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BIOREGIONAL ASSESSMENTS

CSIRO

Petroleum prospectivity of the Beetaloo Sub-basin

Technical appendix for the Geological and Bioregional Assessment: Stage 2

2020

A scientific collaboration between the Department of Agriculture, Water and the Environment, Bureau of Meteorology, CSIRO and Geoscience Australia

The Geological and Bioregional Assessment Program will provide independent scientific advice on the potential impacts from development of selected unconventional hydrocarbon plays on water and the environment. The geological and environmental data and tools produced by the Program will assist governments, industry, landowners and the community to help inform decision making and enhance the coordinated management of potential impacts.

The Program is funded by the Australian Government Department of the Environment and Energy. The Department of the Environment and Energy, Bureau of Meteorology, CSIRO and Geoscience Australia are collaborating to undertake geological and bioregional assessments. For more information, visit http://www.bioregionalassessments.gov.au.

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Authorship is listed in relative order of contribution.

On 1 February 2020 the Department of the Environment and Energy and the Department of Agriculture merged to form the Department of Agriculture, Water and the Environment. Work for this document was carried out under the then Department of the Environment and Energy. Therefore, references to both departments are retained in this report.

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Cover photograph

Mataranka Thermal Pools, Beetaloo GBA extended region, October 2018
Credit: Alf Larcher (CSIRO)
Element: GBA-BEE-2-381

Executive summary

An assessment of petroleum plays in the Beetaloo Sub-basin likely to be developed in a five to ten year time frame has been undertaken as part of the Australian Government's Geological and Bioregional Assessment Program. This aims to both encourage exploration and to understand the potential impacts of petroleum resource development on water resources and the environment.

The Beetaloo Sub-basin is a structural component of the greater McArthur Basin in the NT, located about 500 km south-east of Darwin. It covers an area of approximately 28,000 km^2 and contains a succession of Mesoproterozoic Roper Group sediments more than 5000 m thick. The Beetaloo Sub-basin represents a broad depression bounded by several prominent structural highs, and it is divided into eastern and western elements by the Daly Waters High. The outline of the Beetaloo Sub-basin used in this study is that defined by the Northern Territory Government (Department of Primary Industry and Resources (NT), 2017a). Overlying sedimentary basins include the Neoproterozoic to Paleozoic Georgina, Wiso and Daly basins and the Mesozoic Carpentaria Basin.

The Beetaloo Sub-basin is prospective for unconventional hydrocarbons, and is estimated to contain significant technically recoverable shale and tight gas resources. Plays most likely to be developed in a five to ten year time frame in the Beetaloo Sub-basin include shale plays in the Kyalla Formation and the Amungee Member of the Velkerri Formation. In 2017, following completion of extended production testing at the Amungee NW-1H exploration well, Origin booked 2C contingent resources of 6.6 Tcf for the "B shale" interval in the Amungee Member of the Velkerri Formation. An additional play in the Beetaloo GBA region most likely to be developed in a five to ten year time frame is a tight sandstone play in the Hayfield sandstone member of the Hayfield mudstone. This play occurs in the Neoproterozoic units overlying the Beetaloo Sub-basin.

The volume of hydrocarbons present within a play, as well as the proportion of gas and liquids that can be produced, depends on the play type and the specific geological characteristics of both the source and reservoir rocks. To underpin further work on understanding likely development scenarios, the physical formation properties required for each play to be successful were characterised and play fairway analysis used to map the relative prospectivity of each play across the Beetaloo GBA region. Results show that the Amungee Member of the Velkerri Formation is potentially prospective for either liquids-rich or dry gas over most of the Beetaloo Sub-basin. The Kyalla Formation liquids-rich gas play and Hayfield sandstone member liquids-rich gas/oil play are primarily restricted to the eastern sub-basin area.

Although the extent of the plays mapped here inform the assessment of potential impacts on associated assets at the surface and overlying surface water – groundwater systems, this analysis is based on geological constraints only. Considering the development of each play in the context of likely economic outcomes is important for any future analysis.

Contents

Figures

Tables

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- State and Territory Government Science Technical Review: This group includes scientists and engineers from the Northern Territory Government.

Valuable comments were also provided by Dot Close, Tim Munson, Ben Williams (Northern Territory Geological Survey), Todd Hoffman (Pangaea Resources), David Close, Angus McIntyre (Santos), Alexander Côté, Brenton Richards and Elizabeth Baruch (Origin Energy).

Abbreviations and acronyms

Abbreviation/acronym	Definition
AER	Australian Energy Regulator
AERA	Australian Energy Resources Assessment
API	American Petroleum Institute
A-R	as received
BI	brittleness index
BV	bulk volume
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CO_2	carbon dioxide
CSG	coal seam gas
DOM	dispersed organic matter
DST	drill stem test
EIA	United States Energy Information Administration
GBA	Geological and Bioregional Assessment
GIP	gas-in-place
GOR	gas-to-oil ratio
HI	Hydrogen Index
Ma	million years before the present
MD	measured depth along borehole
MEM	mechanical earth model
MSL	mean sea level
NORR	net organically rich ratio
NSW	New South Wales
NT	Northern Territory
PDPM	pressure decay permeability
PRMS	Petroleum Resources Management System
PV	pore volume
SA	South Australia
SPE	Society of Petroleum Engineers

Abbreviation/acronym	Definition
TOC	total organic carbon
TR	transformation ratio
USGS	United States Geological Survey
WMS	web map service
wt	weight
XRD	X-ray Diffraction

Units

Unit	Description
bbl	barrels
bbl/mmscf	barrels per million standard cubic feet
Bcm	billion cubic metres
%EqVR	vitrinite reflectance equivalent (as a percentage)
g/cc	grams per cubic centimetre
km	kilometres
kPa	kilopascals
MPa	megapascals
MPa/km	megapascals per kilometre
m	metres
m^3	metres cubed
mD	milliDarcy
mg HC/g TOC	milligrams of hydrocarbons per gram of total organic carbon
mg CO_2/g TOC	milligrams of CO_2 per gram of total organic carbon
mg/g	milligrams per gram
mg/L	milligrams per litre
mm/y	millimetres per year
mmbbl	million barrels
mmcfd	million cubic feet per day
mmscf	million standard cubic feet
mS/cm	millisiemens per centimetre (= 1000 uS/cm)
mole%	mole (as a percentage)
PJ	petajoules - 10^{15} joules
psi	pounds per square inch
psi/ft	pounds per square inch per foot
scc/g	standard cubic centimetres per gram
scf	standard cubic foot
scfd	standard cubic foot per day
scf/stb	standard cubic foot per stock tank barrel

Unit	Description
stb	stock tank barrel
t	tonne (1,000 kg)
%TOC	total organic carbon (as a percentage)
Tcf	trillion - 10^{12} cubic feet
TJ	terrajoules
%Ro	vitrinite reflectance in oil (as a percentage)
vol%	volume (as a percentage)
wt%	weight (as a percentage)

The Geological and Bioregional Assessment Program

The $35.4 million Geological and Bioregional Assessment (GBA) Program is assessing the potential environmental impacts of shale and tight gas development to inform regulatory frameworks and appropriate management approaches. The geological and environmental knowledge, data and tools produced by the Program will assist governments, industry, landowners and the community by informing decision making and enabling the coordinated management of potential impacts.

In consultation with state and territory governments and industry, three geological basins were selected based on prioritisation and ranking in Stage 1: Cooper Basin, Isa Superbasin and Beetaloo Sub-basin. In Stage 2, geological, hydrological and ecological data were used to define 'GBA regions': the Cooper GBA region in Queensland, SA and NSW; the Isa GBA region in Queensland; and the Beetaloo GBA region in NT. In early 2018, deep coal gas was added to the assessment for the Cooper GBA region, as this play is actively being explored by industry.

The Program will assess the potential impacts of selected shale and tight gas development on water and the environment and provide independent scientific advice to governments, landowners and the community, business and investors to inform decision making. Geoscience Australia and CSIRO are conducting the assessments. The Program is managed by the Department of the Environment and Energy and supported by the Bureau of Meteorology.

The Program aims to:

- inform government and industry and encourage exploration to bring new gas supplies to the East Coast Gas Market within five to ten years
- increase understanding of the potential impacts on water and the environment posed by development of shale and tight gas resources
- increase the efficiency of assessment and ongoing regulation, particularly through improved reporting and data provision/management approaches
- improve community understanding of the industry.

The Program commenced in July 2017 and comprises three stages:

- **Stage 1 Rapid regional basin prioritisation** identified and prioritised geological basins with the greatest potential to deliver shale and/or tight gas to the East Coast Gas Market within the next five to ten years.
- **Stage 2 Geological and environmental baseline assessments** is compiling and analysing available data for the three selected regions to form a baseline and identify gaps to guide collection of additional baseline data where needed. This analysis includes a geological basin assessment to define structural and stratigraphic characteristics and an environmental data synthesis.
- **Stage 3 Impact analysis and management** will analyse the potential impacts to water resources and matters of environmental significance to inform and support Commonwealth and Territory management and compliance activities.

The PDF of this report and the supporting technical appendices are available at https://www.bioregionalassessments.gov.au/geological-and-bioregional-assessment-program.

About this report

Presented in this technical appendix is the regional prospectivity of the shale and tight gas resources of the Beetaloo GBA region. It provides more detailed information of the regional petroleum prospectivity, exploration history, and the characterisation and analysis of shale and tight gas in the Beetaloo Sub-basin, a structural component of the greater McArthur Basin in the NT. The structure and focus of the synthesis report and technical appendices reflect the needs of government, industry, landowners and community groups.

Technical appendices

Other technical appendices that support the geological and environmental baseline assessment for the Beetaloo GBA region are:

- Orr ML, Bernardel G, Owens R, Hall LS, Skeers N, Reese B and Woods M (2020) Geology of the Beetaloo GBA region.
- Evans TJ, Radke BM, Martinez J, Buchanan S, Cook SB, Raiber M, Ransley TR, Lai ÉCS, Skeers N, Woods M, Evenden C, Cassel R and Dunn B (2020) Hydrogeology of the Beetaloo GBA region.
- Pavey C, Herr A, MacFarlane CM, Merrin LE and O'Grady AP (2020) Protected matters for the Beetaloo GBA region.
- Kirby JK, Golding L, Williams M, Apte S, Mallants D, King J, Otalega I and Kookana R (2020) Qualitative (screening) environmental risk assessment of drilling and hydraulic fracturing chemicals for the Beetaloo GBA region.
- Kear J and Kasperczyk D (2020) Hydraulic fracturing and well integrity review for the GBA regions.

All maps for the Beetaloo GBA region use the Map Grid of Australia (MGA) projection (zone 53) and the Geocentric Datum of Australia 1994 (GDA 1994)

1 Introduction

The Beetaloo Sub-basin is located wholly within the NT, centred about 500 km south-east of Darwin (Figure 1) (Department of Primary Industry and Resources (NT), 2017a). It covers an area of approximately 28,000 km^2 and is a structural component of the Paleoproterozoic to Mesoproterozoic greater McArthur Basin. It is entirely under the cover of younger basin sediments and only the upper part of its stratigraphy has been intersected by petroleum wells.

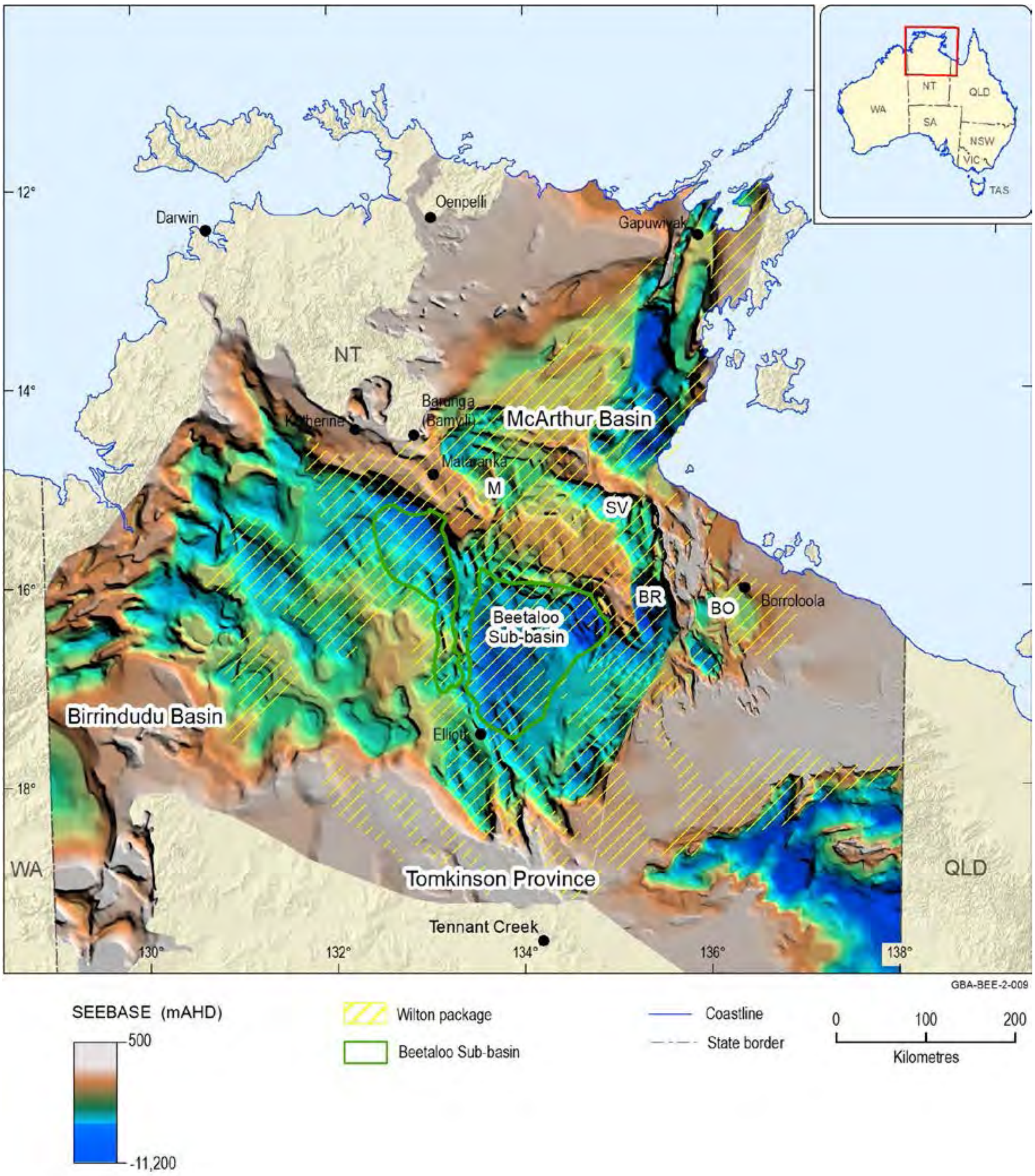

Figure 1 Geological setting of the Beetaloo Sub-basin

M = Maiwok Sub-basin, SV = Saint Vidgeon Sub-basin, BR = Broadmere Sub-basin, BO = Borroloola Sub-basin
Source: Depth to basement SEEBASE® model image sourced from Frogtech Geoscience (2018); Mesoproterozoic Roper Group (Wilton package) distribution from Betts et al. (2015)
Element: GBA-BEE-2-009

The Beetaloo Sub-basin is prospective for petroleum and is estimated to contain significant technically recoverable gas and liquids resources, particularly from shale gas plays within the Kyalla Formation and Amungee Member of the Velkerri Formation of the Mesoproterozoic Roper Group (Revie, 2017c). In 2017, following completion of extended production testing at the Amungee NW-1H exploration well, Origin Energy reported 2C contingent resources of 6.6 Tcf for the “B shale” member of the Velkerri Formation (Origin Energy, 2017, 2016b). With further exploration, resource assessment and infrastructure development, shale gas production is feasible in the Beetaloo Sub-basin within five to ten years (Department of Primary Industry and Resources (NT), 2017a).

The Beetaloo Sub-basin has existing geological, hydrogeological and environmental data available of the type, quality and density to enable a baseline geological and bioregional assessment to be undertaken. This appendix presents a review of the regional petroleum prospectivity, exploration history, and the characterisation and analysis of petroleum plays hosted in the Mesoproterozoic aged sediments of the Beetaloo GBA region (Figure 2). This process aims to address the technical factors likely to assist in identifying whether a viable petroleum play is likely to be present, and makes no attempt to factor economical, political, or social factors into the assessment.

For assessment purposes, the Beetaloo GBA region extent is based on the formal definition of the Beetaloo Sub-basin given by the NT Department of Primary Industry and Resources (Department of Primary Industry and Resources (NT), 2017a) (Figure 3).

The regional geology context of the Beetaloo GBA region and adjacent areas underpinning this prospectivity review are described in the accompanying geology technical appendix (Orr et al., 2020).

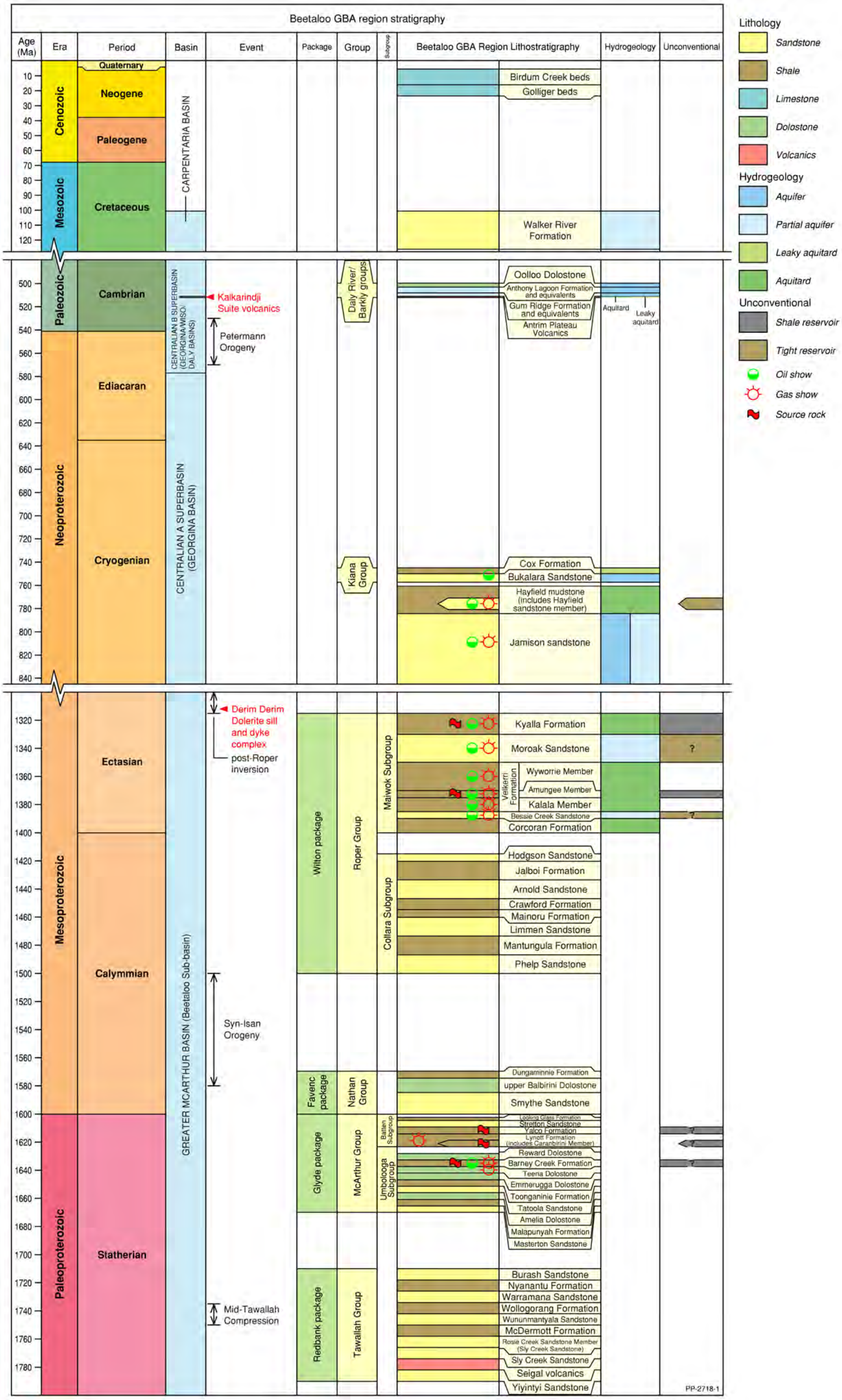

Figure 2 Stratigraphy of the greater McArthur Basin (Beetaloo Sub-basin), the Georgina, Wiso and Daly basins, and Carpentaria Basin in the Beetaloo GBA region

Source: Orr et al. (2020) and references therein
Element: GBA-BEE-2-053
This figure has been optimised for printing on A3 paper (297 mm x 420 mm).

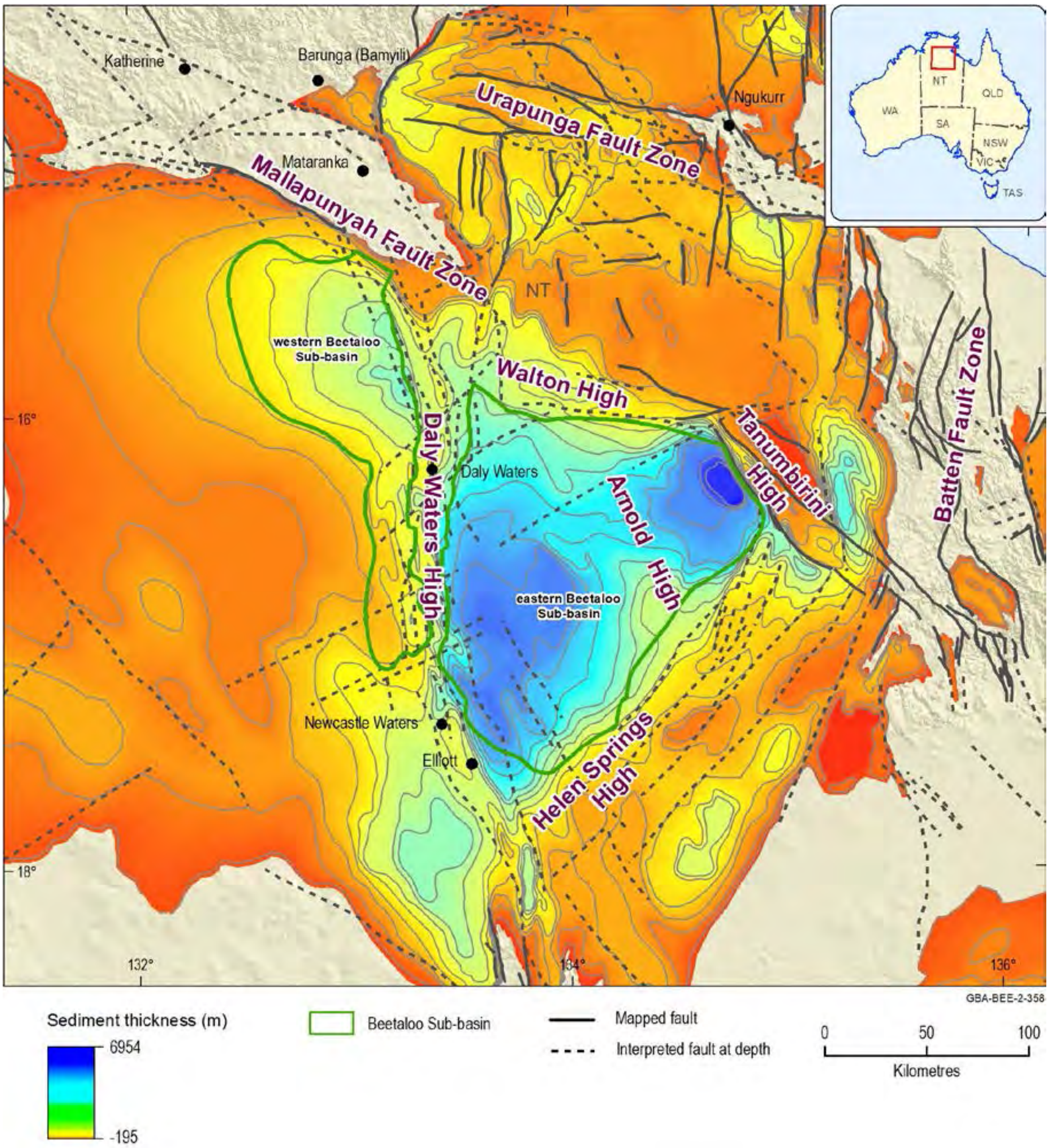

Figure 3 Structural elements map of the Beetaloo Sub-basin showing major faults, overlain on the total sediment thickness from the base of the Mesoproterozoic Roper Group

Source: Major faults and sediment thickness from Frogtech Geoscience (2018); structural elements from Plumb and Wellman (1987), Silverman et al. (2007) and Munson (2016)
Element: GBA-BEE-2-358

2 Conventional and unconventional petroleum

Naturally occurring oil and gas accumulations may be differentiated by the terms ‘conventional’ and ‘unconventional’, depending on how the petroleum is trapped in the geological formation (Figure 4).

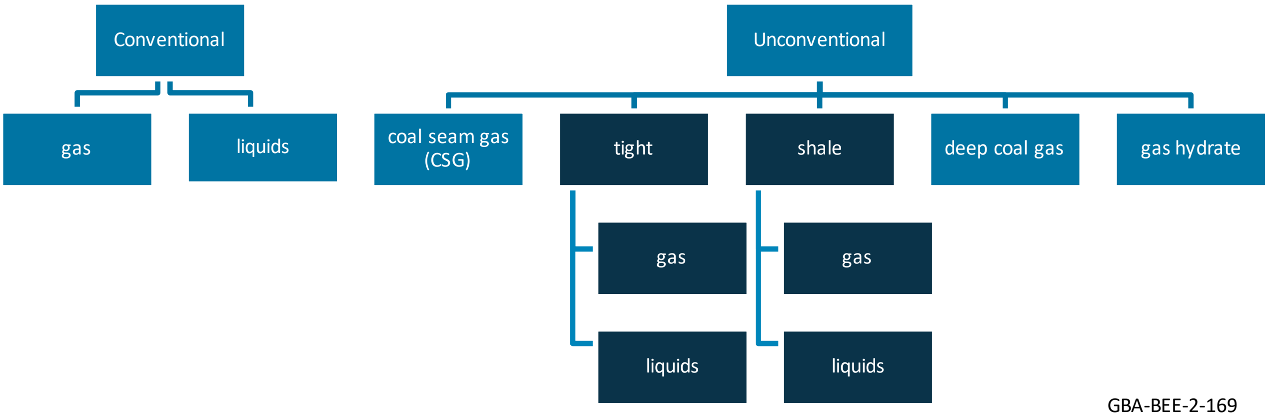

Figure 4 The different types of conventional and unconventional petroleum accumulations

Unconventional play types considered for the Beetaloo GBA region are shown in dark blue. Liquids includes oil and gas condensate.
Source: After Cook et al. (2013)
Element: GBA-BEE-2-169

‘Conventional’ petroleum accumulations (Figure 4 and Figure 5) are so called because they have the longest association with petroleum exploration and production, and are considered the norm (i.e. conventional) by the industry. These accumulations were the first to be exploited historically as they are relatively easy to find and develop, and have produced the majority of oil and gas worldwide to date. However, they are relatively rare and represent only a small part of the petroleum continuum.

‘Conventional’ petroleum accumulations occur as discrete accumulations trapped by a geological structure and/or stratigraphic feature, typically bounded by a down-dip contact with water and capped by impermeable rock (Schmoker, 2002; Schmoker et al., 1995) (Figure 4). The petroleum was not formed in situ; but migrated from the source rocks into a trap containing porous and permeable reservoir rocks.

The term ‘unconventional’ is used to refer to the collection of petroleum accumulations that are characterised by low permeability and require reservoir stimulation to develop. They include shale oil and gas, oil shales, tight sands, basin-centred gas, coal seam gas, deep coal gas, methane hydrates and biogenic gas (Figure 4 and Figure 5). While, ‘unconventional' and 'conventional' petroleum accumulations can form from the same source rocks (Schmoker, 2002; Law and Spencer, 1993; Schmoker et al., 1995), due to differences in expulsion, transport, and trap mechanisms, different extraction methods are required. In the Beetaloo Sub-basin, unconventional gas accumulations including shale gas, tight gas and oil have been identified. These play types are described below.

