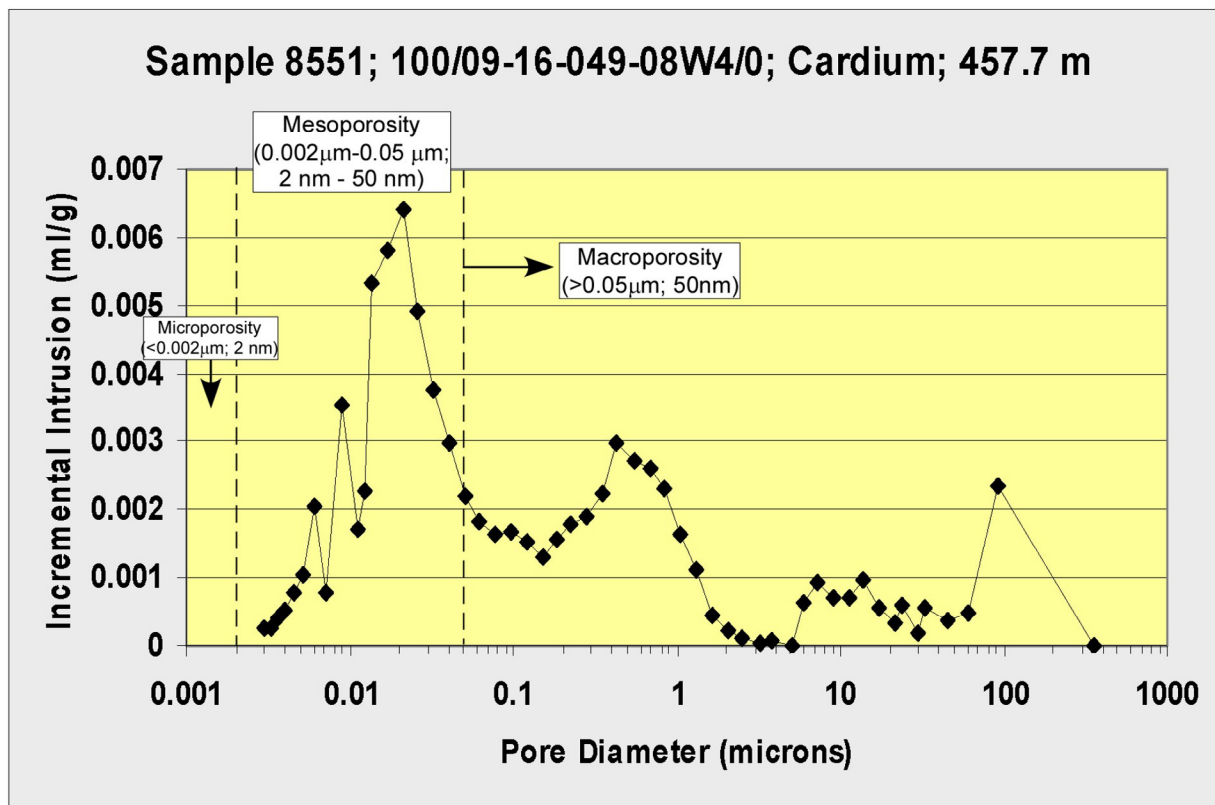


Figure 19. Mercury porosimetry graph, sample 8551, Cardium-equivalent zone, well 100/09-16-49-08W4, core depth 457 m. The smallest pore diameter measurable using mercury porosimetry is about 3 nm (Ross and Bustin 2007).

areas; we are simply suggesting that the *potential* exists for these types of plays in the Colorado Group of Alberta. Also, be aware that we have done few analyses in northern Alberta (i.e., north of Twp. 80), where few shale cores exist and the stratigraphy has yet to be correlated with that in southern Alberta.

The sedimentological characteristics of the shales are very encouraging. Clearly, permeability exists in many of the shale horizons and meets or exceeds the estimations from shale gas plays found in the United States. A significant determination in this section is the presence of microfractures that cut across grains and are more likely to be formed in the subsurface rather than during core retrieval or sample handling. This type of fracturing is rarely seen and may enhance the permeability and gas recovery of a shale gas reservoir, as long as the microfractures are connected, via induced or natural fracturing, to the well bore. However, this is a single viewing of a feature and we would like to see more of this attribute prior to drawing conclusions regarding its cause and pervasiveness. What we have not seen yet in Colorado Group samples is an indication of shale seals. Hence, the question “Are there any seals in Colorado group shale or does the entire stratigraphic column (up to a few hundred metres thick) have potential for resources?” still exists and awaits further analysis.

The gas capacity results were highest for the 1WS and Belle Fourche, while the 2WS, Fish Scales Zone and Blackstone shale samples exhibited a lower gas capacity. However, we cannot make regional interpretations based on the results of a few samples, especially considering that shale texture is heterogeneous and that organic content is variable, which is only one of the limiting factors, so variations in gas capacity are expected. Total gas capacity increased with an increasing thickness of shale, but the question of shale seals, as indicated above, is a valid consideration in resource assessment. We have used

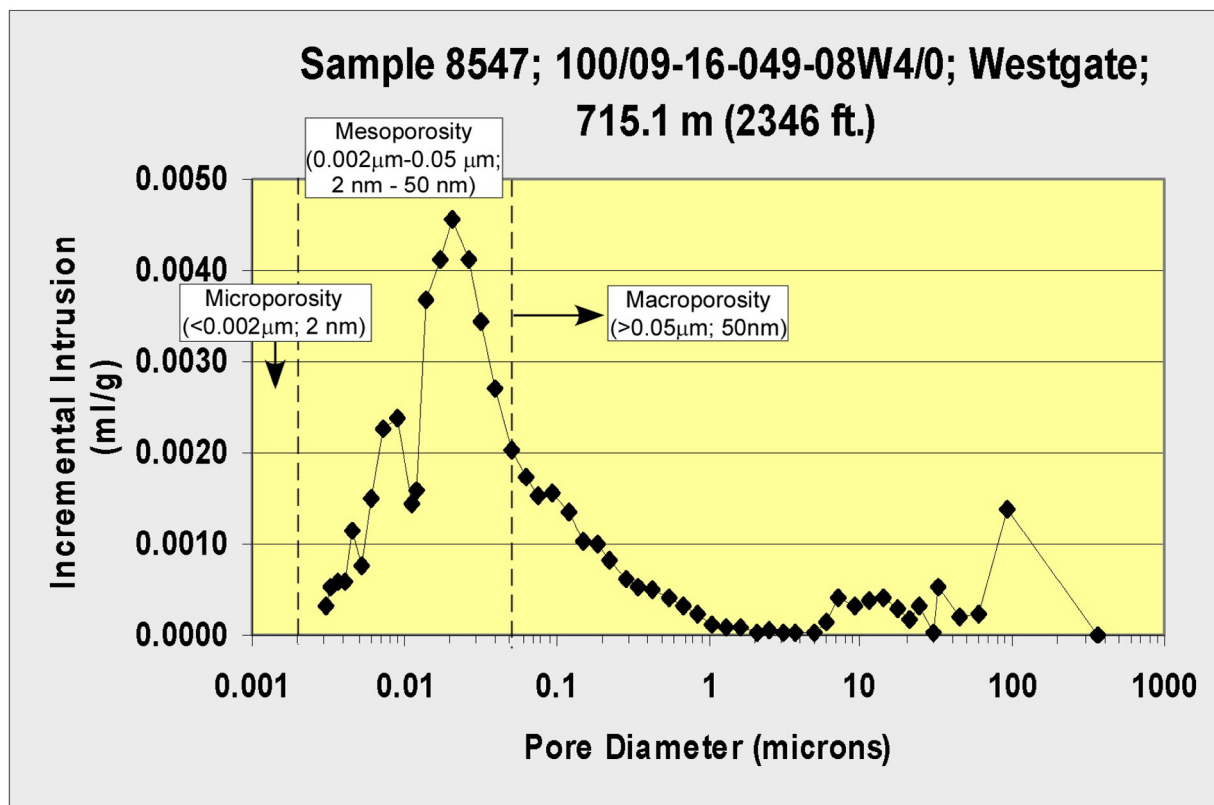


Figure 20. Mercury porosimetry graph, sample 8547, Westgate Formation, well 100/15-03-10-10W4, core depth 715.1 m.

