Integrating Petrophysics and Allostratigraphy to Find Sweet Spots in the Upper Cretaceous Belle Fourche and Second White Specks Alloformations, West-Central Alberta, Canada

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Abstract

The Upper Cretaceous Second White Specks Formation – an organic-rich, calcareous mudrock succession within the lower Colorado Group – is a prolific self-sourcing tight oil reservoir in Alberta. Due to the low porosity and permeability of this interval, localized natural fracture networks have previously provided the only means for oil to flow at economic rates. This study, focused in west-central Alberta, used allostratigraphic methods to subdivide the Second White Specks Formation into allomembers that define hydraulic flow units. The petrophysical properties (porosity, organic content, clay volume, and brittleness) of each allomember were modelled using a basic suite of geophysical wireline logs and sparse core data. When overlain with historic oil production results, modelled petrophysical parameters delineated previously unrecognized “sweet spots” that likely have increased oil potential. Applying the innovative petrophysical workflow developed in this study may increase the likelihood of drilling successful wells in similar exploration scenarios with limited datasets.

Keywords: allostratigraphy, brittleness, Cenomanian-Turonian boundary, formation evaluation, lower Colorado Group, petroleum geology, petrophysics, reservoir characterization, Second White Specks, Western Canada Sedimentary Basin
“It's a dangerous business, Frodo, going out of your door,” he used to say. “You step into the Road, and if you don't keep your feet, there is no knowing where you might be swept off to.

Do you realize that this is the very path that goes through Mirkwood, and that if you let it, it might take you to the Lonely Mountain or even further and to worse places?”

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I thank you, gentle reader, for having the fortitude to pick up this thesis – it had become a veritable tome by the time I ran out of things to say. There are lots of pictures, I promise!

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To my friends: I owe you a drink or five. May we meet again.
Table of Contents

Abstract ................................................................................................................................. ii
Acknowledgments ................................................................................................................ iv
Table of Contents ................................................................................................................ vi
List of Figures ....................................................................................................................... xi
List of Tables ......................................................................................................................... xv
Variables and Abbreviations ............................................................................................... xvi

PART I: INTRODUCTION & LITERATURE REVIEW

Chapter 1 ................................................................................................................................. 1
  1 Introduction ....................................................................................................................... 1
    1.1 Summary ................................................................................................................... 1
  1.2 Problem ......................................................................................................................... 1
    1.2.1 Influence of brittle behaviour ............................................................................... 2
    1.2.2 Influence of porosity ............................................................................................. 4
    1.2.3 Stratal architecture of the Second White Specks ............................................... 5
  1.3 Aims & Objectives ......................................................................................................... 6
    1.3.1 Research aim ......................................................................................................... 6
    1.3.2 Objectives ............................................................................................................. 6
  1.4 Scope ............................................................................................................................... 7
  1.5 Significance ................................................................................................................... 8
  1.6 Overview of thesis structure ....................................................................................... 10

Chapter 2 ............................................................................................................................... 11
  2 Stratigraphy, sedimentology, and play analysis of the Second White Specks and
    Belle Fourche Formations ............................................................................................... 11
    2.1 Overview ................................................................................................................... 11
    2.2 Geologic setting of Lower Colorado Group Shales .............................................. 11
      2.2.1 Tectonic setting ................................................................................................. 13
      2.2.2 Climate and physiography ............................................................................... 17
    2.3 Establishing nomenclature for Upper Cretaceous lower Colorado Group rocks
      in west-central Alberta ............................................................................................... 20
      2.3.1 Fish Scales Formation ...................................................................................... 23
      2.3.2 Belle Fourche Formation .................................................................................. 25
      2.3.3 Second White Specks Formation ................................................................... 26
    2.4 Petroleum system analysis of the lower Colorado Group in the Willesden
      Green – Gilby area ......................................................................................................... 28
      2.4.1 Source rock quality, maturation, and migration .............................................. 28
      2.4.2 Storage capacity ............................................................................................... 30
      2.4.3 Flow capacity .................................................................................................... 32
    2.5 Highlights ................................................................................................................... 35

Chapter 3 ............................................................................................................................... 37
  3 Using wellbore petrophysical data for quantitative geological interpretation ........... 37
    3.1 Overview ................................................................................................................... 37
    3.2 Role of petrophysics in exploration geology ........................................................... 37
    3.3 Connecting petrophysics with stratigraphy ............................................................ 38
    3.4 Overview of well logging ......................................................................................... 39
      3.4.1 Borehole petrophysics ....................................................................................... 40
3.4.2 Drilling mud................................................................. 41
3.4.3 Caliper log.............................................................. 43
3.5 Petrophysical modelling.................................................. 43
  3.5.1 Modelling Archie-type reservoirs .................................. 45
  3.5.2 Modelling shaley sand reservoirs................................. 48
3.6 Interpreting geophysical well log data from unconventional reservoirs 50
  3.6.1 Petrophysical tops guidance for mudstone reservoirs ........... 50
  3.6.2 Well log responses as proxies for mudstone reservoir composition 51
  3.6.2.1 Radioactivity logs.............................................. 53
    3.6.2.1.1 Gamma ray logs........................................... 54
    3.6.2.1.2 Spectral gamma ray logs................................. 56
    3.6.2.1.3 Bulk density log........................................... 60
    3.6.2.1.4 Neutron log................................................ 64
  3.6.2.2 Acoustic logs................................................... 65
    3.6.2.2.1 Tool specifications......................................... 66
    3.6.2.2.2 Environmental effects on sonic logs..................... 66
  3.6.2.3 Electric logs................................................... 67
    3.6.2.3.1 Tool specifications......................................... 69
    3.6.2.3.2 Environmental effects...................................... 69
3.7 Highlights.......................................................................... 70

PART II: RESEARCH METHODOLOGY

Chapter 4 ............................................................................. 71

4 Stratigraphic method.......................................................... 71
  4.1 Overview......................................................................... 71
  4.2 Stratigraphic nomenclature and bounding surfaces................. 71
  4.3 Controls on sedimentation.............................................. 72
    4.3.1 Eustasy................................................................. 72
    4.3.2 Milankovitch orbital forcing....................................... 73
    4.3.3 Sediment supply..................................................... 74
    4.3.4 δ13C/δ18O ratio........................................................ 74
  4.4 Seismic stratigraphy...................................................... 75
  4.5 Sequence stratigraphy................................................... 76
  4.6 Allostratigraphy............................................................ 77
  4.7 Highlights....................................................................... 80

Chapter 5 ............................................................................. 81

5 Petrophysical method......................................................... 81
  5.1 Overview......................................................................... 81
  5.2 Using the petrophysical model to calculate brittleness.............. 81
  5.3 Database development................................................... 81
  5.4 Core-to-log correlation.................................................. 85
    5.4.1 Total organic carbon (TOC) determination....................... 85
    5.4.2 X-ray fluorescence (XRF) analyses............................... 87
    5.4.3 Normalized mineralogy.............................................. 88
  5.5 Allostratigraphic correlation............................................ 89
  5.6 Petrophysical modelling workflow..................................... 90
    5.6.1 Environmental corrections.......................................... 94
      5.6.1.1 Gamma ray corrections......................................... 94
Chapter 6

PART III: RESULTS

6.1 Allostratigraphic correlation of the Lower Second White Specks and Upper Belle Fourche alloformations in the Willesden Green – Gilby region, Alberta, Canada

6.2 Allostratigraphic framework

6.3 Lower Colorado Group facies

6.3.1 Facies observed in core

6.3.1.1 Facies 1: bentonite beds

6.3.1.2 Facies 2: Very dark grey, planar laminated mudstone

6.3.1.3 Facies 3: Weakly bioturbated, medium-grey laminated mudstone, interbedded siltstone, and very fine-grained sandstone

6.3.1.4 Facies 4: Wavy laminated calcareous mudstone, siltstone, and fine-grained sandstone

6.3.1.5 Facies 5: Wavy to undulating laminated calcareous siltstone and fine-grained sandstone

6.3.2 Facies association

6.3.2.1 Offshore to mid-shelf shallow muddy ramp setting

6.4 Fine-grained sediment transport in ancient epicontinental seas

6.5 Core-to-log correlation

6.5.1 Electrofacies

6.5.1.1 Facies 1

6.5.1.2 Facies 2

6.5.1.3 Facies 3
Solving the Second White Specks

10 Discussion ........................................................................................................... 201
10.1 Defining hydraulic flow units ........................................................................... 201
    10.1.1 Significance of allostratigraphic bounding surfaces ............................. 201
    10.1.2 Quantifying lateral facies variation ...................................................... 203
10.2 Petrophysical property modelling .................................................................... 205
    10.2.1 TOC ........................................................................................................ 206
    10.2.2 Porosity .................................................................................................. 207
    10.2.3 Brittleness ............................................................................................... 210
10.3 Sweet spot mapping .......................................................................................... 212
10.4 Recommendations for future Second White Specks exploration .................. 213

Chapter 11 .................................................................................................................. 215
11 Conclusions ........................................................................................................... 215
    11.1 Future work ................................................................................................. 218
Curriculum Vitae ....................................................................................................... 220
References .................................................................................................................. 222
List of Figures

Fig. 1.1: Two adjacent (~1 km well spacing) Second White Specks-targeted wells, drilled by the same operator days apart, in the Willesden Green field of Alberta. 102/14-31 produced economic volumes of light oil (122,551 Bbl), whereas 102/8-36 was unsuccessful. 3

Fig. 1.2: Base map of the Willesden Green – Gilby study area in Alberta, illustrating the spread of available data across the entire area. The scale bar is in metres (m). 9

Fig. 2.1: A composite map of the Second White Specks lithostratigraphic interval in southern Alberta. 12

Fig. 2.2: Schematic of a strike-oriented cross-section through a foreland basin. Modified from DeCelles and Giles (1996), and Allen and Allen (2013). 14

Fig. 2.3: Paleogeographic map of the WCSB during the mid- to Late Cenomanian. 15

Fig. 2.4: Paleogeographic map of the WCSB during the early Turonian. 16

Fig. 2.5: Modified from Blakey (2014). Early Cenomanian through Early Turonian (~99 Ma to ~93.2 Ma) paleogeography of North America, with approximate shoreline locations. 18

Fig. 2.6: Comprehensive table of formations for the study area, combined with WIS sea level changes from Schröder-Adams (2014) and Haq (2014). 22

Fig. 2.7: 1-dimensional burial history diagram (top) of 16-18-52-5W5, modified from Roberts et al. (2005). The inset map is the same as Fig. 2.1, with the study area for this thesis outlined in orange. The 16-18 well is indicated on the inset map as a red dot. 29

Fig. 2.8: A comparison of different oil and gas reservoirs in terms of reservoir quality; modified from CSUR (Canadian Society of Unconventional Resources). The Second White Specks in the Willesden Green area has characteristics of both unconventional and conventional reservoirs and is characterized as a “hybrid shale”. 31

Fig. 2.9: IP4 (initial average oil rate for the first 4 months) map for Second White Specks wells in the study area. 33

Fig. 2.10: Cumulative production map for Second White Specks Formation wells in the study area. Green indicates oil production, red indicates gas production, yellow indicates condensate production, and blue indicates water production. Most Second White Specks wells in this area are primarily oil producers and produce negligible water and condensate, with minor gas production. 34

Fig. 3.1: Schematic of a centered caliper-type tool attached to an instrument assembly, with idealized responses to beds that could potentially be encountered in the lower Colorado Group. 42
Fig. 3.2: Comparison of general petrophysical models for Archie-type, shaley sandstone, and unconventional reservoirs in terms of complexity. The level of petrophysical complexity increases with the number of components, which makes them more difficult to resolve.

Fig. 3.3: A representative well log (7-19-45-06W5) for the Second White Specks interval.

Fig. 3.4: Schematic of a bulk density logging tool in a conventional reservoir.

Fig. 5.1: A process flow diagram illustrating the integrated petrophysical and geological workflows used in this thesis.

Fig. 5.2: A screenshot of the Techlog software used in this project, with individual wells in the left-hand column, the properties of any selected parameters in the second column, and a cross-section visualized across the main section of the screen.

Fig. 5.3: Modified from Ambrose et al. (2010) – this is the petrophysical model used for the Second White Specks in this study.

Fig. 5.4: Modified from Asquith (1990) – this represents the previous petrophysical model (Fig. 5.3) within a very simplified geological context.

Fig. 5.5: Issler model TOC vs. Rock-Eval TOC analyses from the core study interval in the 100/07-19-045-06W5 well. The regression shows a strong linear relationship with a moderately high coefficient of determination ($r^2 = 0.811$).

Fig. 5.6: A log display of the 7-19 well, showing the sonic and resistivity curves that were used as input for the TOC model as well as the porosity model.

Fig. 5.7: A multi-well crossplot with 1946 bulk density and neutron porosity data points from 5 wells (102/14-31-41-06W5, purple; 100/15-36-40-6W5, pink; 100/16-28-37-05W5, brown; 100/14-18-37-7W5, yellow; and 100/10-16-042-06W5, light green) throughout the Second White Specks and Belle Fourche intervals. The y-intercept of the regression is an estimate of the matrix density (100% rock volume) of the Second White Specks and Belle Fourche Formations.

Fig. 5.8: Histograms of uncorrected (above) and kerogen-corrected (below) modelled total density porosities from a selection of wells in the study area within the Second White Specks and Belle Fourche intervals, presented logarithmically.

Fig. 5.9: This is a thorium vs. potassium % chart with data plotted in green from well 100/02-14-38-06W5. This data plots largely in the mixed-layer clay field, providing a basis for using a mixed-layer clay density for effective porosity.

Fig. 5.10: The above graph displays a linear regression of carbonate volume computed from Jiang et al. (2017) in addition to carbonate XRD data from Furmann et al. 2014,
versus modelled kerogen for wells 100/02-14-038-05W5, 100/07-19-045-06W5/00, 102/08-15-036-05W5/00, and 102/08-36-041-07W5/00.

Fig. 5.11: A screenshot from Surfer of the grid geometry parameters used for mapping in this study. Using identical grid geometries for each contour map ensured they could be accurately overlain and compared to each other.

Fig. 6.1: Correlation of the allostratigraphic framework used in this thesis (left) to the framework used by Tyagi et al. (2007), using the K1 disconformity as a datum. Dashed lines indicate the extension of the framework used in this thesis into Tyagi et al. (2007), and vice versa.

Fig. 6.2: An approximately south-to-north oriented cross section displaying the five Second White Specks and Belle Fourche cores logged by this author. Core photos are included for reference to facies.

Fig. 6.3: An approximately south-to-north oriented cross section displaying the available LAS data for cores in the study area.

Fig. 6.4: Cartoons summarizing the paleogeography and paleobathymetry of the Kaskapau delta and its basinal equivalent Second White Specks and Belle Fourche alloformations – vertical scale is extremely exaggerated. This approximates a shallow marine muddy ramp setting with a very low gradient. The approximate location of facies 2 through 5 are shown as circled numbers.

Fig. 6.5: A composite cross-section, using the “red” bentonite as a datum, of the Lower Second White Specks and Belle Fourche alloformations across the study area. Net reservoir intervals are shaded in purple (Belle Fourche) and green (Second White Specks).

Fig. 6.6: Reference map for summary allostratigraphic cross-sections, with core locations for reference.

Fig. 6.7: Allostratigraphic cross-section B to B’, which runs north-south.

Fig. 6.8: Allostratigraphic cross-section C to C’, which runs north-south.

Fig. 6.9: Allostratigraphic cross-section D to D’, which runs north-south.

Fig. 6.10: Allostratigraphic cross-section E to E’, which runs east-west.

Fig. 6.11: Allostratigraphic cross-section F to F’, which runs east-west.

Fig. 6.12: Allostratigraphic cross-section G to G’, which runs east-west.

Fig. 6.13: Allostratigraphic cross-section H to H’, which runs east-west.

Fig. 7.1: 2D structure map of the top of allomember VII, with the Mesozoic deformation front for reference.
Fig. 7.2: 3D structure map of the top of allomember VII. 164
Fig. 7.3: Isochore map of allomember BF1. 167
Fig. 7.4: Isochore map of allomember BF2. 168
Fig. 7.5: Isochore map of allomember BF3. 169
Fig. 7.6: Isochore map of allomember VII. 170
Fig. 7.7: Isolith (isochore thickness overlaid on clay volume) of allomember BF1. 174
Fig. 7.8: Isolith (isochore thickness overlaid on clay volume) of allomember BF2. 175
Fig. 7.9: Isolith (isochore thickness overlaid on clay volume) of allomember BF3. 176
Fig. 7.10: Isolith (isochore thickness overlaid on clay volume) of allomember VII. 177

Fig. 8.1: Comparison of corrected GR (green and yellow colour fill, first track on the left), TOC (blue and red colour fill, second from the right), total porosity (black line with white fill, far right) and effective porosity (far right, blue fill) for 102/14-31-041-06W5, 102/08-36-041-07W5, and 100/07-19-045-06W5. 182
Fig. 8.2: TOC of allomember BF3. 184
Fig. 8.3: TOC of allomember VII. 185
Fig. 8.4: Total porosity of allomember BF3. 186
Fig. 8.5: Total porosity of allomember VII. 187
Fig. 8.6: Effective porosity of allomember BF3. 189
Fig. 8.7: Effective porosity of allomember VII. 190
Fig. 8.8: Porosity thickness for allomember BF3. 192
Fig. 8.9: Porosity thickness for allomember VII. 193
Fig. 8.10: Brittleness of allomember BF3. 194
Fig. 8.11: Brittleness of allomember VII. 195
Fig. 9.1: Sweet spot map for allomember BF3. 198
Fig. 9.2: Sweet spot map for allomember VII. 199
List of Tables

Table 3.1: Table of geophysical well log responses to commonly encountered minerals and compounds in the Lower Colorado Group................................................................. 57

Table 5.1: Table of equations and parameters used for petrophysical modelling in this project. All variables in red font are measurements taken directly from the well logs..... 93

Table 5.2: Table of TOC equations, with remarks related to their physical basis and limitations.......................................................................................................................... 99

Table 5.3: Table of total and effective porosity equations, with remarks related to their usefulness for unconventional reservoirs.................................................................109

Table 5.4: Table of mineralogical brittleness indices in chronological order, with their associated innovations and limitations. Compiled from Jarvie et al. (2007), Wang and Gale (2009), Jin et al. (2014a); Jin et al. (2014b), Katz et al. (2016); Mathia et al. (2016) and Rybacki et al. (2016). ..............................................................119

Table 6.1: The facies codes used in this thesis, along with their descriptions and associated depositional environments. Facies colours reflect the colours used in later cross-sections to indicate those facies. Vertical shifts in facies indicate lateral shift in depositional environment, which are interpreted to be driven by changes in relative advection energy. ........................................................................................................134

Table 6.2: Petrophysical tops guidance for the Second White Specks and Belle Fourche alloformations in the Willesden Green – Gilby area of west-central Alberta. This includes distinguishing log characteristics in addition to problems the interpreter may encounter while picking tops. ...............................................................................................................149
Variables and Abbreviations

\( \delta A \) = rate of change in accommodation
\( \delta S \) = rate of change in sediment supply
\( \gamma \) = gamma ray intensity (API)
\( \gamma API \) = sum of gamma ray energies for spectral gamma ray (API)
\( \gamma_B \) = gamma ray intensity of an organic free shale (API)
\( \phi_d \) = clay porosity (v/v)
\( \phi_D \) = density porosity (v/v)
\( \phi_{DE} \) = effective density porosity (v/v)
\( \phi_E \) = effective porosity (v/v)
\( \phi_S \) = sonic porosity (v/v)
\( \phi_T \) = total porosity (v/v)
\( \phi \) = porosity (v/v)
\( \rho_b \) = bulk density (g/cm\(^3\))
\( \rho_{dryclay} \) = dry clay density (g/cm\(^3\))
\( \rho_e \) = electron density (g/cm\(^3\))
\( \rho_f \) = fluid density (g/cm\(^3\))
\( \rho_{ker} \) = kerogen density (g/cm\(^3\))
\( \rho_{ma} \) = matrix density (g/cm\(^3\))
\( \rho_{wetclay} \) = wet clay density (g/cm\(^3\))
\%R\(_O\) = vitrinite reflectance
\( \Delta \log R \) = Passey method for calculating total organic carbon (wt %)
\( \Delta t_{baseline} \) = interval transit time baseline used for Passey method (\( \mu \)s/m)
\( \Delta t_n \) = interval transit time through fluid (\( \mu \)s/m)
\( \Delta t_{ma} \) = interval transit time through matrix (\( \mu \)s/m)
2WS (Second White Specks)
\( a \) = constant related to sandstone type (unitless)
\( A \) = locally determined calibration component (unitless)
API (American Petroleum Institute units)
Bbl (barrels of oil equivalent)

\( BI = \) brittleness index (v/v or wt %)

BIA (Bow Island Arch)

BF (Belle Fourche)

BFSM (Base of Fish Scales marker)

BOE (barrels of oil equivalent)

\( C \) or \( C_p \) = compaction component (unitless)

CEC (cation exchange capacity)

CGR = uranium-free computed gamma ray (API)

\( CGR_{\text{log}} \) = uranium-free gamma ray value in API from log at a given depth

\( CGR_{\text{max}} \) = uranium-free computed gamma ray value in API or 95\textsuperscript{th} percentile “shale” cutoff

\( CGR_{\text{min}} \) = uranium-free computed gamma ray value in API for 5\textsuperscript{th} percentile “sand” cutoff

DSSI (dipole sonic shear imager)

DT (sonic transit time)

FSU (Fish Scales Upper)

Ga (billion years ago)

GR (gamma ray)

\( GR_{\text{log}} \) = gamma ray value in API from log at a given depth

\( GR_{\text{max}} \) = gamma ray value in API for 95\textsuperscript{th} percentile “shale” cutoff

\( GR_{\text{min}} \) = gamma ray value in API for 5\textsuperscript{th} percentile “sand” cutoff

HCS (hummocky cross-stratification)

\( K \) = kerogen conversion factor (unitless)

keV (kilo electronvolts)

LAS (Log Ascii Standard)

LIP (Large Igneous Province)

LLD (laterolog)

LOM (level of organic maturity)

\( m \) = cementation exponent (unitless)

Ma (million years ago)

MeV (mega electronvolts)
mD (millidarcies)

\( n = \) saturation exponent (unitless)

nD (nanodarcies)

NDIR (nondispersive infrared)

NEU = neutron porosity log reading (v/v)

\( \Delta t = \) interval transit time (\(\mu s/m\))

OAE (Ocean Anoxic Event)

OOIP (original oil in place)

PDMSL (present-day mean sea level)

PEF (photoelectric effect)

PSF (polished slip faces)

\( R_{baseline} = \) baseline resistivity used for Passey method (ohm.m)

\( R_T = \) deep resistivity of partially brine saturated formation (ohm.m)

\( R_w = \) resistivity of saturating brine (ohm.m)

RR (rig-release date)

SGA (Sweetgrass Arch)

SGR (spectral gamma ray)

\( S_O = \) oil saturation (v/v)

\( S_w = \) water saturation (v/v)

SWB (storm wave base)

\( T = \) tortuosity (unitless)

TOC = total organic carbon (wt %)

TVD (true vertical depth, in metres)

\( v/v = \) (volume %)

\( V_{bulk} = \) bulk volume (v/v)

\( V_{cal} = \) calcite volume (v/v)

\( V_{carb} = \) carbonate volume (v/v)

\( V_{cl} = \) clay volume (v/v)

\( V_{dol} = \) dolomite volume (v/v)

\( V_{ker} = \) kerogen volume (v/v)

\( V_{matrix} = \) matrix volume (v/v)
Solving the Second White Specks

\[ V_{qtz} = \text{quartz volume (v/v)} \]
\[ V_{QFM} = \text{quartz-feldspar-mica volume (v/v)} \]
\[ V_{sh} = \text{shale volume (v/v)} \]

WCSB (Western Canada Sedimentary Basin)
WEGSF (wave-enhanced sedimentary gravity flow)

\[ w_{ker} = \text{kerogen wt %} \]
\[ W_{QFM} = \text{quartz-feldspar-mica wt %} \]

wt% (weight %)
XRD (x-ray diffraction)
XRF (x-ray fluorescence)

\[ Z:A = \text{ratio of average atomic number to atomic weight} \]
Chapter 1

1 Introduction

1.1 Summary

This thesis is about the petrophysical analysis of an unconventional oil reservoir. The study developed an innovative method for identifying “sweet spots” in a fracture-controlled unconventional reservoir with limited available core and public geophysical wireline log data. The method involves overlaying maps of petrophysically-derived properties related to effective porosity and mineralogical brittleness. The stratigraphic zones represented by each map are defined using high-resolution allostratigraphic correlations. Using this workflow may increase the likelihood of drilling successful wells in similar exploration scenarios.

1.2 Problem

The calcareous, organic-rich mudstones of the lower Cretaceous Colorado Group represent a major unexploited hydrocarbon resource in the Western Canada Sedimentary Basin (WCSB). In particular, the Second White Specks Formation in Alberta has produced economic volumes of light oil from certain wells (>100,000 barrels of oil equivalent or BOE; exceptionally >1,000,000 BOE), and has an estimated OOIP (original oil in place) of 450 billion barrels (Osadetz et al. 2010). The Second White Specks Formation is a demonstrably effective source rock – a Colorado Group geochemical fingerprint can be recognized clearly in all oils found in Viking, Belly River, and Cardium reservoirs in Alberta (Creaney et al. 1994).

Generating consistent and repeatable results from Second White Specks Formation-targeted wells has proven difficult, despite containing significant reserves (Canadian Discovery 2011). Due to the extremely low permeability of the Second White Specks Formation (<1 mD), fractures are required for oil to flow through the rock matrix. Historically, successful wells targeted small thrust structures where the Second White Specks was naturally fractured – unfortunately, those pools are areally constrained and most have been exploited already (Clarkson & Pedersen 2011). Second White Specks
Formation wells have also been consistently plagued by unreliable production results and severe wellbore instability. The non-brittle and clay-rich nature of the Second White Specks makes it very difficult to yield commercial production rates through hydraulic fracture stimulation methods. These issues have prevented widespread pursuit of the Second White Specks as a viable resource play in Canada (Letourneau et al. 1996; Clarkson & Pedersen 2011; MacKay 2014; Fox & Garcia 2015).

As an example, two seemingly identical adjacent wells, drilled by the same operator days apart (Fig. 1.1), resulted in a success (102/014-31-041-06W5) and an abject failure (102/08-36-041-07W5). Can we reliably predict what geographic areas and stratigraphic zones are more likely to produce consistently well from the Second White Specks Formation, and why? This thesis builds on current knowledge of the stratigraphic architecture of the Second White Specks Formation in west-central Alberta to answer this research question (Tyagi et al. 2007; Varban & Plint 2008a; Tyagi 2009; Plint et al. 2012b; Zajac 2016). Most significantly, this thesis expands on new understandings of two factors governing oil production in west-central Alberta:

1) brittle behaviour (Wang & Gale 2009; Clarkson & Pedersen 2011; Cho & Perez 2014; Furmann et al. 2016; Mathia et al. 2016), and;

2) enhanced porosity (Schieber 2010; Jiang & Cheadle 2013; Furmann et al. 2016).

1.2.1 Influence of brittle behaviour

Historically, unpredictable inflow performance from the Second White Specks Formation has been tied solely to natural fractures in stiff, brittle rocks. Open fractures can locally improve permeability (Bloch et al. 1999; Gale et al. 2007; MacKay 2014). Brittle behaviour and fracability is enhanced in mudstone reservoirs with significant silica, feldspar, or carbonate content, because calcareous and siliceous minerals (except for clay minerals) impart their brittle characteristics to their host rocks (Cho & Perez 2014). The Second White Specks Formation has a significant carbonate lithological component derived from dispersed coccoliths, coccolith-rich fecal pellets, as well as other bioclastic grains and carbonate cements (Bloch et al. 1999). The location of natural fractures in this interval may be tied to increased brittle mineral content, as well as structural elements.
Fig. 1.1: Two adjacent (~1 km well spacing) Second White Specks-targeted wells, drilled by the same operator days apart, in the Willesden Green field of Alberta. 102/14-31 produced economic volumes of light oil (122,551 Bbl), whereas 102/8-36 was unsuccessful.

Petrophysically, these wells appear to be identical (the logs are, from left to right: caliper (mm), gamma ray (API), sonic (us/m), and resistivity (ohm.m). The 102/014-31 well (right, starred) was drilled and perforated first (indicated by vertical blue dots), and successfully produced from the Second White Specks. The 102/08-36 well, drilled 10 days later, was perforated in the same interval and produced insignificant oil volumes. Tops are from Zajac, 2016.
Solving the Second White Specks

1. Introduction

Letourneau et al. 1996; Clarkson & Pedersen 2011).

Previous studies have not attempted to continuously model variations in petrophysical attributes (e.g., brittleness or porosity) throughout the Second White Specks Formation. Instead, the focus has been on historical production results (Clarkson & Pedersen 2011), or indirect reservoir quality indicators like resistivity maps (Zajac 2016). Other studies have relied solely on individual core analysis points to calculate brittleness and porosity (Furmann et al. 2014; Furmann et al. 2016) – this means that vertical and spatial variations in reservoir quality were not adequately captured. Instead, a continuous model of brittleness for the entirety of the Second White Specks Formation can be derived from wireline logs if calibration to core is adequately established (Sondergeld et al. 2010).

Accurate models of mineralogy and brittleness may be the keys to success in this play. Clarkson and Pedersen (2011) recognized that advances in horizontal drilling, hydraulic multi-stage hydraulic fracture stimulation, and improvements to brittleness models have facilitated production of unexpelled hydrocarbons from other fracture-influenced unconventional reservoirs (e.g., the Duvernay Formation in Alberta). The economic success of the Duvernay has helped fund the development of a comprehensive database of lithological and petrophysical information, including cores. The mineralogy and brittleness of the Duvernay Formation, therefore, are well established. A long history of inconsistent production and geomechanical drilling problems has discouraged core recovery from the Second White Specks Formation (Fox & Garcia 2015), making calibration of any petrophysical model dependent on indirect measures of lithology based on well logs.

1.2.2 Influence of porosity

Changes in primary porosity may be an important factor in successful Second White Specks Formation wells. New revelations from mudstone microstructure studies have demonstrated that porous depositional fabrics can be preserved even after deep burial (Schieber 2010; Jiang & Cheadle 2013). Because depositional modes control sediment fabric variation across a basin, a representative paleogeographic interpretation is critical to understand reservoir quality variations in the Second White Specks petroleum system.
To date, petrophysically-derived reservoir quality indicators have not been correlated to inflow performance from Second White Specks Formation-targeted wells, nor has such a connection been sufficiently tested. Establishing the relationship would require robust knowledge of lithological heterogeneity in three dimensions, but this is limited by two key issues with most Second White Specks datasets:

1) Data scarcity caused by a lack of calibration data (i.e., core data, including mineralogical analyses and porosity), and;

2) Widespread data quality problems like borehole environmental effects (e.g., hole washout, thin-bed effects, organic matter effects on gamma ray measurements).

Recent studies have failed to address these challenges, limiting accurate characterization of lithological and petrophysical heterogeneity. Conventional core analyses are especially rare in this interval because it has not been a primary exploration target. This limits petrophysical analyses of the Second White Specks Formation because of the paucity of framework and clay mineralogical data, as well as porosity measurements – these are required for calibration. Despite the aforementioned data issues, heterogeneity can be resolved if adequate environmental corrections are applied. Environmental effects (e.g., borehole washout and high organic content) can be mitigated via robust data conditioning of wireline log measurements, thereby improving the accuracy of acquired data from affected intervals. Borehole corrections like these can help elucidate ambiguous lithologies in logged zones where core data is limited or nonexistent, as is the case for the Second White Specks Formation. In combination with existing core data, properly conditioned borehole measurements may significantly reduce the uncertainty surrounding brittleness and porosity variations in the Second White Specks Formation.

1.2.3 Stratal architecture of the Second White Specks

If increased brittleness and enhanced porosity do correlate with production from Second White Specks wells, completion method notwithstanding, it is essential to determine if and how brittleness and porosity vary across the study area. Once brittleness and porosity parameters have been modelled, they must be described in an allostratigraphic framework in order to analyze hydraulic flow units in their depositional context. Lithostratigraphic methods are used to subdivide rock units on the basis of lithic characteristics;
allostratigraphic methods, in comparison, are used to subdivide rock units via correlation of bounding surfaces with temporal significance (NACSN 1983, 2005). Prior to the work of Tyagi et al. (2007), the Second White Specks was only described within a lithostratigraphic framework (Stott 1963; Wall & Rosene 1977; Leckie et al. 1994; Bloch et al. 1999). These studies failed to resolve the vertical and lateral distribution of coeval strata (allomembers), bounded by time-stratigraphic discontinuities, that constitute the high-resolution record of Second White Specks time. Reconciling the strata with the absolute geologic time scale makes it possible to relate the Second White Specks allomembers to higher-order allogenic drivers such as the tectonic and eustatic history of the WCSB.

1.3 Aims & Objectives

1.3.1 Research aim

The goal of this thesis is to establish the relative contributions of mappable petrophysical properties (i.e., brittleness and porosity) to fluid inflow performance in the Second White Specks Formation within a 110-township area, using pre-existing wireline log data and core data collected by the author. It is hypothesized that areas with higher relative brittleness (increased silica and carbonate content) and increased porosity will collocate with improved oil production from the Second White Specks Formation.

1.3.2 Objectives

This research seeks to answer three key questions related to the research aim.

1) Can the Second White Specks and Belle Fourche Formations in the study area be subdivided into allomembers that provide a framework for mapping coeval geologic units, which may act as hydraulic flow units? This question will be answered through the generation of three key outputs:

- High-resolution (<20 m unit thickness) allostratigraphic cross-sections to establish reservoir geometry in the Willesden Green and Gilby areas;
- Structure, isochore, and petrophysical property maps for mapped allomembers.
2) Can the petrophysical properties (e.g., porosity, organic content, clay content, and brittleness) of the Second White Specks and Belle Fourche Formations be reliably modelled, using limited geophysical well data and sparse core control for calibration? This question will be answered through the generation of two key outputs:

- A petrophysical tops guidance for the Second White Specks and Belle Fourche Formations in the study area, including:
  - A list of generated tops (the elevations of stratigraphic horizons)
  - A workflow for consistent top selection for future workers
  - Correlation of sedimentary facies in core with petrophysical facies from logs
- Continuous, static petrophysical models for porosity, organic content, mineralogy, and brittleness, with average values for modelled petrophysical properties, separated by allomember, for each well.

3) Is there a spatial association (co-location) between reservoir quality indicators (e.g., brittleness and porosity thickness) and oil production? This question will be answered by building a series of “sweet spot” maps that compare reservoir quality indicators (e.g., brittleness and porosity-thickness) and oil production.

By answering these three questions, recommendations will be made for future hydrocarbon exploration in the study area.

1.4 Scope

The study area is constrained to a 110-township region (~11,000 km²) in west-central Alberta extending from Township 35 to 45, and Range 1W5 to 10W5. This region of Alberta contains the Willesden Green and Gilby areas, as well as the town of Rocky Mountain House. In this area, over 2200 wells penetrate the Base of Fish Scales; however, only 118 wells were completed in the Second White Specks zone, of which only 49 produced any significant hydrocarbon volumes (Fig. 1.2). Because these wells appear to be confined to specific geographic areas, stratigraphic correlation on a development well program basis (≥ one well per section) was focused on the surrounding area.
Data for this study area within the zone of interest (the Second White Specks) is limited, which reduces the number of available wells for quantitative petrophysical analysis. Limiting factors include:

- Seven cores available in the zone of interest, of which only three have any core analysis publicly available;
- Limited digital log data (LAS) available; only 227 out of 444 wells used for stratigraphic correlation had LAS data (raster logs cannot be used to create static petrophysical models);
- No dipole sonic (DSSI) logs available (these are normally used for Young’s modulus and Poisson’s ratio calculations, which are quantitative measures of brittleness);
- Not enough photoelectric effect (PEF) and spectral gamma ray (SGR) logs available for field-wide quantitative lithology and mineralogy calculations.

Allostratigraphic mapping was limited to horizons overlying and underlying the perceived “pay zone” within the Second White Specks and Belle Fourche Formations in the Willesden Green – Gilby area. Because the goal of this thesis is to tie allomembers into petrophysical property models, exhaustive high-resolution allostratigraphic mapping of the entirety of the Lower Colorado Group is out of scope for this project.

1.5 Significance

Due to its anisotropic nature and fracture dependency, the Second White Specks tight oil play lends itself well to an integrated petrophysical and stratigraphic study. This study provides a predictive framework for reliable economic exploration, development, completion and production of the Second White Specks Formation by revealing how brittleness and porosity vary in the Willesden Green – Gilby areas. The framework developed here can be extended to other areas where the Second White Specks Formation may be economic, as well as to analogous heterolithic mudstone reservoir units in the Western Canada Sedimentary Basin.
1. Introduction

Fig. 1.2: Base map of the Willesden Green – Gilby study area in Alberta, illustrating the spread of available data across the entire area. The scale bar is in metres (m).

Although ~2200 wells penetrate the Second White Specks in this region, only about 10% (227 wells, indicated in black) had LAS data available in the interval of interest.
1.6 Overview of thesis structure

This thesis consists of ten further chapters, within four main parts. In **PART I** (Chapters 1 through 3), the research problem is introduced, and the study is situated in relation to its associated literature. Chapter 1 deals with the introduction and structure of the thesis. Chapter 2, the first part of the literature review, discusses the stratigraphic context of the Second White Specks Formation. This guides high-resolution allostratigraphy, which provides zone boundaries for petrophysical analysis. Chapter 3, the second half of the literature review, investigates best practices in petrophysical analysis of unconventional reservoirs using conventional well logs.

In **PART II** (Chapters 4 & 5) the research methodology is established. Chapter 4 reviews the allostratigraphic method, which is used to establish the framework for petrophysical modelling. Chapter 5 deals with the methodological issues and research design of this study, providing the procedural description and theoretical basis for the petrophysical approaches used to collect, present, and analyze data.

In **PART III** (Chapters 6 through 9), the results of data analysis of the Second White Specks Formation in the study area from allostratigraphic correlation, isopach and isolith mapping, petrophysical property mapping, and sweet spot maps, respectively, are presented.

**PART IV** (Chapters 10 & 11) contains the discussion, limitations of, conclusions, and recommendations for future work related to this study. Based on this work, inferences and recommendations are drawn to inform and improve the current practice of oil exploration and potential development of Second White Specks-targeted wells.
Chapter 2

2 Stratigraphy, sedimentology, and play analysis of the Second White Specks and Belle Fourche Formations

2.1 Overview

In this chapter, the Second White Specks and Belle Fourche Formations are placed in their proper geologic, spatial, and temporal context in order to guide the high-resolution allostratigraphy used later (Chapters 4 and 6), and to pose key research questions. This chapter identifies several pressing gaps in the literature through a critical review of previous studies of the Second White Specks and Belle Fourche Formations with regards to their tectonic setting, environment of deposition, age, stratigraphic position, bounding discontinuities, lithology, and petroleum system elements.

2.2 Geologic setting of Lower Colorado Group Shales

Thorough studies of conventional sandstone reservoirs within the Upper Cretaceous Colorado Group of Alberta (e.g., the Viking and Cardium Formations) have revealed much about their reservoir properties and sedimentary architecture; these reservoirs contain 14% of the total hydrocarbon reserves in Western Canada (Leckie et al. 1994). In comparison, far less is known about lower Colorado Group mudstones (Bloch et al. 1999; Rokosh et al. 2009) – this includes the Belle Fourche and Second White Specks Formations.

The Fish Scales, Belle Fourche, and Second White Specks Formations (lower Colorado Group mudstones; from oldest to youngest, respectively) are the focus of this study. They were deposited over a period of ~7.0 Ma (92.1 to 99 Ma) from the early Cenomanian to the middle Turonian (Schröder-Adams et al. 1996). These mudstones are thickest in the Alberta Deep Basin, where they can exceed 600 m thick (Fig. 2.1). Lower Colorado Group mudstones appear to be largely unaffected by the subsiding Williston Basin to the southeast, unlike the rocks that comprise the upper Colorado Group (Leckie et al. 1994; Rokosh et al. 2009). Lower Colorado Group mudstones gradually thin eastward to about 120 m in west-central Alberta, where the study area is located, to < 50 m at the eastern
Solving the Second White Specks

2. Stratigraphy, setting, and petroleum geology

Fig. 2.1: A composite map of the Second White Specks lithostratigraphic interval in southern Alberta.

The study area is situated around a cluster of localized Second White Specks oil pools in the Willesden Green field. Modified after Creaney and Allan (1990); Letourneau et al. (1996); Rokosh et al. (2009) and Canadian Discovery (2012).
margin of Alberta (Leckie et al., 1994, Fig. 2.1).

### 2.2.1 Tectonic setting

The WCSB developed into a retroarc foreland basin (Fig. 2.2) during the Jurassic to Early Cretaceous Columbian Orogeny, due to collision and accretion of exotic terranes on the western margin of the North American plate (DeCelles & Giles 1996; Evenchick et al. 2007; Allen & Allen 2013). Accommodation in a retroarc foreland basin is created on the overriding tectonic plate as a result of lithospheric flexure; this is initiated by tectonic loading in a collisional setting (DeCelles & Gilles 1996). The Late Cretaceous to Paleogene Laramide Orogeny created a NNW- to SSE-oriented zone of maximum subsidence and highest sedimentation rate along the western margin of the WCSB. Deposition of the lower Colorado Group coincided with regional tectonic downflexing of the North American craton (Lambeck et al. 1987). An asymmetric foreland basin architecture is revealed by an Upper Cretaceous sedimentary wedge, 700 m thick in the west, which thins to < 50 m from SW to NE along an extremely low-gradient foredeep ramp that onlaps onto the forebulge (Varban & Plint 2005; Varban & Plint 2008b).