Shale gas is natural gas hosted in sedimentary rocks (commonly shales) with low to moderate porosity (with a pore size of 0.005–0.1 µm (Nelson, 2009) and very low permeability. Shales are a common petroleum source rock and may retain more petroleum than they expel during the thermal maturation process of organic matter. Once the gas has generated, some of it remains trapped in the shale, either adsorbed on to the organic matter in a free state in the pores and fractures of the rock. Shale gas plays usually occur at depths greater than 1000 m to 1500 m below the earth's surface. Shale reservoirs occur with significant (10–100 km) lateral continuity and can be of considerable thickness (>100 m). Where shales act as both the petroleum source and reservoir rock, they are sometimes referred to as 'self-sourcing reservoirs'.

Tight gas is natural gas trapped in siltstone and sandstone reservoirs characterised by low porosity (<8–10%) and permeability (<0.1 mD). Tight gas reservoirs have been exploited for several decades in Australia. Tight gas may occur in discrete reservoirs, where migrated gas accumulates in rocks with low porosity and permeability, in a similar manner to conventional accumulations (e.g. Shanley and Robinson (2004)). Alternatively, tight gas may occur in distributed gas accumulations which have been referred to in the United States as basin-centred tight gas (Law and Curtis, 2002; Schmoker et al., 1995). They are low-permeability gas reservoirs which are commonly abnormally overpressured, lack an apparent down-dip water contact and are pervasively gas saturated (Fall et al., 2002; Law and Curtis, 2002).

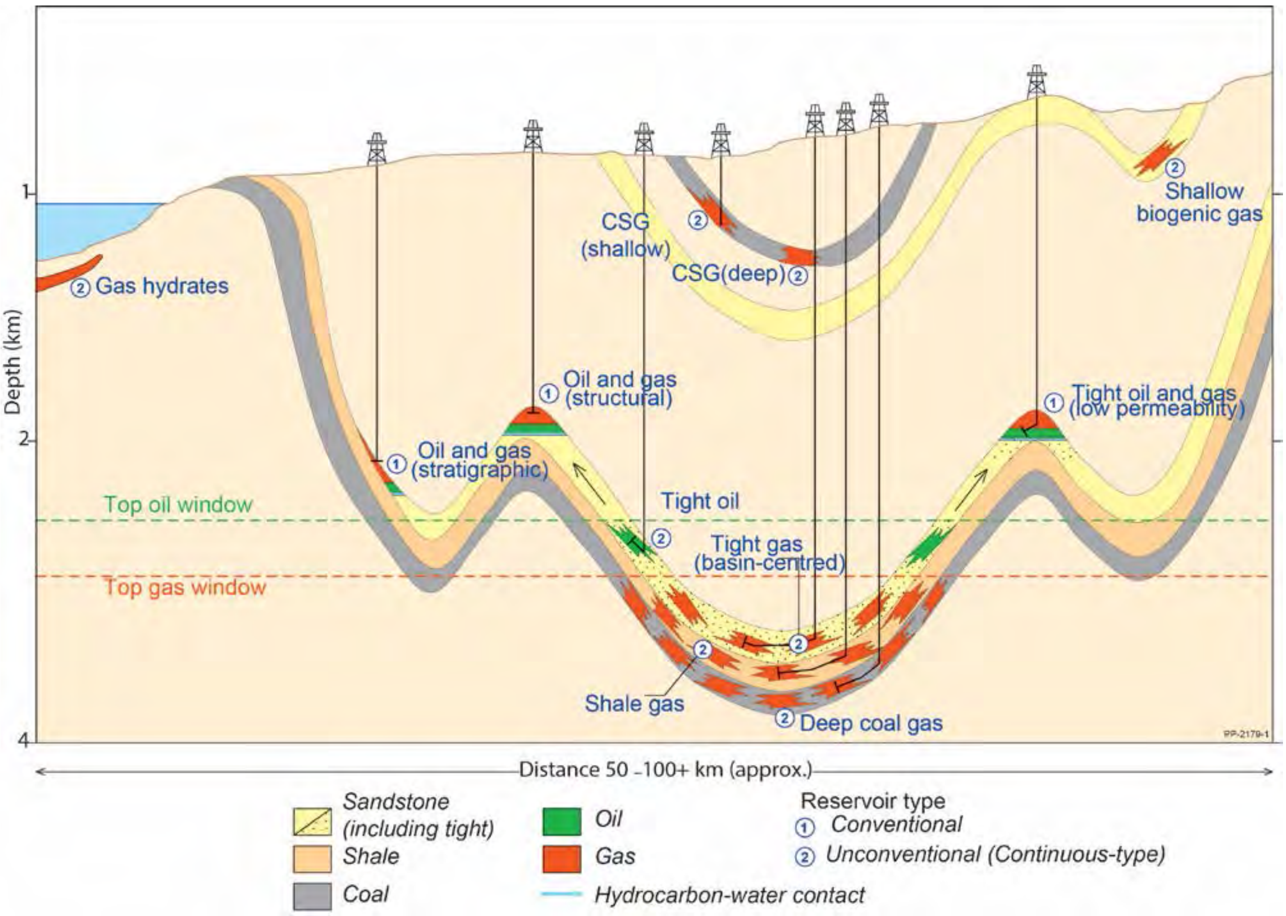

Figure 5 Schematic showing some of the typical types of oil and gas accumulations. These types of conventional and unconventional petroleum accumulations are commonly observed in sedimentary basins, except for gas hydrates, which are located in sediments on the deep continental shelf

The 'oil window' refers to the maturity range in which oil is generated from oil-prone organic matter. Below is the 'gas window', which refers to the maturity range in which gas is generated from organic matter.
Source: after Schenk and Pollastro (2002); Cook et al. (2013); Schmoker et al. (1995)
Element: GBA-BEE-2-148

Gas may be referred to as dry gas or liquids-rich gas depending on its composition. Dry gas is natural gas that is dominated by methane (greater than 95% by volume) with little or no condensate or liquid hydrocarbons. Liquids-rich gas (also known as wet gas) contains less methane than dry gas and more ethane and other more complex hydrocarbons (propane, butane, pentane, hexane and heptane).

The composition of the gas is important for understanding future development scenarios in the Beetaloo Sub-basin, as liquids-rich gas resources are currently more favourable to develop from an economic perspective. Figure 6 shows petroleum resources nomenclature in terms of chemical composition, commercial product and physical state in both the subsurface and at the surface.

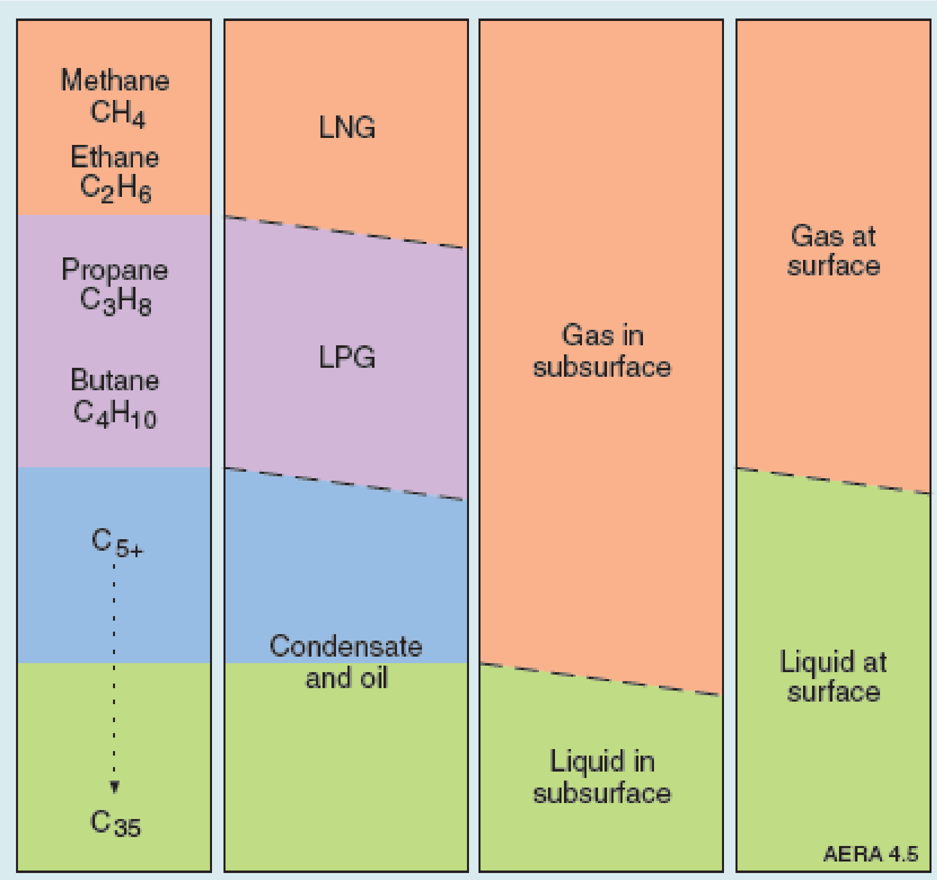

Figure 6 Petroleum resources nomenclature in terms of chemical composition, commercial product, physical state in the subsurface and physical state at the surface

Source: Geoscience Australia and BREE (2014)
Element: GBA-BEE-2-195

3 Petroleum prospectivity of the Beetaloo Sub-basin

The Beetaloo Sub-basin is prospective for petroleum and is estimated to contain significant technically recoverable gas and liquids resources, particularly from shale gas plays within the Kyalla Formation and Amungee Member of the Velkerri Formation of the Mesoproterozoic Roper Group (Revie, 2017c). There is active exploration for petroleum resources in the Beetaloo Sub-basin, with most of the sub-basin extent covered by exploration permits (Figure 7).

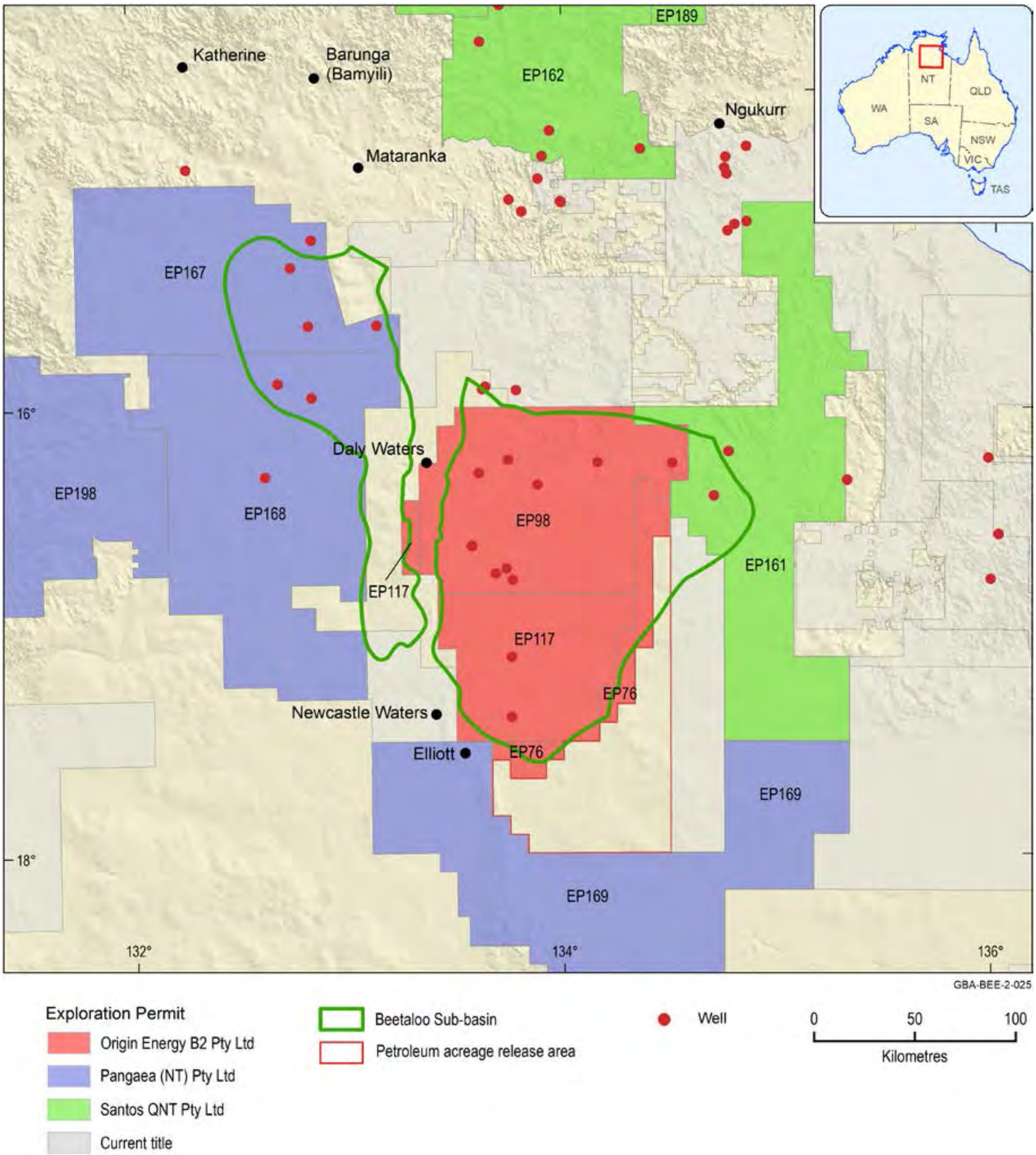

Figure 7 Beetaloo Sub-basin exploration, retention and production permit operators

The Beetaloo Sub-basin outline is the area of interest of the shale and tight gas prospectivity assessment.
Source: Beetaloo Sub-basin outline from Department of Primary Industry and Resources (NT) (2017a).
Data: Permit operators and outlines are provided from GPinfo petroleum database, Petrosys Pty Ltd (2019). Beetaloo Sub-basin outline from Department of Primary Industry and Resources (NT) (2017a).
Element: GBA-BEE-2-025

Exploration has focused in the lower Kyalla Formation and the Amungee Member of the Velkerri Formation (Figure 2). Further details on the exploration history, resources, infrastructure and regional petroleum systems are outlined below (Table 1).

Table 1 Beetaloo GBA region petroleum prospectivity summary

Petroleum systems	Proven (Paleoproterozoic–Mesoproterozoic; Tawallah, McArthur and Uragungan)
Prospectivity	High
Play types	Shale gas, shale oil, tight gas, tight oil
No of wells	19 wells lie within the Beetaloo Sub-basin outline defined by NTGS (excluding re-entries); (western sub-basin: Birdum Creek 1, Tarlee 1-3, Wyworrie 1; eastern sub-basin: Amungee NW1, Balmain 1, Beetaloo W1, Burdo 1, Chanin 1, Elliot 1, Kalala 1, Jamison 1, Mason 1, McManus 1, Ronald 1, Shenandoah 1, Shortland 1, Tanumbirini 1)
Seismic lines	8818 line km, two-dimensional seismic reflection data
Hydrocarbon tests	Amungee NW 1H well
Hydrocarbon production	None to date
2P reserves	None reported (Geoscience Australia, 2018)
Contingent (2C) resources	• 6.6 Tcf shale gas over an area of 1968 km^2 (Origin Energy, 2017) • No conventional 2C resources reported (Geoscience Australia, 2018)
Undiscovered resource estimates	• Fully risked (F50) undiscovered mean resources of 6.1 Tcf of gas and 205 MMbbl of natural gas liquids in the middle Velkerri Formation shale gas assessment area; 1.6 Tcf of gas and 65 MMbbl of natural gas liquids in the lower Kyalla Formation shale gas assessment area; and 429 MMbbl of oil, 0.26 Tcf of gas and 8 MMbbl of natural gas liquids in the lower Kyalla Formation shale oil assessment area (Schenk et al., 2019) • Unrisked P50 prospective resource estimate of 11.1 Tcf for the Velkerrie, Kyalla, Barney Creek and Wollogorang formations (Empire Energy, 2018) • 496 Tcf OGIP in the Middle Velkerri 'B' shale, of which 85 Tcf is estimated to be technically recoverable (prospective area 16,145 km^2) (Falcon Oil and Gas, 2017) • P50 estimate of 202 Tcf undiscovered gas-in-place and 96 MMbbl undiscovered oil-in-place in the Amungee Member shales (Revie, 2017c; Weatherford Laboratories, 2017) • 772 MMbbl (P50) oil-in-place was estimated for the Kyalla Formation (P10: 1163 MMbbl; P90: 414 MMbbl) (Weatherford Laboratories, 2017; Revie, 2017c, 2017b) • Best estimate of recoverable shale gas resource of 3 Tcf for the lower Kyalla Formation (prospective area 898 km^2) and 16 Tcf for the Amungee Member (prospective area 6092 km^2) (AWT International, 2013) • P50 estimate of potentially recoverable shale gas of 37.29 Tcf for the lower Kyalla Formation and 74.50 Tcf for the Amungee Member (prospective area unknown) (RPS, 2013) • Technically recoverable shale gas of 22 Tcf for the lower Kyalla Formation (prospective area - associated gas 4100 mi^2, 2400 mi^2 wet gas, 1310 mi^2 dry gas) and 22 Tcf for the Amungee Member (prospective area - associated gas 2650 mi^2, 2130 mi^2 wet gas, 2480 mi^2 dry gas) (EIA, 2013) • No conventional prospective resources (Geoscience Australia, 2018)

mi^2 = mile squared

3.1 Exploration history

The following review of exploration history in the Beetaloo Sub-basin and surrounds has been updated from Munson (2014); Carr et al. (2016); Revie (2017c).

Exploration for hydrocarbons in the greater McArthur Basin began in the 1960s, but intensified from the 1980s, when a joint venture between Amoco Australia Petroleum Company and Kennecott Copper Corporation completed field mapping, stratigraphic drilling and geophysical surveys. The first discovery of live oil in the region was made during stratigraphic drilling of the Urapunga 4 well by the Bureau of Mineral Resources (now Geoscience Australia), with volatile hydrocarbons bleeding from shales of the Velkerri Formation (Jackson et al., 1986).

This was followed by another period of activity from 1984 to the mid-1990s, when CRA Exploration Pty Ltd (as Pacific Oil and Gas Ltd) acquired aerial photography and undertook field mapping, ground geophysics, acquisition of greater than 2500 km of two-dimensional seismic reflection data, and a significant drilling program.

In 2002, a deep seismic reflection program, was undertaken by Geoscience Australia that assisted in the reinterpretation of the basin architecture of the Batten Fault Zone of the McArthur Basin, east of the Beetaloo Sub-basin (Rawlings et al., 2004).

In the mid-2000s, the Beetaloo Sub-basin was the focus of exploration by Sweetpea Petroleum Pty Ltd, which included two-dimensional seismic survey data and drilling of the Shenandoah 1 well. Falcon Oil and Gas Australia Ltd (Falcon) deepened this well to 2714 m in 2011 and renamed it Shenandoah 1A. A joint venture between Falcon and Hess Australia (Beetaloo) Pty Ltd acquired 3490 km of two-dimensional seismic in 2011 and 2012 (Falcon Oil and Gas, 2019).

In 2013, Pangaea Resources Pty Ltd completed a gravity gradiometry survey and a ~1400 line km two-dimensional seismic survey in the western part of the Beetaloo Sub-basin, followed by an additional ~385 km of seismic data and the drilling of seven petroleum wells over the following two years (Hoffman, 2015, 2014). Also in 2013, in a farm-in arrangement with Tamboran Resources Ltd, Santos Ltd acquired ~500 line km of two-dimensional seismic data in the eastern Beetaloo Sub-basin, and in 2014 drilled the Tanumbirini 1 well to a total depth of 3945 m (Santos Ltd, 2019). Continued exploration interest in 2015 led to encouraging results by Origin Energy and joint venture partner Falcon Oil and Gas Ltd in the Kalala South 1 and Beetaloo W1 wells, and production testing at Amungee NW 1H (Falcon Oil and Gas, 2019; Côté et al., 2018; Close et al., 2017a; Close et al., 2016).

While there has been no commercial gas production to date in the Beetaloo Sub-basin, significant exploration activity is underway (Pepper et al., 2018). In total, more than 30 petroleum wells have been drilled in the Beetaloo Sub-basin and surrounding areas of the greater McArthur Basin (Figure 8, Figure 9). Approximately half of these wells have been drilled in the last ten years. Nineteen of these wells are located within the Beetaloo Sub-basin outline as defined by the NTGS. Five wells are located within the western sub-basin (Birdum Creek 1, Tarlee 1-3, Wyworrie 1) and 14 are located within the eastern sub-basin (Amungee NW1, Balmain 1, Beetaloo W1, Burdo 1, Chanin 1, Elliot 1, Kalala 1, Jamison 1, Mason 1, McManus 1, Ronald 1, Shenandoah 1, Shortland 1, Tanumbirini 1).

Currently, Santos, Origin Energy and Falcon Oil and Gas, and Pangaea Resources are all continuing to investigate key unconventional targets in the Beetaloo Sub-basin (Figure 7) (e.g. Côté et al. (2018); Connors and Krassay (2015); Silverman and Ahlbrandt (2010); Revie and Edgoose (2015a, 2015b); Revie (2017c, 2017b); Close (2014); Scrimgeour (2019)). The Velkerri and Kyalla formations (Roper Group) have been identified as hosting the primary shale plays with the greatest potential for commercial production (Munson, 2014; Revie, 2017b; Origin Energy, 2017). In addition, there is potential for a tight gas and liquids-rich play within the Hayfield sandstone member in the overlying Neoproterozoic units (Munson, 2014; Côté et al., 2018).

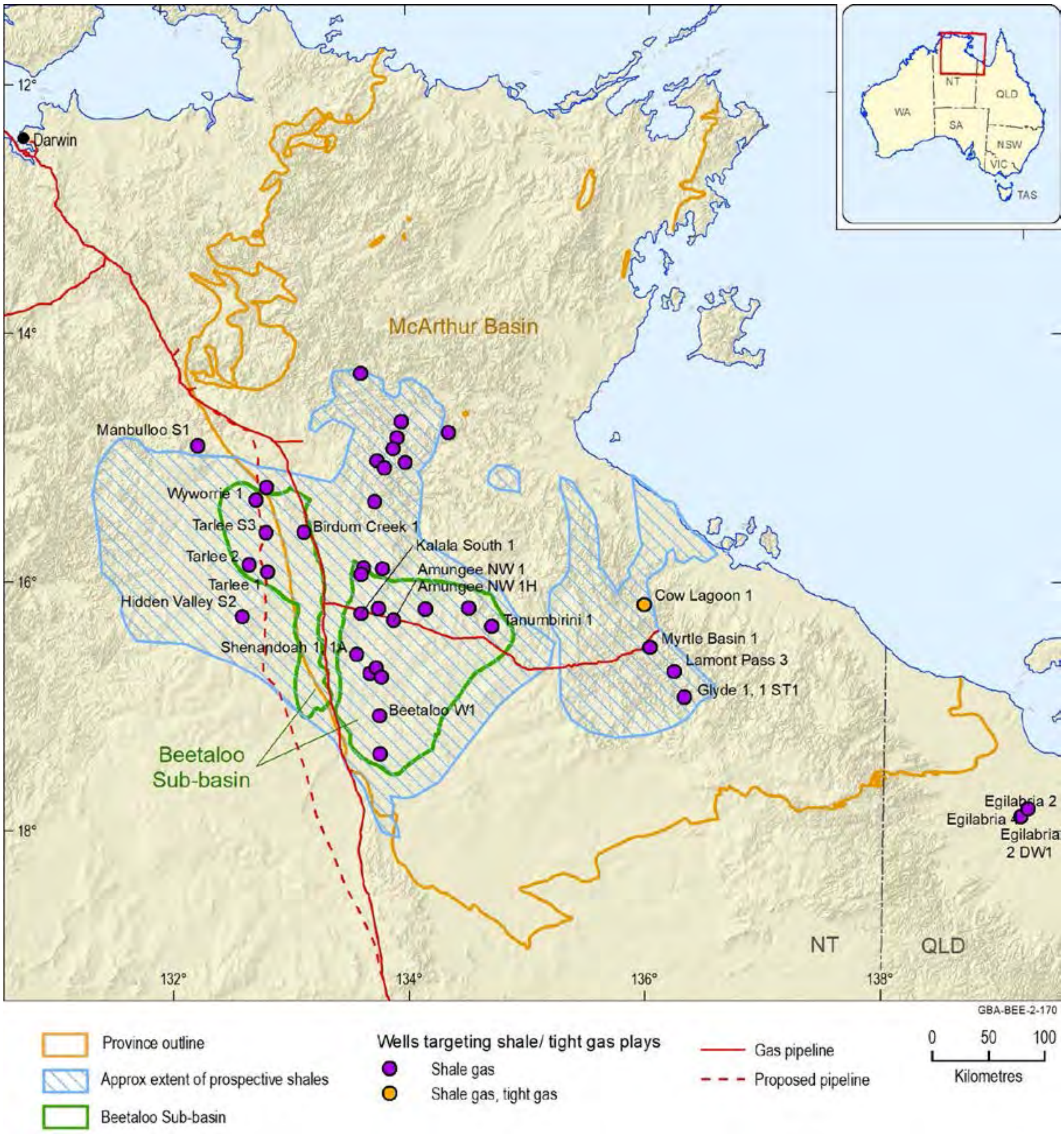

Figure 8 Wells targeting shale and/or tight gas plays in the Beetaloo Sub-basin and adjacent areas of the greater McArthur Basin

Source: Beetaloo Sub-basin outline from Department of Primary Industry and Resources (NT) (2017b). Approximate areas within which key prospective shales are likely to be present sourced from Bruna et al. (2015); Revie (2017b); (Revie, 2017c)
Data: McArthur Basin outline from Raymond et al. (2018) that is currently in revision. Well locations from Department of Primary Industry and Resources (NT) (2018a)
Element: GBA-BEE-2-170

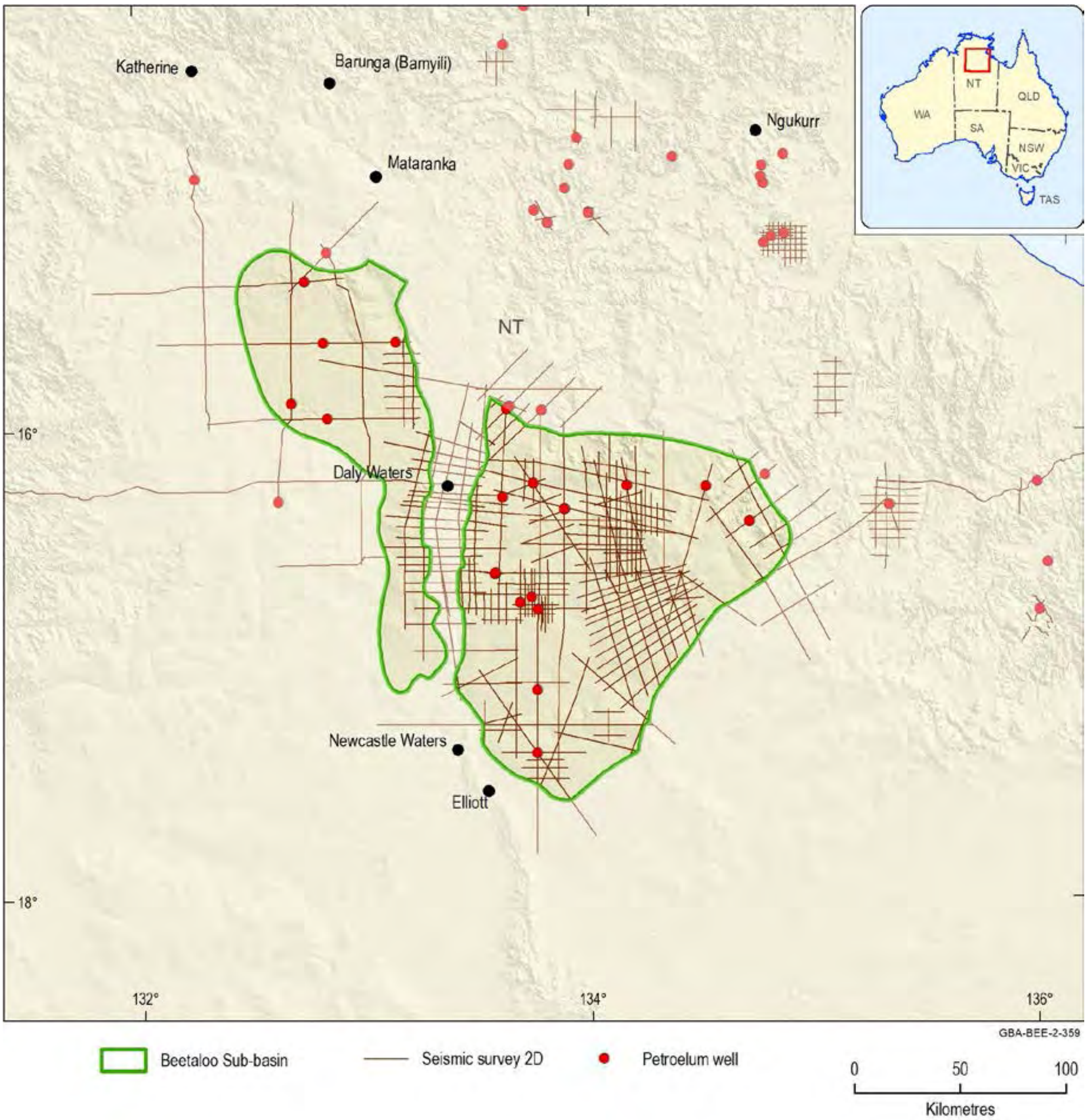

Figure 9 Two-dimensional seismic data coverage across the Beetaloo Sub-basin and surrounding areas

Data: Seismic survey lines from Department of Primary Industry and Resources (NT) (2018b), petroleum well distribution from Department of Primary Industry and Resources (NT) (2018a)
Element: GBA-BEE-2-359

3.2 Reserves and resources

3.2.1 Reserves

To date, no reserves have been booked for any petroleum resource type for the Beetaloo Sub-basin (Table 1) (Geoscience Australia, 2018).