a free gas content of 25% in our calculations, which arguably is low relative to the content suggested in known shale gas fields in the United States (e.g., 60–80% in the Lewis Shale, 80% in the Barnett, 30% in the Antrim, 50% in the Appalachian shale; Faraj et al., 2004). Although the ratio of free gas to adsorbed gas produced in a reservoir is extremely difficult to determine accurately, we have purposely erred on the side of caution until we have data that suggest higher values are warranted.

5 Are There any Colorado Group Shale Gas Wells or Plays in Alberta at Present?

One of the most difficult propositions at present is to determine where shale gas wells, or even shale horizons that have been perforated but are not yet on production, exist in Alberta because there is no easy way to efficiently and effectively search databases for this information. What follows is based on our experience over the last few years and on publicly released data. We stress that this is only a brief analysis of a few ‘shale’ plays.

In the Viking-Kinsella area (~48-12W4), a number of companies are drilling for a target in the middle to lower 1WS that is an approximate age equivalent to the Cardium Formation. One company has publicly announced that they are drilling a shale gas play in the area. To date, there have been more 170 wells drilled, many of which are producing from the ‘Cardium-equivalent’ shale, although some of these are confidential and we do not know the producing formation. After examining core and cross-sections, we postulate that this play is similar to the Lewis Shale in New Mexico, as discussed earlier in this report, in that the primary production interval is well-laminated siltstone within organic-rich shale, rather than strictly speaking ‘black shale’. The laminations are too thin to view on well logs.

Flow rates from the Cardium-equivalent zone vary from about 50 m³/d to about 5000 m³/d, similar to the Lewis Shale (Frantz et al., 1999; Dube et al., 2000). There are indications of additional target zones in the 1WS being perforated, along with production in the 2WS and Fish Scales Zone, so multiple targets are possible throughout this area. The present extent of the play is more than 20 townships, if you count each township where a well is located, or roughly the size of the Lewis Shale play. A brief look for the resource boundaries of the play indicates an area about double the present size; however, a more thorough study will be required to confirm or alter our initial observations.

Presently, most of the shale formations in the Colorado Group have producing shale gas wells, of which the Fish Scales Zone is the most prolific. In fact, oil and gas in the Fish Scales Zone and the Barons sandstone (a radioactive sandstone adjacent to the Fish Scales Zone) were discovered decades ago. The Fish Scales Zone may be prospective for low-productivity shale gas throughout much of eastern Alberta and is a hybrid play, according to Faraj and Benteau (2007), of organic-rich shale with interbedded sandstone and siltstone. The Fish Scales Zone is also known to be a target along the foothills in western Alberta, where it is deeper and thicker and the organic matter is more mature.

The Westgate Formation is also being drilled in southern Alberta. The Westgate was described by Bloch et al. (1999) as an upward-coarsening regressive shale; hence, at present, the play appears to be for siltstone or thin sandstone interlaminated with silty organic shale in the middle to upper part of the unit. Gas wells of relatively low productivity are located in eastern Alberta in Townships 44 to 46, west of the 4th Meridian (*see* Section 2.1.1.2).

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Appendices

Appendix 1 – Cross-Sections

Figure 8. Stratigraphic cross-section C12.

Figure 9. Stratigraphic cross-section C6.

Figure 10. Stratigraphic cross-section C11.

Figure 11. Stratigraphic cross-section C7.

Figure 12. Stratigraphic cross-section C9.

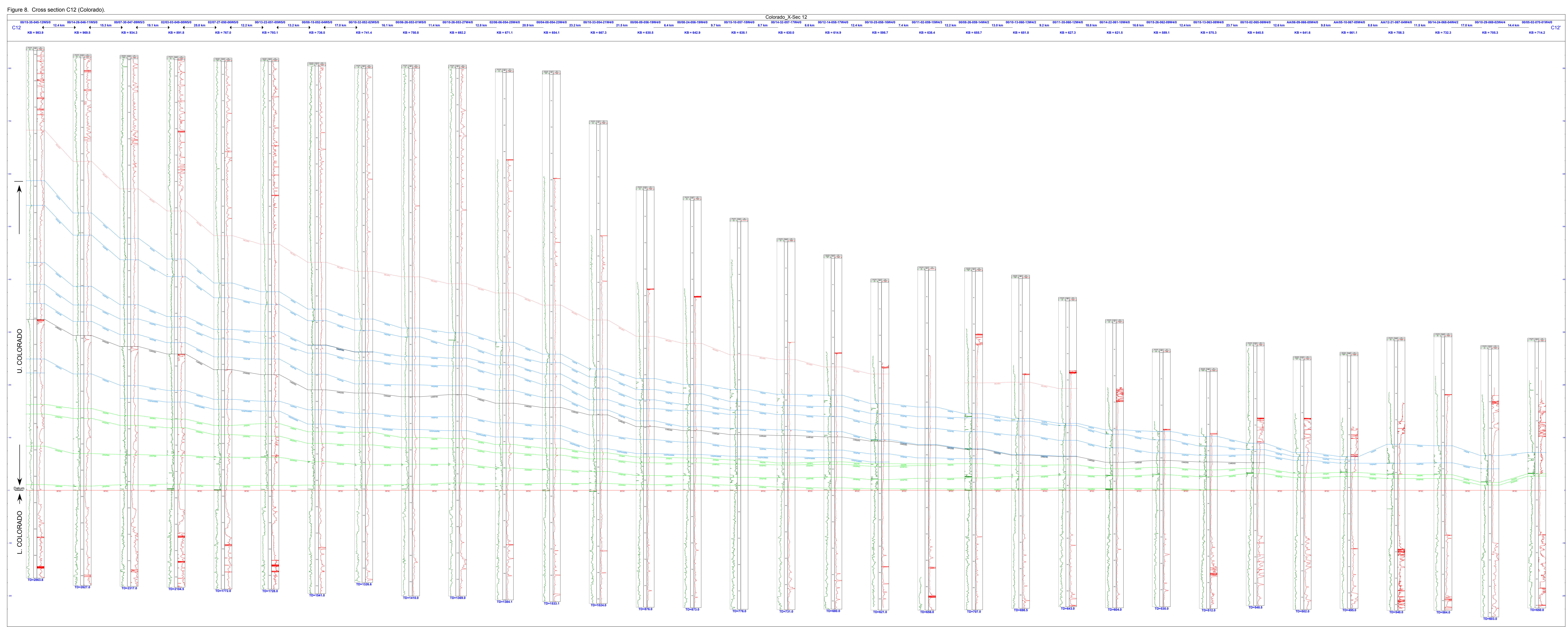


Figure 8. West to east to cross-section C12. Tops picked are informal stratigraphic picks, and are generated for the purpose of determining resource assessment units. All other cross sections on Figure 7 not included in the document are being refined and will be released when complete.