The location and geometry of the forebulge in the WCSB during the Late Cenomanian (Fig. 2.3) and Early Turonian (Fig. 2.4) is controversial (Varban & Plint 2005; Varban & Plint 2008a; Yang & Miall 2008, 2009; Plint et al. 2012a; Percy & Pedersen 2017). The axis and location of the forebulge in the WCSB may have moved throughout the Late Cretaceous (Plint et al. 2012b) – as new terranes progressively accreted onto the western margin, the thrust load would have shifted (Allen & Allen 2013). Utilizing the palaeomagnetic observations of McCausland et al. (2006), Plint et al. (2012b) attributed lower Colorado Group forebulge migration to progressive dextral (south and south-east) movement of the Stikine and Yukon-Tanana terranes, which was initiated in the mid-Cretaceous and continued into the Eocene.

The NE-SW oriented Sweetgrass Arch (SGA) and contiguous Bow Island Arch (BIA) in Alberta and Saskatchewan may have acted as a peripheral forebulge during the Late Cenomanian due to crustal heterogeneities that made it susceptible to flexure.
Fig. 2.2: Schematic of a strike-oriented cross-section through a foreland basin. Modified from DeCelles and Giles (1996), and Allen and Allen (2013).
Fig. 2.3: Paleogeographic map of the WCSB during the mid- to Late Cenomanian.

Adapted from Plint et al. (2012b), Schröder-Adams et al. (2012), Jiang and Cheadle (2013), and Blakey (2017). The study area is shown as a dashed red square; it falls within the foredeep and potentially the forebulge region of Late Cenomanian (Belle Fourche) strata. The present-day Cordilleran deformation front is indicated as a dark brown line.
Fig. 2.4: Paleogeographic map of the WCSB during the early Turonian.

Adapted from Plint et al. (2012b), Schröder-Adams et al. (2012), Jiang and Cheadle (2013), and Blakey (2014). The study area is demarcated as a dashed red square; it falls within the foredeep of early Turonian (Second White Specks) strata. The present-day Cordilleran deformation front is indicated as a dark brown line.
Solving the Second White Specks

2. Stratigraphy, setting, and petroleum geology

(Lorenz 1982). The SGA and BIA are oriented similarly and are geographically close to the axis of the Late Cenomanian forebulge proposed by Plint et al. (2012b). These structural features measurably impact upper Colorado Group strata in Alberta (Nielsen et al. 2008), but their influence – if any – on lower Colorado Group strata has not been quantified.

2.2.2 Climate and physiography

The Cretaceous period was globally characterized by an atypically warm, “greenhouse” climate with ephemeral polar ice caps, high eustasy, and elevated atmospheric CO₂ (Hallam 1985; Haq et al. 1987; Wilson & Norris 2001; Haq 2014). Peak tectonoeustatic conditions allowed the northern Boreal Sea and southern Tethyan Sea to transgress (flood) across the North American continent and join in the Cenomanian, creating a shallow, epicontinental sea known as the Western Interior Seaway, or WIS (Kauffman 1969, 1977; Caldwell et al. 1993; Hay et al. 1993; Kauffman & Caldwell 1993; Kauffman et al. 1993; Leckie et al. 1994; Bloch et al. 1999; Schröder-Adams 2014).

Comingling of warm waters from the Tethyan Sea with the denser mid-latitude waters of the Boreal Sea in a counter-clockwise gyre, driven by Coriolis forces and wind stresses in the Late Cenomanian, likely initiated substantial plankton blooms via nutrient upwelling (Fig. 2.5). This produced an oxygen-poor intermediate zone that fostered organic matter preservation (Schlanger & Jenkyns 1976; Eriksen & Slingerland 1990; Pedersen & Calvert 1990; Hay et al. 1993; Arthur & Sageman 2004; Hay & Floegel 2012; Schröder-Adams 2014). Initiation of global ocean oxidation event OAE-II, an oceanographic crisis and extinction event with biological and sedimentological consequences (Philip & Airaud-Crumiere 1991), encouraged ocean upwelling of nutrients and enhanced organic carbon burial by increasing sea-surface fertility and productivity (Arthur & Sageman 2004). OAE-II peaked near the Cenomanian-Turonian boundary (Arthur et al. 1987).

Lower Colorado Group shales were deposited during the Greenhorn Cycle – this was a sea-level highstand initiated during the latest Albian and coincident with OAE-II (Arthur et al. 1987; Kauffman & Caldwell 1993; Schröder-Adams et al. 1996). From the Late Cenomanian to Middle Turonian, sea-level rose to a maximum (~250 m above present
A) Early Cenomanian (~99 – 98.5 Ma): During the Mowry cycle, cool Arctic waters (blue arrows) incurred into western Canada, facilitating deposition of the Fish Scales Formation.

B) Middle Cenomanian (~96 Ma): Eustatic rise connected the Boreal and Tethys Seas for the first time during the peak of the Mowry Cycle. The Dunvegan delta complex prograded from the northwest as the Mowry Cycle waned, facilitating mud deposition of the Belle Fourche Formation (outlined in grey) in the study area.

C) Early Turonian (~93.2 Ma): At the peak of the Greenhorn Cycle sea-level reached a maximum within the WIS, and normal marine conditions dominated. Mixing of cold Boreal and warm Tethyan waters (red arrows) promoted phytoplankton blooms (shown in green), which helped preserve organic matter in the Second White Specks Formation.
day mean sea-level, PDMSL) just after the Cenomanian-Turonian boundary within the
WIS and the Second White Specks Formation was deposited (Kauffman 1977; Haq
2014). This time of relative sea-level rise was interrupted by brief periods of relative sea-
level fall when the oceanographic connection to the Tethys Ocean was lost (Kauffman
1977; Leckie et al. 1994; Bloch et al. 1999; Schröder-Adams 2014). Following the
termination of OAE-II, global sea-level had fallen by 60 m (~190 m above PDMSL) at
the end of the Turonian (Haq 2014).

Early workers characterized the lower Colorado Group as the record of deposition of fine-
grained sediment in a deep (> 200 m water depth) and quiescent marine basin dominated
by pelagic rainout of “marine snow” (Hay et al. 1993; Schröder-Adams et al. 1996; Bloch
et al. 1999). Stratal patterns of the lower Colorado Group suggest, instead, that sediments
were deposited in an epicontinental, shallow marine muddy ramp setting (< 50 m water
depth) with low relief – even greater than 250 km offshore – via wave-enhanced sediment
gravity flows, or WESGFs (Tyagi et al. 2007; Varban & Plint 2008a; Plint 2014); these
will be discussed further in Chapter 5. This places lower Colorado Group mudstones
within storm wave base for mud, which is less than 70 m (Plint et al. 2012b). The
influence of storms on the Late Cretaceous seabed in Alberta is clearly recorded even the
most distal muddy sediments of the Second White Specks-equivalent Kaskapau
Formation; these rocks contain oscillatory wave and combined-flow ripples, as well as
gutter casts (Varban & Plint 2008a).

High eustasy that led to the flooding of the WIS during the Late Cretaceous has been
linked globally to increases in mid-ocean ridge volcanism, as well as the ascent of a
mantle plume under the Pacific Ocean (Kominz 1984; Harrison 1990; Larsen 1991).
Flare-ups in continental arc magmatism during the Late Cretaceous may have enhanced
the flux of nutrients into the ocean via windblown volcanic ash, further increasing
biological productivity in the WIS and accelerating source rock deposition (Cao et al.
2017; Lee et al. 2018). Arthur et al. (1987) hypothesized that OAE-II may have been
initiated by an as-yet unrecognized volcanogenic event. Although the cause of the
Cenomanian-Turonian boundary event remains unknown, later workers connected OAE-
II to sub-oceanic eruptions that formed Large Igneous Provinces (LIPs) in the Caribbean
and Madagascar (Arthur & Sageman 2004; Snow et al. 2005; Kuroda et al. 2007). Organic carbon burial in lower Colorado Group mudstones was therefore enhanced by volcanic ash as well as by climatic changes that induced biotic crises and anoxia.

Tyagi et al. (2007) designated a prominent bentonite ash bed, the Bighorn River “red” bentonite, as the base of the Second White Specks Formation. Prokoph et al. (2013) determined that the eruption(s) associated with the “red” bentonite and the $\delta^{13}$C$_{org}$-excursion associated with OAE-II were approximately coeval – further constraining the eruption responsible for the “red” bentonite to 94.29 ± 0.13 Ma (Barker et al. 2011). This intimates that the eruption that initiated OAE-II predated the currently accepted age of the Cenomanian-Turonian boundary (93.9 Ma) by 260 to 530 Kyr. The timing of OAE-II, coupled with the age of the bounding discontinuity between the Second White Specks and Belle Fourche Formations (which approximates the Cenomanian-Turonian boundary), suggests that OAE-II and the eruption responsible for the “red” bentonite could have triggered physicochemical changes in the basin (e.g., climatic, ocean chemistry, biological activity, relative sea-level).

2.3 Establishing nomenclature for Upper Cretaceous lower Colorado Group rocks in west-central Alberta

Within industry circles, the Belle Fourche and Second White Specks Formations are colloquially and collectively referred to as the “Second White Speckled Shale”, or simply the “Second White Specks” for convenience. It was first identified by Fraser et al. (1935) in the subsurface during a survey of southern Saskatchewan, where they described a dark, white-speckled (coccolith-rich) shale that could be traced across the Western Canada Sedimentary Basin (WCSB) into Alberta. Following this, Stott (1963) formalized a stratigraphic framework across the central Alberta plains that included the Second White Specks Formation.

Lower Colorado Group stratigraphic nomenclature varies widely, both regionally and between authors. This can be problematic to navigate when conducting larger-scale stratigraphic studies. The discrepancy between stratigraphic subdivisions is rooted in the application of different methods (i.e., lithostratigraphic, allostratigraphic, biostratigraphic,
chemostratigraphic) in independent studies, as well as the periodic revision of terminology over time. The highly diachronous and interfingering relationship between lower Colorado Group mudstones has complicated efforts to regionally correlate coeval strata of the lower Colorado Group (Singh 1983).

At least eight distinct sets of lithostratigraphic terminology exist for lower Colorado Group rocks (Caldwell et al. 1978; Stott 1982; Glass 1990; Bloch et al. 1993; Leckie et al. 1994; Bloch et al. 1999; Roca et al. 2008); three of these are relevant in the Willesden Green – Gilby area. Within industry, lithostratigraphic nomenclature from the Alberta central plains (e.g., Bloch et al. 1993, 1999; Schröder-Adams et al. 1996) is favoured. Those authors divided the lower Colorado Group from bottom to top into four lithostratigraphically-defined shaley units: the Westgate, Fish Scales, Belle Fourche, and Second White Specks Formations. These units were differentiated using their geophysical wireline log signatures and bulk geochemistry. Stott (1967, 1984) subdivided the lower Colorado Group from the bottom up into the Shaftesbury, Fish Scales, Dunvegan, and Kaskapau Formations; this terminology is used in the northwestern plains and Foothills of Alberta. Lastly, in the southern Foothills of Alberta the lower Colorado Group is subdivided into the Sunkay (Westgate, Fish Scales, and Belle Fourche) and Vimy (Second White Specks) Members of the Blackstone Formation (Simons et al. 2003).

Genetically-related, coeval strata should be tied into a stratigraphic framework that emphasizes the time-equivalence between rock packages, rather than their lithological similarities. For this reason, an allostratigraphic approach to correlation is preferred to the lithostratigraphic method (see Chapter 4). The time-equivalency of the lower Colorado Group units discussed above has been confirmed by the correlation of foraminiferal biozones between regions (Schröder-Adams et al. 1996; Schröder-Adams 2014). These units are constrained further by radiometric dating of bentonite marker beds present throughout the Lower Colorado Group (Cadrin 1992; Obradovich 1993; Barker et al. 2011), and regional allostratigraphic correlation (Bhattacharya 1989; Bhattacharya & Walker 1991; Plint 1996, 2000; Kreitner 2002; Varban 2004; Plint & Kreitner 2005; Varban & Plint 2005; Kreitner & Plint 2006; Roca 2007; Tyagi et al. 2007; Roca et al. 2008; Varban & Plint 2008b, a; Tyagi 2009; Plint et al. 2012a; Plint 2014). Figure 2.6
This study uses the forebulge nomenclature from Tyagi et al. (2007) and Roca et al. (2008), even though the study area lies within the foredeep depozone. Allostratigraphic terminology revises Bloch et al. (1993)’s placement of the Second White Specks-Belle Fourche boundary from the “forebulge unconformity” upwards to the Bighorn River “red” bentonite, which approximates the Cenomanian-Turonian boundary; bentonite dates are from Barker et al. (2011).
summarizes the relationship between the lithostratigraphic and allostratigraphic terminology discussed above.

The nomenclature used herein was adapted from the allostratigraphic framework developed by Tyagi et al. (2007) for the distal foredeep and forebulge regions of the lower Colorado Group. This study substitutes some names for allostratigraphic units with the names of more familiar lithostratigraphic equivalents (i.e., substituting Second White Specks alloformation for Kaskapau Formation). Altering the nomenclature in this way should ensure that allostratigraphic units are assigned to consistent stratigraphic positions between individual studies, and also preserves familiar industry terminology. This study focuses on the lower Colorado Group only, as the lower Colorado Group contains the main reservoir interval within the Willesden Green and Gilby areas.

### 2.3.1 Fish Scales Formation

The Fish Scales Formation is a distinct, mappable unit observable in outcrop and wireline logs that is frequently used as a stratigraphic datum across the WCSB (Bhattacharya & Walker 1991; Leckie et al. 1994). The Fish Scales Formation varies in thickness across the Canadian Prairies (Bloch et al. 1999; Schröder-Adams et al. 1999). It is typically 1.5 to 21 m thick, but in southwestern Alberta it may be eroded entirely by the overlying Belle Fourche (Leckie et al. 1994; Bloch et al. 1999).

The Fish Scales Formation is a siliceous, coarse-grained phosphatic unit that contains bentonites < 1 to 30 cm thick, abundant fish skeletal remains, as well as phosphate and chert nodules (Leckie et al. 1994; Schröder-Adams et al. 1996; Bloch et al. 1999; Schröder-Adams et al. 1999; Schröder-Adams et al. 2001). Elevated radioactivity is observed in this zone due to an increased abundance of fish debris relative to vertically adjacent formations (Bloch et al. 1993; Roca et al. 2008). Although algal cysts are abundant in this formation, it is otherwise barren of foraminifera – the Fish Scale Formation has a reduced dinoflagellate assemblage relative to the rest of the lower Colorado Group. It contains a mixture of Type II and III organic matter, and has total organic carbon (TOC) up to 8 wt%, averaging 3.2% regionally (Schröder-Adams et al. 1996; Bloch et al. 1999).
Radiometric dating of bentonite horizons within the Fish Scales Formation (Obradovich 1991; Cadrin 1992; Schröder-Adams et al. 1996), as well as studies of its dinoflagellate assemblage and relative stratigraphic position (Singh 1983; Schröder-Adams et al. 1996; Bloch et al. 1999) firmly establish the formation in the Early Cenomanian (97.2 to 95.8 Ma; Schröder-Adams et al. 1996). Deposition of this unit corresponds with the basin-wide disconformity and global oxidation event OAE-1d (Schröder-Adams 2014).

The base of the Fish Scales Formation (the “Base of Fish Scales Marker” or BFSM in industry) is a diachronous surface that approximates the Albian-Cenomanian boundary in Alberta (Stelck 1962; Stott 1982; Leckie et al. 2000; Ridgley et al. 2001; Schröder-Adams et al. 2012), which is currently accepted to be 100.5 Ma (Cohen et al. 2013). Roca et al. (2008) noted that the positive radioactive excursion demarcating the BFSM becomes progressively diffuse towards northwestern Alberta, suggesting that the BFSM in that area is a non-erosive condensed surface and disconformity. This could indicate the onset of anoxia at the Albian-Cenomanian boundary (Schröder-Adams et al. 1996). South and east of Roca et al. (2008)’s study area, in west-central Alberta, the BFSM is a composite erosional and geochemical unconformity mantled by a thin bed of chert pebbles (Tyagi et al. 2007); this may indicate the location of the Late Cenomanian forebulge (Roca et al. 2008).

Although the top of the Fish Scales Formation (“Fish Scale Upper” or FSU) is well-acknowledged as the base of the Belle Fourche Formation and the time-equivalent Dunvegan Formation (Bhattacharya & Walker 1991), its chronostratigraphic significance has been amended. Once thought to conformably underlie the Belle Fourche Formation (Bloch et al. 1993; Schröder-Adams et al. 1996; Bloch et al. 1999; Schröder-Adams et al. 1999), the FSU is now recognized as a regional non-erosional, condensed downlap surface for successive allomembers of the Lower Belle Fourche equivalent Dunvegan Formation (Bhattacharya & Walker 1991; Plint 2000; Tyagi et al. 2007; Roca et al. 2008).
2.3.2 Belle Fourche Formation

The Belle Fourche Formation is a coarsening-upward, noncalcareous to slightly calcareous mudstone and siltstone that varies in thickness from 20 m in eastern Saskatchewan to approximately 150 m in the Foothills of Alberta (Bloch et al. 1999; Schröder-Adams et al. 1999; Yang & Miall 2009). It is bounded above and below by unconformities: it unconformably overlies the Fish Scales Formation and unconformably underlies the Second White Specks Formation (Tyagi et al. 2007).

Although Planolites and Chondrites traces (horizontal and vertical burrows) are ubiquitous throughout the Belle Fourche regionally, Gordia, Helminthopsis, and Teichichnus traces (curved burrows) are only found in the western Interior Plains and coincide with sideritic concretionary horizons (Bloch et al. 1999). The Fish Scales and Belle Fourche Formations can be distinguished by a slight increase in both calcareous sediment and bioturbation (Schröder-Adams et al. 1999), as well as by the presence of inoceramids (Bloch et al. 1999). In some places, however, no compositional or textural changes are observable over this zone (Bloch et al. 1999). TOC in the Belle Fourche Formation is 1.7 wt% on average, and comprises a mixture of Type II and III organic matter (Schröder-Adams et al. 1996).

The Belle Fourche Formation is Middle to Upper Cenomanian in age and was deposited from 95.8 to 93.3 Ma (Schröder-Adams et al., 1996). This age is based on the presence of Verneuilinoides perplexus in the Belle Fourche of Alberta and its equivalent in Saskatchewan (Schröder-Adams et al., 1996; 1999; Bloch et al., 1999). The Belle Fourche is subdivided into Upper and Lower portions based on Late and Middle Cenomanian ages, respectively. These ages are derived from foraminiferal and ammonite zoning (Ridgley et al. 2001; Tyagi et al. 2007) as well as through allostratigraphic correlation of a correlative conformity between the AX-3 and X flooding surfaces of Tyagi et al. (2007). Obradovich (1993) dated the X-bentonite within the Upper Belle Fourche at $94.93 \pm 0.53$ Ma (Late Cenomanian); Tyagi et al. (2007) traced this bentonite in >1000 wells through the Belle Fourche from Tp. 30 to 65, confirming that the X-bentonite is equivalent to the A bentonite of Gilboy (1988) and lies within unit “B” of Ridgley et al. (2001).
Solving the Second White Specks

Ridgley et al. (2001) and Gilboy (1988) independently noted differential loss of Upper Belle Fourche strata beneath the Second White Specks Formation in Montana and Saskatchewan. Loss of strata and “wedging” appeared to be controlled by major structural lineaments, in addition to additional minor northwest-southeast-trending and northeast-southwest-trending lineaments – potentially defining fault-bounded basement blocks. Differential movement and rotation of these blocks may have influenced tectonic thinning (syndepositional and post-depositional erosion; potentially ravinement) of the Upper Belle Fourche in Saskatchewan and Montana, creating a regional erosional unconformity between the Belle Fourche and Second White Specks (Ridgley et al. 2001; Tyagi 2009; Hicks 2010). Although the existence of this unconformity was refuted by Yang and Miall (2008), it has been extensively documented by other geologists (Caldwell et al. 1978; Bloch et al. 1993; Schröder-Adams et al. 1996; Nielsen et al. 2008; Tyagi 2009).

Reassignment of the base of the Second White Specks from the prominent erosion surface noted by Bloch et al. (1999) to the stratigraphically higher Bighorn River “red” bentonite by Tyagi et al. (2007) paints the existence of the unconformity noted by Ridgley et al. (2001) and Gilboy (1988) in an uncertain light. It is not clear if Unit D of Ridgley et al. (2001) – their Belle Fourche – would be assigned to the allostratigraphically-defined Upper Belle Fourche of Yang and Miall (2009) or the Second White Specks of Tyagi et al. (2007). Regardless, the nature and mechanism of the contact between the Second White Specks and the Upper Belle Fourche, whether it is unconformable or not, has not been adequately investigated.

2.3.3 Second White Specks Formation

The Second White Specks Formation, so-called for the visible “white specks” encountered by drillers within the shale (Leckie et al. 1994), is a calcareous claystone to siltstone found in eastern to southern Alberta. It grades into a calcareous siltstone in northwestern Alberta (Bloch et al. 1999). Like the Fish Scales Formation, the Second White Specks Formation contains horizons of bioclastic conglomerate (Schröder-Adams et al. 1996). The formation thins to the east, where it varies from 90 m near the Peace River Arch in northwestern Alberta to 25 m at the Saskatchewan-Manitoba border.
The Second White Specks Formation is the only Lower Colorado Group formation that contains coccolith assemblages (Schröder-Adams et al. 1996). It contains a large number of calcareous nanofossils that have aggregated into white-coloured, fine to very fine-grained fecal pellets (the so-called “white specks”) which are dispersed throughout parallel-laminated and unidirectional rippled beds 0.25 to 2 cm thick (Leckie et al. 1994; Schröder-Adams et al. 1996). Starved ripples and mm-thick laminae are frequently found; some upper surfaces are potentially wave-rewoked (Schröder-Adams et al., 1996). TOC in the Second White Specks Formation is 5.1 wt% on average, and the organic matter found within the formation is largely type II (marine, oil-prone; Bloch et al., 1999).

The Second White Specks Formation was deposited between 93.3 and 91.2 Ma (Schröder-Adams et al. 1996). Schröder-Adams et al. (1996) recovered one ammonite specimen of Collignoniceras woollgari at 14-29-11-28W4 in the Second White Specks Formation, which was assigned a Middle Turonian age. An unconformity is interpreted between the W. aprica Subzone and the V. perplexus Zone as the Late Cenomanian to Early Turonian age C. simplex Subzone is missing (McNeil and Caldwell, 1981). A transitional zone that includes the benthic calcareous taxon Neobulimina albertensis is also absent (Schröder-Adams et al., 1996).

Defining the stratigraphic base of the Second White Specks Formation has proven problematic due to the highly diachronous nature of the unit. The base should approximate the Cenomanian-Turonian boundary, which spans OAE-II. Bloch et al. (1993) and Bloch et al. (1999) originally defined the base of the formation using the first appearance of abundant coccoliths in the 6-34-30-8W4 type well. Many subsequent studies used this definition (Schröder-Adams et al. 1996; Schröder-Adams et al. 1999; Ridgley & Gilboy 2001; Ridgley et al. 2001; Simons et al. 2003; Fraser 2005). Using allostratigraphic correlation from outcrop and subsurface data, in combination with bentonite dating (Obradovich 1993), Tyagi et al. (2007) contended the Bighorn River “red” bentonite best approximated the Cenomanian-Turonian boundary, and was the most practical means of tracing it in the subsurface. Furmann et al. (2014) placed the base of the Second White Specks Formation several metres below the “red” bentonite of Tyagi et al. (2007) based on mineralogy and organic petrography, but provided no clear
stratigraphic reasoning for this change. Zajac (2016) also used the Furmann et al. (2014) definition, on the basis of changes in depositional patterns from “sheet” (Belle Fourche) to “wedge” (Second White Specks) geometries; placing the boundary between his allomembers V and VI. This fails, however, to reconcile with the allostratigraphic observations made by Tyagi et al. (2007).

2.4 Petroleum system analysis of the lower Colorado Group in the Willesden Green – Gilby area

Although a basin-scale analysis of the entire Lower Colorado Group petroleum system in the WCSB is well beyond the scope of this thesis, some regional context is necessary to adequately investigate the geologic factors controlling the location of Second White Specks oil pools in the Willesden Green study area. The fundamental elements of a successful petroleum system are an effective source rock, porous and permeable reservoir, adequate seal rock, traps formed prior to peak generation, migration, and accumulation of petroleum, and sufficient overburden (Magoon & Dow 1994) – these elements are known with varying levels of certainty for the Second White Specks and Belle Fourche in west-central Alberta.

2.4.1 Source rock quality, maturation, and migration

The thick mudstone successions of the Lower Colorado Group are prolific and demonstrably effective source rocks. The Second White Specks and Belle Fourche Formations are enriched in marine Type II (oil-prone) organic matter (Bloch et al. 1999) and contain 2-5 wt% TOC on average, and exceptionally up to 12 wt% (Bloch et al. 1999; Rokosh et al. 2009). Thermal maturation of all WCSB source rocks and their generated petroleum resources started in the west, near the Rocky Mountains, and progressed up-dip towards the east – in some cases, migrated and trapped petroleum travelled up to 600 km (Higley et al. 2009).

The maturity pattern of the Second White Specks Formation – which increases towards the orogenic front – can be clearly seen in Figs. 2.1 and 2.7. Figure 2.7 is a 1-dimensional burial history model illustrating the burial history of the Lower Colorado Group in the proximal foredeep, north of the study area (100/16-18-52-5W5). The major subsidence
1-D burial history model for 16-18-052-5W5

Fig. 2.7: 1-dimensional burial history diagram (top) of 16-18-52-5W5, modified from Roberts et al. (2005). The inset map is the same as Fig. 2.1, with the study area for this thesis outlined in orange. The 16-18 well is indicated on the inset map as a red dot.

Vitrinite reflectance (bottom left, red dots) using Sweeney and Burnham (1990) and temperature from DSTs (bottom right, green dots) were used by Roberts et al. (2005) to calibrate the burial history model.
period in the WCSB occurred during the Laramide Orogeny (Late Cretaceous to Paleogene); the Second White Specks alloformation reached a maximum burial depth of 2.6 km in the Eocene in that particular well (Roberts et al. 2005); burial depths for the lower Colorado Group in the Willesden Green area commonly exceed 3 km. Vitrinite reflectance (%R₀, a measure of thermal maturity) in the Second White Specks alloformation reached ~0.5% R₀ in 16-18-52-5W5, suggesting that the Second White Specks source rock did not reach sufficient thermal maturity to generate hydrocarbons in that particular well.

Within the Willesden Green field, thermal maturity is not a limiting factor – those pools lie within a NW-SE trending oil fairway that extends from the Peace River Arch in northwestern Alberta to the US border (Letourneau et al. 1996). This is further constrained eastward by Davies et al. (2013) to a NNE-trending fairway approximated by R3-4W5. Davies et al. (2013) noted that the majority of Second White Specks cores they encountered with recorded polished slip faces (PSF – post-depositional shear interfaces that are approximately parallel to bedding, where frictional heating and shear have altered kerogen in the host rock to a black, highly polished surface) were within the Tmax oil window, and that PSF frequency increased westward toward the margin of the Mesozoic Deformation Belt. PSF occurrence may reflect increased burial depth, increased horizontal shear, and consequent increased maturation and generation of hydrocarbons.

### 2.4.2 Storage capacity

Reserves estimates of lower Colorado Group mudstones suggest that large volumes of oil and gas hosted in low porosity rocks remain unexploited. Osadetz et al. (2010) estimated the volume of oil generated by Lower Colorado Group source rocks at ~350 billion m³, of which 95% was expelled (leaving ~17.5 billion m³ unexpelled). They list the following reserve estimates for potential Lower Colorado Group mudstone-sourced resources:

- Potentially commercial tight rocks (5% < φ < 6%) contain ~8 million m³;
- Probably commercial very tight rocks (0.03 < φ < 0.04) contain ~680 million m³;
- Currently non-commercial extremely tight rocks (φ < 0.02) contain ~176 billion m³.
Fig. 2.8: A comparison of different oil and gas reservoirs in terms of reservoir quality; modified from CSUR (Canadian Society of Unconventional Resources). The Second White Specks in the Willesden Green area has characteristics of both unconventional and conventional reservoirs and is characterized as a “hybrid shale”.
Lower Colorado Group mudstones fall into the “hybrid shale” category of shale plays defined by Jarvie (2012a, 2012b) because they contain interbedded organic-rich and organic-lean intervals (Jiang 2013). Other examples of hybrid shales include the Niobrara in Colorado, the Eagle Ford in Texas, and the Bakken in Montana (Jarvie 2012b). The lower Colorado Group falls into the “shale oil” classification of Clarkson and Pedersen (2011) – it is primarily self-sourced (the source rock is the reservoir) with very low matrix permeability and high organic content (Fig. 2.8). Hybrid shales can have increased productivity from conventional lithofacies, due to increased storage capacity from carbonate diagenesis and primary matrix porosity that can survive deep burial (Schieber 2010; Jarvie 2012a; Jiang & Cheadle 2013).

2.4.3 Flow capacity

Most carbonaceous mudstone reservoirs rely on permeability and porosity created by preexisting natural fractures in stiff, brittle rocks (Gale et al. 2007). When placed under enough stress, rocks that break without deformation exhibit brittle behaviour (Cho & Perez 2014). Brittle behaviour is enhanced in mudstone reservoirs with increased silica or carbonate content, because siliceous and calcareous minerals impart their brittle characteristics to their host rocks (Gale et al. 2014). Successful Second White Specks vertical wells in the Willesden Green area targeted small, localized pools (Fig. 2.9 and 2.10) where Laramide faulting created sufficient fracture permeability via natural fractures for conventional oil to flow from otherwise uneconomic siltstones and mudstones (Podruski et al. 1988; Skuce et al. 1992; Letourneau et al. 1996; Clarkson & Pedersen 2011).

There has been recent debate over whether commercial production rates via horizontal drilling could be achieved in areas outside the known fault-controlled plays in Willesden Green, where brittleness and reservoir quality (porosity and permeability) are sufficiently high (Clarkson & Pedersen 2011; MacKay 2014). Insofar as brittleness is concerned, no model for brittleness currently exists for lower Colorado Group mudstones. Porosity has only been adequately examined on a well-by-well basis (Furmann et al. 2014; Furmann et al. 2016). Furthermore, new research suggests that enhanced matrix porosity can positively contribute to production rates, even in fracture-controlled plays.
Fig. 2.9: IP4 (initial average oil rate for the first 4 months) map for Second White Specks wells in the study area.

Black dots indicated all the 2WS penetrations, whereas grey dots indicate all the wells drilled in the area. Yellow polygons delineate known 2WS pool boundaries.
Solving the Second White Specks

2. Stratigraphy, setting, and petroleum geology

Fig. 2.10: Cumulative production map for Second White Specks Formation wells in the study area. Green indicates oil production, red indicates gas production, yellow indicates condensate production, and blue indicates water production. Most Second White Specks wells in this area are primarily oil producers and produce negligible water and condensate, with minor gas production.
Solving the Second White Specks

2. Stratigraphy, setting, and petroleum geology

(Schieber 2010; Clarkson & Pedersen 2011). In order to investigate this, brittleness and reservoir quality variations across the Willesden Green field need to be understood.

Unlike most hybrid plays, which utilize horizontal drilling and multi-stage hydraulic stimulation to optimize access to matrix porosity, the Second White Specks has been primarily developed using vertical wells in the Willesden Green – Gilby area (Clarkson & Pedersen 2011). Operators have historically treated the Second White Specks as a “bail-out zone” rather than a drilling target. This is because of drilling problems such as severe borehole instability, lost circulation, and high-pressure kicks (Letourneau et al. 1996; Clarkson & Pedersen 2011; Fox & Garcia 2015) – these problems can make horizontal wells more challenging (i.e., more expensive).

Although there is no historical consensus on which zones should be completed, the coarser-grained units overlying the “red” bentonite (assigned to the Second White Specks alloformation) are the most commonly perforated in the study area (Canadian Discovery 2014). Frequently, wells that produce from the Second White Specks Formation are commingled (coproduced) with other producing zones (e.g., Cardium, Viking) in order to flow enough liquid hydrocarbons to be economically viable (O’Connell 2003). So far, horizontal wells drilled in the study area have experienced “less than spectacular” production histories (Canadian Discovery 2011). This could be due to several factors: the style of completion and hydraulic fracture treatment selected, completion of non-productive zones, bypassed pay, or insufficient reservoir quality.

2.5 Highlights

- Lower Colorado Group rocks were deposited in a retroarc foreland basin that developed into a marine muddy ramp environment where water depths likely ranged from <40 to 70 m. This depositional setting facilitated organic matter deposition and preservation.
- Nomenclature for lower Colorado Group rocks varies regionally and between authors. The Fish Scales, Belle Fourche, and Second White Specks Formations each contain unconformity- or disconformity-bounded coeval units that can be regionally correlated across the WIS.
• Lower Colorado Group rocks have considerable source rock potential. They reached a sufficient depth of burial in the study area to become thermally mature and produce liquid hydrocarbons.

• Despite considerable hydrocarbon reserves, it has historically proven difficult to produce oil from lower Colorado Group reservoirs. Localized natural fracture networks provide the means for oil to flow out of the reservoir, which has low permeability and porosity. These fracture networks are likely tied to variations in brittleness, which are not currently understood.
Chapter 3

3 Using wellbore petrophysical data for quantitative geological interpretation

3.1 Overview

The theoretical underpinnings of wireline petrophysical methods are reviewed, including: the intersection of petrophysics with stratigraphy and exploration geology, the importance of good petrophysical modelling, and the responses of basic geophysical well logs to shaley lithologies. This sets the stage for a critical examination of stratigraphic methods that rely on wireline log data in Chapter 4, and a review of petrophysical modelling methods for unconventional reservoirs in Chapter 5.

3.2 Role of petrophysics in exploration geology

Petrophysical evaluation is an essential part of petroleum exploration. The principal goals of a petrophysicist are to:

1) ascertain if fluid hydrocarbons are present in the formation of interest, and if so, of what phase (gas or oil);

2) determine the commercial viability of the reservoir by calculating the pore (e.g. porosity, permeability) and fluid phase (i.e. saturation) distribution of the reservoir;

3) evaluate the physical makeup of the reservoir (e.g., mineralogy, organic richness, brittleness), and;

4) develop a representative model of reservoir properties that can be extrapolated into mappable units across the area of interest.

Fundamentally, petrophysics involves transforming the “wiggle traces” acquired by geophysical well logging tools into quantitative geological information. Wireline well logs are graphical portrayals of various recorded drilling conditions or measured subsurface features that relate to the evaluation of an individual well (Tiab & Donaldson 2012). No remote, cost-effective methods for directly measuring mineralogy and porosity currently exist, so interpreting this data in a geological context can be challenging. Instead, petrophysicists principally use indirect measurements (i.e., geophysical well
logs) to quantify the composition and reservoir quality of reservoir rocks in the subsurface, often without calibration data taken directly from that particular well. This is effectively geophysical inverse modelling. Sources of data used for petrophysical analysis and model development consist of (Ellis & Singer 2008):

- Mudlog data, drill stem tests, and drill cuttings (direct) – not included in this study
- Core and sidewall samples (direct) – extremely limited in study area
- Logs acquired via wireline logging tools (indirect) – main source of data
- Borehole seismic and 3D seismic (indirect) – not included in this study

During the exploration phase of a petroleum play, well data is extremely limited, and knowledge of inter-well variation is even more uncertain. Extensive core extraction and core analysis is prohibitively expensive and is only performed when deemed absolutely necessary. Pioneers in the field of petrophysics, a term coined by Archie (1950), have continually sought to enhance sensor capabilities, increase computing speed, and improve measurement resolution so as to improve measurement quality with minimal incremental cost (Bateman 2009); innovation in this field continues to this day. Modern petrophysical analysis utilizes a strong foundation of electrical engineering combined with rock physics principles to characterize hydrocarbon reservoirs (Doveton 2014).

3.3 Connecting petrophysics with stratigraphy

One major function of the petrophysicist is to assist geologists with extrapolation of data away from the wellbore, i.e. developing a scaled-up model of subsurface properties across a field or pool. Such models are crucial to the assessment of storage and flow capacity, as well as reservoir compartmentalization. However, these models require meaningful constraints, and geological context, to be representative of stratigraphic architecture. These constraints are hydraulic flow units, which are defined by Ebanks (1987) as:

“[…] a volume of the total reservoir rock within which geological and petrophysical properties that affect fluid flow are internally consistent and predictably different from properties of other rock volumes (i.e., [other] flow units).

[Hydraulic flow units are] defined by geological properties, such as texture, mineralogy, sedimentary structures, bedding contacts, and the nature of permeability barriers, combined
with quantitative petrophysical properties, such as porosity, permeability, capillarity, and fluid saturations.”

Ebanks (1987) opines further that “[…] flow units do not always coincide with geologic lithofacies”. Lithostratigraphic methods, which do not consider significant time breaks in the sedimentary section (e.g., unconformities, hiatuses, ravinements, and flooding surfaces), often cannot provide adequate geological and geometrical constraints for petrophysical analysis. These breaks in the sedimentary section can be significant impediments to the continuous flow of hydrocarbons. Flow units, therefore, are best defined by bounding surfaces such as permeability barriers (i.e., thick mud drapes or unconformities). Since allomembers (time-stratigraphic units) define genetically-related, lithologically heterogeneous packages of contemporaneous strata (Bhattacharya & Posamentier 1994), they can provide more representative bounding surfaces (or zones) needed for petrophysical modelling within the aforementioned hydraulic flow units. These bounding surfaces may define barriers to the flow of hydrocarbons within a zone, depending on the vertical stacking patterns of lithofacies within separate allomembers.

Previous studies of the lower Colorado Group have used a variety of stratigraphic divisions. Any historically reported petrophysical or geochemical data for this zone needs to be carefully scrutinized to determine its allostratigraphic position (e.g., Belle Fourche or Second White Specks Formation). Moreover, the absence of consistent zoning means that previous petrophysical analyses of the Second White Specks interval have not been placed into the appropriate flow units.

3.4 Overview of well logging

After a vertical well is drilled, and prior to setting casing, the formations of interest are exposed in the open borehole. At this point, cylindrical geophysical measurement tools called sondes are lowered into the wellbore to collect in situ measurements of rock properties. These sondes are connected in series into “tool strings” that can exceed 30 m in total length, allowing for simultaneous measurement of different properties. An armored cable called a wireline provides electrical power for the sondes, as well as a means of transmitting digital data continuously out of the wellbore for geologists to view, in well log format. The tool string is raised from the bottom of the hole at a constant
speed, allowing for the sondes to record data at a constant sampling rate (Glover 2000; Ellis & Singer 2008; Andersen 2011).

Data transmission and computer processing capabilities for well logging evolved from entirely analog in the late 1960s to fully digital by the 1990s (Bateman 2009). Prior to digital logs, if different logging parameters (e.g., a different matrix density for porosity logs) were desired, the entire well had to be re-logged; this was rarely done (Hill 2012). Digital library tape formats, developed first by Schlumberger in 1968, allowed for in-house log processing of individual data tracks post-logging (Hill 2012). Library ASCII Standard (LAS) was adopted as an industry standard for digital log formats in 1989 and is still used today (Struyk et al. 1989; Hill 2012). In a LAS file, the data from each sonde is stored as a separate column called a track (Struyk et al. 1989). This data can be manipulated by the petrophysicist in a worksheet, or in sophisticated formation evaluation programs like Schlumberger’s Techlog™ software.

Recent advancement in well logging has been driven by unconventional reservoir exploration. Reservoirs with “unconventional” components (e.g., clay, kerogen, and carbonate) are more difficult to characterize with petrophysical methods. Consequently, more types of well log data must be acquired in order to adequately describe the formation of interest. Over 50 types of measurement sondes have been developed to measure a diverse set of subsurface properties and monitor drilling progress (Ellis & Singer 2008). It is essential, however, to understand and account for the uncertainties and limitations associated with well log data. Virtually all types of well log data are proxies for direct measurements of petrophysical properties used in modelling. If their limitations are not recognized, well log data acquired in unconventional reservoirs can be misinterpreted (Moore et al. 2011).

3.4.1 Borehole petrophysics

Petrophysical studies are limited by the most prevalent logging suite available. This logging suite is usually a combination of geophysical well logs that are the most economical for drilling operators to run in the borehole (Moore et al. 2011). The Willesden Green field typifies this limitation: due to the vintage of the available log suite
and the status of the Second White Specks Formation as a “bail-out zone” in the area, only common measurements (caliper, gamma ray, spectral gamma ray, bulk density, compressional sonic, and resistivity) will be discussed further. More sophisticated logs (DSSI, PEF; pulsed neutron mineralogy; nuclear magnetic resonance) were not widely available. Section 3.6 will cover open-hole logs from vertical wells in detail.

Petrophysical values (e.g., porosity and clay volume) are imperfect approximations of reservoir properties. This is because petrophysical calculations are made using a limited number of wireline log measurements that have their own sources of uncertainty. The main characteristics that affect log quality are the depth of investigation, vertical resolution, and logging speed. The following section summarizes the specifications and limitations of wireline log measurements used in this thesis (Glover 2000).

3.4.2 Drilling mud

Most petroleum reservoirs are located kilometres below the surface and are at high lithostatic pressures. Drilling the wells with dense drilling mud (1.05 to 1.9 g/cm³) balances the formation fluid pressure and allows safe access to hydrocarbons without blowouts (Glover 2000). Drilling mud, or drilling fluid, is a suspension of mud particles in a water- or oil-based slurry that can contain heavy minerals like barite. When the pressure exerted by drilling fluid exceeds the lithostatic pressure of a formation and permeability is sufficiently high, drilling mud infiltrates or “invades” into the formation. Formation fluids are displaced by mud filtrate (i.e., the fluid component of the drilling mud), and a crust of “mud cake” (i.e., the solid residue of the drilling mud) forms inside the borehole (Fig. 3.1). This can cause permeability to be locally reduced, potentially damaging the reservoir permanently. In highly invaded zones, most logging tools will respond to mud filtrate in the reservoir, rather than formation fluids (Ellis & Singer 2008).