3.2.2 Contingent resources

In 2017, following completion of extended production testing at the Amungee NW 1H exploration well (Origin Energy, 2016b), Origin Energy reported 2C Contingent Resources of 6.6 Tcf for the “B shale” unit of the Amungee Member over an area of 1968 km^2, across permits EP76, EP98 and EP117 in the Beetaloo Sub-basin (Origin Energy, 2017).

It is important to note these 2C Contingent Resources have been reported based on the results from one well, assuming homogeneity in the geological characteristics of the play across the entire region. However, experience in the United States highlights that there is commonly a large degree of heterogeneity in production rates from shale gas plays, even across small areas. In particular, the recovery factor for Amungee NW 1H was reported to be 16% (Revie, 2017c), comparable with well explored shale gas plays in the US. Nevertheless, further wells are required to increase confidence in the long-term development of the play (Revie, 2017c).

3.2.3 Prospective resources

A range of regional-scale prospective resource estimates have been published for shale gas in the Velkerri and Kyalla formations in the greater McArthur Basin, including the Beetaloo Sub-basin, which are listed below.

- The US Geological Survey estimated technically recoverable mean resources of 429 MMbbl of continuous oil and 8 Tcf of continuous gas for the Beetaloo Sub-basin (Schenk et al., 2019). This comprises:
  - 6.1 Tcf of gas and 205 MMbbl of natural gas liquids in the middle Velkerri Formation shale gas assessment area
  - 1.6 Tcf of gas and 65 MMbbl of natural gas liquids in the lower Kyalla Formation shale gas assessment area; and
  - 429 MMbbl of oil, 0.26 Tcf of gas and 8 MMbbl of natural gas liquids in the lower Kyalla Formation shale oil assessment area.
- Empire Energy reported an unrisked P50 prospective resource estimate of 11.1 Tcf for the Velkerrie, Kyalla, Barney Creek and Wollogorang formations in the greater McArthur Basin (Empire Energy, 2018).
- Falcon Oil and Gas (2017) estimated 496 Tcf OGIP in the Beetaloo Sub-basin Middle Velkerri B shale. 85 Tcf of this is estimated to be technically recoverable, assuming a 16% recovery factor (prospective area 16,145 km^2) (Falcon Oil and Gas, 2017).
- The Northern Territory Geological Survey estimated the following in-place resources in the Beetaloo and Broadmere sub-basins (Weatherford Laboratories, 2017; Revie, 2017c, 2017b):

- Amungee Member gas-in-place of 202 Tcf (P50) (range: 293 Tcf (P10) to 118 Tcf (P90))
- Amungee Member oil-in-place of 94 MMbbl (P50) (range: 128 MMbbl (P10) to 72 MMbbl (P90)) and
- Kyalla Formation oil-in-place of 772 MMbbl (P50) of oil-in-place (range: 1163 MMbbl (P10) to 414 MMbbl (P90)).

- RPS reported a P50 estimated of potentially recoverable shale gas resource to be 37.29 Tcf for the lower Kyalla Formation and 74.50 Tcf for the Amungee Member in the Beetaloo Sub-basin (prospective area unknown; RPS (2013). In addition, they reported P50 estimate of potentially recoverable basin-centred gas resources of 5.9 Tcf for the Moroak Sandstone and 44.31 Tcf for the Bessie Creek Sandstone; RPS (2013).
- The US Energy Information Administration (EIA) reported that that the technically recoverable shale gas in the Beetaloo Sub-basin is 22 Tcf for the lower Kyalla Formation (prospective area - associated gas 4100 mi^2, 2400 mi^2 wet gas, 1310 mi^2 dry gas) and 22 Tcf for the Amungee Member (prospective area - associated gas 2650 mi^2, 2130 mi^2 wet gas, 2480 mi^2 dry gas) (EIA, 2013).
- AWT International have reported their best estimate of recoverable shale gas resource to be 3 Tcf for the lower Kyalla Formation (prospective area 898 km^2) and 16 Tcf for the Amungee Member in the Beetaloo Sub-basin (prospective area 6092 km^2) (AWT International, 2013).

Although these results highlight the presence of potentially significant petroleum resources in the Beetaloo Sub-basin and surrounds, the full extent of these resources is still poorly understood and quantified, and any estimates of potential resources have a high degree of uncertainty associated with them. In particular, recovery factors are very poorly understood and vary significantly between each resource assessment.

3.3 Market access and infrastructure

Table 2 provides a summary of market and access infrastructure for the remote and sparsely populated area of the Beetaloo Sub-basin. The communities of Mataranka (population of 400) and Elliot (population of 355) are located on highways in close proximity to the Beetaloo Sub-basin (Figure 10). The nearest town, Katherine (population of around 10,000) is 75 km from the northern-most boundary of the Beetaloo Sub-basin. Sealed arterial roads traverse across the Beetaloo Sub-basin, including the Stuart Highway from Darwin to the northwest and the Carpentaria Highway heading eastwards towards Borroloola. The Alice Springs-Darwin railway is located over the western Beetaloo Sub-basin. The region is also serviced by the Daly Waters to McArthur River Pipeline and the Amadeus Gas Pipeline to Darwin (Figure 10).

Table 2 Summary of market access and infrastructure

Gas market	Northern Territory Gas Market
Proximity to gas pipelines	Daly Waters to McArthur River Pipeline – capacity 16 TJ/day Amadeus Gas Pipeline – capacity 120 TJ/day
Gas processing facilities	None
Approx. distance from existing pipelines to prospective area	0–200 km
Road and rail access	Poorly to moderately well serviced
Approximate development time frame	5–10 years

Source: Hall et al. (2018). Pipeline information from Jemena (2017); Australian Energy Regulator (AER) (2017). Oil and gas infrastructure from Geoscience Australia (2017) and Australian Energy Regulator (AER) (2017)

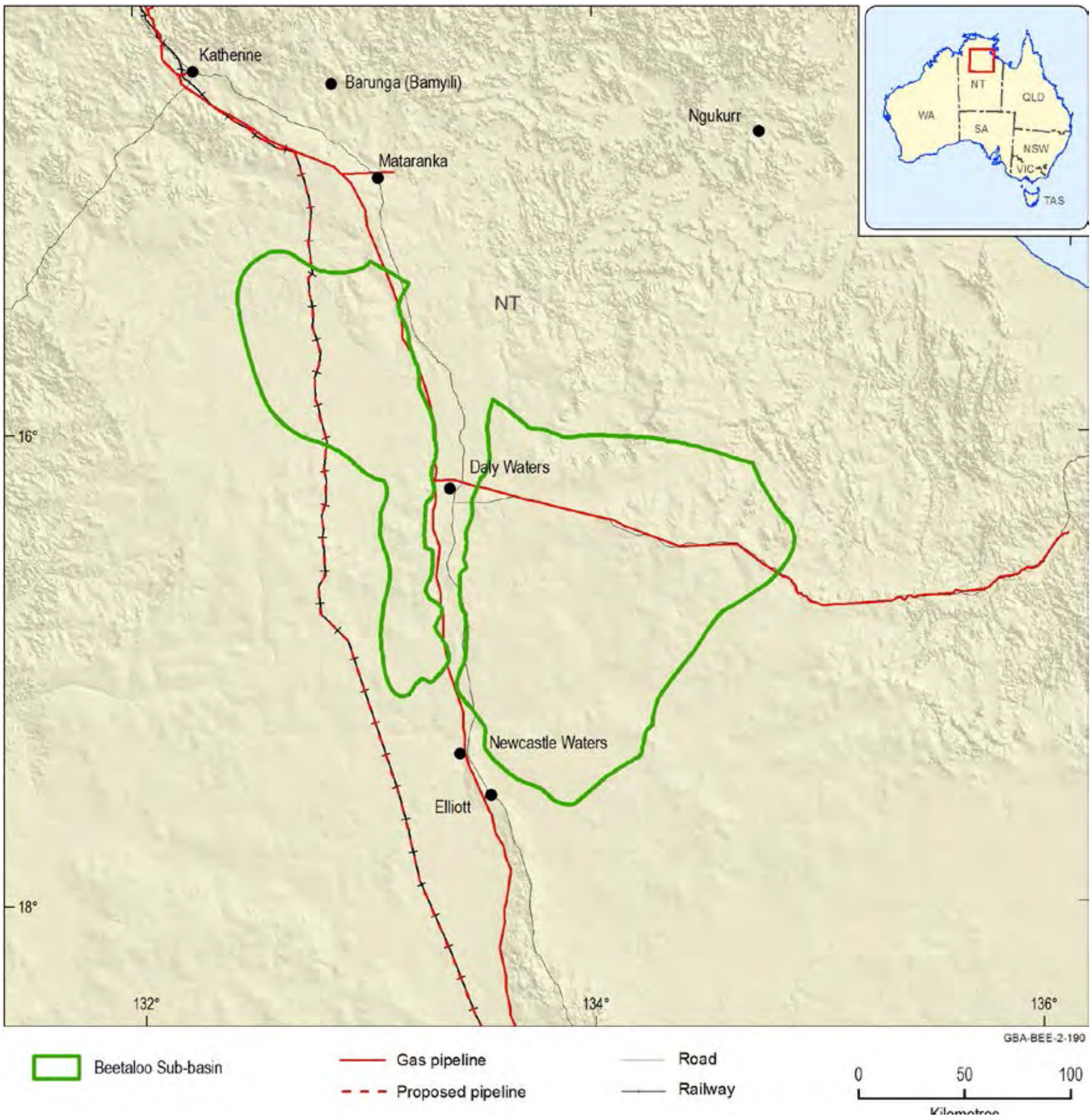

Figure 10 Beetaloo Sub-basin infrastructure and pipelines

Source: Beetaloo Sub-basin outline from Department of Primary Industry and Resources (NT) (2017a). Gas infrastructure from Petrosys Pty Ltd (2019)
Element: GBA-BEE-2-190

3.4 Regional petroleum systems

3.4.1 Introduction

The Beetaloo Sub-basin has long been recognised as having potential for petroleum (e.g. Muir (1980)), with oil and gas occurrences both known. Oil shows are common, and bitumen and pyrobitumen have been reported from many units, including the Paleoproterozoic and Mesoproterozoic sedimentary rocks and the overlying Paleozoic sedimentary rocks (e.g. Muir (1980); Knutson et al. (1979)). Interest was stimulated by the first discovery of live oil in the basin, which was made during stratigraphic drilling of the Urapunga 4 well by the Bureau of Mineral Resources (now Geoscience Australia), with volatile hydrocarbons bleeding from shales of the Velkerri Formation (Jackson et al., 1986).

The petroleum systems of the Beetaloo Sub-basin and surrounds are summarised below and in Table 3. For a more extensive review of the regional petroleum systems, see Munson (2014).

Table 3 Petroleum systems elements

Play types	• Conventional: oil and gas hosted in sandstone reservoirs with structural traps, diagenetic traps, pinch out plays on basin margins and breccia traps • Unconventional: shale gas, shale oil, tight gas, tight oil
Reservoirs	• Tawallah Group: Wollogorang Formation • McArthur Group: Teena Dolostone, Coxco Dolostone Member of the Teena Dolostone, breccia units within the Barney Creek Formation, Yalco Formation, Stretton Sandstone, Looking Glass Formation and lower Balbirini Dolostone • Roper Group: Hodgson Sandstone, Bessie Creek Sandstone, Moroak Sandstone, Jamison sandstone, Bukalara Sandstone and thin sandstone units within Velkerri and Kyalla formations • Unnamed group: Hayfield sandstone member
Seals	• McArthur Group: Barney Creek Formation, Lynott Formation, Donnegan Member, intraformational within Stretton Sandstone • Roper Group: Velkerri Formation, Kyalla Formation • Antrim Plateau Volcanics
Source rocks	• McArthur Group: Barney Creek Formation, Lynott Formation and Donnegan Member • Roper Group: Velkerri Formation, Kyalla Formation, and minor contributions from Mainoru and Corcoran formations
Hydrocarbon shows	• Tawallah Group: Dermott Formation, Wollogorang Formation • McArthur Group: Barney Creek Formation, Coxco Dolostone Member and Lynott Formation • Roper Group: Bessie Creek Sandstone, Velkerri Formation, Moroak Sandstone, Kyalla Formation, Jamison sandstone and Bukalara Sandstone • Unnamed group: Hayfield sandstone member
First major discovery	Amungee NW 1H currently undergoing production testing
Production	None

Source: From Munson (2014); Carr et al. (2016)

3.4.2 Petroleum systems elements

Work on the prospective petroleum systems is focused principally on source rocks within the McArthur and Roper groups in the southern parts of the McArthur Basin. The petroleum systems in the McArthur Group are included within the McArthur Supersystem of Bradshaw et al. (1994) and those of the Roper Group are within the Urapungan Supersystem (Bradshaw, 1993; Laurie, 2012). An older petroleum system is present within the Tawallah Group, since hydrocarbon shows are known in the McDermott and Wollogorang formations (Munson, 2014).

There have been several studies on source rocks in the Beetaloo Sub-basin and surrounds, with key papers including Jackson et al. (1986); Jackson et al. (1988), Powell et al. (1987), Taylor et al. (1994), Warren et al. (1998) and Silverman et al. (2007). A geochemical summary on oil from the Jamison 1 well was undertaken by Summons et al. (2002). An extensive review is provided in Munson (2014). The Mesoproterozoic Roper Group is deposited throughout the southern McArthur Basin, including the Beetaloo Sub-basin, and contains the Velkerri and Kyalla formations, which are the main source rock targets (Figure 11; Figure 12). Another minor source rock in the Roper Group include the Mainoru Formation.

There is evidence for multiple episodes of hydrocarbon and brine migration, with late stage oil migration indicated by solid bitumen occurring within secondary porosity and as coatings on secondary minerals. Dutkiewicz et al. (2007) estimated that the most significant oil migration episode for the Roper Group occurred in the Mesoproterozoic, following compaction, cementation and contact metamorphism during structural inversion between about 1300–1000 Ma (Figure 11). The presence of hydrocarbons in the Bukalara Sandstone in the well Walton 1 also indicates that migration must have also occurred in post-Mesoproterozoic times

There are at least seven reservoir units known to occur in the Beetaloo GBA region, including the Bukalara Sandstone, Hayfield sandstone member of the Hayfield mudstone, Jamison sandstone, Kyalla Formation, Moroak Sandstone, Velkerri Formation and Bessie Creek Sandstone (Table 3; Figure 12; Figure 12). The Bukalara Sandstone has very good reservoir properties, with porosities of 19–24% and permeabilities in the range 50–1000 mD (Lanigan et al., 1994; Law et al., 2010). The Moroak Sandstone is another significant economic reservoir target, with porosities from about 6% to 15%. The Bessie Creek Sandstone also has reported porosities up to 14% and permeabilities up to 50 mD. Reduction of initial porosity due to the diagenetic deposition of quartz and clay minerals in pore spaces, and compaction and pressure solution, are likely to be detrimental to reservoir properties in more deeply buried sections (Lanigan et al., 1994).

Important seals include the Velkerri Formation, the Kyalla Formation and Hayfield mudstone (Figure 11; Figure 12).

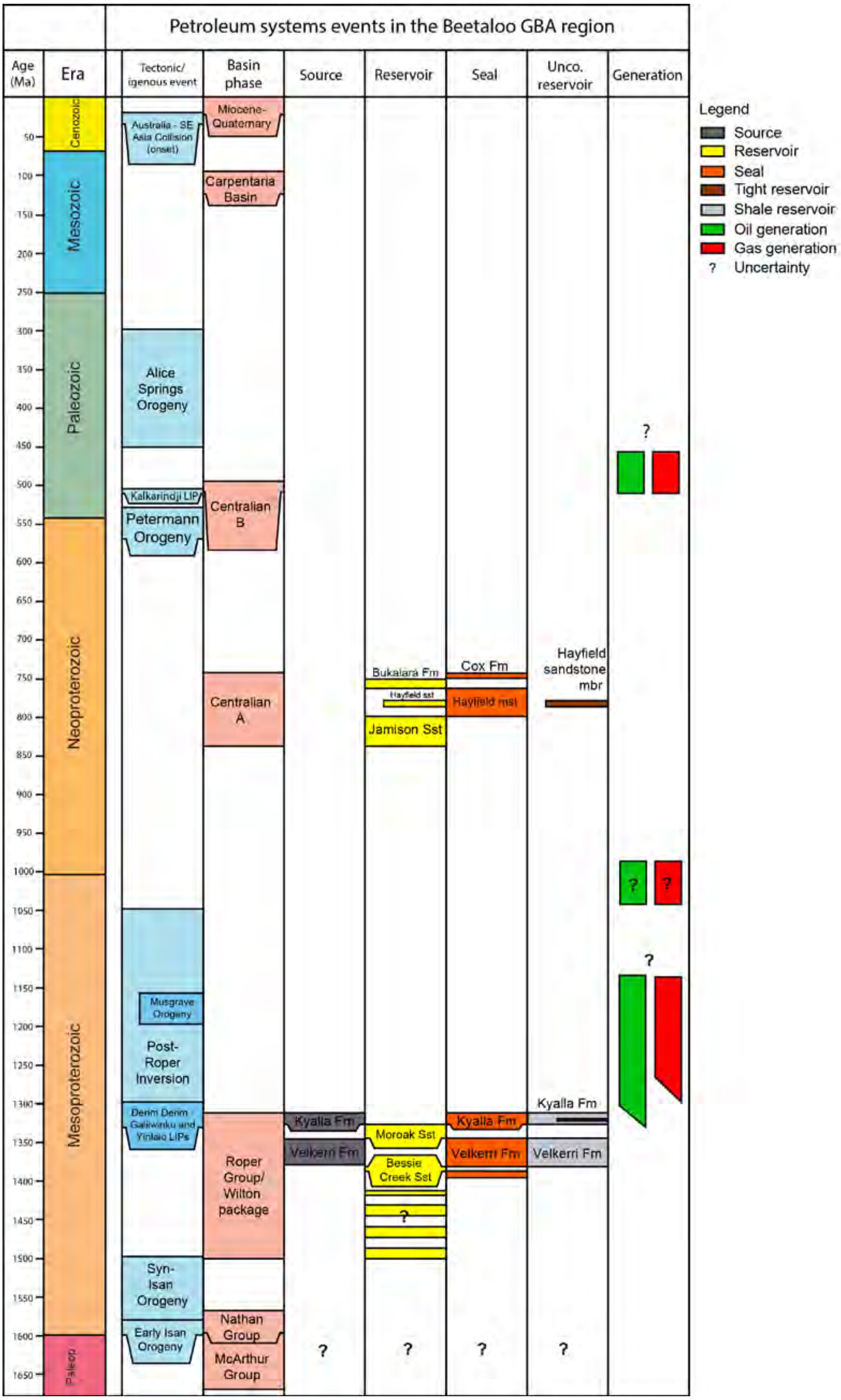

Figure 11 Petroleum systems element chart for the Beetaloo Sub-basin

Source: Orr et al. (2020) and this report

Element: GBA-BEE-2-321

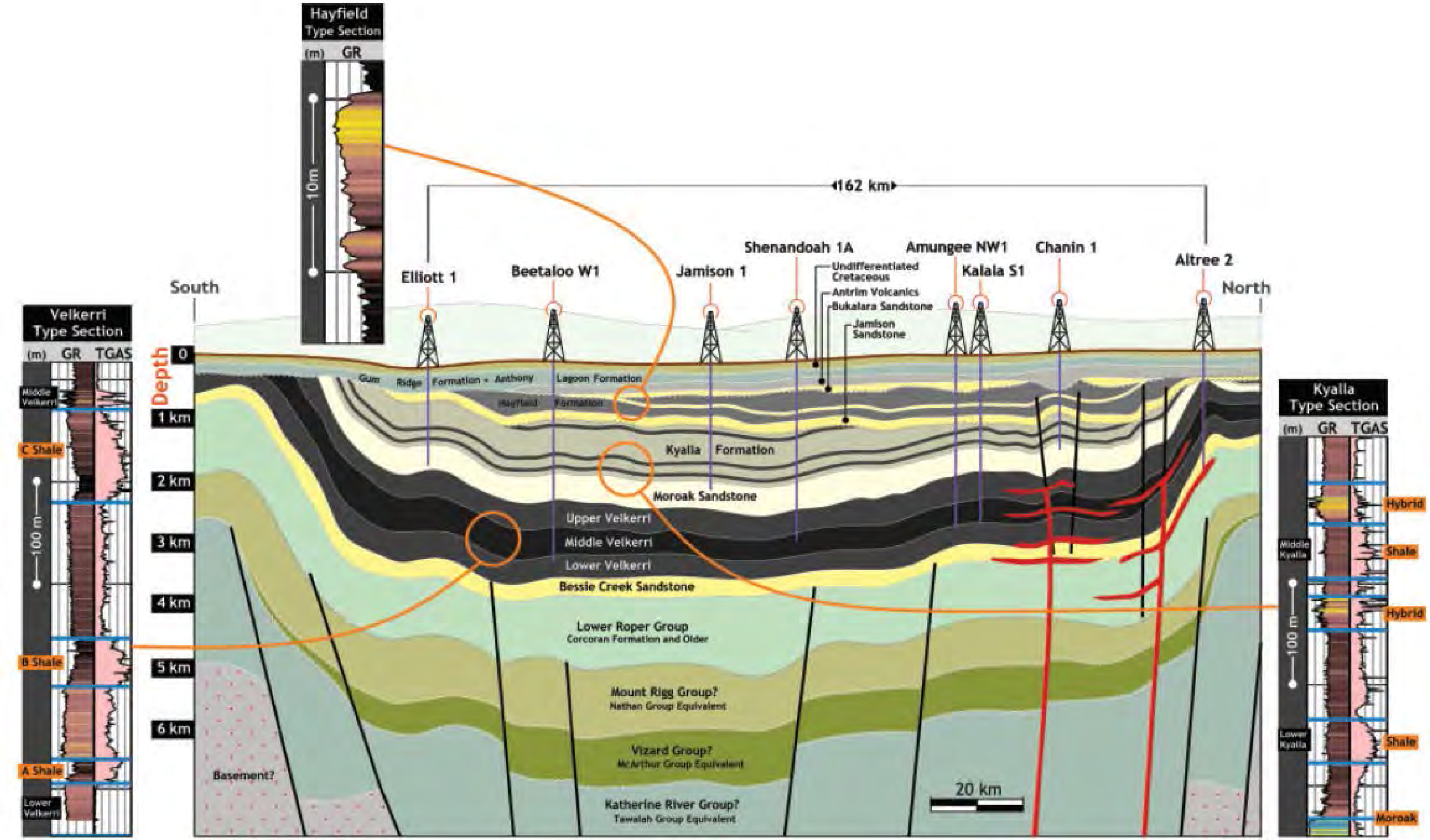

Figure 12 Schematic and type sections of the identified plays within and over the Beetaloo Sub-basin. GR= gamma ray. TGAS= total mud gas

Source: Côté et al. (2018). This figure is covered by a Third Party Creative Commons Attribution licence

Element: GBA-BEE-2-171Petroleum play types

Unconventional petroleum resources are key targets within the Beetaloo Sub-basin (Connors and Krassay, 2015; Revie and Edgoose, 2015a, 2015b). The Velkerri and Kyalla formations have been identified as the primary shale gas plays, having the greatest potential for commercialisation, and are currently being explored and evaluated (Figure 12) (Close et al., 2017a; Côté et al., 2018). In addition, the Hayfield sandstone member oil/condensate play in the overlying Neoproterozoic sedimentary rocks is also under evaluation (Figure 12) (Côté et al., 2018).

3.4.2.1 Velkerri Formation

The Velkerri Formation shale dry gas play is the most mature resource play in the Beetaloo Sub-basin (Close et al., 2017a; Côté et al., 2018). The Velkerri Formation formally subdivided into the Kalala, Amungee and Wyworrie members, which correspond to the previously used lower, middle and upper Velkerri Formation respectively (Munson and Revie, 2018).

Within the Amungee Member of the Velkerri Formation, there are three well defined target intervals, informally known as the A, B and C shales or organofacies (Figure 13) (Close et al., 2017a; Côté et al., 2018; Warren et al., 1998). Although only the B shale has been tested with a horizontal, hydraulically fracture stimulated well, the A and C shales are also considered to be viable targets (Côté et al., 2018). Additionally, a liquids-rich gas play has been identified in the Velkerri Formation along the northern and south-eastern limits of the eastern Beetaloo Sub-basin, as well as in the western sub-basin (Côté et al., 2018; Faiz et al., 2016; Faiz et al., 2018).

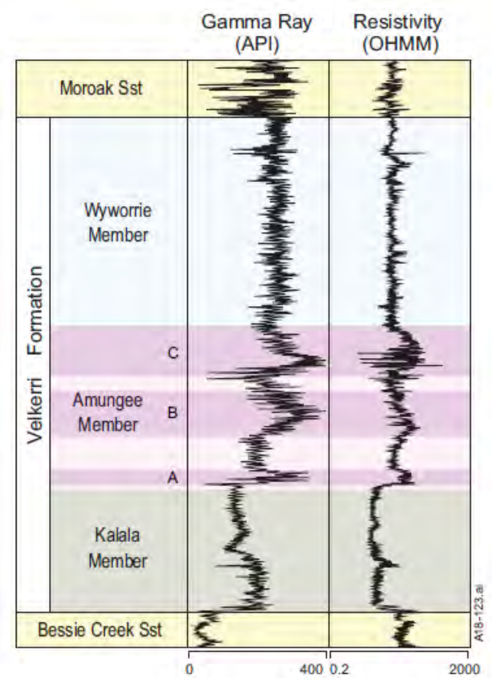

Figure 13 Formal sub-division of Velkerri Formation displayed on composite gamma ray and resistivity logs from Pacific Oil and Gas Ltd drillholes in the Beetaloo Sub-basin

Source: Munson and Revie (2018)
Element: GBA-BEE-2-196

3.4.2.2 Kyalla Formation

There are three well defined source rock intervals in the Kyalla Formation. The lower and middle Kyalla Formation shales are identified to be prospective for liquids-rich gas in deepest sections of both the eastern and western sub-basins (Côté et al., 2018). Oil is likely to be hosted in the upper shale, as well as the lower and middle shales towards the sub-basin margins.

In addition, two prospective hybrid target intervals have also been identified within the Kyalla Formation, which host an additional potential liquids-rich gas play (Altmann et al., 2018). These hybrid lithologies consist of porous and permeable sandstone, interbedded with siltstone and shales. This play is restricted to the south of the eastern Beetaloo Sub-basin and would most likely be developed as a stacked play in association with the adjacent Kyalla Formation shale intervals (Côté et al., 2018).