Figure 9. Cross section C6 (Colorado).

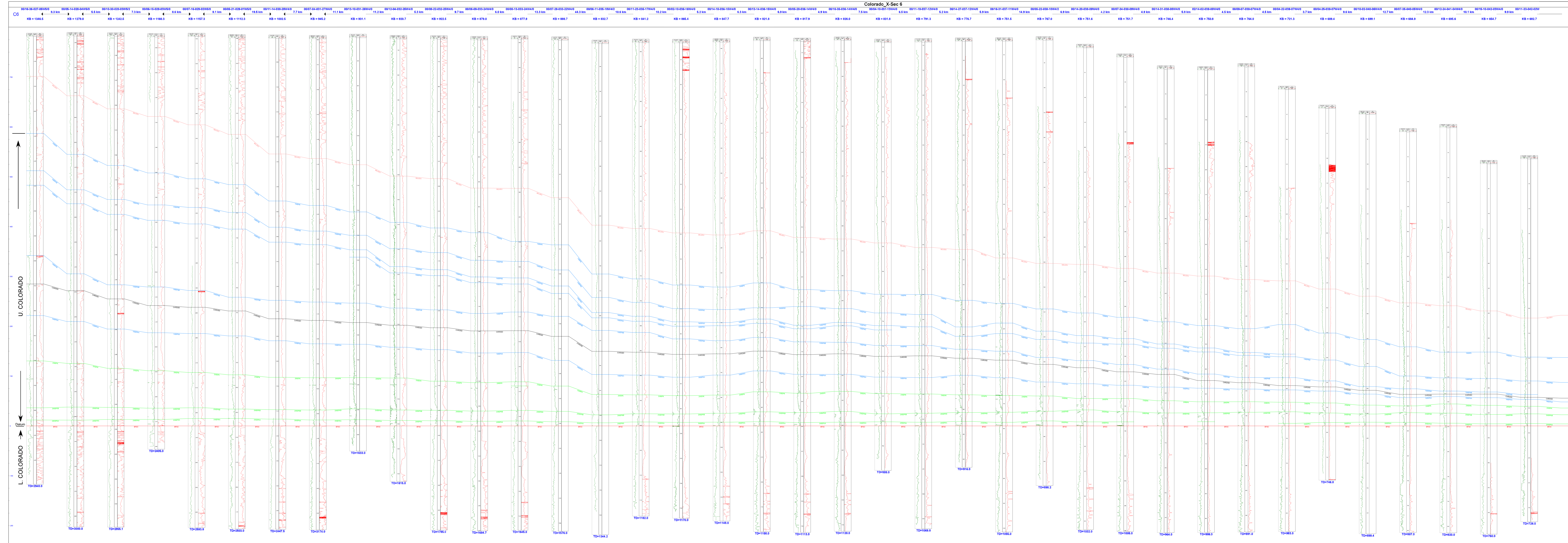


Figure 9. West to east cross-section C6. Tops picked are informal stratigraphic picks, and are generated for the purpose of determining resource assessment units. All other cross sections on Figure 7 not included in the document are being refined and will be released when complete.

Figure 10. Cross section C11 (Colorado).

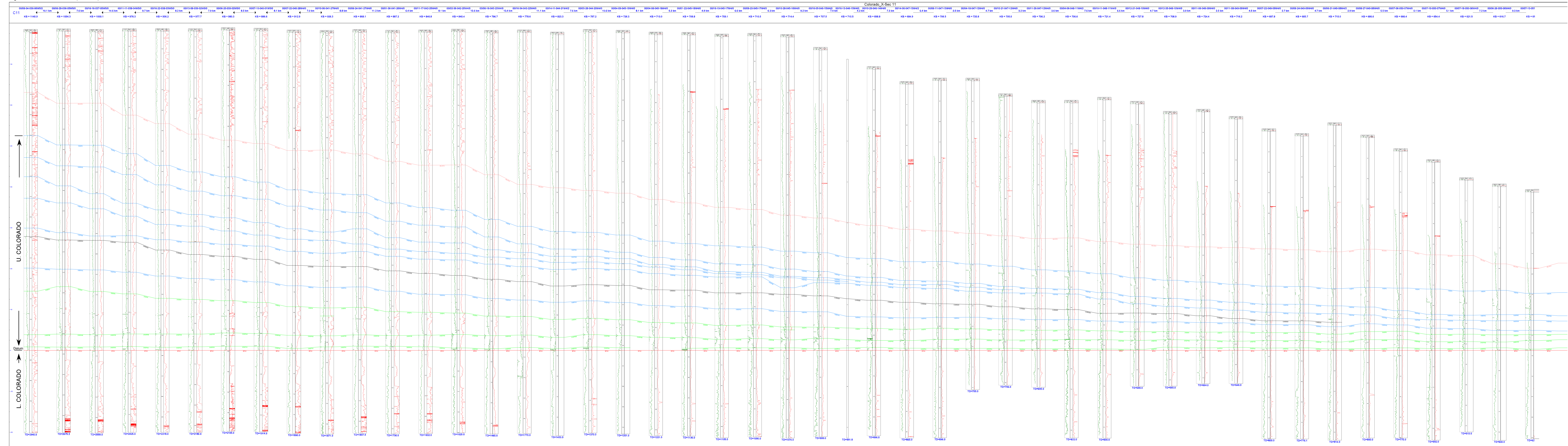


Figure 10. West to east cross-section C11. Tops picked are informal stratigraphic picks, and are generated for the purpose of determining resource assessment units. All other cross sections on Figure 7 not included herein are being refined and will be released when complete.

Figure 11. Cross section C7 (Colorado).