Because the Second White Specks is not a primary target in the study area, drillers sometimes “mud up”, or increase drilling mud density, while drilling through the lower Colorado Group – this conditions the hole for optimal drilling progress and improves the rate of penetration (i.e., drilling speed). As a result, the Second White Specks formation may have lower reservoir quality (formation damage) in intervals where significant
 Fig. 3.1: Schematic of a centered caliper-type tool attached to an instrument assembly, with idealized responses to beds that could potentially be encountered in the lower Colorado Group.

Modified from Glover (2000) and Krygowksi (2004). As the sonde and instrument assembly are slowly raised through the borehole, the caliper arms move if the hole size changes in any way. Breakouts in brittle shale are of particular interest from a correlative and geomechanical perspective in this study.
invasion has occurred. In contrast, excessive borehole breakout was encountered when drilling operators used drilling mud with insufficient density (Fox & Garcia 2015) – evidently, proper mud weight selection is essential to avoid drilling problems in the Second White Specks.

### 3.4.3 Caliper log

Caliper logs provide a constant measurement of hole shape and diameter during logging runs by sensing the movement of measurement pads (calipers) that extend from the sonde (Fig. 3.1). Caliper logs are indicators of the borehole conditions - if the caliper shows that the hole is rough, measurements that require direct sensor contact with the borehole wall will be unreliable. Density, neutron, and resistivity logs are impacted by hole size; caliper logs offer a way to quantify the magnitude of mud cake accumulation or hole washout that is occurring (Krygowski 2004).

### 3.5 Petrophysical modelling

A petrophysical model continuously describes the static properties (i.e., mineralogy and porosity) of a formation, given a set of geophysical well logs and core data for calibration (Doveton 2014). A good petrophysical model allows the geologist to predict variation in reservoir properties within hydraulic flow units across large areas. This is essential for sweet-spotting in unconventional reservoirs – especially when no seismic data is available to verify field-scale anisotropy, and production data is scarce or nonexistent. Sweet spots are loosely defined areas in an unconventional reservoir that produce better than others (Glaser et al. 2013), which may be defined by a series of overlapping reservoir quality parameters (e.g., porosity, TOC, brittleness). Identification of these regions, a process termed “sweet spotting”, enables operators to select optimal well locations (Wang & Gale 2009; Glaser et al. 2013; Ter Heege et al. 2015). Ideally, these reservoir quality parameters are directly correlated to hydrocarbon production data – but these data are often difficult to obtain in North American basins due to their proprietary nature (Ter Heege et al. 2015).

A search of publicly available geochemical and geophysical studies failed to reveal static petrophysical models of the Second White Specks and Belle Fourche Formations at any
scale of observation – previously, core analyses were used to describe regional variations in reservoir quality (Furmann et al. 2014; Zajac 2016). This reveals an opportunity to develop a petrophysical model for an economically important mudstone reservoir, which could potentially be used to detect areas with superior reservoir quality.

Methods for quantifying mineralogy from well logs originated in the mid-1970s – they used log cross-plots such as density-sonic and neutron density to calculate porosity. These methods could adequately characterize formations with two or fewer mineral components (Clavier & Rust 1976; Schlumberger 2009). Modern commercial petrophysical modelling software, developed in the 1980s, uses inverse linear and nonlinear modelling to solve for mineral composition, porosity, and fluid saturation continuously (Mitchell & Nelson 1988; Doveton 1994b; Ellis & Singer 2008). These software models require a large training database of core data and can fail in formations that are petrophysically complex (Heidari 2011). “Petrophysically complex” reservoirs, like the organic-rich mudstones of the Second White Specks and Belle Fourche Formations in west-central Alberta, have the following characteristics (Bloch et al. 1999; Ellis & Singer 2008; Clarkson & Pedersen 2011; Heidari 2011):

1) pervasive thin beds;
2) multimodal mineralogy (3 or more components), particularly clay or kerogen; and
3) multimodal porosity, especially low porosity (<3%).

A lack of core data, combined with enhanced petrophysical complexity, means that applying an inverse model to lower Colorado Group rocks would introduce more uncertainty into any resulting petrophysical model than it would resolve (Yin 2011). This is because inverse linear models should be overdetermined (see section 5.6.2). Instead, lower Colorado Group rocks present an underdetermined problem where unknowns outnumber the available equations. Alternatively, a deterministic petrophysical model can be built, wherein each property is independently (rather than simultaneously) derived from log data and then calibrated to core data (Sondergeld et al. 2010).

A deterministic petrophysical model is restricted by the type, quality, and amount of data available. Although improvements in logging technology (e.g., lithodensity logging, formation micro-imaging, nuclear magnetic resonance imaging, and dipole sonic logs)
have significantly improved the quality and types of data that can be gathered from a single wellbore, these types of logs are costly and often inaccessible to the public. Similar issues arise with core data, which is required for calibration of log data to rock properties. Cores are only drilled occasionally, so representative vertical sampling of any formation (particularly mudstones, which were historically not drilling targets) is typically poor. Furthermore, many studies are limited by the generation of the wells drilled in the area – advanced logging methods may not have existed when those wells were drilled. Digital log files (LAS) may not be available for many older wells, which limits the interpreter to raster log data. As such, despite the existence of sophisticated methods for mudstone petrophysical analysis, this thesis will only discuss those methods that can be completed with basic, conventional well logs (resistivity, porosity, gamma ray) and limited core data.

Creating a good petrophysical model for an unconventional reservoir requires a solid grounding in formation evaluation methods. The Second White Specks and Belle Fourche Formations both have very low porosities, and contain clay, kerogen, and carbonate – thus creating an intriguing petrophysical problem. Basic geophysical logging tools were designed to measure Archie-type reservoirs that are petrophysically “simple”: these are rocks with no clay, kerogen, or carbonate content, and unimodal conventional porosities. Because petrophysical techniques were originally developed to analyze conventional hydrocarbon targets, it is not appropriate to apply the same methods to petrophysically complex mudstone reservoirs. Unconventional reservoirs require “unconventional” methods (Sondergeld et al. 2010; Labani & Rezaee 2015). The methods used for petrophysical modelling methods in this thesis are discussed and reviewed in Chapter 5.

3.5.1 Modelling Archie-type reservoirs

Wireline logging techniques were developed by the Schlumberger brothers in 1927 for subsurface stratigraphic correlation and detection of an oil-saturated target zone (Hill 2012; Hall 2017). Archie (1942) was the first to establish an empirical relationship between conductivity, porosity, and brine saturation in “clean” (clay-free) sandstones, which is still the basis of most conventional log evaluation today (Doveton 1994a):
where $S_w$ is fractional water saturation, $n$ is the saturation exponent, $a$ is a constant related to sandstone type (Winsauer et al. 1952), $R_w$ is the resistivity of the saturating brine, $\phi$ is the porosity of the sandstone, $m$ is the cementation exponent, $n$ is the saturation exponent, and $R_T$ is the resistivity of a partially brine-saturated rock. This is known as the Archie equation. Equation 1 offered the first opportunity for geologists to obtain quantitative porosity information directly from resistivity measurements (Doveton 1994a). To do this routinely, however, required more computing power than was available at the time – calculations had to be made by hand, point by point (Hill 2012). Due to its utility, the Archie equation is a mainstay of conventional petrophysical modelling, despite its origins as an empirical relationship between rock properties in a simplistic reservoir model (Fig. 3.2).

The usefulness, physical significance, and accuracy of the Archie equation has been thoroughly criticized by Luffel and Guidry (1992), Doveton (2001), and Sondergeld et al. (2010), among others. Critically, the Archie equation does not account for the electrical conductivity of clay minerals present in unconventional “shaley sand” or clay-rich reservoirs, causing gross overestimation of $S_w$ (and therefore underestimation of oil saturation, or $S_o$). Clay minerals affect resistivity readings, but they also affect reservoir quality by degrading porosity and permeability; this is called the “shaley sand problem” (Asquith 1990). Other rock properties can cause the Archie (1942) equation to fail – these include thin beds, heterogeneous mineralogy, anisotropy, heavy minerals, multimodal porosity, microfractures, variable water salinity, variable wettability, and when $m$ and $n$ do not equal 2 (Bust et al. 2013). Application of the Archie (1942) equation is inappropriate in clay-rich reservoirs, and the problems are compounded in organic-rich mudstones where low-density kerogen complicates porosity determination.
3. Using petrophysics to model geological properties

Solving the Second White Specks

Fig. 3.2: Comparison of general petrophysical models for Archie-type, shaley sandstone, and unconventional reservoirs in terms of complexity. The level of petrophysical complexity increases with the number of components, which makes them more difficult to resolve.

Compiled and adapted from: Passey et al. (1990); Ellis and Singer (2008); Ambrose et al. (2010); Passey et al. (2010); Ramirez et al. (2011); Bust et al. (2013); Crain and Holgate (2014); Doveton (2014).
3.5.2 Modelling shaley sand reservoirs

To remedy the limitations of the Archie (1942) equation in clay-rich reservoirs, two types of shaley sandstone equations for calculating porosity and water saturation in clay-rich reservoirs have been developed (Worthington 1985):

1) Resistivity-based $V_{sh}$ or $V_{cl}$ based equations – e.g., Simandoux (1963), where shales are homogenously conductive media, regardless of clay mineralogy; key inputs are $V_{sh}$ and shale resistivity.

2) Ionic double-layer or cation exchange capacity (CEC) based equations – e.g., Waxman and Smits (1968); Juhasz (1981); Clavier et al. (1984), where electrical conductivity increases with increased surface area, and therefore altered by clay mineralogy (high surface area, varies with type); this requires measurement of, or proxies for, cation exchange capacity.

Both equation types are of the general form:

$$\frac{1}{R_T} = \frac{S_w^2}{a/\phi \times R_w} + X$$  \[2\]

where $X$ is the electrical conductivity contribution of the shaley portion of the reservoir.

Equation 2 is a simplified Archie equation with a shale correction added. Although ionic double-layer water saturation equations better capture the heterogeneity of electrical conductivity in shaley sand reservoirs, their use is limited and inefficient. This is due to a necessary calibration to CEC – a parameter that is currently impossible to measure directly using geophysical well logs (Doveton 2001). Doveton (2014) declared that “clearly, the ideal shaley sandstone model has not been resolved nor ever will be.” Despite this, the usefulness of shaley sandstone equations in optimizing water saturation calculations is undeniable, provided that their limitations are understood.

Nuclear technology, developed in the 1940s for the Manhattan Project, was repurposed for petrophysical logging in 1950 when a need for reliable wireline porosity measurement arose (Hill 2012). To that end, modern gamma ray and neutron-density porosity logs respond to the absorption or attenuation of radiation, respectively (Glover 2000). The
gamma ray (GR) log is particularly useful for calculating shale volume ($V_{sh}$), because it primarily detects increases in radioactivity that can be attributed to potassium ($^{40}\text{K}$) in clay minerals (Asquith 1990). Shale volume using total GR, $V_{sh} | GR$, is calculated as follows (Asquith 1990; Krygowski 2004):

$$V_{sh} | GR = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}}$$

where $GR_{log}$ is the GR reading at the interval of interest, $GR_{min}$ is the GR value in a nearby “clean” or shale-free zone, and $GR_{max}$ is the gamma ray value in an adjacent shale. It has been long recognized that this linear interpolation can be an overestimate of $V_{sh}$ because GR tools do not respond linearly to shaley lithologies (Asquith 1990; Ellis & Singer 2008; Doveton 2014). Clavier et al. (1971) converted $V_{sh}$ to $V_{cl}$ (clay volume) using the following non-linear correction, which is a pessimistic non-linear corrections of shale volume:

$$V_{cl} = 1.7 - \sqrt{3.38 - (V_{sh} + 0.7)^2}$$

$V_{cl}$ is an important parameter as it allows for the calculation of porosities calculated in clay-rich intervals. Heslop (1974) first noted the need for a distinction between the oft-confused shale volume and clay volume. Shale volume refers to the volume proportion of all fine-grained components regardless of mineralogy, whereas clay volume refers only to the volume proportion of clay minerals. It is generally accepted that using a non-linear correction (e.g., Equation 4) converts $V_{sh}$ to $V_{cl}$; however, it is always prudent to ground-truth and calibrate this assumption with clay mineralogy from XRD or XRF (Quirein et al. 2010; Doveton 2014).

Fig. 3.2 illustrates the differences in petrophysical complexity between different reservoir types. Compared to conventional Archie-type reservoirs and shaley sand reservoirs, unconventional reservoirs have more components and complicated pore geometry; creating an underdetermined problem. Many petrophysical models for unconventional reservoirs have been developed (Passey et al. 1990; Ambrose et al. 2010; Passey et al.)
2010; Ramirez et al. 2011; Bust et al. 2013; Crain & Holgate 2014). The development of shaley sand petrophysics helped pave the way for calculations of the following parameters using conventional well logs:

1) total organic carbon: in v/v, \( V_{ker} \); or, in weight %, TOC;
2) clay volume (\( V_{cl} \));
3) porosity: total (\( \phi_T \)) and effective (\( \phi_E \)); and
4) matrix volume (\( V_{carb} + V_{qtz} \)).

These factors, ultimately, function as measures of reservoir quality – they can be used to estimate brittleness, which is the end goal of this thesis.

3.6 Interpreting geophysical well log data from unconventional reservoirs

The following section reviews how geophysical well log data is collected and should be interpreted in unconventional reservoirs like the Second White Specks Formation, by first considering expected well log responses. Although the advent of shale gas and tight oil exploration has greatly progressed the capacity to characterize unconventional reservoirs, many plays suffer from a scarcity of data. For this reason, the following section will focus on the basic wireline log suite used in this study.

3.6.1 Petrophysical tops guidance for mudstone reservoirs

In unconventional mudstone reservoirs with high organic content, the following log responses are expected (Fertl & Chilingar 1988; Passey et al. 1990; Labani & Rezaee 2015; Zee Ma et al. 2016):

- Elevated gamma ray, due to uranium in organic matter and potassium in clays;
- Low density response, as organic matter has very low density (1.1-1.4 g/cm\(^3\)) relative to quartzofeldspathic matrix (2.6-2.8 g/cm\(^3\)) – the density response may be increased if pyrite (FeS\(_2\)) is present;
- Slow sonic log response, due to low-density organic matter, gas, and clay-bound water reducing compressional wave velocities;
• High neutron-porosity response in clay-rich zones from to water bound to clays; this can be suppressed when hydrocarbons are present (hydrogen response will be reduced by gas and organic matter);

• Increased resistivity, due to presence of non-conductive fluid hydrocarbons and organic matter in the rock matrix; resistivity is also increased relative to the level of organic maturity, and conversion of kerogen to hydrocarbons (relative to organic-poor mudrocks that have decreased resistivity due to clay conductivity).

3.6.2 Well log responses as proxies for mudstone reservoir composition

Figure 3.3 is a well log through a portion of the Second White Specks Formation, illustrating the vertical changes in lithology throughout the stratigraphic interval. This well (7-19-45-6W5) vertically intersected and was perforated in the same productive interval illustrated in Fig. 1.1 but was ultimately abandoned as the unit produced negligible hydrocarbons. Relative to a conventional reservoir (low organic content and clay-free), the wireline log response of the entire stratigraphic interval appears to be unconventional, with high clay and organic content throughout. From this data alone, it is difficult to ascertain why the so-called productive interval proved unproductive in this particular well.

Petrophysical modelling exploits the relationship between well log responses and specific lithologies, like those listed in section 3.6.1. Petrophysicists attempt to estimate rock properties indirectly using measurements of different physical properties (wireline logs) that are proxies for lithology. At each measurement point, logging tools record a signal from the reservoir derived from mineralogy, pore geometry, fluid composition, and borehole conditions. A table of expected petrophysical responses for common lithologies is available from Baker Hughes (https://www.spec2000.net/freepubs/LogResponses.pdf), although these responses are idealized and represent end member cases. The following section considers the potential applications and drawbacks of different conventional well logs to petrophysical modelling and geological interpretation, based on the physics of their respective measurements (radioactivity, acoustic, and electric). Using this
Fig. 3.3: A representative well log (7-19-45-06W5) for the Second White Specks interval.

From left to right, the tracks include caliper (CALL, in mm) shown in red, gamma ray (GR_K) in API, volume % mineralogy, TOC (in weight percent), bulk density (DEN_K) in kg/m$^3$, density correction (DENC), density porosity (PHIT_D) which is overlain by core total porosity, as well as medium and deep resistivity (RES_DEP and RES_MED, both in ohmm).
information, subtle changes in wireline log responses – like as those illustrated in Figs. 1.1 and 3.3 – can be better understood in a geologic context (e.g., change in porosity).

3.6.2.1 Radioactivity logs

Radioactive decay, discovered by Becquerel (1896) and Curie et al. (1898), is a stochastic (random) property of unstable atomic nuclei wherein the nucleus loses energy by emitting radiation (i.e., alpha [$\alpha$], beta [$\beta$], and gamma [$\gamma$] rays) at an exponentially decreasing rate, thus decaying into a more stable daughter nucleus. The emission of a gamma ray – electromagnetic radiation with shortest wavelengths (10 picometers) and highest energies (up to 10 MeV) – occurs after $\alpha$ and $\beta$ decay. Gamma or $\gamma$ decay occurs when the daughter nucleus is produced in an excited state and then decays to a lower energy state by emitting gamma radiation. Gamma radiation interacts with matter through several mechanisms. Three of these mechanisms are important for petrophysical radioactivity logging applications, in order of increasing energy: photoelectric absorption, Compton scattering, and pair production (Ellis & Singer 2008). The probability of a particular photon-matter interaction occurring is dependent on the energy of the incident photons and the atomic number of the material of interest (Ellis & Singer 2008).

The photoelectric effect is a phenomenon that occurs when a low energy photon (<0.1 MeV) interacts with a material of sufficiently high atomic number. The incident photon is absorbed and transfers its energy to a bound electron within the material; that electron is subsequently ejected with an energy proportional to the atomic number of the material (Einstein 1905; Millikan 1913). Because different rock matrices have different average atomic numbers (e.g., sandstone, limestone, dolomite), low-energy photons (in this case, gamma rays) interact predictably with changes in lithology. The photoelectric effect is the physical basis for PEF measurements (Ellis & Singer 2008), which will not be discussed further here.

A gamma ray with intermediate energy (0.1 to 1 MeV) experiences Compton scattering by colliding and subsequently transferring a portion of its energy to an orbital electron (Compton 1923). Incident gamma rays experience a reduction in energy (attenuation) that is directly proportional to the electron density of the material that is being traversed;
increased density causes more energy loss and scattering (Baker 1957). The energy of the orbital electron is proportional to the lithology of the rock type the incident gamma ray passed through. This electron, therefore, produces a measurable signal in petrophysical gamma ray detectors of all types (Ellis & Singer 2008).

Similar to the photoelectric effect, pair production is a process where a gamma ray is absorbed. In this circumstance if the gamma ray exceeds a threshold value of 1.022 MeV, the gamma ray is replaced by an electron-positron (positively charged electron) pair (Blackett & Occhialini 1933; Hubbell 2006). The positron is subsequently annihilated, thereby emitting two gamma rays with reduced energies of 511 keV each (Ellis & Singer 2008). This process contributes only marginal energy to the overall signal of radioactivity tools, so it is only consequential in very dense lithologies that are not likely to be encountered in sedimentary rocks (Glover 2000).

For typical rock formations (no heavy minerals), the average atomic number ranges from 13 to 20. At photon energies less than 0.5 MeV, photoelectric absorption prevails over other interactions. Compton scattering predominates gamma ray attenuation over the energy range from 0.1 MeV to 10 MeV, but most commonly from 0.5 to 3.0 MeV (Glover 2000). The pair production process only becomes significant for lithologies with high atomic numbers and gamma rays surpassing a threshold of 1.022 MeV, and most commonly at energies exceeding 3 MeV (Wilson et al. 1979; Glover 2000).

### 3.6.2.1.1 Gamma ray logs

Modern total gamma ray (GR) logging tools record the radioactivity of the borehole environment. GR detectors consist of two essential parts: a detector (commonly a solid-state sodium iodide [NaI] scintillation crystal) that absorbs incoming gamma rays, and an amplifying-counting system called a photomultiplier. The incoming gamma rays have experienced varying degrees of Compton scattering en route to the tool, depending on the electron density of the formation. When a gamma ray is absorbed by the detector crystal, the crystal emits a flash of light whose intensity is proportional to the energy of the absorbed gamma ray. That flash is detected by the photomultiplier, which transforms it into an electrical pulse that is recorded by the tool. Unlike all other logging tools, the GR
tool is passive – it records data, instead of actively emitting radiation to induce a response measurable by the tool (Adams & Gasparini 1970; Ellis & Singer 2008).

GR curves can be used for correlation, lithological interpretation, and shale volume ($V_{sh}$) calculation. For correlation purposes, GR curves are scanned by the interpreter for similarities in the shape of curve deflections – matching patterns between different wells signifies that the same unit is present in both boreholes (Krygowski 2004). In traditional elastic sedimentology, the shape and patterns of the GR curve are used to infer depositional processes based on vertical trends in the relative proportions of sand and clay in vertical successions of strata. Natural formation radioactivity detected by the GR tool is dominated by the radioactive decay of potassium ($^{40}\text{K}$) in clay minerals (Rider 1990). However, because the lower Colorado Group contains organic-rich mudstones with non-clay components that contribute to total radioactivity, interpreting GR curves requires caveats to avoid serious analytical pitfalls.

Natural radioactivity in sedimentary rocks comes primarily from the radioactive decay of $^{40}\text{K}$ in potassium-rich and, more rarely, from $^{232}\text{Th}$- and $^{238}\text{U}$-bearing zones. Radioactive isotopes are more concentrated in mudstones than in other sedimentary rocks because clays are derived from the weathering and decomposition of igneous rocks – igneous rocks contain volumetrically significant proportions of radioactive elements from micas and feldspars (Glover 2000). The high CEC of clay minerals allows them to retain trace amounts of radioactive elements from their parent rocks (Ellis & Singer 2008). Quartz, the principal component of most sandstones, does not contain any radioactive isotopes (Andersen 2011). For this reason, GR readings are often used as a proxy for grain size: high GR readings are attributed to high clay\textsuperscript{1} content, whereas low GR readings are attributed to low clay content (high sandstone or carbonate content). The intensity of a GR log is often treated as a proxy for the sand-to-clay ratio or grain size of a zone – this is

\footnote{“Clay” or “mud” is used as both a textural and a mineralogical term, leading to some ambiguity when discussing sedimentary rocks. In a textural context, “clay” refers to particles with grain sizes < 4 µm; this may include a fraction of quartz or feldspar grains in addition to clay minerals. In this thesis, “clay” is used only in a mineralogical sense, whereas “mudstones” will refer to fine-grained lithologies.}
a bad assumption because grain size does not always correlate with radioactivity (Rider 1990; Ellis & Singer 2008).

Mudstones have a range of possible GR responses, due to a variety of possible mudstone compositions. They can contain a mixture of radioactive (clay minerals, micas, feldspars, and organic matter) and non-radioactive (quartz, feldspars, carbonates, sulfides and amorphous carbon) constituents (Aplin & Macquaker 2011). Table 3.1 displays the range of minerals that can potentially be found in mudstones and their associated well log responses. Clay minerals can have an array of possible compositions – for example, illite clays \( \text{K}_{0.6-0.85}(\text{Al,Mg})_2(\text{Si,Al})_4\text{O}_{10}(\text{OH})_2 \) may have up to 8% K, whereas chlorite \( ((\text{Mg,Fe})_3(\text{Si,Al})_4\text{O}_{10}(\text{OH})_2\ast(\text{Mg,Fe})_3(\text{OH})_6) \) contains negligible K. Thorium is associated with certain clay minerals and accessory zircons (Krygowski 2004). In addition, a range of radioactive element concentrations are possible for micas and feldspars (Hurst 1990). Mudstones may also contain a significant portion of non-radioactive quartz silt – this could result in a lower GR response than a typical mudstone that has a higher proportion of clay (Rider 1990). Finally, “black” mudstones with elevated organic content can contain high concentrations of \(^{238}\text{U}\) salts precipitated through reduction by organic matter in low-oxygen to intermittently anoxic marine environments (Aplin & Macquaker 2011). Mudstones may also contain fine-grained carbonate particles or cements that have a lower GR response (Rider 1990; Ellis & Singer 2008). Formation compositional effects on GR readings must be considered in order to use GR measurements for petrophysical calculations – this avoids propagating systematic errors. When they are correctly calibrated, GR logs can be used to accurately distinguish mudstone from non-mudstones. These examples illustrate that a GR response is not necessarily solely indicative of high clay content (Equation 3).

### 3.6.2.1.2 Spectral gamma ray logs

GR tools are unable to distinguish between different sources of natural radioactivity – this is a significant obstacle for lithological interpretation. Spectral GR (SGR) detectors rectify this by quantifying the individual contributions of separate radioisotopes (\(^{40}\text{K}, \, ^{232}\text{Th} \) and \(^{238}\text{U}\)) present in a formation; this is particularly useful for quantifying mineralogy (Glover 2000; Ellis & Singer 2008; Hill 2012). This is done by partitioning
### Logging tool responses in Lower Colorado Group components

<table>
<thead>
<tr>
<th>Source</th>
<th>Formula</th>
<th>Density ($\text{g/cm}^3$)</th>
<th>$\phi_{\text{NL}}$</th>
<th>$\Delta$</th>
<th>GR</th>
<th>$\text{U}_{1a}$ (ppm)</th>
<th>$\text{U}_{2a}$ (ppm)</th>
<th>$\text{K}$ (%)</th>
</tr>
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<tr>
<td><strong>Silicates</strong></td>
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<td></td>
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<tr>
<td>Quartz</td>
<td>$\text{SiO}_2$</td>
<td>2.64</td>
<td>-2</td>
<td>56</td>
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<tr>
<td>Micas</td>
<td>Potassium silicate with hydroxyl</td>
<td>2.82 to 2.99</td>
<td>-70</td>
<td>49 to 51</td>
<td>770</td>
<td>0 to 50</td>
<td>1 to 40</td>
<td>6.2 to 10</td>
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<tr>
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<tr>
<td>Calcite</td>
<td>$\text{CaCO}_3$</td>
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<td>0</td>
<td>49</td>
<td></td>
<td></td>
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<td>Dolomite</td>
<td>$\text{CaCO}_3\text{MgCO}_3$</td>
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<td>1</td>
<td>44</td>
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<tr>
<td>Anhydrite</td>
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<tr>
<td>Phosphorus</td>
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<td>-1 to 8</td>
<td>47</td>
<td></td>
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<td><strong>Feldspars</strong></td>
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<td></td>
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<tr>
<td>Alkali</td>
<td>$K\text{AlSi}_3\text{O}_8$</td>
<td>2.53 to 2.39</td>
<td>2 to 3</td>
<td>69</td>
<td>220</td>
<td>3 to 12</td>
<td>0.2 to 3</td>
<td></td>
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<tr>
<td>Plagioclase</td>
<td>$NaAlSi_3\text{O}_8$ and $CaAl_2Si_2\text{O}_8$</td>
<td>2.50 to 2.74</td>
<td>3</td>
<td>45 to 40</td>
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<tr>
<td><strong>Clays</strong></td>
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<td></td>
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<tr>
<td>Kaolinite</td>
<td>$\text{Al}_2\text{Si}_2\text{O}_5(OH)_4$</td>
<td>2.41</td>
<td>37</td>
<td>80 to 140</td>
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<td>1 to 12</td>
<td>0 to 0.6</td>
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</tr>
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<td>180 to 250</td>
<td>3 to 5</td>
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<td></td>
</tr>
<tr>
<td>Biotite</td>
<td>$\text{K}<em>0\text{Li}</em>{1.5}\text{Al}<em>{0.5}\text{Si}</em>{2.5}\text{O}_7\text{(OH)}_2\text{O}_4$</td>
<td>3.17</td>
<td>30</td>
<td>250 to 500</td>
<td>10 to 35</td>
<td>1 to 5</td>
<td>3.5 to 8.3</td>
<td></td>
</tr>
<tr>
<td>Mica-montmorillonite</td>
<td>$(\text{Ca}<em>{0.5}\text{Na}</em>{0.5}\text{Mg}<em>{0.5}\text{Fe})\text{Si}</em>{3}\text{Al}_0\text{Si}_2\text{O}_10\text{(OH)}_2\text{O}_4$</td>
<td>2.17</td>
<td>60</td>
<td>150 to 200</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Drilling mud additives</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Silicate*</td>
<td>$\text{KCl}$</td>
<td>1.86</td>
<td>3</td>
<td>500</td>
<td></td>
<td></td>
<td></td>
<td>52</td>
</tr>
<tr>
<td>Barite*</td>
<td>$\text{BaSO}_4$</td>
<td>4.09</td>
<td>2</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sulfides</td>
<td>$\text{FeS}$</td>
<td>4.99</td>
<td>3</td>
<td>39</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

*Silicate and Barite are common additives to drilling mud. Silicate contains potassium and Barite is very dense.

**Minerals used as matrix components for the Second White Specks petrophysical model.

Table 3.1: Table of geophysical well log responses to commonly encountered minerals and compounds in the Lower Colorado Group.

Compiled from Hurst (1990), Glover (2000), Ellis and Singer (2008), and Schlumberger (2009). Any single well log response (e.g., gamma ray) is a result of measuring a complicated mixture of minerals with different compositions. Travel time is in $\mu\text{s/ft}$.
gamma rays into energy bins according to their unique pulse size or spectra (Gadeken et al. 1991). The sum of the total GR energies from these sources is equal to the total GR response, resulting in the following relationship to total GR in shales where \(^{232}\)Th is in ppm, \(^{238}\)U is in ppm, and \(^{40}\)K is in % (Ellis & Singer 2008):

\[
\gamma_{API} = 4Th + 8U + 16K
\]  \[5\]

Anomalous gamma ray responses associated with uranium in organic matter can make it difficult to quantify clay components of organic-rich formations like the lower Colorado Group. This can be deconvolved from the total GR by utilizing the uranium-free curve (computed gamma ray, CGR):

\[
CGR = \gamma_{API} - 8U = 4Th + 16K
\]  \[6\]

CGR removes radioactive anomalies associated with uranium. The Th/K ratio, in particular, can be used to quantify radioactive mineralogy in shales, as well as identification of mineralogical differences between zones (Ellis & Singer 2008; Schlumberger 2009). Changes in Th/K can indicate a sudden change in depositional environment or an unconformity (Glover 2000). Charts of Th/K are used to determine the types of clay minerals in a mudstone from concentrations measured in the Th- and K-energy windows with a SGR. The intersection point of Th/K for each measurement determines the type of radioactive minerals that the rock contains. An illite-rich “shaley” sandstone would plot between 2.0<Th/K<3.5, with clay-rich zones plotting closer to 70% illite (pink line) and clay-poor units located closer to the origin (Schlumberger 2009).

CGR can be used to calculate clay volumes \(V_{cl}\) that are more robust than those from total GR, because the random contribution of uranium is eliminated (Glover 2000):

\[
V_{sh|CGR} = \frac{CGR_{log} - CGR_{min}}{CGR_{max} - CGR_{min}}
\]  \[7\]

where \(CGR = \gamma_{API} - 8U\). Clearly, SGR data is superior to total GR data in all cases for unconventional reservoir assessment because of their utility and flexibility.

Unfortunately, few wells have SGR logs available due to cost and time associated with
their acquisition. When available, they can and should be used to calibrate clay volume as well as establish radioactive mineral assemblages.

### 3.6.2.1.2.1 Tool specifications

GR intensity is given in American Petroleum Institute units (API) and typically ranges between 0 and 150 API in clastic reservoirs. If the formation of interest is particularly radioactive, readings may exceed 300 API. This intensity is calibrated to an artificially radioactive formation located at the University of Houston, which has approximately twice the radioactivity of a typical shale (200 API; typical shale response is ~100 API). The response of a GR log is a sphere with a depth of investigation of ~10 cm, and the tool has a vertical resolution of 0.4 to 0.9 m; this depth of investigation decreases in denser formations. The precision of the GR tool is ±4 API units (Krygowski 2004; Ellis & Singer 2008).

The GR tool measures the amount of gamma rays resulting from radioactive decay; since radioactivity is a stochastic, spontaneous, and non-continuous process, GR logs contain a significant amount of statistical noise. The only way to reduce these statistical fluctuations is to increase the number of samples measured, either by increasing counting times per sample or increasing radioactive source strength; the former increases time spent logging the well and is expensive, while the latter presents potential safety risks (Ellis & Singer 2008). Statistical fluctuations contribute ±2 API units to GR readings in mudstones, and ±5 API units in non-mudstones (Krygowski 2004).

The sphere of influence of a spectral GR (SGR) log has a depth of investigation identical to total GR tools but can have a higher vertical resolution of ~0.1 m. This is because the tool is run more slowly than normal GR logs. SGR tool precision is slightly lower than total GR tools, at ±5 API units (Krygowski 2004; Ellis & Singer 2008). Count rates are also reduced by up to one-third compared to total GR tools. This increases the amount of drilling rig time required to log the hole, significantly increasing the SGR tool’s associated cost (Krygowski 2004). Consequently, SGR tools are not utilized as often as total GR tools (Ellis & Singer 2008).
3.6.2.1.2.2 Environmental effects

GR tools have a limited depth of investigation and are sensitive to the borehole environment. GR counts and GR log character in open-hole wells are impacted by 4 major borehole environmental factors (Glover 2000; Krygowski 2004):

1) Increasing the hole size (via hole collapse or cave-ins) decreases count rates and mutes the signal of the reservoir, because gamma rays have to travel farther to the detector and experience more Compton scattering;

2) Invasion can increase or decrease count rates depending on drilling mud composition because drilling fluid displaces formation fluids that have different densities;

3) Drilling mud composition: adding barite decreases count rates, because barite is an efficient absorber of gamma ray radiation ($\rho = 4.20 \text{ g/cm}^3$); in comparison, adding KCl to drilling mud increases count rates, because $^{40}\text{K}$ is radioactive, and;

4) Increasing logging speed decreases gamma ray count rates and reduces measurement resolution, because the detector does not have as much time to measure the true GR activity of the formation.

SGR logs, like normal GR logs, are impacted by borehole environmental effects that influence count rates, like changes in hole size and logging speed (Ellis & Singer 2008). Although barite muds still impact count rates of SGR logs, the impact of KCl drilling mud is only experienced by the $^{40}\text{K}$ and total GR curves – $^{232}\text{Th}$ and $^{238}\text{U}$ are not affected (Glover 2000).

3.6.2.1.3 Bulk density log

Figure 3.4 illustrates a bulk density logging set-up. Gamma rays are used to measure bulk density because their scattering and transmission through media is strongly dependent on this property. Unlike GR logs, density logs work via active measuring methods – high energy gamma rays are emitted from a collimated $^{137}\text{Cs}$ or $^{60}\text{Co}$ radioactive source, which then interact with the electrons of elements in the formation (Krygowski 2004; Hill 2012). The $^{137}\text{Cs}$ or $^{60}\text{Co}$ source is chosen so that emitted gamma ray energies are sufficiently low to interact via Compton scattering rather than pair production while exceeding the
Fig. 3.4: Schematic of a bulk density logging tool in a conventional reservoir.

Adapted from Glover (2000) and Ellis and Singer (2008). Assuming a matrix density of 2.55 g/cm$^3$ (weighted average of mudcake and sandstone), the bulk density in the above reservoir would be measured at 2.41 g/cm$^3$. Adding clay or kerogen into the reservoir (like in the above brittle shale) decreases porosity and decreases the matrix density, resulting in a lower bulk density reading.
threshold for photoelectric absorption (Ellis & Singer 2008). The emitted gamma rays 
induce a responding gamma ray emission from the formation. The returning gamma rays 
undergo Compton scattering as they travel back through rock and collide with electrons. 
These slower gamma rays are counted by heavily shielded short- and long-range detectors 
that measure gamma radiation. The attenuation the returning particles undergo is directly 
related to the electron density of the formation, such that induced gamma rays undergo 
more attenuation in high bulk density formations due to high electron density, therefore a 
lower gamma ray count is recorded – and vice versa (Glover 2000; Krygowski 2004).

The measured bulk density of a rock is directly related to its mineralogy, porosity, and the 
density of fluids filling the available porous space (Davis 1954; Baker 1957; Edwards 
1959; Pickell & Heacock 1960). The bulk density of the formation ($\rho_b$) is a function of 
matrix density ($\rho_{ma}$), density porosity ($\phi_D$), and the density of the pore filling fluid ($\rho_{ft}$; 
Davis 1954):

$$\rho_b = (1 - \phi_D)\rho_{ma} + \phi_D \cdot \rho_{ft}$$  \[8\]

Using Equation 8, density porosity can be calculated continuously alongside bulk 
density, provided that matrix density and fluid density are invariant. Ideally, these 
variables reflect the true lithology of the reservoir (i.e., $\rho_{ma}$ has been derived from core). 
Bulk density tools are calibrated to blocks of pure limestone ($\rho_{ma} = 2.71$ g/cm$^3$) saturated 
with freshwater (Pickell & Heacock 1960); these are invalid assumptions for most 
reservoirs (Ellis & Singer 2008).

For a rock with average atomic number $Z$, atomic weight $A$, and density $\rho$, the electron 
density $\rho_e$ is equal to (Pickell & Heacock 1960):

$$\rho_e = \frac{Z}{A} \rho_b$$  \[9\]

For most light elements likely to be encountered in a formation logging scenario, $Z:A$ is a 
constant that approaches 0.5. A constant $Z:A$ ratio is the physical basis for bulk density 
logging – if $Z:A$ deviates from 0.5, the calculated bulk density is no longer valid. This
relationship breaks down when hydrogen in hydrous clay minerals, formation fluids, or organic matter are introduced (Glover 2000) – $Z:A$ for hydrogen is closer to 1 (Gaymard & Poupon 1968). By Equation 9, higher $Z:A$ causes bulk density to appear low. When substituted into Equation 8, the resulting density porosity from a high $Z:A$ is too high. For this reason, high porosities in low bulk density zones are invalid (Sonnergeld et al. 2010).

### 3.6.2.1.3.1 Tool specifications

Bulk density is measured in g/cm$^3$ or kg/m$^3$, and usually ranges from 1.95 to 2.95 g/cm$^3$ because this the natural range for most rocks. The tool automatically compensates for the presence of dense mud cake, which is included as a quality control curve. If this correction exceeds $\pm 0.15$ g/cm$^3$, the bulk density curve is not reliable (Glover 2000).

When run at normal logging speed (396 m/hr), the bulk density tool has a vertical resolution of 0.26 m but can resolve beds $<0.15$ m thick if run slowly. Due to increased gamma ray attenuation with density, depth of investigation decreases with bulk density of matrix. It has a relatively shallow depth of investigation of 10 cm in most reservoir rocks, and a precision of $\pm 0.01$ g/cm$^3$ (Krygowski 2004); this translates to an error of 0.5% (Glover 2000). Due to invasion of drilling fluid, it is normally assumed that the zone of investigation is saturated with mud filtrate (Krygowski 2004).

### 3.6.2.1.3.2 Environmental effects

Similar to GR tools, bulk density tools have a limited depth of investigation, and are therefore sensitive to the borehole environment. Additionally, the eccentric-mounted tool is pressed against the walls of the borehole, which means readings are especially sensitive to rough hole conditions and caving. Bulk density responses in open-hole wells are impacted by the following borehole environmental factors (Glover 2000; Krygowski 2004):

1) Increasing the hole size (via hole collapse or cave-ins) decreases bulk density readings relative to the true bulk density, because the eccentric-mounted tool is no longer in direct contact with the formation, and the detector is therefore reading mud cake and drilling fluid;
2) Choice of drilling mud composition changes the bulk density with additives like barite increases bulk density, because barite is an efficient absorber of gamma ray radiation \( (\rho = 4.20 \text{ g/cm}^3) \); sylvite mud (KCl) has an anomalous Z:A from chlorine;

3) Hydrogen in light hydrocarbons and potentially organic matter decreases the measured bulk density, making density porosity erroneously high.

Other environmental effects are caused by transforming bulk density to density porosity. Because density porosity is calibrated to specific zones, if one of the parameters (e.g., lithology or fluid density) changes, the calculated porosity will be incorrect. This is particularly common in shaley units, because of the varied nature of clay mineral densities. Additionally, if the bulk density is incorrectly calibrated to matrix density or fluid density, resulting density porosities will also be wrong; for this reason, it is always critical to calibrate bulk density logs to core data if possible (Glover 2000).

In highly heterogeneous reservoirs (e.g., organic-rich unconventional reservoirs), matrix density and bulk density (Table 3.1) may vary significantly on a centimeter scale: organic-rich mudstones have highly variable compositions depending on matrix (2.4 - 2.85 g/cm\(^3\)) and organic content (<1.5 gm/cm\(^3\); Glover 2000). However, if clay volume and kerogen volume are continuously modelled across a reservoir interval, their contribution to density porosity can be compensated for. Otherwise, due to the hydrogen content of kerogen, the calculated density porosity will be erroneously high (Sondergeld et al. 2010).

3.6.2.1.4 Neutron log

Like the bulk density log, the neutron log is sensitive to the number of hydrogen atoms in a formation – it offers a third way to calculate porosity indirectly by using logs (Glover 2000). The neutron tool bombards the formation with high energy neutrons from a radioactive source that undergoes Compton scattering and produce gamma rays. Detected gamma ray count rates are proportional to hydrogen atom concentration because hydrogen is an efficient absorber of neutrons (Glover 2000), although it is important to note that neutron tools respond to all sources of hydrogen, not just those contained in the pore spaces (Ellis & Singer 2008).
The neutron porosity responds primarily to hydrogen (Ellis & Singer 2008; Gonzalez et al. 2013). Low neutron count rates are detected from lithologies with a large number of hydroxyls in clay matrices, pore fluids (hydrocarbons or water), or solid hydrocarbons (bitumen and kerogen). Hydroxyls are found in clay-rich, kerogen-rich, or porous rocks with hydrocarbon-filled porosity. In comparison, high count rates are detected from low porosity or clay-free rocks; these lithologies have minimal hydrogen present and experience less neutron absorption (Ellis & Singer 2008).