3.4.2.3 Hayfield sandstone member

The prospective Hayfield sandstone member oil/condensate play is described below following Côté et al. (2018). The Hayfield sandstone member play is thought to be a thin but regionally extensive sandstone confined to an area over the central part of the eastern Beetaloo Sub-basin. This play was identified during the drilling of Amungee NW 1, when a strong wet gas show across the Hayfield sandstone member was observed. The play's trapping mechanism is likely to be a structural-stratigraphic trap containing migrated hydrocarbons from either the Kyalla or Velkerri formation source rocks. Whether this is a gas condensate, volatile oil, or a buoyancy driven play with a gas-condensate cap and a volatile oil leg is still to be determined (Côté et al., 2018).

3.4.2.4 Other plays

The Bessie Creek Sandstone and the Moroak Sandstone are potential tight gas reservoirs where the sub-basin enters the gas window below 1500 m. Commercial production would most likely be contingent on horizontal drilling and hydraulic fracturing (Munson, 2014).

There are numerous other potential unconventional shale targets across the broader greater McArthur Basin, including the Barney Creek Formation, Yalco Formation and Caranbirini Member of the Lynott Formation (Crick et al., 1998).

4 Petroleum play characterisation

4.1 *Introduction to petroleum play characterisation*

Several companies are pursuing a range of unconventional petroleum plays in the Beetaloo Sub-basin within the Mesoproterozoic succession. The amount of gas and liquids present within a play, as well as the proportion of hydrocarbons that can be produced, depends on the play type and the specific geological characteristics of both the source and reservoir rock.

The plays most likely to be developed in a five to ten year time frame are the shale plays in the Mesoproterozoic Velkerri and Kyalla formations and the tight oil/condensate play in the Neoproterozoic Hayfield sandstone member (Côté et al., 2018). To underpin further work on understanding likely development scenarios and recovery factors, the key physical formation properties required for each of these plays to be successful were identified and characterised. The physical properties evaluated, which vary by play type, include formation depths and extents, source rock properties (net thickness, TOC, quality and maturity), reservoir characteristics (porosity, permeability, gas saturation and brittleness), regional stress regime and overpressure. These characteristics, combined with published studies, were used to map the relative prospectivity of each of these plays across the sub-basin at a regional scale.

4.2 Characteristics by formation

4.2.1 Velkerri Formation

Key characteristics of the Velkerri Formation are summarised below in Table 4.

Table 4 Key features of the Velkerri Formation

	Kalala Member - Velkerri Formation	Amungee Member- Velkerri Formation	Wyworrie Member - Velkerri Formation
Unconventional play type	Shale liquids-rich and dry gas plays		
Age	Mesoproterozoic; 1361 ± 21 Ma, 1417 ± 29 Ma (Revie, 2017a; Abbott et al., 2001; Creaser and Kendall, 2007); 1308 ± 41 Ma (Yang et al., 2018)		
Top depth	-109–2937 m MSL		
Gross formation thickness	<50–1784 m		
Lithology	Varying portions of siltstone, claystone and sandstone		
Depositional environment	Shallow to distal marine shelf (Revie, 2017a; Abbott et al., 2001)		
Net source rock thickness (present day) [a]	0–31 m	52–246 m	0–34 m
Total organic carbon (present day)	Mean 0.9 wt% Range 0–7 wt%	Mean 3.4 wt% Range 0–30 wt%	Mean 0.9 wt% Range 0–11 wt%
Hydrogen Index (present day)	4–233 mg HC/g TOC	1–800 mg HC/g TOC	8–461 mg HC/g TOC
Source rock thermal maturity	Immature to dry gas		
Average permeability [b]	5.7 x 10^{-5} mD (1 sample only)	Mean 1.6 x 10^{-5} mD Range 1.9 x 10^{-5}–6.3 x 10^{-4} mD	Mean 8.1 x 10^{-5} mD Range 1.6 x 10^{-5}–1.6 x 10^{-4} mD
Average porosity [c]	7.0% (1 sample only)	Mean 7.3% Range 4.1–11.0%	Mean 8.9% Range 7.7–10.3%
Average water saturation [d]	96.1% (1 sample only)	Mean 55.3% Range 33.9–69.9%	Mean 58.2% Range 53.2–65.6%
Average oil saturation [d]	1.8% (1 sample only)	Mean 5.2% Range 0.5–11.3%	Mean 5.0% Range 2.4–8.4%
Average gas saturation [e]	2.1% (1 sample only)	Mean 39.5% Range 28.7–63.7%	Mean 36.8% Range 32.0–42.6%
Average brittleness [f]	Brittle (0.475)		
Pressure regime	Indications of overpressure		

HC = hydrocarbons; mD = milliDarcy; MSL = mean sea level; TOC = total organic carbon; wt% = weight %
All public domain Velkerri Formation samples have been analysed; no distinction has been made between the properties of reservoir versus non-reservoir units. aNet source rock thickness represents the cumulative thickness of organically rich shale with a present day TOC content > 2 wt % based on available well intersections. b As-received pressure decay permeability by well. c Average porosity represents the dry helium porosity as a % of bulk rock volume by well. d As received saturation as a % of the pore volume by well. e As received gas saturation as a % of pore volume by well. f The brittleness index (BI) was calculated from mineral content using the method of Jarvie et al. (2007).

4.2.1.1 Age and stratigraphic relationships

The Velkerri Formation is early Mesoproterozoic in age. Organic-rich shales of the Velkerri Formation in the Urapunga region returned Re-Os dates of 1361±21 Ma and 1417±29 Ma (Kendall et al., 2009). These currently constrain the depositional ages of the Amungee Member C and A organofacies of the Velkerri Formation (Munson and Revie, 2018).

The Velkerri Formation is part of the Maiwok Subgroup of the Roper Group. It conformably overlies the Bessie Creek Sandstone and is conformably overlain by the Moroak Sandstone. The Velkerri Formation is formally divided into the Kalala, Amungee and Wyworrie members (Figure 13) (Munson and Revie, 2018). These correspond respectively to the previously used lower, middle and upper Velkerri Formation.

4.2.1.2 Extent, depth and gross formation thickness

The Velkerri Formation is present across the Beetaloo Sub-basin, however, surface outcrop is limited to poor exposures present to the north of the sub-basin. Within the Beetaloo Sub-basin, the maximum depth of the top Velkerri Formation (based on well intersections) reaches 2437 m in Tanumbirini 1 in the eastern sub-basin and 1095 m in Birdum Creek 1 in the western sub-basin (Figure 14).

The maximum thickness of the Velkerri Formation based on well intersections is approximately 1483 m (Tanumbirini 1) in the eastern Beetaloo Sub-basin and 734 m (Birdum Creek 1) in the western sub-basin (Figure 15) (Munson and Revie, 2018). The geological model derived from seismic interpretation (Orr et al., 2020) suggests the formation thickness reaches 1784 m (Figure 15).

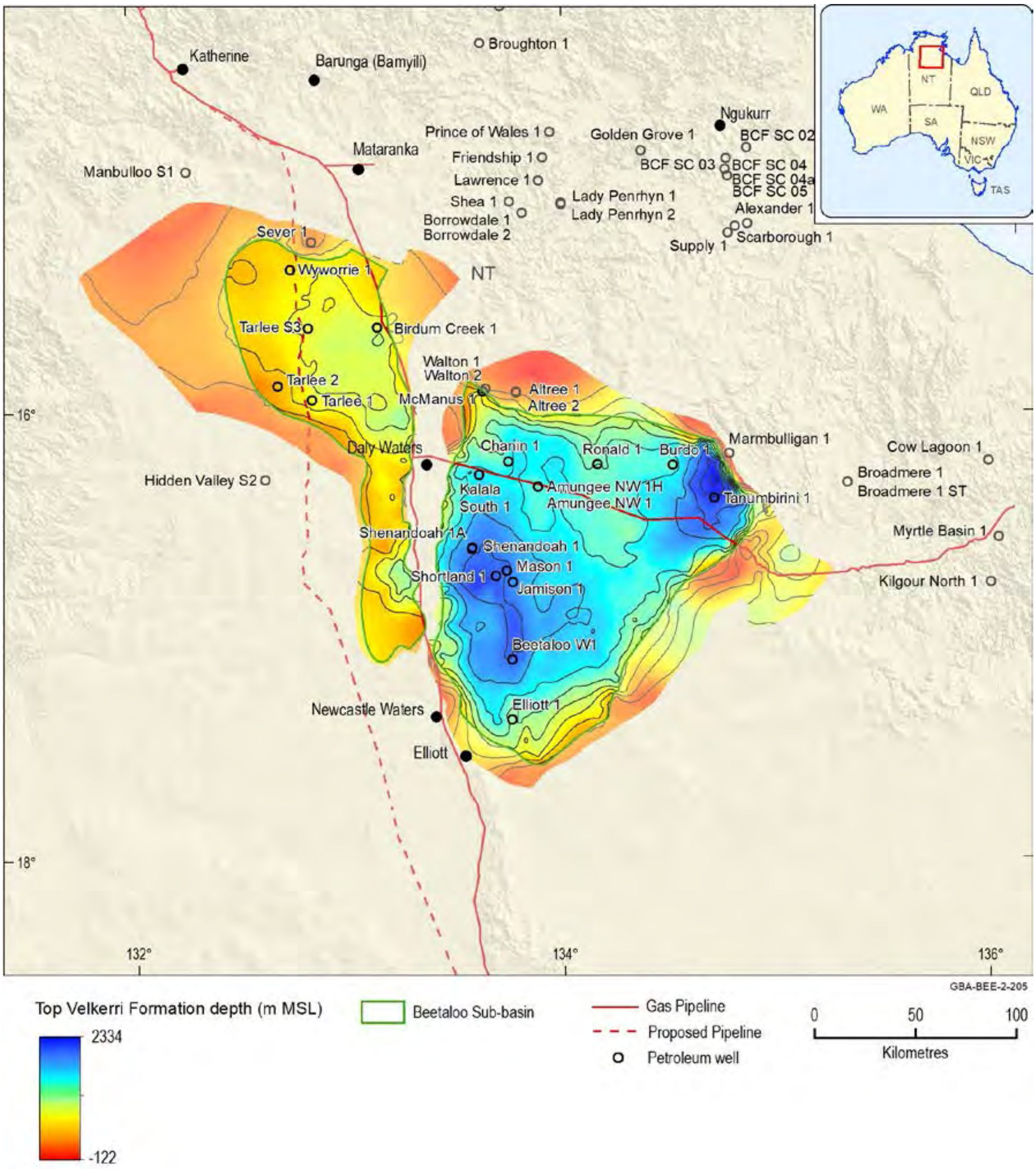

Figure 14 Velkerri Formation top depth (m MSL)

Contour interval = 250 m; MSL = mean sea level
Source: Orr et al. (2020)
Data: Geological and Bioregional Assessment Program (2019b); GBA derived dataset based on Williams (2019) and Northern Territory Government (2018b)
Element: GBA-BEE-2-205

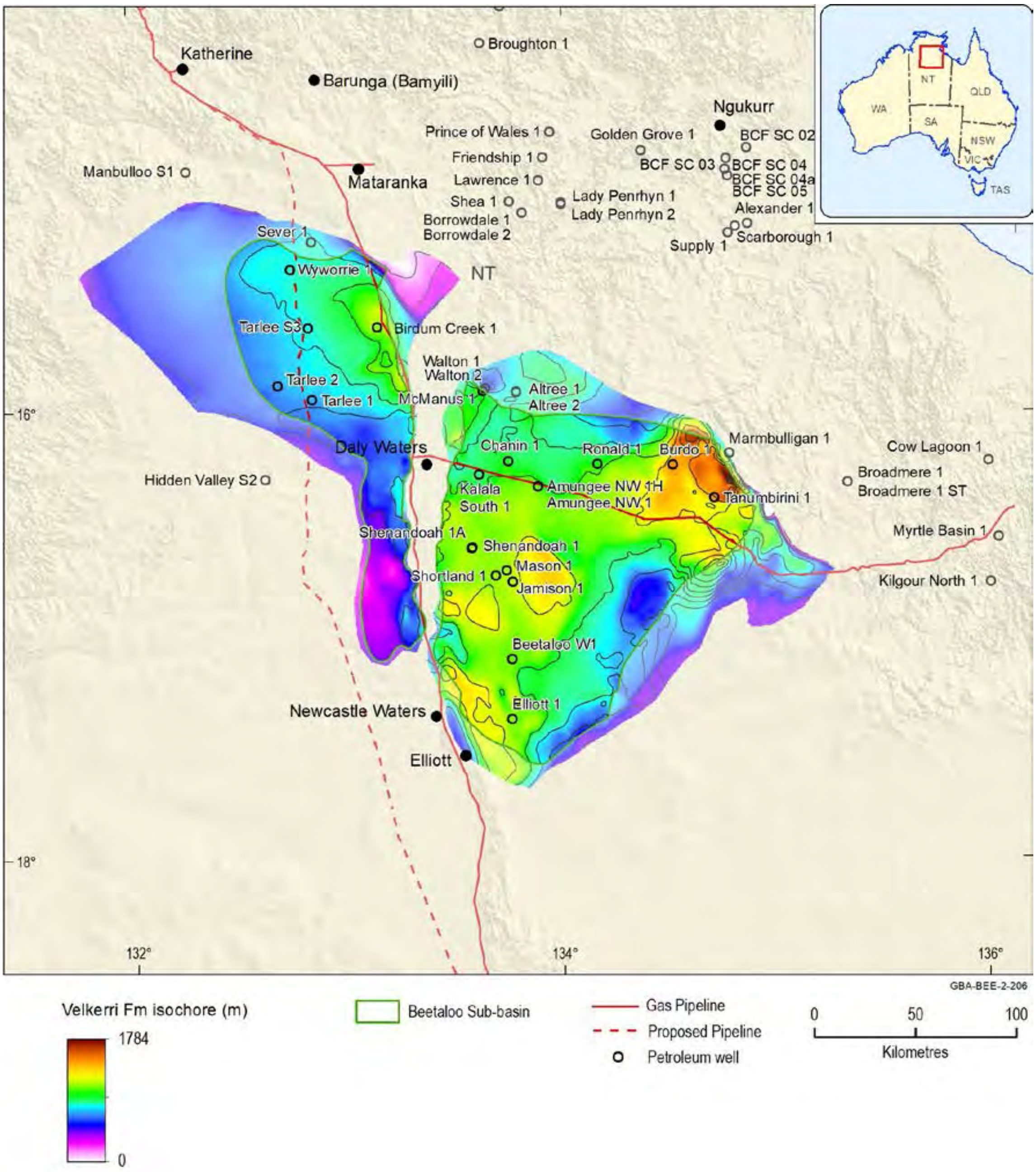

Figure 15 Velkerri Formation total vertical thickness (m)

Contour interval = 250 m
Source: Orr et al. (2020)
Data: Geological and Bioregional Assessment Program (2019b); Velkerri Formation isochore grid GBA derived dataset based on Williams (2019) and Northern Territory Government (2018b)
Element: GBA-BEE-2-206

4.2.1.3 Lithology and palaeoenvironment

The Velkerri Formation is a medium-grey to black laminated shale, with thin interbeds of siltstone and fine-grained sandstone (Munson, 2016). The Kalala Member is a grey to blue claystone with silty mudstone and interbedded sandstones; the Amungee Member is an organic-rich dark grey to black claystone, mudstone and siltstone; and the Wyworrie Member is a grey mudstone and siltstone with fine sandstone towards the top of the unit (Munson, 2014; Munson and Revie, 2018; Lanigan et al., 1994). The Amungee Member is the most organically rich and therefore the most prospective interval in the Beetaloo Sub-basin (Munson, 2014; Munson and Revie, 2018). Further details are provided in the accompanying geology technical appendix (Orr et al., 2020).

The facies variations within the Velkerri Formation, coupled with its great thickness, has provided ample discussion on the depositional setting (Abbott and Sweet, 2000; Abbott et al., 2001; Donnelly and Crick, 1988; Gorter and Grey, 2012; Jackson et al., 1987; Jackson and Raiswell, 1991; Johns et al., 2017; Powell et al., 1987) . The presence of acritarchs and glauconite confirms a marine depositional environment (Grey, 2015). Munson (2016) synthesised the Velkerri Formation depositional environments from previous interpretations as marine, sub-tidal, sub-wave base and generally quiet, but affected by regular current activity. The Amungee Member represents the deepest and most distal environments with the highest proportion of fine-grained sediments (Munson, 2016).

Three organically rich intervals are present within the Amungee Member, separated by organically lean sections. The organically rich shale intervals are informally named the A, B and C shales or organofacies, in ascending stratigraphic order (Close et al., 2017a; Côté et al., 2018; Munson and Revie, 2018). They have a distinct log character which has been identified in all well intersections of the Velkerri Formation (Hoffman, 2015; Warren et al., 1998) and are a primary targets for shale gas exploration in the Beetaloo Sub-basin (Close et al., 2017a; Côté et al., 2018). The Amungee Member A, B and C shales are inferred to have been deposited without a major break in sedimentation. Given the low biotic diversity of the Precambrian, the organic matter is likely to be derived from similar organisms (Côté et al., 2018).

4.2.1.4 Source rock characteristics

The principal petroleum source rocks of the Velkerri Formation are the organic-rich shale units. Jarrett et al. (2019) reviewed the source rock geochemistry and maturity of all known source rock units and associated data from the greater McArthur Basin, including the Velkerri Formation, based on the dataset of Revie and Normington (2018). This study builds on the assessment of Jarrett et al. (2019) by incorporating additional well data for Tarlee 1, 2 and 3, Birdum Creek 1 and Wyworrie 1 provided by Pangaea (Pangaea NT Pty Ltd, 2019). In addition, the source rock distribution, quality and type were characterised separately for all three members of the Velkerri Formation. Statistics were calculated based on a quality controlled dataset, filtered using the screening criteria defined in Jarrett et al. (2018); see also methods snapshot below.

Methods snapshot: Rock-Eval data quality assurance

Rock-Eval pyrolysis is the screening method of choice for source rock evaluation; however, data have to be checked for quality before starting interpretation. Indeed, some data can be unreliable for a number of reasons such as contamination of cuttings with drilling fluid or low TOC content (Carvajal-Ortiz and Gentzis, 2015; Peters, 1986; Dembicki, 2009). To ensure the integrity of the Rock-Eval pyrolysis data, the following data were excluded from analysis:

- Rock-Eval pyrolysis data derived from kerogens
- Internally inconsistent Rock-Eval pyrolysis data, with indices entered into the database not relating correctly to the measured parameters (e.g. HI does not equal S2/TOC *100)

- Rock-Eval pyrolysis data where S2 < 0.1 mg HC/g rock: Rock-Eval pyrolysis results may be unreliable for organically lean samples as they yield low and poorly defined S2 peaks resulting in unreliable Tmax and HI values
- Rock-Eval pyrolysis data where Tmax < 380°C: low values may imply an incorrect programmatical selection of the S2 peak, or the S1 peak is broad due to the presence of non-indigenous free hydrocarbons, either migrated hydrocarbons or drilling fluid contaminants
- Rock-Eval pyrolysis data where OI > 350 mg CO_2/g TOC: high OI values may be unreliable due to either thermal breakdown of carbonates, the presence of oxidised organic matter or the presence of drilling fluid contaminants.

Both oil staining due to migration and contamination from mud additives and oil-based drilling fluids affect the Rock-Eval pyrolysis data. Cuttings samples and side-wall cores are typically more prone to drilling fluid contamination than whole-core samples. Contamination or hydrocarbon migration may result in high PI and low Tmax values (Peters, 1986; Peters and Cassa, 1994). The primary focus of this study are in-situ source rocks, therefore Rock-Eval pyrolysis data meeting the following criteria were flagged as possibly being affected by either migrated hydrocarbons or drilling fluid contaminants, and were removed from the analysis:

- PI > 0.2 with Tmax < 435°C
- PI > 0.3 with Tmax between 435–445°C.

To estimate the extent of the petroleum-generation process and the total generative capacity in an already mature source rock, information on the TOC and HI of organic matter prior to the onset of hydrocarbon generation is required (Jarvie, 2012; Peters et al., 2005). Although source rock statistics and maps presented here reflect the present day measured values, original TOC values were estimated for key wells assuming a Type I kerogen (original HI of 750 mg HC/g TOC) and a Type II kerogen (original HI of 450 mg HC/g TOC). Further analysis of original TOC and HI are outside the scope of this study, but would be an important consideration for any future petroleum systems analysis study in the region.

The net source rock thickness, represented by the net thickness of organically rich material with a total organic carbon (TOC) content of > 2 wt%, was also estimated for wells where Schlumberger LithoScanner log data are available. This high-precision element capture spectroscopy well logging technology provides a continuous measurement of total carbon content down well. A continuous TOC profile may then be calculated by subtracting the inorganic carbon associated with carbonate minerals from the total carbon content. Due to the reduction in TOC with increasing maturity discussed above, using a present day TOC cut off of 2 wt% provides a minimum estimate of the original source rock thickness in regions where significant oil and gas generation has already occurred.

4.2.1.4.1 Total Velkerri Formation

Figure 16 and Figure 17 show example sections through the Velkerri Formation for 2 wells in the western sub-basin and 2 wells in the eastern sub-basin, highlighting the down well variability in lithology, source rock properties and maturity.

Source rock statistics for the entire Velkerri Formation are summarised in Table 5 based on a dataset of 2734 TOC samples and 741 Rock-Eval pyrolysis samples. The present day organic richness of the Velkerri Formation varies from 0 to 31 wt% TOC, with a mean of 2.3 wt% TOC, demonstrating excellent source rock richness (Table 5; Figure 18; Figure 19). Present day hydrogen indices range from 1 mg HC/g TOC to 800 mg HC/g TOC (Table 5; Figure 18), indicating excellent source rock quality (Figure 18).

The present day net organically rich ratio (NORR), representing the fraction of the formation with a TOC greater than 2 wt%, was calculated for eight wells. The average NORR of the Velkerri Formation is 0.3068 (Table 6; 0.333 in the eastern sub-basin and 0.2631 in the western sub-basin). Figure 20a shows the distribution of NORR data by well, along with a NORR grid across the Beetaloo Sub-basin, interpolated from the well data using a simple minimum curvature gridding algorithm.

The present day net source rock thickness, equivalent to the net thickness of organically rich shales with a TOC > 2 wt%, was calculated using the product of the NORR and the gross formation thickness. Net source rock thickness was calculated for eight wells, using the total intersected formation thickness as the gross thickness. The net source rock thickness by well ranges between 89 m and 724 m, with an average of 300 m (Table 6; Figure 20b). For all wells except Tanumbirini 1, these net source rock thicknesses represent minimum values as total depth was reached in the Velkerri Formation and the entire gross formation thickness was not penetrated.

A net source rock thickness grid was also calculated using the product of the NORR grid and the total formation thickness from the three-dimensional geological model (Orr et al., 2020) (Figure 20b). Further work is required to link source rock properties, including thickness and organic richness, to facies variations across the basin.

Organic petrology and other thermal maturity indicators (e.g. Tmax) indicate that the Velkerri Formation is mature for liquids-rich gas to dry gas (Figure 16; Figure 17). Source rock maturity for the Velkerri Formation is discussed in further detail in Section 4.3, which describes the use of one-dimensional petroleum systems modelling to map the distribution of the oil, wet gas and dry gas windows across the Beetaloo Sub-basin.

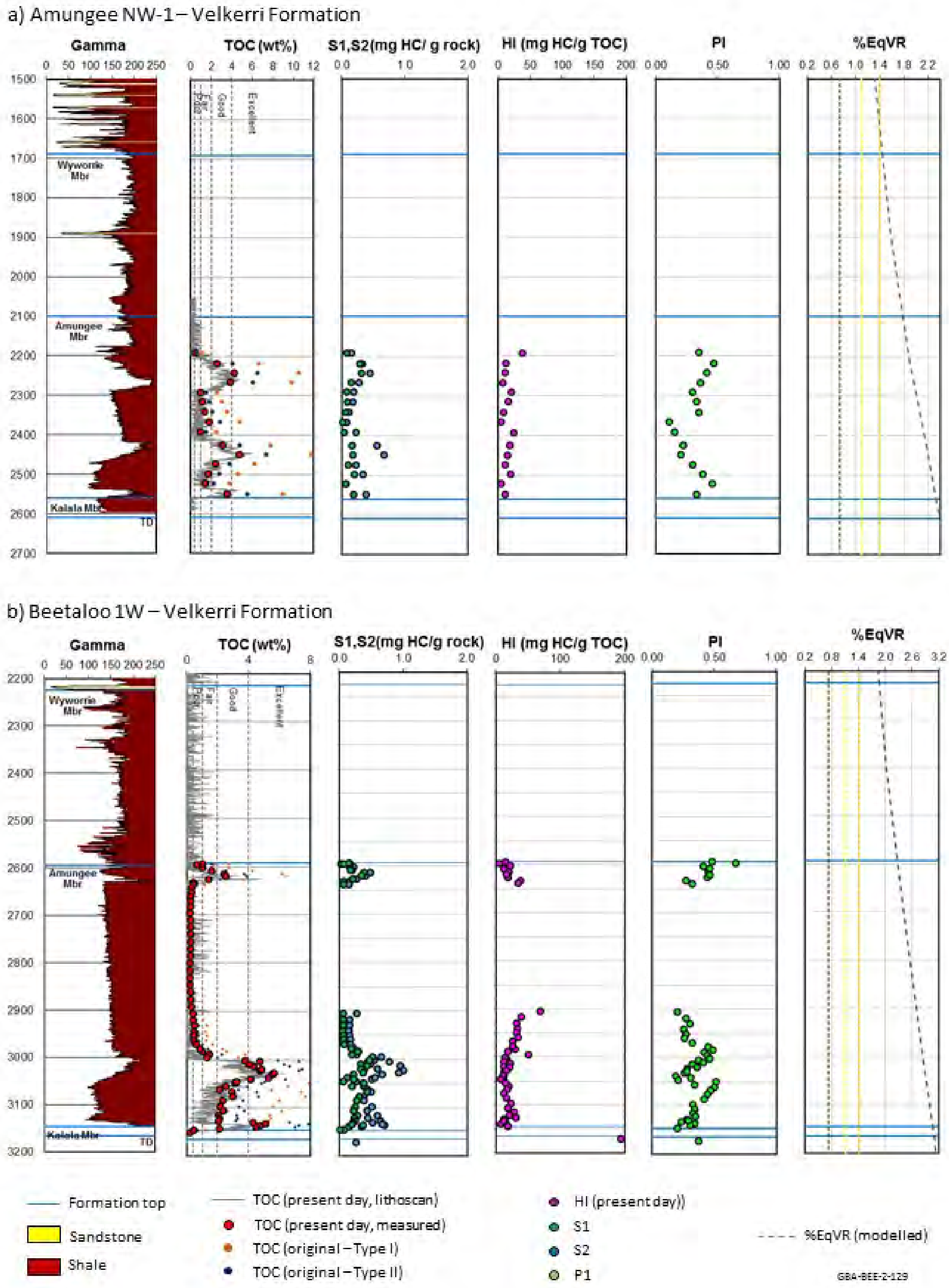

Figure 16 Velkerri Formation source rock characteristics in the a) Amungee NW1 and b) Beetaloo W1 wells in the eastern Beetaloo Sub-basin

TD = total depth; TOC = total organic carbon; HI = hydrogen index; S1, S2, S3 = Rock-Eval parameters; PI = production index; %EqVR = vitrinite reflectance equivalent; ppm = parts per million; wt% = weight as a percentage. Two sets of original TOC data are estimated assuming original HIs of 750 mg HC/g TOC) and 450 mg HC/g TOC, using the equation of Peters et al. (2005). Modelled maturity is sourced from one-dimensional petroleum system model presented in Section 4.3.

