North Dakota Geological Survey

Examination of the Icebox Formation's (Winnipeg Group, Ordovician) Source Rock Potential within North Dakota

By

Timothy O. Nesheim

and

Stephen H. Nordeng

Geological Investigation No. 169
North Dakota Geological Survey
Edward C. Murphy, State Geologist
Lynn D. Helms, Director Dept. of Mineral Resources
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Figures

Table

Appendix A

Appendix B (CD version only)

Introduction

Previously reported geochemical data on the Icebox Formation's source rock potential varies significantly between North Dakota and Saskatchewan. From a data set of 11 samples (Fig. 1), Dow (1974) and Williams (1974) reported the Icebox Formation averages 0.42 weight % total organic carbon (TOC) within North and estimated the Icebox Formation has generated and expelled 600 million barrels of oil. Further north, a handful of Icebox samples from southern Saskatchewan, analyzed by Osadetz and Snowden (1986; 1995, Appendix A-Table 1), average a more promising 1.52% TOC with an S_2 of 10.37 mg/g (Hydrogen Index, HI = 682). More recently, a larger data set in both distribution and size was produced by Siebel (2002, Appendix A-Table 1) from Icebox samples distributed across Saskatchewan's Williston Basin (Fig. 1) which combine to average 2.32% TOC with an S_2 of 14.23 mg/g (HI = 620). Previously reported data from North Dakota indicates the Icebox is organic-lean and a poor quality source rock (<0.5% TOC) (Dow, 1974; Williams, 1974), conversely, geochemical data from Saskatchewan indicates the Icebox in Canada averages as a more promising source rock (~2.1% TOC & 13.5 mg/g S_2 - Osadetz and Snowden 1986; 1995; Siebel, 2002).

Geologic Background

The Winnipeg Group extends across most of North Dakota and into parts of the surrounding states and provinces (Fig. 1). The Winnipeg Group has been broken down into three formations (Fig. 2): the basal Black Island Formation consists primarily of sandstone deposited in a shallow marine environment, the middle Icebox Formation is made up mostly of shale deposited within an offshore marine shelf, and the upper Roughlock Formation is a transitional interval between clastic shale dominated deposition to carbonate deposition. Conodont studies conducted on outcrops located around the peripheral extent of the Winnipeg Group place deposition within the Blackriveran to Shermanian Stages (Sweet, 1982) (Fig. 2), which correlates with the beginning of the Upper Ordovician. Thompson (1984) described the Winnipeg Group as being time-transgressive, with each unit being deposited first in the central portions of the Williston Basin before transgressing outwards. Since the Winnipeg conodonts were collected along the Winnipeg's peripheral extent, part of the Winnipeg Group within the central portions of the Williston Basin may be Middle Ordovician in age.

The Icebox Formation reaches a maximum thickness of 156 ft. within the central portions of the Williston Basin and tends to be 120-130 ft. thick throughout most of North Dakota (Ellingson and LeFever, 1995) (Fig. 3). The Icebox Formation consists primarily of green to grey to black shale that was deposited within a restricted marine to an offshore marine shelf setting (Siebel, 2002) (Fig. 4). Mild burrowing is common throughout the Icebox section with occasional fossiliferous beds (Ellingson and LeFever, 1995).

The Icebox Formation contains a number of sandy shale to sandstone intervals that vary in thickness and extent. Several east-west trending sand bodies formed during the Icebox's deposition, possibly as mid-shelf sand ridges deposited along areas of low basement subsidence with storm and tidal currents transporting sediments (Kessler, 1991). The largest of these mid-shelf sand ridges described by Kessler

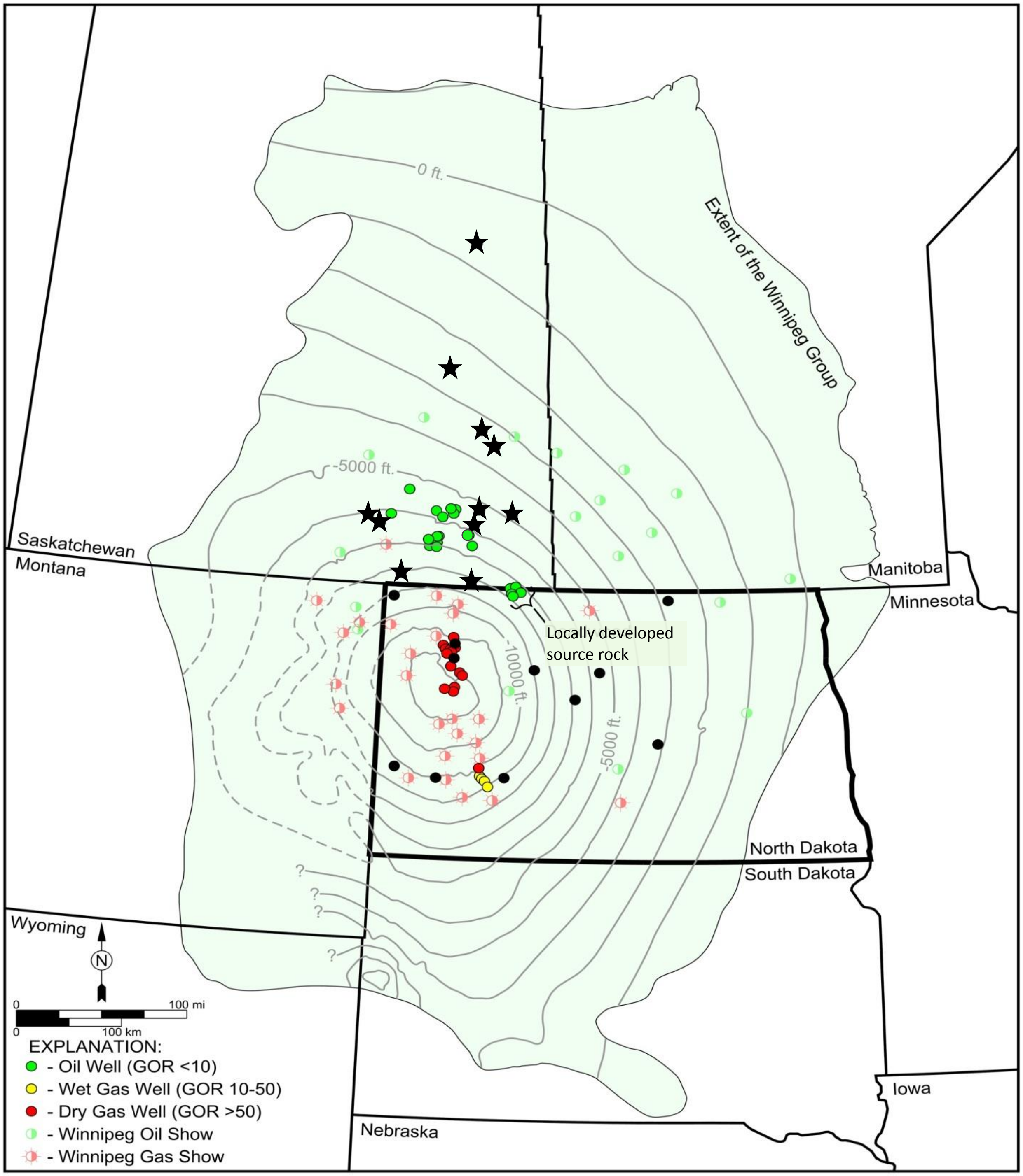

Figure 1. Regional extent map of the Winnipeg Group with productive oil and gas wells completed in the Black Island (Winnipeg Group) and/or Deadwood Formations. The extent (light green shaded area) and structure contours (grey lines) for the Winnipeg Group were compiled from Kreis (2004), Bezys and Conley (1998), LeFever et al. (1987), and Anna (2010). Black circles show well locations of Icebox samples analyzed for TOC wt. % by Williams (1974) and black stars by Osadetz and Snowden (1986; 1995) and Siebel (2002). The Newporte Field, located in north-central North Dakota, produces oil and gas generated by a locally developed source rock (Castano et al., 2008).

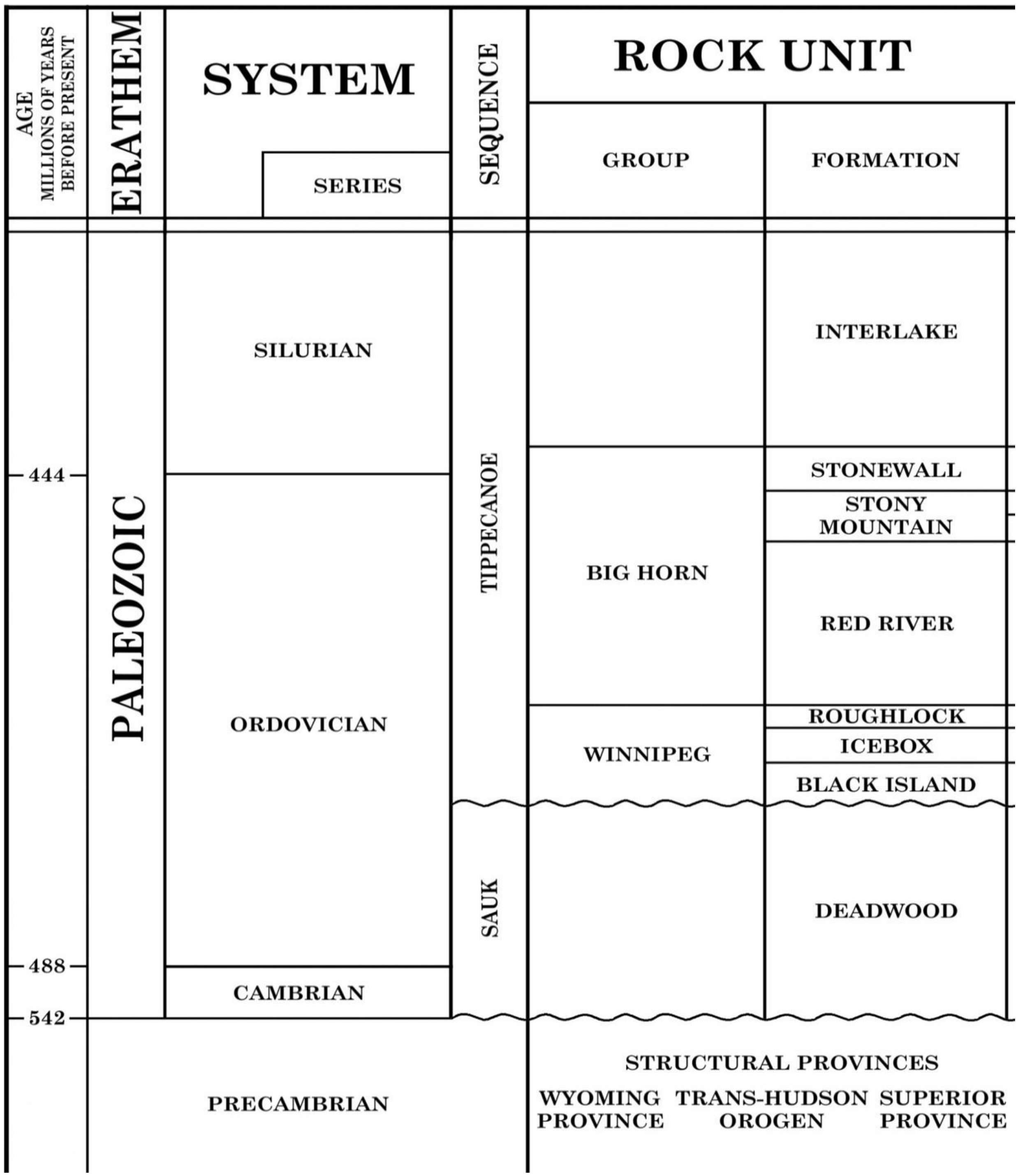

Figure 2. Partial stratigraphic section of North Dakota's Williston Basin. The Winnipeg Group is Middle to Upper Ordovician in age and rests unconformably on the Deadwood Formation across most of North Dakota (sometimes rests directly on the Precambrian unconformity) while conformably grading into the overlying Red River Formation. Conodont studies place most of the Winnipeg section within the Blackriveran to Shermanian Stages (Sweet, 1982; Thompson, 1984). Modified from Murphy et al. (2009).

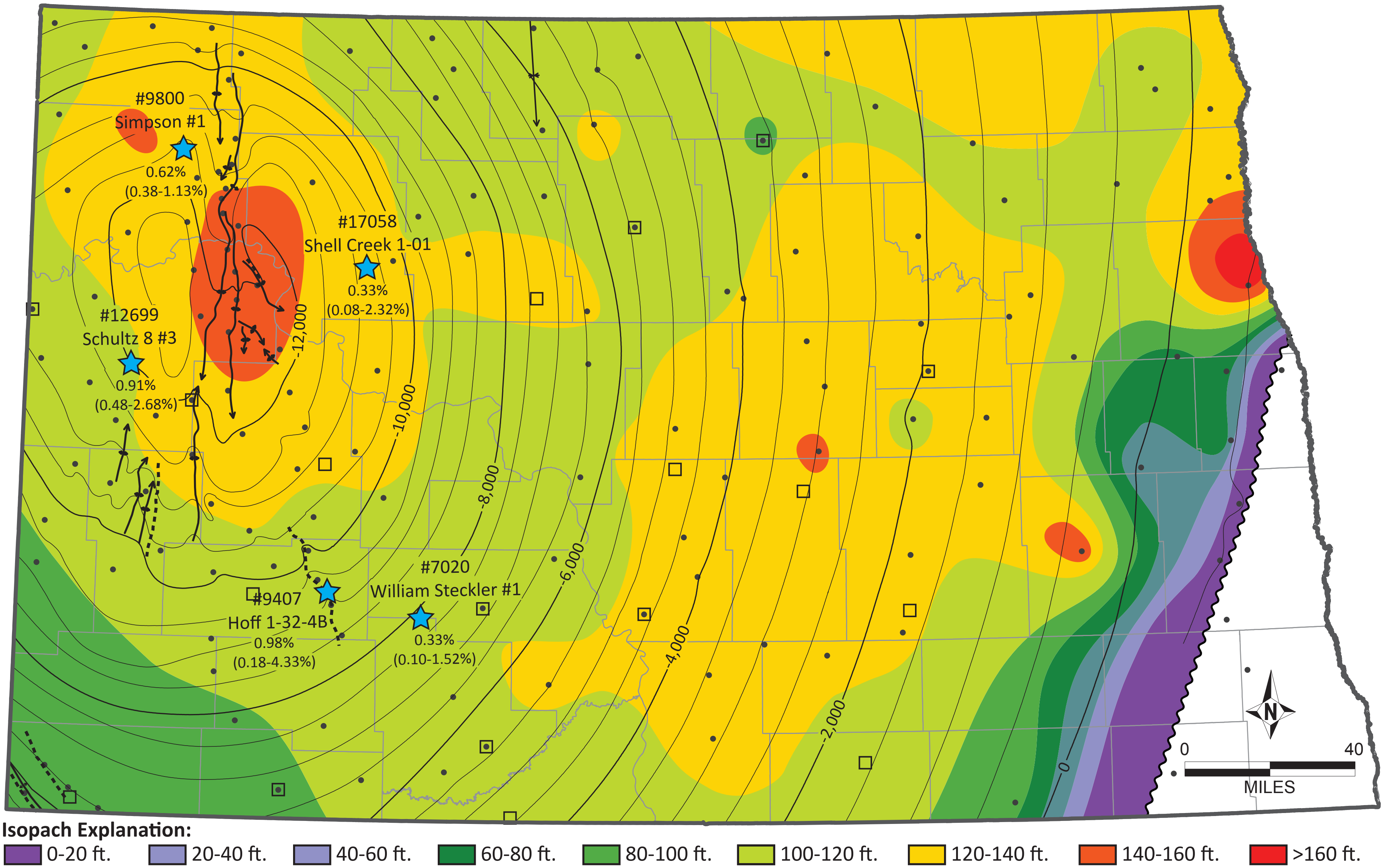

Figure 3. Isopach (color shading) and structure (thin black lines) map of the Icebox Formation with well locations (stars) of the five Icebox cores sampled and examined by this study. Structure contours are in feet below sea level of the Icebox Formation top. Black dashed lines are faults and the continuous thick black lines are folds. The North Dakota Industrial Commission (NDIC) number and original well name is listed above each well of interest with core measured TOC averages from Icebox shale samples listed below and TOC ranges in parantheses. Black dots show the locations of control wells used to generate the stucture and isopach contour layers. Open squares show the location of wells from which Icebox drill cuttings were analyzed for TOC wt. %. Structure contours in the northwestern portion of the state were adjusted to better align with the Kibbey Lime structure top (see appendix).

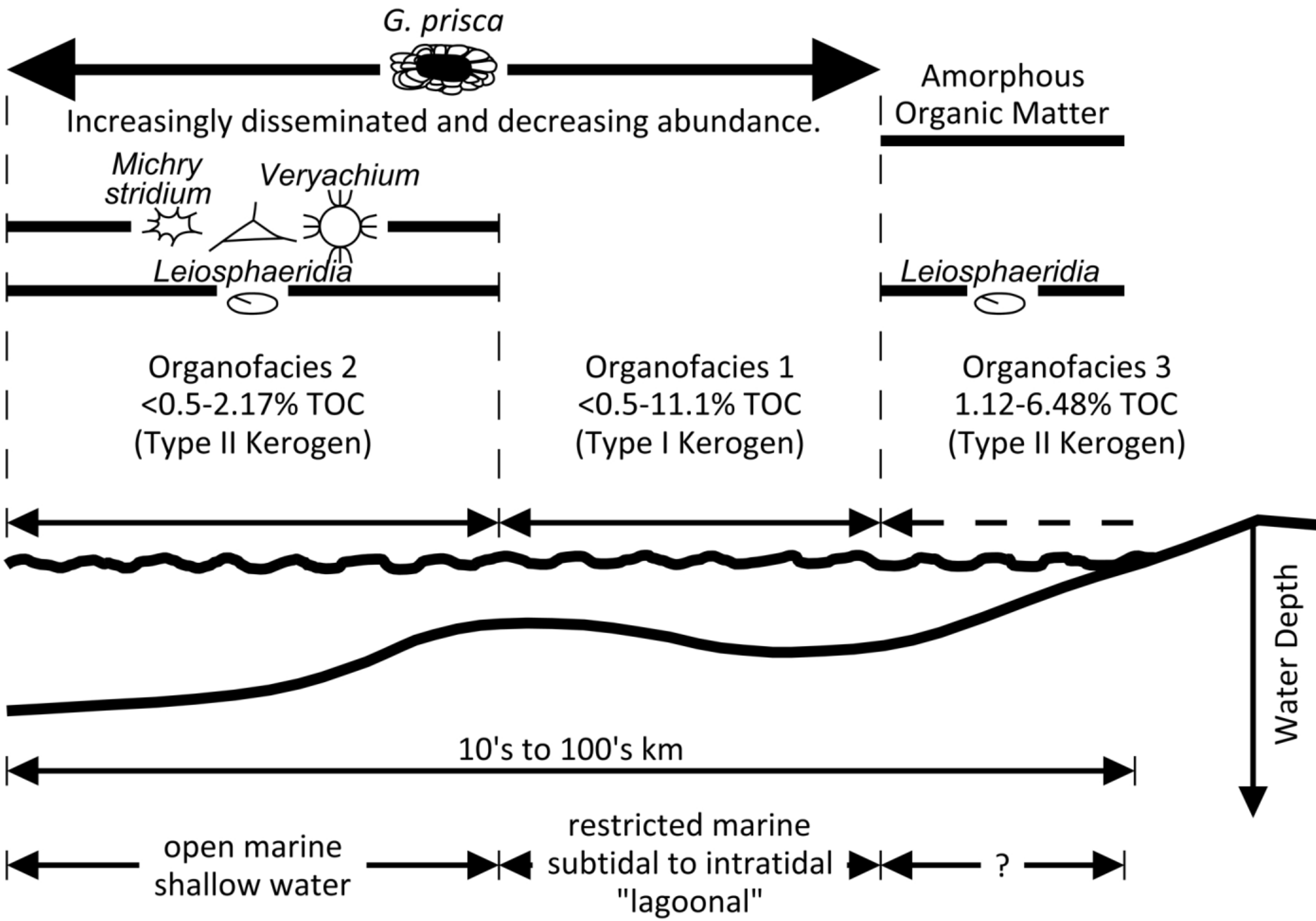

Figure 4: Schematic diagram depicting the distribution and depositional setting of interpreted organofacies present within the Icebox Formation, modified from Siebel (2002).

(1991) is the Carmen Sand located in southern Manitoba. There are two smaller sandstone bodies in Walsh and Grand Forks Counties of eastern North Dakota (Kessler, 1991). More recently, Ulishney et al. (2005) mapped out forty sandy lithofacies within the Icebox section. Ulishney described five of these sandy lithofacies as having regional extent, spanning 10's of miles, while the others are more local in extent.

Well Histories and Core Descriptions

Texas Pacific Oil Company's William Steckler #1

The William Steckler #1 (NDIC: 7020, API: 33-037-00023-00-00) was spudded in June 1979 by Texas Pacific Oil Company in northwestern Grant County (Fig. 3). Drilling vertically to a total depth of 11,027 ft., the William Steckler #1 encountered the Winnipeg Group (Roughlock Formation) starting at 10,195 ft. and the Icebox Formation from 10,195-10,316 ft. (Fig. 5). 61 ft. of Winnipeg core was cut consisting of approximately 24 ft. of Icebox Formation (10,292-10,316 ft.) and 37 ft. of underlying Black Island Formation (10,316-10,353 ft.) (Fig. 5). No reported Winnipeg test was run on the William Steckler #1 before the well was plugged and abandoned within a year of being spudded.

The Icebox core from the William Steckler #1 consists of medium grey to black shale with occasional faint laminations and gradational color shade changes (Fig. 5, 6). The Black Island portion of the core is composed of mostly of grey bioturbated silty to shaley sandstone interbedded with dark grey shale and nonbioturbated, white to gray, massive to cross-bedded silty sandstone (quartz arenite) (Fig. 5). Overall, the Black Island section fines upwards (Fig. 5).

Gulf Oil's Hoff 1-32-4B

The Hoff 1-32-4B (NDIC: 9407, API: 33-089-00270-00-00) was spudded in March, 1982 by Gulf Oil Company as a step-out, developmental well of the Taylor Field in southwestern North Dakota. While a drill stem test run on the Black Island Formation (11,578-11,622 ft.) recovered some gas (Fig. 7), the Hoff 1-32-4B was plugged and abandoned as a dry hole. A 35 ft. core of the lower Icebox and upper Black Island Formations (11,576-11,611 ft.) was cut and analyzed using standard core analysis (perm., porosity, oil and water saturations) (Fig. 7).

The Hoff's Winnipeg core consists of approximately 15 ft. of Icebox section (11,581-11,596 ft.), green-grey to black shale (Fig. 7, 8), and 20 ft. of underlying Black Island section (11,596-11,616 ft.), bioturbated shaley to silty quartzose sandstone (Fig. 7). Overall, the Black Island core averages 5.5% porosity (2.6-9.9%) with 0.18 millidarcies of permeability (0.01-6.20) and 10.7% oil saturation (0.0-37.0%) with 66.9% water saturation (42.5-93.4%). The Icebox core averages 5.7% porosity (3.5-9.1%) with 0.02 millidarcies of permeability (0.01-0.10) and 25.7% oil saturation (4.3-74.6%) with 49.3% water saturation (13.6-74.5%) (Appendix A: Table 2).