Because the neutron log is sensitive to hydrogen, the neutron porosity log is used as a proxy for clay volume in concert with the density log. This clay volume is considered superior to GR-derived clay volume, but because it requires 0% clay for calibration it can be difficult to apply this method in unconventional reservoirs (Glover 2000).

3.6.2.2 Acoustic logs

Sonic logs measure the interval travel time (\(\Delta t\)), or “slowness”, of a sound wave through a formation; they can be used to derive wave velocity as well as porosity (Wyllie et al. 1956; Raymer et al. 1980; Glover 2000; Krygowski 2004). First, high amplitude and high frequency pulses (20 to 40 kHz, 10 to 60 per second) are discharged from a tool-mounted transmitter. In the intervening time, the pulse travels through the rock of the formation where it attenuates and disperses, before it is detected shortly thereafter by two or more receivers on the tool (Glover 2000). Sound energy arrives at the receivers in different times, depending on the type of wave that arrives (in order of arrival time: P, S, Rayleigh, and Stoneley). More complex tools measure P- and S-waves, and some (full waveform logs) can record the entirety of the wave train (Glover 2000). The speed that sound travels through the formation is largely dependent on the reservoir’s mineral composition and porosity (Andersen 2011). The capacity for rocks to transmit elastic waves varies with lithology and texture, markedly decreasing with increasing effective porosity (Ellis & Singer 2008). Finally, the slowness of a P-wave is inversely proportional to the strength of the material, and directly proportional to the density of the material (Glover 2000):

\[
\Delta t \propto \frac{\rho}{\text{strength}}
\]
where strength is related to bulk modulus (incompressibility and stiffness) and shear modulus (rigidity; Ellis & Singer 2008). At slow $\Delta t$ or wave velocity, the P-wave undergoes more attenuation and dispersion, thus arriving at the receiver later; conversely, at fast $\Delta t$ or high wave velocity, the P-wave undergoes less attenuation and dispersion, thus arriving at the receiver earlier.

Along with being a lithology indicator, wave velocity can be used to derive porosity from the sonic log using Wyllie et al. (1956), who related slowness ($\Delta t$) to porosity ($\phi_S$), fluid transit time ($\Delta t_{ft}$) and matrix transit time ($\Delta t_{ma}$) by the following equation:

$$\Delta t = (1 - \phi_S) \Delta t_{ma} + \phi_S \Delta t_{ft} \tag{11}$$

although porosities derived from density logs are considered superior to porosity from sonic (Glover 2000). Using this equation can be tricky in petrophysically complex reservoirs because $\Delta t_{ma}$ needs to be calibrated to the formation of interest and is especially variable in shales (Ellis & Singer 2008).

### 3.6.2.2.1 Tool specifications

Lithology and porosity affect $\Delta t$, making sonic logs useful for many petrophysical applications (Varhaug 2016). $\Delta t$ is measured in $\mu$s/ft or $\mu$s/m, and commonly ranges from 130 to 820 $\mu$s/m in most formations. The depth of investigation depends on the frequency ($f$) of the pulse emitted from the acoustic source and the slowness of the formation, and commonly ranges from 0.025 m to 0.25 m. As wavelength is a function of velocity over frequency, formations with reduced slowness (higher velocity) can be penetrated more deeply by the acoustic log (Glover 2000; Krygowski 2004). Denser, more consolidated formations typically have a faster $\Delta t$ than unconsolidated formations, or those with fluid-filled porosity (Varhaug 2016). Finally, the maximum vertical resolution of a standard acoustic log is equal to the detector spacing, which is commonly $\sim$0.60 m (Glover 2000).

### 3.6.2.2.2 Environmental effects on sonic logs

“Cycle skipping” occurs when the first P-wave to reach the detector fails to exceed a threshold amplitude value on the first arrival, causing that peak to be missed by one of the
detectors. As a result, that first P-wave is detected in the following cycle, 40 µs later, and \( \Delta t \) is perceived to be higher. This effect creates spikes in the sonic log on the order of 130 µs/m, and may indicate the presence of fractures or gas-filled porosity (Glover 2000; Ellis & Singer 2008). Cycle skipping, however, can also be caused by enlarged borehole conditions or improper tool centralization (Krygowski 2004).

### 3.6.2.3 Electric logs

Resistivity logs attempt to measure the resistivity (inverse of conductivity) of the formation of interest, both adjacent to and surrounding the borehole (Krygowski 2004). Laterologs, a type of resistivity log used primarily in saline water-based muds, work by creating an electric circuit in the formation through the pore network and formation fluid (Andersen 2011). This process works via a low frequency current that flows from source electrodes in the tool. Arrays on either side of the source electrode force the measuring current into a thin disc-shape perpendicular to the borehole that penetrates deep into the formation (Krygowski 2004). The amount of current returning to the tool is detected by a measuring electrode, and the amount of current that is lost represents the virgin formation resistivity, which can be used to calculate water saturation and fluid content (Ellis & Singer 2008).

The pioneering work of Archie (1942), followed by Winsauer et al. (1952), established an empirical relationship between porosity and electrical resistivity. The electrical resistivity of brine-saturated rocks was later observed to increase with pore throat constriction (reduced permeability), reduced porosity, and elevated tortuosity – the latter is the effective distance available for electrical current flow through a reservoir (Owen 1952; Towle 1962; Helander & Campbell 1966). The relationship between formation resistivity, porosity, and tortuosity can be expressed as (Helander & Campbell 1966):

\[
\frac{R_T}{R_W} = \frac{(T)^2}{\phi}
\]

where \( T \) is tortuosity and \( R_W \) is the resistivity of the saturating brine. By Equation 12, porosity is inversely related to \( R_T \) and directly proportional to the square of tortuosity.
Although tortuosity cannot be directly measured directly in the lab, it can be estimated by the following relationship (Pérez-Rosales 1982):

\[ T = \frac{\phi}{\phi^m} \]  

[13]

where \( m \) is the cementation exponent from the Archie (1942) equation (Equation 1).

Formation resistivity, \( R_T \), can be used to calculate water saturation by taking advantage of Equation 1 (Archie 1942; Glover 2000). As discussed previously in section 3.5.2, the Archie (1942) equation fundamentally overlooks the elevated electrical conductivity of certain lithologies (especially clay and organic matter). Clay minerals reduce formation resistivity compared to equivalent clay-free zones due to enhanced conductivity from bound water in the clay structure (Krygowski 2004). This causes Archie water saturations to appear erroneously high (Worthington 1985; Asquith 1990). Resistivity measurements in unconventional reservoirs, therefore, should be interpreted with caution (Bust et al. 2013). \( R_T \) is affected by porosity, fluid saturation, and mineralogy (Ellis & Singer 2008):

- Low \( R \) / high conductivity: formation brines and water-based mud filtrates have low electrical resistivity, therefore rocks with high brine saturations (high porosity) are highly conductive;

- High \( R \) / low conductivity: matrix material (especially carbonates), hydrocarbons, and oil-based mud filtrate all have high electrical resistivity; additionally, organic-rich mudstones have high resistivity due to low porosity and water saturation.

Representative brine resistivity, \( R_W \), and \( R_T \) values are essential for calculating water saturation. Small changes can alter water saturation calculations by ±10% (Glover 2000). Ideally, these parameters would be determined in a lab using water samples retrieved from the Second White Specks Formation in the study area, but this information is not available. There is significant potential risk of propagating error in water saturation calculations for the Second White Specks without calibration to core data. It is more responsible to use resistivity logs as a secondary indicator of matrix composition.
3.6.2.3.1 Tool specifications

Resistivity is measured in ohm-m, and ranges from 0.2 (highly conductive) to greater than 20000 ohm-m (highly resistive). The readings are presented graphically in a logarithmic manner to enhance small changes in resistivity over a short vertical distance. Laterologs are run centered in the borehole with water-based drilling mud, and must make electrical contact with the formation in order to get a resistivity reading (Krygowski 2004). At shallow depths of investigation (<0.5 m) the measured resistivity is not normally equal to the virgin formation resistivity, because conductive mud in the borehole and mud filtrate invasion into the formation distort the signal from the formation (Cosmo et al. 1991). To combat this, laterologs are used with different electrode spacings to get resistivity at multiple depths of investigation (i.e., deep, shallow, and microlog). Reducing the electrode spacing of a laterolog improves vertical resolution at the cost of reduced penetration depth (Glover 2000).

The deep laterolog (LLD) has a vertical resolution of 0.6 m, and a 1.5 to 2.1 m depth of investigation. It is precise to ±0.2 ohm-m. In comparison, the shallow laterolog (LLS) has comparable vertical resolution and precision but shallow depth of investigation (0.6 to 0.9 m). The microlog (RXO), which has closely spaced electrodes for maximum vertical resolution (3 to 8 cm), has a significantly reduced radius of investigation (2.5 to 10 cm), and is precise to ±0.2 ohm-m (Krygowski 2004).

3.6.2.3.2 Environmental effects

Historically, resistivity logging in thin beds has proven difficult (De Witte 1954; Cosmo et al. 1991). Laterolog tools are calibrated by computing the current flow and potential distribution patterns in a standard homogenous medium, where current flow spreads out over a very large volume after leaving the tool (Woodhouse 1978); in reality, distribution patterns are distorted by any resistivity anisotropy present (Threadgold 1972). In heterogeneous thinly-layered formations, electrical current tends to flow preferentially into more conductive beds; under these conditions, anisotropy is particularly extreme. This phenomenon, called the “shoulder-bed effect”, causes laterolog readings to be distorted at bed boundaries (Ellis & Singer 2008). Differential invasion into thin sand-
shale (permeable vs. non-permeable) beds can further exacerbate this problem (Minette 1990). Even if micrologs are run over the formation of interest, they do not provide reliable formation resistivities (Glover 2000; Krygowski 2004). With current technology, beds < 1 m thick are not easily resolved without NMR (nuclear magnetic resonance) logs, which are expensive and not commonly run in the Second White Specks interval.

Invasion of mud filtrate into permeable zones causes virgin formation fluids to be displaced. Although the LLD normally measures deep enough to extract the true formation resistivity (required for the calculation of water saturation), if “formation damage” (invasion) is extreme this value may be incorrect (Glover 2000). Resistivity curves at different depths of investigation should be identical in impermeable beds, where invasion does not occur. In comparison, in invaded zones, an “invasion profile” is visible: if the mud filtrate resistivity exceeds the formation resistivity then the $R_{\Omega}$ and LLS should read higher resistivities than the LLD, and vice versa (Krygowski 2004).

3.7 Highlights

- Petrophysicists assess hydrocarbon reservoirs by using indirect measurements (geophysical wireline logs) collected from the subsurface to model rock properties. Storage and flow capacity can be evaluated remotely using this data.
- Petrophysical models require meaningful constraints in order to accurately represent natural variations in rock properties. Stratigraphic architecture controls compartmentalization of the reservoir into hydraulic flow units.
- Wireline log measurements are used as proxies for reservoir quality indicators like mineralogy, porosity, and water saturation. These tools were originally designed to assess “conventional” reservoirs that did not contain clay or organic matter. As focus has now shifted to low porosity “unconventional” reservoirs that contain large amounts clay and kerogen, the tool responses to unconventional reservoirs need to be well constrained. Elevated gamma ray, low density, slow sonic travel time, high neutron porosity, and increased resistivity responses are expected in reservoirs with high organic and clay content.
Chapter 4

4 Stratigraphic method

4.1 Overview

Allostratigraphic correlations form the basis for zonal analyses of petrophysical properties presented in Chapters 6 through 8. The following section reviews the allostratigraphic method used in this study to define reservoir compartments called hydraulic flow units. Following the allostratigraphic method validates the stratigraphic picks herein.

4.2 Stratigraphic nomenclature and bounding surfaces

The sedimentary rock record can be subdivided and correlated several different ways. Two methods are relevant to this study: lithostratigraphy, the subdivision of rock units based on lithic characteristics; and allostratigraphy, the subdivision of rock units via correlation of bounding surfaces with temporal significance (NACSN 1983, 2005). This thesis uses the allostratigraphic method for subdivision of the lower Colorado Group, extending the work of Tyagi et al. (2007). Bounding surfaces with allostratigraphic significance include unconformities and conformities.

Unconformities are stratigraphic surfaces that separate younger from older strata and represent gaps in sedimentation (Cross & Lessenger 1988). These include but are not limited to:

1) subaerial unconformities, *sensu* Sloss et al. (1949): these are unconformities that form under subaerial conditions as a result of fluvial erosion or sedimentary bypass, among other processes;
2) marine flooding surfaces: a surface that indicates an abrupt increase in water depth;
3) regressive surfaces of marine erosion, *sensu* Plint (1988): an erosional surface that forms via wave scouring during forced regression in wave-dominated shallow water settings due to relative sea-level fall.

A conformity is a surface that separates younger from older strata but does not indicate erosion or significant non-deposition – this includes surfaces that experienced very slow rates of deposition such as condensed sections (Loutit *et al.* 1988).
4.3 Controls on sedimentation

Sedimentary rocks are inherently cyclical – they exhibit specific and recognizable stratal stacking patterns that reflect allogenic forcing (Helland-Hansen & Gjelberg 1994; Dalrymple 2010a). These patterns, called “sequences”, are sedimentary successions deposited during an entire cycle of change in accommodation and supply (Posamentier et al. 1988; Galloway 1989; Catuneanu et al. 2009). Accommodation defines the available space that sediment can fill (Jervey 1988). The major controls on accommodation are changes in relative sea level and changes in the rate of sediment supply to the basin (Jervey 1988; Posamentier et al. 1988; Galloway 1989; Plint et al. 1992; Schlager 1993; Muto & Steel 1997, 2000; Catuneanu 2002, 2006; Catuneanu et al. 2011).

4.3.1 Eustasy

Eustasy is the change in sea-level relative to a fixed datum, like the centre of the earth (Posamentier et al. 1988). Basin tectonics locally affect the elevation of the sea floor which serves as a local datum, and the position of the eustatically determined sea surface relative to this local datum is known as the relative sea level (Posamentier et al. 1988). Many cyclical sedimentary patterns are observed globally and appear to be driven by eustatic variation (Haq et al. 1987; Haq 2014). Eustatic change is primarily controlled by fluctuations in oceanic water volumes (Donovan & Jones 1979; Miller et al. 2005) – this flux comprises the creation or removal of accommodation within a particular basin.

Eustatic processes, once classified on the basis of their magnitude (Vail et al. 1977), are now recognized as episodic, hierarchical phenomena that operate on a variety of timescales. These processes are listed below, in order from low to high frequency (Vail et al. 1977; Donovan & Jones 1979; Plint et al. 1992; Miall 2010):

1) First order (400 to 500 Myr periodicity) cycles are related to global cycles of supercontinent formation and breakup;

2) Second order (10 to 100 Myr periodicity) cycles are linked to volume flux of mid-ocean ridge spreading centres;

3) Third order (0.1 to 10 Myr periodicity) cycles are correlated with regional basement tectonic plate kinematics, and;
4) Fourth and fifth order (10 Kyr to 500 Kyr periodicity) cycles are caused by Milankovitch orbital forcing (Milankovitch 1941).

Only Milankovitch processes will be discussed further. Although higher order cyclicity may have played a role in sedimentation during the Late Cretaceous, the time scales on which higher order cycles operate is likely beyond the vertical resolution of stratigraphic section and time considered in this thesis.

4.3.2 Milankovitch orbital forcing

Milankovitch cycles are attributed to the climatic imprint of Earth’s periodic orbital variations. These cycles include orbital eccentricity, obliquity, and precession (Milankovitch 1941). Milankovitch cycles change the amount of solar energy at the earth’s surface, in addition to its latitudinal and seasonal distribution – thus globally influencing climate (Arthur & Philip 1986). These climate cycles regulate fluctuations in the global volume of continental ice sheets (glacioeustasy), which is the primary mechanism for high frequency eustatic variation (Plint et al. 1992; Miall 2010). High frequency sedimentary cycles attributed to Milankovitch cyclicity have been recognized in Cretaceous rocks across the WIS (Plint 1991; Varban & Plint 2008b) although their linkage to glacioeustasy is contentious. The existence of ice caps during Cretaceous time has been hotly debated (Huber et al. 2002), due to the “greenhouse” climate of the Cretaceous period that should have prohibited continental ice sheet growth. δ¹⁸O isotope data from Turonian sediments recovered in the tropical Atlantic record exhibit positive excursions that are synchronous with the eccentricity orbital cycle, suggesting that continental ice sheets may have been extant, at least for periods of time, during the Late Cretaceous (Bornemann et al. 2008).

Milankovitch cyclicity has been documented in rocks from the WIS that span the Cenomanian-Turonian boundary. For example, Sageman et al. (1997) correlated limestone/marlstone bedding couplets of the Second White Specks-equivalent Greenhorn Formation in Colorado with Milankovitch obliquity cycles (41 Kyr). Prokoph et al. (2001) used core from Bloch et al. (1999)’s Second White Specks Formation type well (6-34-30-8W4) to determine that Milankovitch cyclicity was a significant control on
Solving the Second White Specks

sedimentation during OAE-II, but they were unable to link overall sea-level rise during the Late Cenomanian and OAE-II to a specific mechanism. These observations suggest that rocks of the lower Colorado Group in west-central Alberta contain regionally correlative cycles that are related to eustasy and changes in accommodation.

4.3.3 Sediment supply

Clastic detritus is transported to basins at variable rates, depending on climatic factors and relative sea-level change (Miall 2010). Climate controls the sedimentation rate by prohibiting or encouraging erosion (Nichols 2009). Highest sedimentation rates are encountered in temperate climates that experience seasonal variability and increased precipitation (Miall 2010), because erosion and weathering processes (both chemical and physical) are enhanced (Nichols 2009).

Rivers adjust their profiles as relative sea-level drops, re-equilibrating to a lower “base level” (Nummedal et al. 1993). Shanley and McCabe (1994) defined base level as:

“[…] the potential energy surface that describes the direction in which a stratigraphic system is likely to move, toward sedimentation and stratigraphic preservation or sediment bypass and erosion.”

Lowering base level triggers the erosion of topographic highs by rivers, which then transport sediment to the ocean. Raising base level, conversely, favors sedimentation and stratigraphic preservation. Base level is, fundamentally, the equilibrium surface to which rivers erode – it approximates relative sea-level in the marine realm (Wheeler 1964).

4.3.4 $\delta A/\delta S$ ratio

Variations in the ratio of change in accommodation ($\delta A$) to the rate of change sediment supply ($\delta S$) is frequently invoked as the primary mechanism for shoreline migration. The interaction between these rates ($\delta A/\delta S$) determines shoreline trajectories (Jordan & Flemings 1991; Swift & Thorne 1991; Posamentier et al. 1992; Schlager 1993; Muto & Steel 1997; Martinsen et al. 1999; Muto & Steel 2000). If accommodation rates are approximately equal to sedimentation rates ($\delta A = \delta S$), shorelines remain stationary and produce aggradational successions. If accommodation rates and sediment supply are not
balanced, depositional systems will shift in space to reach equilibrium (Catuneanu 2006). When supply exceeds accommodation ($\delta S > \delta A$), a regression occurs: shorelines and facies shift seaward, resulting in progradational (lateral outbuilding) stacking patterns. When accommodation exceeds supply ($\delta A > \delta S$), the shoreline experiences a landward transgression, which also constitutes a landward facies shift – this results in retrogradational stacking patterns (Catuneanu 2002).

### 4.4 Seismic stratigraphy

Based on the observations of Vail et al. (1977), Mitchum et al. (1977) introduced the concept of “seismic stratigraphy” from their analysis of two dimensional seismic reflection data. Surfaces of contrasting acoustic impedance (i.e., surfaces that separate different lithologies) generate seismic reflections (Neidell 1979). Seismic stratigraphy associates seismic reflections with unconformities and stratal surfaces – therefore assigning time-stratigraphic significance to strong seismic reflectors (Vail et al. 1977; Cross & Lessenger 1988). Seismic data allows for the observation of stratal terminations, stacking patterns, and 3D visualization of stratigraphic surfaces (Posamentier 2000).

Seismic stratigraphy is restricted by the limitations of seismic data. The bandwidth of seismic exploration data (20 to 40 Hz, ~30 m vertical resolution) may be insufficient to characterize high frequency stratigraphic cycles (Catuneanu et al. 2009). In some cases, surfaces of contrasting acoustic impedance occur at sedimentary facies boundaries that are not time-stratigraphic surfaces (i.e., lithostratigraphic boundaries) – thus, seismic reflections may cross time lines (Cross & Lessenger 1988). Impedance contrasts over diffuse stratigraphic boundaries with minimal facies contrast (e.g., correlative conformities) generate little to no seismic reflection (Neidell 1979), so their time-stratigraphic significance may be overlooked (Cross & Lessenger 1988).

Regardless of its limitations, seismic stratigraphy afforded the delineation of cyclical stratigraphic packages bounded by regional unconformities induced by relative sea-level fall (Vail 1987). It is now generally accepted that these cycles, or genetic sequences, result from the complex interplay between changes in accommodation, sedimentation, and erosion (Posamentier & Vail 1988). Integration of seismic stratigraphic methods with
outcrop and well log data resulted in the creation of sequence stratigraphic concepts (Posamentier & Vail 1988; Van Wagoner et al. 1988).

4.5 Sequence stratigraphy

Van Wagoner et al. (1988) defined sequence stratigraphy as:

“[...] the study of rock relationships within a chronostratigraphic framework of repetitive, genetically related strata bounded by surfaces of erosion or nondeposition, or their correlative unconformities.”

Catuneanu et al. (2009), alternatively, defined sequence stratigraphy as the study of stratal stacking patterns and their variations within a temporally-constrained framework of bounding surfaces. These patterns, or sequences, constitute stratal successions “deposited during a full cycle of change in accommodation or sediment supply” and are bound by sequence stratigraphic surfaces called sequence boundaries (Catuneanu et al. 2009).

Sequence boundaries delineate systems tracts of regionally mappable and correlative depositional systems (Brown & Fisher 1977; Posamentier et al. 1988): these are the lowstand, transgressive, highstand, and falling-stage system tracts (Mitchum 1977; Posamentier & Vail 1988; Van Wagoner et al. 1988; Plint & Nummedal 2000). Systems tracts are coeval depositional systems defined by their stratal geometry, stratigraphic position, and parasequence stacking patterns (Posamentier et al. 1988). Parasequences are smaller elements (metre scale) within an individual sequence (Van Wagoner 1985): they are short-term, higher frequency flooding events (Haq et al. 1987) that may originate from orbital forcing on Milankovitch (<500 Kyr) scales (Read & Goldhammer 1988).

Sequence stratigraphic methods can be used to interpret stratigraphic hierarchy on the basis of interactions with allogenic factors – this is because stratigraphic architecture has diagnostic geometry in different depositional settings (Catuneanu 2006). Systems tracts define the four possible relationships between $\delta A/\delta S$ and are representative of different depositional environments and sedimentary architecture, because shifts in $\delta A/\delta S$ can create or destroy sequence-stratigraphic surfaces (Catuneanu 2006). Re-equilibrating to
base level after a shift in \( \delta A/\delta S \) takes time to occur – as a result, sequence stratigraphic surfaces are inherently diachronous and may cross time lines (Cross & Lessenger 1988).

The applications of sequence stratigraphy to petroleum geology are clear – many significant reservoirs contained within the WCSB are associated with unconformities inferred as a result of relative sea level fall, and transgressive disconformities produced during sea level rise (Bhattacharya & Posamentier 1994; Leckie et al. 1994). The Cenomanian period is widely recognized as a highstand that reached eustatic maximum in the early Turonian, coincident with OAE-II (Haq et al. 1987; Sageman et al. 1997; Haq 2014). The Bighorn River “red” bentonite is a marker bed that approximates the Cenomanian-Turonian boundary in west-central Alberta (Tyagi et al. 2007; Tyagi 2009). This horizon is associated with the Cenomanian eustatic maximum and may have some sequence stratigraphic significance if it was reworked by waves.

Stratal patterns observed in passive continental margin settings – which have distinct slope-shelf breaks – formed the original basis for sequence stratigraphic models (Vail et al. 1977; Jervey 1988; Posamentier et al. 1988; Posamentier & Vail 1988). Subsidence patterns in foreland basins fundamentally differ from passive continental margins. In a foreland basin setting, flexural loading by thrust sheets causes subsidence rates on the tectonically-active side of the basin to decrease progressively with distance from the orogenic belt (Beaumont 1981; DeCelles & Giles 1996; DeCelles 2012). Passive margin settings, in comparison, experience increased subsidence in the seaward direction. Depositional sequences in foreland basins will exhibit landward-thickening, wedge-like geometries (Posamentier & Allen 1993); this is the reverse of passive margin settings. This evidence suggests that traditional sequence stratigraphy may have limited application to foreland basin settings.

### 4.6 Allostratigraphy

Allostratigraphic units, or allomembers, are defined by laterally traceable bounding discontinuities that constrain coeval rock units (NACSN 1983, 2005). Contrary to lithostratigraphic methods, which define stratal units on the basis of similar lithologies, allostratigraphy is predicated on the correlation of time-equivalent units regardless of
lateral variability – thereby assigning critical chronological and spatial context to facies and thickness changes. Similar to seismic stratigraphy, it is assumed that allostratigraphic surfaces correspond to physically continuous surfaces and approximate timelines (Bhattacharya & Posamentier 1994). By constraining geological zones in this manner, allostratigraphic maps illustrate coeval depositional systems (i.e., paleogeography) in such a way that the influence of tectonism, changes in A/S, and erosion may be inferred (Martinsen et al. 1993; Shank & Plint 2013). This establishes a predictive framework for rock properties, such as clay content and thickness, based on their associations with modern depositional environments.

Correlating allostratigraphic bounding surfaces establishes an allostratigraphic framework, which distinguishes the stratal geometry of individual allomembers; this has some parallels to sequence stratigraphic methods. Allomembers, when mapped across a region, provide well-constrained “time slices” of rock properties at a vertical scale that closely matches that of the hydraulic flow units described by Ebanks (1987). Each allomember is expected to have a distinct set of petrophysical properties indicative of the environmental conditions where it was deposited. This is fundamentally similar to slicing and flattening a 3-D seismic volume along a stratigraphic surface – to a certain extent, the resulting surface reflects the conditions it was deposited under. Typical allomember thicknesses are in the range of 3 to 15 metres.

Allostratigraphy conceptually differs from sequence stratigraphy on how bounding surfaces are defined. Subaerial unconformities and erosional surfaces of marine ravinement (i.e., sequence boundaries) can be highly diachronous, limiting their usefulness as stratigraphic timelines (Plint & Nummedal 2000; Bhattacharya 2001). In addition, subaerial unconformities are either not preserved or rarely developed in strata from the Kaskapau alloformation, so it is difficult to apply sequence stratigraphic criteria and define sequences (Plint et al. 2012a). Marine transgressive surfaces – which are also sequence boundaries – better approximate time-stratigraphic surfaces for allostratigraphy (Vail et al. 1977; Cross & Lessenger 1988; Plint et al. 2012b) despite their moderately diachronous nature (Roca et al. 2008). Flooding surfaces are regionally extensive and
commonly preserved within sedimentary strata in the WCSB, and so are more easily correlated throughout the basin.

Smectite-rich volcanic ash beds (bentonites) are common in strata of Late Cretaceous age (Kauffman 1984). Bentonites contain igneous minerals, such as zircons, which can be isotopically dated (e.g., Barker et al. 2011). Volcanic ash, produced by explosive volcanic events, is deposited quickly (days to weeks) and results in the deposition of bentonite beds that are considered coeval (Obradovich & Cobban 1975). Bentonite ash beds are mainly distributed via high altitude (10 to 15 km) winds, which can achieve ash dispersion over large geographic regions (Slaughter & Earley 1965). Bentonite preservation is enhanced when sedimentation rates are low, as ashfalls will condense into composite ash beds that are undiluted by background sediments (Ver Straeten 2004). Volcanic ash, however, may also be redistributed by current transport if it is deposited above storm wave base – if this occurs, the ash bed will be physically reworked and non-uniform in thickness (Knechtel & Patterson 1956; Ver Straeten 2004).

Of the volcanic events indicated by bentonite beds in the WIS, approximately 85% have been correlated to major transgressive episodes (Kauffman & Caldwell 1993). Bentonites contained within the Blackstone Formation were spatially associated with major flooding surfaces, wave-rippled silty beds, and were typically non-bioturbated (Tyagi 2009). These observations suggest that the bentonites observed by Tyagi (2009) were likely deposited during marine transgressions above storm wave base, and bentonite preservation may have been assisted by a lack of bioturbation (Tyagi 2009).

Flooding surfaces and bentonites constitute examples of basin-wide, coeval depositional surfaces. This is supported by the relative parallelism of bentonites and flooding surfaces (Asquith 1970; Hattin 1971; Tyagi et al. 2007; Varban & Plint 2008a). Flooding surfaces, which are recognizable in outcrop or core and distinguishable in wireline logs (Varban & Plint 2005), are particularly useful because their geophysical responses reflect an abrupt upward shift to clay-rich or shaley lithologies (Rider 1990; Catuneanu 2006; Ellis & Singer 2008).
4.7 Highlights

- Sedimentary cycles, or sequences, reflect environmental responses to cyclical changes in accommodation and sediment supply to the basin. These sequences can be stratigraphically correlated and mapped.
- Allostratigraphic zones, which are defined by coeval depositional surfaces, best approximate hydraulic flow units. Coeval depositional surfaces include flooding surfaces, bentonite horizons, unconformities, and correlative conformities.
Chapter 5

5 Petrophysical method

5.1 Overview

Geological data (wireline logs and core data) was transformed into a 3-dimensional petrophysical model for the Second White Specks and Belle Fourche alloformations that can be used for first-pass sweet spotting, even when data is sparse. The process outlined in this chapter integrates the allostratigraphic method outlined in Chapter 4 with the petrophysical best practices examined in Chapter 3, resulting in a repeatable workflow that reduces uncertainty.

5.2 Using the petrophysical model to calculate brittleness

The primary goal of this thesis is to assess the degree of spatial association between high relative brittleness, increased porosity, and improved oil production from the Second White Specks Formation. The project workflow (Fig. 5.1) has been reverse-engineered with that goal in mind. In common practice, geological and petrophysical studies are performed separately and without reference to each other – this can limit their usefulness and general applicability. The approach used in this study integrates stratigraphic and petrophysical methods to improve the predictive capacity of the resulting maps.

5.3 Database development

The LAS files, core analysis, production data, and raster logs used in this project were imported into industry petrophysical modelling software and geological mapping programs (i.e., Schlumberger’s Techlog™ and geoLOGIC’s geoSCOUT™ program) in the Petroleum Geoscience Laboratory at the University of Western Ontario and used to build a project database of stratigraphic tops and petrophysical calculations. This database was continuously updated and modified as correlations and parameters were refined. The final user database is available as an attachment to this thesis.
Fig. 5.1: A process flow diagram illustrating the integrated petrophysical and geological workflows used in this thesis.

Green boxes indicate raw data inputs – the green boxes on the top row are petrophysical inputs, whereas the left-side green boxes indicate geological inputs. Purple boxes indicate volume models that were used for the brittleness index (BI), whereas blue boxes indicate items that were not included in the BI. The grey box encompasses all the results that were used to create sweet spot maps.

Using geophysical wireline logs and core data as inputs, a volumetric petrophysical model that has been corrected for clay and kerogen (\(V_{\text{clay}} + V_{\text{dol}} + V_{\text{QFM}} + V_{\text{ker}} + \phi_E = 1\)) is built, and placed into petrophysical zones (isochores). These properties are used to calculate brittleness indices (BI) for each allomember. Lastly, each property is placed into an allostratigraphic context and overlain to create maps of potential sweet spots.
Divestco supplied a license to their EnerGISite™ web portal in support of this research. EnerGISite™ is an online database that contains tens of thousands of LAS curves for oil and gas wells drilled in western Canada. Within the project area, 227 vertical wells had LAS data available in the Second White Specks interval – this is a small fraction of the >20 000 wells drilled in this area. To supplement this, and increase spatial control, raster log data for a further 217 wells was sourced using geoSCOUT™. LAS data is essential for petrophysical model development; wells with raster data only can only be used for stratigraphic correlation. In total, 444 individual wells were correlated.

Raw LAS data was uploaded into the Techlog™ 2015 program (Fig. 5.2), where it was standardized into log curves with universal names and units. Despite various generations of data, differing standards, and several types of tools that were used by the different logging companies, there are fundamental similarities in how the logging data can be used for petrophysical analysis. Although this is a major simplifying assumption, it allows for bulk processing of petrophysical data. In this format, LAS data can be easily manipulated for large groups of wells and processed quickly either with Techlog’s petrophysical workflows or by custom Python code for functions outside of Techlog’s core capabilities. Python code written in support of this project is available as an attachment to this thesis (Appendix B).

On average, a density of approximately three wells per township were used in cross-sections (refer to Fig. 1.2). This afforded reasonable confidence in allomember geometry and thickness when correlating stratigraphic surfaces across the study area. In areas like Willesden Green (Township 41 to 42, Range 4W5 to 6W5), well density was increased to greater than 10 wells to resolve major discrepancies (e.g., unexpected changes in allomember thickness) over close well spacing (<1 km) and to simulate production well spacing. Near the edges of the study area, where not many wells were drilled to sufficient depth to reach the Second White Specks Formation, well density is typically less than one well per township.

Due to the highly diachronous nature of some portions of the lower Colorado Group, the Second White Specks interval is defined lithostratigraphically within geoSCOUT’s
Solving the Second White Specks

5. Petrophysical method

Fig. 5.2: A screenshot of the Techlog software used in this project, with individual wells in the left-hand column, the properties of any selected parameters in the second column, and a cross-section visualized across the main section of the screen.
stratigraphic database. This made it difficult to select cores that fell within the interval of interest (lower interval of the Second White Specks and Upper Belle Fourche) without first performing low-resolution lithostratigraphic correlations. Once the preliminary correlations had been completed, it was determined that eight cores vertically intersected the interval of interest; of those, only one covered the entire interval (07-19-45-06W5). Only three cores from that subtotal had core analyses available within geoSCOUT. To supplement the project database of core, five cores were logged and sampled in detail by the author at the Alberta Energy Regulator (AER) Core Research Centre in Calgary, Alberta. This process included describing the visible lithology, grain size, composition, sedimentary and structural features, as well as the trace fossil assemblages.

5.4 Core-to-log correlation

To reduce the uncertainty associated with extrapolating sparse core data, 4 cores were sampled for LECO TOC analysis and major element X-ray fluorescence (XRF). This helped to constrain lateral variations in organic richness and mineralogy across the study area, to ensure that any resulting models would represent the subsurface geology. Although X-ray diffraction (XRD) was planned to aid in the determination of volume % mineralogy (Quirein et al. 2010), it was not performed due to logistical issues. All of the core data gathered for this study, including detailed core logs and core analysis, is presented in Chapter 5.

The 100/07-19-045-06W5 core was not logged by this author, as it had been previously logged by another student and sampled for Rock-Eval 6 analysis in 2012. There is abundant existing data for this core in the public domain: it has been extensively analyzed by Furmann et al. (2014) and Furmann et al. (2016) for XRD and total porosity. In addition to that work, the AGS has published Rock-Eval data for this core.

5.4.1 Total organic carbon (TOC) determination

TOC measurements are often used as a first-pass evaluation of a formation’s potential to generate hydrocarbons (Jarvie 1991). TOC analysis was performed in-house by Dr. Charlie Wu at the Laboratory for Geochemical Analysis at the University of Western Ontario in London, Ontario using a LECO CS-244 carbon/sulfur analyzer on 51 mudrock
samples from the Second White Specks Formation. The CS-244 analyzer uses the dry combustion-infrared absorption method to calculate total carbon. This method is a destructive analytical technique that can be used to solve for TOC by difference using the following relationship (Schumacher 2002):

\[
TC = TIC + TOC
\]  

[14]

where \( TIC \) is the total inorganic carbon (wt%; derived from carbonate minerals), \( TOC \) is the total organic carbon (wt%), and \( TC \) is the total carbon in the sample.

Samples were powdered and weighed into 10 to 15 g aliquots. These aliquots are split – one half (used for TOC) is treated with a HCl solution to digest inorganic carbon associated with carbonate minerals, the other (used for TC) is not chemically treated. These powdered samples were then oven-dried at 105°C overnight to remove excess water. Once they were sufficiently dry, the samples were combusted at 1350°C in an induction furnace where they were exposed to a stream of pure oxygen with catalysts added to ensure complete combustion (LECO 1996; Schumacher 2002). The exposure of the combusted samples to oxygen allowed for the carbon gases to oxidize, forming CO\(_2\). The amount of CO\(_2\) produced during the oxidization process is directly proportional to the carbon content of the sample, although it may be an underestimate if sulfur, water, and carbonates have not been adequately removed prior to analysis (Law 1999). The resulting CO\(_2\) gaseous phase flowed through scrubber tubes to remove unwanted moisture and chlorine. The gaseous phase flowed into an nondispersive infrared (NDIR) detection cell that was calibrated to CO\(_2\) (Bernard et al. 1995). The NDIR cell was tuned to the absorption of infrared energy by CO\(_2\) (2.6 to 4 microns). As the gaseous phase entered the NDIR cell, it absorbed infrared radiation and lost energy. This energy loss is converted by the NDIR cell to a wt % TOC or TC; TIC is calculated using Equation 14 (Schumacher 2002).

Based on duplicate samples taken for quality assurance, the analytical errors for TOC ranged from 0.3 to 2.3%. These issues may have resulted from the incomplete removal of pyrite (which contains sulfur) or carbonate minerals from the sample, or due to
heterogeneities between sample splits. The raw LECO TOC analyses are available as an attachment to this thesis.

5.4.2 X-ray fluorescence (XRF) analyses

Whole rock major oxide XRF was performed on 51 pulverized mudrock samples with a Philips PW-1480/10 wavelength dispersive spectrometer (WDS or WDX) unit by Dr. Charlie Wu at the Laboratory for Geochemical Analysis at the University of Western Ontario in London, Ontario using the fusion bead preparation method. The fusion bead method, first introduced by Claisse (1957), is an effective sample preparation technique for accurate XRF analysis of powdered rock samples because it eliminates effects associated with heterogeneities in grain size and mineralogy (Yamada 2010; Homma et al. 2012). Samples were powdered and weighed into 1.0 to 2.0 g aliquots. These powdered samples were then oven-dried at 105°C overnight to remove excess water. After drying, the samples were placed into crucibles and weighed. These crucibles were heated in a furnace at 1000°C for several hours, combusting the sample. Following cooling, the crucible and now combusted LOI sample were reweighed; the difference in weight was recorded as the percentage of sample lost on ignition, or LOI (King & Vivit 1988). LOI represents the organic carbon compounds and hydrous minerals such as carbonate or clay that were volatized during this stage (Yamada 2010). A 0.50 g aliquot of the combusted sample was fused with lithium borate (Li$_2$B$_4$O$_7$) flux to form a fused disc for XRF analysis.

Modern x-ray fluorescence (XRF) spectrometry is a non-destructive method often used to obtain concentrations for major and trace elemental rock analyses due to its relative simplicity and cost-effectiveness over other geochemical processes (La Tour 1989; Henry & Goodge 2016). Abbott (1948) built the first commercial x-ray fluorescence spectrometer, which has since been improved upon (Arai 2007). When electrons with sufficient energy (15 to 20 keV) impact a target, they generate x-rays (electromagnetic radiation in the 0.01 to 10 nanometer wavelength band) and associated electrons with wavelengths proportional to the atomic number of the target (Roentgen 1896; Moseley 1913; Henry & Goodge 2016).
In WDS XRF spectroscopy, a single crystal is used to disperse fluorescent X-rays induced in a rock sample via a collimated electron beam. The crystal is selected such that only those induced X-rays with specific wavelengths can travel in the spaces between crystal lattice planes (a phenomenon known as “Bragg diffraction”) and are reflected by the crystal towards a detector (Bragg & Bragg 1913; Kawahara & Shoji 2007). An X-ray detector is used to convert the energy released by the reflected X-ray into an electrical signal, which corresponds to the concentration of a particular element in the sample (Longoni & Fiorini 2007). Crystals with different lattice spacings are used to isolate the concentrations of different elements (Henry & Goodge 2016).

The 51 fused samples were analyzed using the Philips PW-1480/10 WDS XRF unit for the following major oxides: SiO$_2$, TiO$_2$, Al$_2$O$_3$, Fe$_2$O$_3$, MnO, MgO, CaO, K$_2$O, Na$_2$O, P$_2$O$_5$, Cr$_2$O$_3$, BaO, and SrO. 4 synthetic standards from certified reference materials (SY-2, R.V., JB-2, and JG-1A) were used as standard samples for calibration.

Based on duplicate samples taken for quality assurance, the analytical errors for XRF ranged from 0.2 to 3.1%. Similar to the LECO TOC analyses, these issues may have arisen from heterogeneities between sample splits. The raw XRF analyses are available as an attachment to this thesis.

5.4.3 Normalized mineralogy

XRF provides major oxide element concentration, not volume % mineralogy. Due to unforeseen circumstances, XRD could not be performed and another method for determining volume % mineralogy was required that could utilize the data that had already been gathered. Normative mineralogical calculation, such as the calculation of a CIPW norm, is a routine procedure in igneous geochemistry wherein bulk geochemical analyses are inverted to estimate the mineral assemblage for a particular rock sample (Cross et al. 1902; Verma et al. 2003). In this process, it is assumed that the composition of the magma that the igneous rock crystallized constrains its mineralogy rock to a series of idealized mineral components (Sen 2014). In contrast, normative mineralogical calculation is rarely done for clastic sedimentary rocks. This is because clastic mineralogy is affected by diverse independent variables, including sediment provenance, weathering
reactions, erosion processes, transport and depositional processes, pore water and brine chemistry; and early through late diagenetic reactions (Kackstaetter 2014). Despite this, Rosen et al. (2004) stated:

“[there are] significant statistical regularities in the mineralogical compositions of sedimentary rocks [...] that can be used to provide pointers to [their] mineralogical compositions.”