Data: Revie and Normington (2018)

Element: GBA-BEE-2-361

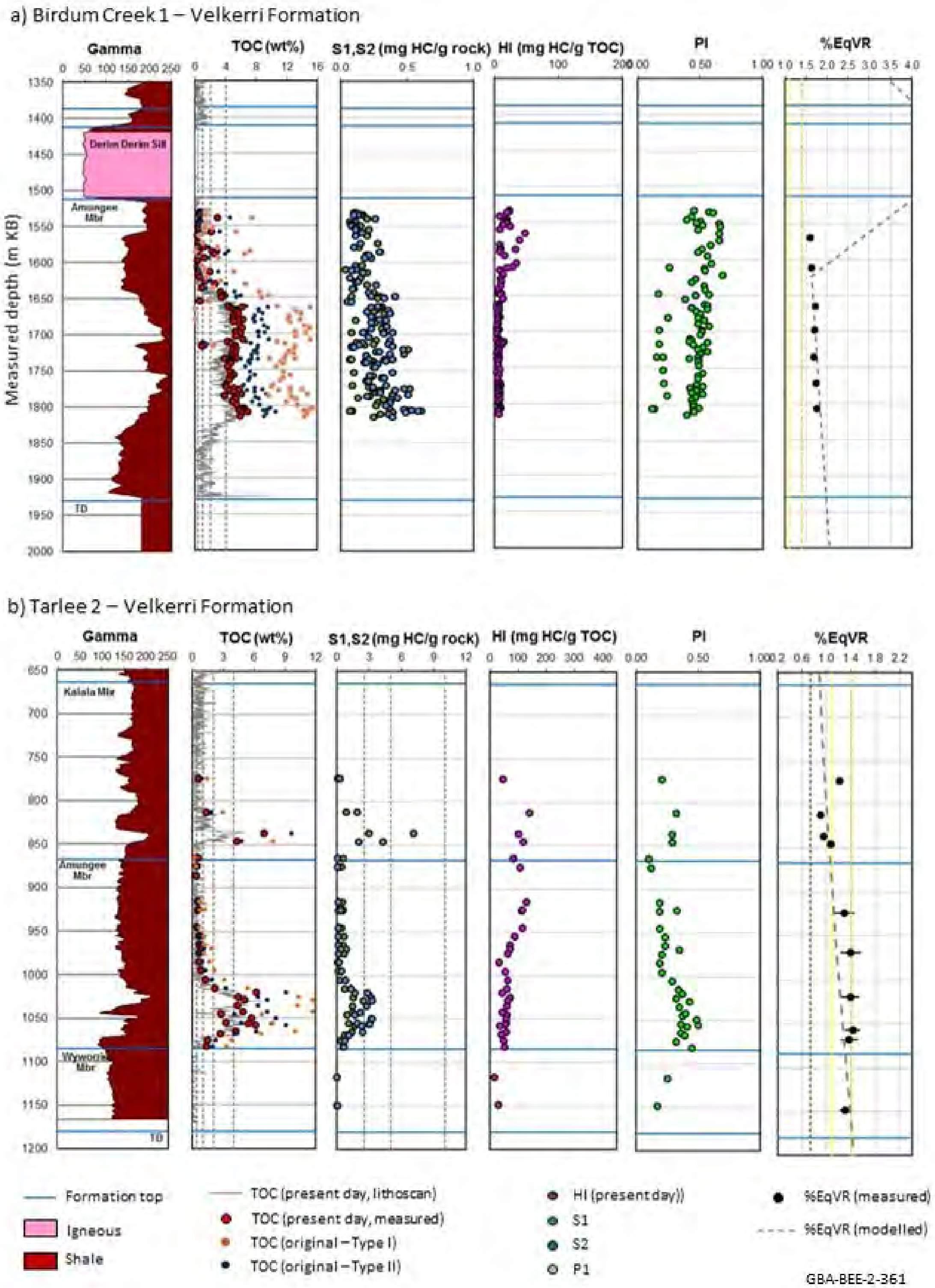

Figure 17 Velkerri Formation source rock characteristics in the a) Birdum Creek 1 and b) Tarlee 2 wells in the western Beetaloo Sub-basin

TD = total depth; TOC = total organic carbon; HI = hydrogen index; S1, S2, S3 = Rock-Eval parameters; PI = production index; %EqVR = vitrinite reflectance equivalent; ppm = parts per million; wt% = weight as a percentage. Two sets of original TOC data are estimated assuming original HIs of 750 mg HC/g TOC) and 450 mg HC/g TOC, using the equation of Peters et al. (2005). Modelled maturity is sourced from one-dimensional petroleum system model presented in Section 4.3.
Data: Revie and Normington (2018); Pangaea NT Pty Ltd (2019)
Element: GBA-BEE-2-130

Table 5 Velkerri Formation source rock properties. Statistics are based on the analysis of 2734 TOC samples and 741 Rock-Eval pyrolysis samples. Rock-Eval pyrolysis data was quality controlled prior to calculating statistics using the screening criteria defined in Jarrett et al. (2018)

	Mean	Min	Max	Stdev	P10	P50	P90
TOC (wt%)	2.3	0.0	31.0*	2.5	0.3	1.5	5.3
S1 (mg HC/g rock)	1.4	0.0	6.5	1.3	0.1	1.2	3.2
S2 (mg HC/g rock)	8.6	0.1	78.7	11.5	0.2	5.0	19.6
S3 (mg HC/g rock)	0.5	0.0	6.5	0.7	0.1	0.3	1.0
Tmax (°C)	454	390	618	39	430	442	506
HI (mg HC/g TOC)	193	1	800	149	9	184	398
OI (mg CO_2/g TOC)	19	0	347	32	2	10	41
PI (unit less)	0.2	0.0	0.7	0.1	0.1	0.2	0.4

mg CO2/g TOC = milligrams of CO2 per gram of total organic carbon; mg HC/g TOC = milligrams of hydrocarbons per gram of total organic carbon; TOC = Total Organic Carbon; S1, S2, S3 and Tmax = Rock-Eval pyrolysis parameters; HI = Hydrogen Index; OI = Oxygen Index; PI = Production Index; stdev: standard deviation; P10: 10th percentile; P50: 50th percentile; P90: 90th percentile; wt% = weight as a percentage.
*TOC values greater than 10% may represent graphite formed in association with local igneous intrusions.
Data: Revie and Normington (2018); Pangaea NT Pty Ltd (2019)

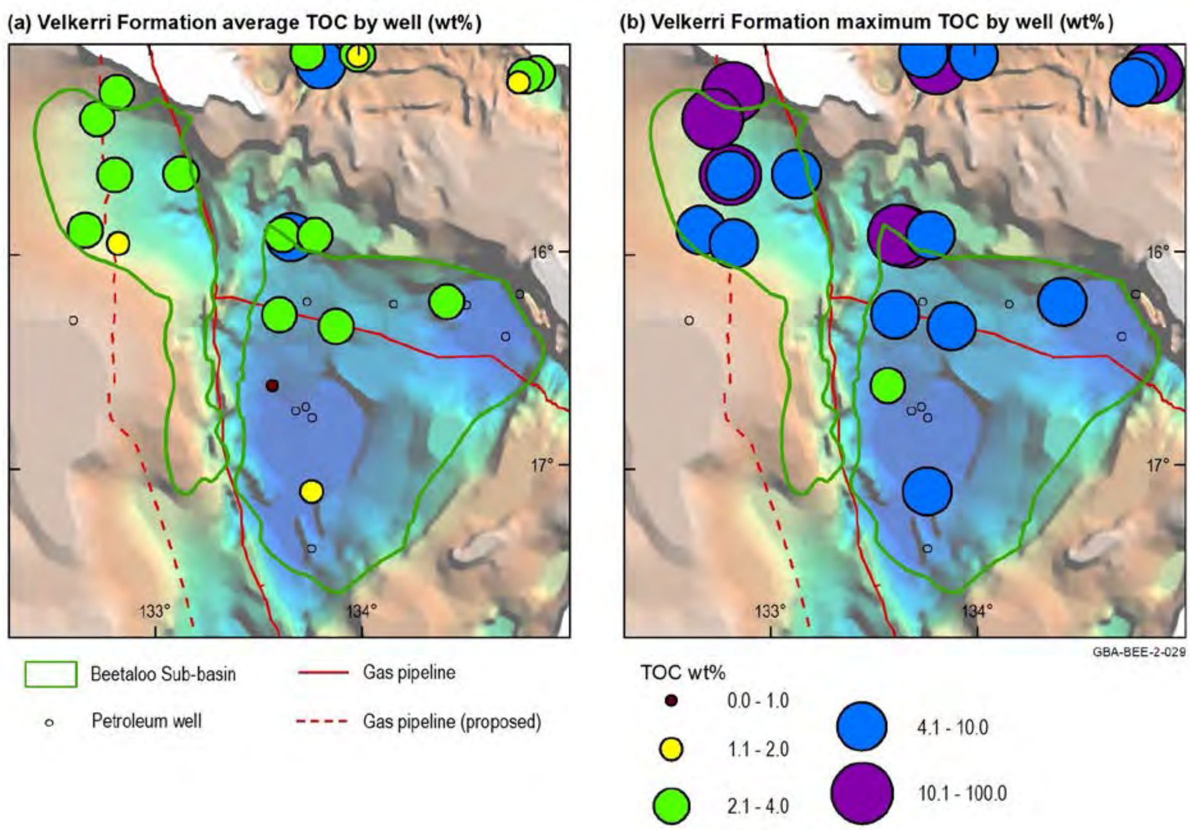

Figure 18 Velkerri Formation TOC distribution shown over the depth to base Roper Group

TOC = total organic carbon; wt% = weight as a percentage
Source: modified from Jarrett et al. (2019); depth to base Roper Group (Wilton package) sourced from Frogtech Geoscience (2018)
Data: TOC data from Revie and Normington (2018); Pangaea NT Pty Ltd (2019)
Element: GBA-BEE-2-029

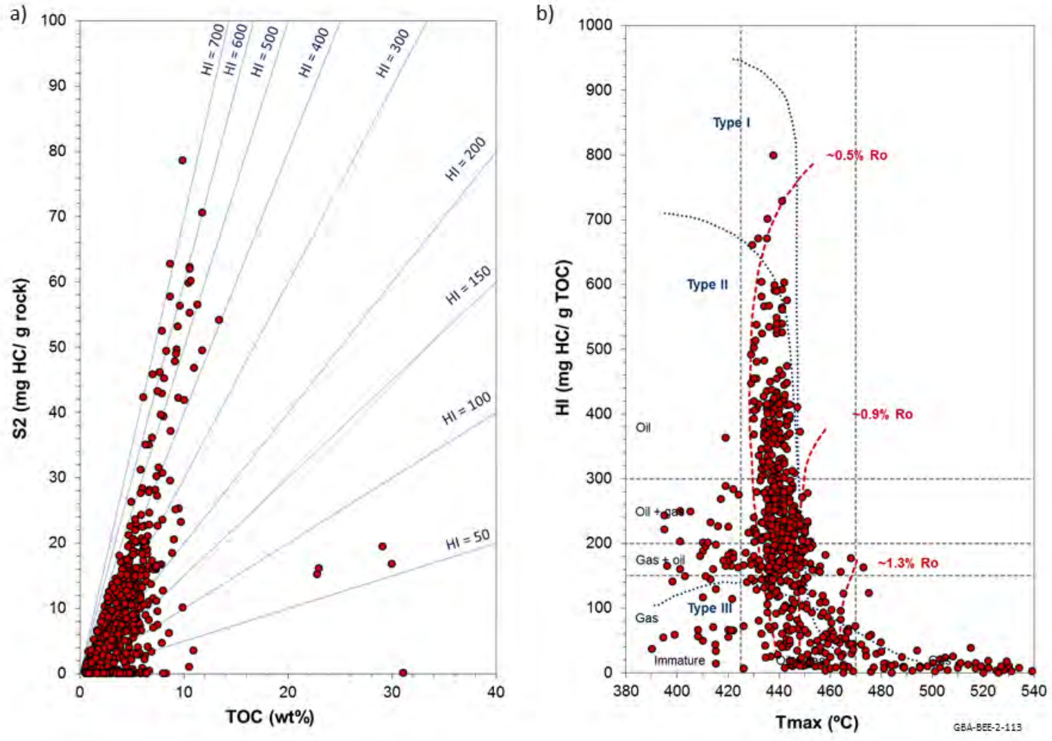

Figure 19 Rock-Eval pyrolysis data plots for the Velkerri Formation: (a) TOC carbon vs S2 yield; (b) Tmax vs present day HI

TOC = total organic carbon; S2 and Tmax = Rock-Eval pyrolysis parameters; HI = hydrogen index; wt% = weight as a percentage; HC = hydrocarbons; %Ro = vitrinite reflectance maturity
Source: modified from Jarrett et al. (2019)
Data: Revie and Normington (2018); Pangaea NT Pty Ltd (2019)
Element: GBA-BEE-2-113

Table 6 Net organically rich ratio (NORR) of the Velkerri Formation shales in the Beetaloo Sub-basin

	Well	Net organically rich ratio (fraction)	Total formation thickness (m)*	Net thickness of organically rich section (m)*
Eastern	Amungee NW1	0.31	919	287
Eastern	Beetaloo W1	0.10	940	89
Western	Birdum Creek 1	0.25	834	204
Eastern	Kalala S1	0.24	776	190
Eastern	Tanumbirini 1	0.49	1483	734
Western	Tarlee 1	0.40	540	219
Western	Tarlee 2	0.14	516	72
Western	Wyworrie 1	0.52	597	309
	Average	0.31	991	301

*Note all wells except Tanumbirini reach total depth in the Velkerri Formation, therefore for both the total formation thickness and the net thickness of organically rich material represent minimum values for these wells.
Data: Revie and Normington (2018)

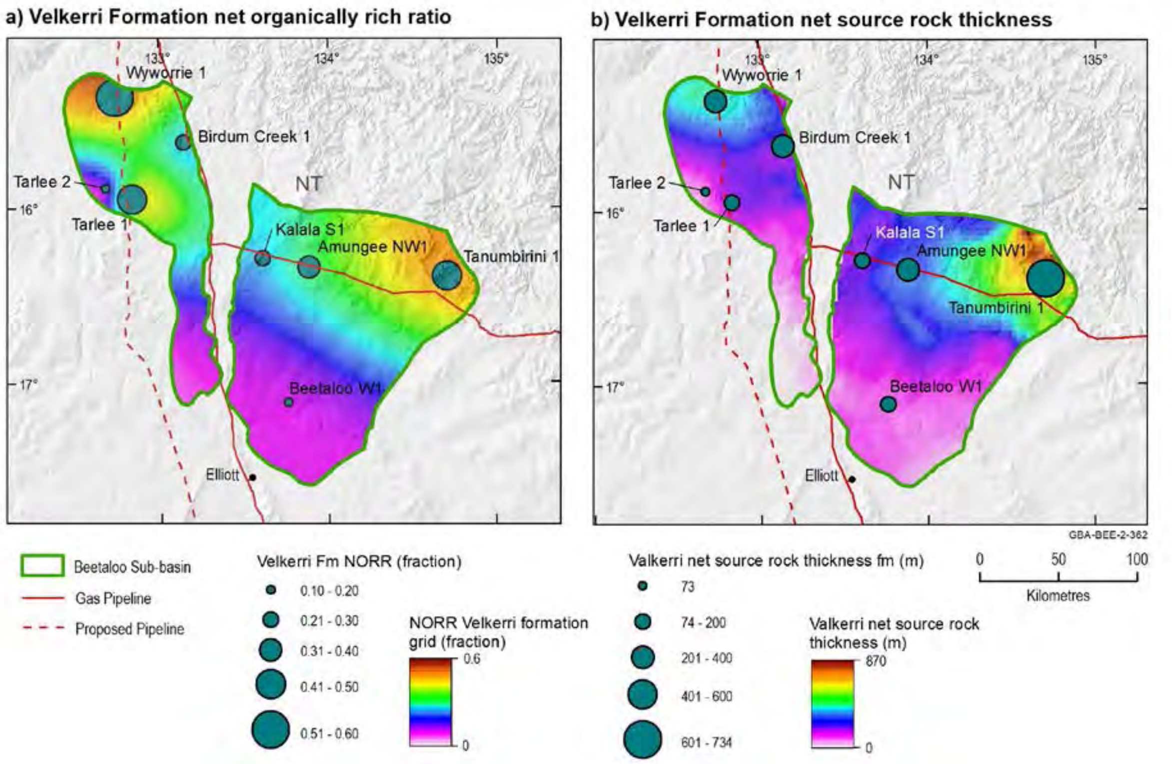

Figure 20 a) Net organically rich ratios of the Velkerri Formation shales and b) net Velkerri Formation source rock thickness in the Beetaloo Sub-basin and surrounds

*Note all wells except Tanumbirini 1 reach total depth in the Velkerri Formation, therefore the net thickness source rock thickness represent minimum values all wells except Tanumbirini 1.
Data: Revie and Normington (2018)
Element: GBA-BEE-2-362

4.2.1.4.2 Kalala Member

Source rock statistics for the Kalala Member are summarised in Table 7 based on a dataset of 505 TOC samples and 75 Rock-Eval pyrolysis samples sourced from Revie and Normington (2018) and Pangaea NT Pty Ltd (2019). The organic richness of the Kalala Member varies from 0 to 7 wt%, with mean of 0.9 wt% TOC (Table 7). Samples with TOC > 2 wt% are restricted to the northern boundaries of both the eastern and western Beetaloo Sub-basin (Figure 21). Kalala Member present day hydrogen indices range from 4 mg HC/g TOC to 233 mg HC/g TOC (Table 7), indicating predominantly gas-prone kerogens (Figure 22). Although two samples show excellent source rock quality (HI > 500 mg HC/g TOC), the data suggests possible staining due to migration, so they are excluded from this data analysis.

The present day net source rock thickness, equivalent to the net thickness of organically rich shales with a TOC > 2 wt%, was calculated using the product of the NORR and the gross thickness of the Kalala Member. Net source rock thickness was calculated for six wells, using the total intersected formation thickness as the gross thickness. The distribution of NORR varies significantly, from 0 to 0.6, with an average of 0.2 (Table 8). For all wells except Tanumbirini 1, these net source rock thicknesses represent minimum values as total depth was reached in the Kalala Member and therefore the entire gross formation thickness was not penetrated.

Table 7 Kalala Member source rock properties. Statistics are based on the analysis of 505 TOC samples and 75 Rock-Eval pyrolysis samples. Rock-Eval pyrolysis data was quality controlled prior to calculating statistics using the screening criteria defined in Jarrett et al. (2018)

	Mean	Min	Max	Stdev	P10	P50	P90
TOC (wt%)	0.9	0.0	7.0	1.2	0.1	0.4	2.7
S1 (mg HC/g rock)	0.6	0.0	2.9	0.7	0.1	0.3	1.5
S2 (mg HC/g rock)	2.5	0.1	11.6	2.9	0.2	0.9	6.9
S3 (mg HC/g rock)	0.3	0.0	2.6	0.5	0.0	0.2	0.8
Tmax (°C)	456	390	576	30	426	453	476
HI (mg HC/g TOC)	92	4	233	61	17	89	180
OI (mg CO_2 g TOC)	23	1	264	43	2	9	48
PI (unit less)	0.2	0.0	0.6	0.1	0.1	0.2	0.4

mg CO2/g TOC = milligrams of CO2 per gram of total organic carbon; mg HC/g TOC = milligrams of hydrocarbons per gram of total organic carbon; TOC = Total organic carbon; S1, S2, S3 and Tmax = Rock-Eval pyrolysis parameters; HI = Hydrogen Index; OI = Oxygen Index; PI = Production Index; stdev: standard deviation; P10: 10th percentile; P50: 50th percentile; P90: 90th percentile; wt% = weight as a percentage.
Data: Revie and Normington (2018); Pangaea NT Pty Ltd (2019)

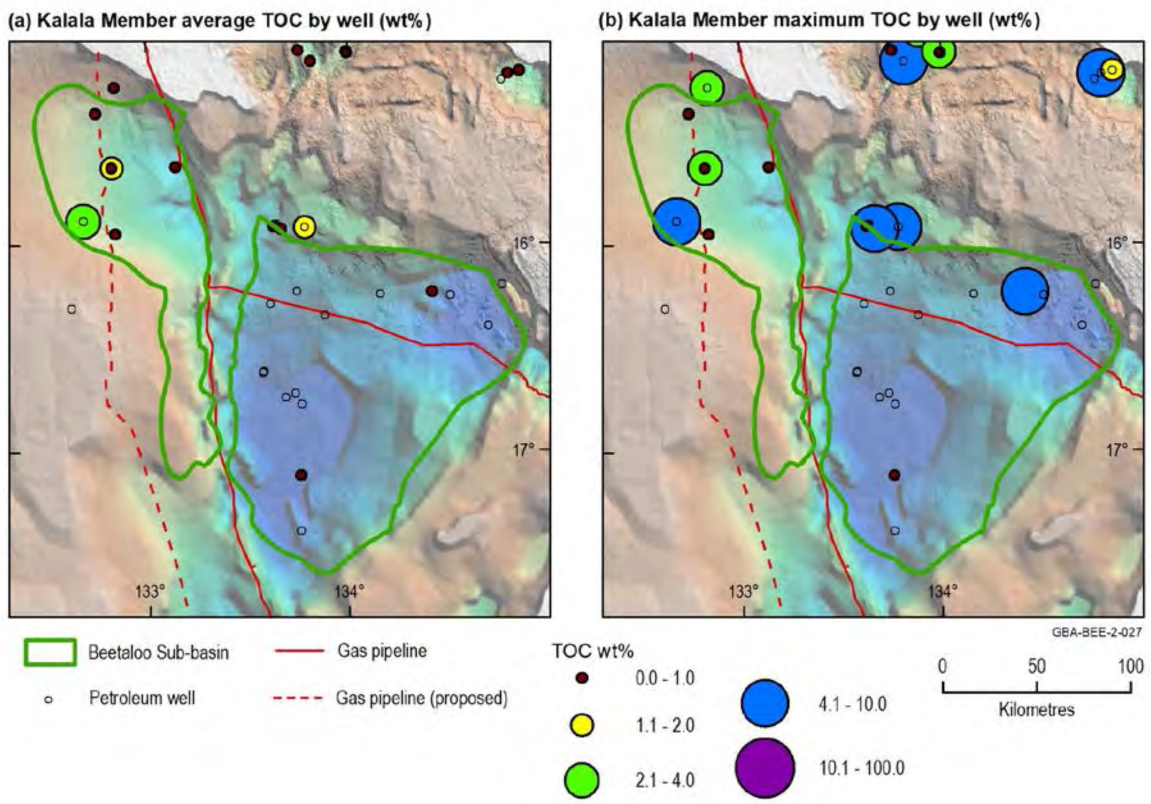

Figure 21 Kalala Member (Velkerri Formation) TOC distribution show over the depth to base Roper Group

TOC = total organic carbon; wt% = weight as a percentage
Source: modified from Jarrett et al. (2019); depth to base Roper Group (Wilton package) sourced from Frogtech Geoscience (2018)
Data: Revie and Normington (2018); Pangaea NT Pty Ltd (2019)
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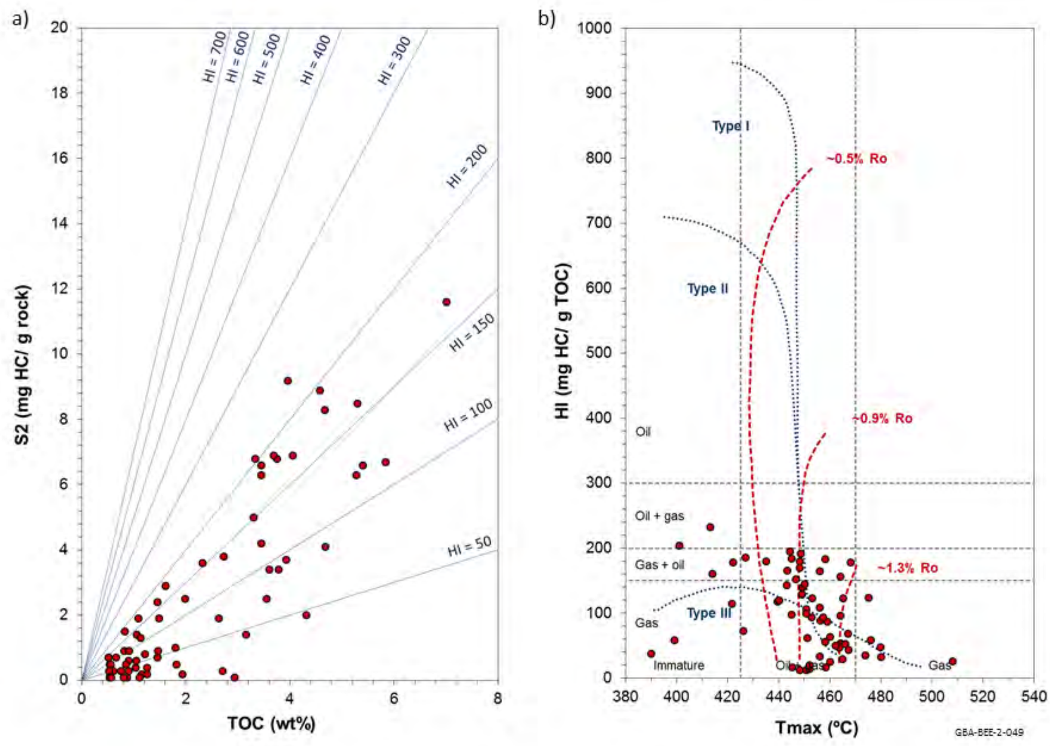

Figure 22 Rock-Eval pyrolysis data plots for the Kalala Member of the Velkerri Formation, modified from Jarrett et al. (2019): (a) TOC content vs S2 yield; (b) Tmax vs HI

TOC: total organic carbon; HI: hydrogen index; wt%: weight %; HC: hydrocarbons; Ro: maturity
Source: modified from Jarrett et al. (2019)
Data: Revie and Normington (2018); Pangaea NT Pty Ltd (2019)
Element: GBA-BEE-2-049

Table 8 Net organically rich ratio (NORR) of the Kalala Member shales in the Beetaloo Sub-basin

Beetaloo Sub-basin region	Well	Net organically rich ratio (fraction)	Total formation thickness (m)*	Net thickness of organically rich section (m)*
Eastern	Amungee NW1	0	57	0
Eastern	Kalala S1	0	49	0
Western	Tarlee 1	0.62		
Western	Tarlee 2	0.08	100	8
Western	Wyworrie 1	0.51	60	31
	Average	0.20		

All wells reach total depth within the Kalala Member, therefore for the total formation thickness and the net thickness of organically rich material represent minimum values.
Data: Revie and Normington (2018)

4.2.1.4.3 Amungee Member

Source rock statistics for the Amungee Member are summarised in Table 9 based on a dataset of 1520 TOC samples and 525 Rock-Eval pyrolysis samples sourced from Revie and Normington (2018) and Pangaea NT Pty Ltd (2019). Amungee Member TOC varies from 0.1 to 30 wt%, with a mean value of 3.4 wt% TOC, demonstrating excellent source rock richness (Table 9).

Samples with TOC content > 2 wt% are distributed across both the eastern and western Beetaloo Sub-basin, demonstrating the presence of excellent quality source rock facies across the sub-basin (Figure 23). Amungee Member present day hydrogen indices range from 1 mg HC/g TOC to 800 mg HC/g TOC (Table 9). The very high hydrogen indices indicate excellent source rock quality and the presence of liquid-prone kerogens (Figure 24; Table 9) (Taylor et al., 1994; Summons et al., 1994).

The NORR of the Amungee Member, representing the fraction of formation with a TOC greater than 2 wt%, was calculated for eight wells. The NORR ranges from 0.16 to 0.53 with the average of 0.35 (Table 10). Figure 25a shows the distribution of Amungee Member NORR by well, along with a NORR grid across the Beetaloo Sub-basin, interpolated from the well data using a simple minimum curvature gridding algorithm. However, further work is required to link source rock properties, including thickness and organic richness, to facies variations across the basin.

The present day net source rock thickness, equivalent to the net thickness of organically rich shales with a TOC > 2 wt%, was calculated using the product of the NORR and the gross formation thickness. Net source rock thickness was calculated for eight wells, using the total intersected formation thickness as the gross thickness. The net source rock thickness by well ranges between 52 m and 246 m, with an average of 157 m (Table 10; Figure 25b). A net source rock thickness grid was also calculated using the product of the NORR grid and the total formation thickness from the three-dimensional geological model (Orr et al., 2020) (Figure 25b).