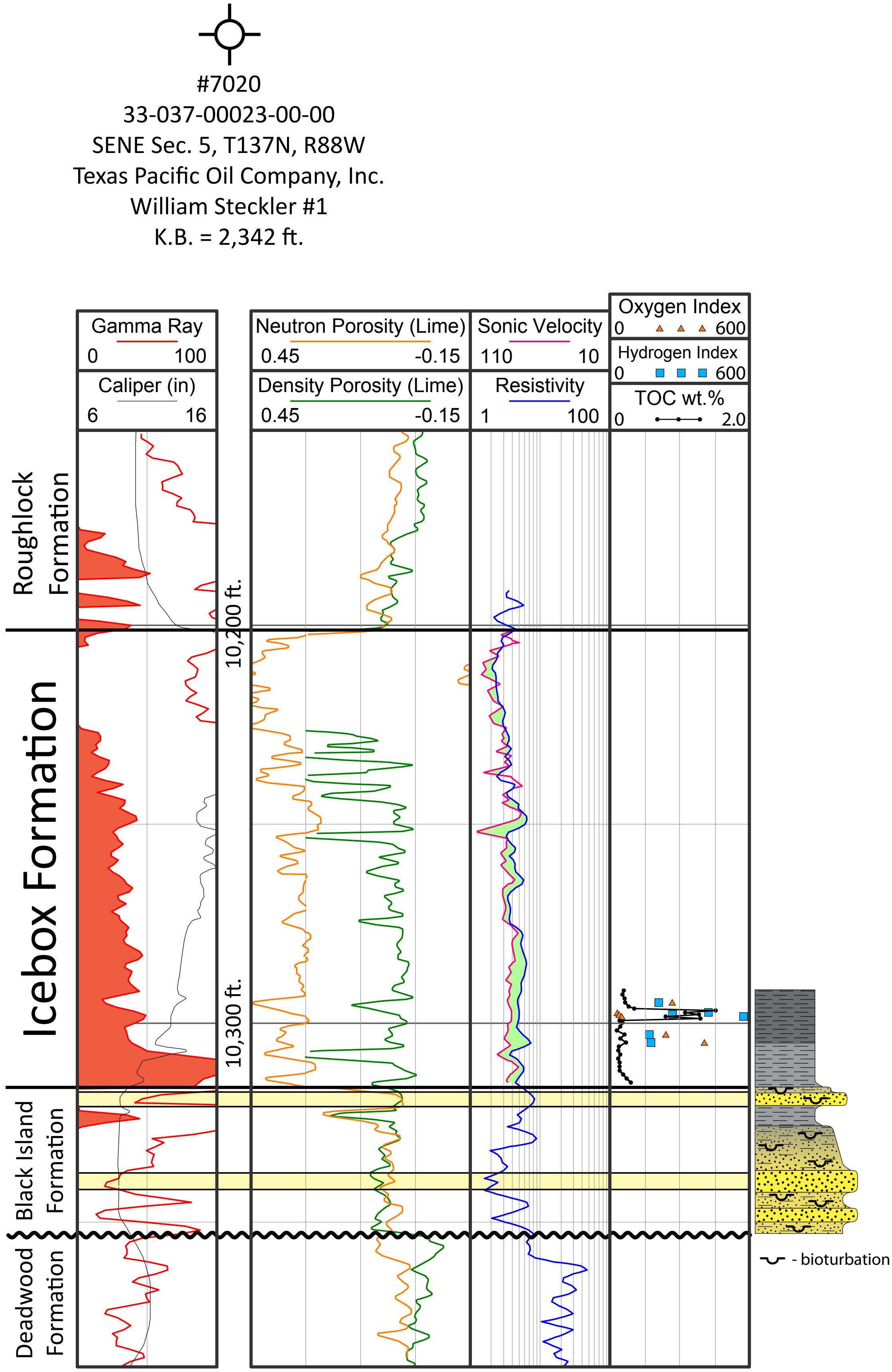

Figure 5. Wireline log of Texas Pacific Oil's William Steckler #1 with illustrated core lithologies and geochemical data from the lower Icebox Formation. The illustrated core symbol explanation is listed on Figure 21. The yellow shaded intervals represent Sandstones B and C of the Garland Member, Black Island Formation (Nesheim, 2013). Core + 10 ft. = Log

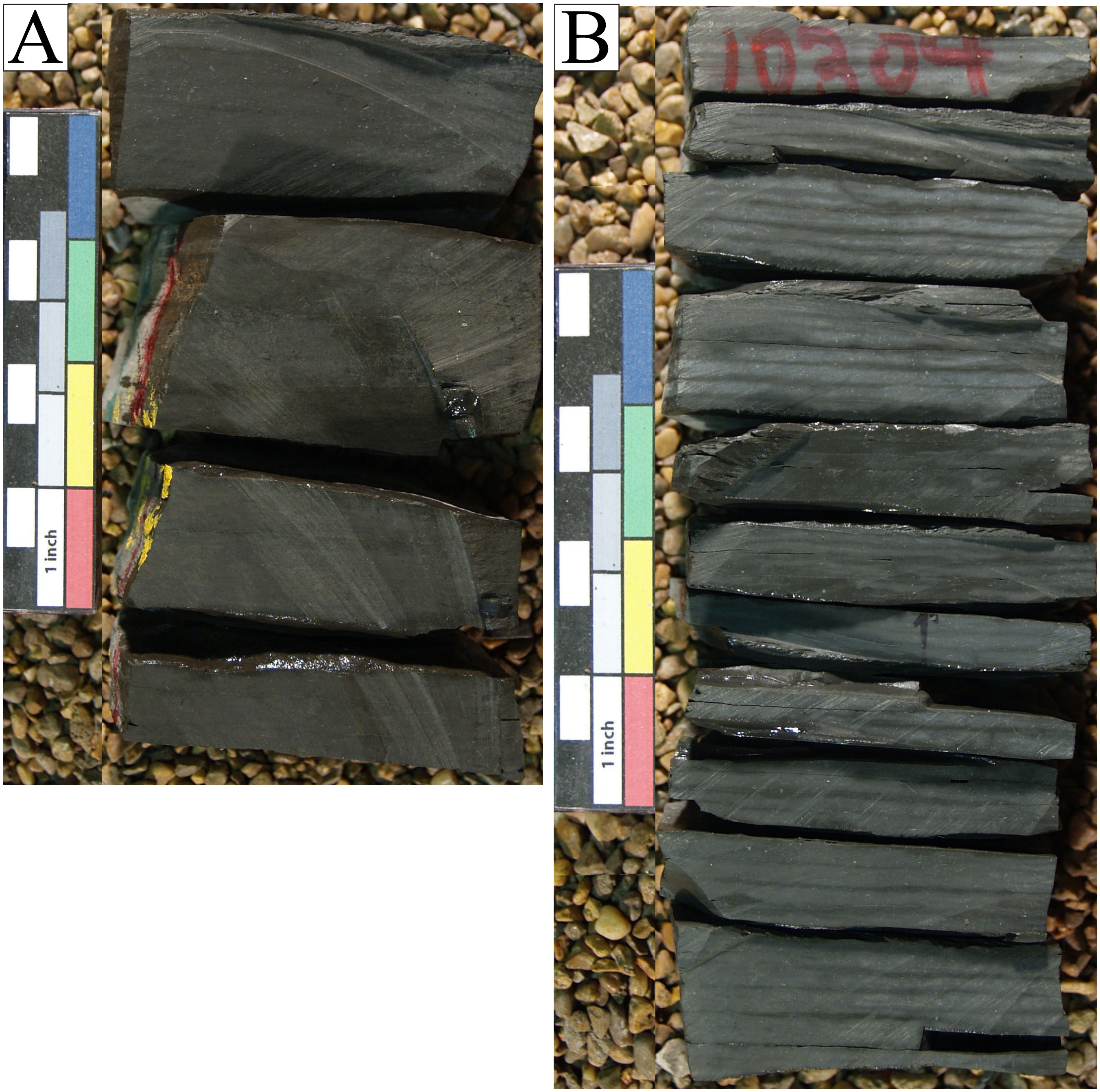

Figure 6. Core photographs of the Icebox Formation from Texas Pacific's William Steckler (NDIC: 7020). A) Very dark grey to black shale (10,288.1-10,288.6 ft. - log depth), moderately organic-rich (0.8-1.3% TOC). B) Green-grey shale (10,304.0-10,304.7 ft. - log depth), organic-lean (0.2-0.3% TOC). Core + 10 ft. = Log

#9407
33-089-00270-00-00
NESW Sec. 32, T139N, R92W
Gulf Oil Corp
Hoff 1-32-4B
K.B. = 2,391 ft.

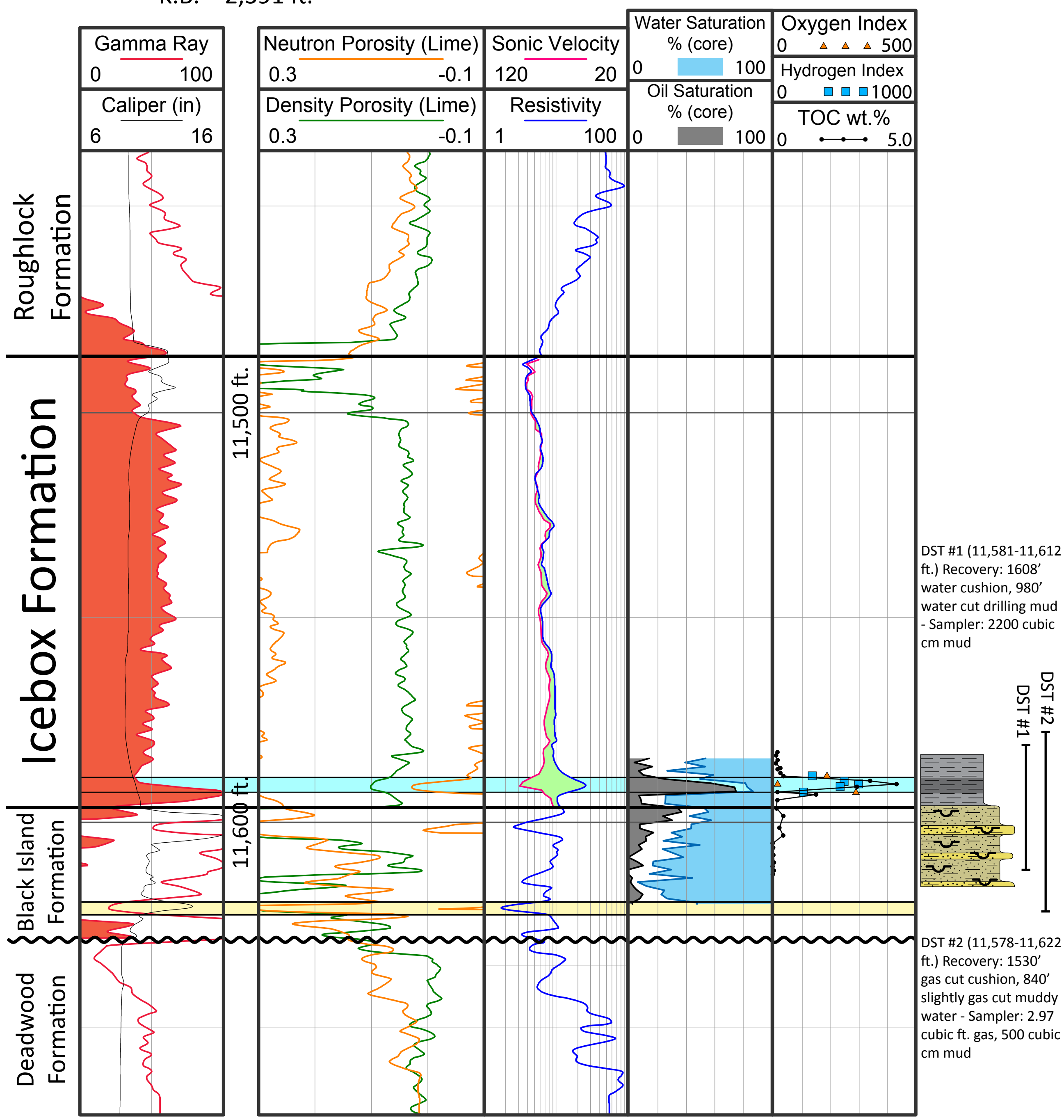

Figure 7. Wireline log of Gulf Oil's Hoff 1-32-4B with illustrated lithologies, geochemical data, and standard core analysis data from the basal Icebox/upper Black Island Formations. The blue shaded interval represents the Government Creek Shale and the yellow shaded interval represents Sandstone B (Nesheim, 2013). Standard core analysis data (e.g. oil & water saturations) is included within the appendix. Core + 6.5 ft. = Log

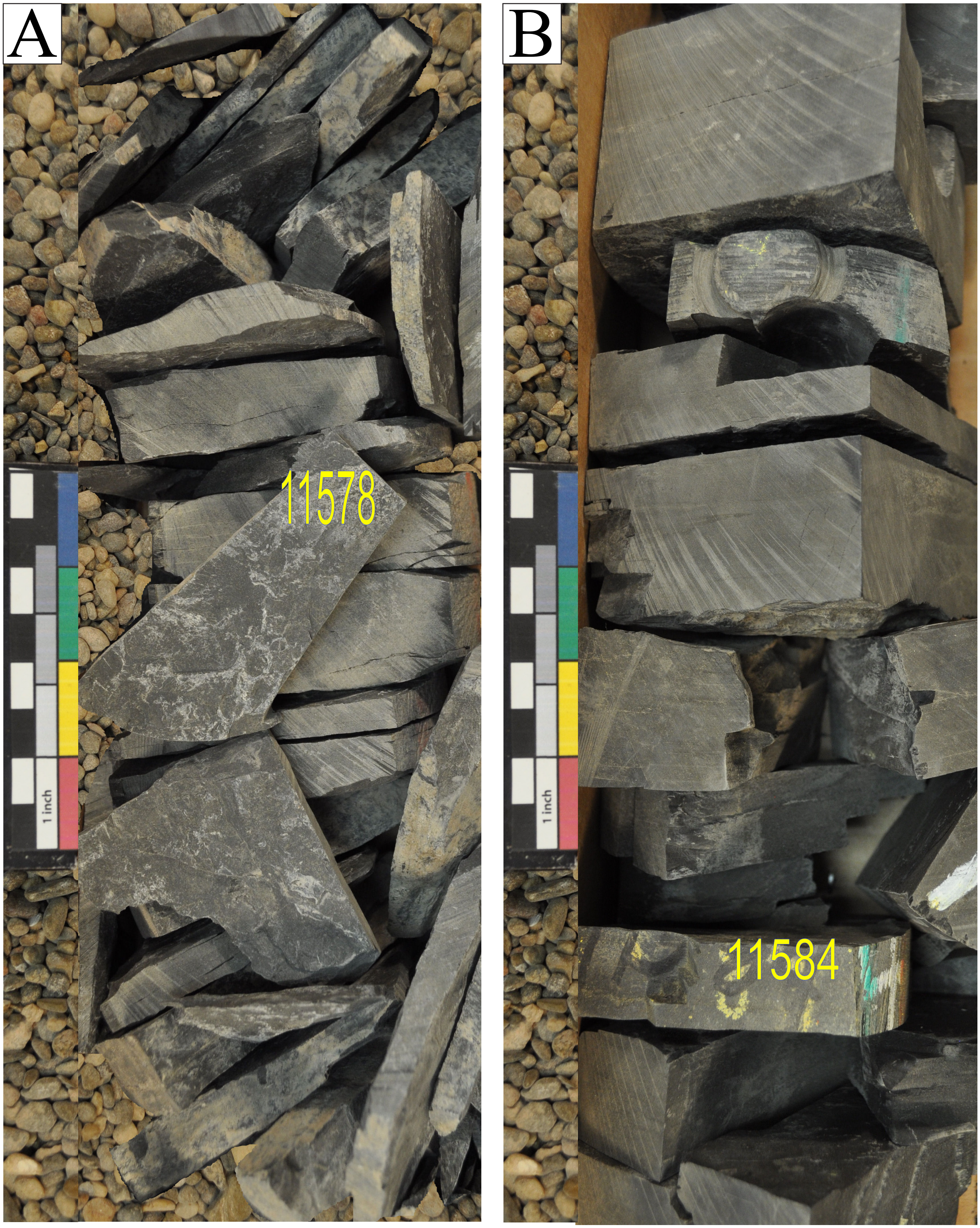

Figure 8. Core photographs of the Icebox Formation from Gulf Oil's Hoff 1-32-4B. A) Dark grey shale (~11,584.5-11,585.5ft. - log depth), organic-lean (0.2% TOC). B) very dark grey to black shale (~11,590.5-11.591.5 ft. - log depth), organic-rich (4.3% TOC), from the Government Creek Shale. Core + 6.5 ft. = Log

EOG Resources Shell Creek 1-01

The Shell Creek 1-01 (NDIC: 17058, API: 33-061-00660-00-00) was initially spudded in February 2008 by EOG Resources within the Parshall Field of Mountrail County (Fig. 3). Drilling vertically to a total depth of 13,459 ft., the Shell Creek 1-01 drilled through the entire Winnipeg section (13,006-13,330 ft., Icebox Fm. 13,042-13,170 ft.) and cut an 88 ft. core (13,078-13,166 ft.) of the lower two-thirds of the Icebox Fm. (Fig. 9). After good hydrocarbon shows were reported throughout the Black Island section, the Shell Creek 1-01 was perforated and tested across multiple intervals within the Black Island and Deadwood Formations (Fig. 9) (flow rate information was not reported) but was plugged back and completed in the Dakota Group as a salt water disposal well.

The Shell Creek Icebox core consists of ~86 ft. of medium grey-green to very dark grey-black shale with <2 ft. of dark grey sandy bioturbated shale at the base of the core (Fig. 9, 10), which presumably represents the beginning of the Black Island Formation. Minor burrowing and pyrite is present intermittently throughout most of the core and is moderately concentrated near the middle portions of the core where the shale color gradationally transitions from very dark grey to grey moving up section (Fig. 9).

Conoco's Schultz 8 #3

The Schultz 8 #3 (NDIC: 12699, API: 33-053-02293-00-00) was initially spudded in October 1989 by Conoco Incorporated within the Buffalo Wallow Field of central McKenzie County (Fig. 3). The Schultz 8 #3 encountered the top of the Winnipeg Group at 14,214 ft. (Icebox Formation: 14,247-14,365 ft.) and reached a total depth of 14,514 ft. A 59 ft. core (14,337-14,399 ft.) was cut from the Schultz 8 #3 across the base of the Icebox and the upper Black Island Formations (Fig. 11). The Schultz 8 #3 was initially completed in the Red River Formation and produced over 260,000 BBLS oil and 6.6 BCF gas before being recompleted in October, 2012 in the Madison pool. Since the recompletion, the Schultz 8 #3 has averaged 17 BOPD (barrels of oil per day) with 116 BWPD (barrels of water per day) from the Madison perforations.

The Schultz 8 #3 Winnipeg core consists of approximately 25 ft. of the basal Icebox (14,337-14,362 ft., Fig. 11, 12) and 34 ft. of the upper Black Island Formations (14,362-14,399 ft., Fig. 11). The Icebox portion of the core is made up of dark grey to black shale with minor bioturbation and pyrite throughout (Fig. 11, 12). The Black Island portion of the core consists of bioturbated grey to dark grey shaley sandstone interbedded with very light grey to tan bioturbated sandstone (Fig. 11). Black Island standard core analyzes average 6.4 % porosity and 0.36 millidarcies of permeability with 29.2% oil saturation and 54.7% water saturation (Appendix A: Table 5) (the cleaner, less shaley sandstone intervals average 7.0% porosity versus 5.7% for the shaley intervals while the permeability and oil-water saturation averages are very similar).

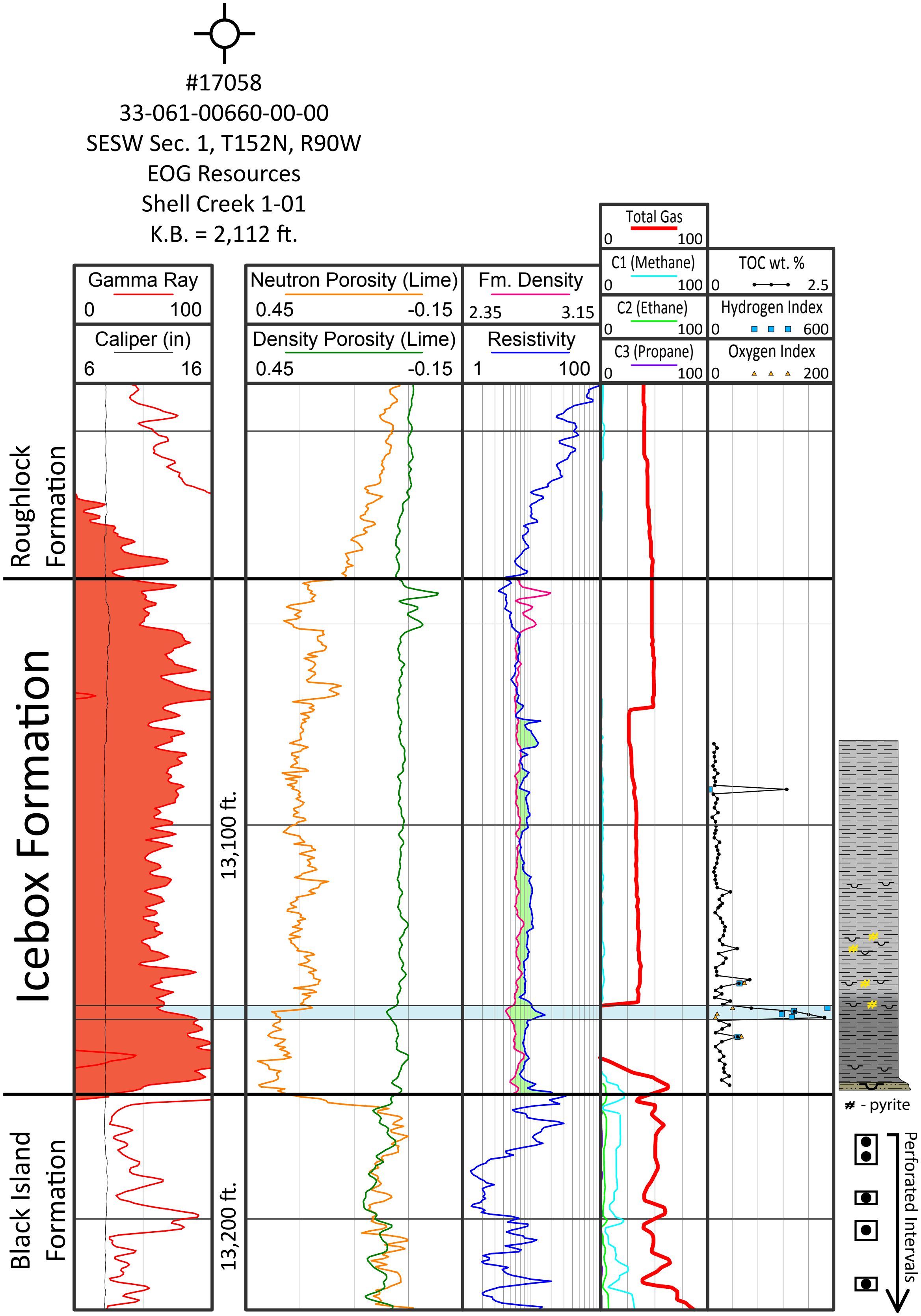

Figure 9. Wireline log of EOG Resources Shell Creek 1-01 with illustrated core lithologies and geochemical data from Icebox Formation core. Note that resistivity is cross-plotted with formation density which examines organic-richness similarly to a resistivity-sonic velocity cross-plot (Passey et al., 1990). Good hydrocarbon shows were reported within the Black Island Formation, and three sets of tests were run with perforations spanning 13,170 ft. to 13,418 ft., but the test results are not available in the oil & gas well file. The blue shaded interval represents the Goverment Creek Shale. Core + 8 ft. = Log

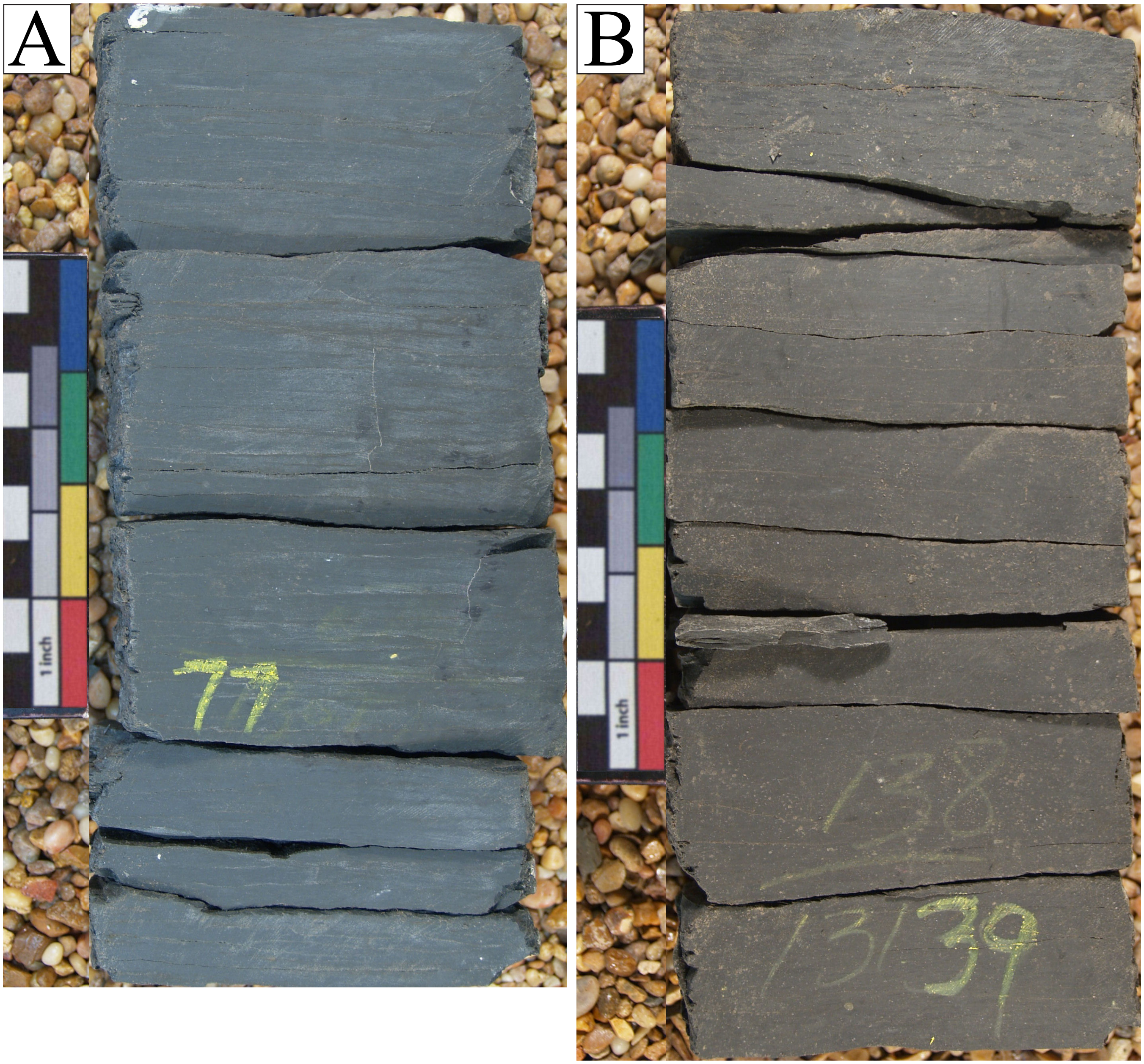

Figure 10. Core photographs of the Icebox Formation from EOG Resources Shell Creek 1-01 (NDIC: 17058). A) Grey-green shale (13,084.5-13,085.3 ft. - log depth), organic-lean (<0.2% TOC). B) Very dark grey to black shale (13,146.4-13,147.1 ft. - log depth), organic-rich (1.7-2.0% TOC), from the Government Creek Shale. Core + 10 ft. = Log