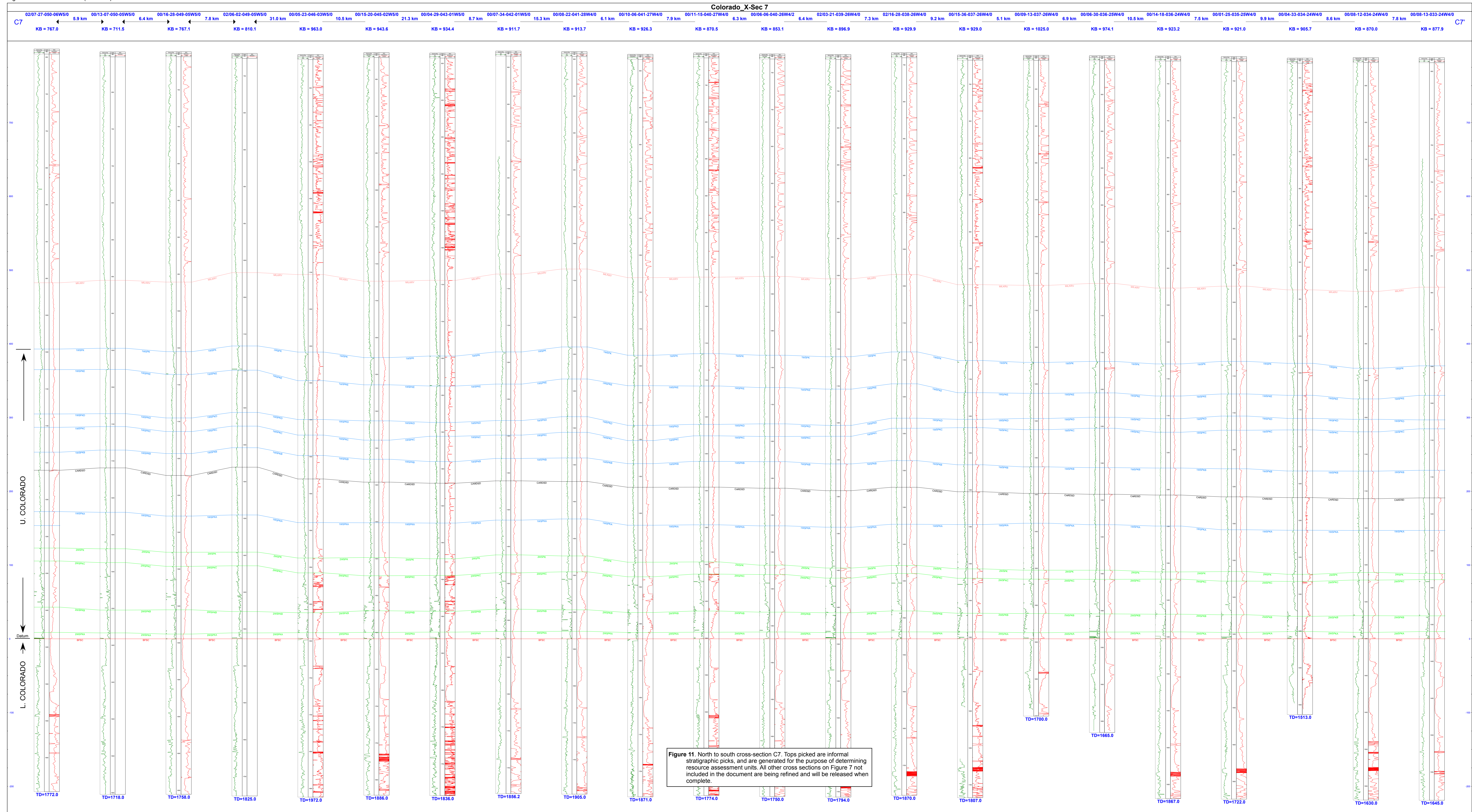


Figure 12. Cross section C9 (Colorado).

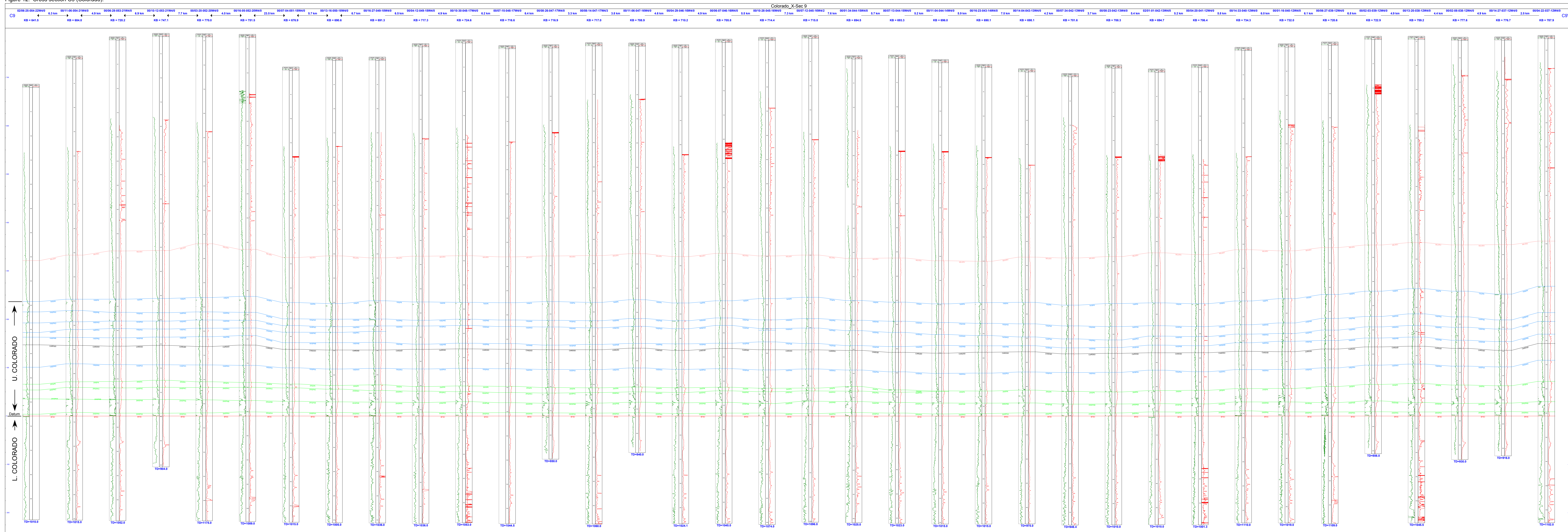


Figure 12. North to south cross-section C9. Tops picked are informal stratigraphic picks, and are generated for the purpose of determining resource assessment units. All other cross sections on Figure 7 not included in the document are being refined and will be released when complete.

Appendix 2 – Descriptions of Outcrop Sections

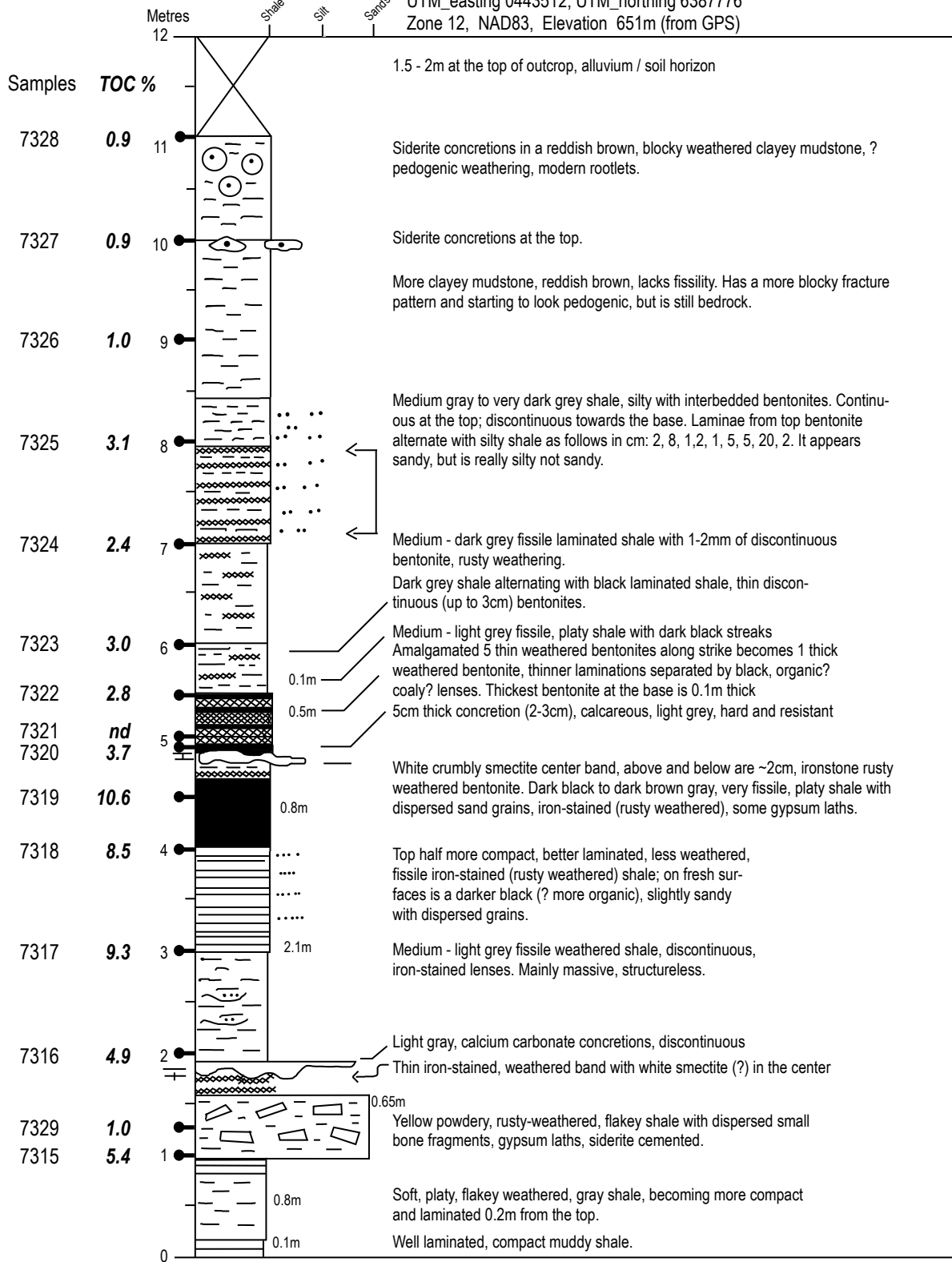
Asphalt Creek Colorado Section, Birch Mountains