Table 9 Amungee Member source rock properties. Statistics based on analysis of 1520 TOC samples and 525 Rock-Eval pyrolysis samples. Rock-Eval pyrolysis data was quality controlled prior to calculating statistics using the screening criteria defined in Jarrett et al. (2018)

	Mean	Min	Max	Stdev	P10	P50	P90
TOC (wt%)	3.4	0.1	29.9*	2.6	0.6	3.1	6.1
S1 (mg HC/g rock)	1.7	0.0	6.5	1.3	0.1	1.6	3.6
S2 (mg HC/g rock)	10.5	0.1	78.7	12.5	0.2	7.3	22.7
S3 (mg HC/g rock)	0.5	0.0	5.5	0.7	0.1	0.3	1.1
Tmax (°C)	458	395	618	43	430	442	528
HI (mg HC/g TOC)	210	1	800	159	7	208	415
OI (mg CO_2/g TOC)	14	0	94	14	2	9	34
PI (unit less)	0.2	0.0	0.7	0.2	0.1	0.2	0.5

mg CO2/ g TOC = milligrams of CO2 per gram of total organic carbon; mg HC/g TOC = milligrams of hydrocarbons per gram of total organic carbon; TOC = total organic carbon; S1, S2, S3 and Tmax = Rock-Eval pyrolysis parameters; HI = Hydrogen Index; OI = Oxygen Index; PI = Production Index; stdev: standard deviation; P10: 10th percentile; P50: 50th percentile; P90: 90th percentile; wt% = weight as a percentage. *TOC values > 10% may represent graphite formed in association with local igneous intrusions. Data: Revie and Normington (2018); Pangaea NT Pty Ltd (2019)

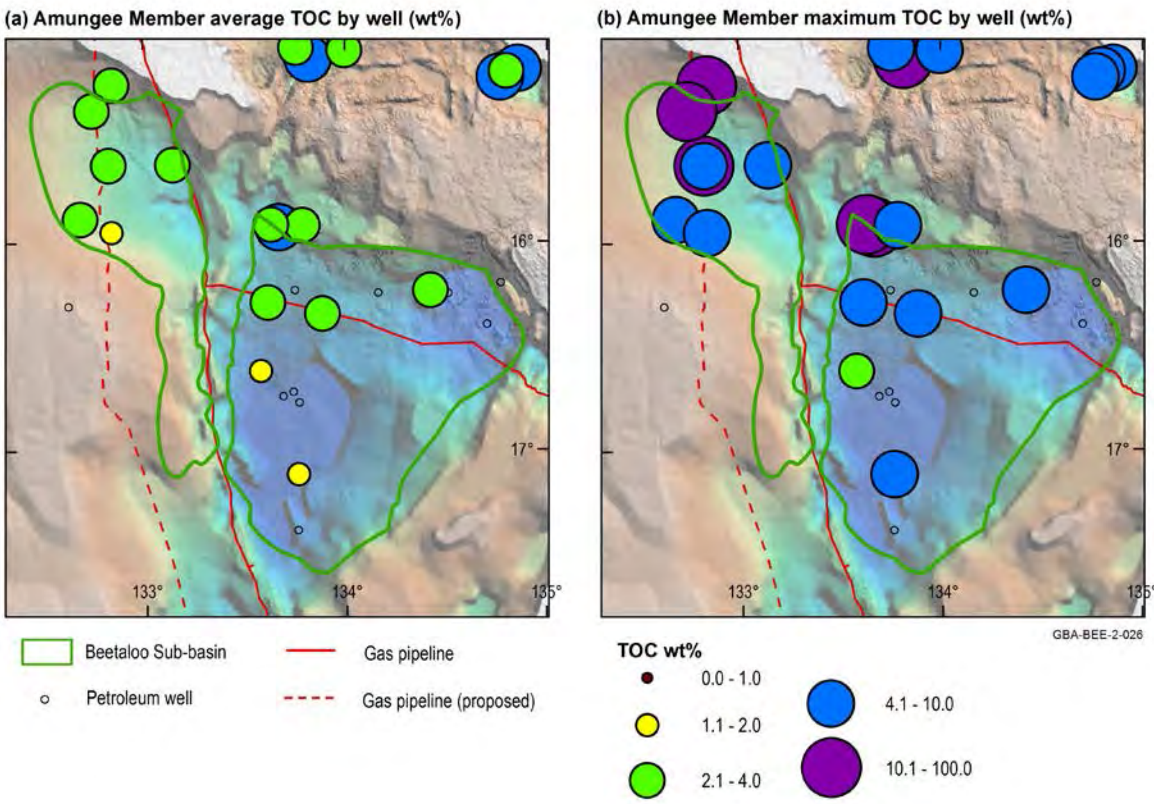

Figure 23 Amungee Member (Velkerri Formation) TOC distribution shown over the depth to base Roper Group

TOC = total organic carbon; wt% = weight as a percentage
Source: modified from Jarrett et al. (2019); depth to base Roper Group (Wilton package) sourced from Frogtech Geoscience (2018)
Data: Revie and Normington (2018); Pangaea NT Pty Ltd (2019)
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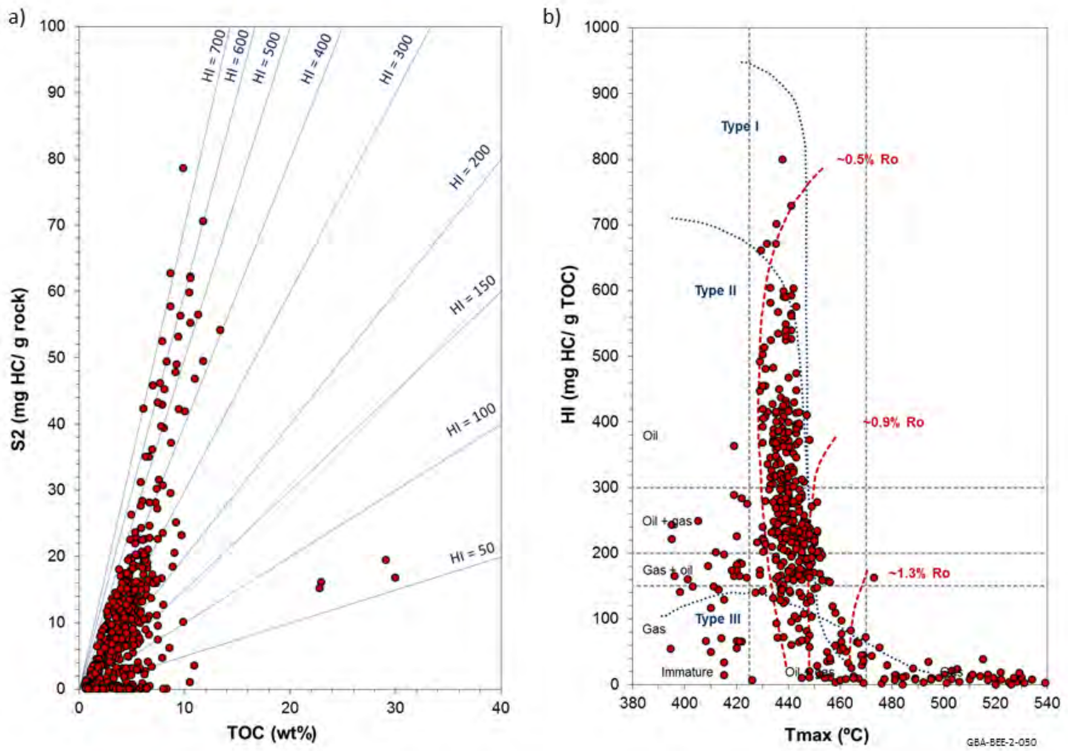

Figure 24 Rock-Eval pyrolysis data plots for the Amungee Member of the Velkerri Formation: (a) TOC content vs S2 yield; (b) Tmax vs HI

TOC = total organic carbon; S2 and Tmax = Rock-Eval pyrolysis parameters; HI = hydrogen index; wt% = weight as a percentage; HC = hydrocarbons; %EqVR = vitrinite reflectance maturity
Source: modified from Jarrett et al. (2019)
Data: Revie and Normington (2018); Pangaea NT Pty Ltd (2019)
Element: GBA-BEE-2-050

Table 10 Net organically rich ratio (NORR) of the Amungee Member shales in the Beetaloo Sub-basin

Beetaloo Sub-basin region	Well	Net organically rich ratio (fraction)	Total unit thickness (m)*	Net thickness of organically rich section (m)*
Eastern	Amungee NW1	0.35	460	159
Eastern	Beetaloo W1	0.16	553	88
Western	Birdum Creek 1	0.37	554	207
Eastern	Kalala S1	0.27	508	135
Eastern	Tanumbirini 1	0.49	497	246
Western	Tarlee 1	0.51	347	176
Western	Tarlee 2	0.24	217	52
Western	Wyworrie 1	0.53	369	196
	Average	0.36		157

Data: Revie and Normington (2018)

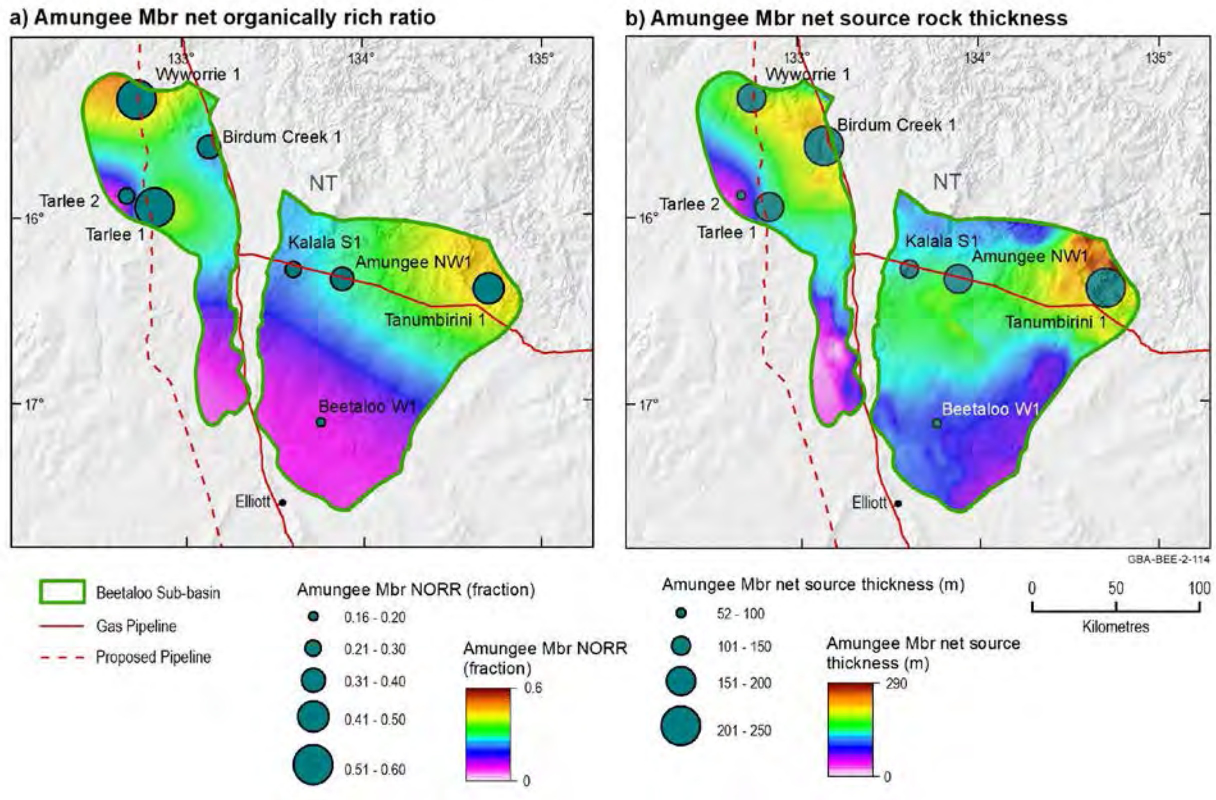

Figure 25 a) Net organically rich ratios of the Amungee Member shales and b) net Amungee Member source rock thickness in the Beetaloo Sub-basin

Data: Revie and Normington (2018)
Element: GBA-BEE-2-114

4.2.1.4.4 Wyworrie Member

Source rock statistics for the Wyworrie Member are summarised in Table 11 based on a dataset of 669 TOC samples and 117 Rock-Eval pyrolysis samples sourced from Revie and Normington (2018) and Pangaea NT Pty Ltd (2019). The organic richness of Wyworrie Member varies from 0.1 to 11 wt%, with a mean of 0.9 wt% TOC (Table 11). Samples with TOC > 2 wt% are restricted to the northern boundaries of both the eastern and western Beetaloo Sub-basin (Figure 26). Wyworrie Member present day hydrogen indices range from 8 mg HC/g TOC to 461 mg HC/g TOC (Table 11). The high hydrogen indices (> 300 mg HC/g TOC) indicate excellent source rock quality and the presence of liquid-prone kerogens (Figure 27).

The present day net source rock thickness, equivalent to the net thickness of organically rich shales with a TOC > 2 wt%, was calculated using the product of the NORR and the gross formation thickness. Net source rock thickness was calculated for six wells, using the total intersected formation thickness as the gross thickness. The distribution of NORR varies significantly, from 0 to 0.27, with an average of 0.048 (Table 12). This corresponds to a range in net source rock thickness from 0 to 34 m, with an average of 8 m. For most wells, these net source rock thicknesses represent minimum values as the lithoscanner log data does not cover the entire gross thickness of the Wyworrie Member. There was insufficient data density to map the NORR.

Table 11 Wyworrie Member source rock properties. Statistics are based on the analysis of 669 TOC samples and 117 Rock-Eval pyrolysis samples. Rock-Eval pyrolysis data was quality controlled prior to calculating statistics using the screening criteria defined in Jarrett et al. (2018)

	Mean	Min	Max	Stdev	P10	P50	P90
TOC (wt%)	0.9	0.1	10.6	1.0	0.3	0.7	1.6
S1 (mg HC/g rock)	0.7	0.0	3.4	0.8	0.1	0.3	2.1
S2 (mg HC/g rock)	3.1	0.2	27.9	4.5	0.3	1.5	7.3
S3 (mg HC/g rock)	0.5	0.0	6.5	0.7	0.1	0.2	1.0
Tmax (°C)	440	415	488	7	434	439	446
HI (mg HC/g TOC)	183	8	461	116	32	175	353
OI (mg CO_2/g TOC)	45	1	347	59	6	20	115
PI (unit less)	0.2	0.0	0.4	0.1	0.1	0.2	0.3

mg CO2/g TOC = milligrams of CO2 per gram of total organic carbon; mg HC/g TOC = milligrams of hydrocarbons per gram of total organic carbon; TOC = total organic carbon; S1, S2, S3 and Tmax = Rock-Eval pyrolysis parameters; HI = Hydrogen Index; OI = Oxygen Index; PI = Production Index; stdev: standard deviation; P10: 10th percentile; P50: 50th percentile; P90: 90th percentile; wt% = weight as a percentage.
All public domain samples have been analysed; no distinction has been made between the properties of reservoir versus non-reservoir units.
Production Index; Stdev = standard deviation; P10 = 10th percentile; P50 = 50th percentile; P90 = 90th percentile
Data: Revie and Normington (2018); Pangaea NT Pty Ltd (2019)

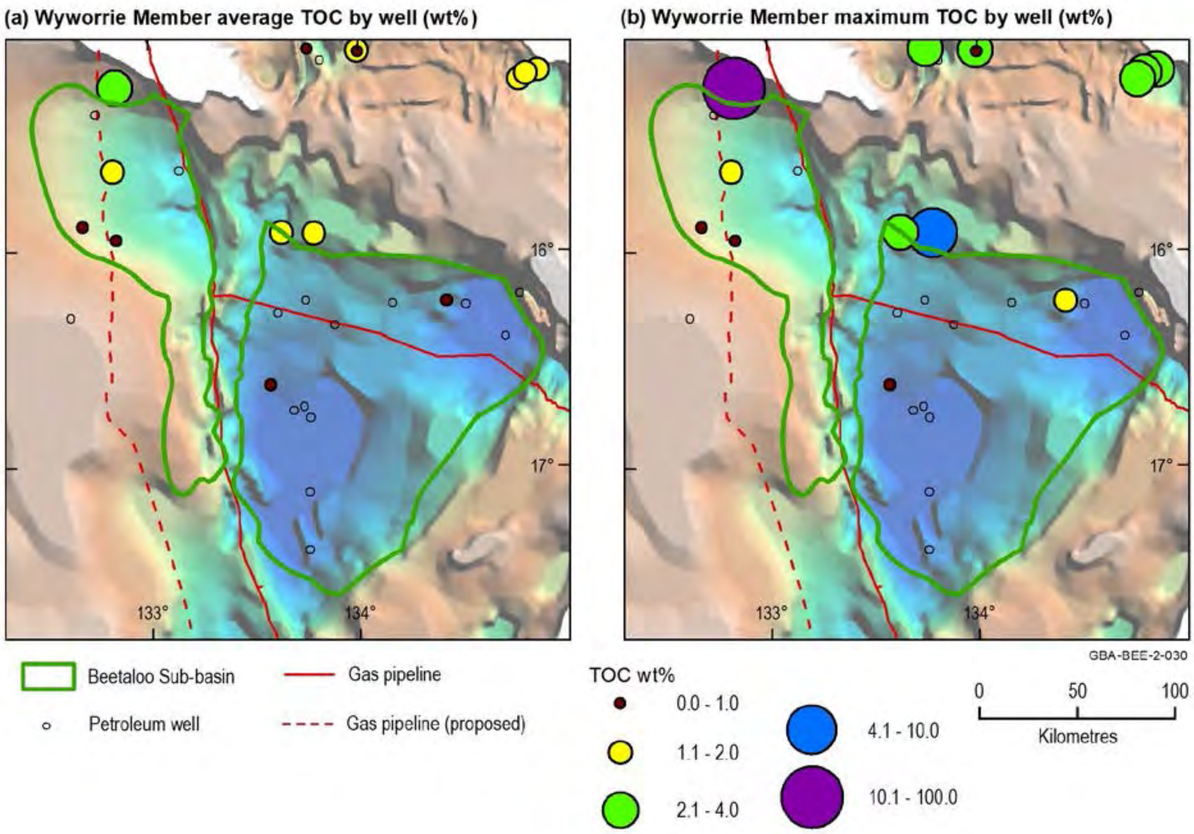

Figure 26 Wyworrie Member of the Velkerri Formation TOC (wt%) distribution show over the depth to base Roper Group

TOC = total organic carbon; wt% = weight as a percentage
Source: modified from Jarrett et al. (2019); depth to base Roper Group (Wilton package) sourced from Frogtech Geoscience (2018)
Data: Revie and Normington (2018); Pangaea NT Pty Ltd (2019)
Element: GBA-BEE-2-030

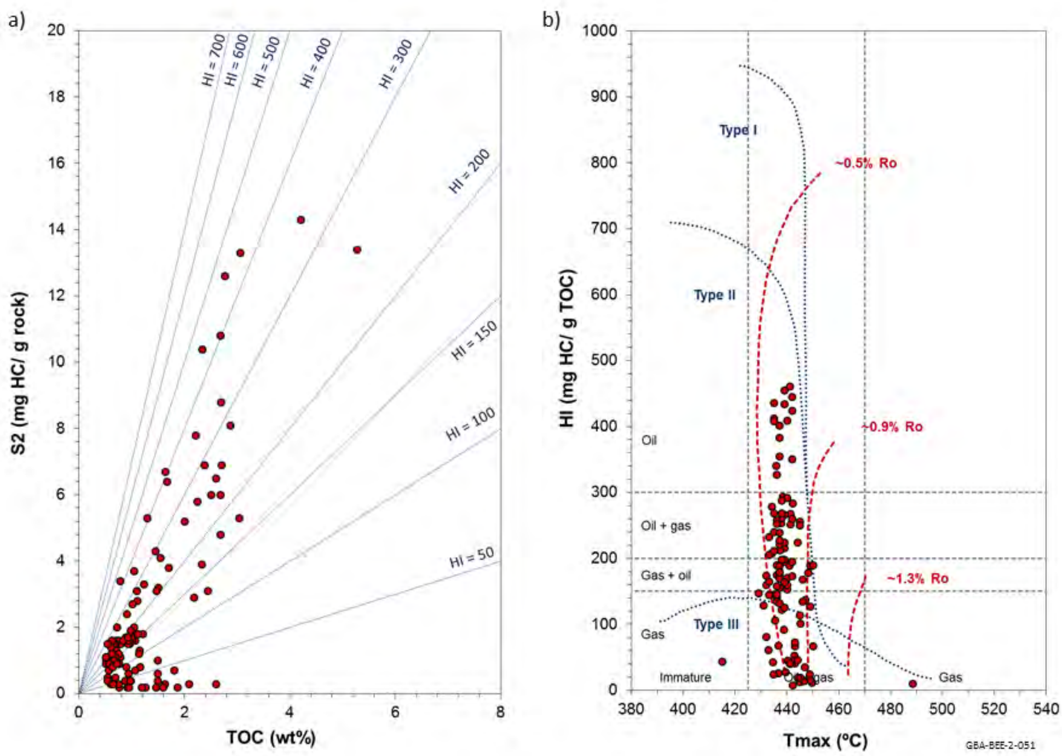

Figure 27 Rock-Eval pyrolysis data plots for the Wyworrie Member of the Velkerri Formation: (a) TOC content vs S2 yield; (b) Tmax vs HI

TOC: Total Organic Carbon; S2 and Tmax: Rock-Eval pyrolysis parameters; HI: hydrogen index; wt%: weight %; HC: hydrocarbons; Ro: vitrinite reflectance maturity
All public domain samples have been analysed; no distinction has been made between the properties of reservoir versus non-reservoir units.
Source: modified from Jarrett et al. (2019)
Data: Revie and Normington (2018); Pangaea NT Pty Ltd (2019)
Element: GBA-BEE-2-051

Table 12 Net organically rich ratio (NORR) of the Wyworrie Member shales in the Beetaloo Sub-basin

Beetaloo Sub-basin region	Well	Net organically rich ratio (fraction)	Total formation thickness (m)	Net thickness of organically rich section (m)
Eastern	Amungee NW1	0	404	0
Eastern	Beetaloo W1	0.0016	364	1
Western	Birdum Creek 1	0.0011	281	<1
Eastern	Kalala S1	0	213	0
Western	Tarlee 1	0.276	124	34
Western	Tarlee 2	0.0608	203	12
	Average	0.0565		8

Data: Revie and Normington (2018)

4.2.1.5 Shale reservoir characteristics

4.2.1.5.1 Petrophysical properties

Porosity, permeability and fluid saturation are three of the key petrophysical input parameters required for characterising shale plays. Based on laboratory tests (as-received basis) on 99 rock samples from 11 wells the Beetaloo Sub-basin and surrounds, the Velkerri Formation shales have an average total porosity (helium porosity of dry samples) of 7.29%, average bulk density of 2.489 gm/cc, average water saturation of 55.12%, average gas saturation of 39.80%, average gas-filled porosity of 3.05% and average permeability of 1.535 X 10^{-4} mD. Table 13 and Figure 28 show the details of above parameters by well. Among the 99 Velkerri Formation shale samples, there are only 3 samples (McManus 1, Lady Penrhyn 2, Scarborough 1) from the Wyworrie Member and 1 sample (Scarborough 1) from the Kalala Member.

Table 14, Table 15 and Table 16 show the averaged as-received laboratory measured shale rock properties the Wyworrie, Amungee and Kalala members in the Beetaloo Sub-basin and surrounds. Four shale samples from the Amungee Member B shale in Shenandoah 1/1A were tested, and the averaged shale rocks properties include as-received bulk density of 2.613 g/cc, water saturation of 53.93%, oil saturation of 1.40%, gas saturation of 44.67%, gas-filled porosity of 1.76%, and pressure decay permeability of 9.09 x 10^{-5} mD, and the dry helium porosity of 4.06%.

Table 13 Average laboratory measured as-received shale rock properties of the entire Velkerri Formation for key wells in the Beetaloo Sub-basin and surrounds

Well (number of tests)	A-R Bulk Density (g/cc)	Dry Helium Porosity (% of BV)	A-R Water Saturation (% of PV)	A-R Oil Saturation (% of PV)	A-R Gas Saturation (% of PV)	A-R Gas - Filled Porosity (% of BV)	A-R Pressure Decay Permeability (mD)
Altree 2 (4)	2.4	7.5	50.6	11.3	38.1	3.7	1.288 x 10^{-4}
Birdum Creek 1 (5)	2.5	6.0	69.9	1.2	28.9	2.0	4.197 x 10^{-5}
Lady Penrhyn 2 (1)	2.6	7.7	53.2	4.2	42.6	3.3	1.610 x 10^{-4}
McManus 1 (54)	2.4	10.3	44.3	6.3	49.4	5.0	3.333 x 10^{-4}
Scarborough 1 (7)	2.5	9.1	61.9	8.0	30.2	2.8	2.947 x 10^{-5}
Sever 1 (4)	2.5	6.5	33.9	2.4	63.8	4.2	6.260 x 10^{-4}
Shea 1 (1)	2.4	6.5	61.4	9.9	28.7	1.9	1.860 x 10^{-5}
Shenandoah 1/1A (8)	2.6	4.1	65.4	0.8	33.8	1.4	4.761 x 10^{-5}
Tanumbirini 1 (5)	2.6	6.4	56.4	0.5	43.1	2.8	8.124 x 10^{-5}
Tarlee S3 (6)	2.6	5.1	59.1	2.0	38.9	2.2	8.015 x 10^{-5}
Walton 2 (4)	2.3	11.0	50.3	9.4	40.4	4.5	1.409 x 10^{-4}
Average	2.5	7.3	55.1	5.1	39.8	3.1	1.535 x 10^{-4}

A-R = as received; BV = bulk volume; g/cc = grams per centimetre cubed; PV = pore volume; mD = millidarcies
All public domain samples have been analysed; no distinction has been made between the properties of reservoir versus non-reservoir units.
Data: Revie and Normington (2018)

Table 14 Average laboratory measured as-received shale rock properties of the Wyworrie Member of the Velkerri Formation for key wells in the Beetaloo Sub-basin and surrounds

Well (number of tests)	A-R Bulk Density (g/cc)	Dry Helium Porosity (% of BV)	A-R Water Saturation (% of PV)	A-R Oil Saturation (% of PV)	A-R Gas Saturation (% of PV)	A-R Gas - Filled Porosity (% of BV)	A-R Pressure Decay Permeability (mD)
Lady Penrhyn 2 (1)	2.59	7.69	53.22	4.18	42.61	3.27	1.61×10^{-4}
McManus 1 (1)	2.44	10.31	55.65	8.40	35.94	0.28	6.64×10^{-5}
Scarborough 1 (1)	2.54	8.71	65.64	2.39	31.97	2.79	1.61×10^{-5}
Average	2.52	8.90	58.17	4.99	36.84	2.11	8.12×10^{-5}

A-R = as received; BV = bulk volume; g/cc = grams per centimetre cubed; PV = pore volume; mD = millidarcies
All public domain samples have been analysed; no distinction has been made between the properties of reservoir versus non-reservoir units.
Data: Revie and Normington (2018)

Table 15 Average laboratory measured as-received shale rock properties of the Amungee Member of the Velkerri Formation for key wells in the Beetaloo Sub-basin and surrounds

Well (number of tests)	A-R Bulk Density (g/cc)	Dry Helium Porosity (% of BV)	A-R Water Saturation (% of PV)	A-R Oil Saturation (% of PV)	A-R Gas Saturation (% of PV)	A-R Gas - Filled Porosity (% of BV)	A-R Pressure Decay Permeability (mD)
Altree 2 (4)	2.45	7.48	50.57	11.30	38.14	3.67	1.29×10^{-4}
Birdum Creek 1 (5)	2.55	6.02	69.90	1.16	28.94	1.98	4.20×10^{-5}
McManus 1 (53)	2.41	10.33	44.32	6.30	49.39	4.98	3.33×10^{-4}
Scarborough 1 (5)	2.42	9.12	61.87	7.98	30.15	2.80	2.95×10^{-5}
Sever 1 (4)	2.53	6.50	33.89	2.36	63.75	4.18	6.26×10^{-4}
Shea 1 (1)	2.39	6.49	61.40	9.89	28.71	1.86	1.86×10^{-5}
Shenandoah 1/1A (8)	2.61	4.13	65.38	0.83	33.80	1.36	4.76×10^{-5}
Tanumbirini 1 (5)	2.57	6.36	56.41	0.49	43.10	2.75	8.12×10^{-5}
Tarlee S3 (6)	2.57	5.10	59.11	2.02	38.87	2.17	8.01×10^{-5}
Walton 2 (4)	2.25	11.01	50.29	9.35	40.36	4.51	1.41×10^{-4}
Average	2.47	7.25	55.31	5.17	39.52	3.03	1.53×10^{-4}

A-R = as received; BV = bulk volume; g/cc = grams per centimetre cubed; PV = pore volume; mD = millidarcies
All public domain samples have been analysed; no distinction has been made between the properties of reservoir versus non-reservoir units.
Data: Revie and Normington (2018)

Table 16 Average laboratory measured as-received shale rock properties of the Kalala Member of the Velkerri Formation for key wells in the Beetaloo Sub-basin and surrounds

Well (number of tests)	A-R Bulk Density (g/cc)	Dry Helium Porosity (% of BV)	A-R Water Saturation (% of PV)	A-R Oil Saturation (% of PV)	A-R Gas Saturation (% of PV)	A-R Gas - Filled Porosity (% of BV)	A-R Pressure Decay Permeability (mD)
Scarborough 1 (1)	2.62	7.01	96.11	1.80	2.09	0.15	5.74×10^{-7}

A-R = as received; BV = bulk volume; g/cc = grams per centimetre cubed; PV = pore volume; mD = millidarcies

All public domain samples have been analysed; no distinction has been made between the properties of reservoir versus non-reservoir units.