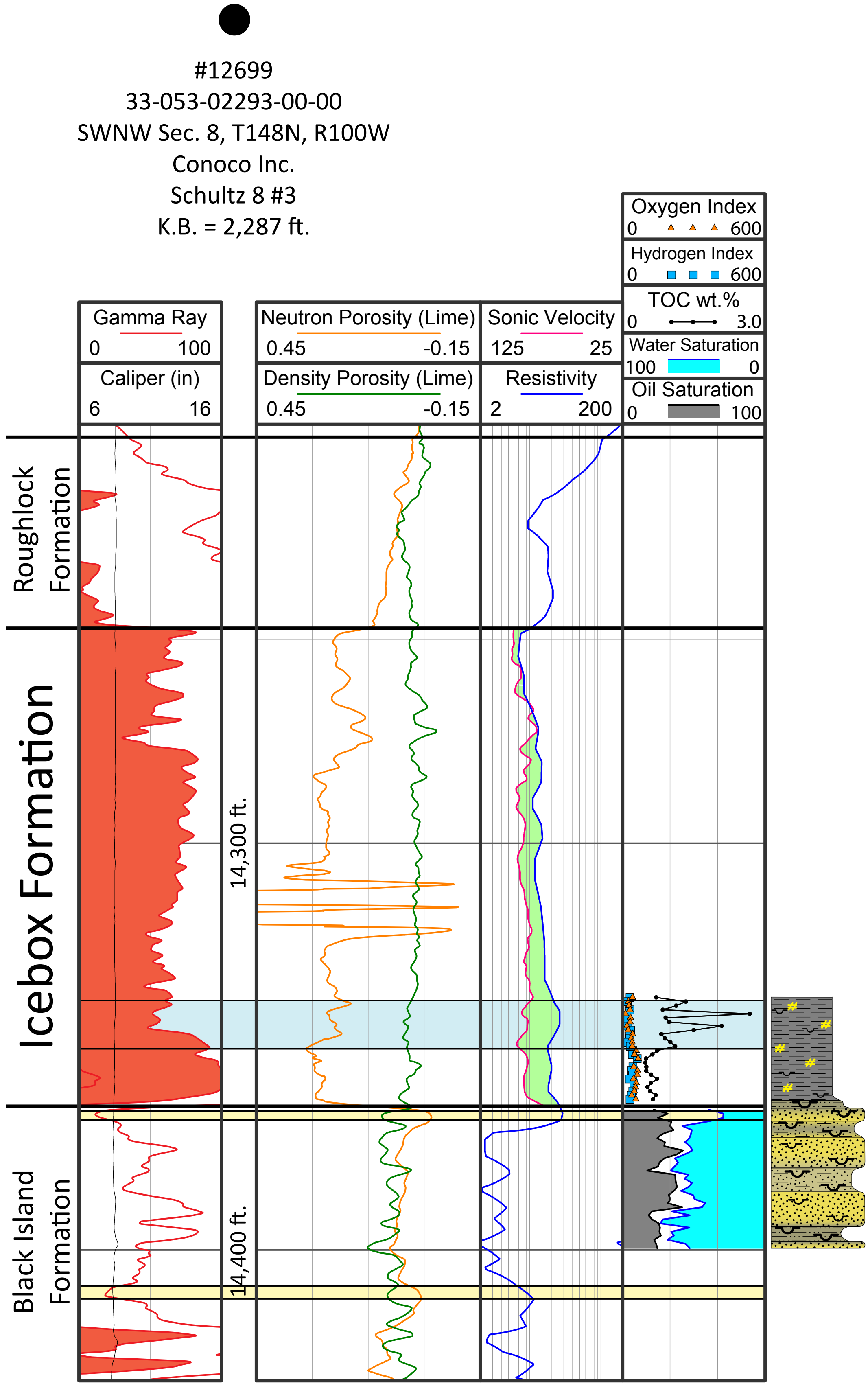

Figure 11. Wireline log of Conoco's Schultz 8 #3 with illustrated lithologies, geochemical data, and core analysis data from the basal Icebox-upper Black Island core. The blue shaded interval represents the Government Creek Shale. The yellow shaded intervals represent Sandstones B & C. Core + 13 ft. = Log

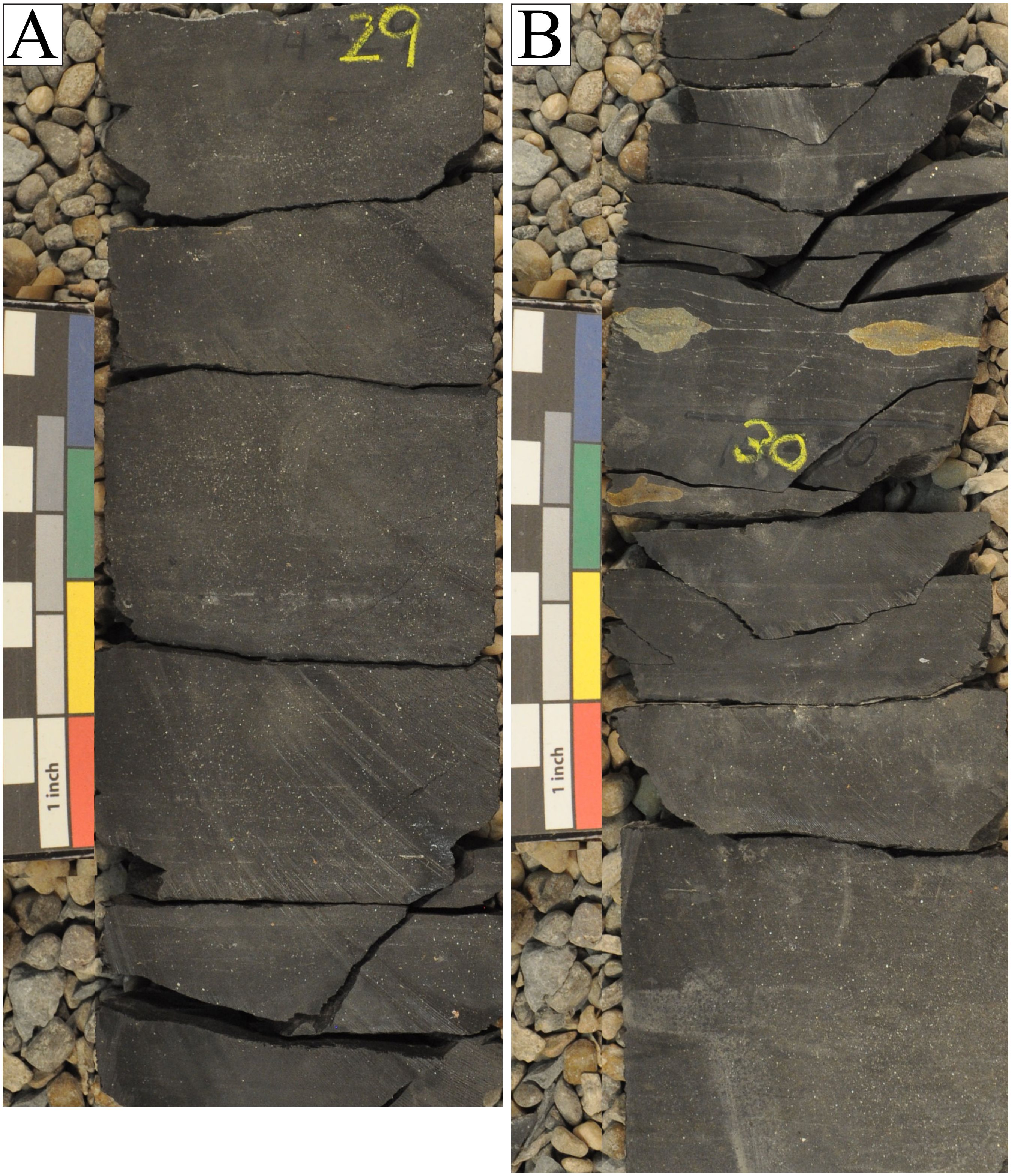

Figure 12. Core photographs of the Icebox Formation (Government Creek Shale) from Conoco's Schultz 8 #3 (NDIC: 12699). A) Very dark to black shale (14,342.0-14,342.7 ft. - log depth), organic-rich (2.7% TOC). B) Very dark grey to black shale (14,342.7-14,343.5 ft. - log depth), moderately organic-rich (0.9% TOC). Core + 13 ft. = Log

Atlantic Richfield's Simpson #1

The Simpson #1 (NDIC: 9800, API: 33-105-01044-00-00) was initially spudded in October 1982 by Atlantic Richfield Company several miles west of the Tioga Field along the northern portions of the Nesson Anticline (Fig. 3). Drilling vertically to a total depth of 14,433 ft., the Simpson #1 drilled through the entire Winnipeg section, 13,863-14,210 ft. (Icebox: 13,881-14,017 ft.), and cut a 45 ft. core along the base of the Icebox and upper Black Island Formations (Fig. 13). A drill stem test run on the upper Black Island Formation (14,007-14,076 ft.) recovered mostly water with some drilling mud and a small amount of gas (Fig. 13). After short lived completions in the Deadwood pool (cum. prod: 953 BBLS oil and 3,180 BBLS water) and Madison pool (cum. prod: 1,278 BBLS oil and 6,294 BBLS water), the Simpson #1 was re-drilled in 2005 as a Bakken horizontal well. After approximately 4 years of minimal Bakken production (3,531 BBLS oil and 23,670 BBLS water), the Simpson #1 was plugged and abandoned.

The Simpson #1 Winnipeg core consists of approximately 41 ft. of lower Icebox section (13,987-14,028 ft.) and approximately 4 ft. of upper Black Island section (14,028-14,032 ft., Fig. 13). Most of the core consists of dark grey to black silty to sandy bioturbated shale interbedded with very dark grey to black shale with minor amounts of pyrite and grey shaley sandstone (Fig. 13, 14). Around 14,005 ft. there is a 7-9 ft. interval of grey to dark grey bioturbated shaley siltstone to fine grained sandstone that exhibits a couple feet of possible oil staining. Also, the basal several feet of the core grades into a few inches of white to very light grey quartz arenite, which may represent Sandstone C of the upper Black Island Formation Garland Member (Nesheim, 2013).

Methodology

The purpose of this study is to further evaluate the Icebox Formation's source rock quality within North Dakota in order to determine whether the Icebox Formation may have generated significant quantities of hydrocarbons (oil and gas). Important components to examine when evaluating potential petroleum source rocks include: total organic carbon (TOC), live hydrocarbon mass (S_2), kerogen type/s of the organic carbon, thermal maturation as well as thickness and extent.

Both drill cutting and core samples from the Icebox Formation were collected and analyzed for this study (Table 1). In 2012, Icebox Formation drill cuttings were collected from 18 different wells and analyzed at Weatherford Labs for Total Organic Carbon (TOC) weight percent. In 2013, five partial Icebox cores from western North Dakota (Fig. 1) were also sampled as part of this study for geochemical analysis. For the William Steckler #1 (#7020), Simpson #1 (#9800), and Schultz 8 #3 (#12699), the Icebox portion of each core was sampled and analyzed in 1 ft. intervals. The Hoff 1-32-4B (#9407, Fig. 1) was sampled and analyzed in 2 ft. intervals as part of this study and independently by Chesapeake Energy in off-setting 2 ft. intervals. The Shell Creek 1-01 (#17058, Fig. 1) core was sampled and analyzed by Chesapeake Energy in 3-5 ft. sample intervals. After examining Chesapeake's data, the core was additionally sampled and analyzed to produce a composite data set with a ~1 ft. sample interval. The

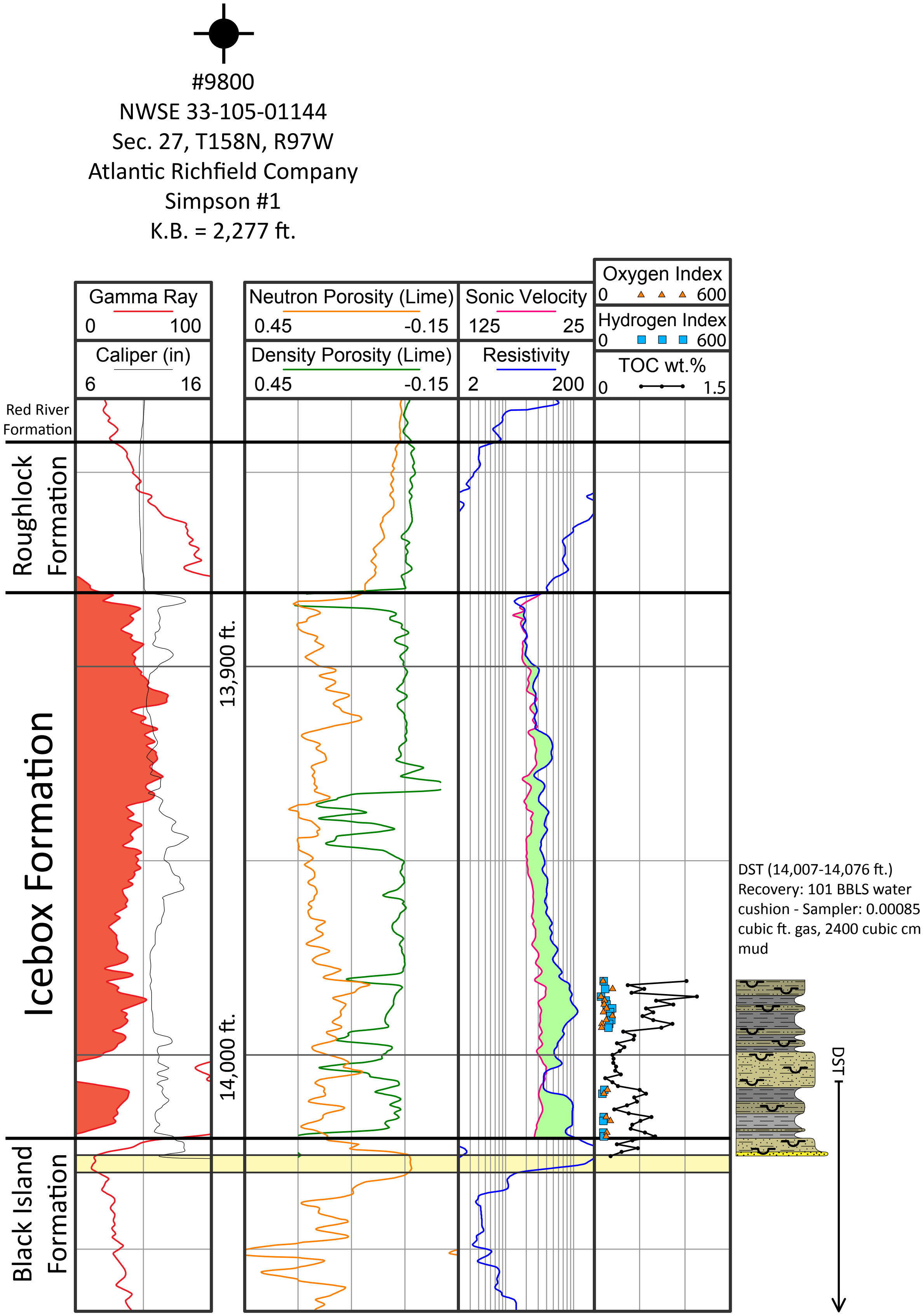

Figure 13. Wireline log of Atlantic Richfield's Simpson #1 with illustrated core lithologies and geochemical data from the lower Icebox/upper Black Island Formations. The yellow shaded interval indicates Sandstone C (Nesheim, 2013). Core - 3 ft. = Log

Figure 14. Core photographs of the Icebox Formation from Atlantic Richfield's Simpson #1 (NDIC: 9800). A) Very dark grey to black shale (13,985.2-13,985.9 ft. - log depth), organic-rich (1.1% TOC). B) orange to dark grey shaley sandstone to sandy shale (14,001.9-14,002.7 ft. - log depth), organic-lean (0.2% TOC). Core - 3 ft. = Log

Table 1. List of wells with Winnipeg Group TOC/RockEval data completed or compiled by this study

Well Name	NDIC #	API Number	Location	Sample Type	Top	Base
William Steckler	7020	33-037-00023	Sec. 5, T137, R88W	Core	10,282	10,305
Hoff 1-32-4B	9407	33-089-00270	Sec. 32, T139, R92W	Core	11,576	11,607
Shell Creek 1-01	17058	33-061-00660	Sec. 1, T152, R90W	Core	13,070	13,157
Simpson #1	9800	33-105-01044	Sec. 27, T158, R97W	Core	13,984	14,029
Schultz 8 #3	12699	33-053-02293	Sec. 8, T148, R100W	Core	14,325	14,350
North Dakota State #1	230	33-043-00004	Sec. 16, T143N, R71W	Cuttings	4,800	4,970
Zach Brooks-State #1	485	33-011-00042	Sec. 16, T129N, R104W	Cuttings	9,705	9,810
F.C. Neuman #1	588	33-101-00009	Sec. 33, T152N, R82W	Cuttings	9,460	9,650
Karl Schock #1	622	33-051-00005	Sec. 17, T131N, R69W	Cuttings	3,660	3,770
F. L. Robertson #1	673	33-093-00014	Sec. 26, T138N, R67W	Cuttings	3,530	3,670
Anton Novy #1	763	33-015-00009	Sec. 14, T144N, R77W	Cuttings	6,740	6,900
Burlington Northern #1	5572	33-037-00020	Sec. 27, T132N, R86W	Cuttings	7,780	7,940
Jacobs #1	6654	33-085-00005	Sec. 27, T129N, R85W	Cuttings	7,100	7,150
Welch #1	7010	33-015-00042	Sec. 31, T138, R78W	Cuttings	6,320	6,480
Anderson #12-9	7271	33-027-00009	Sec. 9, T148N, R65W	Cuttings	3,470	3,620
Jacob Christman #1	7642	33-001-00009	Sec. 28, T130N, R95W	Cuttings	9,670	9,800
Olin #1	7691	33-059-00027	Sec. 19, 138, R85W	Cuttings	9,190	9,350
Larson #1	8307	33-049-00125	Sec. 31, T155N, R77W	Cuttings	6,920	7,100
Mary Artz #1-5-2A	8546	33-053-01311	Sec. 5, T150N, R104W	Cuttings	13,100	13,250
Mormon Butte Fed. #2-25-2C	8663	33-053-01341	Sec. 25, T147N, R98W	Cuttings	14,340	14,480
Halliday #16-6	9080	33-025-00274	Sec. 28, T138N, R102W	Cuttings	13,150	13,310
Miller 33-1 #1	10570	33-089-00313	Sec. 1, T138N, R96W	Cuttings	12,250	12,390
L. Selvig #1	12125	33-069-00043	Sec. 1, T158N, R72W	Cuttings	5,230	5,360

geochemical data set produced by Chesapeake Energy from Icebox Formation cores yielded similar values to the data set produced by this study and was therefore incorporated into this report. All of the recent geochemical data from Icebox Formation core and drill cuttings completed and compiled by this study is displayed in Table 3 and 4 of Appendix A.

Drill cutting and core samples were analyzed for this study using the LECO® TOC (Bernard et al., 2009) method at Weatherford Labs. The LECO® TOC method measures the total organic carbon (TOC) weight percent in a given sample while excluding the inorganic carbon. Source rock quality can be classified in terms of weight % TOC (Dembicki, 2009) as follows:

Poor	<0.5%
Fair	0.5 to <1.0%
Good	1.0% to <2.0%
Excellent	≥2.0%

Core samples with ≥0.5 wt. % TOC were also analyzed using Rock Eval 6 at Weatherford Labs. Rock Eval is an analytical method that artificially matures a rock sample by subjecting the samples to elevated temperatures. Components measured during Rock Eval include: free hydrocarbon mass (S1), live hydrocarbon mass (S_2), and the mass of oxygen-bearing hydrocarbons (S3). While some of the components of Rock Eval are discussed below, further review, discussion, and additional references of the method can be found in Dembicki (2009) and Nordeng (2012).

S_2, live hydrocarbon mass, is the amount of organic carbon (kerogen) measured during Rock Eval analysis which is capable of being converted into hydrocarbons and is measured in milligrams of hydrocarbons per gram of sample (mg/g). As an organic-rich source rock matures and kerogen is converted into hydrocarbons, the source rock's S_2 decreases. Source rock quality can be classified in terms of S_2 (Dembicki, 2009) as follows:

Poor	<2.5 mg/g
Fair	2.5 to <5 mg/g
Good	5 to <10 mg/g
Excellent	≥10 mg/g

Depending on the type of kerogen present, an organic-rich source rock may be prone to generating oil and/or gas during the "oil generation window." Type I kerogen is prone to generating oil, Type II is prone to generating oil and gas, Type III is prone to generating gas, and Type IV is inert, incapable of generating either oil or gas. Type I and II kerogen commonly form within lacustrine and/or marine settings whereas Type III typically forms from terrestrial origins (e.g. land plants). Rock Eval measures S_2 (live hydrocarbon mass) and S3 (oxygen-bearing hydrocarbon mass) which can be converted into Hydrogen Index and Oxygen Index values. The ratio of Hydrogen Index versus Oxygen Index can provide insight into the type/s of kerogen present within a source rock (e.g. Figure 15). Type I and II kerogen

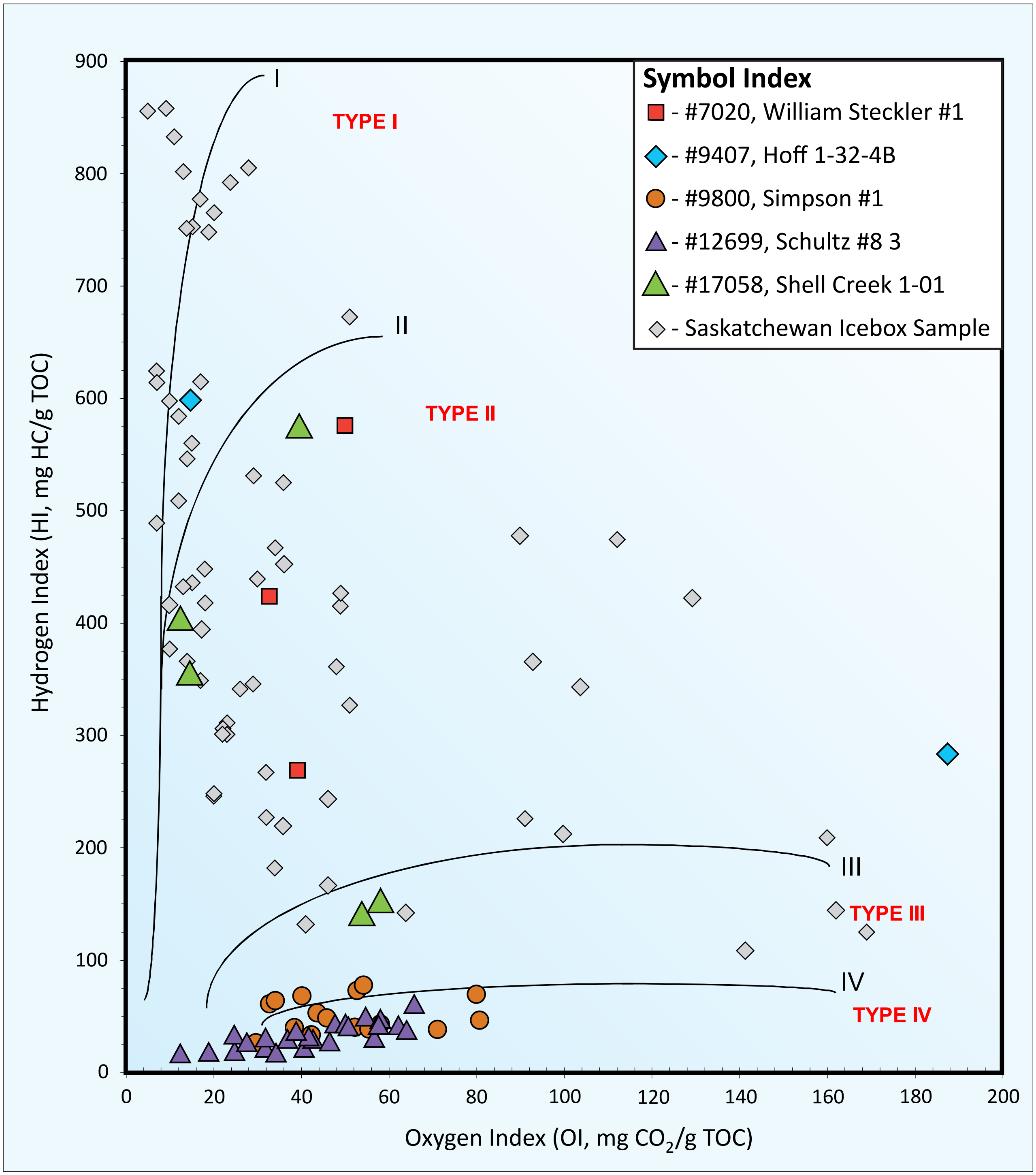

Figure 15. Modified van krevelen diagram plotting Hydrogen vs. Oxygen Index values for Icebox Formation samples from across Saskatchewan and western North Dakota. The Saskatchewan data set is compiled from Osadetz and Snowden (1986; 1995) and Siebel (2002). Explantion of sample symbols is explained above (top right). Several samples plot off scale (primarily to the right). Samples from the Hoff 1-32-4B and Shell Creek 1-01 cores analyzed by Chesapeake Energy did not include Oxygen Index values and therefore were not plotted above. Samples from the Simpson #1 and Schultz 8 #3 consist of Type IV inert kerogen.

display higher Hydrogen Index values (S_2) with low Oxygen Index values (S3). During maturation, the overall Hydrogen Index of a source rock will become lower.