Sample Locations in the Colorado Blackstone Formation from Cadomin Railway Section along McLeod River

Greystone Creek Colorado Section, Birch Mountains

Asphalt Creek Colorado Section - Birch Mountains

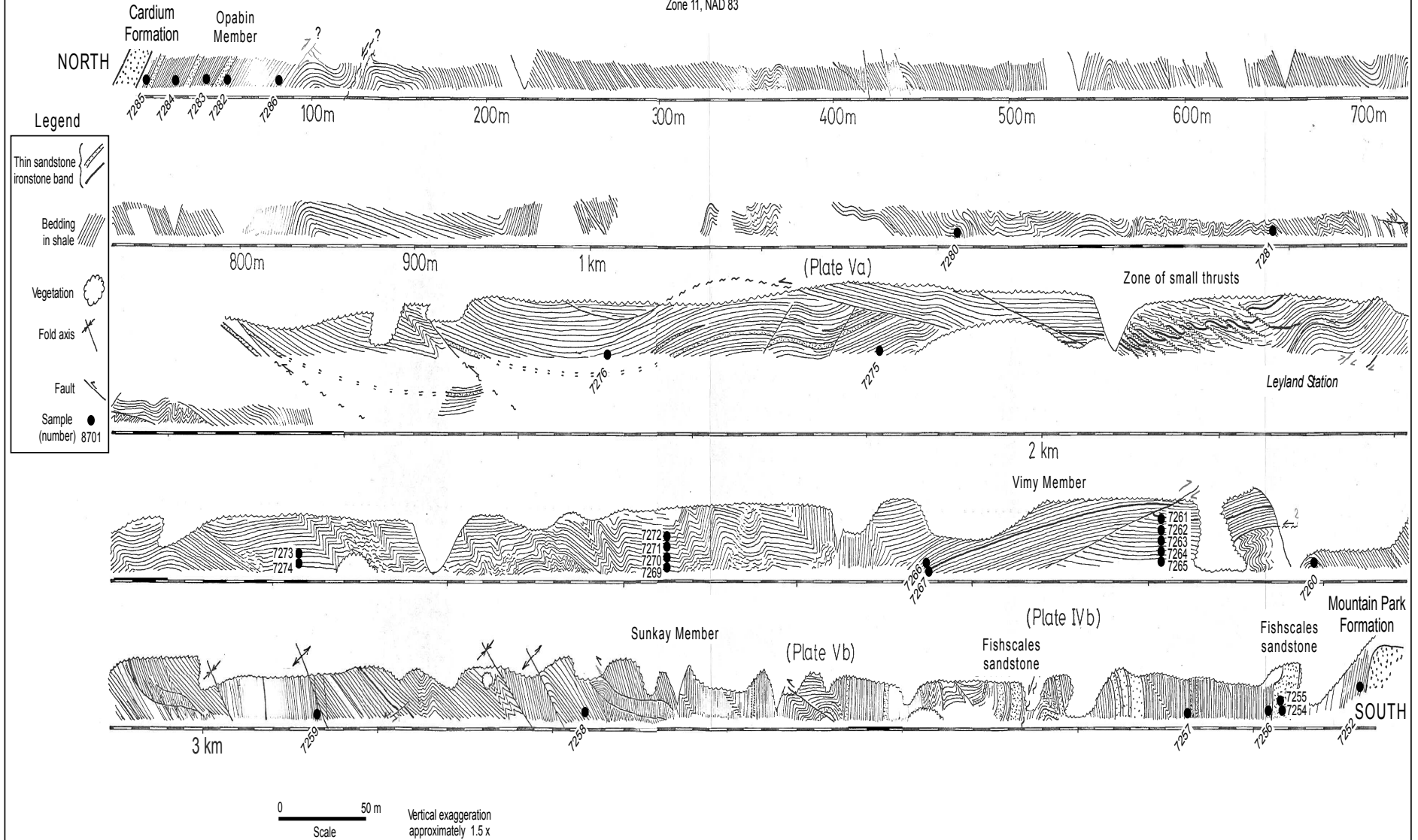
UTM_easting 0443512, UTM_northing 6387776
Zone 12, NAD83, Elevation 651m (from GPS)