Data: Revie and Normington (2018)

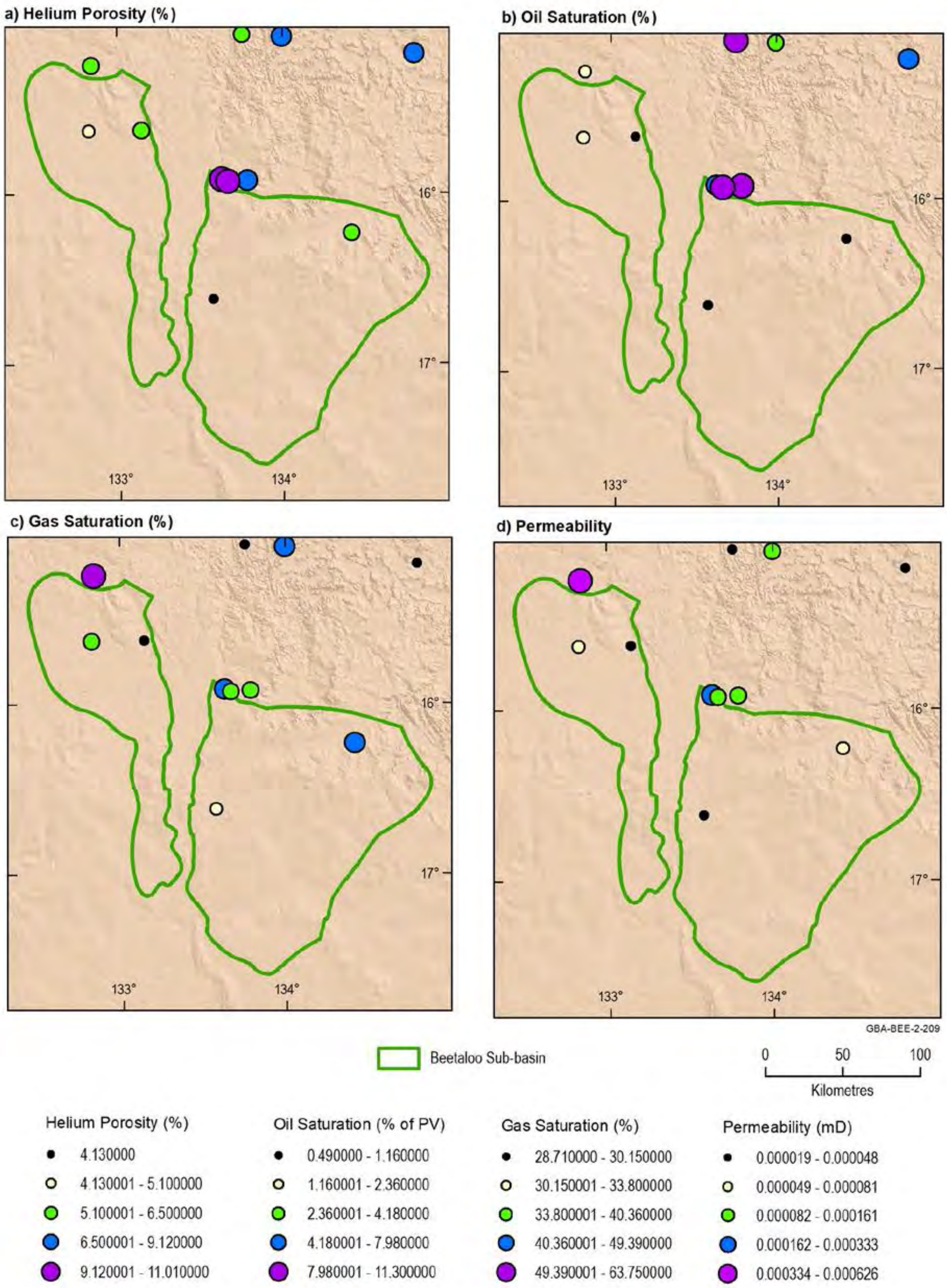

Figure 28 Petrophysical properties of the Velkerri Formation: (a) Averaged dry helium porosity, (b) as-received oil saturation, (c) gas saturation and (d) pressure decay permeability (PDPM)

mD = millidarcies; PV = pore volume
Data: Revie and Normington (2018)
Element: GBA-BEE-2-209

4.2.1.5.2 Total gas content and total gas storage capacity

Gas in shale is stored as adsorbed gas on the organic matter, free gas stored in the pore spaces and dissolved gas in the formation water. Eighteen air-dry core samples from the Amungee Member in Shenandoah 1/1A, Tarlee 1 and Tarlee 2 were tested for gas content. The averaged total gas content was 3.31 scc/g in the Shenandoah 1/1A, 1.25 scc/g in Tarlee 1 and 3.97 scc/g in Tarlee 2 (Table 17) (Falcon Oil and Gas, 2012; Pangaea NT Pty Ltd, 2019)

Table 17 Desorbed gas content test results of the shale samples from the Amungee Member in Shendandoah 1/1A ("B Shale"), Tarlee 1 and Tarlee 2

Sample ID	Top (m)	Bottom (m)	Lost Gas Content (scc/g)	Measured Gas Content (scc/g)	Residual Gas Content (scc/g)	Total Gas Content (scc/g)
Shenandoah 1/1A	2,511.40	2,511.70	1.25	1.25	0.56	3.06
	2,513.40	2,513.70	2.08	1.19	0.63	3.90
	2,515.40	2,515.70	0.76	0.39	1.83	2.98
	Average		1.36	0.94	1.01	3.31
Tarlee 1	1023.8	1024.1	0.24	0.69	0.68	1.61
	1052.3	1052.6	0.15	0.62	no data	0.77
	1092.84	1093.14	0.15	0.48	no data	0.63
	1116.8	1117.1	0.13	0.45	no data	0.57
	1141.05	1141.35	0.12	0.44	no data	0.55
	1160.56	1160.86	0.23	0.4	no data	0.63
	1189.84	1190.15	0.05	0.3	no data	0.35
	1200.82	1201.11	0.49	0.49	0.77	1.75
	1227.29	1227.58	0.1	0.51	0.74	1.35
	1239.9	1240.2	0.45	1.83	0.74	3.01
	1259.16	1259.48	0.44	0.86	0.7	2
	1277.06	1277.35	0.5	0.59	0.71	1.8
	Average		0.25	0.64	0.72	1.25
Tarlee 2	1055.8	1056.2	1.42	0.86	2.38	4.65
	1049.3	1049.7	1.1	0.61	0.82	2.53
	1028.5	1028.9	2.06	1.52	1.14	4.73
	Average		1.53	1	1.45	3.97
Average (3 wells)			1.05	0.86	1.06	2.84

scc/g = cubic centimetre at standard condition per gram
No distinction has been made between the properties of reservoir versus non-reservoir units.
Source: Falcon Oil and Gas (2012)
Data: Pangaea NT Pty Ltd (2019); Revie and Normington (2018)

In addition to data from the direct desorbed gas content tests, methane isotherm test data were compiled for 25 Amungee Member shale samples from 10 wells and used to describe the adsorbed gas storage capacity of these shales, which can indicate the approximate adsorbed gas content. Table 18 lists the averaged methane isotherm test results of these samples (under the reservoir temperature), including the total organic content (wt%), crushed sample density (g/cc), Langmuir storage capacity (as-received, scc/g), Langmuir pressure (kPa) and adsorbed gas storage capacity (as-received, scc/g).

Table 18 Averaged methane isotherm test data of 23 samples from the Amungee Member in the Beetaloo Sub-basin and surrounds

Well (number of tests)	Total Organic Content (wt%)	Crushed Sample Density (g/cc)	Langmuir Storage Capacity, As-Received (scc/g)	Langmuir Pressure (kPa)	Adsorbed Gas Storage Capacity, As-Received (scc/g)
Birdum Creek 1 (5)	3.56	2.61	2.91	10988	2.27
Kalala S1 (1)	4.22	2.62	4.67	12928	3.17
Tanumbirini 1 (2)	3.82	2.70	2.57	6201	2.19
Tarlee 1 (1)	0.32	2.68	0.78	11942	0.41
Tarlee S3 (2)	2.43	2.65	1.07	4911	0.84
Wyworrie 1 (1)	1.37	2.62	3.11	30358	1.07
Beetaloo W1 (4)	3.61	2.64	3.53	14410	2.5
Tanumbirini 1 (3)	1.52	2.76	1.81	16550	1.48
Shenandoah 1/1A (4)	1.78	2.64	2.41	9245	1.82
Tarlee 1 (2)	4.46	2.54	2.04	4246	1.59
Average	2.71	2.65	2.49	12178	1.73

g/cc = grams per cubic centimetre; kPa = kilopascals; scc/g = cubic centimetre at standard condition per gram; wt% = weight %
No distinction has been made between the properties of reservoir versus non-reservoir units.
Data: Pangaea NT Pty Ltd (2019); Revie and Normington (2018)

Two samples from the Amungee Member B shale in Shenandoah 1/1A were tested and analysed for total gas storage capacity. Table 19 shows the averaged gas storage capacities of different storage mechanisms and total gas storage capacity of the B shale in Shenandoah 1/1A. The main gas storage mechanism is the adsorbed storage in the B shale, and the total gas storage capacity of the two B shale samples is 2.027scc/g.

Table 19 Averaged gas storage capacities of different storage mechanisms of two Amungee Member shale samples from Shenandoah 1/1A in the Beetaloo Sub-basin

Formation	Gas storage capacity
Dissolved Gas-in-Water Storage Capacity (scc/g)	0.024
Dissolved Gas-in-Water Fraction (vol%)	1.27
Free Gas Storage Capacity (scc/g)	0.115
Free Gas Fraction (vol%)	4.48
Adsorbed Gas Storage Capacity (scc/g)	1.889
Adsorbed Gas Fraction (vol%)	94.26
Total Gas Storage Capacity (scc/g)	2.027

scc/g = cubic centimetre at standard condition per gram; vol% = volume %
Data: Revie and Normington (2018)

4.2.1.6 Mineralogy and brittleness

The mineral assemblage and brittleness of the Velkerri Formation shales were described using XRD analyses of 185 shale samples from seven wells in the Beetaloo Sub-basin (29 samples from the Wyworrie Member, 134 samples from the Amungee Member and 22 samples from the Kalala Member (Table 20) (Revie and Normington, 2018)

The Velkerri Formation comprises quartz, kaolinite, mica/illite, feldspar, chlorite, siderite, rutile and anatase (Revie, 2017c). Figure 29 shows the ternary plots of the dominant mineral content of the Amungee Member, including contents of total clay, carbonates and other; the “other” included all the minerals other than clay or carbonate minerals. The brittleness index (BI) was calculated from mineral composition using the method of Jarvie et al. (2007). In a case study in the Barnett Shale by Perez Altamar and Marfurt (2014), the following brittleness classifications were applied: Brittle: BI > 0.48; Less brittle: BI = 0.32–0.48; Less ductile: BI = 0.16–0.32; and Ductile: BI < 0.16. Overall, the Velkerri Formation shales are classified as ‘brittle’, with an average BI of 0.533 (Table 20). The averaged brittleness indices of the Wyworrie, Amungee and Kalala Member shales are 0.441, 0.556 and 0.514 respectively.

Table 20 Main mineral assemblage statistics of the Wyworrie, Amungee and Kalala members analysed by XRD and average brittleness indices estimated from mineral assemblages using the method of Jarvie et al. (2007)

Well	Total clay (wt%)	Carbonates (wt%)	Other (wt%)	Brittleness index (fraction)
Altree 2 (41)	33.5	7.0	59.4	0.518
McManus 1 (30)	33.3	8.8	57.9	0.501
Sever 1 (39)	32.1	2.6	65.3	0.588
Shenandoah 1/1A (27)	38.7	1.5	60.0	0.554
Tanumbirini 1 (5)	41.2	2.2	56.6	0.475
Tarlee S3 (16)	38.5	0.3	61.3	0.536
Walton 2 (27)	37.1	1.8	61.1	0.560
Average	36.3	3.4	60.2	**0.533**

wt% = weight %
Data: Revie and Normington (2018)

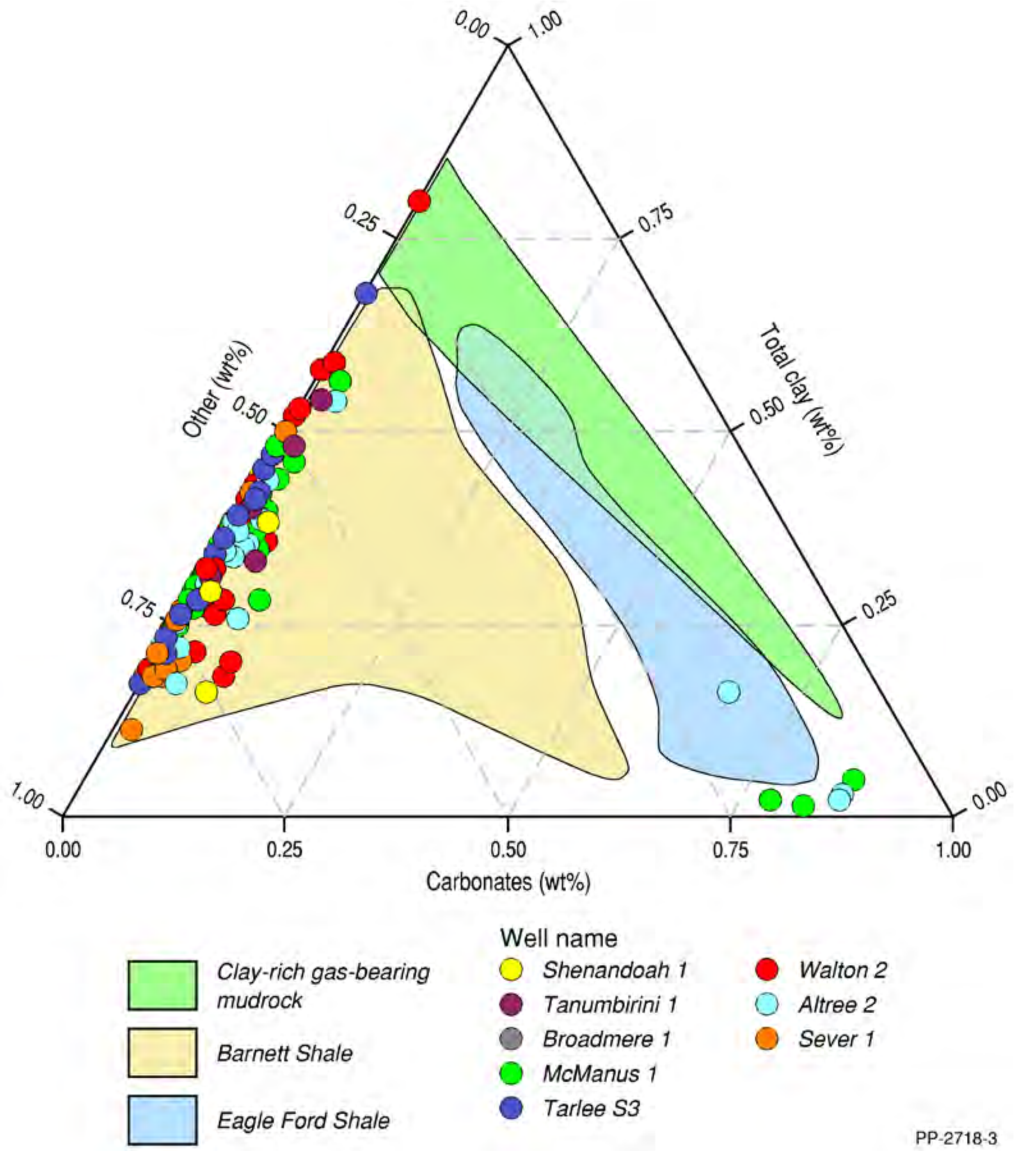

Figure 29 Ternary plot of mineral content (wt% fraction) for shales of the Amungee Member, previously known as the middle Velkerri Formation (Revie, 2017c)

wt% = weight %
For comparison producing USA shale plays (the Barnett and Eagle Ford shales) are shown after Passey et al. (2010)
Source: updated from Revie (2017c)
Data: Revie and Normington (2018)
Element: GBA-BEE-2-077

4.2.1.7 Gas composition

Two desorbed gas samples from the middle Velkerri “B Shale” in Shenandoah 1/1A were tested with gas chromatography (Revie, 2017a; Falcon Oil and Gas, 2012). Table 21 shows the results of gas compositions.

Table 21 Integrated contaminant-corrected gas composition of the Amungee Member B shale from Shenandoah 1/1A

Mid-depth (m)	Methane (mol%)	Ethane (mol%)	Propane (mol%)	Oxygen (mol%)	Nitrogen (mol%)	Carbon dioxide (mol%)	Hydrogen (mol%)
2513.6	88.34	6.38	0.52	0	0	4.76	0
2515.6	92.32	3.15	0.22	0	0	4.31	0
Average	90.33	4.77	0.37	0	0	4.54	0

mol% = molar percentage of total gas component
Source: Falcon Oil and Gas (2012)
Data: Revie and Normington (2018)

Mud logging entails gathering qualitative and semi-quantitative data from hydrocarbon gas detectors that record the level of natural gas returned to the surface in the drilling fluid. Chromatographs are used to determine the chemical makeup of the gas by separating the gas stream into fractions according to molecular weight.

Table 22 shows the averaged hydrocarbon (gas) compositions of the Velkerri Formation from mud logging data in the Beetaloo Sub-basin (Origin Energy, 2015b, 2015a, 2016a; Santos Ltd, 2014; Falcon Oil and Gas, 2012).

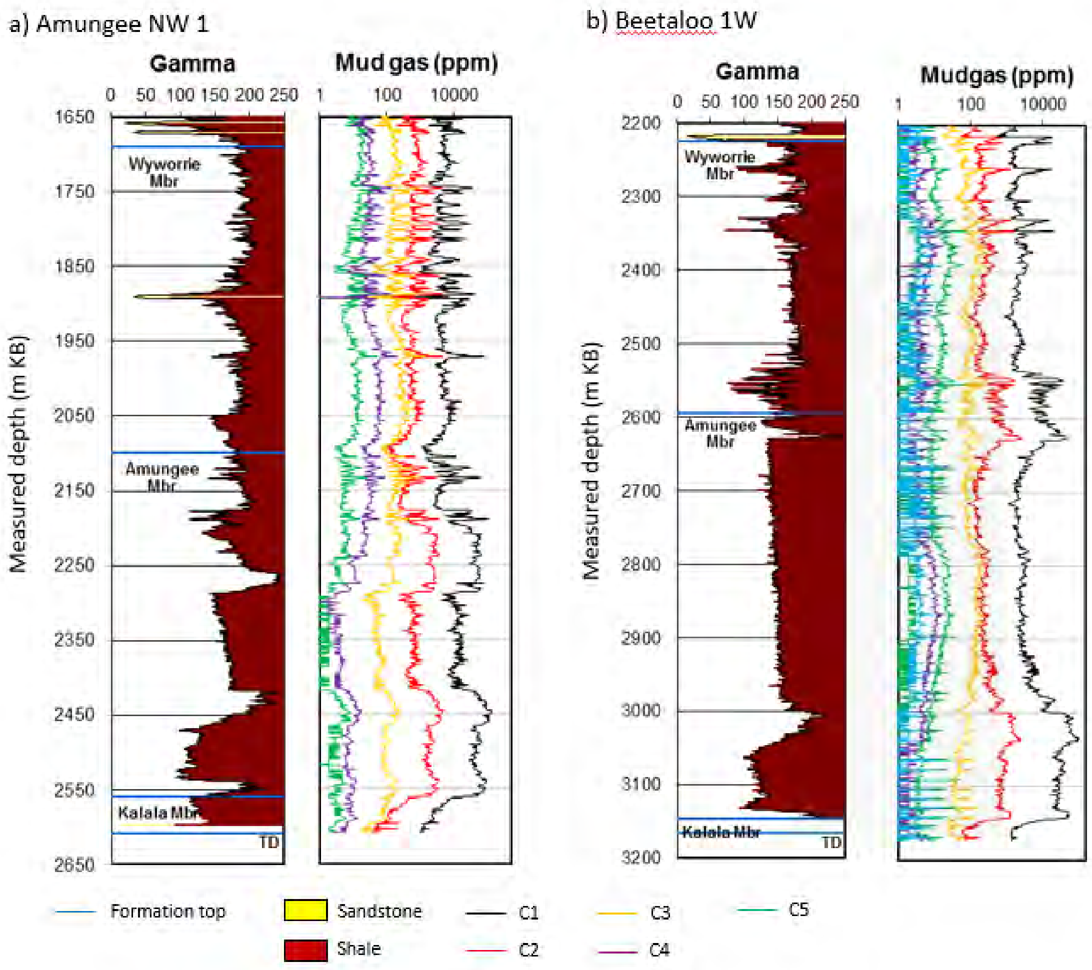

Figure 30 Velkerri Formation mud gas data for a) Amungee NW-1 and b) Beetaloo W1

ppm = parts per million
Data: Revie and Normington (2018)
Element: GBA-BEE-2-197

Table 22 Averaged hydrocarbon (gas) compositions (mol%) of the whole Velkerri Formation derived from mud logging data in the Beetaloo Sub-basin

Well	Methane (%)	Ethane (%)	Propane (%)	Isobutane (%)	n-Butane (%)	Isopentane (%)	n-Pentane (%)
Kalala S1	95.10	4.38	0.44	0.02	0.05	0.01	0.01
Amungee NW1	93.89	5.14	0.79	0.04	0.12	0.02	0.01
Beetaloo W1	94.77	4.03	0.97	0.05	0.13	0.02	0.02
Shenandoah 1/1A	92.82	6.28	0.78	0.03	0.07	0.01	0.00
Tanumbirini 1	96.22	3.20	0.49	0.04	0.05	0.00	0.00
Average	94.56	4.61	0.69	0.03	0.08	0.01	0.01

Source: Falcon Oil and Gas (2012); Origin Energy (2015b, 2016a, 2015a); Santos Ltd (2014)
Data: Revie and Normington (2018)

Seven canister desorbed gas samples from the Amungee Member shales in Tarlee 1 were analysed by gas chromatography. The average gas composition includes 65.66% methane, 14.06% ethane, 3.87% propane, 13.27% heavier hydrocarbon (butane plus) and 3.14% of carbon dioxide (Figure 19) (Pangaea NT Pty Ltd, 2019).

Table 23 N_2 and O_2 set to zero gas compositions of the desorbed gas samples from the Amungee Member shales in Tarlee 1 (Pangaea NT Pty Ltd, 2019)

Sample number	Top (m)	Bottom (m)	Methane (mol%)	Ethane (mol%)	Propane (mol%)	Butane plus (mol%)	Carbon dioxide (mol%)
TL1_DS5	1023.80	1024.10	30.68	14.57	12.00	41.09	1.67
TL1_DS8	1116.80	1117.10	47.48	9.36	6.28	33.98	2.91
TL1_DS10	1160.56	1160.86	72.47	6.56	1.57	16.06	3.35
TL1_DS12	1200.82	1201.11	78.29	12.53	2.19	4.25	2.75
TL1_DS13	1227.29	1227.58	78.75	11.87	1.44	3.77	4.16
TL1_DS14	1239.90	1240.20	81.52	13.96	1.04	0.65	2.83
TL1_DS16	1277.06	1277.35	66.67	25.50	2.61	0.92	4.30
Average			65.66	14.06	3.87	13.27	3.14

mol% = molar percentage of total gas component
Data: Pangaea NT Pty Ltd (2019)

4.2.2 Kyalla Formation

Key characteristics of the Kyalla Formation are summarised below in Table 24.

Table 24 Key features of the Kyalla Formation

Unconventional play types	Shale and hybrid liquids-rich gas and oil/ condensate plays
Age	Mesoproterozoic (Ectasian); 1313±47 Ma (Yang et al., 2018)
Top depth	0–1112 m
Gross formation thickness	<30–960 m
Lithology	Claystone interbedded with siltstone and sandstone
Depositional environment	Storm-dominated marine shelf (Abbott et al., 2001; Revie, 2017c)
Net source rock thickness (present day) [a]	5–93 m
Total organic carbon (present day)	Mean 1.1 wt%; range 0–9 wt%
Hydrogen Index (present day)	6–777 mg HC/g TOC
Thermal maturity	Immature to liquids-rich gas
Average permeability [b]	Mean 7.9 x 10^{-5} mD; range 1.1 x 10^{-5}–1.1 x 10^{-4} mD
Average porosity [c]	Mean 5.9%; range 3.5–6.1%
Average effective water saturation	Mean 62%; range 56–71%
Average oil saturation [d]	Mean 5.7%; range 0.9–10.1%
Average gas saturation [e]	Mean: 33%; range 28–34%
Average brittleness	Brittle (0.406[f])
Pressure regime	Indications of overpressure

HC = hydrocarbons; mD = milliDarcy; TOC = total organic carbon; wt% = weight %
All public domain Kyalla Formation samples have been analysed; no distinction has been made between the properties of reservoir versus non-reservoir units. A net source rock thickness represents the cumulative thickness of organically rich shale with a present day TOC content > 2 wt % based on available well intersections. b As-received pressure decay permeability by well. c Average porosity by well represents the dry helium porosity as a % of bulk rock volume. d As received saturation as a % of the pore volume. e As received gas saturation by well as a % of pore volume. f The brittleness index (BI) was calculated from mineral content using the method of Jarvie et al. (2007), however, recent petrophysical, core and geomechanical analyses demonstrate that the Kyalla Formation completion quality more is favourable than that suggested by mineralogy alone (Altmann et al., 2018; Baruch et al., 2018).

4.2.2.1 Age and stratigraphic relationships

The Kyalla Formation is Ectasian in age. Zircon geochronology provides an age date of 1313±47 Ma (Yang et al., 2018). The Kyalla Formation is part of the Roper Group. It conformably overlies the Sherwin Formation or Moroak Sandstone Formation, and is disconformably overlain by the Bukalorkmi Formation.

4.2.2.2 Extent, depth and gross formation thickness

The Kyalla Formation is present across the Beetaloo Sub-basin (Figure 31). The sub-basin has been defined based on a top Kyalla Formation depth of 400 m below ground surface (Northern Territory Government, 2018a). Within the Beetaloo Sub-basin, the maximum depth of the top Kyalla Formation (based on well intersections) is 1061.3 m (Tanumbirini 1) in the eastern sub-basin and 639 m in Birdum Creek 1 in the western sub-basin (Figure 31). The maximum thickness of the Kyalla Formation based on well intersections is approximately 786 m (Beetaloo West 1). The geological model derived from seismic interpretation (Orr et al., 2020) suggests the formation reaches a maximum thickness of 960 m (Figure 32).

4.2.2.3 Lithology and palaeoenvironment

The Kyalla Formation is medium-grey to black laminated shale with interbeds of thin siltstone and fine-grained sandstone (Munson, 2016). The Kyalla Formation has been subdivided informally into upper, middle and lower units (Baruch et al., 2018). A prominent sandstone interval in the lower Kyalla Formation appears to be continuous across the wells of the eastern Beetaloo Sub-basin, and has been informally termed the “Elliot Sandstone member” (Gorter and Grey, 2013).