Tmax is the temperature during Rock Eval analysis that produces the most hydrocarbon vapor and can be used to estimate a source rock's level of thermal maturity. Samples with measured S_2 values of <0.5 mg/g yield unreliable Tmax values, and samples with measured S_2 values of 0.5-1.0 mg/g yield questionable Tmax values. Samples with >1 mg/g of S_2 should provide reliable Tmax values. Approximate ranges (windows) of maturation based on Tmax are listed below:

Immature	<435°
Oil Generation	435° to 455°
Wet Gas	455° to 475°
Dry Gas	>475°

The above Tmax ranges are approximate and can vary several degrees either plus or minus depending on the kinetics of the organic material present in the source rock. A source rock may thermally generate small amounts of oil and/or gas within the immature window, but not enough to be economically significant. During oil generation (Tmax: ~435°-455°), most of a source rocks S_2 is converted into oil and/or gas and the TOC wt. % drops. As a mature source rock begins to move through the wet gas window and into the dry gas window, previously generated oil begins to convert into hydrocarbon gas (e.g. methane).

In addition to geochemical analysis (TOC & Rock Eval), this study incorporated the use of the Δ log R technique developed by Passey et al. (1990), a wireline log analysis technique that can differentiate organic-rich versus organic-lean intervals. The Δ log R technique involves combining deep resistivity with sonic velocity, neutron porosity, or formation density log to examine and potentially calculate TOC values. Within this report, cross-plots of deep resistivity and sonic velocity are displayed and referred to for wells of interest. Typically, immature organic-rich rock intervals display slower sonic velocities than organic-lean rock intervals, because sonic waves take longer to travel through organic material. An organic-rich source rock's sonic velocity will decrease during thermal maturation as organic material is converted to hydrocarbons (Passey et al., 1990). Meanwhile, the resistivity signature will increase during maturation as non-conductive hydrocarbons are generated and displace the typically more conductive formation water (Passey et al., 1990).

Results

Texas Pacific Oil Company's William Steckler #1

Overall, the Icebox portion from the William Steckler #1 Winnipeg core averages 0.37% TOC (0.10-1.52%). A thin, ~2 ft. thick interval near the top of the core averages 1.2% TOC (0.80-1.52%) with Hydrogen (HI) and Oxygen (OI) Index values that plot near a Type II kerogen curve (Fig. 15) and classifies as fair to good quality source rock (Fig. 16). This organic-rich interval does not stand out on the deep resistivity-sonic velocity cross-plot (Fig. 5), a log analysis method used to pick out organic-rich intervals

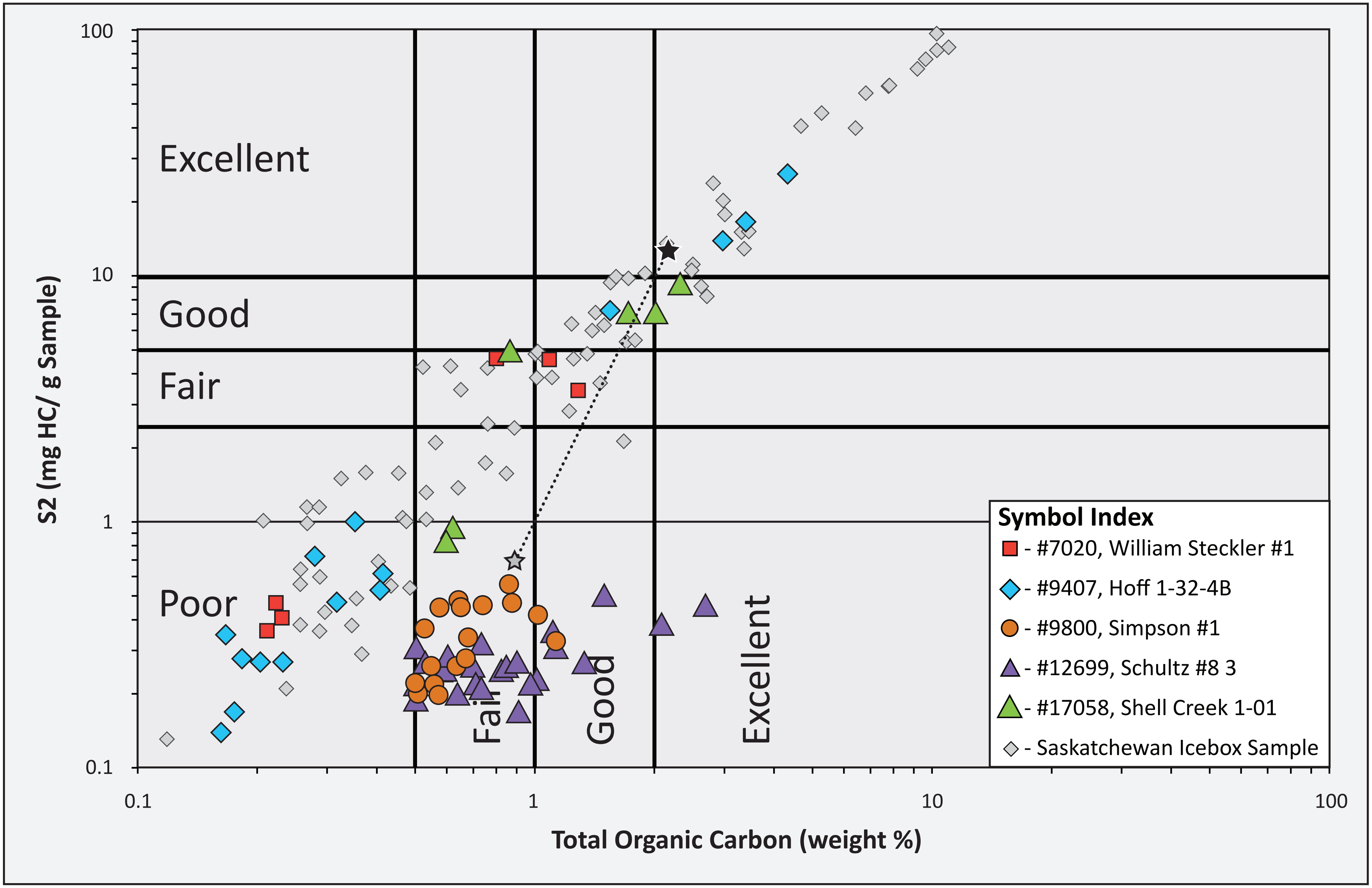

Figure 16. Organic-richness plot (Dembicki, 2009) of Icebox core samples from North Dakota and Saskatchewan. The black star depicts the average Icebox Formation sample from the Saskatchewan data set (Osadetz and Snowden, 1986; 1995; Siebel, 2002) and the grey star represents the average Saskatchewan sample after 95% kerogen conversion from its current state.

(Passey et al., 1990). With reliable Tmax values of 434-436° (S_2 ~3-4 mg/g), the Icebox Formation in the area of the William Steckler #1 is likely located near the beginning of the intense oil generation window.

Gulf Oil's Hoff 1-32-4B

Overall, the Icebox core samples analyzed from the Hoff 1-32-4B by the NDGS and Chesapeake combine to average 0.98% TOC (0.16-4.33%). Most of the Icebox samples, however, contain <0.35% TOC with the exception of a thin, 3-4 ft. shale interval near the base of the Icebox section that averages 3.56% TOC (2.95-4.33%) with an S_2 of 18.9 mg/g (14.1-25.9) (Fig. 7) which plots as an excellent quality source rock (Fig. 16) consisting of Type I/Type II kerogen (Fig. 15). This thin organic-rich shale displays a more positive deep resistivity- sonic velocity cross-plot divergence signature than the surrounding section (Fig. 7). The deep resistivity and sonic velocity logs cross-plot nearly on top of one another for the remainder of the Icebox section, indicating the low TOC values measured from the upper several feet of the Hoff core extend across most of the Icebox section. Tmax values measured across the more organic-rich interval were 442-448°, which place maturation within the middle of the oil generation window.

EOG Resources Shell Creek 1-01

The Shell Creek 1-01 Icebox core samples range from 0.08 to 2.32% TOC and average 0.33% TOC. The upper 37 ft. of the core averages 0.20% TOC while the lower 49 ft. of the core becomes a little more organic-rich averaging 0.43% TOC (Fig. 9). Near the base of the Shell Creek 1-01 is a thin, ~2.5 ft. thick organic-rich shale section (13,145.5-13,148 ft., Fig. 9), similar to the Hoff 1-32-4B Icebox core. Samples from this thin organic-rich shale interval average 1.73% TOC (0.86-2.32%), classify as fair to excellent quality source rock (Fig. 16), and plot along a Type II kerogen curve (Fig. 15). This organic-rich interval does have a slightly positive deep resistivity-formation density cross-plot signature indicating organic-richness (Passey et al., 1990), primarily with a higher resistivity than the surrounding section (Fig. 9). Reliable Tmax values of 437-440° suggest the core was collected from the Icebox Formation's oil generation window. This organic-rich interval is more darkly colored than most of the remaining cored Icebox section (Fig. 10).

Conoco's Schultz 8 #3

TOC values from Conoco's Schultz 8 #3 Icebox core range from 0.48 to 2.68% TOC with an average 0.91% TOC. Notably, the lower 12 ft. of the core is less organic-rich with an 0.59% TOC average while the upper 13 ft. is more organic-rich with an average of 1.23% TOC (Fig. 11). The upper, more organic-rich half of the Icebox core correlates with a slightly more positive sonic velocity-deep resistivity cross-plot log signature than the surrounding section, most notably having a higher resistivity (Fig. 11). Using the upper 30-40 ft. of the Icebox Formation as a baseline, the lower 90 ft. of the Icebox section displays a consistent positive sonic velocity-resistivity cross-plot divergence suggesting the lower 90 ft. of the Icebox is more organic-rich than the upper 30-40 ft. Despite fair to excellent quality TOC values, the Conoco Schultz Icebox samples contained very low S_2 values, indicating very low remaining hydrocarbon generation potential.

Tmax values from the Conoco Schultz Icebox core range from 408° to 509° and cluster around 475°, indicating the core was retrieved from the Icebox's dry gas window. However, nearly all of the Tmax values from the Schultz 8 #3 are unreliable due to low S_2 values (<0.5 mg/g). Even though the Tmax values are unreliable, Black Island bottom hole temperatures measured during drill stem tests run within surrounding wells were ≥275° F, a sufficient temperature level where the Icebox Formation should have undergone significant thermal maturation. High levels of thermal maturation may account for the low S_2 values.

Atlantic Richfield's Simpson #1

Samples from the Simpson #1 core yielded TOC values ranging from 0.12 to 1.13% with an average of 0.45% TOC. The sandy shale to sandstone samples average 0.28% TOC while the shale samples range from 0.38-1.13% TOC and average 0.62%. Similar to the Schultz 8 #3, the sonic velocity-deep resistivity cross-plot consistently diverges across most of the lower 100 ft. of the Icebox Formation (Fig. 13) where core shale samples average 0.62% TOC. The Tmax values measured primarily range from 480°-502° and indicate the Icebox Fm. is within the dry gas window, however the S_2 values measured were all too low (<0.5 mg/g) for the Tmax values to be reliable. A bottom hole temperature of 276°F was recorded during a Black Island drill stem test run on the Simpson #1. This should be an adequate temperature level to have significantly thermally matured the Icebox Formation. Low S_2 and Hydrogen Index values indicate the Icebox portion of the Simpson #1 core has very low remaining hydrocarbon generation potential which could be the result of significant thermal maturation (Fig. 15 and 16).

Core Data Set Summary

A total of 209 Icebox core samples were analyzed from the five cores reviewed above between this study (166) and the Chesapeake Energy project (43). Overall, the Icebox core data set ranges from 0.05% to 4.33% TOC with an average of 0.47%. Seventy seven samples were analyzed using Rock Eval. Sample core depths ranged from 10,282 ft. to 14,350 ft. with reliable Tmax values from 434° to 448°. Samples from core depths of greater than 13,900 ft. did not yield reliable Tmax values. Eleven of the seventy seven samples analyzed using Rock Eval had S_2 values greater than 2.5 mg/g, which classify as fair quality source rock or better.

Drill Cutting Data Set

An initial set of Icebox Formation drill cutting samples were collected during this study (Fall 2011) and analyzed at Weatherford Labs (Winter 2011-12) for weight percent total organic carbon (TOC) (Appendix A-Table 4). Drill cutting sets were collected from the entire Icebox section from sixteen different wells located across North Dakota, and partial sections of the Icebox Formation from two additional wells (Fig. 3). None of the Icebox drilling cuttings analyzed for the NDGS were analyzed using Rock Eval. For the 221 Icebox drill cutting samples analyzed, the TOC wt. % ranged from 0.11% to 2.32% TOC and averaged of ~0.53%.

Discussion and Interpretations

The drill cutting TOC data set was generated during this study prior to examining available Icebox core. Upon examining available Icebox core and then reexamining the remaining, non-analyzed Icebox drill cuttings from sampled wells, the Icebox drill cuttings were noted to contain variable amounts of white limestone. None of the Icebox cores examined contained any amount of white limestone, which suggests the white limestone may have originated as caved materials from an overlying interval such as the Red River Formation. Assuming the white limestone is very organic-lean (<0.2% TOC), the TOC values measured off of the Icebox drill cuttings (contaminated with lower Red River white limestone) are likely low to the actual TOC values of the Icebox Formation. Drill cutting TOC values tend to increase downward through the Icebox section for wells sampled from western North Dakota, which could be the result of decreasing organic-lean caving material contaminating the Icebox drill cuttings (Fig. 17 and 18).

The drill cutting TOC average (0.53%) is similar to the Icebox TOC average reported by Williams (1974) of 0.42%. Williams (1974) noted that Ordovician strata (including the Winnipeg shale/Icebox Formation) tend to be organic-lean due to thermal exposure driving off volatile material (maturation) and dilution from organic-poor caved materials. Considering Williams (1974) comments about caved materials, and that most of the Icebox cores observed by this study were cut after 1974, most (possibly all) of the Icebox Formation samples analyzed by Williams (1974) were likely drill cuttings which may have been subject to caved white limestone contaminated as described above. Overall, the Icebox TOC values measured off of drill cuttings (Fig. 17, 18) are assumed to be minimum values of the Icebox Formation's actual TOC.

While the Icebox TOC core average reported by this study of 0.47% is similar to that of the drill cutting TOC average (0.53%), the core data set is moderately biased and likely has been affected by thermal maturation. Forty percent (two-fifths) of the Icebox core samples included in this study were from the Shell Creek 1-01 (84 of 211 samples), which had the lowest TOC average of the five cores sampled (0.33%). Additionally, all of the cores sample were collected from depths of greater than 10,000 ft. and typically yielded Tmax values indicating moderate to high levels of thermal maturation which would have lowered the original TOC values. Thermal maturation of the Icebox Formation is discussed below.

Thermal Maturity

To examine the Icebox's thermal maturity, core measured Tmax values were correlated with preliminary thermal modeling. Preliminary thermal modeling was completed using the methodology of Nordeng and Nesheim (2011) with a Bakken shale member activation energy (the energy necessary to convert kerogen to hydrocarbons) to calculate the percentage of Icebox kerogen converted to hydrocarbons (Fig. 19). The William Steckler #1 (#7020) is located near the outer edge of the Icebox Formation's oil generation window both in terms of kerogen conversion (<5%, Fig. 19) and measured Tmax values (434-436°). The Hoff 1-32-4B (#9407) and Shell Creek 1-01 (#17058) both plot within the area of 5-95%

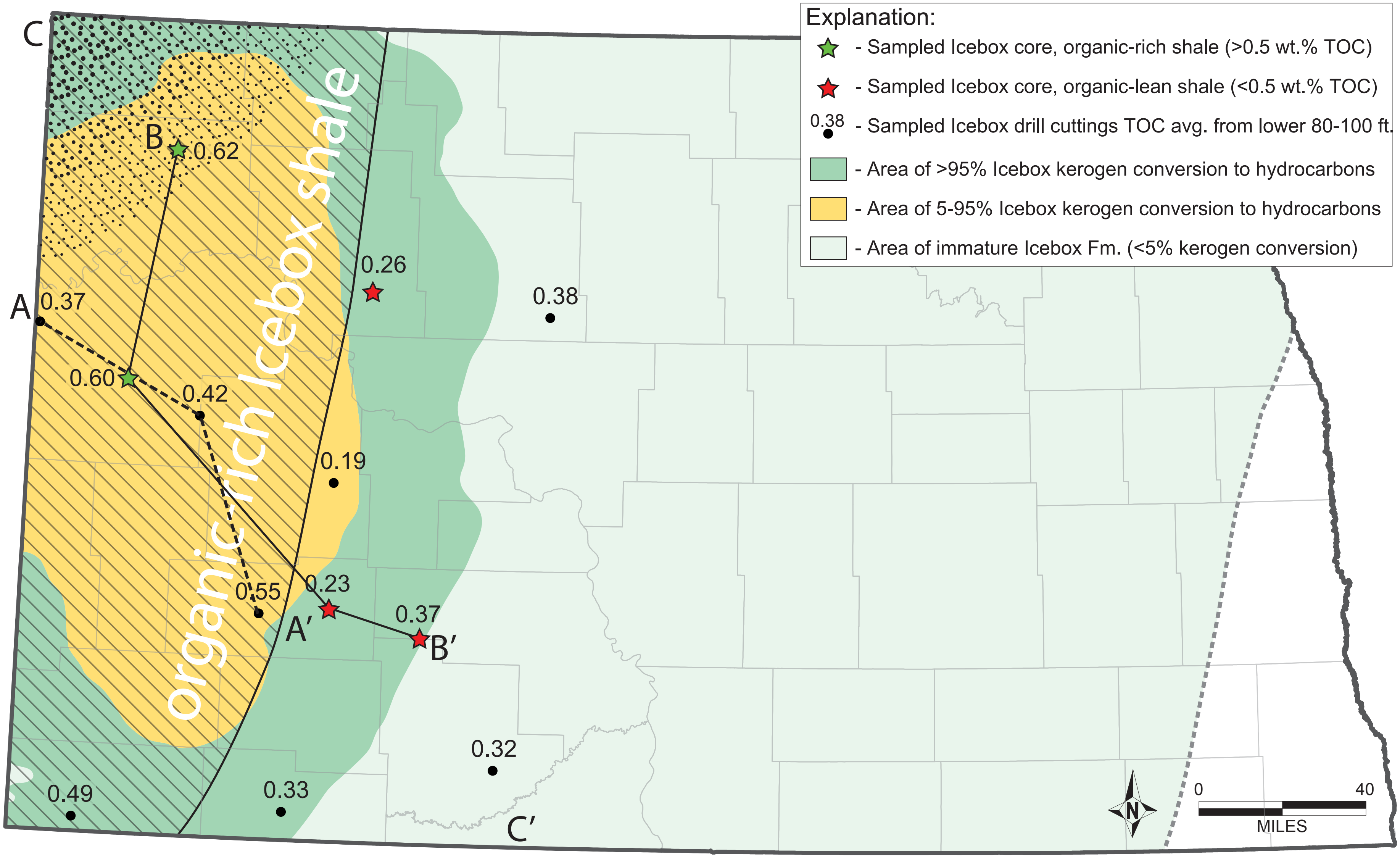

Figure 17. Map depicting the approximate area where the lower 70-100 ft. of the Icebox Formation (minus the Government Creek Shale) averages as a fair to good quality source rock. Core TOC averages (numbers above stars) exclude the Government Creek Shale (GCS). Drill cutting samples were analyzed "as is," meaning that sluff/contaminent pieces from the overlying lower Red River and Roughlock Formations were not removed prior to analysis (these overlying intervals likely average <0.2% TOC). A-A′ depicts the position of the Figure 18 cross-section, B-B′ the Figure 21 cross-section, and C-C′ the Figure 22 cross-section.

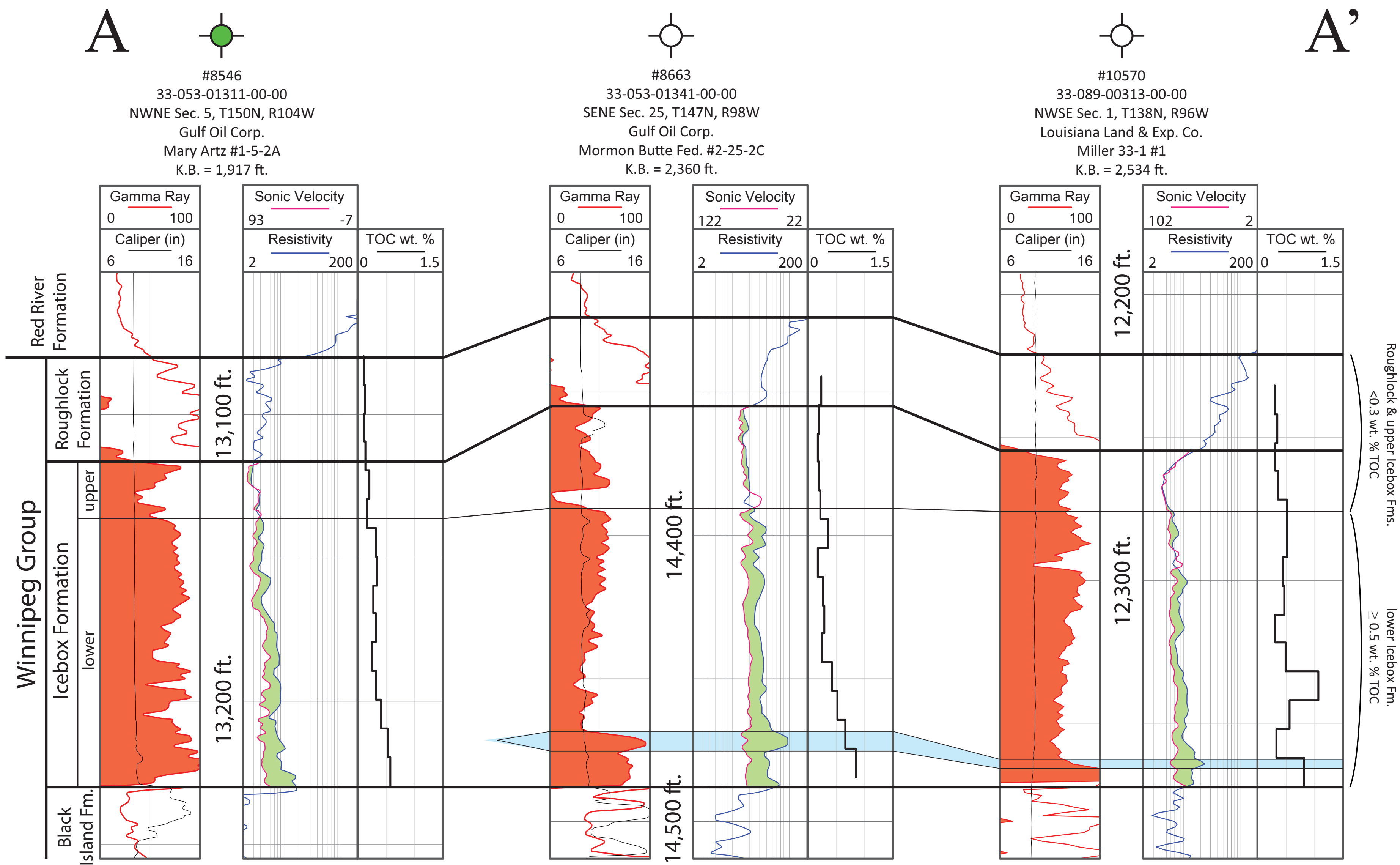

Figure 18. Stratigraphic cross-section of the Icebox Formation with Total Organic Carbon weight percent (TOC wt. %) measured off of drill cuttings. Drill cuttings were collected in 10 ft. intervals across the Winnipeg Group for the wells displayed above. The measured TOC content begins to increases 20-40 ft. from the top of the Icebox Formation, which is also where a positive resistivity-sonic velocity cross-plot divergence begins (indicating an increase in organic-richness, Passey et al., 1990). Together, the log response and the measured TOC values indicate the lower 80-100 ft. of the Icebox Formation is more organic-rich than the upper 20-40 ft. Note how within the Mary Artz and Mormon Butte Federal wells, the measured TOC values continue to increase moving towards the base of the Icebox Formation which could be the result of a decrease in organic-lean (<0.3% TOC) upper Icebox, Roughlock, and basal Red River Formations mixing with the modestly organic-rich (≥ 0.5 TOC) lower Icebox Formation . The upper/lower Icebox distinction is merely a separation between the apparent organic-lean (<0.3% TOC) upper 20-40 ft. of the Icebox section and the moderately organic-rich (≥ 0.5% TOC) lower 80-100 ft. of the Icebox section.