Kackstaetter (2014) developed a normative mineralogy method that quantifies and applies the assumptions made by Rosen et al. (2004) to sedimentary rocks. The Kackstaetter (2014) method partitions major element concentrations from XRF into sedimentary minerals with idealized chemistry. This method is not proven, but it provides a first-pass estimation of mineral composition.

Although the Kackstaetter (2014) method is fundamentally limited because the mineral compositions it uses are underdetermined (Spencer & Weedmark 2015), it provided a consistent match with published mineral compositions from Furmann et al. (2016) in the key well, 07-19-45-06W5. For this reason, the Kackstaetter (2014) method was used to convert all XRF data points into relative mineral compositions. The spreadsheet that Kackstaetter (2014) developed and was used in this thesis is available from http://earthscienceeducation.net/SEDMINSedimentaryMineralCalculator.xlsx. Ideally, the Kackstaetter (2014) method should be supplemented with sulfur content from LECO TOC method to estimate pyrite concentration. The Second White Specks and Belle Fourche Formations are known to contain some amount of pyrite (~5%), but pyrite could not be reliably modelled. As a consequence, pyrite was not included in the multimineral model.

5.5 Allostratigraphic correlation

The allomembers mapped in this study are extensions of and subdivide the framework developed by Tyagi et al. (2007). This work extended their allomember VII (lower Second White Specks) throughout the area and is bounded below by the Bighorn River “red” bentonite. Tyagi et al. (2007)’s allomember VI (Upper Belle Fourche), which is bounded above by the “red” bentonite and below by the K1 unconformity, is subdivided
in this work into three separate allomembers (Upper Belle Fourche 1, 2, and 3). Petrophysical zonations were created by importing the allostratigraphic tops from geoSCOUT into the Techlog project – these zones served as the vertical constraints for the petrophysical models described below.

5.6 Petrophysical modelling workflow
This section outlines the petrophysical modelling process implemented in this thesis, drawn from the petrophysical best-practices outlined in Chapter 3. A petrophysical model was developed by adapting previous models made for unconventional mudstones; Ambrose et al. (2010) was used as a template with some simplifications (Fig. 5.3 and 5.4); most notably, the model used here does not include pyrite or immobile hydrocarbons. Selecting this petrophysical model restricted the number of unknowns and identified the components that could be calculated. The petrophysical model used here only has seven components – in comparison, the unconventional petrophysical model illustrated in Fig. 3.2 can have greater than nine components. Petrophysical complexity increases with the number of unknowns, increased porosity modality, the introduction of microporosity, and by introducing matrix and fluid components with varied density and conductivity.

All of the procedures described below were implemented using built-in Techlog modules, or custom Python code written by the author for this project. Environmental corrections were applied when borehole conditions were poor, and where feasible with the available log data. The petrophysical modelling process was heuristic and iterative – methods were improved and altered as new problems were encountered and new data was introduced. The Techlog Quanti.Elan module was used to calculate weighted averages of each parameter within the allostratigraphic zones established in section 6.2. The project specific parameters and techniques are summarized in Table 5.1 where they can be easily accessed by the reader but will be described in detail in the following section.

LAS data is recorded every 0.1 to 0.2 m. The petrophysical calculations listed here, unless derived from core data, have the same sampling rate as the raw data.
Fig. 5.3: Modified from Ambrose et al. (2010) – this is the petrophysical model used for the Second White Specks in this study.
Fig. 5.4: Modified from Asquith (1990) – this represents the previous petrophysical model (Fig. 5.3) within a very simplified geological context.
### Equations used for petrophysical modelling in the 2WS

<table>
<thead>
<tr>
<th>Type</th>
<th>Equation</th>
<th>Remarks</th>
</tr>
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<tbody>
<tr>
<td><strong>Total organic carbon</strong></td>
<td>$TOC = A \times (\Delta t + 195 \times \log_{10} R) - 31.86$</td>
<td>$A = -0.0125$</td>
</tr>
<tr>
<td><strong>Kerogen volume</strong></td>
<td>$V_{ker} = \frac{W_{ker}}{\rho_{ker}}$ where $W_{ker} = \frac{TOC \times \rho_{ker}}{\rho_{ker} \times K}$ and $K &lt; 1$</td>
<td>$K = 0.8$  $</td>
</tr><tr>
<td>ho_{ker} = 1.15 \text{ g/cm}^3$</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Clay volume</strong></td>
<td>$V_{cl} = 1.7 - \sqrt{3.38 - (V_{sh} + 0.7)^2}$ where $V_{sh} = \frac{GR_{clean} - GR_{shale}}{GR_{clean} - GR_{shale}}$</td>
<td>$GR_{clean}$ selected using $5^\text{th}$ percentile cutoff  $GR_{shale}$ selected using $95^\text{th}$ percentile cutoff</td>
</tr>
<tr>
<td><strong>Void volume</strong></td>
<td>$\phi_{T,KER} = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_{fl}} \left( \frac{w_{KER} \times \rho_{KER}}{\rho_{KER}} - 1 \right)$</td>
<td>$\rho_{ma} = 2.74 \text{ g/cm}^3$  $\rho_{fl} = 1.05 \text{ g/cm}^3$  $\rho_{KER} = 1.15 \text{ g/cm}^3$</td>
</tr>
<tr>
<td><strong>Effective porosity</strong></td>
<td>$\phi_E = \phi_{T,KER} - V_{cl} \left( \frac{\rho_{dryclay} - \rho_b}{\rho_{wetclay} - \rho_{fl}} \right)$</td>
<td>Used mixed-layer (illite) density.  $\rho_{dryclay} = 2.7 \text{ g/cm}^3$  $\rho_{wetclay} = 1.7 \text{ g/cm}^3$</td>
</tr>
<tr>
<td><strong>Carbonate volume</strong></td>
<td>$V_{carb} = \frac{w_{carb}}{\rho_{carb}}$  where $w_{carb} = \frac{23}{3} TIC$ [71</td>
<td>$V_{dot} = 7.01 \times V_{ker} + 0.0168$  [72</td>
</tr>
<tr>
<td><strong>Matrix volume</strong></td>
<td>$V_{QFM} = 1 - V_{cl} - V_{carb} - V_{ker}$</td>
<td>Model assumes a 5-component system where porosity is zero</td>
</tr>
<tr>
<td><strong>Brittleness index</strong></td>
<td>$BI = \frac{V_{QFM} + V_{carb}}{V_{QFM} + V_{carb} + V_{cl} + V_{ker}}$</td>
<td>Assumes only QFM and carbonate contribute to brittle behaviour</td>
</tr>
</tbody>
</table>

Table 5.1: Table of equations and parameters used for petrophysical modelling in this project. All variables in red font are measurements taken directly from the well logs.
5.6.1 Environmental corrections

All wireline logging companies provide unique environmental correction charts for their tools to account for changes in borehole environment (Dresser 1979; Glover 2000; Schlumberger 2009). These corrections, in theory, adjust raw log measurements to bring them back to standard conditions. The accuracy of these corrections decreases with increased borehole diameter, mud cake thickness, and magnitude of invasion (Glover 2000). The Second White Specks Formation is notorious for bad hole conditions, making borehole corrections an essential part of petrophysical assessment. Previous studies of the Second White Specks Formation have not adequately corrected for borehole environmental effects. This reduces the reliability and precision of models build using said data (Knox 1975; Patchett & Coalson 1979; Howard & Hunt 1986; Guidry et al. 1990; Pursell et al. 1998). Data scarcity, however, presents a significant barrier to extensive application of borehole environmental corrections. Certain variables (e.g., drilling mud density, mud filtrate resistivity) are required to compute correction factors. This data, which is inconsistently recorded in log headers, is difficult to access.

5.6.1.1 Gamma ray corrections

Where caliper logs and drilling mud data were available, raw total GR was corrected for hole size (\(CAL\), in mm) and mud weight (\(MWT\), in kg/m\(^3\)) using the following general equation (Dresser 1979; Crain 2018):

\[
GR_C = GR [1 + 0.000322(MWT - 1000)][1 + 0.0024(CAL - 203)]
\]

[15]

where \(GR_C\) is the corrected GR in API units. The magnitude of corrections ranged from 0 to 60 API units. Where a gamma ray correction has been applied, deflections in the character of the gamma ray curve are more likely to represent bulk lithological changes rather than borehole breakout. This provides increased confidence to use gamma ray logs for correlation even in poor borehole conditions.
5.6.1.2 Density log corrections

If the computed density correction reading exceeded ±0.15 g/cm$^3$, the log was considered invalid and not used for porosity calculation. No further corrections were applied to the density logs as mudcake density and mudcake thickness were not known (Glover 2000).

5.6.1.3 Resistivity corrections

The “shoulder-bed effect” in shales can be corrected via a nonlinear joint inversion process (Cosmo et al. 1991; Warrilow et al. 1995; Heidari et al. 2012; Heidari & Torres-Verdin 2014), but this process can introduce significant uncertainty if calibration data is not available (Yin 2011). For this reason, no environmental corrections were applied to the resistivity log.

5.6.2 Volume modelling

Mineral components in a particular reservoir are preferably determined using core data, but core data is limited. The availability of core data and lithological logs (e.g., lithodensity and PEF) are limiting factors on mineralogical analysis. Methods for the compositional analysis of rocks using wireline logs have evolved concurrently with improvements in logging technology. To extend mineralogical models from key wells with core to the maximum number of possible wells, petrophysical models must be as simple as possible while still respecting the geology (Moore et al. 2016). For multimineral compositional analysis, it is important to find a technique that balances the true lithological heterogeneity of the reservoir while simultaneously respecting the dataset limitations (i.e., log suite).

When a sufficient variety of geophysical well logs are available, all mineral component volumes can be confidently resolved (Doveton 1994b). More often, however, there are insufficient logs available to solve for the volumes of all the minerals present in a formation. The number of linear equations based on geophysical well log responses, in relation to the number of desired unknowns (mineral volumes), designates the system as “underdetermined” (more volumes than well logs), “overdetermined” (fewer volumes than well logs), or “balanced” (equal number of well logs and volumes). In balanced and
overdetermined systems, a unique compositional solution can always be found. This is not the case for underdetermined systems, which have infinite possible solutions (Mitchell & Nelson 1988). In unconventional reservoirs, which have many mineralogical components, petrophysical models are usually underdetermined. This problem also arises in older (pre-1980s) fields where mineralogical logging was never implemented. When the geophysical well log database contains insufficient data to define a balanced or overdetermined system, either linear inversion, nonlinear joint inversion, or deterministic (sequential) methods can be used to estimate composition (Mitchell & Nelson 1988; Ellis & Singer 2008; Sondergeld et al. 2010).

Many algorithms exist for linear inverse estimation of mineral compositions (Mayer & Sibbit 1980; Quirein et al. 1986; Doveton 1994b; Rabateau et al. 2003). Implicit in these programs is the assumption that geophysical wireline log measurements (i.e., density, PEF, neutron porosity, and sonic transit time) are linear functions of the mineral and fluid volume concentrations in the wellbore. Light hydrocarbons, organic matter, and clay minerals render this assumption invalid (Heidari et al. 2012), as the nonlinear responses of those lithologies to certain well logs (e.g., GR and neutron porosity) are well established (see section 3.6.2). This can be mitigated through the use of nonlinear minimization and statistical algorithms (e.g., cluster analysis and principal component analysis) to better constrain lithology (Mitchell & Nelson 1988; Doveton 1994b; Rabateau et al. 2003). Linear inverse estimation methods also require a priori constraints (i.e., core data) to achieve unique compositional solutions, as the system of equations used is almost always underdetermined (McCarty et al. 2015).

Nonlinear joint inversion methods (Liu et al. 2007; Sanchez-Ramirez et al. 2009; Heidari 2011; Heidari et al. 2012; Gao et al. 2013; Heidari & Torres-Verdin 2014; Klenner et al. 2014; McCarty et al. 2015) modify the generalized nonlinear least squares method, developed by Tarantola and Valette (1982), to obtain estimates of petrophysical parameters from geophysical well logs. These methods have been used to estimate mineralogy where linear methods had previously failed. Heidari et al. (2012), for example, demonstrated that nonlinear joint inversion is viable way to estimate complex lithology in a thinly-bedded invaded reservoir. Despite these recent successes, nonlinear
joint inversion methods are not always recommended for petrophysical modelling – particularly when calibration data is scarce (McCarty et al. 2015). Application of these methods may result in model instability (i.e., when small changes in inputs significantly affect model outputs) and non-unique results (Tarantola & Valette 1982).

Deterministic petrophysical methods estimate each component in a semi-independent fashion (Sondergeld et al. 2010). After each individual component is solved, usually in a specific sequence, the results are used as input into the next model (Mitchell & Nelson 1988). These methods, such as the processes described by Poupon et al. (1971) and Clavier and Rust (1976), are economical but are often only valid in one type of formation (e.g., shaley sands) – this restricts their wider application. It is also difficult to modify the logical steps in a sequential petrophysical modelling method to accommodate new types of data (Ellis & Singer 2008).

Developing a linear or nonlinear inversion method for mineralogy was beyond the scope of this project. A deterministic method was applied instead: after determining other volume components (kerogen volume, clay volume, porosity), quartz and carbonate volumes were calibrated to core data and then solved by difference for the total volume. Due to the limited geophysical log data set available for this study area, it was only feasible to solve for volumetric components in a reservoir with five or fewer assumed components. The petrophysical model from Fig. 4.3 was further simplified to a five-component system because water saturation and hydrocarbon saturation could not be reliably modelled. Each volume component \( (V_{\text{clay}}, V_{\text{dol}}, V_{\text{QFM}}, V_{\text{ker}}, \text{and } \phi_T) \) was independently calculated in Techlog using methods that will be described below. The volume components of a formation with the petrophysical model from Fig. 5.3 (clay volume, \( V_{\text{clay}} \); kerogen volume, \( V_{\text{ker}} \); dolomite volume, \( V_{\text{dol}} \); quartz-feldspar-mica volume, \( V_{\text{QFM}} \); total porosity, \( \phi_T \)) are expressed as fractions of unit bulk volume. This gives rise to the following equation (Guidry et al. 1990):

\[
1 = V_{\text{QFM}} + V_{\text{cl}} + V_{\text{dol}} + V_{\text{ker}} + \phi_T
\]

[16]
5.6.2.1 Kerogen volume from logs
Kerogen is solid organic matter, rich in carbon, that is found in sedimentary rocks. The physical properties of kerogen can confound standard log analysis methods, providing overly optimistic estimates of porosity and fluid saturations (Crain & Holgate 2014). Quantifying TOC is essential for constraining petrophysical models because the total amount of kerogen (TOC, wt%; $V_{KER}$, v/v) impacts unconventional play economics (Haecker et al. 2016). Kerogen that has thermally degraded and produced hydrocarbons may develop porosity. Producible hydrocarbons can be stored in this porosity (Ambrose et al. 2010, 2012; Zee Ma et al. 2016). TOC, however, can only be measured directly using LECO TOC and Rock-Eval methods on rock samples. Geochemical analyses like this are relatively expensive, time consuming, and subject to sampling bias (Heslop 2010). Alternatively, petrophysicists can use in situ methods derived from log measurements to estimate vertical changes in TOC (Labani & Rezaee 2015). In situ methods are economical, have superior data availability, and sample the vertical succession continuously (Schmoker 1981). Previous workers have attempted to characterize the relationship between organic matter and one or more petrophysical well logs (e.g. gamma ray, density, sonic, and resistivity) with varying degrees of success. These models are summarized and compared in Table 4.2; the $\Delta \log R$ and Issler et al. (2002) methods are discussed in detail in the following section.

5.6.2.1.1 $\Delta \log R$ or Exxon method
The presence of organic matter in mudstones increases the apparent sonic porosity and elevates resistivity (see section 3.6.1). Passey et al. (1990) developed an empirical relationship between TOC, elevated formation resistivity, and apparent porosity. In their method, apparent porosity (usually using $\Delta t$ as a proxy) is plotted over resistivity and then scaled so that the two curves overlay as a baseline in zones with organic-poor shales above and below the organic shale. Zones that do not lie along this baseline appear as a curve separation. This curve separation, called $\Delta \log R$, is related to total organic content. The algorithm for calculation of $\Delta \log R$ from the overlay of sonic and resistivity is (Passey et al. 1990):
### Table 5.2: Table of TOC equations, with remarks related to their physical basis and limitations.

<table>
<thead>
<tr>
<th>Type</th>
<th>Equation</th>
<th>Physical basis</th>
<th>Remarks</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Density</strong></td>
<td>$V_{KER} = \frac{\rho_B - \rho}{1.378}$ where $\rho_B$ is the density of an organic-free zone and $\rho$ is the bulk density measurement from the logs</td>
<td>Bulk density of kerogen is low relative to matrix density (Tissot &amp; Welte 1978)</td>
<td>Sensitive to severe borehole rugosity, which is common in shaley formations (Haecker et al. 2016)</td>
</tr>
<tr>
<td>Schmoker (1979)</td>
<td>$TOC = \frac{154.497}{\rho - 57.261}$ where $\rho$ is the bulk density measurement from the logs</td>
<td>Bulk density of kerogen is low relative to matrix density (Tissot &amp; Welte 1978)</td>
<td>Assumes inorganic density = 2.69 g/cm³; underestimates TOC in clay- and carbonate-rich rocks (Gonzalez et al. 2013)</td>
</tr>
<tr>
<td>Schmoker and Hester (1983)</td>
<td>$V_{KER} = \frac{\gamma_B - \gamma}{1.378} * A$ where $\gamma_B$ is the GR intensity of an organic-free zone and $\gamma$ is the GR intensity measurement from the logs $A$ is a locally determined calibration</td>
<td>Total GR is elevated in shales due to clay and organic matter (Ellis &amp; Singer 2008)</td>
<td>Response conflates radioactivity from clay ($^{40}$K and $^{232}$Th) with radioactivity from organic matter (Fertl &amp; Chilingar 1988)</td>
</tr>
<tr>
<td>Schmoker (1981)</td>
<td>Correlated $[^{238}$U] with TOC and $V_{KER}$</td>
<td>$^{40}$K and $^{232}$Th are associated with clay, $^{238}$U occurs in organic matter (Ellis &amp; Singer 2008).</td>
<td>SGR is infrequently run (Ellis &amp; Singer 2008). Correlation of $^{238}$U with TOC can vary within a single formation (Cluff &amp; Miller 2010).</td>
</tr>
<tr>
<td>Fertl and Chilingar (1988)</td>
<td>$\Delta logR = \log_{10} \left( \frac{R}{R_{baseline}} \right) + 0.02 * (\Delta t - \Delta t_{baseline})$</td>
<td>Shales have higher resistivity and increased sonic porosity relative to non-shaley units</td>
<td>Sensitive to LOM, requires normalization, and not calibrated to local geology (Issler et al. 2002)</td>
</tr>
<tr>
<td>Guidry et al. (1990)</td>
<td>$TOC = \Delta logR * 10^{(-2.297-0.1688 \cdot LOM)} * C$ where $C$ is a compaction component &lt;1</td>
<td>Shales have higher resistivity and increased sonic porosity relative to non-shaley units</td>
<td></td>
</tr>
<tr>
<td>Passey et al. (1990) [17] and [18]</td>
<td>$TOC = A * (\Delta t + 195 * \log_{10} R) - 31.86$</td>
<td>Shales have higher resistivity and increased sonic porosity relative to non-shaley units</td>
<td>Calibrated to local geology, no normalization, and independent of LOM.</td>
</tr>
<tr>
<td>Issler et al. (2002); Crain and Holgate (2014) [19]</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
\[ \Delta \log R = \log_{10} \left( \frac{R}{R_{\text{baseline}}} \right) + 0.02 \times (\Delta t - \Delta t_{\text{baseline}}) \]  

where \( \Delta \log R \) is the curve separation measured in logarithmic resistivity cycles, \( R \) is the resistivity measured in ohm-m by the logging tool, \( \Delta t \) is the measured transit time in \( \mu s/ft \), \( R_{\text{baseline}} \) is the resistivity corresponding with the \( \Delta t_{\text{baseline}} \) value when the curves overlie in organic-poor (non-source), clay-rich rocks.

\( \Delta \log R \) separation is linearly related to TOC and is a function of the level of organic metamorphism (LOM), as well as kerogen type. The level of organic metamorphism (LOM) represents the degree of thermal metamorphism a particular mudstone has undergone, which increases with burial depth and increased geothermal gradients (Hood et al. 1975). Good estimates of TOC from \( \Delta \log R \) require a priori knowledge of LOM and calibration to TOC from rock samples – this is difficult when geochemical analyses are scarce. Sondergeld et al. (2010) suggested a modification to the Passey equation for LOM to prevent underestimates of TOC in overmature gas shales, which have \( LOM > 14 : \)

\[ TOC = \Delta \log R \times 10^{(2.297 - 0.1688 \times LOM)} \times C \]  

where \( C \) is a multiplier > 1 that is calibrated to measured TOC from core.

The Passey et al. (1990) method is practical and easily applied. It does have drawbacks: it requires similar clay mineralogy and conductive mineral components (i.e., pyrite) in the source and non-source intervals. The method also assumes that the baseline shale and organic shale have similar matrix properties (i.e., resistivity and apparent porosity). This may not be representative of the formation’s true vertical heterogeneity. Graphical log overlay methods like \( \Delta \log R \) require log normalization, and the baseline determination can be subjective (Issler et al. 2002).

The \( \Delta \log R \) method can produce false positives (Passey et al. 1990). Anomalous \( \Delta \log R \) separation not associated with organic shales can be caused by:

1) hydrocarbon-bearing reservoir intervals,
2) poor borehole conditions,
3) uncompacted sediments,
4) low porosity intervals,
5) volcanics, and
6) evaporites.

1), 2) and 4) are characteristic of Lower Colorado Group shales – it is likely that using the $\Delta log R$ method would overestimate TOC in this interval. Due to a lack of geochemical analyses and the uncertainty introduced by the $\Delta log R$ method, this method was not used in this thesis for evaluation of the lower Colorado Group.

5.6.2.1.2 Issler et al. method

Using core measurements of WCSB Colorado Group rocks, Issler et al. (2002) developed a porosity-resistivity method for calculating TOC that does not require baselines, normalization, or a priori knowledge of LOM. Crain and Holgate (2014) provide a multiple regression of the Issler et al. (2002) graphs, which gives the following general equation:

$$TOC = A \times (\Delta t + 195 \times \log_{10} R) - 31.86$$  \hspace{1cm} [19]$$

where A is a local calibration that is < 0.1.

5.6.2.1.3 Application of TOC modelling to the lower Colorado Group

The Issler et al. (2002) method for TOC calculation was chosen to calculate TOC. The general equation derived by Crain and Holgate (2014) from multiple regression of the Issler et al. (2002) graphs was coded into Techlog (Equation 19). A was set to -0.0125 for this study area. This value for A was chosen on the basis of optimal modelled TOC curve matching with Rock-Eval 6 TOC data (Fig. 5.5) collected by another student from the Western University Petroleum Geology Laboratory. This core, from the 100/07-19-045-06W5 or “7-19” well, vertically samples the entire interval of interest for this study. Fig. 5.5 shows a strong linear relationship between the Issler model predictions and Rock-Eval 6 calibration data. This relationship is also visible in the vertical profile of TOC shown in Fig. 5.6. On the basis of this relationship, the Issler et al. (2002) method was applied to all
Fig. 5.5: Issler model TOC vs. Rock-Eval TOC analyses from the core study interval in the 100/07-19-045-06W5 well. The regression shows a strong linear relationship with a moderately high coefficient of determination ($r^2 = 0.811$).
Solving the Second White Specks

5. Petrophysical method

Fig. 5.6: A log display of the 7-19 well, showing the sonic and resistivity curves that were used as input for the TOC model as well as the porosity model.

The track second from the right shows the Rock-Eval core data (TOC_G) as black circles overlaid on the modelled TOC (blue and red fill) in the Belle Fourche and Second White Specks Formations; the TOC curve reflects the log character of both the sonic and resistivity curves.

On the far right, black circles indicate the helium porosimetry data points taken from Furmann et al. (2014). These are plotted against the kerogen-corrected total porosity model (PHIT_CORR) and the effective porosity model, shown as blue-filled areas. The kerogen-corrected total porosity is a good fit for the core porosities, generally agreeing within a percent.
Solving the Second White Specks

5. Petrophysical method

eligible wells with LAS, deep resistivity, and sonic; this constituted 84 of the 227 wells with LAS data in the study area. Modelled TOC values ranged from 0.5 to 5% in the area.

Petrophysical models require components reported in volume percent, not weight percent. To do this, TOC (weight %) must be converted to kerogen volume ($V_{ker}$). Organic petrography is a recommended step in developing robust kerogen density measurements because organic maceral chemistry and LOM affect kerogen density (Stankiewicz et al. 2015). Crain and Holgate (2014) use the following equation for kerogen volume % ($V_{ker}$), which is derived from the work of Guidry et al. (1990):

$$V_{ker} = \frac{TOC \times \rho_{ker}}{\rho \times K} / \rho_{ker}$$

[20]

where $\rho_{ker}$ is the density of kerogen, and $K$ is a kerogen conversion factor <1. Although $\rho_{ker}$ can be derived from geochemical data, Okiongbo et al. (2005) cautioned that kerogen in organic shales is difficult to chemically separate from pyrite, which results in a wide range of reported densities for kerogen in specific formations. Although estimating $\rho_{ker}$ becomes more difficult without organic geochemical data, Ward (2010) suggested the following relationship between vitrinite reflectance ($%R_O$) and $\rho_{ker}$ in the Marcellus Shale:

$$\rho_{ker} = 0.342 \times %R_O + 0.972$$

[21]

$\rho_{ker}$ was set to 1.15 g/cm$^3$ based on $%R_O$ data from Furmann et al. (2014) and Equation 21. This value for $\rho_{ker}$ falls within the theoretical limits for kerogen density of 1.1 to 1.4 g/cm$^3$ set by Tissot and Welte (1978). Lacking more $%R_O$ data for local calibration, this $\rho_{ker}$ value was used for the entire Willesden Green field.

5.6.2.2 Clay volume from logs

Clay quantification in any reservoir is key to building a good petrophysical model, because virtually all log measurements are affected by the volume fraction and type of clay minerals present in a formation (see section 3.6.1). This is especially true of the Second White Specks Formation, which can contain greater than 40% clay by volume (Furmann et al. 2014). Clay volume would ideally be determined via x-ray diffraction
(XRD) – unfortunately, this type of mineralogical data is slow to process (i.e., in time to influence production geology decisions) and is relatively expensive (Ellis & Singer 2008; Doveton 2014). Similar to other geochemical data sources, XRD results may not be representative due to vertical sampling bias. Total gamma ray scaling techniques, developed for the purposes of shaley sand corrections (see section 3.5.2), are more economical. These scaling techniques utilize the ability of the gamma ray log to detect potassium associated with clay minerals (Asquith 1990; Krygowski 2004).

Total gamma ray clay volume techniques can be highly subjective and err by overestimating clay volume. The total gamma ray curve includes uranium counts that are not associated with clay minerals. This, however, is often the only alternative if core is not available (Ellis & Singer 2008). Clay volume overestimation can be mitigated through scaling techniques that use the uranium free (Th/K) curve from SGR logging when available. Th/K is a better indication of clay volume because the uranium-free curve (see section 3.6.2.1.2) isolates GR intensity to potassium and thorium associated with clays and accessory zircons (Krygowski 2004).

5.6.2.2.1 Application of clay volume to the lower Colorado Group

After applying environmental corrections to the gamma ray logs, shale volume ($V_{sh}$) was calculated using 5th percentile cutoffs for $GR_{min}$ and 95th percentile cutoffs for $GR_{max}$ over the entire lower Colorado Group interval. These cutoffs were individually set for each well in Techlog, ensuring that $V_{sh}$ would be correctly calibrated for each data point. $V_{sh}$ was calculated using Equation 3 and corrected to estimate clay volume ($V_{cl}$) using Equation 4. Published clay XRD data from Furmann et al. (2014) in the 100/07-19-045-06W5 well was used to calibrate the $V_{cl}$ model.

5.6.2.3 Porosity from logs

Porosity ($\phi$) is the total nonsolid volume in a reservoir. This includes all pores, fractures, vugs, intercrystalline and intracrystalline volumes (Glover 2000). All porosity equations are of the form:
where $V_{\text{pore}}$, $V_{\text{bulk}}$, and $V_{\text{matrix}}$ are pore volume, bulk volume, and matrix volume, respectively. An organic-rich mudstone like the Second White Specks is normally composed of solid clay, non-clay, and organic components, with pore space between and within them (Ambrose et al. 2012). Ideally, porosity models should be calibrated with porosities measured from core and log-derived porosities to ensure accuracy (Glover 2000). This is relatively easy to do in conventional plays, where core analysis is frequently performed and readily available. The fundamental physical properties of unconventional shales (i.e., low porosity, <10%; and low permeability, <100 nD) make them very difficult to measure using conventional core analysis methods (Ramirez et al. 2011; Handwerger et al. 2012; Busch et al. 2017). As a result, the porosity of unconventional reservoirs is often approximated using geophysical wireline logs.

### 5.6.2.3.1 Total porosity

Total porosity ($\phi_T$) is the ratio of total void space in a reservoir to its bulk volume (see Figs. 5.3 and 5.4). It is the combination of intergranular connected porosity, isolated (inaccessible) porosity, and apparent clay porosity (Byrnes 1997; Moore et al. 2016). A linear relationship between bulk density and porosity is commonly utilized to create a density porosity curve by rearranging Equation 8 (Davis 1954; Baker 1957):

$$\phi_D = \frac{\rho_b - \rho_{ma}}{\rho_{fl} - \rho_{ma}}$$

The matrix and fluid densities, $\rho_{ma}$ and $\rho_{fl}$, respectively, need to be assigned values to calculate $\phi_D$. A quartz matrix density of $\rho_{ma} = 2.65$ g/cm$^3$ and a fluid density of $\rho_{fl} = 1.00$ g/cm$^3$ (water) is commonly assigned. This, however, can be inappropriate in unconventional reservoirs like the Second White Specks Formation, which are mineralogically complex and contain unknown fluids. Matrix density must be determined from core, when available, and calibrated to cross-plots of other logging measurements (i.e., neutron porosity and bulk density). Fluid density, $\rho_{fl}$, should approximate mud
filtrate density ($\geq 1.00 \, \text{g/cm}^3$) due to filtrate invasion into the formation. Using this approach can be effective for generating reasonable porosity estimates (Byrnes & Castle 2000), although its application is restricted in petrophysical modelling approaches that rely on basic log suites (Moore et al. 2016). Barring borehole environmental concerns, organic content and clay minerals are the primary sources of petrophysical uncertainty in the Second White Specks when trying to calculate total porosity. Calculating total porosity with multiple independent parameters, such as with the neutron porosity and sonic logs, can help reduce this uncertainty to some extent (Ellis & Singer 2008).

Sonic logs can also be used to calculate porosity, with some caveats (Table 4.3). Organic mudstones can influence sonic porosity, depending on the density and volume of the clay minerals in the reservoir, as well as their level of compaction (Wyllie et al. 1956). Lower density and lower compaction rates increase sonic transit times, and result in higher sonic porosities (Glover 2000). This effect could be difficult to parse in an unconventional reservoir like the Second White Specks, which is compacted, but also rich in low-density organic material. Zee Ma et al. (2016) noted that acoustic logs are notoriously difficult to calibrate to reservoir properties compared to neutron and density logs. This suggests that sonic porosity should be used with caution in organic-rich reservoirs. Finally, neither Wyllie et al. (1956) or Raymer et al. (1980)’s method for calculating sonic porosity should be used without numerous core data points for calibration of matrix sonic transit time – this is not an option when core data is limited (Glover 2000).

The effect of clay minerals on neutron log porosity is well understood – emitted neutrons are slowed by contact with hydroxyls found in the clay structure, causing an increase in neutron porosity (see section 3.6.2.1.4). Mud filtrate invasion and hydrocarbons have similar effects (Glover 2000). Organic matter and thermal maturity impact apparent neutron porosity, but their influence is less pronounced on neutron porosity measurements compared to sonic porosity readings (Zee Ma et al. 2016). In organic-poor and clay-rich units, neutron porosity is typically greater than density in the range of 3 to 10%; however, organic-rich mudstones can have elevated neutron porosity in addition to elevated density porosity (Krygowski 2004). Without a priori knowledge of TOC and clay content, this
### Porosity equations

<table>
<thead>
<tr>
<th>Type</th>
<th>Equation</th>
<th>Remarks</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total porosity</td>
<td>( \phi_T = \frac{V_{pore}}{V_{bulk}} = \frac{V_{bulk} - V_{matrix}}{V_{bulk}} )</td>
<td>Porosity is a volume fraction</td>
</tr>
<tr>
<td>Total porosity</td>
<td>( \phi_D = \frac{\rho_b - \rho_{ma}}{\rho_{fl} - \rho_{ma}} )</td>
<td>Formula is derived from a mass-balance relationship</td>
</tr>
<tr>
<td>Density</td>
<td>where ( \rho_b ) is the measured density from logs, ( \rho_{ma} ) is the assumed matrix density and ( \rho_{fl} ) is the assumed fluid density (usually mud filtrate)</td>
<td></td>
</tr>
<tr>
<td>Total porosity</td>
<td>( \phi_S = \frac{\Delta t - \Delta t_{ma}}{\Delta t_{fl} - \Delta t_{ma}} \times \frac{1}{C_p} )</td>
<td>Measures connected interparticle porosity, works best in consolidated and compacted formations; cannot handle vugs</td>
</tr>
<tr>
<td>Compressional sonic</td>
<td>where ( C_p = \frac{\Delta t_{sh} \times c}{100} ) (compaction correction factor) and ( 1.0 &lt; C &lt; 1.3 ) depending on regional geology, and ( \Delta t_{sh} ) is the sonic transit time in the adjacent shale</td>
<td></td>
</tr>
<tr>
<td>Wyllie et al. (1956)</td>
<td></td>
<td>Good for carbonates when porosity is relatively uniform</td>
</tr>
<tr>
<td>Total porosity</td>
<td>Calculated by tool</td>
<td>Neutrons are slowed by collisions with hydroxyls (found in clays, pore fluid, drilling fluid)</td>
</tr>
<tr>
<td>Neutron</td>
<td>Tool measures size of neutron cloud by characterizing falloff of neutrons between two detectors</td>
<td></td>
</tr>
</tbody>
</table>
### Total porosity

**Compressional sonic**

Raymer *et al.* (1980)

\[
\phi_s = -\alpha - [\alpha^2 + (\Delta t_{ma}/\Delta t) - 1]^{1/2}
\]

where \(\alpha = \left(\Delta t_{ma}/2\Delta t_{fl}\right) - 1\)

Corrects for observed anomalies and shortcomings of the Wyllie equation; no need for compaction correction

Based on larger sample of measurements and accommodates the entire porosity range

Second-order model to be used when improved accuracy is key

---

**Density, kerogen-corrected**

Sondergeld *et al.* (2010) [24]

\[
\phi_{T_{KER}} = \frac{\rho_{ma} - \rho \cdot \left(\rho_{ma} \cdot \frac{w_{KER}}{\rho_{KER}} - w_{KER} + 1\right)}{\rho_{ma} - \rho_{fl}}
\]

where \(\rho_{ker} = 0.342 \cdot R_o + 0.972\)

and \(V_{ker} = \frac{\text{TOC} \cdot \rho_{ker}}{\rho\cdot\kappa}\) where \(K<1\)

Corrects for kerogen contribution to density log, resulting in a lower porosity estimate

---

** Effective porosity **

[25]

\[
\phi_E = \phi_T - V_{cl}(\phi_{cl})
\]

Corrects total porosity for porosity contribution from clay

---

** Effective porosity **

Density

Doveton (2014) [26]

\[
\phi_{DE} = \phi_T - V_{cl} \left(\frac{\rho_{dry\text{ clay}} - \rho}{\rho_{wet\text{ clay}} - \rho_{fl}}\right)
\]

Corrects total porosity for porosity contribution from specific clay minerals

---

Table 5.3: Table of total and effective porosity equations, with remarks related to their usefulness for unconventional reservoirs.
effect can be difficult to isolate without extensive local calibration in nearby organic-poor intervals. Neutron porosities, therefore, were not used in this study.

Some lithological effects on total porosity can be corrected for, like the presence of kerogen. Kerogen can have a significant impact on total porosity measurements that utilize the bulk density log – resulting in \( \phi_D \) values that are unrealistically high (Crain & Holgate 2014). Sondergeld et al. (2010) demonstrated that the kerogen contribution to total porosity could be suppressed by isolating the contribution of kerogen to the bulk density measurement. They did this by combining Equations 20 and 21 with Equation 23:

\[
\phi_{T_{KER}} = \frac{\rho_{ma} - \rho \ast \left( \rho_{ma} \ast \frac{W_{KER}}{\rho_{KER}} - W_{KER} + 1 \right)}{\rho_{ma} - \rho_{fl}} \tag{24}
\]

where \( \phi_{T_{KER}} \) is the kerogen-corrected total porosity.

### 5.6.2.3.2 Total porosity for the lower Colorado Group

For wells in which bulk density logs were available, total porosity was calculated using a matrix density of 2.74 g/cm\(^3\). This matrix density was selected using a neutron porosity-density cross-plot (Fig. 5.7), because core bulk density measurements were not available. Both the bulk density log (g/cm\(^3\); y-axis) and the neutron porosity log (v/v, x-axis) are measurements of total porosity – points of constant porosity in a given pure lithology will fall along a diagonal line. When a linear regression is plotted through the point cloud of porosity measurements and extrapolated back to a neutron porosity reading of 0% (the y-intercept), the line should intersect the y-axis at a bulk density measurement equivalent to a rock volume of 100%. The y-intercept should approximate the matrix density (Glover 2000). A matrix density of 2.74 g/cm\(^3\) is higher than quartz (2.65 g/cm\(^3\)) – it approaches either the bulk density of dry illite clay (2.79 g/cm\(^3\)), or a mixture of matrix minerals that could include dolomite (2.87 g/cm\(^3\)) and clay minerals in addition to low density organic matter (~1.15 g/cm\(^3\)).
Fig. 5.7: A multi-well crossplot with 1946 bulk density and neutron porosity data points from 5 wells (102/14-31-41-06W5, purple; 100/15-36-40-6W5, pink; 100/16-28-37-05W5, brown; 100/14-18-37-7W5, yellow; and 100/10-16-042-06W5, light green) throughout the Second White Specks and Belle Fourche intervals. The y-intercept of the regression is an estimate of the matrix density (100% rock volume) of the Second White Specks and Belle Fourche Formations.
The fluid density variable, \( \rho_{fl} \), was set to a constant value of 1.05 g/cm\(^3\) to approximate mud filtrate invasion into the formation. Fluid densities in the range of 1.02 to 1.125 g/cm\(^3\) were reported in the log headers of wells in the project area, and 1.05 g/cm\(^3\) approximated an average fluid density value. The total porosity was corrected for low-density kerogen using Equation 24 (Fig. 5.8). Furmann et al. (2014) provided the only available helium porosimetry data for the Second White Specks in the 100/07-19-45-06W5 well – this data was compared with the kerogen-corrected porosity model to test the model’s validity. The kerogen-corrected total porosity was a good approximation for the core data (Fig. 5.7), providing the necessary confidence to use \( \phi_{T,KER} \) going forward.

### 5.6.2.3.3 Effective porosity

Effective porosity (\( \phi_E \)) is the intergranular connected porosity, which ranges from 2 to 12% in tight gas sandstones (Byrnes 1997). Effective porosity does not include the immovable water bound to clays (Fig. 5.4), so effective porosity is always less than total porosity (Glover 2000). Doveton (2014) uses the following equation to reduce \( \phi_T \) to \( \phi_E \):

\[
\phi_E = \phi_T - V_{cl}(\phi_{cl})
\]  

[25]

where \( \phi_{cl} \) is the porosity associated with the immovable water bound to the clay volume fraction, \( V_{cl} \). To calculate \( \phi_{cl} \) for a specific clay mineralogy, \( \phi_{cl} \) can be calculated by using the dry (\( \rho_{dryclay} \)) and wet (\( \rho_{wetclay} \)) clay densities (Doveton 2014):

\[
\phi_E = \phi_T - V_{cl}\left(\frac{\rho_{dryclay} - \rho_b}{\rho_{wetclay} - \rho_{fl}}\right)
\]  

[26]

Clay densities vary depending on clay mineral type (esp. smectite) due to differences in surface area and clay-bound water content (Chitale 2010). Dry and wet clay densities can be determined in the laboratory on core samples by using XRD, or by using SGR log data (Schlumberger 2009).

### 5.6.2.3.4 Effective porosity for the lower Colorado Group

Equation 26 requires a valid estimate of wet and dry clay densities to calculate effective porosity – this can be problematic due to the wide range of densities that are possible for
Fig. 5.8: Histograms of uncorrected (above) and kerogen-corrected (below) modelled total density porosities from a selection of wells in the study area within the Second White Specks and Belle Fourche intervals, presented logarithmically.

Prior to the correction, the porosity was lognormally distributed. After the kerogen correction is applied, fewer porosities exceed 8%, so it appears that anomalously high total porosities have been largely suppressed.
clay minerals (Deer et al. 1966). Without detailed clay mineralogical data, (e.g., XRD), the only way to estimate clay mineralogy was with the Th/K curve from SGR logging in the target interval. This data was only available in the 100/02-14-38-06W5 well. Plotting this data on Schlumberger Chart Lith-2 (Fig. 5.9) shows that the Th/K data from the 100/02-14-38-06W5 well clusters largely within the mixed-layer clay field, which is defined by $12 < \text{Th/K} < 3.5$ (Schlumberger 2009). Figure 5.9 indicates that the clay mineralogy of the lower Colorado Group in well 100/02-14-38-06W5 approaches a mixed-layer (illite and smectite) composition, which corresponds to a $\rho_{\text{wetclay}}$ of 1.7 g/cm$^3$ and a $\rho_{\text{dryclay}}$ of 2.7 g/cm$^3$ (Chitale 2010). The calculated effective porosity is consistently less than the kerogen-corrected total porosity. Unlike the total porosity, which can be verified against routine core porosimetry analyses, verification of effective porosity requires special core analytical methods such as mercury injection tests (Burdine 1953). This type of core analysis was not available for this study.