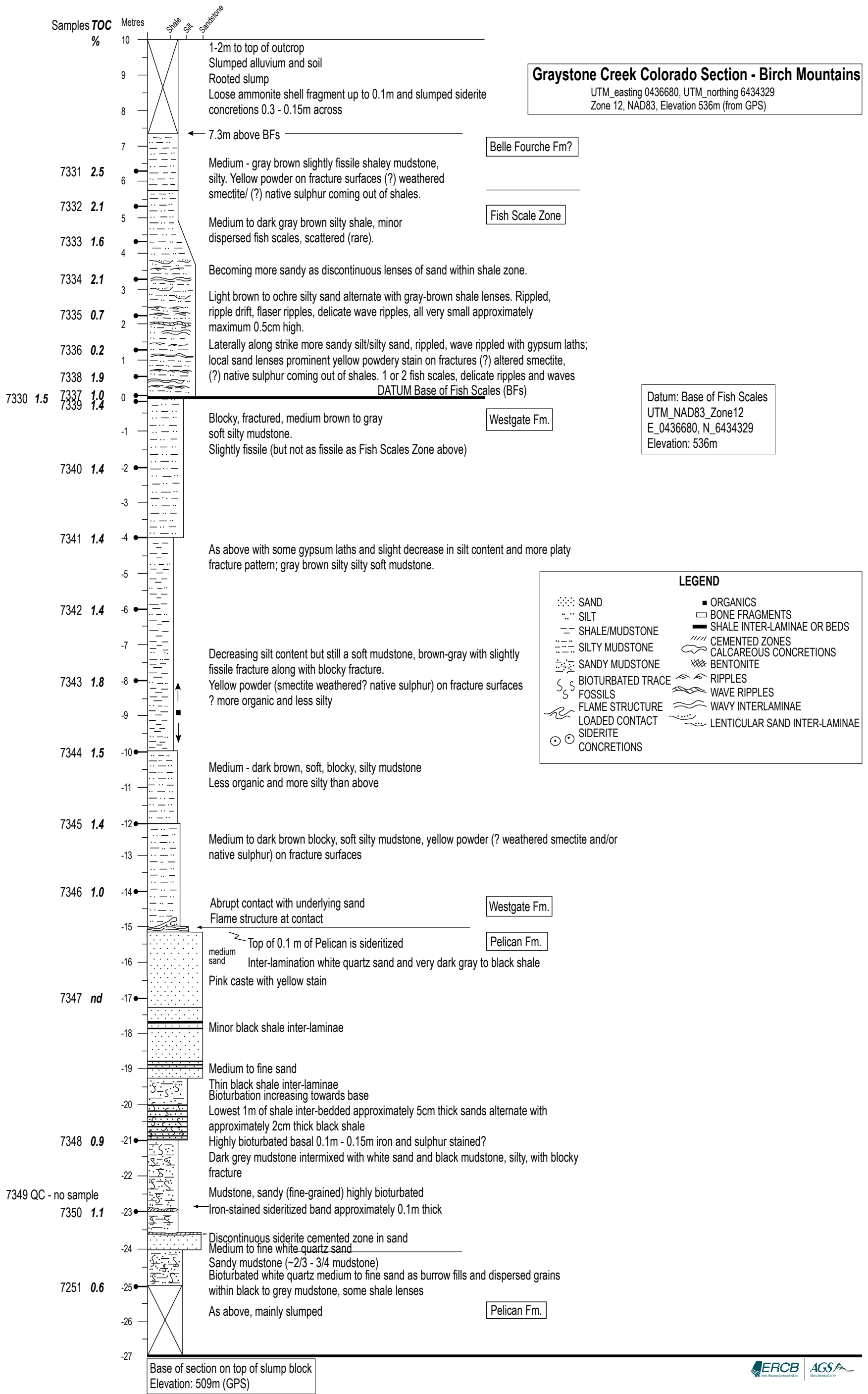


Datum = base of section at stream level 651 meters above sea level

Sample locations in the Colorado Blackstone Formation from Cadomin railway section along McLeod River.
 (Diagrammatic section modified from Hill, 1980)

UTM_E 478522
 UTM_N 5876250
 Zone 11, NAD 83



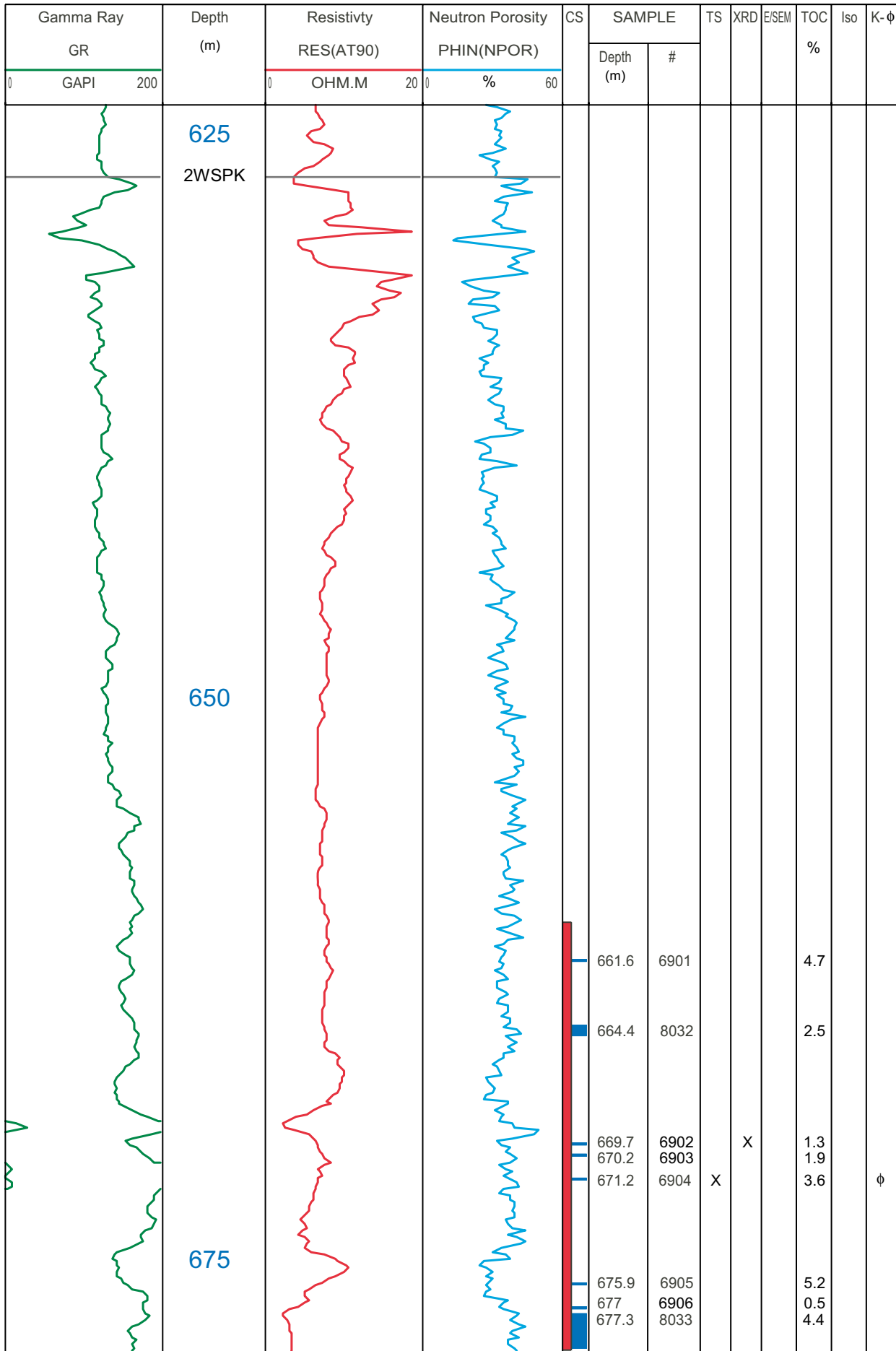


Appendix 3 – Core and Well Logs

02-03-14-18W4
08-24-14-28W4
11-32-17-11W4
03-14-18-11W4
14-19-19-18W4
13-03-20-11W4 (Upper)
13-03-20-11W4 (Lower)
09-05-22-2W4
06-08-26-19W4
10-12-28-21W4
04-11-28-22W4
06-34-30-08W4
06-29-30-16W4
08-09-31-24W4
06-15-33-12W4
16-21-42-21W4
06-23-43-11W4
07-12-48-10W4
06-36-49-5W4
05-30-49-07W4
09-16-49-08W4
08-27-49-22W4
06-11-51-06W4
12-32-54-16W4
06-21-26-03W5
06-17-30-03W5
07-19-45-06W5
06-20-45-08W5
13-20-51-14W5
04-31-52-13W5
16-29-54-21W5 (Upper)
16-29-54-21W5 (Lower)
15-27-60-20W5
05-27-61-22W5
12-16-75-15W5
04-29-84-15W5
04-13-57-02W6