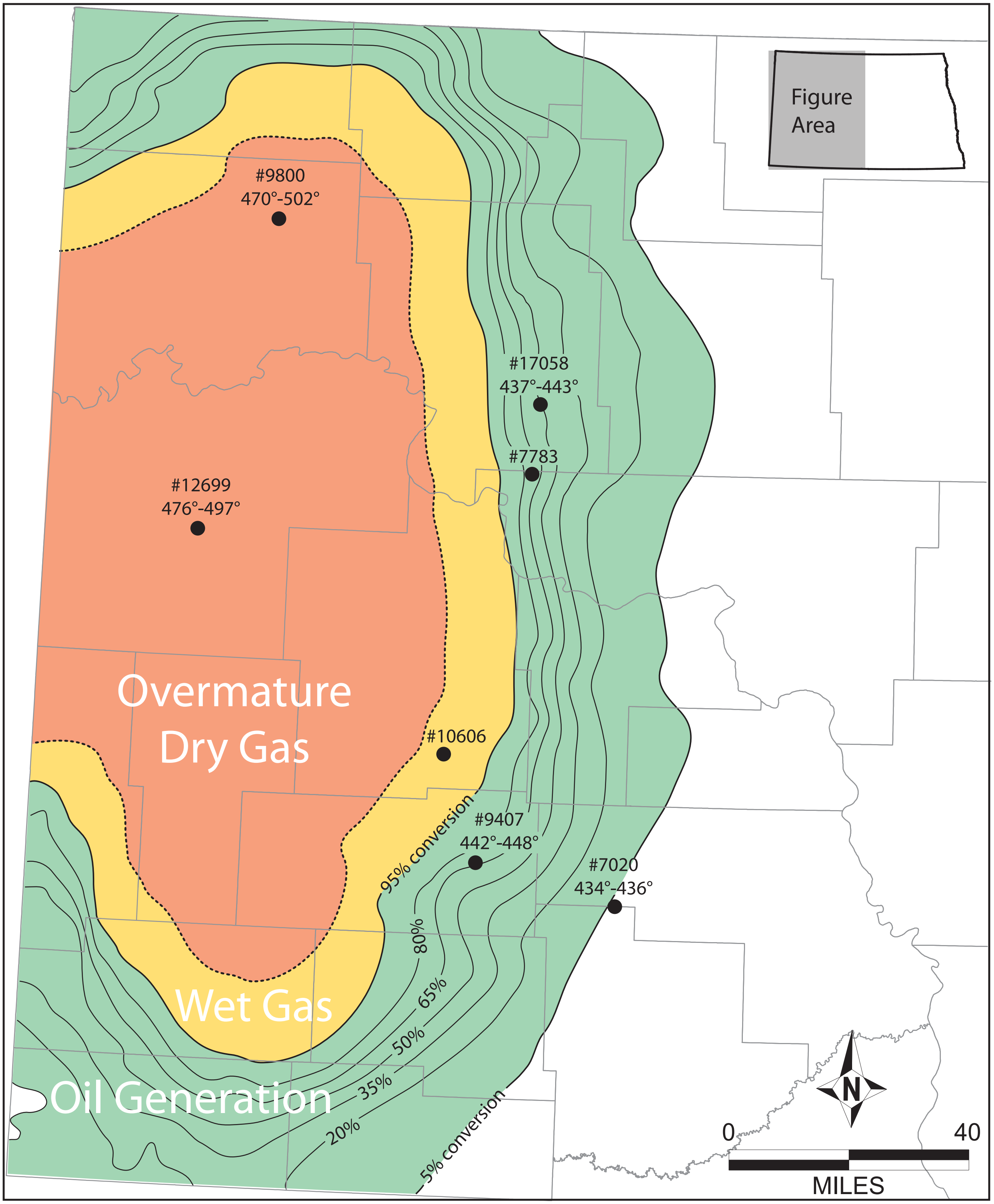

Figure 19. Enhanced version of a Time-Temperature Index map illustrating the expected percentage of the Icebox's original kerogen that has been converted to hydrocarbons (assumes a Bakken shale equivalent activition energy). Tmax values measured from Icebox Fm. core samples are posted above respective wells along with the well NDIC numbers. The Icebox Fm. in wells #7783 and #10606 were modeled by L.N.R. Roberts (USGS) using Woodford source rock kinetics to have undergone 96% and 100% kerogen conversion with oil generation starting around 90 Ma (Anna, 2010). Most of the Tmax values from wells #9800 and #12699 are unreliable (S2 < 0.5 mg/g).

kerogen conversion, the Icebox Formation's approximate oil generation window, and also yielded Tmax values within the range of oil generation (437-448°). While both the Schultz 8 #3 (#12699) and Simpson #1 (#9800) yielded unreliable Tmax values, they both fall within the model area of >95% kerogen conversion which may correlate with the Icebox's wet gas to dry gas windows (Fig. 19). So while the thermal modeling displayed in Figure 19 is preliminary and requires additional work, the core measured Tmax values approximately align maturity trends displayed within the preliminary thermal maturity model.

Government Creek Shale

Near the base of the Icebox Formation is a regionally extensive, organic-rich shale interval that is informally referred to in this study as the Government Creek Shale. This study initially noted a 3-4 ft. shale interval present near the base of the Hoff 1-32-4b's Icebox core that is more darkly colored than the surrounding shale (Fig. 7, 8) with previous core measured oil saturations of ~70% versus 15-20% oil saturation within the surrounding shale (Fig. 7). A very positive deep resistivity-sonic velocity cross-plot log signature (Fig. 7) was also noted across this darkly colored, oil saturated shale interval which indicates organic-richness through log analysis (Passey et al., 1990). Geochemical analysis confirmed this shale interval to be an excellent quality source rock within the Hoff core (TOC: 2.95-4.33%, S_2: 14.1-25.9 mg/g) and the positive resistivity-sonic velocity cross-plot signature was mapped throughout surrounding wells (e.g. Fig. 20, 21). This organic-rich shale interval near the base of the Icebox section was informally named by this study as the Government Creek Shale (GCS) after the Government Creek which runs near the Hoff 1-32-4b well location.

The Government Creek Shale (GCS) is also noted to be present within the Shell Creek 1-01 (Fig. 9, 10, 21), and the Schultz 8 #3 (Fig. 11, 12, 21) cores, while being absent from the Simpson #1 and William Steckler #1 Icebox cores. The GCS thins to ~2.5 ft. thick within the Shell Creek 1-01 and averages 1.7% TOC, and thickens to ~12 ft. with an average TOC of 1.3% within the Schultz 8 #3. The lower TOC average of the GCS within the Schultz 8 #3 versus the Hoff 1-32-4B may in part be due to higher levels of thermal maturity that has converted some of the original organic-carbon into hydrocarbons. While elements of the GCS may be present in the Simpson #1 (Fig. 21), the organic material of the interval has been marginalized by increased quartz sand content (Fig. 13, 14, 21). The William Steckler's Icebox core contains a more organic-rich shale section (Fig. 5, 6), but it appears to be stratigraphically high (Fig. 21) and does not correlate with a substantially positive deep resistivity-sonic velocity cross-plot signature (Fig. 5).

Non-GCS Organic-Richness

Within the eastern portion of the study area (~central North Dakota), the non-Government Creek Shale (non-GCS) portion of the Icebox Formation appears to overall be organic-lean. Within the three eastern sampled Icebox cores, the William Steckler #1 (#7020), Hoff 1-32-4b (#9407), and Shell Creek 1-01

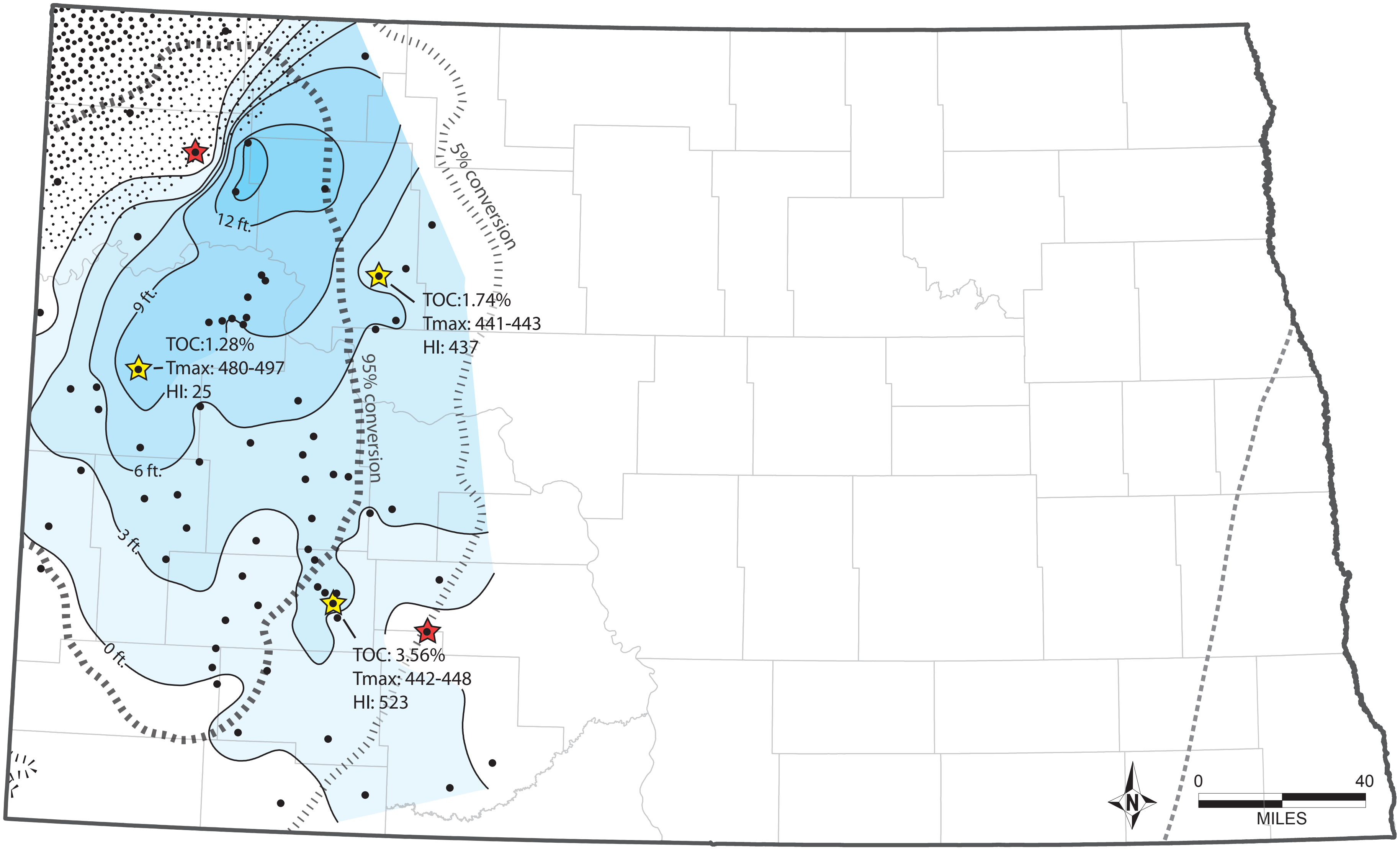

Figure 20. Isopach map of the Government Creek Shale (GCS) with geochemical core data. The black dots represent the control wells used to generate the GCS isopach contours by picking the GCS top and base off of wireline log cross-plots of deep resistivity and sonic velocity (e.g. Fig. 7, 9, 11, 21). The red stars represent basal Icebox cores that do not appear to contain the GCS. The yellow stars represent basal Icebox cores examined and sampled by this study that contain the GCS. The dotted area in the northwestern corner of the map represents where the base of the Icebox Formation contains sandy to sandstone lithofacies. The 5% and 95% conversion contours are borrowed from Figure 19.

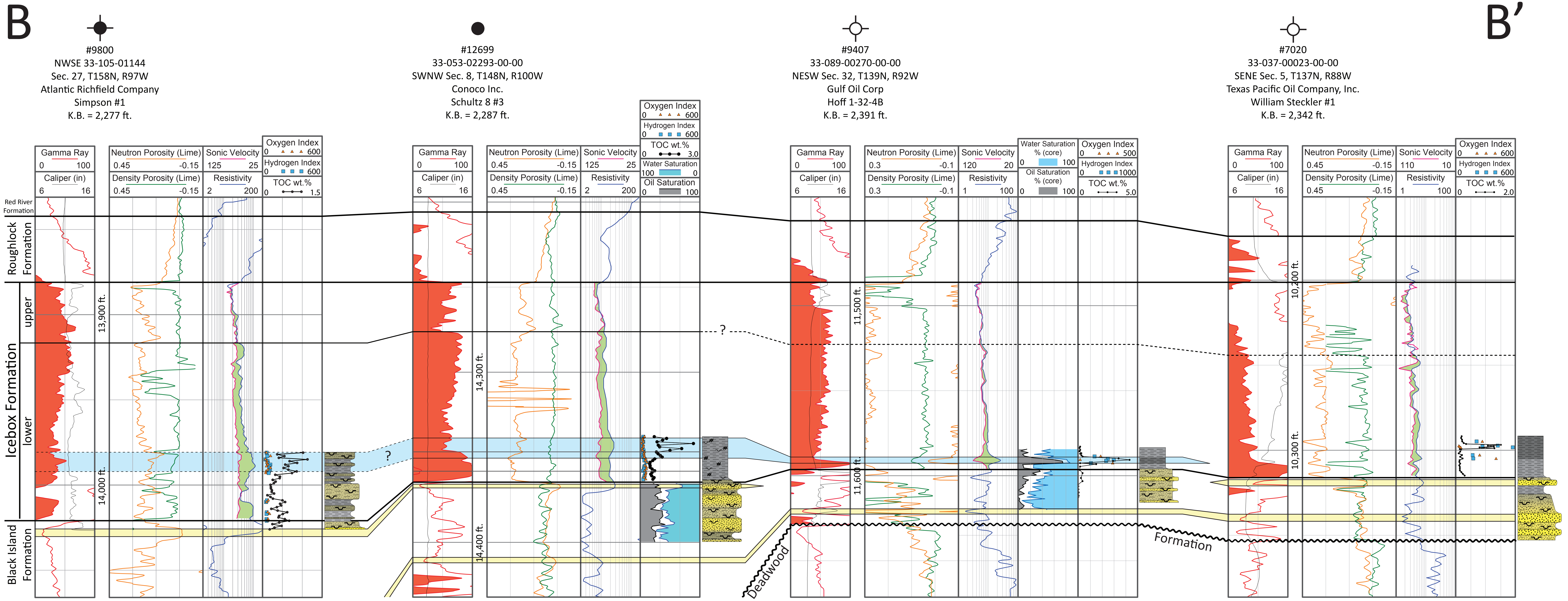

Figure 21. Stratigraphic cross section of the Icebox Formation with wireline logs and core information. The location of A-A' is displayed on Figure 17. The upper-lower Icebox Fm. contact is placed where the sonic velocity-deep resistivity log cross-plot diverges, presumably because the lower 80-100 ft. of the Icebox is more organic-rich upper 30-40 ft. The upper-lower Iceobx distinction appears to only be valid in the deeper and/or more western portions of the Williston Basin in North Dakota. The entire Icebox section appears to become organic-lean moving eastwards in North Dakota. The blue shaded interval represents the Government Creek Shale.

(#17058), the non-GCS Icebox shale samples average 0.23 to 0.37% TOC (Fig. 17) with overall low S_2 values that classify as poor quality source rock (TOC <0.5%, S_2 <2.5 mg/g). All three of these cores were collected near or within the Icebox Formation's preliminary oil generation window (Fig. 17). Thermal maturation therefore may have lowered the original TOC values to some degree. However, with TOC values averaging well under 0.5%, the non-GCS shale at these well locations was very likely poor quality source rock before any thermal maturation took place.

Moving westwards, the non-GCS shale portion of the Icebox Formation becomes more organic-rich despite greater burial depths and higher levels of maturation. The non-GCS Icebox shale samples within the Schultz 8 #3 (#12699) and Simpson #1(#9800) average ~0.6% TOC, which is about two to three times higher than any of the three eastern core averages (Fig. 17). Examining the Schultz and Simpson wireline logs (Fig. 11, 13, 21), both wells have a similar positive deep resistivity-sonic velocity cross-plot divergence across most of the lower 90-100 ft. of the Icebox section which suggests the non-GCS ~0.6% TOC core average may extend across most of the lower 90-100 ft. of the Icebox section. Both of the western two cores (Schultz 8 #3 and Simpson #1) fall within the Icebox Formation's preliminary wet to dry gas window (Fig. 19, depths of $\geq$14,000 ft. and temperatures $\geq$275°F) where most of the organic carbon (active kerogen) that was capable of converting to hydrocarbons has been converted. Figure 22 schematically illustrates the Winnipeg Group's geology along with the interpreted distribution of current organic carbon content across Icebox Formation. Assuming the Icebox Formation originally had hydrocarbon generation potential, the current TOC and S_2 values of the Schultz and Simpson cores are significantly lower than they were pre-maturation.

Original Non-GCS Icebox Shale TOC wt. % and S_2 Values across western North Dakota

The western quarter of North Dakota, where the non-Government Creek Shale (non-GCS) portion of the lower Icebox Formation is more organic-rich, shares a northern border with Saskatchewan (Fig. 1). In Saskatchewan, the Icebox Formation is at shallower depths with lower thermal maturity levels and has good hydrocarbon generation potential (Osadetz and Snowden, 1986; 1995; Siebel, 2002). The Saskatchewan Icebox data set compiled during this study from Osadetz and Snowden (1986; 1995) and Siebel (2002) averages 2.18% TOC with an S_2 of 13.52 mg/g. The S_2 (13.52 mg/g) component alone is 1.35 wt. %, which is approximately 62% of the overall TOC.

If the average Saskatchewan Icebox sample was matured to the point of 95% kerogen conversion to hydrocarbons from its current state, and the hydrocarbon volume was expelled, the average TOC would drop from 2.18% to 0.90% (Eq. 1) with an S_2 of 0.68 mg/g (Fig. 16).

Eq. 1 original TOC wt. % - (original S_2 wt. % x 0.95 conversion) = post-mature TOC wt. %

2.18 wt. % - (1.35 wt. % x 0.95) = 0.90 wt. % (post-mature Icebox TOC, Sask.)

Assuming the non-GCS Icebox shale of the Schultz 8 #3 and Simpson #1 cores are representative of the Icebox Formation across western North Dakota, and were similar to the current average Icebox sample

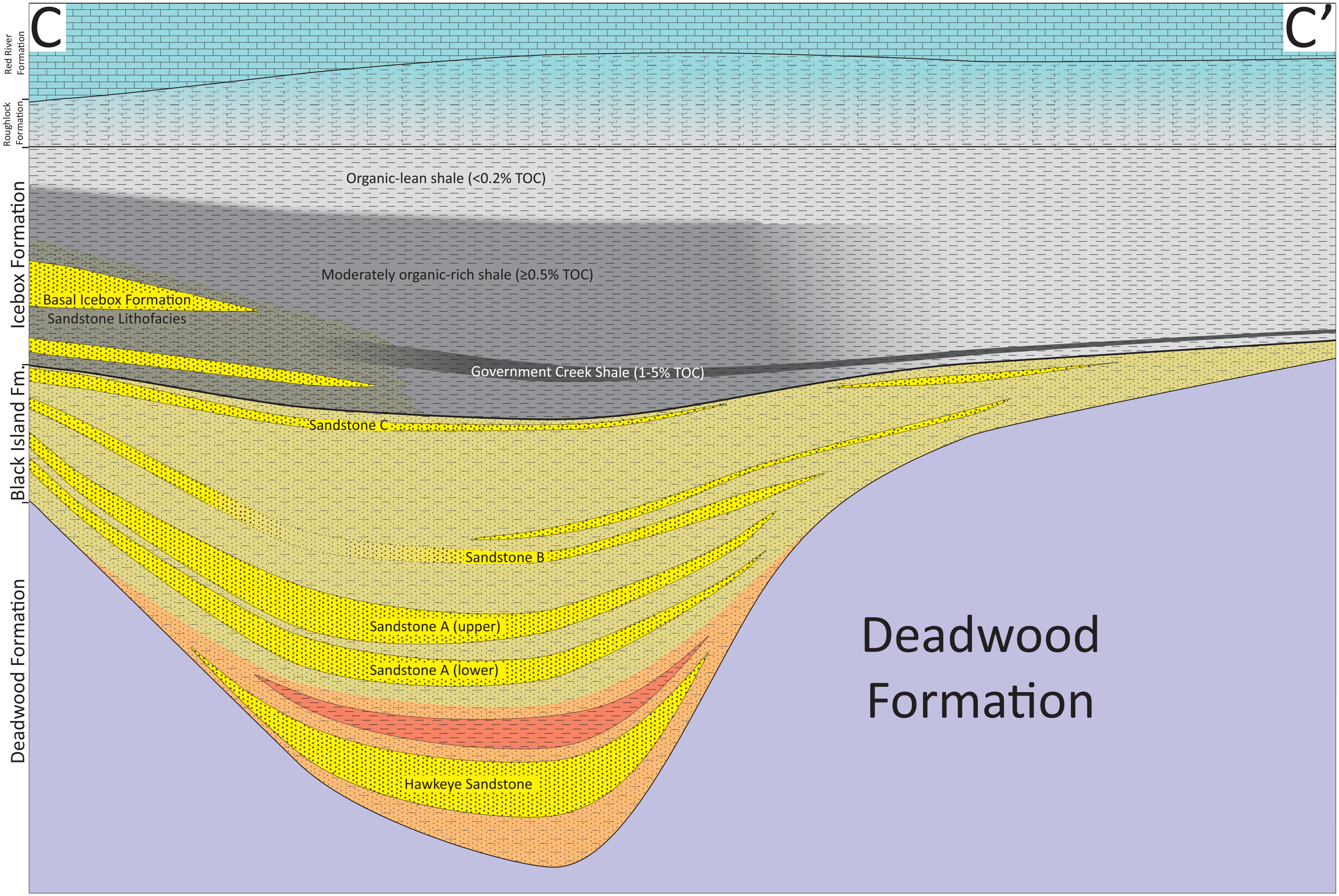

Figure 22. Schematic stratigraphic cross-section of the Winnipeg Group (positioned upon the Icebox Formation top) oriented approximately north-south across western North Dakota. The position of C-C’ is displayed upon the Figure 17 map. This cross-section represents approximately 475 ft. of vertical section across 240 horizontal miles.

from Saskatchewan before maturation took place, the non-GCS shale of western North Dakota would have originally had a TOC of approximately 1.43 wt. % (Eq. 2) which classifies as a good quality source rock.

Eq. 2 ND post-mature TOC x (Sask. pre-mature TOC ÷ Sask. Post-mature TOC) = ND pre-mature TOC

0.59 wt. % x (2.18 wt. % ÷ 0.90 wt. %) = 1.43 wt. % (original non-GCS Icebox TOC, ND)

Further assuming that the non-GCS Icebox shale of North Dakota had a similar TOC to S_2 ratio as the Saskatchewan data set, the average original S_2 of the non-GCS Icebox shale of the Schultz and Simpson cores would have been 8.87 mg/g (Eq. 3) which also classifies as a good quality source rock.

Eq. 3 ND pre-mature TOC x (Sask. pre-mature S_2 ÷ Sask. premature TOC) = ND pre-mature S_2

1.43 wt. % TOC x (13.52 mg/g ÷ 2.18 wt. % TOC) = 8.87 mg/g (original non-GCS Icebox S_2, ND)

Conclusions

1) Based on TOC values measured from core and drilling cutting samples, the Icebox Formation averages as a borderline poor/fair quality source rock (TOC $\approx$ 0.5%) across North Dakota.

2) Near the base of the Icebox Formation across western North Dakota is a 0-15 ft. thick shale interval, the Government Creek Shale (GCS), which is substantially more organic-rich than the surrounding Icebox section. Core measurements from the GCS averaged as high as 3.56% TOC with an S_2 of 18.9 mg/g (Hoff 1-32-4B, oil window) and as low as 1.3% TOC with an S_2 of <0.5 mg/g (Conoco Schultz 8 #3, overmature, dry gas window).

3) Based on limited TOC analyzes from core samples in combination with log observations, the non-GCS shale portions of the lower 80-100 ft. of the Icebox Formation become more organic-rich to the west (transitions from <0.3% to ~0.6% TOC) despite increasing levels of thermal maturity. The lower 80-100 ft. of the Icebox Formation may have originally averaged as a good quality source (1-2% TOC, 5-10 mg/g S_2) before thermal maturation took place.