5.6.2.4 QFM and carbonate mineral volumes

Jiang et al. (2017) demonstrated that mineral carbon (%) values from Rock-Eval could be used with confidence to estimate total carbonate in sedimentary rock samples:

$$V_{\text{dot}} = \frac{w_{\text{dot}}}{\rho_{\text{dot}}}$$

where $w_{\text{dot}} = \frac{23}{3} \text{TIC}$

where TIC is the total inorganic carbon (wt %), $V_{\text{dot}}$ is the carbonate volume fraction (v/v), $w_{\text{dot}}$ is the weight percent dolomite, and $\rho_{\text{dot}}$ is the density of dolomite (2.87 g/cm$^3$). Using Equation 28, the modelled carbonate volumes from TIC published carbonate data from Furmann et al. (2014), but only when the mineral assemblage was simplified to only include one carbonate mineral – dolomite. Although other carbonate minerals are contained within the lower Colorado Group, dolomite is the most volumetrically significant (5 to 30%) in the study area (Canadian Discovery 2014).

The Jiang et al. (2017) method cannot be applied to TOC data. Only TOC had been modelled for non-cored wells, so there was no way to calculate TIC for those wells. In
Fig. 5.9: This is a thorium vs. potassium % chart with data plotted in green from well 100/02-14-38-06W5. This data plots largely in the mixed-layer clay field, providing a basis for using a mixed-layer clay density for effective porosity.
order to calculate carbonate volume for non-cored wells, a relationship between carbonate volume and kerogen volume was established in wells with core (Fig. 5.10), which was calibrated to specific allomembers:

\[
\text{Allomember VII} \quad V_{\text{dot}} = 7.01 \times V_{\text{ker}} + 0.0168 \quad [29]
\]

\[
BF3 \quad V_{\text{dot}} = 24.8 \times V_{\text{ker}} + 0.476 \quad [30]
\]

The remaining mineral volume \( V_{\text{QFM}} \) was solved by rearranging Equation 16 to subtract the previously acquired volumes from unity:

\[
V_{\text{QFM}} = 1 - V_{\text{ct}} - V_{\text{carb}} - V_{\text{ker}} \quad [31]
\]

### 5.6.3 Britteness

Most unconventional reservoirs require flow capacity created by natural fracturing of brittle rocks to produce oil at commercial rates (Gale et al. 2007). Rocks exhibit brittle behaviour when they break without deformation under sufficient stress (Cho & Perez 2014). Knowing how brittleness varies with reservoir properties is key to identifying sweet spots where natural fractures are more likely to be present, and if hydraulic fracturing will effectively connect the borehole to the microporosity of the formation (Jarvie et al. 2007). Brittleness, however, is difficult to quantify (Fox et al. 2013; Cui et al. 2017) – it is a complex function of rock strength, lithology, texture, effective stress, pressure, temperature, fluid type, diagenesis, and TOC (Wang & Gale 2009; Rybacki et al. 2016). Determining an appropriate value for brittleness is a challenging task, because no universally accepted, standardized definition or measurement method for brittleness currently exists (Yang et al. 2013).

Since the first brittleness index was developed by Jarvie et al. (2007), a multitude of brittleness indices have emerged – each with different definitions and different results, even on identical samples (Yang et al. 2013). Three main varieties exist:

1) Static mechanical indices, based on direct measurements of rock strength on core (i.e., compressive, tensile, and residual strength; and fracture toughness) and strain relations (Heidari et al. 2013; Yang et al. 2013; Hu et al. 2015);
Fig. 5.10: The above graph displays a linear regression of carbonate volume computed from Jiang et al. (2017) in addition to carbonate XRD data from Furmann et al. 2014, versus modelled kerogen for wells 100/02-14-038-05W5, 100/07-19-045-06W5/00, 102/08-15-036-05W5/00, and 102/08-36-041-07W5/00.
2) Elastic moduli (Young’s Modulus and Poisson’s ratio), which are calculated from downhole measurements (P- and S-wave sonic logs) or seismic (Rickman et al. 2008; Jin et al. 2014a; Jin et al. 2015) and;

3) Lithological indices, based on weight or volume ratios of brittle minerals (Jarvie et al. 2007; Wang & Gale 2009; Katz et al. 2016; Mathia et al. 2016; Rybacki et al. 2016) – these indices are summarized and compared in Table 5.4.

5.6.3.1 Lithological brittleness indices

Lithological brittleness indices carry the assumption that brittleness is related to the relative abundance of brittle rock framework components and ductile components (Jarvie et al. 2007). Since fractures are supported by the matrix framework, matrix composition must be a fundamental part of any brittleness calculation (Cho & Perez 2014). It is generally accepted that brittle behaviour is enhanced in mudstone reservoirs with increased silica or carbonate content, because siliceous and calcareous minerals impart their brittle characteristics to their host rocks (Gale et al. 2014). In comparison, reservoirs rich in clay minerals and organic matter fail in a ductile manner when hydraulically stimulated, deforming the matrix and inhibiting fracture propagation (Fox et al. 2013).

Mineralogical brittleness indices are popular due to their relative simplicity and associated with lithology, which can be determined from core, cuttings, or logs (Cui et al. 2017). Lithological brittleness indices do not incorporate texture or rock fabric, which can impact brittle rock behaviour (Katz et al. 2016). These types of indices are, in effect, more of a brittle rock-type indicator than a direct measure of mechanical brittleness. All mineralogical-based definitions result in a higher brittleness index assigned to quartz-rich rocks than clay-rich lithologies (Herwanger & Mildren 2015), thereby highlighting zones that are more easily hydraulically fractured (Mathia et al. 2016). Carbonate minerals, especially dolomite, can further increased brittle rock behaviour, although the relative contribution of carbonate minerals to brittleness is less than that of quartzose lithologies (Mathia et al. 2016). Britteness indices that include dolomite as a ductile component rather than a brittle component (e.g., Jarvie et al. 2007), therefore, will underestimate the brittleness of dolomitic reservoirs.
## Mineralogical brittleness indices

<table>
<thead>
<tr>
<th>Author</th>
<th>Equation</th>
<th>Remarks</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jarvie <em>et al.</em> (2007)</td>
<td>( BI = \frac{W_Q}{W_Q + W_{cat} + W_{ct}} )</td>
<td>First lithological brittleness index&lt;br&gt;Only quartz is considered brittle&lt;br&gt;Uses wt %</td>
</tr>
<tr>
<td>Wang and Gale (2009)</td>
<td>( BI = \frac{W_Q + W_{dot}}{W_Q + W_{dot} + W_{lm} + W_{ct} + W_{TOC}} )</td>
<td>Considered dolomite brittle, limestone ductile&lt;br&gt;Added TOC wt %&lt;br&gt;Does not account for low density of organic matter</td>
</tr>
<tr>
<td>Jin <em>et al.</em> (2014a); Jin <em>et al.</em> (2014b)</td>
<td>( BI = \frac{W_{QFM} + W_{carb}}{W_{tot}} )</td>
<td>Included all effective minerals (feldspar and mica)&lt;br&gt;All siliceous and carbonate minerals considered brittle</td>
</tr>
<tr>
<td>Katz <em>et al.</em> (2016); Mathia <em>et al.</em> (2016)</td>
<td>( BI = \frac{V_{QFM} + V_{dot} + V_{cat}}{V_{QFM} + V_{dot} + V_{cat} + V_{ct} + V_{KER}} )</td>
<td>Uses volume % instead of wt % to compensate for low density of kerogen</td>
</tr>
<tr>
<td>Rybacki <em>et al.</em> (2016)</td>
<td>( BI = \frac{a(V_{sb})}{a(V_{sb}) + b(V_{carb}) + c(V_{wa}) + d\phi} )</td>
<td>Includes pyrite as a brittle mineral&lt;br&gt;Uses weighting factors to compensate for deformation conditions and relative mechanical strength&lt;br&gt;Includes porosity (v/v)</td>
</tr>
</tbody>
</table>

Table 5.4: Table of mineralogical brittleness indices in chronological order, with their associated innovations and limitations. Compiled from Jarvie *et al.* (2007), Wang and Gale (2009), Jin *et al.* (2014a); Jin *et al.* (2014b), Katz *et al.* (2016); Mathia *et al.* (2016) and Rybacki *et al.* (2016).
Most of the brittleness indices shown in Table 5.4 do not account for differences in the relative contributions of different minerals (i.e., carbonate) to brittle rock behaviour (Gale et al. 2014; Hu et al. 2015). This suggests that weighting factors, such as those used by Rybacki et al. (2016), should be included to compensate for the relative differences in mechanical strength between different minerals. Defining these weighting factors would require extensive calibration to rock mechanical measurements from core in the study area – this type of data was not available, so a weighted brittleness index was not used.

Although Mathia et al. (2016) did not observe a difference between brittleness values that were calculated using volume versus weight percent, Rybacki et al. (2016) noted that in organic-rich shales, the difference in mineral fractions in volume versus weight percent may reach up to 8% in the case of organic matter (low density) and pyrite (high density). Moreover, the volume fractions and relative distributions of minerals with different brittleness likely exert control on the ability of the rock matrix to develop and maintain open fractures (Rybacki et al. 2016). This suggests that brittleness indices that rely on weight percentages (e.g., Jarvie et al. 2007; Wang & Gale 2009; Jin et al. 2014a,b) should not be used in reservoirs that contain large proportions of low density or high density minerals (i.e., organic-rich mudstones).

If the volume and distribution of minerals with different brittleness throughout a reservoir impacts fracture propagation and preservation, the role of porosity in brittle behaviour must also be considered. The role of porosity in brittle behaviour (poroelasticity) is controversial: Heidari et al. (2013) and Mathia et al. (2016) did not observe any evidence for a correlation between brittleness indices and porosity. Jin et al. (2014a,b), however, observed a negative relationship between neutron porosity ($\phi_N$) and brittleness ($BI$). They proposed a global correlation of:

$$BI = -1.8748 \times \phi_N + 0.9679$$

[32]

where $BI$ is the brittleness index in volume %. This relationship suggests that lower porosity rocks have higher brittleness. Similarly, Cho and Perez (2014) showed that highly porous rocks are geomechanically weak, as they easily fail and fracture. A mineralogy-based brittleness index that incorporates porosity is in the early stages of
development (Rybacki et al. 2016), but its practicality and applicability need to be better established due to its reliance on weighting factors. Uncertainty clouds the role of porosity in brittle behaviour. Porosity, therefore, was not included in the brittleness calculation used in this study. Despite their problems, mineralogical brittleness indices can provide necessary insight into fracability when data is limited, provided that volumetric mineralogy can be estimated and adequately calibrated to core.

5.6.3.2 Application of brittleness indices to the lower Colorado Group

The lithological brittleness index described by Mathia et al. (2016) was the best fit for the lower Colorado Group dataset, as it included carbonate minerals as a brittle component. Moreover, this index includes components that can be estimated using the limited log suite available in this study. The index was modified to include dolomite as the sole carbonate mineral and makes the assumption that only quartz and carbonates contribute to brittle behaviour. Using the petrophysical models calculated in section 4.6.2, the following brittleness index was calculated, on a zonal basis, for wells in the study area:

\[
BI = \frac{V_{QFM} + V_{dot}}{V_{QFM} + V_{dot} + V_{clay} + V_{ker}}
\]  

5.7 Mapping

5.7.1 Spatial interpolation

For the purposes of mapping, the petrophysical model parameters were reduced to a single value over each allomember via a thickness weighted average in the Techlog Summaries module. The weighted averages were imported as a comma-separated values file (.csv) into geoSCOUT to create irregularly spaced grids of data points that were exported to the Golden Software™ Surfer 14 program, a data visualization and mapping software. To ensure each map was generated with identical parameters and could be used for consistent grid calculations, identical grid geometries were used for each map (Fig. 5.11).

Raw, irregularly spaced data must be spatially interpolated into a regularly spaced grid prior to geological mapping (Dubrule 1983). Gridding algorithms estimate values at grid
Solving the Second White Specks

5. Petrophysical method

Fig. 5.11: A screenshot from Surfer of the grid geometry parameters used for mapping in this study. Using identical grid geometries for each contour map ensured they could be accurately overlain and compared to each other.
nodes based on weighting functions that vary according to the interpolation method. Once grid node values (z-coordinates) are assigned to regularly spaced x and y coordinates, the mapping software treats the grid file (x, y, z) as a continuous surface. These surfaces can be used for mathematical operations and contour mapping (Jones et al. 1986). Common spatial interpolation methods include kriging, nearest neighbour, natural neighbour, and spline methods (Davis 2002). This study utilized a kriging algorithm.

First introduced by Krige (1951), kriging is a gridding method that is widely utilized for computer mapping in the earth sciences and other fields. The characteristics of semi-variograms, a measure of the variance between observations as a function of the distance between them, are utilized by kriging algorithms to estimate values for the regularly spaced grid nodes based on the weighting of irregularly spaced well data (Jones et al. 1986). Kriging methods explicitly account for the degree of spatial dependence between data points, known as spatial autocorrelation (Clark 1979). A spatially autocorrelated data point is assumed to be closely related to values at nearby points, and less closely related to points that are further away (Davis 2002).

Nearest neighbour interpolation methods assign grid node values by using the closest data point, or “nearest neighbour”, to interpolate data. This procedure extends the area of influence of each value halfway to the closest adjacent data point, thus defining polygons with a value at the center (Jones et al. 1986). This method is most effective for regularly-spaced dataset, as each polygon is equally weighted. Otherwise, local variations may be over- or under-represented (Davis 2002). Well data is not equally spaced in this study, so the nearest neighbour method was not recommended.

By developing a weighted average from neighbouring points, natural neighbour methods can more accurately represent local spatial variation. Natural neighbour methods are superior to nearest neighbour algorithms for irregularly spaced data (Sibson 1980). As the natural neighbour method cannot be used to extrapolate data (Sibson 1980), natural neighbour methods were not used in this study.

Spline functions interpolate between data points by connecting them with a smooth, continuous line that minimizes overall surface curvature (Davis 2002). This is a
nongridding interpolation method that can predict values that are less or greater than the values of existing control points, due to the flexure of the spline function applied (Burrough 1986). Despite honouring all control points, spline interpolation methods have issues delineating local variation (Burrough 1986). Additionally, when used for surface-to-surface operations, spline functions can produce artefacts that may not be based in reality, such as negative values for thickness or porosity (Davis 2002).

Although kriging has been historically criticized due to its supposed subjectivity and perceived inability to provide accurate predictions compared to other interpolation methods (Philip & Watson 1986), it is now broadly accepted and is an option in most geostatistical mapping programs. Error variances of kriging estimates are the minimum possible of any existing linear interpolation method, and the error can be approximated at the location of each kriging estimate (Nagy et al. 1999; Davis 2002). This provides a concrete expression of the uncertainty associated with a contoured surface. Finally, kriging can be used to estimate grid node values in a way that simulates manual or hand contouring, because both methods account for spatial autocorrelation (Dahlberg 1975; Dutton-Marion 1988). Using a kriging algorithm afforded increased confidence in the reliability of the contoured data.

5.7.2 Surface-to-surface operations

The four allomembers mapped in this study are presented as isochore (equal vertical thickness) and structure maps. Isochore maps were generated in Surfer by subtracting bounding surfaces (structural surfaces) from each other, as follows:

\[
\text{Isochore} = \text{base} - \text{top}
\]

where the isochore thickness is the difference in the subsea elevations of the top and base of a stratigraphic unit. Isochore maps were used in this study to identify areas of increased or decreased stratigraphic thickness, thereby establishing the geometry of specific allomembers. Isochore maps were also used to create porosity-thickness maps by multiplying the thickness values by the weighted average of effective porosity.
Isochore maps are often used in lieu of isopach (equal true thickness) maps because, for vertical wells, the isochore is equivalent to the drilled distance along the well trajectory from the top to the bottom of the stratigraphic interval of interest. If a vertical well intersects a dipping (sub-horizontal) unit, the measured apparent thickness of a geological unit will increase — using isochore thickness rather than isopach thickness allows for thickness map generation without needing to correct for apparent bed thickness. Equation 35 shows the conversion from isochore thickness to isopach thickness:

\[ Isopach = \cos \theta (Isochore) \]  

For units with shallow dip (<15°) — as is the case in the study area — isochore thickness approximates isopach thickness because \( \cos \theta \) is greater than 0.97 (Hesthammer 1998; Lisle 2004). Once property maps were generated, anomalous values (“busts” or “bullseyes”) were isolated and either verified or excluded on the basis of geophysical data quality.

Storage capacity can be estimated by calculating reservoir or porosity thickness using the following relationship (Tiab & Donaldson 2012):

\[ \phi \ast h = \phi_E \ast Isochore \]  

where \( \phi_E \) is the thickness weighted average of effective porosity over an interval and \( h \) is the isochore thickness.

Faults were not mapped in this study due to a lack of spatial resolution; areas that are faulted are not recognized by the kriging algorithm as discrete bounding surfaces (Davis 2002).

### 5.8 Analysis

The goal of this thesis was to investigate the possible connection between well performance from Second White Specks-targeted wells and variations in mappable petrophysical properties via sweet spot identification. Sweet spots are arbitrarily defined regions of a mudstone reservoir that have higher reservoir quality and production
Solving the Second White Specks

5. Petrophysical method

potential (Glaser et al. 2013). Sweet-spotting is a subjective technique that is driven largely by the desired result of the interpreter, and can overlook the value of the entire area if the focus is too small (Haskett 2014). If the study area is too small, regional geologic controls on reservoir properties may not be adequately characterized. By evaluating the entire study area prior to sweet spot identification, this thesis intended to avoid these issues.

Co-location pattern mining is an algorithm that can identify regions of different physical properties that are closely located or overlapping (i.e., co-located), with the goal of modelling the spatial correlation between the two features (Sengstock et al. 2012). This process has clear parallels to sweet spot identification, which seeks to identify areas where favorable reservoir properties overlap with increased hydrocarbon production. Analyses of co-location are frequently done with categorical datasets in the fields of natural science and geography – but in this study the modelled data is in the form of continuous random variables, so features are not discrete (Eick et al. 2008). Isolating “interesting” regions of petrophysical parameters requires meaningful boundary conditions on the continuously modelled data, like cutoffs related to enhanced reservoir quality (e.g., total porosity < 8%). Once these cutoffs are applied, isolated regions of interest (instances of co-location) can be recognized via overlapping polygons (Eick et al. 2008). Cartographic representations like this are an effective and easily communicable data visualization method for co-location pattern identification (Desmier et al. 2011).

In this study, co-location pattern mining was simulated by using cutoffs to identify overlapping sweet spots – regions with enhanced reservoir quality (porosity-thickness and brittleness) that were spatially associated with improved well performance. The resulting polygons are effectively Boolean AND operators for well data within them. For a well to reside within a sweet spot, it must meet at least three conditions: it must have enhanced porosity-thickness, brittleness, and hydrocarbon production.

5.9 Highlights

- Sparse core data and a limited geophysical wireline log dataset present the main procedural challenges to petrophysical modelling in this thesis.
• Mineral volumes were modelled using a deterministic method wherein each volume was independently calculated and input into a five-component petrophysical model. A lithology-based brittleness index was used to estimate variations in brittle rock behaviour.

• Sweet spot delineation was achieved by overlaying areas with enhanced porosity-thickness and brittleness with oil production results.
Chapter 6

6. Allostratigraphic correlation of the Lower Second White Specks and Upper Belle Fourche alloformations in the Willesden Green – Gilby region, Alberta, Canada

6.1 Overview

This chapter presents the results of core logging and high-resolution allostratigraphic correlation of the Lower Second White Specks and Belle Fourche alloformations in the Willesden Green area of west-central Alberta. A shallow muddy ramp is introduced as a depositional model for the Second White Specks and Belle Fourche alloformations.

6.2 Allostratigraphic framework

The study area overlaps with Tyagi et al. (2007)’s high-resolution allostratigraphic study of the Blackstone Formation. Tyagi et al. (2007) mapped nine regionally correlative flooding surfaces that bound eight allomembers in the Sunkay and Vimy Members of the Blackstone Formation over an area of 200,000 km². Of those allomembers, three fell within the stratigraphic interval of interest for this study (Fig. 6.1). The surfaces used to constrain those allomembers are the X-flooding surface, the K-1 unconformity, the “red” bentonite, and an unnamed flooding surface above the red bentonite. These surfaces exhibited negligible topographic relief over Tyagi et al. (2007)’s study area, suggesting that unit was deposited on a sea floor with extremely low gradient. This is inferred from the lack of shelf-slope physiography and little to no clinoform development, which is typical of a shallow, epicontinental ramp setting (Asquith 1970; Varban & Plint 2005; Midtkandal et al. 2007; Varban & Plint 2008a).

The X-flooding surface, K1 disconformity, and the “red” bentonite were traced by Tyagi et al. (2007) from Townships 23 to 58, originating northeast of Grande Cache in British Columbia and extending through the Alberta Foothills, and terminating in western Saskatchewan. The X and K1 surfaces, defined by Plint (2000), were traced into the Foothills of British Columbia and the Peace River area by Kreitner (2002). The X-flooding surface is an important regional transgressive surface that is linked to major
Fig. 6.1: Correlation of the allostratigraphic framework used in this thesis (left) to the framework used by Tyagi et al. (2007), using the K1 disconformity as a datum. Dashed lines indicate the extension of the framework used in this thesis into Tyagi et al. (2007), and vice versa.
lowstand units of the Kaskapau Formation that were mapped by Plint and Kreitner (2005). The K1 surface is a major beveling unconformity in northwest Alberta, but becomes a transgressive disconformity within central Alberta (Plint 2000; Kreitner & Plint 2006) – it coincides with the top of the Pouce Coupe sandstone in northeastern Alberta (Varban & Plint 2005).

The “red” bentonite, which approximates the Cenomanian-Turonian boundary, has been traced by Tyagi et al. (2007) and others throughout 235 000 km² in Alberta and British Columbia (Stott 1963; Varban 2004; Varban & Plint 2005; Varban & Plint 2008a; Tyagi 2009; Plint et al. 2012a). Allomembers of Unit II (lower Kaskapau alloformation) from Varban and Plint (2005) progressively downlap onto the top of the “red” bentonite towards west-central Alberta. Extending the correlations of Varban and Plint (2005), Tyagi (2009) interpreted the “red” bentonite surface as a basin-wide hiatal surface that occurred during the onset of the Early Turonian – he estimated that the hiatal surface represents approximately 500 Kyr of missing time. These observations were corroborated by Plint et al. (2012a): they observed the expression of this hiatal surface as a minor unconformity that was correlated from Mount Robert in northeastern British Columbia into northwestern Alberta (well 15-34-77-1W6).

The 100/07-19-045-06W5 core and the type well extracted from by Tyagi et al. (2007) were used to extend the allostratigraphic framework developed by Tyagi et al. (2007) into the lower Colorado allogroup in the Willesden Green and Gilby areas by correlating the major bounding surfaces (the X-flooding surface, the K1 disconformity, and the “red” bentonite) through a coarse grid (1 well per township) of wells. These correlations were used to determine the vertical stratigraphic placement of Second White Specks and Belle Fourche Formation cores in the study area.

Tyagi (2009) subdivided the lower Colorado Group was subdivided into three alloformations above the Fish Scales Formation: the Lower and Upper Belle Fourche alloformations, and the Second White Specks alloformation. The Upper Belle Fourche alloformation was further subdivided by this author into three allomembers (BF1, BF2, and BF3). Similarly, the Second White Specks alloformation was subdivided by this
author into two allomembers (allomembers VII and VIII). Of these units only allomembers VII, BF2, and BF3 were completely present in cores that were logged within the study area. Emphasis was placed on these allomembers due to their spatial association with the typical “Second White Specks” reservoir interval.

6.3 Lower Colorado Group facies

Dalrymple (2010a) defines facies as:

“...[bodies] of rock characterized by a particular combination of lithology, physical, and biological structures that bestow an aspect different from the bodies above, below, and laterally adjacent.”

Facies are controlled by the sedimentary processes operating in the depositional environment where they are deposited. Describing facies, therefore, is essential for the interpretation of depositional processes (Catuneanu 2006).

Many authors have described facies of the Belle Fourche and Second White Specks Formation and their equivalents (Stott 1963, 1984; Leckie et al. 1994; Plint 2000; Kreitner 2002; Fraser 2005; Varban & Plint 2005; Tyagi et al. 2007; Varban & Plint 2008a; Tyagi 2009; Yang & Miall 2009, 2010; Plint et al. 2012b; Jiang 2013; Jiang & Cheadle 2013). Although high-resolution allostratigraphy of the entire lower Colorado alloformation was out of scope for this project, defining facies and determining their distribution across the study area was an essential step in establishing reservoir geometry. Five facies were identified in core (Table 5.2), and were differentiated on the basis of composition, clay content, grain size, sedimentary structures, and bioturbation (Figs. 5.2 and 5.4).

The facies of the Second White Specks and Belle Fourche alloformations in this thesis (Table 5.1) were derived from observations made from six cored wells: 102/08-15-036-05W5, 100/02-14-038-05W5, 100/04-27-39-06W5, 102/08-36-041-07W5, 100/16-28-041-04W5, and 100/07-19-045-06W5. The first five of these cores were logged and sampled in detail at the Alberta Energy Regulator (AER) Core Research Centre in Calgary, Alberta (Fig 5.2). This process included describing the visible lithology, grain
Core cross-section through the Second White Specks and Belle Fourche alloformations in Willesden Green, Alberta

Fig. 17: An approximately 1:1 scale cross-section core cross-section showing the Fish Fourche alloformations and Belle Fourche alloformations logged by this author. Core photos are included for reference to facies.
Fig. 6.3: An approximately south-to-north oriented cross section displaying the available LAS data for cores in the study area.
## Table 6.1: Facies Codes and Depositional Environments

<table>
<thead>
<tr>
<th>Facies</th>
<th>Description</th>
<th>Depositional Environment (Facies association)</th>
<th>Relative advection energy</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Bentonite beds</td>
<td>Bentonite ashfall Dispersed by wind and water currents</td>
<td>-</td>
</tr>
<tr>
<td>2</td>
<td>Very dark grey, planar-laminated mudstone interbedded with siltstone</td>
<td>Distal offshore shallow ramp Influenced by combined flows, ~70 m water depth Anoxic bottom water</td>
<td>Low</td>
</tr>
<tr>
<td>3</td>
<td>Weakly bioturbated, medium-grey laminated mudstone, interbedded siltstone, and very fine-grained sandstone</td>
<td>Offshore shallow ramp Influenced by combined flows, 40 to 70 m water depth Dysoxic bottom water</td>
<td>Intermediate to low</td>
</tr>
<tr>
<td>4</td>
<td>Wavy to planar-laminated calcareous mudstone, siltstone, and fine-grained sandstone</td>
<td>Offshore shallow ramp Influenced by combined flows, 40 to &lt;70 m water depth Variably dysoxic bottom water</td>
<td>Intermediate</td>
</tr>
<tr>
<td>5</td>
<td>Wavy to undulating laminated calcareous siltstone and fine-grained sandstone with frequent lag deposits</td>
<td>Marginal offshore to mid-shelf shallow ramp Influenced by combined flows, &lt;40 m water depth Variably oxic to dysoxic bottom water</td>
<td>High</td>
</tr>
</tbody>
</table>

Table 6.1: The facies codes used in this thesis, along with their descriptions and associated depositional environments. Facies colours reflect the colours used in later cross-sections to indicate those facies. Vertical shifts in facies indicate lateral shift in depositional environment, which are interpreted to be driven by changes in relative advection energy.
size, composition, sedimentary and structural features, as well as the trace fossil assemblages. The graphic logs from the logged cores are illustrated in Fig. 6.2. The geophysical well logs associated with these cores (Fig. 6.3) were used to help identify major compositional changes in the core and tie those changes to their respective log signatures. This evidence will be discussed in section 6.5, after the facies have been described.

6.3.1 Facies observed in core

The following observations of facies and their accompanying descriptions are derived from the five cores logged for this study and was supplemented with data from the 100/07-19-045-06W5 core. From these observations, five facies were identified and related to a shallow marine muddy ramp environment.

6.3.1.1 Facies 1: bentonite beds

Facies 1 contains bentonite beds that are white to grey in colour, and range in thickness from 5 to 40 cm. The bentonites were typically soft and very powdery, suggesting that the measured thicknesses may not be representative of their true vertical thickness in the subsurface (the core may not have achieved 100% recovery).

Elder (1988) determined that his B bentonite, which correlates with the Bighorn River “red” bentonite of Tyagi et al. (2007), was derived from the western Cordilleran orogenic belt near the border between the United States and Canada. The time interval around the Cenomanian-Turonian boundary coincided with a major period of pluton emplacement in the western Cordillera (Chen & Moore 1982). Elder (1988) interpreted his B bentonite as the reflection of an ashfall event that was primarily dispersed by wind in an overall north-to northwest wind direction, based on its geometry (uniform thickness) and a lack of evidence for physical reworking of the bentonite.

Facies 1 is interpreted as the record of volcanic ashfall from an eruption in the western Cordillera that dispersed smectite-rich clays across a shallow marine ramp in west-central Alberta. Although the bentonite did not appear to be physically reworked or bioturbated, it does vary in thickness between the cores from the study area – suggesting that currents
may have contributed to bentonite redistribution and therefore were within storm wave base for silt (<70 m water depth). Ash dispersion was likely facilitated by a combination of wind- and current-related processes. Because the “red” bentonite is concomitant with OAE-II, the bentonite facies was likely deposited during a marine transgression when biotic activity was relatively low.

6.3.1.2 Facies 2: Very dark grey, planar laminated mudstone

Facies 2 is a mudstone facies that contains a relatively low proportion of silt (<5 to 25%), as well as rare disseminated pyrite grains (<1%) – sand is not present in this facies. Rocks of facies 2 are typically very dark grey in colour, consist of very thin (1 to 2 cm) normally graded beds, and lack evidence of bioturbation. Normally graded siltstone laminae are either planar laminated or discontinuous. Discontinuous fish scale and shell fragment lags were occasionally observed and were always less than 5 mm thick. Reverse graded beds were encountered in 102/08-15-036-05W5 but were not observed in other wells. Individual beds are sharp-based, occasionally with sharp scours. Bivalve shells and shell fragments (< 2 cm long, 5 mm wide) were frequently encountered. Isolated siderite concretions, ranging from 5 mm to 1 cm in size and ellipsoidal in shape, were also observed. Measured TOC in this facies ranged from 1.75 to 2.5%.

Planar lamination in sandstones is typically developed directly above the erosional, scoured bases of storm beds (Cheel 1991). Petrographical studies such as Macquaker et al. (2010) and Plint et al. (2012a) have demonstrated that planar laminae in mudstones are often internally cross-laminated. These beds, therefore, represent cycles of advective sedimentation – possibly during storms – that are delimited by periods of erosion or non-deposition, rather than passive settling in a low-energy environment (Trabucho-Alexandre 2015).

In shallow marine environments where oxygen is readily available, laminated sediments will only be preserved when sedimentation rates are especially high (1.0 to 10 cm/y) – such as in a delta front or inner shelf setting (Nittrouer et al. 1986). Tyagi (2009), however, demonstrated that sedimentation rates for his laminated mudstone facies in the Blackstone Formation were exceedingly low (< 5 cm/Kyr) and therefore could not have...
been deposited in an oxic setting. In anoxic marine environments, the mudstone laminations are preferentially observed when bioturbation is absent (Byers 1974). Laminated, nonbioturbated, and organic-rich mudstone successions are typically interpreted as the record of fine-grained sediment deposition in variably anoxic, low-energy settings (Demaison & Moore 1980), although Plint et al. (2012a) showed that similar successions can be deposited by advective means.

Authigenic minerals are derived from pore water solutes, so their compositions (e.g., siderite and pyrite) should reflect the pore water chemistry where they precipitate (Curtis & Coleman 1986). Pyrite, a common sulfide mineral in lower Colorado Group mudstones (Bloch et al. 1999), is an early diagenetic mineral that forms depending on the amount of available organic matter, dissolved sulfate, and reactive iron minerals (Berner 1984). Diagenetic pyrite is most commonly formed and preserved in anoxic environments (Berner 1984), although pore waters were likely only anoxic at a depth of a few millimeters below the sediment/water interface (Hudson & Martill 1991). Siderite is an iron carbonate mineral that occurs in lower Colorado Group mudstones as concretions (Bloch et al. 1999). Siderite concretions document the activity of anaerobic, methane-producing bacteria at the sediment/water interface (Curtis et al. 1972). Similar to pyrite, the precipitation of siderite concretions requires the development of strongly reducing, or dysaerobic, bottom water conditions (Fritz et al. 1971). Other early diagenetic features, such as early cementation, have been interpreted as the record of significant hiatuses in sediment accumulation related to sediment bypass and winnowing of the seafloor (Macquaker et al. 2007).

Facies 2 is interpreted as the distal expression of mud and silt deposited by combined flows along a distal shallow ramp setting. Deposition occurred in an anoxic marine environment that was below storm wave base for sand, and variably within storm wave base for silt and mud (70 to 100 m water depth). This is evidenced by the lack of sandy beds and bioturbation. The presence of pyrite and siderite, which are early diagenetic minerals, suggests that the bottom water conditions were at least dysoxic if not anoxic.
6.3.1.3 Facies 3: Weakly bioturbated, medium-grey laminated mudstone, interbedded siltstone, and very fine-grained sandstone

Facies 3 is coarser-grained than facies 2. It is a mudstone facies that is interbedded with 25 to 40% silt, and 0 to 5% very fine sand. Rocks of facies 3 are lighter grey than facies 2 and comprise thin (1.5 to 3 cm) normally graded beds with scoured bases. Beds are typically planar laminated but may exhibit subtle cross-stratification. The tops of some individual beds are partially or weakly churned by sub-horizontal burrowing. Lenses of very fine sand are rare, but when they appear they contain subtle cross-laminations, mud flasers, and are typically oil-stained (Fig. 6.2F). Like facies 2, fish scale and shell fragment lags were occasionally observed and were always less than 1 cm thick – these lags are more continuous than those observed in facies 2. Sideritic concretions were common throughout this facies. Small, ellipsoid rip-up clasts (<4 mm) were observed in this facies as a mm-thick lag horizon in the 102/08-15-036-05W5 well. Bivalve shells and shell fragments (< 2 cm long, 5 mm wide) were frequently encountered. Measured TOC in facies 3 ranged from 2 to 3.75%.

Across mud-dominated shelves, sand is rare and confined to storm-associated laminae on the inner shelf (Plint 2010). This is because higher oscillatory wave velocities are required to entrain sand grains, relative to finer-grained silt or mud-sized particles. Low unidirectional flow velocities (<10 cm/s) and intermediate oscillatory current velocities (20 to 50 cm/s) are required to form symmetrical and asymmetrical wave ripples in very fine sand (Dumas et al. 2005).

Fluid mud deposition inhibits benthic colonization, so bioturbation of muddy shelf sediments is normally rare. Combined flows associated with geostrophic flows and storms can erode partially consolidated mud, which can then be burrowed – this produces a succession of mud sequences that are capped by scoured and burrowed surfaces (Rine & Ginsburg 1985; Kuehl et al. 1996).

The presence of very fine sandy lenses and interbeds with subtle cross-stratification suggest that deposition of facies 3 occurred between the storm wave base for sand and silt (40 to 70 m water depth). Sandy interbeds indicate sand emplacement during storms,
whereas silty and muddy laminae record the waning phase of storms and periods of time when slightly lower-energy advective flows dominated. Sub-horizontal burrows at the tops of some beds suggest sedimentation was punctuated by periods of erosion, during which the sediment/water interface became dysaerobic and benthic colonization could take place. Overall, facies 3 is interpreted as a slightly shallower water facies than facies 2 and was deposited within an offshore shallow ramp setting.

6.3.1.4 Facies 4: Wavy laminated calcareous mudstone, siltstone, and fine-grained sandstone

Facies 4 is coarser-grained than both facies 2 and 3: it is a calcareous mudstone that is interbedded with greater than 40% silt, and 5 to 10% very fine and upper fine-grained sand. Sequences within facies 4 comprise packages (~3 cm thick) of alternating fining-upwards and coarsening upwards beds, although the majority of beds are fining upwards. Like facies 2 and 3, these beds have scoured bases (Fig. 6.2A) that may develop into small-scale gutter casts (5 by 10 cm). Fig. 6.2H depicts a steeply-dipping erosional scour in this facies that contains a relatively coarse, bioclastic lag horizon. Some individual beds are well churned by sub-vertical and vertical burrows (Fig. 6.2G) – in those cases, primary sedimentary structures are partially obliterated. In other cases, however, bioturbation is weak or non-existent (Figs. 6.2A, 6.2B). Lenses and interbeds of very fine sand and exceptionally upper fine-grained sand are more common than in facies 3, comprising more than 40% of this facies. Weakly convoluted or disturbed bedding, which sometimes appeared to have been partially lithified prior to deformation was occasionally observed, as well as small load casts (< 5 mm) at the bases of some beds. Like facies 2 and 3, fish scale, shell fragment, and sideritic nodule lags were occasionally observed and were always less than 1 cm thick. Bivalve shells and shell fragments (< 2 cm long, 5 mm wide) were frequently encountered. Measured TOC in facies 4 ranged from 1.5 to 3.5%.

Soft-sediment deformation structures in clastic sediments are defined by Shanmugam (2017) as “features that form before lithification of sediments and that form under a state of liquidization.” For soft-sediment deformation to occur, a threshold value must be exceeded: for instance, the gradual accumulation of dense sediment on top of less dense, water-saturated sediment can initiate water-escape and the formation of load casts (van
Solving the Second White Specks

6. Core-log correlation and allostratigraphy

Loon 2009). Soft-sediment deformation is associated with a wide range of sedimentary environments worldwide, and over 120 types of soft-sediment deformation have been characterized (Shanmugam 2017). Convolute bedding, in particular, is a type of soft-sediment deformation associated with the response of cohesive plastic sediment to bottom currents (Dzulynski & Smith 1963; Shipboard Scientific Party 1998).

Facies 4 comprises a higher percentage of coarser-grained sediment than facies 2 and 3 and is more frequently bioturbated. This suggests that deposition of facies 4 occurred in shallower water than the preceding facies while remaining within the transition zone between storm wave base for sand and silt (40 to 70 m water depth). Convolute bedding and soft-sediment deformation structures could indicate partial liquidization of unconsolidated muddy substrate. For the same reasons discussed for facies 3, facies 4 is interpreted as a slightly shallower water facies than facies 2 and 3 and was deposited in an offshore shallow ramp setting.

6.3.1.5 Facies 5: Wavy to undulating laminated calcareous siltstone and fine-grained sandstone

Facies 5 consists of the coarsest-grained sediments of all the described lower Colorado Group facies. It is a calcareous siltstone interbedded with upper fine-grained quartz sand as well as occasional carbonate sand grains. The soft-sediment deformation structures described for facies 4 are also present in facies 5, but are more common (Figs. 6.2C, 6.2D). Sequences within facies 5 comprise cm-scale packages of fining-upwards beds. The tops of these sequences are frequently burrowed and are typically capped with a thin (< 5 mm) layer of black mudstone. Like facies 2 through 4, 1 to 2 cm thick fish scale, shell fragment, and sideritic nodule lags were frequently observed, and sometimes occurred repeatedly. A large siderite nodule was encountered in the 100/04-27-39-06W5 well (Fig. 6.2E). Measured TOC in facies 4 ranged from 2.5 to 4%.

Relative to the preceding facies, facies 5 comprises the highest percentage of coarse-grained sediment and is the most frequently bioturbated. This suggests that deposition of facies 5 occurred in shallower water than the preceding facies and approached storm wave base for sand (~40 m water depth), where the bottom water was variably
oxygenated. Numerous lag horizons suggest repeated periods of sediment winnowing and erosion by storms and combined flows. Convolute bedding and soft-sediment deformation structures could indicate partial liquidization of unconsolidated muddy substrate during advective flow. Facies 5 is interpreted as a shallower water facies than facies 2 through 4 and was deposited in a marginal offshore to mid-shelf shallow ramp setting.

6.3.2 Facies association

Facies can be grouped into successions, which are recurring, genetically-related associations of lithological characteristics (Collinson 1969). When defined in three dimensions, a facies association constitutes a depositional sequence (Brown & Fisher 1977). Facies associations can have significant predictive power when the consequences of Walther’s Law are considered (Middleton 1973). Walther’s Law states that a vertical succession of facies that conformably grade into one another were once laterally juxtaposed; in contrast, chronologically disconformable facies (e.g., separated by erosional or hiatal surfaces) are not genetically related. Ultimately, all surfaces across which there is evidence of abrupt facies dislocation are potentially important (Galloway & Hobday 1996).

The relationship between grain size and variations in sediment transport energy is the cornerstone of fluvial, deltaic, and turbidite facies models. Gravity drives sediment dispersal in these systems, primarily via selective deposition and preservation. This results in an overall “down-system fining” trend, where particles tend to become finer with distance along a particular sediment transport path (Aigner & Reineck 1982). The energy needed to maintain grain motion decreases with particle size and specific gravity – as a result, fine-grained particles can be transported farther by low-energy advective conveyance mechanisms like combined flows or WESGF’s (Dumas et al. 2005; Dalrymple 2010b; Plint et al. 2012a; Allen & Allen 2013; Plint 2014).

Using Walther’s Law, the facies association observed in core is interpreted in the context of a depositional environment (shallow muddy ramp; Table 6.1 and Fig. 6.4). This
established a relationship between laterally and vertically adjacent facies, which helped to constrain the allostratigraphic framework.