02/11-32-017-11W4/0

KB 758.8 m



02/03-14-018-11W4/0

KB 764.1m

Gamma Ray GR	Depth (m)	Resistivity RES(ILD)		Neutron Porosity PHIN(NPOR)		CS	SAMPLE		TS	XRD	E/SEM	TOC %	Iso	K-φ
		0	20	0	60		Depth (m)	#						
0		0	20	0	60									
API		OHMM		%										
200														
	1WSPK													
	400						400	8517				2.2		
							407.5	8518	X		X	0.4		φ
							410.1	8519				3.1		
	1WSPKE													
	425						417.8	8520	X			2.8		

00/06-08-026-19W4/0

KB 933.2 m

Gamma Ray GR	Depth (m)	Resistivity	Neutron Porosity	CS	SAMPLE		TS	XRD	E/SEM	TOC %	Iso	K- ϕ			
		RES(ILD)	PHIN(CNL)		Depth (m)	#									
0 API 200		0 OHM.M 20	0 % 60												
	1WSPK														
					811.5	8581				2.5					
					813.8	8582				2.7					
					818	8583				1.9					
					822.4	8584				0.6					
					823	8585				1.4					
	825				825	8586				2.4					
					828.5	8587				0.6					
					832.4	8588				2.0		ϕ			
					833.7	8589				3.2					
					836.1	8590				1.3					
					841.4	8591				3.4					
	1WSPKE														
	850														
	847.8	8592					1.7								
	850.4	8593					1.7								
	853.7	8594					1.8								
	856.2	8595					1.2								

02/10-12-028-21W4/0

KB 838.5 m

Gamma Ray GR(GRGM)	Depth (m)	Resistivity		Neutron Porosity		CS	SAMPLE		TS	XRD	E/SEM	TOC %	Iso	K- ϕ
		RES(RILD)	OHM.M	PHIN(NPRL)	%		Depth (m)	#						
0 GAPI 200		0	20	0	60									
	2WSPK													
	1075						1075	8036				2.9		
	1100						1089.2	8037				1.7		ϕ

00/06-29-030-16W4/0

KB 923.2 m

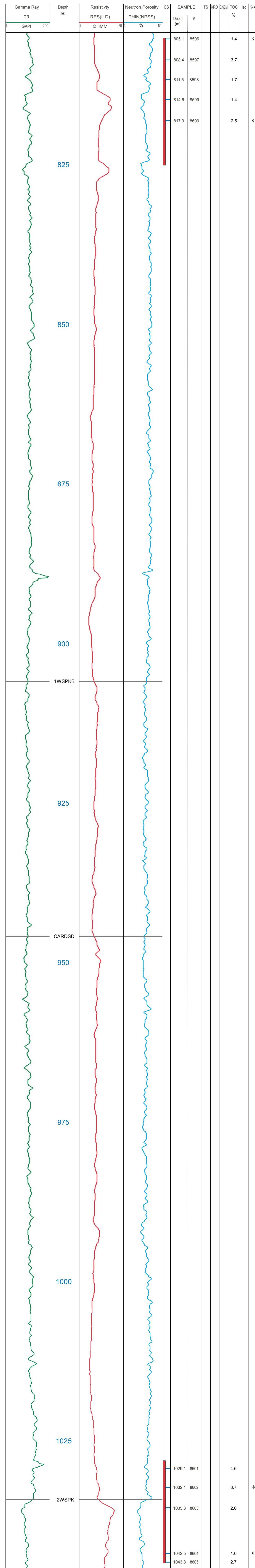
Gamma Ray GR	Depth (m)	Resistivity		Neutron Porosity		CS	SAMPLE		TS	XRD	E/SEM	TOC %	Iso	K- ϕ	
		RES(ID)	OHMM	PHIN(N/A)	%		Depth (m)	#							
0 200 GAPI		0 20	20	0 60											
	1050														
	2WSPKA														
						1060.7	8535					3.6			
						1062.2	8536					2.7			
						1064.1	8537			X		1.1		ϕ	
						1069.5	8538					2.3			
	BFSC 1075					1077.9	8539					1.3			

00/08-09-031-24W4/0

KB 906.5 m

Gamma Ray GR(GRD)	Depth (m)	Resistivity		Neutron Porosity		CS	SAMPLE		TS	XRD	E/SEM	TOC %	Iso	K-φ
		RES(LAT)	OHM/M	PHIN(NPHI_S)	%		Depth (m)	#						
0 200 GAPI		0 20	0 60											
	BFSC													
	1425													
	VIKING													
	1450													
												1.6 1.6		
								1448.6 8554 1449 8555						

00/16-21-042-21W4/0
KB 813.7 m



00/08-27-049-22W4/0

KB 774.4 m

Gamma Ray		Depth (m)	Resistivity		Neutron Porosity		CS	SAMPLE		TS	XRD	E/SEM	TOC %	Iso	K- ϕ
GR			RES(AF60)		PHIN(NPSS)			Depth (m)	#						
0	GAPI 200		0	OHM.M 20	0	% 60									
		725													
							738.3	8664			3.0				
							742.5	8665			3.0	ϕ			
							745	8666			1.2				
		1WSPKB					747.5	8667			1.3				
		750													
		CARDSD													

00/12-32-054-16W4/0

KB 679.7 m

Gamma Ray GR	Depth (m)	Resistivity	Neutron Porosity	CS	SAMPLE		TS	XRD	E/SEM	TOC %	Iso	K-φ
		RES(AF90) OHM.M	PHIN(NPSS) %		Depth (m)	#						
0 GAPI 200		0 20	0 60									
	1WSPKD				417.2	8566	X			5.4		
					420.5	8567				2.0		
					423	8568				1.4		
	425				425.5	8569				1.8		φ
	1WSPKB											
	450											
	CARDSD				459	8570				5.9		
					461.2	8571				0.7		
					464	8572				0.4		
					466.5	8573				0.5		
					471.2	8574				0.4		