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Appendix A: Table 1. Compiled geochemical data set on the Icebox Formation from Saskatchewan

Well Name	Location	Sample Type	Depth (ft)	TOC (wt. %)	S1 (mg/g)	S2 (mg/g)	S1+S2	S3 (mg/g)	Tmax (°C)	HI	OI	PI	Reference
Norcanols Parry No. 1	16-3-9-21W2	Cuttings	8545	1.27	0.13	4.62	4.75	0.61	438	363	48		*a*
Norcanols Parry No. 1	16-3-9-21W2	Cuttings	8550	1.41	0.24	6.04	6.28	0.70	434	428	49		*a*
Norcanols Parry No. 1	16-3-9-21W2	Cuttings	8550	1.51	0.16	6.30	6.46	0.74	435	417	49		*a*
Berkley et al Midale 12-2-7-11	12-2-7-11W2	Core?	8782.2	0.66	0.23	3.46	3.69	0.24	452	527	36	0.06	*c*
Berkley et al Midale 12-2-7-11	12-2-7-11W2	Core?	8783.1	1.74	1.01	9.76	10.77	0.26	449	562	15	0.09	*c*
Californian Standard Bannock 15 5	15-5-46-9W2	Core	2514.4	1.12	0.13	3.89	4.02	0.32	427	348	29	0	*c*
Californian Standard Bannock 15 5	15-5-46-9W2	Core	2520.0	2.51	0.31	10.51	10.82	0.44	430	420	18	0	*c*
Californian Standard Bannock 15 5	15-5-46-9W2	Core	2523.0	2.74	0.28	8.29	8.57	0.64	428	303	23	0	*c*
Californian Standard Bannock 15 5	15-5-46-9W2	Core	2523.6	3.40	0.27	12.91	13.18	0.74	426	308	22	0	*c*
Californian Standard Bannock 15 5	15-5-46-9W2	Core	2524.0	2.65	0.35	9.06	9.41	0.69	426	343	26	0	*c*
Californian Standard Bannock 15 5	15-5-46-9W2	Core	2525.1	1.92	0.40	10.21	10.61	0.55	436	533	29	0	*c*
Californian Standard Bannock 15 5	15-5-46-9W2	Core	2525.9	6.48	0.93	39.91	40.84	1.08	430	616	17	0	*c*
CUTARM #1	1-4-20-32W1	Core	4511	0.53	0.00	4.28	4.28	0.15	442	807	28		*b*
CUTARM #1	1-4-20-32W1	Core	4548	1.48	0.11	3.67	3.78	0.3	426	248	20	0.03	*c*
CUTARM #1	1-4-20-32W1	Core	4550	11.14	0.32	85.39	85.71	2.26	435	767	20	0	*c*
CUTARM #1	1-4-20-32W1	Core	4555.6	9.73	0.32	75.86	76.18	1.7	431	780	17	0	*c*
CUTARM #1	1-4-20-32W1	Core	4555.8	10.37	0.3	82.36	82.66	2.47	433	794	24	0	*c*
CUTARM #1	1-4-20-32W1	Core	4556	3.01	0.13	20.29	20.42	1.54	427	674	51	0.01	*c*
CUTARM #1	1-4-20-32W1	Core	4558	9.3	0.22	69.84	70.06	1.79	432	751	19	0	*c*
CUTARM #1	1-4-20-32W1	Core	4564	10.41	1.08	96.19	97.27	1.76	435	924	16		*b*
ECHO ATWATER 4-22	4-22-21-2W2	Core	4720	3.50	0.33	15.17	15.5	0.45	431	434	13	0	*c*
ECHO ATWATER 4-22	4-22-21-2W2	Core	4729	0.29	0.03	0.60	0.63	2.08	427	207	717	0	*c*
ECHO ATWATER 4-22	4-22-21-2W2	Core	4740	2.53	0.10	11.07	11.17	0.37	425	438	15	0	*c*
ECHO ATWATER 4-22	4-22-21-2W2	Core	4740.6	7.85	0.12	59.36	59.48	1.17	433	757	15	0	*c*
ECHO ATWATER 4-22	4-22-21-2W2	Core	4745	0.76	0.09	1.74	1.83	0.24	422	229	32	0	*c*
ECHO ATWATER 4-22	4-22-21-2W2	Core	4746	3.04	0.10	17.80	17.9	0.37	429	586	12	0	*c*
ECHO ATWATER 4-22	4-22-21-2W2	Core	4748	3.36	0.13	15.11	15.24	0.60	428	450	18	0	*c*
ECHO ATWATER 4-22	4-22-21-2W2	Core	4755	0.86	0.07	1.58	1.65	0.29	418	184	34	0	*c*
ECHO ATWATER 4-22	4-22-21-2W2	Core	4759	7.89	0.19	59.58	59.77	1.10	433	755	14	0	*c*
Founders et al Hartaven D12-1T-10-9	12-1T-10-9W2	Cuttings	7792	1.69	0.16	2.13	2.29	2.85	433	127	169	0	*c*
Founders et al Hartaven D12-1T-10-9	12-1T-10-9W2	Cuttings	7841	0.37	0.03	0.29	0.32	1.72	432	81	465	0	*c*

Well Name	Location	Sample Type	Depth (ft)	TOC (wt. %)	S1 (mg/g)	S2 (mg/g)	S1+S2	S3 (mg/g)	Tmax (°C)	HI	OI	PI	Reference
Founders et al Hartaven D12-1T-10-9	12-1T-10-9W2	Cuttings	7858	0.12	0.02	0.13	0.15	0.93	438	108	775	0	*c*
Founders et al Hartaven D12-1T-10-9	12-1T-10-9W2	Cuttings	7874	0.30	0.02	0.43	0.45	1.40	437	143	467	0	*c*
Founders et al Hartaven D12-1T-10-9	12-1T-10-9W2	Cuttings	7890	0.46	0.04	1.58	1.62	0.48	439	346	104	0	*c*
Imperial Humming Bird 6 13 2 19	6-13-2-19W2	Core	10144	0.26	0.01	0.38	0.39	0.42	440	146	162	0.03	*c*
Imperial Humming Bird 6 13 2 19	6-13-2-19W2	Core	10152	0.47	0.03	1.04	1.07	0.17	442	221	36	0.03	*c*
Imperial Humming Bird 6 13 2 19	6-13-2-19W2	Core	10156	0.77	0.36	4.21	4.57	0.11	452	548	14	0.08	*c*
Imperial Humming Bird 6 13 2 19	6-13-2-19W2	Core	10159	0.26	0.02	0.64	0.66	0.12	441	246	46	0.03	*c*
Imperial Humming Bird 6 13 2 19	6-13-2-19W2	Core	10169	1.02	0.45	3.87	4.32	0.1	444	379	10	0.1	*c*
Imperial Humming Bird 6 13 2 19	6-13-2-19W2	Core	10170	0.27	0.1	0.99	1.09	0.25	441	367	93	0.09	*c*
Imperial Humming Bird 6 13 2 19	6-13-2-19W2	Core	10171	1.44	0.87	7.07	7.94	0.1	445	491	7	0.11	*c*
Imperial Humming Bird 6 13 2 19	6-13-2-19W2	Core	10175	2.17	1.25	13.56	14.81	0.15	447	626	7	0.08	*c*
Imperial Humming Bird 6 13 2 19	6-13-2-19W2	Core	10177	1.62	1.24	9.91	11.15	0.12	452	616	7	0.11	*c*
Imperial Humming Bird 6 13 2 19	6-13-2-19W2	Core	10183	0.33	0.07	1.5	1.57	0.12	434	455	36	0.04	*c*
Imperial Pangman 3 14 8 20	3-14-8-20W2	Core	8507	0.21	0.04	1.01	1.05	0.19	445	480	90		*b*
Imperial Pangman 3 14 8 20	3-14-8-20W2	Core	8507.6	0.26	0.03	0.56	0.59	0.26	438	215	100	0.05	*c*
Imperial Pangman 3 14 8 20	3-14-8-20W2	Core	8513.1	0.41	0.03	0.69	0.72	0.19	431	168	46	0.04	*c*
Imperial Pangman 3 14 8 20	3-14-8-20W2	Core	8514	0.38	0.04	1.59	1.63	0.04	446	418	10		*b*
Imperial Pangman 3 14 8 20	3-14-8-20W2	Core	8524	0.29	0.05	1.15	1.20	0.05	441	396	17		*b*
Tide Water Beaver Hills Crown No. 1	16-23-26-9W2	Core	4991	1.37	0.08	4.81	4.89	0.23	427	351	17	0	*c*
Tide Water Beaver Hills Crown No. 1	16-23-26-9W2	Core	4995	1.81	0.23	5.49	5.72	0.39	426	303	22	0	*c*
Tide Water Beaver Hills Crown No. 1	16-23-26-9W2	Core	4995.5	1.72	0.14	5.38	5.52	0.39	429	313	23	0	*c*
Tide Water Beaver Hills Crown No. 1	16-23-26-9W2	Core	4998.3	6.89	0.33	55.31	55.64	0.89	434	803	13	0	*c*
Trilink PCP Gooseverry	3-27-11-9W2	Core	7595.8	2.85	1.00	23.79	24.79	0.32	446	835	11	0	*c*
Trilink PCP Gooseverry	3-27-11-9W2	Core	7596.1	5.35	1.81	45.89	47.7	0.29	443	858	5	0	*c*
Trilink PCP Gooseverry	3-27-11-9W2	Core	7596.5	4.74	1.62	40.75	42.37	0.42	445	861	9	0	*c*
TW PAN-AM WHITE BEAR CR 5 15 10 2	5-15-10-2W2	Cuttings	7455	0.49	0.05	0.54	0.59	0.69	425	110	141	0	*c*
TW PAN-AM WHITE BEAR CR 5 15 10 2	5-15-10-2W2	Core?	7484	0.90	0.06	2.41	2.47	0.29	432	269	32	0	*c*
TW PAN-AM WHITE BEAR CR 5 15 10 2	5-15-10-2W2	Core	7485	1.24	0.16	2.83	2.99	1.13	435	228	91	0	*c*
TW PAN-AM WHITE BEAR CR 5 15 10 2	5-15-10-2W2	Core	7487	1.07	0.17	4.72	4.89	0.33	440	441	30		*b*
TW PAN-AM WHITE BEAR CR 5 15 10 2	5-15-10-2W2	Core	7487	1.02	0.10	4.79	4.89	0.35	435	469	34		*b*
TW PAN-AM WHITE BEAR CR 5 15 10 2	5-15-10-2W2	Core	7487	1.03	0.33	4.91	5.24	1.16	438	476	112		*b*
TW PAN-AM WHITE BEAR CR 5 15 10 2	5-15-10-2W2	Core	7488	0.77	0.04	2.50	2.54	0.39	432	329	51	0	*c*

Well Name	Location	Sample Type	Depth (ft)	TOC (wt. %)	S1 (mg/g)	S2 (mg/g)	S1+S2	S3 (mg/g)	Tmax (°C)	HI	OI	PI	Reference
TW PAN-AM WHITE BEAR CR 5 15 10 2	5-15-10-2W2	Core	7492.5	0.24	0.04	0.21	0.25	1.93	419	100	804	0	*c*
TW PAN-AM WHITE BEAR CR 5 15 10 2	5-15-10-2W2	Core	7496	0.29	0.02	0.36	0.38	0.12	424	134	41	0	*c*
TW PAN-AM WHITE BEAR CR 5 15 10 2	5-15-10-2W2	Core	7497	0.57	0.24	2.10	2.34	0.08	438	368	14		*b*
TW PAN-AM WHITE BEAR CR 5 15 10 2	5-15-10-2W2	Core	7497	0.27	0.00	1.15	1.15	0.35	431	425	129		*b*
TW PAN-AM WHITE BEAR CR 5 15 10 2	5-15-10-2W2	Core	7497	0.36	0.04	0.49	0.53	0.23	428	144	64	0	*c*
TW PAN-AM WHITE BEAR CR 5 15 10 2	5-15-10-2W2	Core	7498	0.54	0.04	1.32	1.36	0.11	432	250	20	0	*c*
TW PAN-AM WHITE BEAR CR 5 15 10 2	5-15-10-2W2	Core	7499	1.57	0.06	9.39	9.45	0.15	434	600	10	0	*c*
TW PAN-AM WHITE BEAR CR 5 15 10 2	5-15-10-2W2	Core	7500	1.25	0.29	6.39	6.68	0.15	439	511	12		*b*
Vista Glen Ewen	16A-23-2-1W2	Cuttings	8842	0.35	0.04	0.38	0.42	1.35	434	109	386	0.1	*c*
Vista Glen Ewen	16A-23-2-1W2	Cuttings	8858	0.44	0.05	0.55	0.6	1.2	438	125	273	0.09	*c*
Vista Glen Ewen	16A-23-2-1W2	Cuttings	8875	0.54	0.06	1.03	1.09	1.2	440	191	222	0.05	*c*
Vista Glen Ewen	16A-23-2-1W2	Cuttings	8885	0.48	0.06	1.02	1.08	0.97	442	213	202	0.05	*c*
Vista Glen Ewen	16A-23-2-1W2	Cuttings	8891	0.65	0.06	1.37	1.43	1.04	442	211	160	0.04	*c*

a = Osadetz and Snowden, 1986

b = Osadetz and Snowden, 1995

c = Siebel, 2002

Appendix A: Table 2. Standard core analysis data from Gulf Oil's Hoff 1-32-4B (NDIC: 9407)

Well Name	NDIC	Formation	Core Depth (ft.)	Log Depth (ft.)	Permeability (millidarcys)	Porosity %	Oil Sat. %	Water Sat. %	Total
Hoff 1-32-4B	9407	Icebox	11576.5	11583	0.02	5.6	14.5	46.4	60.9
Hoff 1-32-4B	9407	Icebox	11577.5	11584	0.01	3.8	4.3	60.7	65.0
Hoff 1-32-4B	9407	Icebox	11578.5	11585	0.02	4.9	16.7	46.7	63.4
Hoff 1-32-4B	9407	Icebox	11579.5	11586	0.02	4.5	7.3	73.1	80.4
Hoff 1-32-4B	9407	Icebox	11580.5	11587	0.01	7.8	10.3	41.1	51.4
Hoff 1-32-4B	9407	Icebox	11581.5	11588	0.03	5.3	25.1	50.3	75.4
Hoff 1-32-4B	9407	Icebox	11582.5	11589	0.03	6.7	56.9	19.0	75.9
Hoff 1-32-4B	9407	Icebox	11583.5	11590	0.05	8.9	73.6	17.5	91.1
Hoff 1-32-4B	9407	Icebox	11584.5	11591	0.1	9.1	74.6	13.6	88.2
Hoff 1-32-4B	9407	Icebox	11585.5	11592	0.02	4.4	7.4	74.1	81.5
Hoff 1-32-4B	9407	Icebox	11586.5	11593	0.01	3.7	8.9	74.2	83.1
Hoff 1-32-4B	9407	Icebox	11587.5	11594	0.01	3.5	9.3	74.5	83.8
Hoff 1-32-4B	9407	Black Island	11588.5	11595	0.02	4.8	34.0	47.6	81.6
Hoff 1-32-4B	9407	Black Island	11589.5	11596	0.02	4.4	37.0	44.4	81.4
Hoff 1-32-4B	9407	Black Island	11590.5	11597	0.53	6.8	24.0	57.6	81.6
Hoff 1-32-4B	9407	Black Island	11591.5	11598	0.04	5.3	30.4	42.5	72.9
Hoff 1-32-4B	9407	Black Island	11592.5	11599	0.04	4.0	8.0	56.3	64.3
Hoff 1-32-4B	9407	Black Island	11593.5	11600	0.38	9.4	8.1	56.4	64.5
Hoff 1-32-4B	9407	Black Island	11594.5	11601	0.17	9.0	17.5	70.1	87.6
Hoff 1-32-4B	9407	Black Island	11595.5	11602	0.26	6.6	12.0	62.6	74.6
Hoff 1-32-4B	9407	Black Island	11596.5	11603	0.73	2.6	12.6	75.7	88.3
Hoff 1-32-4B	9407	Black Island	11597.5	11604	0.38	4.4	7.2	50.5	57.7
Hoff 1-32-4B	9407	Black Island	11598.5	11605	2	3.4	9.5	76.2	85.7
Hoff 1-32-4B	9407	Black Island	11599.5	11606	0.01	3.3	4.9	68.5	73.4
Hoff 1-32-4B	9407	Black Island	11600.5	11607	0.54	2.6	0.0	61.7	61.7
Hoff 1-32-4B	9407	Black Island	11601.5	11608	0.09	2.8	5.9	82.6	88.5
Hoff 1-32-4B	9407	Black Island	11602.5	11609	0.06	3.2	10.4	83.0	93.4
Hoff 1-32-4B	9407	Black Island	11603.5	11610	0.21	3.2	0.0	70.2	70.2
Hoff 1-32-4B	9407	Black Island	11604.5	11611	0.18	9.1	0.0	85.2	85.2
Hoff 1-32-4B	9407	Black Island	11605.5	11612	0.13	5.6	2.8	55.6	58.4
Hoff 1-32-4B	9407	Black Island	11606.5	11613	0.01	9.9	1.6	93.4	95.0
Hoff 1-32-4B	9407	Black Island	11607.5	11614	0.31	9.2	3.5	87.2	90.7
Hoff 1-32-4B	9407	Black Island	11608.5	11615	2.2	5.1	6.2	74.9	81.1
Hoff 1-32-4B	9407	Black Island	11609.5	11616	0.2	7.8	10.1	77.1	87.2
Hoff 1-32-4B	9407	Black Island	11610.5	11617	6.2	4.0	8.1	73.2	81.3
Hoff 1-32-4B	9407	Black Island	11611.5	11618	0.36	5.5	2.9	52.4	55.3

Core + 6.5 ft. = Log

Appendix A: Table 3. TOC and Rock Eval data set from North Dakota Icebox core samples

Well Name	NDIC	Location	Source	Depth (ft.)	TOC (wt. %)	S1 (mg/g)	S2 (mg/g)	S3 (mg/g)	S1 + S2 (mg/g)	Tmax (°C)	HI	OI	PI
William Steckler #1	7020	Sec. 5-T137-R88W	NDGS	10282	0.20								
William Steckler #1	7020	Sec. 5-T137-R88W	NDGS	10283	0.18								
William Steckler #1	7020	Sec. 5-T137-R88W	NDGS	10284	0.21								
William Steckler #1	7020	Sec. 5-T137-R88W	NDGS	10285	0.22	0.09	0.47	0.6	0.56	429	211	269	0.16
William Steckler #1	7020	Sec. 5-T137-R88W	NDGS	10286	0.27								
William Steckler #1	7020	Sec. 5-T137-R88W	NDGS	10286.5	0.35								
William Steckler #1	7020	Sec. 5-T137-R88W	NDGS	10287	1.52								
William Steckler #1	7020	Sec. 5-T137-R88W	NDGS	10287.5	1.08	0.15	4.59	0.35	4.74	434	425	32	0.03
William Steckler #1	7020	Sec. 5-T137-R88W	NDGS	10288	1.28	0.17	3.46	0.5	3.63	435	270	39	0.05
William Steckler #1	7020	Sec. 5-T137-R88W	NDGS	10288.5	0.80	0.15	4.61	0.4	4.76	436	576	50	0.03
William Steckler #1	7020	Sec. 5-T137-R88W	NDGS	10289	1.30								
William Steckler #1	7020	Sec. 5-T137-R88W	NDGS	10289.5	0.14								
William Steckler #1	7020	Sec. 5-T137-R88W	NDGS	10290	0.18								
William Steckler #1	7020	Sec. 5-T137-R88W	NDGS	10291	0.15								
William Steckler #1	7020	Sec. 5-T137-R88W	NDGS	10292	0.10								
William Steckler #1	7020	Sec. 5-T137-R88W	NDGS	10293	0.21	0.06	0.36	0.51	0.42	428	170	241	0.14
William Steckler #1	7020	Sec. 5-T137-R88W	NDGS	10294	0.15								
William Steckler #1	7020	Sec. 5-T137-R88W	NDGS	10295	0.23	0.08	0.41	0.94	0.49	426	177	407	0.16
William Steckler #1	7020	Sec. 5-T137-R88W	NDGS	10296	0.13								
William Steckler #1	7020	Sec. 5-T137-R88W	NDGS	10297	0.12								
William Steckler #1	7020	Sec. 5-T137-R88W	NDGS	10298	0.15								
William Steckler #1	7020	Sec. 5-T137-R88W	NDGS	10299	0.12								
William Steckler #1	7020	Sec. 5-T137-R88W	NDGS	10300	0.14								
William Steckler #1	7020	Sec. 5-T137-R88W	NDGS	10301	0.14								
William Steckler #1	7020	Sec. 5-T137-R88W	NDGS	10302	0.14								
William Steckler #1	7020	Sec. 5-T137-R88W	NDGS	10303	0.19								
William Steckler #1	7020	Sec. 5-T137-R88W	NDGS	10304	0.24								
William Steckler #1	7020	Sec. 5-T137-R88W	NDGS	10305	0.30								
Hoff 1-32-4B	9407	Sec. 32-T139-R92W	NDGS	11576	0.18								
Hoff 1-32-4B	9407	Sec. 32-T139-R92W	Chesapeake	11576.5	0.16	0.03	0.14		0.17	441	86		
Hoff 1-32-4B	9407	Sec. 32-T139-R92W	NDGS	11578	0.19								

Well Name	NDIC	Location	Source	Depth (ft.)	TOC (wt. %)	S1 (mg/g)	S2 (mg/g)	S3 (mg/g)	S1 + S2 (mg/g)	Tmax (°C)	HI	OI	PI
Hoff 1-32-4B	9407	Sec. 32-T139-R92W	Chesapeake	11578.5	0.18	0.03	0.17		0.20	441	97		
Hoff 1-32-4B	9407	Sec. 32-T139-R92W	Chesapeake	11580	0.23	0.05	0.27		0.32	442	116		
Hoff 1-32-4B	9407	Sec. 32-T139-R92W	NDGS	11580	0.25								
Hoff 1-32-4B	9407	Sec. 32-T139-R92W	Chesapeake	11581	0.32	0.08	0.47		0.55	446	148		
Hoff 1-32-4B	9407	Sec. 32-T139-R92W	NDGS	11582	0.35	0.11	1.00	0.66	1.11	436	284	188	0.10
Hoff 1-32-4B	9407	Sec. 32-T139-R92W	Chesapeake	11583	3.40	0.58	16.77		17.35	447	493		0.03
Hoff 1-32-4B	9407	Sec. 32-T139-R92W	NDGS	11584	4.33	1.37	25.93	0.63	27.30	442	598	15	0.05
Hoff 1-32-4B	9407	Sec. 32-T139-R92W	Chesapeake	11584.5	2.95	0.50	14.08		14.58	448	477		0.03
Hoff 1-32-4B	9407	Sec. 32-T139-R92W	NDGS	11586	0.17	0.08	0.35	0.49	0.43	437	210	293	0.19
Hoff 1-32-4B	9407	Sec. 32-T139-R92W	Chesapeake	11586.5	1.54	0.22	7.18		7.40	451			
Hoff 1-32-4B	9407	Sec. 32-T139-R92W	Chesapeake	11588	0.20	0.06	0.27		0.33	450	133		
Hoff 1-32-4B	9407	Sec. 32-T139-R92W	NDGS	11588	0.18								
Hoff 1-32-4B	9407	Sec. 32-T139-R92W	Chesapeake	11590	0.18	0.07	0.28		0.35	444	152		
Hoff 1-32-4B	9407	Sec. 32-T139-R92W	Chesapeake	11592	0.41	0.07	0.62		0.69	441	150		
Hoff 1-32-4B	9407	Sec. 32-T139-R92W	Chesapeake	11595	0.28	0.15	0.72		0.87	443	258		
Hoff 1-32-4B	9407	Sec. 32-T139-R92W	Chesapeake	11597	0.41	0.07	0.53		0.60	442	130		
Hoff 1-32-4B	9407	Sec. 32-T139-R92W	Chesapeake	11599	0.05	0.06	0.06		0.12	313	116		
Hoff 1-32-4B	9407	Sec. 32-T139-R92W	Chesapeake	11600	0.07	0.21	0.11		0.32	258	163		
Hoff 1-32-4B	9407	Sec. 32-T139-R92W	Chesapeake	11602	0.07	0.11	0.09		0.20	298	125		
Hoff 1-32-4B	9407	Sec. 32-T139-R92W	Chesapeake	11604	0.10	0.21	0.12		0.33	258	121		
Hoff 1-32-4B	9407	Sec. 32-T139-R92W	Chesapeake	11605	0.05	0.06	0.07		0.13	287	153		
Hoff 1-32-4B	9407	Sec. 32-T139-R92W	Chesapeake	11606	0.09	0.06	0.05		0.11	321	57		
Hoff 1-32-4B	9407	Sec. 32-T139-R92W	Chesapeake	11607	0.05	0.06	0.13		0.19	455	277		
Simpson #1	9800	Sec. 27-T158-R97W	NDGS	13984	1.02	0.22	0.42	0.39	0.64	434	41	38	0.34
Simpson #1	9800	Sec. 27-T158-R97W	NDGS	13985	0.37								
Simpson #1	9800	Sec. 27-T158-R97W	NDGS	13986	0.55	0.13	0.26	0.44	0.39	478	48	81	0.33
Simpson #1	9800	Sec. 27-T158-R97W	NDGS	13987	0.41								
Simpson #1	9800	Sec. 27-T158-R97W	NDGS	13988	1.13	0.15	0.33	0.33	0.48	500	29	29	0.31
Simpson #1	9800	Sec. 27-T158-R97W	NDGS	13989	0.68	0.14	0.34	0.31	0.48	502	50	46	0.29
Simpson #1	9800	Sec. 27-T158-R97W	NDGS	13990	0.87	0.18	0.47	0.38	0.65	491	54	43	0.28
Simpson #1	9800	Sec. 27-T158-R97W	NDGS	13991	0.57	0.18	0.45	0.31	0.63	493	78	54	0.29
Simpson #1	9800	Sec. 27-T158-R97W	NDGS	13992	0.65	0.15	0.45	0.26	0.60	497	69	40	0.25