6.3.2.1 Offshore to mid-shelf shallow muddy ramp setting

Figure 6.4 is a cartoon of a paleoenvironmental reconstruction of the mud-dominated shallow ramp environment interpreted for the Second White Specks and Belle Fourche alloformations. During times of relative sea-level rise (transgressive and highstand time), muddy heterolithic deposits were dispersed seaward via combined flows. Times of sea-level fall, comparatively, promoted progradation of the Kaskapau delta across the inner ramp. The mid-shelf and offshore environments experienced progressive erosion by wave scouring, which may have carved out gutter casts as the geographic position of sand and silt storm wave base shifted seaward. This exposed early diagenetic products, such as siderite nodules, to winnowing. The gutter casts became filled with coarser-grained storm deposits like sand and rip-up clasts. In this model, facies 2 through 5 developed as laterally adjacent facies.

6.4 Fine-grained sediment transport in ancient epicontinental seas

Epicontinental seas are partially enclosed, shallow seas (water depth in 10s of metres) with normal marine salinity within continental areas, and form large expanses when they are substantially flooded by oceans (Shaw 1964; Johnson & Baldwin 1996). Ancient epicontinental seas, for which there are no modern analogues (Hay et al. 1993), differed from modern shelf environments due to the large lateral extent and low shelf gradients of the former (Shaw 1964). Modern continental shelves are typically 10 to less than 100 kilometres wide with bottom slopes ranging from 0.02 to 0.1°, whereas ancient epicontinental seas were commonly 1000’s of kilometres wide and had bottom slopes in the range of 0.005 to 0.001° (Shaw 1964; Johnson & Baldwin 1996). Ancient epicontinental seas, therefore, had gently sloping ramp-like profiles without defined shelf-slope physiography (Keulegan & Krumbein 1949). As turbidity currents require sufficient slope to form, turbidity currents were likely not an important mechanism for sediment transport across shallow epicontinental shelves (Curray 1960). The rock record of ancient epicontinental seas, like the WIS, contain fine-grained clastic sediments (e.g., the lower Colorado Group) that can be traced over 1000 km offshore from their respective basin.
Solving the Second White Specks

6. Core-to-log correlation and allostratigraphy

Fig. 6.4: Cartoons summarizing the paleogeography and paleobathymetry of the Kaskapau delta and its basinal equivalent Second White Specks and Belle Fourche alloformations – vertical scale is extremely exaggerated. This approximates a shallow marine muddy ramp setting with a very low gradient. The approximate location of facies 2 through 5 are shown as circled numbers.

Adapted from Varban and Plint (2008a), Plint et al. (2012a), and Plint (2014).
margins (Schieber 2016). This presents an intriguing problem: how could mud have been mobilized over long distances offshore across a shallow, low-gradient ramp?

Classic models of mud deposition in low-gradient offshore settings dictate that organic-rich mud is deposited in relatively deep water (> 100 m water depth), where continuous pelagic rainout of sediment dominates in a relatively low-energy setting (McCave 1984; Alldredge & Silver 1988; Potter et al. 2005). Newer studies have dispelled this notion: low-energy depositional conditions for fine-grained sediments are the exception, rather than the rule (Schieber et al. 2007; Bhattacharya & MacEachern 2009; Schieber 2010; Aplin & Macquaker 2011; Laycock 2014; Plint 2014). It is now generally accepted that mudstones can be deposited in a variety of depositional settings via relatively high-energy processes, as well as at different water depths.

Formation of a marine pycnocline – a boundary separating two layers of different densities due to changes in water salinity or temperature – can influence the redistribution of fine-grained sediment. Fine-grained particles entering shelf seas via riverine deltas readily fall out of suspension from hypopycnal plumes as aggregates formed due to flocculation and coagulation (Plint 2010, 2014). Flocculation denotes the adhesive clustering and attachment of clay minerals, organic polymers, and clastic debris (Grabowski et al. 2011). Large cations like sodium and calcium can reduce the thickness of the electric double layer in clay minerals, facilitating coagulation – the agglomeration of clay minerals with similar compositions – at higher salinities (Bennett et al. 1991; Grabowski et al. 2011). Aggregation may be further enhanced by van der Waals forces, as well as extracellular polysaccharides from biotic excretion (McCave 1984; Plint 2014). Aggregates settle into a turbid mud “fluff” layer (nepheloid layer) that exists within 10 kilometres of river mouths (Grabowski et al. 2011). This nepheloid layer may flow downslope and offshore as a hyperpycnal density current (Schieber et al. 2007). If resuspension via storms occurs when the bottom nepheloid layer has begun to consolidate, intraclastic aggregates (IAs) may be advected further offshore via alongshore bottom currents like geostrophic flows (Plint 2010). IAs were observed by Plint (2014) in rocks of the Cenomanian Dunvegan delta and by Jiang and Cheadle (2013) in the Second White Specks Formation – suggesting that erosional working of partially-
lithified muddy substrate by storms was a widespread phenomenon during the Late Cretaceous.

Evidence for advective mud transport in the Late Cretaceous WIS in relatively shallow water (<100 m water depth) is well documented (Varban & Plint 2005; Varban & Plint 2008a, b; Bhattacharya & MacEachern 2009; Plint et al. 2012b; Shank & Plint 2013; Plint 2014). Plint (2014) determined that mudstone deposition on the distal prodelta, which was greater than 120 km offshore from the Dunvegan delta of the Upper Cretaceous Colorado Group, occurred at water depths of 20 to 70 m (SWB for mud). This process was aided by the resuspension of fine-grained sediment aggregates by storms – it cannot be explained by classic “marine snow” models of mud deposition. Storm waves can initiate offshore mud deposition by triggering downslope flows of dense, fluid mud (McCave 1984; Grabowski et al. 2011). Fluid muds are high particle-density and low wet bulk density fluids with suspended sediment concentrations exceeding 10 g/L (Nishida et al. 2013). Density flows of fluid mud are an important transport mechanism for fine-grained sediment in the marine domain. Termed “wave-enhanced sediment gravity flows” (WEGSFs) by Macquaker et al. (2010), WESGFs are recognized by a “triplet” pattern of silt, intercalated silt and clay, followed finally by a clay drape. This pattern reflects an initial wave-induced turbulent flow that gradually wanes in strength, eventually allowing suspension settling to dominate.

In marine depositional settings, storms commonly generate combined flows. Combined flows have both unidirectional and oscillatory components – these are produced by the interaction of geostrophic flows and increased wave activity (Murray 1970; Nittrouer & Wright 1994). Geostrophic flows are downwelling bottom currents that are generated by gravity-driven relaxation flows from coastal set-up during storm surges. In the northern hemisphere, the return flow is deflected to the right (Heezen et al. 1966; Swift et al. 1986). Varban and Plint (2008a) invoked storm-driven geostrophic flows as the primary transport mechanism for mudstones of the Kaskapau Formation over 300 km offshore. These bottom currents can efficiently entrain sediment and advect it obliquely or parallel to the shoreline, up to hundreds of kilometres offshore. In this manner, muddy clinoforms can experience substantial increases in environmental energy in their bottom set regions.
while maintaining basinward progradation (Cattaneo et al. 2007; Laycock 2014). Formed during highstand system tracts, mud can develop into prismatic, shore-parallel detached “mud wedges” or “subaqueous deltas”. These are characterized by wave-ravined muddy clinoforms that downlap onto a sediment-starved shelf (Abbott 2000; Cattaneo et al. 2003; Cattaneo et al. 2007; Plint 2010).

### 6.5 Core-to-log correlation

As previously discussed in Chapter 3, cores need to be correlated to geophysical well logs in order to ground-truth petrophysical responses. This provides a theoretical basis for extrapolating rock properties from sparsely located control points across a large area, particularly in the absence of outcrop information – sedimentary successions can be associated with distinct electrofacies, or “…[a] set of log parameters that characterizes a sediment and permits the sediment to be distinguished from others” (Serra & Abbott 1982). As this study only has limited core data, it can be difficult to establish an association between core-derived parameters (e.g., porosity and TOC) and log-derived attributes (Amaefule et al. 1993). Amaefule et al. (1993) recognized that by dividing reservoirs into statistically-defined hydraulic flow units, porosity and permeability could be estimated reasonably well with limited core data. Instead, this study uses the qualitative definition of hydraulic flow units described by Ebanks (1987), where it is assumed that coeval rock units (in this case, allomembers) have defined relationships between their petrophysical properties because they are genetically related. This provides the interpreter with a way to extrapolate the available core data to distant wells.

Figure 6.2 illustrates a S-N oriented cross-section with all the cores logged by this author (with the exception of the 7-19 core, which was included for reference) with their corresponding log signatures beside them. Figure 6.3 illustrates the same cross-section, with the full suite of petrophysical parameters that were calculated for this thesis (clay volume, TOC, total and effective porosity, volumetric mineralogy, and brittleness). In certain places (esp. BF1), the clay volume (VSH_GR) curve was a particularly useful addition to the normal logs used for allostratigraphy (GR, DT, and RES) as it provided a standardized measure of clay content in a particular interval.
6.5.1 Electrofacies

6.5.1.1 Facies 1

Facies 1 is most easily identified by its spiky, high GR reading, which is associated with $^{40}\text{K}$ in bentonite clays. This response may be subdued if the bentonite is particularly thin (< 10 cm), as is the case in well 100/07-19-45-06W5, due to the limited vertical resolution of standard GR tools (~0.4 to 0.9 m).

6.5.1.2 Facies 2

The geophysical wireline log response to facies 2 is characteristic of a clay-rich composition: it has a relatively high GR response (lower than facies 1), reduced bulk density, and faster sonic travel times. Despite the high proportion of organic content (a lithology with high resistivity) in this facies, the elevated conductivity of clay minerals present in the rock matrix likely contributes to a resistivity signature that is relatively low.

6.5.1.3 Facies 3

The GR tool response to facies 3, which is intermediately high, reflects a slightly reduced proportion of clay minerals relative to facies 2. The upward transition of facies 2 into the coarser-grained sediments of facies 3 is reflected as a gradually suppressed GR response. Siderite (iron carbonate) nodules have a significant impact on the log character of facies 3, as the GR response sharply decreases – although this effect is dependent on the concentration of nodules within the particular horizon. Sonic travel times in this facies are slightly increased relative to facies 2, which may represent a marginal increase in porosity that is associated with reduced clay content. The resistivity reading in facies 3 is slightly elevated relative to facies 2, potentially responding to an increase in organic content and a simultaneously decrease in clay content.

6.5.1.4 Facies 4 and 5

Several compositional factors contribute to facies 4 and 5 having a significantly suppressed GR signature relative to facies 2 and 3. Of the facies described in this study, facies 4 and 5 are the most heterolithic: they contain a higher proportion of calcareous matrix, elevated organic content, reduced clay, and also exhibit a marked increase in
 siderite nodule concentration. These mineralogical components, which are variably interbedded and distributed, result in a GR signal that is reduced overall but also inconsistent.

6.5.1.5 Electrofacies summary

The upward transition from the Upper Belle Fourche alloformation to the Second White Specks alloformation is marked by an abrupt shift to a more calcareous matrix, reduced clay content, a suppressed gamma ray profile, as well as elevated resistivity and TOC (Bloch et al. 1993, Furmanm et al. 2014). To ensure allostratigraphic tops were picked consistently across the entire area and could be easily utilized by other geologists, a petrophysical tops guidance was developed (Table 6.2). Due to the limited petrophysical contrast between some of the allomembers, multiple logs were used to confirm picks (GR, DT, DEN, LLD, and neutron if it was available).

6.6 Allostratigraphic correlation

The facies from section 6.3, the electrofacies from section 6.5.1, and the allostratigraphic framework described in section 6.2 were integrated in order to guide regional allostratigraphic correlations and to estimate the spatial distribution of facies throughout the area. Fig. 6.5 summarizes the relationship between these three datasets.

Figure 6.6 illustrates the four west-east oriented and three north-south oriented allostratigraphic cross-sections that have been included for reference (Figs. 6.7 through 6.13). In cross-section, the Upper Belle Fourche and Second White Specks allomembers mapped in this study exhibit varied geometries. BF1 appears to fill in a limited amount of erosional topography onto the K1 disconformity and thickens overall from southwest to northeast. BF2, which appears to be preserved in its entirety, is relatively sheet-like overall, but thins from west to east. In contrast, BF 3 exhibits wedge-like geometry, experiencing pronounced thickening northwards to townships 40-43 before becoming thinner north of township 42-43. Finally, allomember VII also exhibits a northwards-thickening trend, without the pronounced bulge exhibited by BF3.
<table>
<thead>
<tr>
<th>Allomember name</th>
<th>Marker</th>
<th>Log character</th>
<th>Common pitfalls</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Second White Specks</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Allo VIII</td>
<td>-</td>
<td>Elevated GR relative to Allo VII</td>
<td>Often impacted by borehole breakout which makes the true GR character difficult to discern</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Allo VII</td>
<td>Flooding surface at the top</td>
<td>Suppressed GR and slow sonic related to increased carbonate content</td>
<td>High porosity units are very thin (&lt;1 m) and can be difficult to correlate due to limited lateral extent</td>
</tr>
<tr>
<td><strong>Upper Belle Fourche</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>BF3</td>
<td>“Red” bentonite from Tyagi et al. (2007)</td>
<td>“Coarsening upwards” pattern in GR with high GR unit at base</td>
<td>“Coarse” facies may not be present at the top of the well due to lateral variation or subtle erosion, use offsetting wells to confirm if erosion has occurred</td>
</tr>
<tr>
<td>BF2</td>
<td>Flooding surface</td>
<td>Contains two lower-order “coarsening upward” cycles – visible in sonic and resistivity</td>
<td>Towards the north of the study area, coarser facies appears “transitional” into BF3 due to limited vertical petrophysical contrast; use other logs to confirm pick</td>
</tr>
<tr>
<td>BF1</td>
<td>Flooding surface</td>
<td>Highest GR of all Upper BF units, borehole breakout is common, elevated resistivity; serrated GR pattern with no apparent coarsening upward or fining upward pattern</td>
<td>Drapes over K1 unconformity, which has some topographic irregularity – this unit can be very thin in places but is always present</td>
</tr>
<tr>
<td><strong>Lower Belle Fourche (Lower BF)</strong></td>
<td>Double “spike” in GR, DT, DEN, and LLD; correlates to K1 unconformity from Varban and Plint (2008a)</td>
<td>Elevated GR, lower density relative to Upper BF from higher organic content</td>
<td>“Spike” may be subtle in certain wells, can confirm pick with resistivity and sonic</td>
</tr>
</tbody>
</table>

Table 6.2: Petrophysical tops guidance for the Second White Specks and Belle Fourche alloformations in the Willesden Green – Gilby area of west-central Alberta. This includes distinguishing log characteristics in addition to problems the interpreter may encounter while picking tops.
Fig. 6.5: A composite cross-section, using the “red” bentonite as a datum, of the Lower Second White Specks and Belle Fourche alloformations across the study area. Net reservoir intervals are shaded in purple (Belle Fourche) and green (Second White Specks)
6.6.1 Upper Belle Fourche (BF2 and BF3)

In core, the Upper Belle Fourche contains two several coarsening up sequences (allomembers BF2 and BF3) that are bounded above by sharp-based erosional contacts or shelly lags (Fig. 6.2A, 6.2G, 6.2H). These units are clay-rich, and display increases in silt- and carbonate-content towards the tops of individual parasequences (Fig. 6.3). BF3 thickens north of township 36, reaching maximum thickness in 102/14-31-041-06W5. North of township 42, BF3 is clearly truncated by the overlying Second White Specks. In BF2, facies 3 and 4 are thicker towards the south of the study area and appear to gradually transition into facies 2 laterally, disappearing entirely north of township 41. These allomembers are interpreted to record an overall rise in base level, which was punctuated by brief base level falls that allowed for coarser sediment supply from the Kaskapau delta to be transported farther into the basin via combined flows.

BF 3 is anomalously thick in townships 41 and 42; this could be due to tectonic thickening and/or differential erosion of the top of the unit. The appearance of facies 3 suggests that higher energy processes dominated in this sequence over BF2, possibly due to shallower water. The disappearance of facies 3 and 4 in 100/04-27-39-06W5 appears to suggest a subtle erosional unconformity at the top of BF 3, but it could also be caused by a lateral facies change. This facies change could be facilitated by a channelized or lenticular combined flow preferentially moving coarse sediment to other parts of the study area, such as townships 41-42.

Figure 6.5 illustrates the irregular nature of the boundary between the Second White Specks and Upper Belle Fourche alloformations, as well as its potential relationship with production. The boundary between Second White Specks allomember VII (green) and the Belle Fourche is unconformable – the lower gamma ray unit at the top of the Belle Fourche 3 allomember appears to truncate against the “red” bentonite both to the north and south of township 41, reappearing in a condensed form south of township 38. This electrofacies – outlined in purple – does not reappear in the 4-27 or 7-19 cores.

The 14-31 well, which is one of the best producing wells in the area, is included for comparison to the 102/08-36 offset well – in 14-31, allomember BF3 has developed a
Fig. 6.6: Reference map for summary allostratigraphic cross-sections, with core locations for reference.
Fig. 6.7: Allostratigraphic cross-section B to B', which runs north-south.
Fig. 6: Allostratigraphic cross-section C to C', which runs north-south.
Fig. 6.10: Allostratigraphic cross-section D to D', which runs north-south.
Fig. 6.10: Allostratigraphic cross-section E to E', which runs east-west.
Fig. 6.11: Allostratigraphic cross-section F to F', which runs east-west.
Fig. 6.12: Allostratigraphic cross-section G to G', which runs east-west.
Fig. 6.13: Allostratigraphic cross-section H to H', which runs east-west.
thicker section of reservoir (purple). Allomember BF3 is thinner in 102/08-36 and was not perforated, potentially indicating a bypassed pay scenario. Notably, this unit disappears south of township 41 and north of township 42, only reappearing south of township 38. Because the underlying Belle Fourche units are not significantly altered in the 4-27 well, where the reservoir interval is missing, it is suspected that there has been some type of lateral facies change or subtle regional erosion, rather than a major uplift and/or erosional event. In contrast, in the 7-19 well, all Belle Fourche units “jump” upwards and the top of the unit is truncated, potentially indicating erosion that occurred prior to Second White Specks deposition.

BF3 is mantled by a bentonite (the Bighorn River “red” bentonite), facies 1. It is interpreted to record a volcanic eruption or a series of volcanic eruptions from the western Cordillera, which spread volcanic ash across the WIS. This ash fell out of suspension and was eventually deposited on the seafloor. The presence of the bentonite in all wells suggests that the bentonite ashfall was likely deposited after the sedimentary hiatus that occurred during the Cenomanian-Turonian boundary.

### 6.6.2 Second White Specks (Allomember VII)

Allomember VII of the Second White Specks thins from north to south. Compositionally, allomember VII contains less clay and more carbonate content than the Belle Fourche; this is consistent with core analysis from Tuzo Energy (Canadian Discovery 2014). This allomember is internally complex. Three groups of “reservoir facies” units subdivide this unit in Fig. 6.4 (pale green) and were correlated on the basis of similar grain size patterns. The presence of multiple siderite pebble lags and the vertical stacking of the “reservoir facies” units suggests some degree of amalgamation, possibly by storms. Storm-deposited sediments on a shallow marine shelf may develop into laterally continuous, amalgamated sheets that have enhanced permeability and porosity at the top of each upwards coarsening sequence (Atkinson et al. 1986; Gaynor & Schiehing 1988).

Allomember VII represents a shift to higher energy transport mechanisms in a slightly shallower environment, represented by the predominance of coarse-grained facies 4 and 5, as well as the absence of facies 2. The frequent presence of soft-sediment deformation,
siderite lags, and erosional surfaces are interpreted to represent many cycles of combined flow winnowing, erosion, and general predominance over settling processes. At least five different packages can be identified in allomember VII on the basis of grain size patterns; these may reflect cyclicity in ocean currents and climate patterns, as well as pulses of sea-level fall.

Allomember VII is bounded by an erosive transgressive lag and a major flooding surface, which was likely generated by a marine transgression.

6.6.3 Overall interpretation

The facies sequence of Cenomanian to Turonian-aged mudstones of the Lower Colorado Group in west-central Alberta are consistent with a shallow marine environment affected by combined flows during a global highstand, which was punctuated by brief periods of relative base level fall and largely remained within storm wave base. The Second White Specks and Upper Belle Fourche-equivalent Kaskapau alloformation represents the majority of the Greenhorn transgressive-regressive cycle, which peaked during the Turonian (Kauffman & Caldwell 1993). During that time, several small-scale base level fluctuations occurred (Haq 2014), which initiated lower-order regressions and basinward progradation.

6.7 Highlights

- The allostratigraphic interval of interest in this study is constrained below by the K1 disconformity, and above by the allomember VII flooding surface. By extending the allostratigraphic correlations of Tyagi et al. (2007) and subdividing his allomembers on the basis of previously uncorrelated flooding surfaces.
- Facies observed in this study are consistent with a distal to mid-shelf, marine, low-gradient ramp setting where water depths ranged between 40 and 70 m. Fine-grained sediments were transported offshore by storm-generated combined flows.
- The contact between the Belle Fourche and Second White Specks alloformation, indicated by the presence of the “red” bentonite, is unconformable and occasionally erosional across the study area. This is consistent with the work of Tyagi et al. (2007) and Plint et al. (2012a).
Chapter 7

7 Depositional trends of the Second White Specks and Belle Fourche alloformations in the Willesden Green – Gilby region, Alberta, Canada

7.1 Overview

Structure, thickness, and isolith maps of the Lower Second White Specks and Belle Fourche alloformations in the Willesden Green area of west-central Alberta are presented.

7.2 Structure mapping

A structure map establishes the subsurface geometry of a geologic surface, including regional dip and areas that may be deformed or faulted (Nelson et al. 1999). In this study, structure maps were primarily used to delineate regional dip and structural features. Contour lines on a structure map represent lines of equal subsurface elevation or depth of a particular allomember. The shape and location of contour lines on a structure map can be used to infer the shape of three-dimensional structures (Lisle 2004):

- Parallel, equally spaced contours represent a uniformly dipping surface;
- Closely spaced contours represent a steeply dipping surface;
- Closed concentric arrangements of contours reveal isolated hills or bowl structures;
- Valleys and ridges, which may indicate fault locations, give rise to V-shaped patterns.

Structure maps for each allomember were generated from subsurface stratigraphic picks using the kriging algorithm in Surfer. Changes in the geometry of surfaces bounding individual allomembers can delineate structural features that may have influenced deposition, and potentially identify structural traps for future petroleum exploration.

In the lower Colorado Group of west-central Alberta, the changes between structural maps for each allomember are extremely subtle and thus only one has been included for reference. Figures 7.1 and 7.2 illustrate the subsea elevation of allomember VII in two- and three-dimensions, respectively. As evidenced by subparallel, approximately equidistant contour lines of constant subsea elevation, this surface dips relatively uniformly to the southwest up until the edge of the Mesozoic deformation front.
Fig. 7.1: 2D structure map of the top of allomember VII, with the Mesozoic deformation front for reference.
Fig. 7.2: 3D structure map of the top of allomember VII.
In three dimensions, the effect of the Laramide orogeny on lower Colorado Group strata is clearly seen (Fig 7.2) – the Mesozoic deformation front is oriented approximately NNW and dips towards the southwest. This is the prevailing dip direction and structural style of the entire region. Localized perturbations associated with small-scale structural relief are more easily visible in three-dimensions, particularly in townships 41 to 42 from R6 to 7W5.

7.3 Isochore mapping

A “depocentre” refers to an area of maximum stratigraphic thickness where deposition was concentrated (Gary et al. 1974). Basins can have multiple depocentres and their locations may shift over time if they experience lateral changes in sediment supply, have multiple drainage areas, or have complicated subsidence histories (Armentrout 1999). The spatial distribution of facies within a particular depocentre in a shelf setting is controlled by the ratio of accommodation to sediment supply (Van Wagoner et al. 1988), as well as by the mechanism of sedimentary transport across the shelf (Armentrout 1999). By mapping coeval stratigraphic thicknesses (i.e., allostratigraphically-defined isochores), shifts in the extent and locations of depocentres can temporally and spatially constrained within a particular basin (Armentrout 1999).

Contour lines on an isochore map represent lines of equal true vertical thickness (Lisle 2004). Isochore maps can be interpreted on the basis of contour spacing and geometry, as follows:

- Parallel, widely spaced contours represent a sheet-like stratigraphic unit whose thickness is relatively constant
- Parallel, equally spaced contours represent a wedge-like stratigraphic unit whose thickness is changing at a constant rate;
- Parallel, closely spaced contours represent a wedge-shaped stratigraphic unit whose thickness is changing at a variable rate;
- Closed concentric arrangements of increasing contours reveal isolated regions of increased stratigraphic thickness, which could represent sedimentary depocentres;
• Closed concentric arrangements of decreasing contours reveal isolated regions of
decreased stratigraphic thickness, which could reveal eroded regions or areas with
decreased available accommodation;
• Valleys and ridges indicate irregular stratigraphic geometry (i.e., not sheet-like).

Figures 7.3, 7.4, 7.5 and 7.6 illustrate the isochore thickness of allomembers BF1, BF2,
BF3 and VII, respectively.

7.3.1 Allomember BF1

Allomember BF1 (Fig 7.3), which is bounded below by the K1 disconformity and above
by a major flooding surface, illustrates an overall southward-thickening trend. It ranges
from a maximum thickness of 24 m in T37-R6W5 to a minimum thickness of 0.3 m in the
northwest corner of the study area. This allomember has two NNW-oriented zones of
increased thickness outlined by the 12 m contour. These features, interpreted as
depocentres, extend from township 36 to township 40 and are approximately 20
kilometres wide. These depocentres do not follow the westward-thickening trend that is
expected for the lower Colorado Group due to flexural loading from the Laramide
orogeny during the Late Cenomanian (cf. Figs. 2.1 and 2.2). The location of these
depocentres is likely related to pockets of accommodation that developed during the
deposition of allomember BF1, which could have been generated by localized subsidence
or by erosional topography on the K1 surface.

7.3.2 Allomember BF2

Allomember BF2 (Fig. 7.4), bounded below by BF1 and above by a major flooding
surface, depicts an overall westward-thickening trend – emulating the expected
depositional pattern of the lower Colorado Group (cf. Fig 2.1). This thickness pattern
suggests clockwise rotation and a northwest shift in the location of maximum
accommodation from allomember BF1, which had reached maximum thickness in the
southern part of the study area. Allomember BF2 ranges from a maximum thickness of
over 30 m in T41 RW5 to approximately 5 m in the northeast corner of the study area, but
averages 10 to 12 m thick across most of the study area. East of R6W5, the geometry of
this allomember is relatively sheet-like – contours are widely spaced (particularly
Fig. 7.3: Isochore map of allomember BF1.
Fig. 7.4: Isochore map of allomember BF2.
Fig. 7.5: Isochore map of allomember BF3.
Allomember VII isochore

Fig. 7.6: Isochore map of allomember VII.
between 12 and 8 m). Allomember BF2 develops a north-south oriented depocentre west of R8W5 that stretches from T37 to 43 – although well control is poor in this region.

### 7.3.3 Allomember BF3

Allomember BF3 (Fig. 7.5), which is bounded below by the BF2 flooding surface and bounded above by the “red” bentonite, reveals an overall northwest thickening trend across the study area – it ranges from a minimum thickness of approximately 4 m in T35 R5W5 to a maximum thickness of 19 m in T43 R3W5. The 12 m thickness contour reveals a large, oblong depocentre, approximately 25 km wide and 90 km long, that is oriented 60 degrees east of north. This depositional pattern represents an overall clockwise and northeast sense of rotation to the location of maximum accommodation in the study area, relative to allomembers BF2 and BF1. The westward edge of this depocentre, defined by T44 R8W5 and T43 R9W5, exhibits a NNE-trending thin that extends ~40 km south into T41 R9W5 – it is possible that this “thinning” trend may represent erosion of BF3 prior to “red” bentonite deposition.

### 7.3.4 Allomember VII

Allomember VII (Fig. 7.6), which is bounded below by the “red” bentonite and above by a major flooding surface, depicts an overall northeast thickening trend. This allomember ranges from a maximum thickness of approximately 16 m in T41 R7W5 to a minimum thickness of 3 m in the southwest corner of the study area. The 9.5 m contour delineates a depocentre in the northeast that trends at approximately 30 degrees west of north; this depositional pattern represents an overall clockwise rotation in maximum accommodation in the study area relative to allomembers from the Belle Fourche alloformation. An irregular, “finger” shaped departure from the main depocentre extends from T41 R7W5 just over 40 km towards the south. Similar to allomember BF3, this depocentre is defined to the west by a NNE-trending thin that extends 40 km south from T43 R8W5 into T39 R10W5.
7.4 Isolith mapping

An isolith map made within a coeval interval can be used to reconstruct paleogeography and establish the distribution of reservoir facies (Armentrout 1999; Tearpock & Bischke 2002). Isolith mapping are typically generated by creating a map of the “net to gross” or “sand to shale” ratio where the thickness of “net sand” is divided by the gross isochore thickness of the entire interval (Tearpock & Bischke 2002). Net sand is determined by adding up the total thickness of sand, which is determined using a GR cutoff (e.g., 50 API) in a stratigraphic unit across a series of wells (Dikkers 1985). By constructing an isolith map in this way, only geologic units that exceed a threshold GR value are contoured (see Varban and Plint, 2008b). GR logs have varied responses to common lithological components of unconventional reservoirs (e.g., clay minerals and kerogen content) like the Second White Specks Formation – applying a GR cutoff, therefore, does not adequately capture the amount of non-clay minerals in a stratigraphic zone. The net sand method is used to establish the distribution of a particular lithology (i.e., sand) across an area. This implies that net sand contours are associated with variations in grain size (le Roux 1993) – grain size can only be accurately determined through observations of measured sections, core, or drill cuttings. GR logs record variations in radioactivity, which does not always correlate with grain size (see section 3.6.2.1.1).

Composite isolith maps can be generated by superimposing different base maps (Sloss et al. 1960) – this is most effective when no more than two or three maps are overlain (Merriam & Jewett 1989). In this study, composite isolith maps were generated by overlapping the isochore maps with weighted interval average maps of clay volume. Clay volume is an important part of reservoir assessment as the presence of clay minerals in the rock matrix can reduce porosity (see Fig. 5.4). Areas with low clay volume may have higher porosity, and therefore have increased storage capacity. The composite isolith maps are interpreted as follows:

- Areas where low clay volume values (orange) overlap with regions that have elevated isochore thickness represent thick accumulations of clay-poor facies, where accommodation increased and coarse sediment supply was available (i.e., facies 3 through 5);
• Regions with low clay volume overlapping with regions of reduced isochore thickness represent thin accumulations of clay-poor facies, where accommodation was reduced but coarse-grained sediment supply was still available;
• Areas where high clay volume values (grey) overlap with greater stratigraphic thickness represent accumulations of clay-rich facies (i.e., facies 2), where accommodation was increased but coarse sediment supply was not available;
• Regions with high clay volume that overlap with regions of reduced isochore thickness represent thin accumulations of clay-rich facies, where accommodation was limited, and coarse-grained sediment supply was not available;
• Shifts in the location of clay-poor facies between allomembers should indicate shifts in sediment supply locations.

Figures 7.7, 7.8, 7.9 and 7.10 illustrate the composite isolith maps of allomembers BF1, BF2, BF3 and VII, respectively, with clay volume in grey and orange and isochores overlaid as transparent contours. As fewer wells were used to calculate clay volume than were used to calculate isochore thickness, the data points that were used to generate these maps do not perfectly overlap – although their grid geometries are identical. Only wells that were completed in the Second White Specks and Belle Fourche Formations have been included on these maps.

7.4.1 Allomember BF1

The weighted average clay volume of allomember BF1 (Fig. 7.7) is lowest in the southeast corner of the study area, which largely overlaps with the major depocentre of this unit (Fig. 7.3). Clay volume in this interval ranges from 0.32 in the south east corner of the study area to a maximum of 0.84 at the northern edge of the study area. Because low clay volume overlaps with the region of increased isochore thickness, it is interpreted that a source of coarse sediment supply for allomember BF1 was located in the south and sufficient accommodation was available in this region for sediment to accumulate.

7.4.2 Allomember BF2

The clay volume of allomember BF2 (Fig. 7.8) is highest (0.7) in the northeast corner of the study area and reaches a minimum value of 0.06 in T41 R10W5. The clay volume of
Fig. 7.7: Isolith (isochore thickness overlaid on clay volume) of allomember BF1.
Fig. 7.8: Isolith (isochore thickness overlaid on clay volume) of allomember BF2.
BF3 clay volume and isochore overlay

Fig. 7.9: Isolith (isochore thickness overlaid on clay volume) of allomember BF3.
Allomember VII clay volume and isochore overlay

Fig. 7.10: Isolith (isochore thickness overlaid on clay volume) of allomember VII.
allomember BF2 increases from west to east across the study area. The region of lowest clay volume is best constrained by clay volume contours less than 0.22, which are concentrated in an area west of R7W5 that is oriented approximately north-south. This region of lowest clay volume largely overlaps with the depocentre indicated in Fig. 7.4, which is approximated by an isochore thickness of 13 m. There is a region in the southern part of the study area with relatively low clay volume (<0.22) and reduced isochore thickness of BF2, which overlies with the depocentre and source of coarse sediment indicated for BF1. This indicates that coarse sediment was still being supplied to that area but was no longer the main sedimentary depocentre. The main depocentre and source of coarse-grained sediment for BF2 is located in the west, representing an overall clockwise sense of rotation of maximum accommodation and sediment supply.

7.4.3 Allomember BF3

The clay volume of allomember BF3 (Fig. 7.9) ranges from 0.1 in T40 R9W5 to 0.55 in T37 R7W5. There are two trends of low clay volume that are relatively linear and trend at 60 degrees west of north. The first begins in T44 R4W5 and is 30 km wide, extending 60 km southeast to T41 R1W5. The other begins in T41 R10W5, ranges from 20 to 40 km wide, and stretches southeast to T38 R1W5. These two low clay volume trends are separated by a region of high clay volume that passes through the middle of the main depocentre in Fig. 7.5. This is notable as the high clay volume trend passes through the middle of the main depocentre – this region had available accommodation for sediment, but coarse-grained sediment was not evenly distributed across the area of increased thickness. Two separate bands of coarse-grained facies developed from west to east, possibly driven by paleobathymetry or subtle changes in sediment sources. A third, lobate region of low clay volume encompasses a region that stretches from T38 R4W5 to T35 R7W5 – this area is significant because the isochore thickness of allomember BF3 is relatively low in this area. This suggests that accommodation was reduced, but coarse-grained sediment was still available.
7.4.4 Allomember VII

The clay volume of allomember VII (Fig. 7.10) trends at approximately 80 degrees east of north and decreases towards the northern half of the study area – it ranges from a maximum clay volume of 0.56 in the south to 0.04 in T41 R10W5. Lowest clay volumes are found north of T40, and largely coincide with regions with increased isochore thickness. The only exception to this is found in the northwest corner of the study area, west of the 9.5 m thickness contour – in this area, low clay volumes coincide with reduced isochore thickness. Similar to allomember BF3, this region may represent an area where accommodation was reduced, but coarse-grained sediment was still available.

7.5 Highlights

- The regional structure of the study area dips gently towards the Mesozoic deformation front in the southwest.
- Isochore maps reveal a sense of clockwise rotation and an overall northward shift in the location of Belle Fourche and Second White Specks depocentres across the basin.
- Isolith maps, constructed by overlaying clay volume with isochore thickness, demonstrate lateral facies heterogeneity across the study area and between allomembers.
Chapter 8

8. Petrophysical property mapping of the Lower Second White Specks and Upper Belle Fourche alloformations in the Willesden Green – Gilby region, Alberta, Canada

8.1 Overview

This chapter presents total organic carbon, total porosity, effective porosity, porosity-thickness, and brittleness models of the Lower Second White Specks and Belle Fourche alloformations in the Willesden Green area of west-central Alberta.

8.2 TOC

The hydrocarbon generation potential of a rock interval can be assessed by measuring TOC (Law 1999). Hydrocarbon generation is caused by the thermal decomposition of organic matter over time (Jarvie 1991). In tight oil petroleum systems like the Second White Specks Formation, oil is generated in place and stored within low permeability shale – so high TOC indicates elevated source and reservoir quality (Jarvie 2012b). Organic matter enrichment is a function of biotic productivity in the photic zone, minus any destruction or dilution of organic matter that may occur due to biotic activity or clastic input (Pedersen & Calvert 1990; Bohacs et al. 2005). Within an individual mudstone formation, organic richness may vary vertically on a sub-metre scale (Bohacs 1998; Bohacs et al. 2005; Passey et al. 2010; Aplin & Macquaker 2011; Jarvie 2012a). Variations in TOC can be due to depositional environmental conditions, organofacies differences, thermal maturity, and stratigraphic architecture (Passey et al. 2010; Jarvie 2012a). Within coeval strata, lateral TOC variations are associated with changes in the predominance of organic matter production, destruction, and dilution (Bohacs & Lazar 2008; Guthrie & Bohacs 2009; Passey et al. 2010).

Creaney and Passey (1993) suggested that high TOC values in proximally-located source rocks were associated with increased sediment starvation and organic matter deposition during maximum flooding events. Decreases in TOC are associated with clastic dilution and degradation of organic matter (Passey et al. 2010). In the Creaney and Passey (1993) model, TOC profiles for most source rocks should exhibit a “higher at the base” pattern.
Jarvie (2012a) cautions that laboratory measurements of TOC strictly represent present-day TOC – in thermally mature source rocks, TOC is decreased due to the generation and migration of hydrocarbons out of the reservoir. Decreases in measured TOC, therefore, could be affected by subtle differences in thermal maturity.

TOC was modelled from resistivity and sonic using the Crain and Holgate (2014) and Issler et al. (2002) method described in section 5.6.2.1. Figure 8.1 illustrates the lateral and vertical variations of TOC between allomembers in the study area: individual allomembers have different vertical TOC profiles. The TOC of allomembers BF2 and BF1 exhibit decreasing upwards profiles, whereas allomembers BF3 and VII demonstrate increasing upwards profiles. Highest TOC values (2.75 to 3.5%) were recorded in allomember VII and near the top of allomember BF3. Between wells 102/14-31-041-06W5 and 102/08-36-041-07W5, 1.5 m of high TOC (red) at the top of allomember BF3 in 102/14-31 is no longer present in 102/08-36. This supports previous interpretations from chapters 6 and 7 that the “red” bentonite caps an unconformity between the Belle Fourche and Second White Specks alloformations. Most significantly, there is a stark difference in productivity between the two wells, which can be attributed to increased porosity-thickness and a greater thickness of high TOC in the 102/14-31 well relative to the 102/08-36 well. The difference in the thickness of this petrophysical zone between the two wells is less than 1.5 m, underscoring the importance of observing subtle changes within and between allomembers.

Lower Colorado Group strata have vertical TOC profiles that are constrained to specific allomembers, suggesting that vertical variations in TOC are primarily controlled by genetic depositional conditions rather than thermal maturity. Allomembers BF3 and VII, however, do not exhibit the expected “higher at the base” TOC profile described by Creaney and Passey (1993): allomembers BF3 and VII contain more of the coarser-grained and more proximal facies 4 and 5, and should therefore have a TOC profile that is higher at the base and decreases upward; they instead record upwards increases in TOC. This upwards increase in TOC may have been caused by the initiation of OAE-II, which increased nutrient upwelling in the WIS and enhanced organic carbon burial (see section 2.2.2).
Fig. 8.1: Comparison of corrected GR (green and yellow colour fill, first track on the left), TOC (blue and red colour fill, second from the right), total porosity (black line with white fill, far right) and effective porosity (far right, blue fill) for 102/14-31-041-06W5, 102/08-36-041-07W5, and 100/07-19-045-06W5.

The 14-31 and 8-36 wells were both completed and fracked by the same company within 10 days of one another. The 14-31 well was productive, whereas the 8-36 well was not. Thinning of the high effective porosity interval in allomember BF3, indicated as an orange overlay, between these wells suggest that subtle differences in effective porosity and porosity-thickness (m-scale) may have impacted the productivity of these wells.
Maps of modelled TOC variation across the study area are presented for the two reservoir allomember BF3 and VII (Figs. 8.2 and 8.3). Allomembers BF3 (Fig. 8.2) and VII (Fig. 8.3) both exhibit similar pattern of modelled TOC. TOC is highest (> 2.23 wt%) in a north-south oriented fairway in the middle of the study area (R4W5 to R7W5) and decreases both to the west and east of that fairway. Lateral increases in TOC may be associated with increases in biotic production as well as decreases in clastic dilution and organic matter degradation – these maps, therefore, demonstrate that TOC preservation was highest in the centre fairway.

8.3 Porosity

8.3.1 Total porosity

Low density kerogen impacts bulk density readings, and therefore influences total density porosities. After converting modelled TOC to kerogen, the kerogen contribution to total porosity calculations was suppressed by using the density porosity correction method (Equation 24) described by Sondergeld et al. (2010). Using this method removed anomalously high total porosities associated with high kerogen volume (see Fig. 5.7).

Figure 8.1 illustrates the lateral and vertical variations of total porosity (curve labelled PHIT_CORR) between allomembers in the study area. The 100/07-19-045-06W5 well data was supplemented with helium porosimetry data from Furmann et al. (2014) – this data is visible as black points in the far-right hand column that have been overlaid over the total porosity model from this project. The log-derived porosities matched this core data, providing confidence to use this model for other wells across the study area.