00/06-17-030-03W5/0

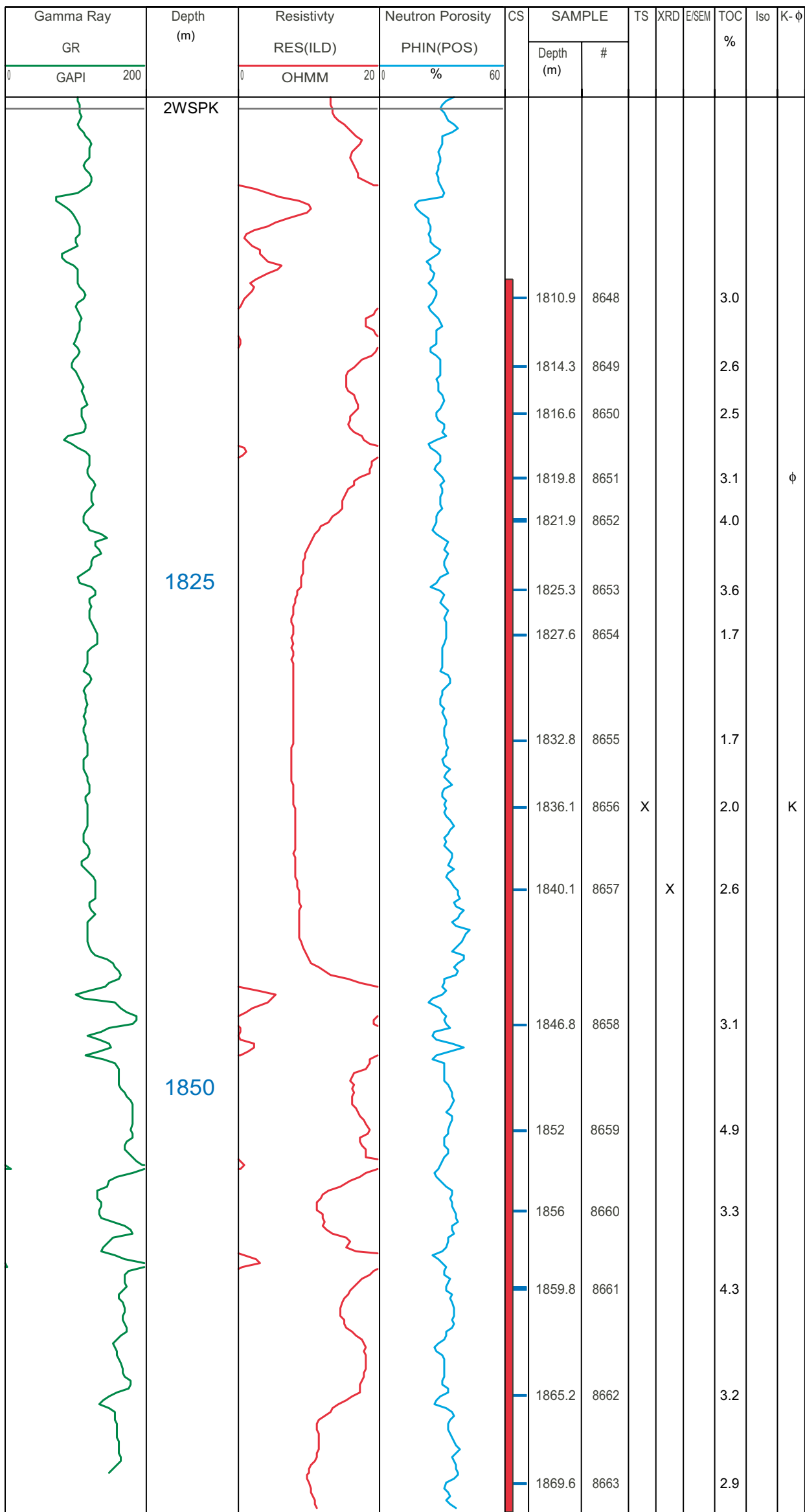
KB 1102.2 m

Gamma Ray GR(GRD)	Depth (m)	Resistivity		Neutron Porosity		CS	SAMPLE		TS	XRD	E/SEM	TOC %	Iso	K- ϕ		
		RES(ILD)	OHMM	PHIN(NPHI)	%		Depth (m)	#								
0 GAPI 200		0	20	0	60											
	2WSPKA				2319.7	8606	X				2.9					
	2325				2323.5	8607					2.5					
					2326	8608					3.0					
	BFSC				2328.9	8609	X			3.0						
					2330.2	8610				1.1						
					2333	8611		X		1.5		ϕ				
					2336.3	8612				1.4						
	VIKING															
	2350															

ϕ

00/07-19-045-06W5/0

KB 944.6 m



00/06-20-045-08W5/0

KB 919.5 m

Gamma Ray GR	Depth (m)	Resistivity RES(ILD)		Neutron Porosity PHIN(NPSS)		CS	SAMPLE		TS	XRD	E/SEM	TOC %	Iso	K- ϕ
		OHM/M	20	%	60		Depth (m)	#						
0 API 200		0	20	0	60									
	CARDSD				1772.4	8613						1.0		
	1750				1775	1773.6	8614	X					1.1	ϕ

ϕ

00/13-20-051-14W5/0

KB 964.7 m

Gamma Ray GR	Depth (m)	Resistivity RES(DVR2)		Neutron Porosity PHIN(NPHI)		CS	SAMPLE		TS	XRD	E/SEM	TOC %	Iso	K-φ	
		OHM.M	20	%	60		Depth (m)	#							
0 200															
	2WSPK			2017.5	8637						3.4				
				2021.8	8638	X			3.4	φ					
	2025														
	2050														
	2075						2071.5	8639					2.1		
				2078	8640					1.7					

00/05-27-061-22W5/0

KB 961.4 m

Gamma Ray GR	Depth (m)	Resistivity		Neutron Porosity		CS	SAMPLE		TS	XRD	ESEM	TOC %	Iso	K-φ
		RES(AF90)	OHM.M	PHIN(NPSS)	%		Depth (m)	#						
0 200 API		0	20	0	60									
	1775													
	BFSC													
	1800													
	1825													
	1850													
						1852.7	8644					1.1		
						1854.3	8645					1.1		
						1857	8646					1.0		
						1860.5	8647	X				1.2	φ	

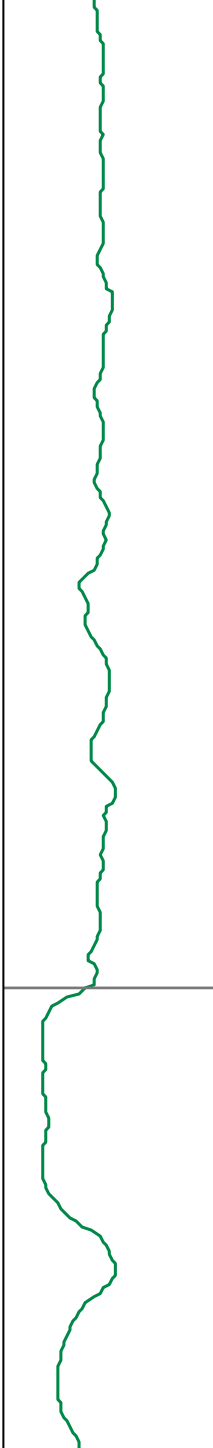



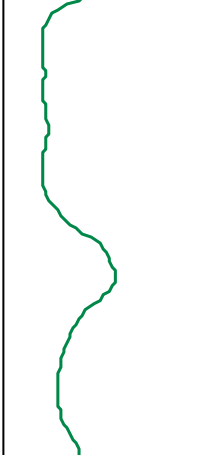
00/04-29-084-15W5/0

KB 703.5 m

Gamma Ray GR(N/A)	Depth (m)	Resistivity	Neutron Porosity	CS	SAMPLE		TS	XRD	E/SEM	TOC %	Iso	K-φ
		RES(N/A)	PHIN(N/A)		Depth (m)	#						
GAPI 200		0 20	0 % 60									
	975			960	8627					1.5		
				979	8628		X			1.7		
				986	8629					1.5		
	1000											
				1012	8630					1.4		
	1025			1032	8631					1.9		φ

00/04-13-057-02W6/0

KB 1318.9 m

Gamma Ray		Depth (m)	Resistivity		Neutron Porosity		CS	SAMPLE		TS	XRD	E/SEM	TOC %	Iso	K- ϕ	
GR	GAPI		RES(ILD)	OHM/M	PHIN(N/A)	%		Depth (m)	#							
0	200		0	20	0	60										
		2575							2582.3	8668				1.2		ϕ
		2589.1							8669			1.9	K			
		2592.5							8670			1.0				
		2593.8							8671			3.4				
									CARDSD 2600	