Well Name	NDIC	Location	Source	Depth (ft.)	TOC (wt. %)	S1 (mg/g)	S2 (mg/g)	S3 (mg/g)	S1 + S2 (mg/g)	Tmax (°C)	HI	OI	PI
Simpson #1	9800	Sec. 27-T158-R97W	NDGS	13993	0.53	0.13	0.37	0.42	0.50	470	70	80	0.26
Simpson #1	9800	Sec. 27-T158-R97W	NDGS	13994	0.65	0.17	0.48	0.34	0.65	491	74	53	0.26
Simpson #1	9800	Sec. 27-T158-R97W	NDGS	13995	0.86	0.19	0.56	0.29	0.75	502	65	34	0.25
Simpson #1	9800	Sec. 27-T158-R97W	NDGS	13996	0.74	0.17	0.46	0.24	0.63	500	62	32	0.27
Simpson #1	9800	Sec. 27-T158-R97W	NDGS	13997	0.32								
Simpson #1	9800	Sec. 27-T158-R97W	NDGS	13998	0.44								
Simpson #1	9800	Sec. 27-T158-R97W	NDGS	13999	0.43								
Simpson #1	9800	Sec. 27-T158-R97W	NDGS	14000	0.25								
Simpson #1	9800	Sec. 27-T158-R97W	NDGS	14001	0.33								
Simpson #1	9800	Sec. 27-T158-R97W	NDGS	14002	0.28								
Simpson #1	9800	Sec. 27-T158-R97W	NDGS	14003	0.20								
Simpson #1	9800	Sec. 27-T158-R97W	NDGS	14004	0.21								
Simpson #1	9800	Sec. 27-T158-R97W	NDGS	14005	0.21								
Simpson #1	9800	Sec. 27-T158-R97W	NDGS	14006	0.24								
Simpson #1	9800	Sec. 27-T158-R97W	NDGS	14007	0.23								
Simpson #1	9800	Sec. 27-T158-R97W	NDGS	14008	0.29								
Simpson #1	9800	Sec. 27-T158-R97W	NDGS	14009	0.12								
Simpson #1	9800	Sec. 27-T158-R97W	NDGS	14010	0.20								
Simpson #1	9800	Sec. 27-T158-R97W	NDGS	14011	0.26								
Simpson #1	9800	Sec. 27-T158-R97W	NDGS	14012	0.50	0.06	0.22	0.29	0.28	486	44	58	0.21
Simpson #1	9800	Sec. 27-T158-R97W	NDGS	14013	0.57	0.07	0.20	0.24	0.27	481	35	42	0.26
Simpson #1	9800	Sec. 27-T158-R97W	NDGS	14014	0.44								
Simpson #1	9800	Sec. 27-T158-R97W	NDGS	14015	0.47								
Simpson #1	9800	Sec. 27-T158-R97W	NDGS	14016	0.36								
Simpson #1	9800	Sec. 27-T158-R97W	NDGS	14017	0.22								
Simpson #1	9800	Sec. 27-T158-R97W	NDGS	14018	0.38								
Simpson #1	9800	Sec. 27-T158-R97W	NDGS	14019	0.63	0.09	0.26	0.33	0.35	497	41	52	0.26
Simpson #1	9800	Sec. 27-T158-R97W	NDGS	14020	0.51	0.06	0.20	0.36	0.26	551	39	71	0.23
Simpson #1	9800	Sec. 27-T158-R97W	NDGS	14021	0.42								
Simpson #1	9800	Sec. 27-T158-R97W	NDGS	14022	0.40								
Simpson #1	9800	Sec. 27-T158-R97W	NDGS	14023	0.56	0.07	0.22	0.31	0.29	482	39	55	0.24
Simpson #1	9800	Sec. 27-T158-R97W	NDGS	14024	0.67	0.09	0.28	0.35	0.37	491	42	52	0.24

Well Name	NDIC	Location	Source	Depth (ft.)	TOC (wt. %)	S1 (mg/g)	S2 (mg/g)	S3 (mg/g)	S1 + S2 (mg/g)	Tmax (°C)	HI	OI	PI
Simpson #1	9800	Sec. 27-T158-R97W	NDGS	14025	0.42								
Simpson #1	9800	Sec. 27-T158-R97W	NDGS	14026	0.25								
Simpson #1	9800	Sec. 27-T158-R97W	NDGS	14027	0.48								
Simpson #1	9800	Sec. 27-T158-R97W	NDGS	14028	0.30								
Simpson #1	9800	Sec. 27-T158-R97W	NDGS	14029	0.18								
Schultz 8 #3	12699	Sec. 8-T148-R100W	NDGS	14325	0.71	0.07	0.22	0.30	0.29	487	31	42	0.24
Schultz 8 #3	12699	Sec. 8-T148-R100W	NDGS	14326	1.33	0.14	0.27	0.33	0.41	492	20	25	0.34
Schultz 8 #3	12699	Sec. 8-T148-R100W	NDGS	14327	1.13	0.11	0.31	0.31	0.42	497	27	27	0.26
Schultz 8 #3	12699	Sec. 8-T148-R100W	NDGS	14328	0.85	0.07	0.26	0.27	0.33	486	31	32	0.21
Schultz 8 #3	12699	Sec. 8-T148-R100W	NDGS	14329	2.68	0.40	0.46	0.33	0.86	482	17	12	0.47
Schultz 8 #3	12699	Sec. 8-T148-R100W	NDGS	14330	0.91	0.07	0.17	0.31	0.24	480	19	34	0.29
Schultz 8 #3	12699	Sec. 8-T148-R100W	NDGS	14331	0.98	0.09	0.22	0.31	0.31	481	23	32	0.29
Schultz 8 #3	12699	Sec. 8-T148-R100W	NDGS	14332	2.09	0.26	0.39	0.39	0.65	485	19	19	0.40
Schultz 8 #3	12699	Sec. 8-T148-R100W	NDGS	14333	1.50	0.40	0.51	0.37	0.91	486	34	25	0.44
Schultz 8 #3	12699	Sec. 8-T148-R100W	NDGS	14334	0.82	0.06	0.25	0.35	0.31	485	30	42	0.19
Schultz 8 #3	12699	Sec. 8-T148-R100W	NDGS	14335	0.90	0.05	0.27	0.33	0.32	486	30	37	0.16
Schultz 8 #3	12699	Sec. 8-T148-R100W	NDGS	14336	1.01	0.05	0.23	0.41	0.28	484	23	41	0.18
Schultz 8 #3	12699	Sec. 8-T148-R100W	NDGS	14337	1.11	0.07	0.36	0.46	0.43	490	32	42	0.16
Schultz 8 #3	12699	Sec. 8-T148-R100W	NDGS	14338	0.73	0.05	0.32	0.42	0.37	488	44	57	0.14
Schultz 8 #3	12699	Sec. 8-T148-R100W	NDGS	14339	0.63	0.05	0.26	0.32	0.31	481	41	51	0.16
Schultz 8 #3	12699	Sec. 8-T148-R100W	NDGS	14340	0.50	0.04	0.31	0.33	0.35	411	62	66	0.11
Schultz 8 #3	12699	Sec. 8-T148-R100W	NDGS	14341	0.48								
Schultz 8 #3	12699	Sec. 8-T148-R100W	NDGS	14342	0.50	0.04	0.22	0.24	0.26	476	44	48	0.15
Schultz 8 #3	12699	Sec. 8-T148-R100W	NDGS	14343	0.50	0.04	0.19	0.32	0.23	478	38	64	0.17
Schultz 8 #3	12699	Sec. 8-T148-R100W	NDGS	14344	0.60	0.05	0.25	0.37	0.30	484	42	62	0.17
Schultz 8 #3	12699	Sec. 8-T148-R100W	NDGS	14345	0.73	0.05	0.21	0.34	0.26	484	29	46	0.19
Schultz 8 #3	12699	Sec. 8-T148-R100W	NDGS	14346	0.60	0.04	0.29	0.35	0.33	485	48	58	0.12
Schultz 8 #3	12699	Sec. 8-T148-R100W	NDGS	14347	0.53	0.05	0.27	0.29	0.32	484	51	55	0.16
Schultz 8 #3	12699	Sec. 8-T148-R100W	NDGS	14348	0.58	0.05	0.25	0.29	0.30	484	43	50	0.17
Schultz 8 #3	12699	Sec. 8-T148-R100W	NDGS	14349	0.70	0.06	0.26	0.27	0.32	484	37	39	0.19
Schultz 8 #3	12699	Sec. 8-T148-R100W	NDGS	14350	0.64	0.05	0.20	0.36	0.25	485	31	56	0.20
Shell Creek 1-01	17058	Sec. 1-T152-R90W	Chesapeake	13070.36	0.12								

Well Name	NDIC	Location	Source	Depth (ft.)	TOC (wt. %)	S1 (mg/g)	S2 (mg/g)	S3 (mg/g)	S1 + S2 (mg/g)	Tmax (°C)	HI	OI	PI
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13071.5	0.18								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13072.6	0.12								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13073.7	0.13								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	Chesapeake	13074.9	0.15								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13076	0.10								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13077	0.14								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	Chesapeake	13077.92	0.20								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13079	0.12								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13080	0.15								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13081	0.14								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	Chesapeake	13082	1.57	0.02	0.07		0.09		4		
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13083.2	0.11								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13084.4	0.19								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	Chesapeake	13085.48	0.16								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13086.7	0.13								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13087.9	0.20								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	Chesapeake	13089.12	0.08								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13090.2	0.15								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13091.3	0.16								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13092.4	0.16								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	Chesapeake	13093.2	0.14								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13094.3	0.13								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13095.4	0.23								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	Chesapeake	13096.56	0.17								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13097.5	0.20								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13098.5	0.22								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13099.5	0.19								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	Chesapeake	13100.8	0.18								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13102	0.14								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13103	0.12								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	Chesapeake	13103.96	0.15								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13105	0.15								

Well Name	NDIC	Location	Source	Depth (ft.)	TOC (wt. %)	S1 (mg/g)	S2 (mg/g)	S3 (mg/g)	S1 + S2 (mg/g)	Tmax (°C)	HI	OI	PI
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13106	0.17								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13107	0.19								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	Chesapeake	13108.08	0.45								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13109	0.29								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13110	0.23								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13111	0.29								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	Chesapeake	13112.14	0.20								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13113.4	0.15								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13114.8	0.25								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	Chesapeake	13115.92	0.29								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13117	0.34								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13118	0.33								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	Chesapeake	13119.24	0.31								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13120.4	0.23								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13121.5	0.30								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	Chesapeake	13122.56	0.58								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13123.8	0.21								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13125.04	0.36								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13126.28	0.31								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	Chesapeake	13127.4	0.16								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13128.4	0.17								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13129.4	0.18								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	Chesapeake	13130.5	0.83								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13131.4	0.62	0.08	0.95	0.36	1.03	438	153	58	0.08
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13132.3	0.27								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13133.2	0.15								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	Chesapeake	13134.1	0.28								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13135	0.14								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13135.9	0.45								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13136.8	0.29								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13137.7	0.86	0.26	4.97	0.34	5.23	443	575	39	0.05
Shell Creek 1-01	17058	Sec. 1-T152-R90W	Chesapeake	13138.5	1.72	0.42	7.1		7.52		413		

Well Name	NDIC	Location	Source	Depth (ft.)	TOC (wt. %)	S1 (mg/g)	S2 (mg/g)	S3 (mg/g)	S1 + S2 (mg/g)	Tmax (°C)	HI	OI	PI
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13139.3	2.01	0.56	7.11	0.29	7.67	443	354	14	0.07
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13140.1	2.32	0.54	9.35	0.28	9.89	441	403	12	0.05
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13140.9	0.22								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	Chesapeake	13142	0.43								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13143	0.29								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13144	0.16								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13145	0.60	0.07	0.84	0.32	0.91	437	141	54	0.08
Shell Creek 1-01	17058	Sec. 1-T152-R90W	Chesapeake	13146.26	0.28								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13147.5	0.15								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13148.74	0.24								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	Chesapeake	13149.94	0.32								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13151	0.23								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13152.06	0.34								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	Chesapeake	13153	0.31								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13154	0.32								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13155	0.43								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	NDGS	13156	0.27								
Shell Creek 1-01	17058	Sec. 1-T152-R90W	Chesapeake	13157.3	0.43								

Appendix A: Table 4. TOC data set measured off of Winnipeg Group drill cuttings from North Dakota

Original Well Name	NDIC	Location	Depth (ft.)		Formation	TOC wt. %
			Top	Base		
North Dakota State #1	230	Sec. 16, T143N, R71W	4800	4810	Icebox	0.62
North Dakota State #1	230	Sec. 16, T143N, R71W	4810	4820	Icebox	0.653
North Dakota State #1	230	Sec. 16, T143N, R71W	4820	4830	Icebox	0.487
North Dakota State #1	230	Sec. 16, T143N, R71W	4830	4840	Icebox	0.563
North Dakota State #1	230	Sec. 16, T143N, R71W	4840	4850	Icebox	1.327
North Dakota State #1	230	Sec. 16, T143N, R71W	4850	4860	Icebox	0.539
North Dakota State #1	230	Sec. 16, T143N, R71W	4860	4870	Icebox	0.438
North Dakota State #1	230	Sec. 16, T143N, R71W	4870	4880	Icebox	0.518
North Dakota State #1	230	Sec. 16, T143N, R71W	4880	4890	Icebox	0.427
North Dakota State #1	230	Sec. 16, T143N, R71W	4890	4900	Icebox	0.942
North Dakota State #1	230	Sec. 16, T143N, R71W	4900	4910	Icebox	0.708
North Dakota State #1	230	Sec. 16, T143N, R71W	4910	4920	Icebox	0.526
North Dakota State #1	230	Sec. 16, T143N, R71W	4920	4930	Icebox	0.615
North Dakota State #1	230	Sec. 16, T143N, R71W	4930	4940	Icebox	0.413
North Dakota State #1	230	Sec. 16, T143N, R71W	4940	4950	Icebox	0.476
North Dakota State #1	230	Sec. 16, T143N, R71W	4950	4960	Icebox	0.786
North Dakota State #1	230	Sec. 16, T143N, R71W	4960	4970	Icebox	0.511
Zach Brooks-State #1	485	Sec. 16, T129N, R104W	9705	9710	Icebox	0.187
Zach Brooks-State #1	485	Sec. 16, T129N, R104W	9710	9715	Icebox	0.427
Zach Brooks-State #1	485	Sec. 16, T129N, R104W	9725	9730	Icebox	0.219
Zach Brooks-State #1	485	Sec. 16, T129N, R104W	9730	9735	Icebox	0.203
Zach Brooks-State #1	485	Sec. 16, T129N, R104W	9735	9740	Icebox	0.343
Zach Brooks-State #1	485	Sec. 16, T129N, R104W	9760	9765	Icebox	0.385
Zach Brooks-State #1	485	Sec. 16, T129N, R104W	9765	9770	Icebox	0.514
Zach Brooks-State #1	485	Sec. 16, T129N, R104W	9770	9775	Icebox	0.359
Zach Brooks-State #1	485	Sec. 16, T129N, R104W	9775	9780	Icebox	0.475
Zach Brooks-State #1	485	Sec. 16, T129N, R104W	9780	9785	Icebox	0.523
Zach Brooks-State #1	485	Sec. 16, T129N, R104W	9785	9790	Icebox	1.048
Zach Brooks-State #1	485	Sec. 16, T129N, R104W	9790	9795	Icebox	0.491
Zach Brooks-State #1	485	Sec. 16, T129N, R104W	9795	9800	Icebox	0.145
Zach Brooks-State #1	485	Sec. 16, T129N, R104W	9800	9805	Icebox	0.492
Zach Brooks-State #1	485	Sec. 16, T129N, R104W	9805	9810	Icebox	0.355
F.C. Neuman #1	588	Sec. 33, T152N, R82W	9460	9470	Icebox	0.188
F.C. Neuman #1	588	Sec. 33, T152N, R82W	9470	9480	Icebox	0.436
F.C. Neuman #1	588	Sec. 33, T152N, R82W	9480	9490	Icebox	0.212
F.C. Neuman #1	588	Sec. 33, T152N, R82W	9510	9520	Icebox	0.431
F.C. Neuman #1	588	Sec. 33, T152N, R82W	9520	9530	Icebox	0.272
F.C. Neuman #1	588	Sec. 33, T152N, R82W	9530	9540	Icebox	0.399
F.C. Neuman #1	588	Sec. 33, T152N, R82W	9570	9580	Icebox	0.342
F.C. Neuman #1	588	Sec. 33, T152N, R82W	9580	9590	Icebox	0.364
F.C. Neuman #1	588	Sec. 33, T152N, R82W	9590	9600	Icebox	0.454
F.C. Neuman #1	588	Sec. 33, T152N, R82W	9600	9610	Icebox	0.386
F.C. Neuman #1	588	Sec. 33, T152N, R82W	9610	9620	Icebox	0.308
F.C. Neuman #1	588	Sec. 33, T152N, R82W	9620	9630	Icebox	0.306
F.C. Neuman #1	588	Sec. 33, T152N, R82W	9630	9640	Icebox	0.412
F.C. Neuman #1	588	Sec. 33, T152N, R82W	9640	9650	Icebox	0.417
Karl Schock #1	622	Sec. 17, T131N, R69W	3610	3620	Roughlock	0.755
Karl Schock #1	622	Sec. 17, T131N, R69W	3620	3630	Roughlock	0.569
Karl Schock #1	622	Sec. 17, T131N, R69W	3630	3640	Roughlock	0.725
Karl Schock #1	622	Sec. 17, T131N, R69W	3640	3650	Icebox	1.223
Karl Schock #1	622	Sec. 17, T131N, R69W	3650	3660	Icebox	2.322

Original Well Name	NDIC	Location	Depth (ft.)		Formation	TOC wt. %
			Top	Base		
Karl Schock #1	622	Sec. 17, T131N, R69W	3660	3670	Icebox	1.987
Karl Schock #1	622	Sec. 17, T131N, R69W	3670	3680	Icebox	0.722
Karl Schock #1	622	Sec. 17, T131N, R69W	3680	3690	Icebox	2.176
Karl Schock #1	622	Sec. 17, T131N, R69W	3690	3700	Icebox	0.949
Karl Schock #1	622	Sec. 17, T131N, R69W	3700	3710	Icebox	0.899
Karl Schock #1	622	Sec. 17, T131N, R69W	3710	3720	Icebox	0.482
Karl Schock #1	622	Sec. 17, T131N, R69W	3720	3730	Icebox	0.645
Karl Schock #1	622	Sec. 17, T131N, R69W	3730	3740	Icebox	0.875
Karl Schock #1	622	Sec. 17, T131N, R69W	3740	3750	Icebox	0.8
Karl Schock #1	622	Sec. 17, T131N, R69W	3750	3760	Icebox	1.048
Karl Schock #1	622	Sec. 17, T131N, R69W	3760	3770	Icebox	0.928
F. L. Robertson #1	673	Sec. 26, T138N, R67W	3530	3540	Icebox	1.372
F. L. Robertson #1	673	Sec. 26, T138N, R67W	3540	3550	Icebox	0.72
F. L. Robertson #1	673	Sec. 26, T138N, R67W	3550	3560	Icebox	0.325
F. L. Robertson #1	673	Sec. 26, T138N, R67W	3560	3570	Icebox	0.539
F. L. Robertson #1	673	Sec. 26, T138N, R67W	3570	3580	Icebox	0.979
F. L. Robertson #1	673	Sec. 26, T138N, R67W	3580	3590	Icebox	0.523
F. L. Robertson #1	673	Sec. 26, T138N, R67W	3590	3600	Icebox	0.856
F. L. Robertson #1	673	Sec. 26, T138N, R67W	3600	3610	Icebox	0.672
F. L. Robertson #1	673	Sec. 26, T138N, R67W	3620	3630	Icebox	1.146
F. L. Robertson #1	673	Sec. 26, T138N, R67W	3630	3640	Icebox	1.282
F. L. Robertson #1	673	Sec. 26, T138N, R67W	3640	3650	Icebox	0.817
F. L. Robertson #1	673	Sec. 26, T138N, R67W	3650	3660	Icebox	0.65
F. L. Robertson #1	673	Sec. 26, T138N, R67W	3660	3670	Icebox	0.545
Anton Novy #1	763	Sec. 14, T144N, R77W	6740	6750	Icebox/Roughlock?	0.342
Anton Novy #1	763	Sec. 14, T144N, R77W	6750	6760	Icebox/Roughlock?	0.221
Anton Novy #1	763	Sec. 14, T144N, R77W	6760	6770	Icebox/Roughlock?	0.348
Anton Novy #1	763	Sec. 14, T144N, R77W	6860	6870	Icebox Fm.	0.341
Anton Novy #1	763	Sec. 14, T144N, R77W	6870	6880	Black Island/Deadwood?	0.349
Anton Novy #1	763	Sec. 14, T144N, R77W	6880	6890	Black Island/Deadwood?	0.299
Anton Novy #1	763	Sec. 14, T144N, R77W	6890	6900	Black Island/Deadwood?	0.32
Burlington Northern #1	5572	Sec. 27, T132N, R86W	7780	7790	Icebox	0.36
Burlington Northern #1	5572	Sec. 27, T132N, R86W	7790	7800	Icebox	0.424
Burlington Northern #1	5572	Sec. 27, T132N, R86W	7800	7810	Icebox	0.445
Burlington Northern #1	5572	Sec. 27, T132N, R86W	7810	7820	Icebox	0.399
Burlington Northern #1	5572	Sec. 27, T132N, R86W	7820	7830	Icebox	0.398
Burlington Northern #1	5572	Sec. 27, T132N, R86W	7830	7840	Icebox	0.424
Burlington Northern #1	5572	Sec. 27, T132N, R86W	7840	7850	Icebox	0.363
Burlington Northern #1	5572	Sec. 27, T132N, R86W	7850	7860	Icebox	0.377
Burlington Northern #1	5572	Sec. 27, T132N, R86W	7860	7870	Icebox	0.35
Burlington Northern #1	5572	Sec. 27, T132N, R86W	7870	7880	Icebox	0.352
Burlington Northern #1	5572	Sec. 27, T132N, R86W	7880	7890	Icebox	0.251
Burlington Northern #1	5572	Sec. 27, T132N, R86W	7890	7900	Icebox	0.228
Burlington Northern #1	5572	Sec. 27, T132N, R86W	7900	7910	Icebox	0.266
Burlington Northern #1	5572	Sec. 27, T132N, R86W	7910	7920	Icebox	0.282
Burlington Northern #1	5572	Sec. 27, T132N, R86W	7920	7930	Icebox	0.351
Burlington Northern #1	5572	Sec. 27, T132N, R86W	7930	7940	Icebox	0.46
Jacobs #1	6654	Sec. 27, T129N, R85W	7100	7110	Icebox	0.779
Jacobs #1	6654	Sec. 27, T129N, R85W	7110	7120	Icebox	0.387
Jacobs #1	6654	Sec. 27, T129N, R85W	7120	7130	Icebox	0.357
Jacobs #1	6654	Sec. 27, T129N, R85W	7130	7140	Icebox	0.456
Jacobs #1	6654	Sec. 27, T129N, R85W	7140	7150	Icebox	0.427
Welch #1	7010	Sec. 31, T138, R78W	6320	6330	Icebox	0.46

Original Well Name	NDIC	Location	Depth (ft.)		Formation	TOC wt. %
			Top	Base		
Welch #1	7010	Sec. 31, T138, R78W	6330	6340	Icebox	0.464
Welch #1	7010	Sec. 31, T138, R78W	6340	6350	Icebox	0.251
Welch #1	7010	Sec. 31, T138, R78W	6350	6360	Icebox	0.288
Welch #1	7010	Sec. 31, T138, R78W	6360	6370	Icebox	0.318
Welch #1	7010	Sec. 31, T138, R78W	6370	6380	Icebox	0.348
Welch #1	7010	Sec. 31, T138, R78W	6380	6390	Icebox	0.389
Welch #1	7010	Sec. 31, T138, R78W	6390	6400	Icebox	0.42
Welch #1	7010	Sec. 31, T138, R78W	6400	6410	Icebox	0.404
Welch #1	7010	Sec. 31, T138, R78W	6410	6420	Icebox	0.398
Welch #1	7010	Sec. 31, T138, R78W	6420	6430	Icebox	0.339
Welch #1	7010	Sec. 31, T138, R78W	6430	6440	Icebox	0.35
Welch #1	7010	Sec. 31, T138, R78W	6440	6450	Icebox	0.348
Welch #1	7010	Sec. 31, T138, R78W	6450	6460	Icebox	0.318
Welch #1	7010	Sec. 31, T138, R78W	6460	6470	Icebox	0.3
Welch #1	7010	Sec. 31, T138, R78W	6470	6480	Icebox	0.334
Anderson #12-9	7271	Sec. 9, T148N, R65W	3470	3480	Roughlock	0.266
Anderson #12-9	7271	Sec. 9, T148N, R65W	3480	3490	Roughlock?	0.123
Anderson #12-9	7271	Sec. 9, T148N, R65W	3490	3500	Icebox	0.267
Anderson #12-9	7271	Sec. 9, T148N, R65W	3500	3510	Icebox	0.271
Anderson #12-9	7271	Sec. 9, T148N, R65W	3510	3520	Icebox	0.217
Anderson #12-9	7271	Sec. 9, T148N, R65W	3520	3530	Icebox	0.276
Anderson #12-9	7271	Sec. 9, T148N, R65W	3530	3540	Icebox	0.45
Anderson #12-9	7271	Sec. 9, T148N, R65W	3540	3550	Icebox	0.373
Anderson #12-9	7271	Sec. 9, T148N, R65W	3550	3560	Icebox	0.232
Anderson #12-9	7271	Sec. 9, T148N, R65W	3560	3570	Icebox	0.221
Anderson #12-9	7271	Sec. 9, T148N, R65W	3570	3580	Icebox	0.235
Anderson #12-9	7271	Sec. 9, T148N, R65W	3580	3590	Icebox	0.255
Anderson #12-9	7271	Sec. 9, T148N, R65W	3590	3600	Icebox	0.18
Anderson #12-9	7271	Sec. 9, T148N, R65W	3600	3610	Icebox	0.213
Anderson #12-9	7271	Sec. 9, T148N, R65W	3610	3620	Black Island	0.142
Jacob Christman #1	7642	Sec. 28, T130N, R95W	9670	9680	Icebox	0.156
Jacob Christman #1	7642	Sec. 28, T130N, R95W	9680	9690	Icebox	0.159
Jacob Christman #1	7642	Sec. 28, T130N, R95W	9690	9700	Icebox	0.151
Jacob Christman #1	7642	Sec. 28, T130N, R95W	9700	9710	Icebox	0.158
Jacob Christman #1	7642	Sec. 28, T130N, R95W	9710	9720	Icebox	0.189
Jacob Christman #1	7642	Sec. 28, T130N, R95W	9720	9730	Icebox	0.286
Jacob Christman #1	7642	Sec. 28, T130N, R95W	9730	9740	Icebox	0.266
Jacob Christman #1	7642	Sec. 28, T130N, R95W	9740	9750	Icebox	0.231
Jacob Christman #1	7642	Sec. 28, T130N, R95W	9750	9760	Icebox	0.306
Jacob Christman #1	7642	Sec. 28, T130N, R95W	9760	9770	Icebox	0.392
Jacob Christman #1	7642	Sec. 28, T130N, R95W	9770	9780	Icebox	0.393
Jacob Christman #1	7642	Sec. 28, T130N, R95W	9780	9790	Icebox	0.467
Jacob Christman #1	7642	Sec. 28, T130N, R95W	9790	9800	Icebox	0.138
Olin #1	7691	Sec. 19, 138, R85W	9190	9200	Icebox	1.851
Olin #1	7691	Sec. 19, 138, R85W	9200	9210	Icebox	1.048
Olin #1	7691	Sec. 19, 138, R85W	9210	9220	Icebox	0.607
Olin #1	7691	Sec. 19, 138, R85W	9220	9230	Icebox	0.658
Olin #1	7691	Sec. 19, 138, R85W	9230	9240	Icebox	1.128
Olin #1	7691	Sec. 19, 138, R85W	9240	9250	Icebox	2.297
Olin #1	7691	Sec. 19, 138, R85W	9250	9260	Icebox	2.255
Olin #1	7691	Sec. 19, 138, R85W	9260	9270	Icebox	1.868
Olin #1	7691	Sec. 19, 138, R85W	9270	9280	Icebox	1.472
Olin #1	7691	Sec. 19, 138, R85W	9280	9290	Icebox	1.448