Figures 8.4 and 8.5 illustrate the distributions of total porosity for allomembers BF3 and VII, respectively. Both allomembers have highest total porosities (>9%) in a north-south oriented central fairway that stretches from T43 R7W5 southwards to T36 R6W5. This trend is more laterally continuous for allomember BF3 than allomember VII. This total porosity fairway exhibits some similarities to the geometry of modelled TOC shown in Figs. 8.2 and 8.3. In addition to the central fairway, total porosities of both allomembers are elevated west of R9W5 and east of R3W5, where well control is relatively poor.
Fig. 8.2: TOC of allomember BF3.
Fig. 8.3: TOC of allomember VII.
Fig. 8.4: Total porosity of allomember BF3.
Allomember VII total porosity

Fig. 8.5: Total porosity of allomember VII.
compared to the rest of the study area.

8.3.2 Effective porosity

High clay volumes reduce the porosity that can effectively transmit fluids, known as effective porosity (see section 5.6.2.3.3). After total porosity had been calculated, it was reduced to effective porosity using equation 27. Using this method removed the “ineffective” porosity associated with high clay volumes, as can be seen in the right-hand columns of well plots in Fig. 8.1.

Figure 8.1 illustrates the lateral and vertical variations in effective porosity (PHIT_E_KER in Fig. 8.1) across a small section of the study area and between allomembers. Their associations with clay volume can be seen in Fig. 6.3; highest effective porosities are associated with low clay volumes (approximately <0.2). Across the study area, effective porosity is generally highest at the top of allomember BF3 and throughout allomember VII, although in places (e.g., 100/07-19-045-06W5 and 102/08-36-041-07W5) the effective porosity may be only present in streaks that are less than 0.20 m thick.

Figures 8.6 and 8.7 illustrate the distributions of effective porosity for allomembers BF3 and VII, respectively. Although the distribution of effective porosity is relatively similar to the total porosity, their geometry is influenced by high clay volumes. For example, the effective porosity of allomember BF3 is significantly reduced in allomember BF3 in a west-east oriented region that stretches from T41 R7W5 to T41 R4W5. This area corresponds with the region of high clay volume identified in Fig. 7.9. A similar effect is observed in the effective porosities of allomember VII (Fig. 8.7), wherein effective porosity is removed in T36 R6W5 to 5W5: this area has relatively high clay volumes (Fig 7.10).

8.3.3 Porosity-thickness

Porosity-thickness (Equation 36) represents the net porous reservoir present in an allomember, thereby quantifying its storage capacity. Reduced porosity-thickness indicates decreased porosity and/or a decline in isochore thickness. Increased porosity-
Fig. 8.6: Effective porosity of allomember BF3.
Fig. 8.7: Effective porosity of allomember VII.
thickness, alternatively, signifies either an increase in porosity or an increase in isochore thickness.

Figures 8.8 and 8.9 depict the effective porosity-thickness of allomembers BF3 and VII, respectively. The porosity-thickness of allomember BF3 closely resembles the effective porosity map shown in Fig. 8.6; this is because the isochore thickness of this allomember (Fig. 7.5) only experiences gradual changes in thickness across the study area. In contrast, the porosity-thickness of allomember VII is significantly reduced south of T39 – this is due to the dramatic thinning of allomember VII past this point (Fig. 7.6).

8.4 Brittleness

The brittleness index used in this study was chosen to reflect the proportion of brittle minerals (quartz and carbonate) versus non-brittle or ductile minerals (clay and kerogen) present in the rock matrix (Equation 33). Figures 8.10 and 8.11 illustrate the model of brittleness that was generated for allomembers BF3 and VII, respectively, across the study area in west-central Alberta. These maps closely resemble the maps of clay volume that were generated in Chapter 7 (see Fig. 7.8 and 7.9); high clay volumes correspond with lower brittleness values, whereas low clay volumes are associated with higher brittleness values (>0.81 for allomember BF3 and >0.855 for allomember VII). There is also a strong association between higher brittleness and low TOC (see Figs. 8.2 and 8.3).

8.5 Highlights

- Vertical changes in TOC within coeval strata record depositional conditions that favoured organic matter preservation. Allomembers BF3 and VII exhibit upwards increases in TOC that may reflect the initiation of OAE-II. Modelled TOC is highest in a north-south oriented fairway in the centre of the study area.
- Modelled total porosity, effective porosity, and porosity-thickness for allomembers BF3 and VII indicate that the highest proportion of porous and clay-free reservoir is found in a NNW-oriented fairway in the centre of the study area. Low clay content and increased stratigraphic thickness have the most positive effect on net porous reservoir development.
- Lateral variations in brittleness are controlled by clay volume and organic richness.
Fig. 8.8: Porosity thickness for allomember BF3.
Fig. 8.9: Porosity thickness for allomember VII.
Fig. 8.10: Brittleness of allomember BF3.
Fig. 8.11: Britteness of allomember VII.
Chapter 9

9. Sweet spot mapping of the Second White Specks and Belle Fourche alloformations in the Willesden Green – Gilby region, Alberta, Canada

9.1 Overview

This chapter presents sweet spot maps of the Lower Second White Specks and Belle Fourche alloformations in the Willesden Green area of west-central Alberta.

9.2 Sweet spot maps

9.2.1 Location of producing wells

This thesis sought to determine the degree of co-location between reservoir quality indicators and oil production from Second White Specks wells. Figures 2.9 and 2.10 illustrate the spatial distribution and productivity of successful wells that targeted strata from the Second White Specks Formation. The number of wells in these maps were reduced to only include wells that exclusively produced from the desired target interval – commingled wells were excluded. Second White Specks wells with the highest cumulative oil production are found in a region broadly constrained by T43 to 35, R7 to 3W5 that trends approximately NNW (Fig. 2.10). As cumulative production maps like Fig. 2.10 are biased in favour of older wells – they have had more time to produce greater hydrocarbon volumes – the IP4 map shown in Fig. 2.9 likely better illustrates the true distribution of higher performing Second White Specks wells. Figure 2.9 shows three loosely defined groups of producing wells:

1) T40 to 43, R4 to 7W5
2) T39 to 40, R8 to 9W5
3) T36 to 39, R3 to 7W5.

9.2.2 Overlay maps

The contour maps of petrophysical properties that were generated in Chapter 8 (TOC, clay volume, porosity-thickness, and brittleness) are overlain for allomembers BF3 and VII in Figs. 9.1 and 9.2, respectively. Cutoffs for these petrophysical properties, which
represent different measures of reservoir quality (i.e., storage and flow capacity) were selected on the basis of defining major geometric features like fairways. Areas where multiple reservoir quality indicators overlap are designated “sweet spots” if they coincide with increased lower Colorado Group oil production. If no producing wells are present in the overlapping regions, those areas delineate regions where the Second White Specks and Belle Fourche alloformations have the potential to produce oil at economic rates and should be investigated further. Sweet spots demarcate areas where the probability of a vertical well intersecting a natural fracture network located in porous and permeable reservoir is increased.

9.2.2.1 Allomember BF3

1) T40 to 43, R4 to 7W5: elevated porosity-thickness (>0.1) and brittleness generally overlap with each other and co-locate with better producing wells. This is not the case in T41 to 42 R4W5 and T42 to 43, R7W5; in these areas, brittleness is reduced but porosity-thickness is elevated. The opposite is observed (brittleness is elevated but porosity-thickness is reduced) in T41 R4W5 to 7W5. Brittleness and porosity-thickness appear to define the geometry of this group of successful wells. A weaker association with lower clay volumes (<0.26) is also observed (see T41 and 42, R6W5 and T41 and 42, R4W5).

2) T39 to 40, R8 to 9W5: elevated porosity-thickness and brittleness coincide and co-locate with producing wells. The non-producing well located in T39 R8W5 has elevated brittleness but no developed porosity-thickness.

3) T36 to 39, R3 to 7W5: elevated porosity-thickness and brittleness only overlap in a NNW-oriented region east of R5W5, and do not appear to define the boundaries of this group of producing wells. TOC and porosity-thickness, instead, appear to best define the boundaries of this group of wells.

9.2.2.2 Allomember VII

Sweet spots for allomember VII can be broadly divided into two categories: those north of township 38, and those south of township 39. North of township 39, elevated porosity-
BF3 sweet spot mapping

![Diagram of BF3 sweet spot mapping]

Fig. 9.1: Sweet spot map for allomember BF3.
Fig. 9.2: Sweet spot map for allomember VII.
thickness and brittleness overlap with low clay content. These polygons and define an irregular V-shape that contains many of the wells located in group 1 (T40 to 43, R4 to 7W5). Similar to allomember BF3, wells in group 2 (T39 to 40, R8 to 9W5) are delineated by elevated brittleness and low clay content, although the spatial association with increased porosity-thickness is weaker for allomember VII than for allomember BF3. South of township 39, however, only elevated TOC appears to be associated with better producing wells.

9.3 Highlights

- North of township 39, sweet spots are defined by regions where elevated porosity-thickness and brittleness coincide with reduced clay content. These petrophysical properties define regions where well productivity from the Second White Specks interval is historically higher. Vertical wells that experienced increased production in these areas are attributed to thicker units of porous and permeable reservoir that was likely naturally fractured.

- For allomember BF3, sweet spots south of township 39 are defined either by the intersection of elevated brittleness and increased porosity-thickness, or by elevated TOC coinciding with increased porosity-thickness.

- For allomember VII, the sweet spot south of township 39 is best defined by modelled TOC, although this spatial association is somewhat weaker than in the northern half of the study area.
10 Discussion

10.1 Defining hydraulic flow units

10.1.1 Significance of allostratigraphic bounding surfaces

Hydraulic flow units within the Second White Specks and Belle Fourche alloformations were defined on the basis of allostratigraphic bounding surfaces, upon which contrasting facies were vertically juxtaposed. These surfaces include the K1 disconformity, major flooding surfaces, and the erosional disconformity at the top of allomember BF3 that is mantled by the “red” bentonite (Fig. 6.1). The “red” bentonite surface has been previously recognized as a hiatal surface of nondeposition between the Belle Fourche and Second White Specks alloformations (Tyagi 2009) and later as a subtle unconformity by Plint et al. (2012a). The presence and nature of this unconformity is not acknowledged by Furmann et al. (2014) or Zajac (2016) – they place the Cenomanian-Turonian boundary in a stratigraphically lower position (within allomember BF3) on the basis of bulk geochemistry.

As Fig. 6.5 demonstrates, the amount of erosion experienced by allomember BF3 is relatively subtle; generally, less than a few metres of allomember BF3 are removed. Towards the north of the study area, however (i.e., between wells 06-07-042-07W5 and 07-19-45-06W5), greater than six metres of allomember BF3 are removed. This can be seen in Fig. 7.5; north of T42 R10W5, the isochore thickness of allomember BF3 significantly decreases. In places where the coarser-grained facies of allomember BF3 has been eroded, the coarser-grained facies of allomember VII unconformably overlie finer-grained strata from allomember BF3. Because this erosional surface represents a significant amount of missing time, this study takes a position similar to Tyagi (2009) and Plint et al. (2012a) that the Cenomanian-Turonian boundary is best approximated by this combined hiatal and erosional unconformity.

The origin of the Belle Fourche/Second White Specks unconformity is somewhat enigmatic. If this unconformity only recorded nondeposition (i.e., no erosion), the most
likely scenario for its generation is sediment starvation during maximum sea level, such as the global highstand associated with OAE-II. Because erosion of allomember BF3 is sometimes observed, sediment winnowing and advective transport of fine-grained sediment must have occurred. Figure 6.4 illustrates a scenario during a relative fall in sea-level (generated by eustatic fall or tectonic uplift) – in this depositional model, the sea floor can be progressively eroded by storm-driven bottom currents. The development of the Belle Fourche/Second White Specks unconformity across a shallow epicontinental marine shelf setting could, therefore, be generated by apparently conflicting mechanisms.

As OAE-II was a global highstand event, the mechanism for lowering base level was likely eurybatic (local) in nature. Orogenic loading of the western margin near the Cenomanian-Turonian boundary could have initiated subtle uplift of the sea floor into local bathymetric highs, which could then be eroded by geostrophic flows during storms. Small basins between these bathymetric highs would experience no sediment deposition during lowstand or falling-stage system tracts – in these areas, a disconformity correlative with the erosive unconformity would be recorded. Because the epicontinental shelf gradient was so shallow, even subtle uplift or sea level fall could have significantly impacted sedimentation in this manner. Within the study area, this unconformity represents non-deposition and erosion that is associated with some type of relative base level fall.

Defining the mechanism and extent of the Belle Fourche/Second White Specks unconformity was out of scope for this study. The recognition of this allostratigraphic surface revealed regions where erosion of allomember BF3 had removed potentially economic, porous reservoir rock (see Figs. 6.5 and 8.1), which has not been observed in other studies of the same rocks. The degree of erosion along the Belle Fourche/Second White Specks unconformity, therefore, exerts control on the vertical stacking of reservoir facies within the Belle Fourche and Second White Specks alloformations. This observation has major implications for future exploitation of the Second White Specks stratigraphic interval – if potential reservoir has been eroded, less net pay will be present within that well.
10.1.2 Quantifying lateral facies variation

In this study, the “red” bentonite surface marks the vertical transition between the finer-grained facies of allomember BF3 and the highly amalgamated coarser-grained facies (facies 3 through 5) of allomember VII (see Fig. 6.5). Across the Belle Fourche/Second White Specks unconformity, the degree of facies amalgamation increases. Within the Belle Fourche alloformation, facies stacking patterns reflect a gradual vertical transition into coarser-grained, shallower water facies. Allomember VII, in contrast, exhibits a significant increase in coarse-grained facies amalgamation. This suggests that deposition of allomember VII took place in higher energy, shallower water conditions than allomembers from the Belle Fourche alloformation. This unconformity, therefore, represents a period of environmental change that occurred near the Cenomanian-Turonian boundary. Laterally continuous, amalgamated sheets of sediment may be deposited by storms on shallow marine shelves (Atkinson et al. 1986; Gaynor & Schiehing 1988) – this appears to be analogous to the facies stacking patterns and geometry of allomember VII that is observed in this study.

Plint et al. (2012b) demonstrated that changes in the orogenic thrust load could cause regions of maximum accommodation (depocentres) to shift laterally between allomembers, thereby influencing paleogeography and sedimentation patterns. Previous studies utilized thickness (isopach or isochore) maps to estimate the location of lower Colorado Group mudstone depocentres across Alberta and British Columbia (Kreitner 2002; Plint & Kreitner 2005; Varban & Plint 2005; Kreitner & Plint 2006; Tyagi et al. 2007; Varban & Plint 2008a,b; Tyagi 2009; Plint et al. 2012b; Zajac 2016). On their own, thickness maps cannot quantify the lateral distribution of facies within allomembers, as there is no way to establish lateral changes in mineralogy.

Zajac (2016) observed significant lateral facies changes within individual allomembers of the Belle Fourche and Second White Specks alloformations in west-central Alberta. He interpreted these variations as the result of subtle changes in water depth and sedimentary transport processes across a shallow epicontinental shelf, which may have included combined flows generated by storms. In his study, resistivity and gamma ray values were considered good proxies for lithology variation within lower Colorado Group
Similarly, Varban and Plint (2008b) used a gamma ray cutoff of 50 API to estimate the distribution of net sand (rocks with >50% sand) within the Kaskapau alloformation. These approaches do not adequately capture the mineralogical variation of organic-rich shaley rocks: resistivity measurements and gamma ray logs are strongly affected by organic matter and clay content as well as borehole environmental effects (e.g., invasion and borehole breakout). To parse the individual contributions of lithological components (e.g., clay content, TOC), these components must be modelled in three dimensions.

Lateral facies variations were quantified in three dimensions in this study by creating isolith maps. In these maps, isochore thicknesses (Figs. 7.3 through 7.6) were overlain with clay volume (Figs. 7.7 through 7.10). By constructing isolith maps in this way, it was possible to discern the relative contributions of fine-grained sediment supply (clay) and accommodation (thickness) to the facies within individual allomembers. The isochore maps revealed a previously unrecognized clockwise and northwards shift in maximum accommodation across the basin, which may have been caused by tectonic flexure from subtle changes in orogenic loading (Plint et al. 2012b). Shifts in the location of clay-poor facies (low clay volume) between allomembers were interpreted to record changes in sediment supply locations.

Comparison of the clay volume and isochore maps revealed regions where clay volumes were low but isochore thicknesses were reduced (e.g., the northwest corner of the study area in Fig. 7.10) – these regions delineate places where clay was not deposited, and accommodation space was limited. This resulted in deposition of thin and clay-poor rocks. Alternatively, regions where isochore thicknesses were increased and clay volumes are higher (e.g., T41 to 42 and R5 to 6W5 in Fig. 7.9) demarcate areas where accommodation was increased but coarse sediment supply was not available. These observations suggested there is significant lateral facies heterogeneity across the study area and between allomembers. These maps may also be used to show the distribution of net reservoir across west-central Alberta; increased isochore thickness and decreased clay volume correspond with the preferred reservoir facies (facies 3 through 5) shown in Fig. 6.5. Using the repeatable and petrophysically sound methods developed in this thesis,
these maps have helped to establish – for the first time – the lateral facies heterogeneity of the lower Colorado Group in west-central Alberta.

Composite isolith maps are commonly made in industry but are not frequently utilized in the literature. This is likely because petrophysical and stratigraphic studies are most often performed independently. These maps are relatively simple to construct and have significant interpretive power – they should be more widely utilized in future stratigraphic studies where lateral facies changes are under investigation.

Less than half of the wells used for isochore thickness mapping were usable for clay volume calculation, and only one well (100/07-19-045-06W5) had clay XRD data available for petrophysical model adjustment. This means that a denser average well spacing was used for thickness mapping relative to clay volume calculation – the two maps do not perfectly correspond with one another. The mismatch in resolutions could have been rectified by removing data points associated with wells that did not have LAS data.

10.2 Petrophysical property modelling

Prior to this work, there were no publicly available static petrophysical models of the Second White Specks and Belle Fourche alloformations. Regional variations in reservoir quality and lithology had been characterized on the basis of maps of average wireline log values (Zajac 2016) and core analyses (Bloch et al. 1999; Furmann et al. 2014; Zajac 2016).

This study sought to reduce uncertainty associated with petrophysical modelling of Second White Specks reservoirs. The magnitude of error, however, remains unknown. Wireline logging tools are proprietary – there is no way to access the code that was used to transform the signal from the reservoir into a recorded measurement. Log measurements have some amount of error associated with this data transformation: they represent imperfect proxies of rock properties such as TOC or clay volume. Moreover, the wireline logging tools are individually calibrated by the logging company to each well and may be further calibrated during separate logging runs. There are also differences in geophysical wireline log tools depending on the vintage of the tool and the operating
company it was developed by – the tool physics and design may vary on the basis of sensitivity, accuracy, precision, or depth of penetration. The tool specifications discussed in section 3.6.2 represent average tool configurations, and only approximate the most likely setup of a particular sonde. To adequately characterize measurement errors from the primary acquisition of petrophysical data, the well log dataset would have to be restricted to wells where all the logging parameters were known – this is not feasible due to the extremely limited nature of the well log dataset in this study.

Although some of the uncertainties mentioned above could have been resolved through a wireline log normalization process, normalization may have potentially suppressed lateral changes in lithology across the study area. Quantifying the error associated with geophysical wireline logging is beyond the scope of this project – this uncertainty, however, can be mitigated by setting reasonable constraints for well log responses in expected lithologies for individual allomembers (Table 6.2 and Fig. 6.3). This establishes commonalities between wells that may have had different logging configurations (e.g., different operators, well vintages, tool physics, calibration), thereby allowing for correlation of hydraulic flow units between wells (Fig. 6.5) that can be used for petrophysical modelling.

10.2.1 TOC

Although the thermal maturity of the Second White Specks and Belle Fourche alloformations is well constrained (e.g., Furmann et al. 2014), variations in source rock quality had not been previously investigated prior to this study. Figure 8.1 illustrates the estimated TOC profiles through the Belle Fourche and Second White Specks alloformations for three wells in the study area. The Issler et al. (2002) method was used on the basis of a strong linear relationship between modelled values and Rock-Eval TOC analyses from the 7-19 core (Fig. 5.5). Highest modelled TOC values (2.75 to 3.5%) were recorded at the top of allomember BF3 and throughout allomember VII. This upwards increase in TOC relative to the preceding allomembers (BF1 and BF2) may have been caused by the initiation of OAE-II, which increased nutrient upwelling in the WIS and enhanced organic carbon burial. Figures 8.2 and 8.3 illustrate the modelled distribution of TOC throughout the study area in allomembers BF3 and VII, respectively – highest TOC
values occur in a north-south oriented fairway in the middle of the study area (R4W5 to R7W5) and decreases both to the west and east of that fairway.

Total organic carbon (TOC) was modelled in this study using the Issler et al. (2002) and Crain and Holgate (2014) method. This method relies on elevated resistivity and slow sonic responses to detect intervals with elevated organic content. Implicit in this method is the assumption that these well log responses are uniquely related to kerogen volume – this is not necessarily true. Increased resistivity measurements can be produced by an increase in carbonate mineral matrix or by non-conductive liquid hydrocarbons stored in matrix or fracture porosity, in addition to their association with elevated organic content. Sonic travel times, similarly, can be slowed by hydrocarbon-filled porosity, clay-bound water, natural fractures, or low-density organic matter. Consequently, the combined Issler method may not provide a unique solution for TOC – the TOC model presented in this study may actually delineate the locations of open, hydrocarbon-filled natural fractures in addition to areas with increased organic richness.

10.2.2 Porosity

Furmann et al. (2014) observed that the highest reservoir quality (elevated total porosity) interval in the 7-19 core occurred at the top of their Belle Fourche Formation, which approximates the top of allomember BF2 in Fig. 8.1. Although this observation is true for the 7-19 core, it is not representative of most of west-central Alberta. Highest modelled effective porosities (>2.5 volume %), which best approximate the potential storage capacity of the Second White Specks and Belle Fourche alloformations due to their high clay volumes, were observed in this study in allomember VII and in the coarser-grained facies of allomember BF3. The coarse-grained facies of allomember BF3 is not present in the 7-19 core due to removal by the Second White Specks/Belle Fourche erosional unconformity (Figs. 6.5 and 8.1). This unconformity was not detected by Furmann et al. (2014) because they placed the Second White Specks – Belle Fourche boundary stratigraphically lower compared to the “red” bentonite used by Tyagi et al. (2007) and others, including this study.
Lateral variations in total porosity within the Second White Specks and Belle Fourche alloformations had previously been constrained by helium porosimetry data from several cores spread across Alberta, British Columbia, and Saskatchewan (Bloch et al. 1993, 1999; Furmann et al. 2014; Zajac 2016). Using the allostratigraphic framework to define petrophysical zones permitted the application of a kerogen-corrected total density porosity model across the study area, which was calibrated on the basis of helium porosimetry data taken from one well (7-19) in the study area by Furmann et al. (2014). Using a kerogen-corrected porosity model suppressed anomalous density porosities associated with low-density organic matter (Fig. 5.8), resulting in a porosity model that agreed closely with the total porosity measurements from Furmann et al. (2014). When modelled total porosity, effective porosity, and porosity-thickness were extended across the study area, the highest proportion of porous and clay-free reservoir within allomembers BF3 and VII were found in a NNW-oriented fairway in the centre of the study area.

Relying on the 7-19 core to constrain lateral variations in total porosity introduced some uncertainty with greater distance away from the 7-19 well. In this study, lateral constraints of porosity in this study rely on log-based calculations of density porosity, rather than porosity analyses from other cores in the area as none were available. The total porosity model used a matrix density (2.74 g/cm$^3$) derived from a neutron porosity and bulk density cross plot that used log data from four wells (Fig. 5.7) – a 1% shift in the $y$-intercept (matrix density) introduces a $\pm 0.027$ g/cm$^3$ shift in uncorrected matrix density (no kerogen correction), which translates to calculated total density porosity variations of $\pm 1.4\%$. A 1% shift in matrix density is well within the limit of neutron and density porosity variation observed within the Second White Specks and Belle Fourche intervals in Fig. 5.7. Without core data for calibration, however, 2.74 g/cm$^3$ is the best available estimation of matrix density for the study area. Establishing the confidence interval in this chart would have helped to improve confidence in the selected matrix density value.

The kerogen-corrected density porosity equation used in this study (Equation 24) is derived from an assumption that low bulk density readings are associated with increased matrix porosity and reduced fluid density (i.e., the presence of hydrocarbons). This
assumption is not correct, because porosity modes associated with open natural fractures and organic matter cannot be discriminated from matrix porosity using this method. Clarkson and Pedersen (2011) demonstrated that Second White Specks wells have production histories that reflect dual porosity modes that are most likely associated with increased depositional porosity and fracture porosity. Porosity within organic matter in magnetic resonance (NMR) logs are required to assess the contribution of fracture porosity to the modelled porosities – this type of log data was not available. As fracture porosity cannot be deconvolved from total or effective porosities without NMR log data, the kerogen-corrected density porosity could reflect a combination of fracture and matrix porosity.

Calculating kerogen-corrected density porosity required an estimate of kerogen density, which was not available in the study area. Kerogen density was assumed to be a constant value of 1.15 g/cm$^3$ throughout the study area, on the basis of vitrinite reflectance data from Furmann et al. (2014). If this estimate was too low, the kerogen-corrected density porosity will have underestimated the total density porosity of the Second White Specks and Belle Fourche alloformations. An overestimate of kerogen density, conversely, would have caused an overestimate of total density porosity. In the 7-19 well, the kerogen-corrected density porosity agrees with the helium porosimetry data (Fig. 8.1) – providing a basis for using this kerogen density in other wells. This, however, is an oversimplification. Kerogen density varies with thermal maturity and organic matter type and, therefore, may vary both laterally between wells and vertically within allomembers. Due to the model agreement with the porosity data from core, the kerogen density of 1.15 g/cm$^3$ presented a best possible fit for the available data.

Effective porosity (Equation 26) removes the contribution of clay porosity to total porosity, thereby establishing the storage capacity available for hydrocarbons in the reservoir. No core calibration data was available to constrain the effective porosity model (e.g., mercury injection tests). Higher effective porosities calculated in Chapter 8 and the coarser-grained reservoir facies mapped in Chapter 6 overlap (Fig. 8.1), providing some assurance that the effective porosity maps (Figs. 8.6 and 8.7) are actually capturing variations in depositional effective porosity.
Clay volume, $V_{\text{clay}}$, impacts effective porosity (Equations 3 and 4). Higher $V_{\text{clay}}$ values reflect a larger differential between the measured GR values and $GR_{\text{clean}}$ ($5^{th}$ percentile clay-free gamma ray value). In organic-rich shales, the measured GR value can be significantly increased by uranium in organic matter, thereby causing an overestimate of $V_{\text{clay}}$ and an underestimation of the effective porosity in that interval. Although this effect can be resolved through the use of the uranium-free (CGR) curve, SGR log data was only available for one well (2-14). As the lateral distribution of uranium in the Second White Specks and Belle Fourche alloformations is not currently known, the modelled effective porosity may be inaccurate in organic-rich zones. The magnitude of this effect, however, cannot be determined with currently available core and log data.

Effective porosity is also affected by clay mineralogy (Equation 26). By Equation 26, clay minerals with increased differences between their dry and wet densities (i.e., mixed layer clays with more bound water) have higher clay porosities, and therefore reduce effective porosity by a larger amount. Detailed clay mineralogy from core was not available, so the Th/K ratio from SGR logging of the 2-14 was utilized for clay mineral determination instead (Fig. 5.9). Figure 5.9 indicates that the clay mineralogy approaches a mixed-layer (illite and smectite) composition, which corresponds to a $\rho_{\text{wetclay}}$ of 1.7 g/cm$^3$ and a $\rho_{\text{dryclay}}$ of 2.7 g/cm$^3$ (Chitale 2010). If no smectite is present and illite clays dominate the rock matrix, $\rho_{\text{wetclay}}$ increases to 2.5 g/cm$^3$ and the calculated clay porosity decreases. As Furmann et al. (2014) reported between 12 and 36 wt% illite in the 7-19 core, the $\rho_{\text{wetclay}}$ used in this study may have been too low. Using an illite clay density would significantly improve the effective porosity-thickness present in the Belle Fourche and Second White Specks alloformations in this study, but there is no basis for changing this until calibration to core is established.

### 10.2.3 Brittleness

No DSSI logs or geomechanical tests run or core were available to establish the brittleness of the Second White Specks or Belle Fourche alloformations in the study area. To compensate for this, Furmann et al. (2014) calculated brittleness using the lithological index defined by Wang and Gale (2009), which uses wt %. They reported that the $BI$ for
their Second White Specks Formation averaged 47% and ranged from 39 to 61%, whereas the $BI$ for their Belle Fourche Formation was slightly lower on average (42%) and ranged from 25 to 46%. The slight difference in brittleness between formations was attributed to a higher proportion of carbonate minerals in the Second White Specks Formation relative to the Belle Fourche (Gale et al. 2014). As noted in section 5.6.3, brittleness indices that use volume % (e.g. Katz et al 2016; Mathia et al. 2016; Rybacki et al. 2016) are preferred for use in organic-rich reservoirs over those that use wt % (e.g., Jarvie et al. 2007; Wang & Gale 2009; Jin et al. 2014a,b) because the contribution of low-density organic matter to ductile behaviour may be otherwise overlooked (Rybacki et al. 2016). In this study, the volumetric brittleness index described by Mathia et al. (2016) was used for the Belle Fourche and Second White Specks alloformations, thereby resulting in average $BI$ of 0.79 and 0.82 for those formations, respectively. The results from Furmann et al. (2014) and this study cannot be directly compared, as the indices used were fundamentally different and their stratigraphic zonation also differs. They do, however, support the incremental increase in the brittleness of allomember VII relative to BF3.

The Second White Specks and Belle Fourche alloformations contain pyrite, multiple carbonate mineral phases (calcite, siderite, and dolomite) as well as different types of clay minerals. These mineral phases may all have different contributions to brittleness (Rybacki et al. 2016). This study assumed that all carbonate minerals were associated with dolomite, and all clay minerals were mixed-layer clays (illite or smectite). This is a simplification of the real mineral assemblage. XRD analysis of mineral volumes would have enabled more accurate estimation of clay volume (ductile), pyrite (brittle) and multiple carbonate (brittle) mineral phases, as well as their associated volumes.

The carbonate volume model used in this study (Equation 28) only works for cored wells that have total inorganic carbon data available (Jiang et al. 2017). Because inorganic carbon was not available for non-cored wells, kerogen volume was used to calculate carbonate volume % using a linear regression (Fig. 5.10). In general practice, PEF logs would be used to establish carbonate mineral volumes, so kerogen was used in their absence. Based on the LECO TOC data that is attached to this thesis, inorganic carbon
was often twice as high as the TOC. As a result, the regressions shown in Fig. 5.10 likely underestimate the percentage of dolomite present in the reservoir. The maps of brittleness for allomembers BF3 and VII (Figs. 8.10 and 8.11), however, mostly reflect the geometry of the clay volume maps from Chapter 7 and the TOC model from Chapter 8 — thereby suggesting that lateral variations in brittleness mostly correspond to the volume of ductile components.

### 10.3 Sweet spot mapping

Zajac (2016) identified reservoir fairways in the Second White Specks Formation on the basis of gamma ray and resistivity heat maps. As Chapter 3 demonstrated, the responses of these well logs to organic, clay-rich lithologies are complex. High resistivities may correspond to the presence of hydrocarbons, solid organic matter, and organic maturity levels, whereas high gamma ray values are associated with formation radioactivity that originates from organic matter or clay minerals. Consequently, these measurements do not correspond with reservoir quality indicators like clay volume, porosity, organic richness, hydrocarbon saturation, or brittleness. By applying a rigorous approach to petrophysical modelling, this thesis sought to deconvolve the signals of reservoir quality indicators embedded within a basic suite of well logs in order to establish changes in rock properties that could impact well production.

The sweet spot maps in Chapter 9 reveal regions where modelled petrophysical properties co-locate with successful producing wells from allomembers BF3 and VII. Producing wells for allomembers BF3 and VII can be broadly separated by township 39. North of township 39, elevated porosity-thickness and brittleness overlap with reduced clay content and improved well performance — this is likely due to the presence of thick, relatively porous and brittle reservoir that became naturally fractured. South of township 39, sweet spots are constrained best by modelled TOC. The sweet spots in this region do not exhibit the same degree of overlap between modelled petrophysical properties as is seen north of township 39. These fairways have not been previously delineated in any studies that are currently publicly available.
The sweet spot maps included in this work suffer from a certain degree of confirmation bias, as there are not many wells located outside the delineated fairways. This is partially due to the exclusion of commingled wells: these are wells where the Second White Specks Formation was being co-produced with other formations in order to improve the overall well production. In general practice, formations are commingled when any single formation does not have sufficient reservoir quality to produce hydrocarbons at economic rates. From an oil production perspective, these wells are problematic to deal with as the individual contributions of each formation cannot be easily separated.

The producing wells in this study could not be separated on the basis of perforation locations and hydraulic fracturing styles within specific allomembers due to the limited number of producing wells in the area. Moreover, the reported position of perforations and hydraulic fracture treatments in geoSCOUT may not actually capture the location and extent of induced fractures: they may extend into other allomembers, particularly if relative brittleness values between allomembers favour vertical fracture propagation.

The relative contributions of individual reservoir quality indicators to well performance from the Second White Specks interval could not be established, likely due to the somewhat non-unique nature of the model responses. It is possible that the maps of TOC, brittleness, and effective porosity and, by extension, porosity-thickness presented in this thesis may have detected enhanced reservoir quality associated with open, hydrocarbon-filled natural fractures.

10.4 Recommendations for future Second White Specks exploration

- Careful delineation of the Second White Specks/Belle Fourche unconformity may help identify areas with vertically-stacked pay in both allomembers BF3 and VII.

- The sweet spots identified in this study, which likely delineate areas with increased reservoir quality, should be high-graded as targets for three-dimensional seismic acquisition and geophysical inversion. This should confirm if the sweet spots identified in this thesis actually capture regions with increased reservoir quality.
• NMR and DSSI logs should be run in any new wells drilled in the Second White Specks Formation in order to assess fracture porosity and elastic moduli, respectively. This would better establish brittleness variation and potentially help avoid areas where wellbore stability in long horizontal wells had previously caused issues. Additionally, running borehole XRF logs would help constrain mineralogical variations.

• Over 2200 wells in the study area penetrate the Second White Specks interval, of which less than 5% are completed in the lower Colorado Group. Existing, non-producing wells should be re-logged with cased hole tools to try and identify missed pay in allomembers BF3 and VII.
Chapter 11

11 Conclusions

The primary goal of this research was to find a way to reliably predict what geographic areas and stratigraphic zones are more likely to produce consistently well from the Second White Specks Formation. It was hypothesized that areas with higher relative brittleness (increased silica and carbonate content) and increased porosity would co-locate with improved inflow performance from the Second White Specks Formation. To adequately test this hypothesis, this study sought to answer three key questions. The answers to these conclusions are drawn from the discussion in Chapter 10.

1) Can the Second White Specks and Belle Fourche Formations in the study area be subdivided into allomembers that provide a framework for mapping coeval hydraulic flow units?

- Coeval depositional units (allomembers) were defined by extending and subdividing the regional allostratigraphic framework established by Tyagi et al. (2007). This was accomplished by correlating previously unrecognized flooding surfaces throughout the study area, which were tied to core data and geophysical wireline log signatures. The interval of interest, which was constrained below by the K1 disconformity and above by the allomember VII flooding surface, was subdivided into four allomembers.

- Facies observed in this study are consistent with a distal to mid-shelf, marine, low-gradient ramp setting in a shallow (40 to 70 m water depth) epicontinental sea. Sediments were transported offshore by storm-generated combined flows. Isolith maps, constructed by overlaying clay volume with isochore thickness, demonstrate lateral facies heterogeneity across the study area and between allomembers.

- The contact between the Belle Fourche and Second White Specks alloformation, capped by the “red” bentonite and spanning the Cenomanian-Turonian boundary,
is unconformable across the study area. The top of allomember BF3 was, at times, truncated by this unconformity. Across this unconformity, the depositional style of lower Colorado Group allomembers subtly change: in the Belle Fourche alloformation, coarser-grained “reservoir” facies do not exhibit a high degree of amalgamation; in the Second White Specks Formation, by comparison, a higher degree of amalgamation and vertical stacking of coarser-grained facies was observed. This results in increased reservoir facies thickness in allomember VII relative to allomembers from the Belle Fourche (BF1, BF2, and BF3).

- Second White Specks and Belle Fourche allomembers exhibit significant lateral facies heterogeneity across the study area. This was established on the basis of isolith maps. These maps illustrate changes in clay content associated with sediment supply, and stratal thickness variations that were attributed to shifts in the location of sedimentary depocentres.

- Allomembers of the Second White Specks and Belle Fourche represent coeval depositional units that function as hydraulic flow units for petrophysical analysis and sweet spotting.

2) Can the petrophysical properties of the Second White Specks and Belle Fourche Formations be reliably modelled, using limited geophysical well data and sparse core control for calibration?

- Using the Issler method, TOC was modelled for hydraulic flow units within allomembers from the Second White Specks and Belle Fourche Formations. This model was in agreement with LECO TOC and Rock-Eval data collected from cores in the study area. Elevated TOC in allomembers BF3 and VII reflect the initiation of OAE-II near the Cenomanian-Turonian boundary. Allomembers exhibit lateral variations in organic richness (TOC) that are likely associated with increased organic carbon preservation in the centre of the study area.

- Using a kerogen-corrected porosity method, total density porosity was modelled for lower Colorado Group allomembers. This model provided a close match to
existing core porosity measurements. The kerogen-corrected porosity method effectively suppressed anomalous porosities associated with increased organic richness. In addition to illustrating lateral and vertical variations in matrix porosity, this porosity model may have captured regions with enhanced natural fracture porosity.

- By assuming a mixed-layer clay mineral assemblage, effective porosity was modelled for the Belle Fourche and Second White Specks Formations. Units with effective porosity coincide with coarser-grained “reservoir” facies at the top of individual allomembers. Effective porosity was particularly well developed in allomembers BF3 and VII, suggesting that these units have improved storage capacity.

- Applying a volumetric brittleness index to allomembers BF3 and VII revealed significant lateral variability in brittle rock behaviour across the study area. These variations appear to be controlled by elevated ductile mineral components (clay content and TOC).

- *Reasonable estimates of reservoir quality can be developed even when data is sparse. Depositionally controlled variations in reservoir quality were revealed when petrophysical parameters (lithology, porosity, and brittleness) were confined to allomembers.*

3) **Is there a spatial association (co-location) between reservoir quality indicators (e.g., brittleness and porosity thickness) and oil production?**

- *Combining brittle mineral models with porosity-thickness, TOC, and clay volume trends into sweet spot maps revealed potentially economic fairways in the Second White Specks and Belle Fourche alloformations that co-located with increased historical oil production. These trends have not been previously recognized in the literature.*

This thesis used petrophysical principles and theory to apply petrophysical methods to real geological data. The integrated petrophysical and allostratigraphic method of sweet
spot mapping established in this thesis provides a framework for delineating fairways in underexplored unconventional basins where well log data is scarce. Although the petrophysical models developed in this work are imperfect and potentially non-unique responses to reservoir quality indicators, they provide critical information about variations in reservoir quality and brittle behaviour. Sequence stratigraphic methods and petrophysical analyses are often combined when seismic data is available for nonlinear joint inversions. The practice of integrating petrophysics and allostratigraphy for exploration purposes, however, is not commonly attempted. The method presented in this thesis provides a way to estimate lateral and vertical variations in reservoir quality without needing seismic data.

11.1 Future work

The core analysis database developed within this study should be supplemented with several key analyses to improve the accuracy of the petrophysical models herein:

- Helium porosimetry data taken from other cores and at higher vertical resolution (< 0.5 m) to ground-truth modelled lateral and vertical variations in total porosity within coeval strata;
- Core bulk density and core matrix density data to calibrate the matrix density used for total porosity estimation, and to better establish pore fluid density;
- Local measurements of kerogen density to improve the total porosity correction for organic content;
- Total sulphur measurements to estimate the distribution of pyrite;
- XRD analysis of matrix and clay mineralogy to constrain the lithological variations of individual allomembers, especially with regards to carbonate mineralogy as it is not easily modelled without PEF logs.

Further improvements to the petrophysical model could be achieved through more sophisticated well logging:

- The addition of uranium-free SGR log data would assist in improved calibration of clay volumes across the area, reducing uncertainty associated with the calculation of effective porosity.
• Mineralogical logs are rarely available. Regional, field-scale studies of brittleness within the Second White Specks and Belle Fourche alloformations would benefit significantly from robust mineralogical modelling because vertical and lateral variations in apparent brittleness could be investigated.

• The addition of DSSI logs would assist in the development of static geomechanical models of brittleness, which could be compared and contrasted with lithological brittleness indices. This would help establish an association, if any, between changes in brittle mineralogy and elastic moduli in organic-rich mudstones. Trend surface mapping (e.g., residual mapping) could help constrain the localized perturbations associated with small-scale structural relief along major bounding surfaces – these small variations may be associated with small faults or natural fractures.

Successful vertical Second White Specks Formation wells have historically accessed natural fracture networks with enhanced flow capacity. Although this work has better constrained lateral variations in the brittleness of the Second White Specks Formation across west-central Alberta, the locations of those natural fracture networks remain somewhat uncertain. High brittleness values only indicate possible natural fracture development within an area. If 3D seismic data is available for the Willesden Green region in the lower Colorado Group interval, an integrated petrophysical, stratigraphic, and structural study should be undertaken within the high-graded “sweet spots” shown in Chapter 9 to ascertain the location of fault networks and natural fractures. Trend surface mapping (e.g., residual mapping) could help constrain the localized perturbations associated with small-scale structural relief along major bounding surfaces – these small variations may be associated with small faults or natural fractures. A 3D seismic dataset would enable the use of nonlinear joint inversion methods for estimation of reservoir quality parameters (e.g., clay volume, porosity, total organic content, and brittleness), which could help constrain the otherwise sparsely located well data and resulting petrophysical models of the lower Colorado Group. This could serve as a case study for the comparison of deterministic and inverse petrophysical modelling methods. This could also help separate the relative contributions of different petrophysical properties to improved well performance.
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