Original Well Name	NDIC	Location	Depth (ft.)		Formation	TOC wt. %
			Top	Base		
Olin #1	7691	Sec. 19, 138, R85W	9290	9300	Icebox	1.57
Olin #1	7691	Sec. 19, 138, R85W	9300	9310	Icebox	2.105
Olin #1	7691	Sec. 19, 138, R85W	9310	9320	Icebox	1.97
Olin #1	7691	Sec. 19, 138, R85W	9320	9330	Icebox	1.81
Olin #1	7691	Sec. 19, 138, R85W	9330	9340	Icebox	2.122
Olin #1	7691	Sec. 19, 138, R85W	9340	9350	Icebox	1.921
Larson #1	8307	Sec. 31, T155N, R77W	6920	6930	Roughlock?	0.576
Larson #1	8307	Sec. 31, T155N, R77W	6930	6940	Roughlock?	0.341
Larson #1	8307	Sec. 31, T155N, R77W	6940	6950	Icebox	0.312
Larson #1	8307	Sec. 31, T155N, R77W	6950	6960	Icebox	1.154
Larson #1	8307	Sec. 31, T155N, R77W	6960	6970	Icebox	0.415
Larson #1	8307	Sec. 31, T155N, R77W	6970	6980	Icebox	0.462
Larson #1	8307	Sec. 31, T155N, R77W	6980	6990	Icebox	0.239
Larson #1	8307	Sec. 31, T155N, R77W	6990	7000	Icebox	0.299
Larson #1	8307	Sec. 31, T155N, R77W	7000	7010	Icebox	0.321
Larson #1	8307	Sec. 31, T155N, R77W	7010	7020	Icebox	0.409
Larson #1	8307	Sec. 31, T155N, R77W	7020	7030	Icebox	0.394
Larson #1	8307	Sec. 31, T155N, R77W	7030	7040	Icebox	0.73
Larson #1	8307	Sec. 31, T155N, R77W	7040	7050	Icebox	0.332
Larson #1	8307	Sec. 31, T155N, R77W	7050	7060	Icebox	0.356
Larson #1	8307	Sec. 31, T155N, R77W	7060	7070	Black Island?	0.234
Larson #1	8307	Sec. 31, T155N, R77W	7070	7080	Black Island?	0.417
Larson #1	8307	Sec. 31, T155N, R77W	7080	7090	Black Island?	0.26
Larson #1	8307	Sec. 31, T155N, R77W	7090	7100	Black Island?	0.275
Mary Artz #1-5-2A	8546	Sec. 5, T150N, R104W	13100	13110	Roughlock?	0.106
Mary Artz #1-5-2A	8546	Sec. 5, T150N, R104W	13110	13120	Roughlock?	0.122
Mary Artz #1-5-2A	8546	Sec. 5, T150N, R104W	13120	13130	Roughlock?	0.119
Mary Artz #1-5-2A	8546	Sec. 5, T150N, R104W	13130	13140	Roughlock?	0.137
Mary Artz #1-5-2A	8546	Sec. 5, T150N, R104W	13140	13150	Icebox	0.202
Mary Artz #1-5-2A	8546	Sec. 5, T150N, R104W	13150	13160	Icebox	0.16
Mary Artz #1-5-2A	8546	Sec. 5, T150N, R104W	13160	13170	Icebox	0.319
Mary Artz #1-5-2A	8546	Sec. 5, T150N, R104W	13170	13180	Icebox	0.339
Mary Artz #1-5-2A	8546	Sec. 5, T150N, R104W	13180	13190	Icebox	0.272
Mary Artz #1-5-2A	8546	Sec. 5, T150N, R104W	13190	13200	Icebox	0.322
Mary Artz #1-5-2A	8546	Sec. 5, T150N, R104W	13200	13210	Icebox	0.267
Mary Artz #1-5-2A	8546	Sec. 5, T150N, R104W	13210	13220	Icebox	0.331
Mary Artz #1-5-2A	8546	Sec. 5, T150N, R104W	13220	13230	Icebox	0.42
Mary Artz #1-5-2A	8546	Sec. 5, T150N, R104W	13230	13240	Icebox	0.514
Mary Artz #1-5-2A	8546	Sec. 5, T150N, R104W	13240	13250	Icebox	0.56
Mormon Butte Fed. #2-25-2C	8663	Sec. 25, T147N, R98W	14340	14350	Icebox	0.249
Mormon Butte Fed. #2-25-2C	8663	Sec. 25, T147N, R98W	14350	14360	Icebox	0.193
Mormon Butte Fed. #2-25-2C	8663	Sec. 25, T147N, R98W	14360	14370	Icebox	0.182
Mormon Butte Fed. #2-25-2C	8663	Sec. 25, T147N, R98W	14370	14380	Icebox	0.19
Mormon Butte Fed. #2-25-2C	8663	Sec. 25, T147N, R98W	14380	14390	Icebox	0.213
Mormon Butte Fed. #2-25-2C	8663	Sec. 25, T147N, R98W	14390	14400	Icebox	0.376
Mormon Butte Fed. #2-25-2C	8663	Sec. 25, T147N, R98W	14400	14410	Icebox	0.169
Mormon Butte Fed. #2-25-2C	8663	Sec. 25, T147N, R98W	14410	14420	Icebox	0.251
Mormon Butte Fed. #2-25-2C	8663	Sec. 25, T147N, R98W	14420	14430	Icebox	0.297
Mormon Butte Fed. #2-25-2C	8663	Sec. 25, T147N, R98W	14430	14440	Icebox	0.236
Mormon Butte Fed. #2-25-2C	8663	Sec. 25, T147N, R98W	14440	14450	Icebox	0.419
Mormon Butte Fed. #2-25-2C	8663	Sec. 25, T147N, R98W	14450	14460	Icebox	0.531
Mormon Butte Fed. #2-25-2C	8663	Sec. 25, T147N, R98W	14460	14470	Icebox	0.669
Mormon Butte Fed. #2-25-2C	8663	Sec. 25, T147N, R98W	14470	14480	Icebox	0.84

Original Well Name	NDIC	Location	Depth (ft.)		Formation	TOC wt. %
			Top	Base		
Halliday #16-6	9080	Sec. 28, T138N, R102W	13150	13160	Icebox	0.287
Halliday #16-6	9080	Sec. 28, T138N, R102W	13160	13170	Icebox	0.205
Halliday #16-6	9080	Sec. 28, T138N, R102W	13170	13180	Icebox	0.159
Halliday #16-6	9080	Sec. 28, T138N, R102W	13180	13190	Icebox	0.223
Halliday #16-6	9080	Sec. 28, T138N, R102W	13190	13200	Icebox	0.108
Halliday #16-6	9080	Sec. 28, T138N, R102W	13200	13210	Icebox	0.138
Halliday #16-6	9080	Sec. 28, T138N, R102W	13210	13220	Icebox	0.177
Halliday #16-6	9080	Sec. 28, T138N, R102W	13220	13230	Icebox	0.143
Halliday #16-6	9080	Sec. 28, T138N, R102W	13230	13240	Icebox	0.126
Halliday #16-6	9080	Sec. 28, T138N, R102W	13240	13250	Icebox	0.143
Halliday #16-6	9080	Sec. 28, T138N, R102W	13260	13270	Icebox	0.186
Halliday #16-6	9080	Sec. 28, T138N, R102W	13270	13280	Icebox	0.225
Halliday #16-6	9080	Sec. 28, T138N, R102W	13280	13290	Icebox	0.237
Halliday #16-6	9080	Sec. 28, T138N, R102W	13300	13310	Icebox	0.336
Miller 33-1 #1	10570	Sec. 1, T138N, R96W	12250	12260	Icebox	0.296
Miller 33-1 #1	10570	Sec. 1, T138N, R96W	12260	12270	Icebox	0.367
Miller 33-1 #1	10570	Sec. 1, T138N, R96W	12270	12280	Icebox	0.312
Miller 33-1 #1	10570	Sec. 1, T138N, R96W	12280	12290	Icebox	0.353
Miller 33-1 #1	10570	Sec. 1, T138N, R96W	12290	12300	Icebox	0.508
Miller 33-1 #1	10570	Sec. 1, T138N, R96W	12300	12310	Icebox	0.515
Miller 33-1 #1	10570	Sec. 1, T138N, R96W	12310	12320	Icebox	0.444
Miller 33-1 #1	10570	Sec. 1, T138N, R96W	12320	12330	Icebox	0.458
Miller 33-1 #1	10570	Sec. 1, T138N, R96W	12330	12340	Icebox	0.315
Miller 33-1 #1	10570	Sec. 1, T138N, R96W	12340	12350	Icebox	0.481
Miller 33-1 #1	10570	Sec. 1, T138N, R96W	12350	12360	Icebox	1.058
Miller 33-1 #1	10570	Sec. 1, T138N, R96W	12360	12370	Icebox	0.566
Miller 33-1 #1	10570	Sec. 1, T138N, R96W	12370	12380	Icebox	0.337
Miller 33-1 #1	10570	Sec. 1, T138N, R96W	12380	12390	Icebox	0.811
L. Selvig #1	12125	Sec. 1, T158N, R72W	5230	5240	Red River/Roughlock	0.482
L. Selvig #1	12125	Sec. 1, T158N, R72W	5240	5250	Icebox	0.825
L. Selvig #1	12125	Sec. 1, T158N, R72W	5250	5260	Icebox	0.409
L. Selvig #1	12125	Sec. 1, T158N, R72W	5260	5270	Icebox	0.588
L. Selvig #1	12125	Sec. 1, T158N, R72W	5270	5280	Icebox	0.475
L. Selvig #1	12125	Sec. 1, T158N, R72W	5280	5290	Icebox	0.611
L. Selvig #1	12125	Sec. 1, T158N, R72W	5290	5300	Icebox	0.622
L. Selvig #1	12125	Sec. 1, T158N, R72W	5300	5310	Icebox	0.301
L. Selvig #1	12125	Sec. 1, T158N, R72W	5310	5320	Icebox	0.331
L. Selvig #1	12125	Sec. 1, T158N, R72W	5320	5330	Icebox	0.291
L. Selvig #1	12125	Sec. 1, T158N, R72W	5330	5360	Black Island?	0.302

Appendix A: Table 5. Standard core analysis data from Conoco's Schultz 8 #3 (NDIC: 12699)

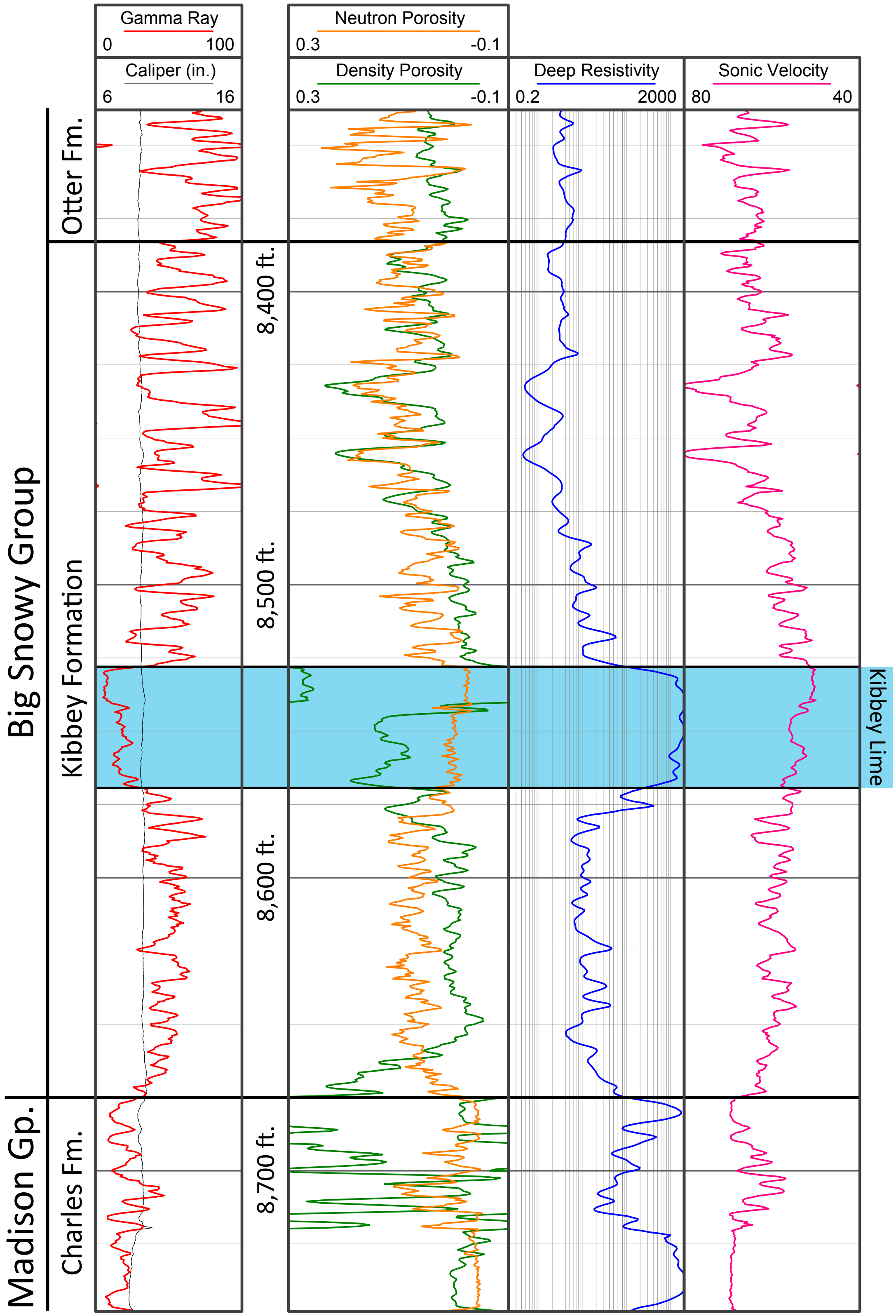
Well Name	NDIC	Formation	Core Depth (ft.)	Log Depth (ft.)	Permeability (millidarcys)	Porosity %	Oil Sat. %	Water Sat. %	Total
Schultz 8 #3	12699	Black Island	14352.5	14365.5	0.18*	2.5	21.5	39.9	61.4
Schultz 8 #3	12699	Black Island	14353.5	14366.5	2.3*	4	31.5	29.4	60.9
Schultz 8 #3	12699	Black Island	14354.5	14367.5	0.31	4.7	24.6	29.6	54.2
Schultz 8 #3	12699	Black Island	14355.5	14368.5	0.02	2.7	34.0	40.8	74.8
Schultz 8 #3	12699	Black Island	14356.5	14369.5	0.03	4.7	33.1	58.3	91.4
Schultz 8 #3	12699	Black Island	14357.5	14370.5	0.68	6.6	35.6	51.6	87.2
Schultz 8 #3	12699	Black Island	14358.5	14371.5	0.39	8.8	27.8	52.2	80.0
Schultz 8 #3	12699	Black Island	14359.5	14372.5	0.93	7.2	24.1	53.3	77.4
Schultz 8 #3	12699	Black Island	14360.5	14373.5	0.13	7.2	29.5	56.4	85.9
Schultz 8 #3	12699	Black Island	14361.5	14374.5	0.72	7	29.0	53.0	82.0
Schultz 8 #3	12699	Black Island	14362.5	14375.5	0.48	4.7	42.2	51.1	93.3
Schultz 8 #3	12699	Black Island	14363.5	14376.5	0.13	7.4	38.1	56.5	94.6
Schultz 8 #3	12699	Black Island	14364.5	14377.5	0.42	8	29.0	63.5	92.5
Schultz 8 #3	12699	Black Island	14365.5	14378.5	2.4*	8.5	25.6	61.3	86.9
Schultz 8 #3	12699	Black Island	14366.5	14379.5	0.86	8.2	24.6	63.7	88.3
Schultz 8 #3	12699	Black Island	14367.5	14380.5	0.38*	1.3	17.1	66.6	83.7
Schultz 8 #3	12699	Black Island	14368.5	14381.5	0.22	3.7	36.8	54.1	90.9
Schultz 8 #3	12699	Black Island	14369.5	14382.5	0.73*	3.7	36.8	56.7	93.5
Schultz 8 #3	12699	Black Island	14370.5	14383.5	0.7	7.2	37.3	51.5	88.8
Schultz 8 #3	12699	Black Island	14371.5	14384.5	1	8.2	38.0	53.9	91.9
Schultz 8 #3	12699	Black Island	14372.5	14385.5	0.34	8	35.8	59.2	95.0
Schultz 8 #3	12699	Black Island	14373.5	14386.5	2.5	8.8	32.1	50.7	82.8
Schultz 8 #3	12699	Black Island	14374.5	14387.5	1.7	8.3	33.4	49.7	83.1
Schultz 8 #3	12699	Black Island	14375.5	14388.5	6.9*	8.3	31.7	42.2	73.9
Schultz 8 #3	12699	Black Island	14376.5	14389.5	3.2*	5.9	41.5	44.5	86.0
Schultz 8 #3	12699	Black Island	14377.5	14390.5	1.5	7	20.4	65.6	86.0
Schultz 8 #3	12699	Black Island	14378.5	14391.5	2.1*	2.2	18.1	53.1	71.2
Schultz 8 #3	12699	Black Island	14379.5	14392.5	0.28	7.3	20.5	72.0	92.5
Schultz 8 #3	12699	Black Island	14380.5	14393.5	0.04	5.2	25.3	73.7	99.0
Schultz 8 #3	12699	Black Island	14381.5	14394.5	2.3*	7.6	26.0	53.3	79.3
Schultz 8 #3	12699	Black Island	14382.5	14395.5	24*	5.1	25.6	66.1	91.7
Schultz 8 #3	12699	Black Island	14383.5	14396.5	0.3	4.9	26.7	64.2	90.9
Schultz 8 #3	12699	Black Island	14384.5	14397.5	0.61	6	22.0	68.7	90.7
Schultz 8 #3	12699	Black Island	14385.5	14398.5	6.3*	11.9	23.3	56.0	79.3
Schultz 8 #3	12699	Black Island	14386.5	14399.5	9.3*	10.7	24.2	53.2	77.4

Core + 13 ft. = Log

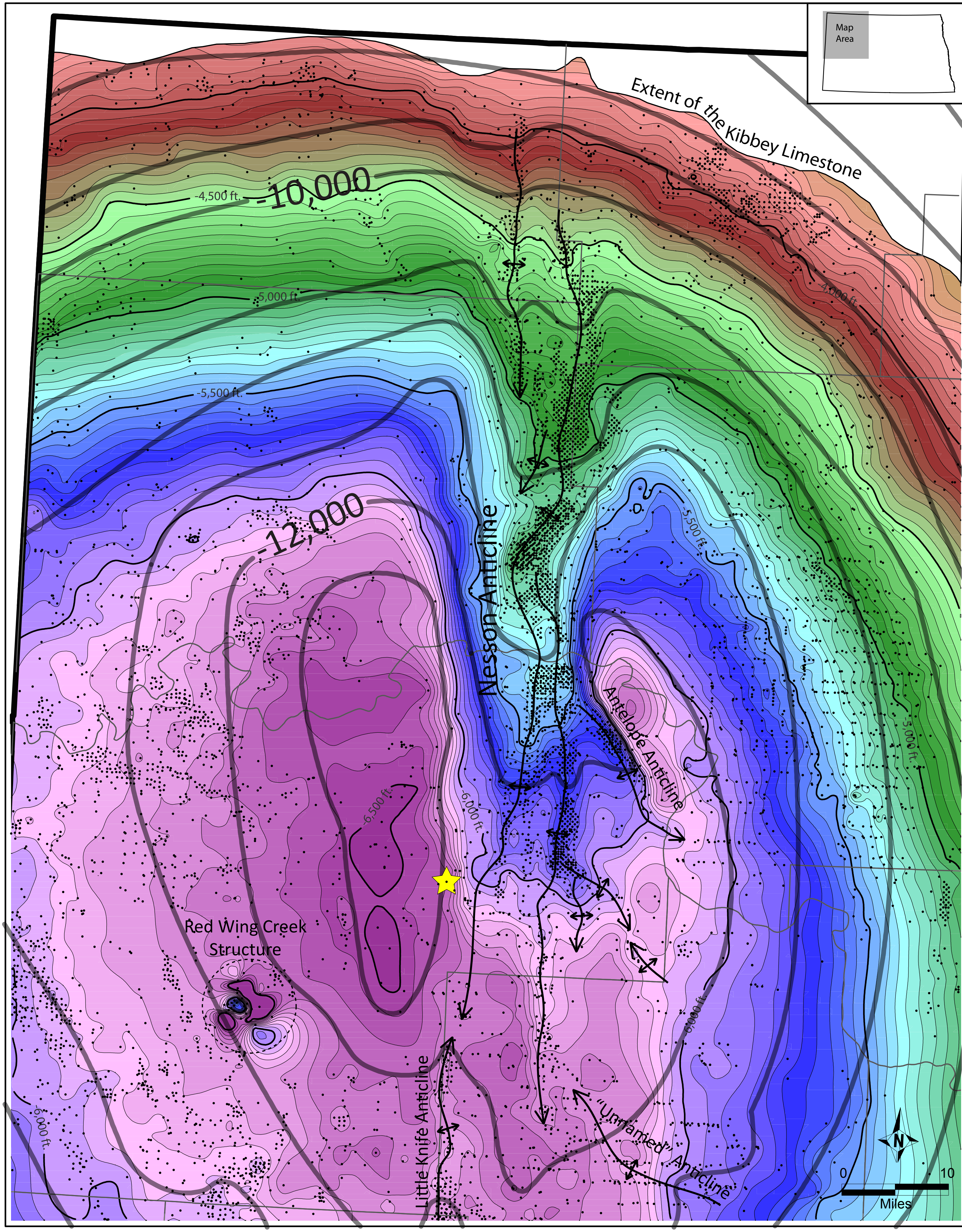
*Dehydration crack affecting permeability

Appendix A: Figure 1. Wireline log example of the Kibbey Limestone interval from Lyco Energy Corporation’s Titan E-Gierke 20-1-H.

#15923
33-053-02672-00-00
NENE Sec. 20, T150N, R97W
Lyco Energy Corporation
Titan E-Gierke 20-1-H
K.B. = 2121 ft.



Appendix A: Figure 2. Structure contour map (feet below sea level) of the Kibbey limestone top across northwestern North Dakota. In part due to its low stratigraphic position and deep depths, there are few wells that penetrate the Icebox Formation which yields minimal control points for generating Winnipeg Group related structure and isopach maps. Therefore, the Icebox Formation top structure contours displayed in Figure 3 were adjusted to mimic the structure displayed in the shallower Kibbey limestone surface. The Kibbey Limestone top is a consistent and easy top to pick from wireline logs (Appendix A: Figure 1) and therefore useful for conducting structure related studies. The yellow star displays the location of Lyco Energy Corporation's Titan E-Gierke 20-1-H (Appendix A: Figure 1).


Map
Area
Extent of the Kibbey Limestone
-10,000
-4,500 ft.
-5,000 ft.
-5,500 ft.
4,000 ft.
-12,000
-5,500 ft.
Nesson Anticline
Antelope Anticline
-6,500 ft.
-6,000 ft.
5,000 ft.
Red Wing Creek
Structure
6,000 ft.
-6,000 ft.
Little Knife Anticline
"Unnamed" Anticline
N
0
10
Miles

Appendix A: Figure 3. Map depicting the extent of the Winnipeg Group in southeastern North Dakota. The black outlined circles show the locations of oil and gas test wells from which wireline logs were examined by this study. The red outlined circles show the locations of test wells from the Red River Valley Drilling Project (Moore, 1978). Moore (1978) interpreted the presence or absence of the various formations of the Winnipeg Group using drill core and cutting samples with wireline logs from the Red River Valley Drilling Project test wells (red circles-RRVD labeled wells on map).

Extent of the Winnipeg Group: southeastern North Dakota