The interbedded and interlaminated nature of the Kyalla Formation, along with diagnostic sedimentary structures (Abbott et al., 2001), suggests deposition in a storm-dominated marine shelf environment (Munson, 2016).

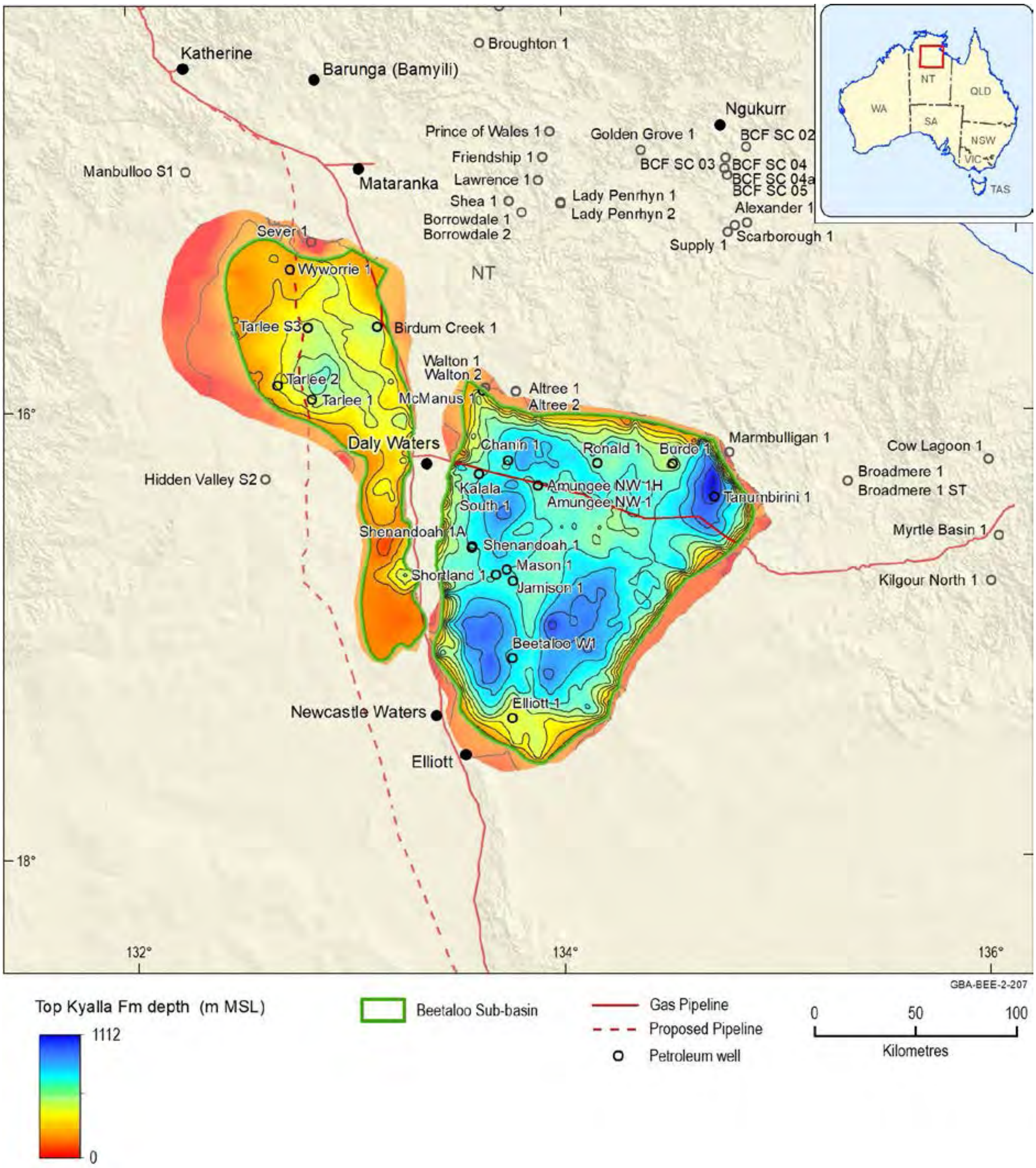

Figure 31 Kyalla Formation top depth (m)

Source: Orr et al. (2020)
Data: Geological and Bioregional Assessment Program (2019b); GBA derived dataset based on Williams (2019) and Northern Territory Government (2018b)
Element: GBA-BEE-2-207

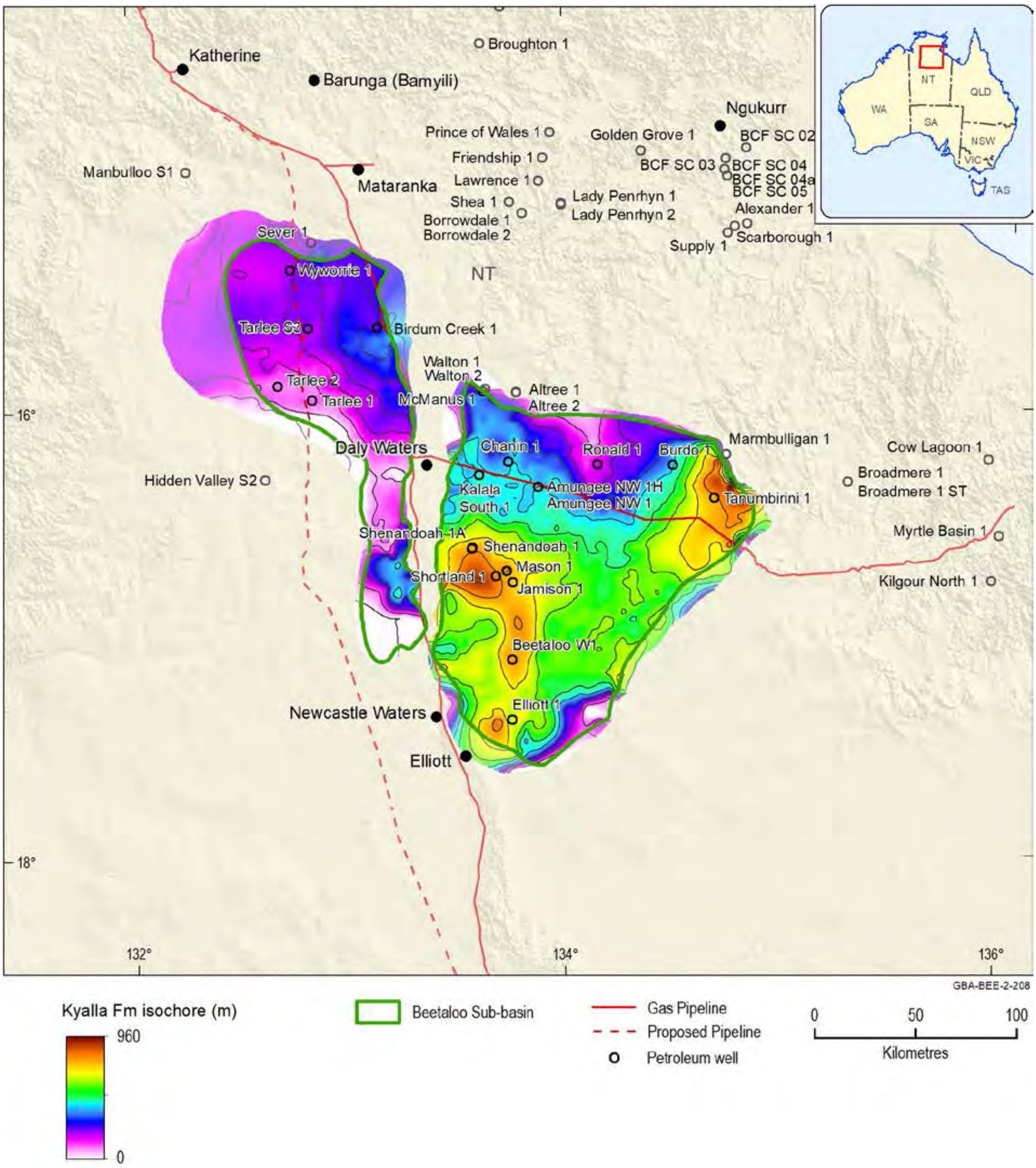

Figure 32 Kyalla Formation total vertical thickness (m)

Source: Orr et al. (2020)

Data: Geological and Bioregional Assessment Program (2019b); GBA derived dataset based on Williams (2019) and Northern Territory Government (2018b)

Element: GBA-BEE-2-208

4.2.2.4 Source rock properties

Figure 33 and Figure 34 show type sections through the Kyalla Formation for 2 example wells in the western sub-basin and 2 in the east, highlighting the variation in lithology, source rock properties and maturity down well.

The principal petroleum source rocks of the Kyalla Formation are shales. Drilling of the Kyalla Formation in, for example, the Jamison 1, Balmain 1 and Shenandoah 1A wells, has resulted in reports of strong petroliferous odours and oil bleeds.

Jarrett et al. (2019) reviewed the source rock geochemistry and maturity of all known source rock units and associated data from the greater McArthur Basin, including the Kyalla Formation, based on the dataset of Revie and Normington (2018). This study builds on the assessment of Jarrett et al. (2019) by incorporating additional well data for Tarlee 1, 2 and 3, Birdum Creek 1 and Wyworrie 1 provided by Pangaea (Pangaea NT Pty Ltd, 2019).

Source rock statistics for the Kyalla Formation are summarised in Table 25, based on a dataset of 960 TOC samples and 520 Rock-Eval pyrolysis samples. As was done for the Velkerri Formation, statistics were calculated on a quality controlled data filtered using the screening criteria defined in Jarrett et al. (2018).

The organic richness of Kyalla Formation source rocks varies from 0 to 9 wt% TOC, with a mean of 1.1 wt% TOC (Table 25). Samples with TOC content > 2 wt% are distributed across both the eastern and western Beetaloo Sub-basin, demonstrating the presence of source rock facies across the sub-basin (Figure 35).

Kyalla Formation present day hydrogen indices range from 6 mg HC/g TOC to 777 mg HC/g TOC (Table 25; Figure 36). Plots of the Rock-Eval pyrolysis data indicate there are two relatively distinct groups of samples (Figure 36). A set of samples characterised by high TOC content and very high HI values (> 500 mg HC/g TOC) represent well preserved, oil-prone kerogen containing filamentous algae and/or cyanobacterial biomass (Revie, 2017c). A second set of samples have lower HI values of < 500 mg HC/g TOC and much higher OI values of > 30 mg CO_2/g TOC. These are likely to represent lower-quality organic matter that has been partially oxidised prior to preservation (Revie, 2017c).

As was done for the Velkerri Formation, the net thickness of organically rich Kyalla Formations shales was calculated using the product of net organically rich ratio (NORR) with TOC greater than 2 wt% and gross formation thickness (EIA, 2013). Table 26 lists the NORRs of the Kyalla Formation in the Beetaloo Sub-basin calculated for 4 wells. The average NORR is 0.3034 and the average total thickness of organically rich material is 44.6 m. There was insufficient data density to map the NORR.

Organic petrology and other maturity indicators (e.g. Tmax) indicate that the Kyalla Formation is mature for oil or liquids-rich gas (Figure 33, Figure 34). Source rock maturity for the Kyalla Formation is discussed in further detail in Section 4.3, which describes the use of one-dimensional petroleum systems modelling to map the distribution of the oil, wet gas and dry gas windows across the Beetaloo Sub-basin.

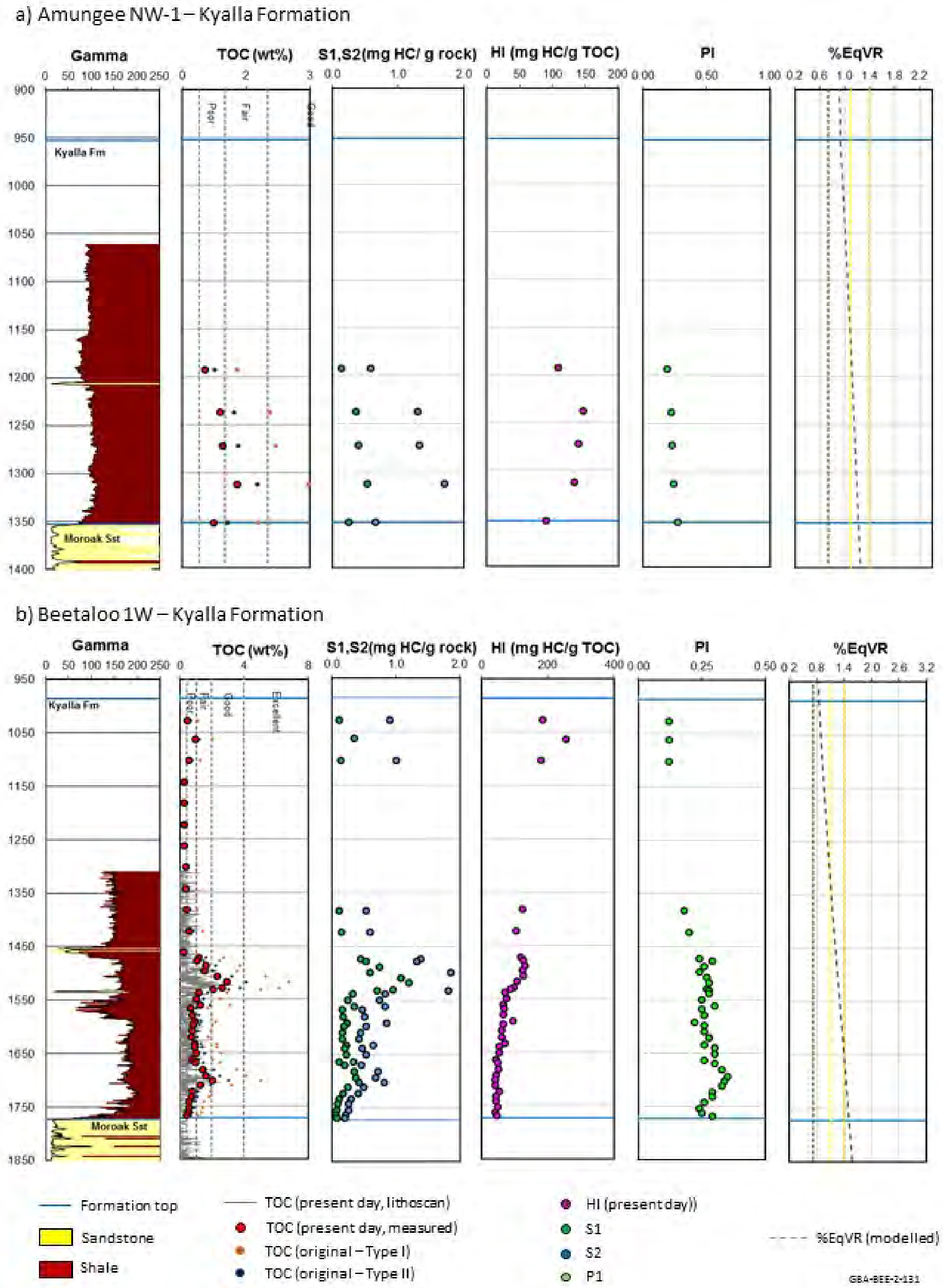

Figure 33 Kyalla Formation source rock characteristics in the a) Amungee NW 1 and b) Beetaloo W1 wells in the eastern Beetaloo Sub-basin

TD = total depth; TOC = total organic carbon; HI = hydrogen index; S1, S2, S3 = Rock-Eval parameters; PI = production index; %EqVR = vitrinite reflectance equivalent; wt% = weight as a percentage. Two sets of original TOC data are estimated assuming original HIs of 750 mg HC/g TOC and 450 mg HC/g TOC, using the equation of Peters et al. (2005). Modelled maturity is sourced from one-dimensional petroleum system model presented in Section 4.3.
Data: Revie and Normington (2018); Pangaea NT Pty Ltd (2019)
Element: GBA-BEE-2-131

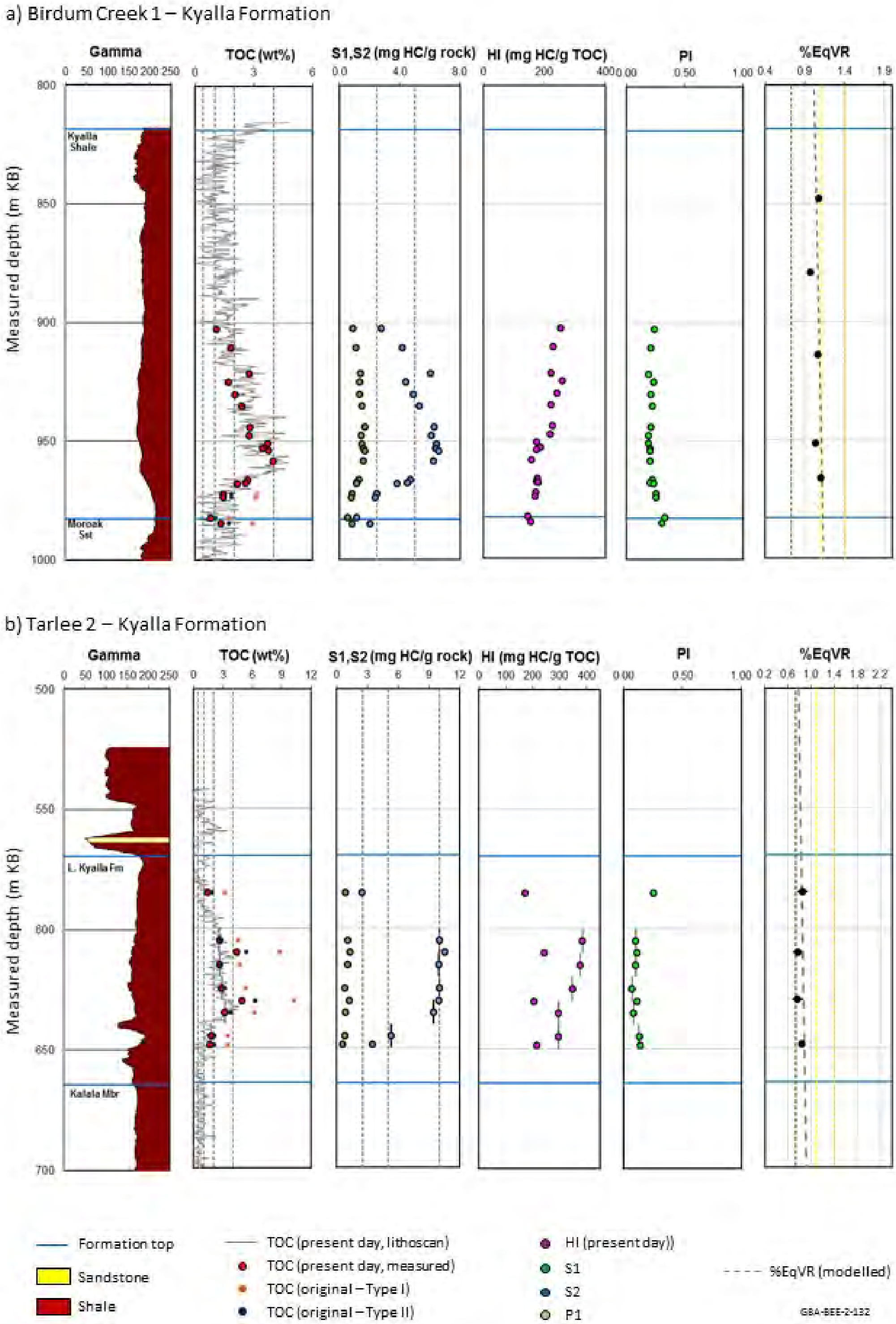

Figure 34 Kyalla Formation source rock characteristics in the a) Birdum Creek 1 and b) Tarlee 2 wells in the western Beetaloo Sub-basin

TD = total depth; TOC = total organic carbon; HI = hydrogen index; S1, S2, S3 = Rock-Eval parameters; PI = production index; %EqVR = vitrinite reflectance equivalent; wt% = weight as a percentage. Two sets of original TOC data are estimated assuming original HIs of 750 mg HC/g TOC and 450 mg HC/g TOC, using the equation of Peters et al. (2005). Modelled maturity is sourced from one-dimensional petroleum system model presented in Section 4.3.

Data: Revie and Normington (2018); Pangaea NT Pty Ltd (2019)

Element: GBA-BEE-2-132

Table 25 Kyalla Formation source rock properties. Statistics are based on analysis of 960 TOC samples and 520 Rock-Eval pyrolysis samples. Rock-Eval pyrolysis data was quality controlled prior to calculating statistics using the screening criteria defined in Jarrett et al. (2018)

	Mean	Min	Max	Stdev	P10	P50	P90
TOC (wt%)	1.1	0.0	9.0	0.9	0.3	0.8	2.4
S1 (mg HC/g rock)	0.5	0.0	3.6	0.5	0.1	0.3	1.3
S2 (mg HC/g rock)	3.0	0.1	22.8	4.4	0.2	1.1	9.9
S3 (mg HC/g rock)	0.5	0.0	5.9	0.7	0.1	0.3	1.2
Tmax (°C)	453	411	530	19	435	448	482
HI (mg HC/g TOC)	172	6	777	176	25	96	469
OI (mg CO_2/g TOC)	48	0	343	66	5	20	148
PI (unit less)	0.3	0.0	0.8	0.1	0.1	0.2	0.5

mg CO2/g TOC = milligrams of CO2 per gram of total organic carbon; mg HC/g TOC = milligrams of hydrocarbons per gram of total organic carbon; TOC = total organic carbon; S1, S2, S3 and Tmax = Rock-Eval pyrolysis parameters; HI = Hydrogen Index; OI = Oxygen Index; PI = Production Index; stdev: standard deviation; P10: 10th percentile; P50: 50th percentile; P90: 90th percentile; wt% = weight as a percentage.
Data = Revie and Normington (2018); Pangaea NT Pty Ltd (2019)

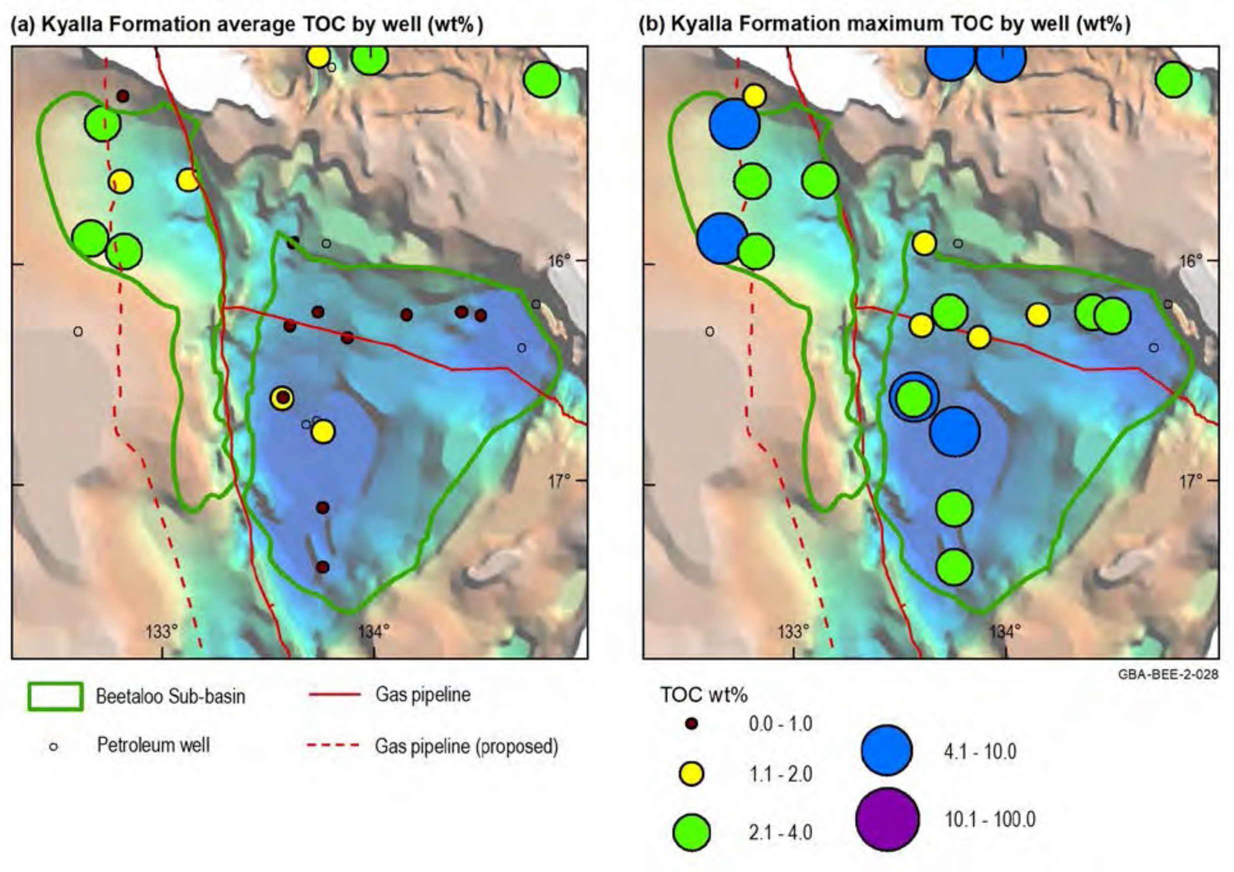

Figure 35 Total organic carbon distribution of the Kyalla Formation

TOC = total organic carbon; wt% = weight %
Source: modified from Jarrett et al. (2019); depth to base Roper Group (Wilton package) sourced from Frogtech Geoscience (2018)
Data: Revie and Normington (2018); Pangaea NT Pty Ltd (2019)
Element: GBA-BEE-2-028

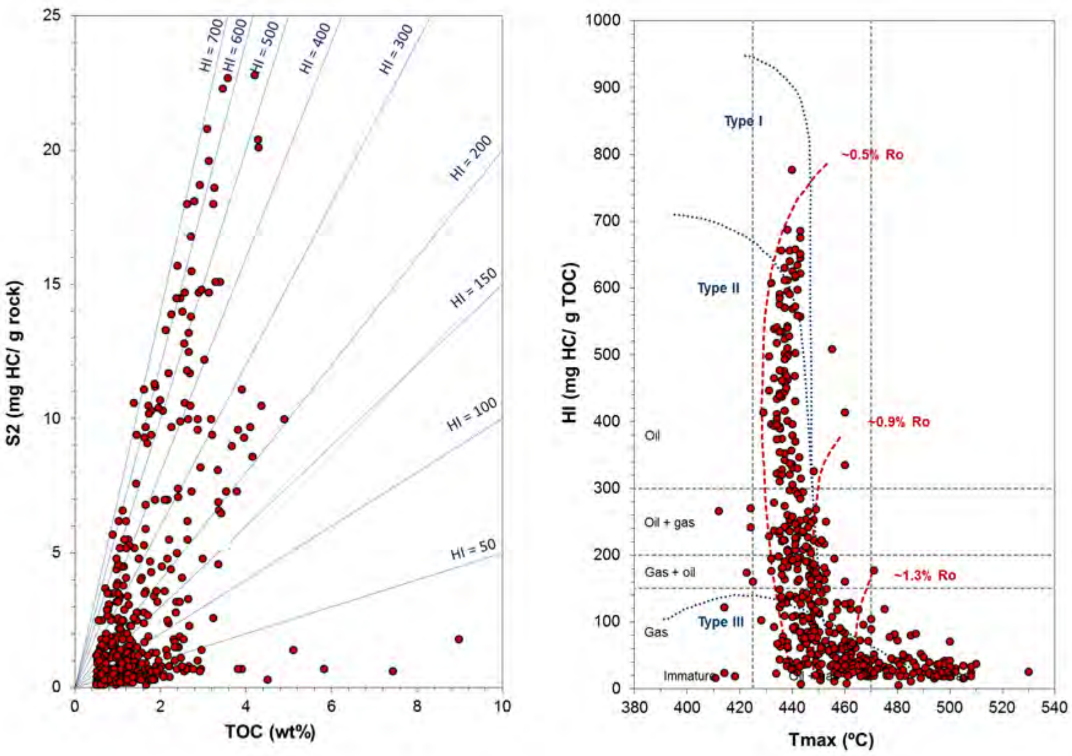

Figure 36 Rock-Eval pyrolysis data plots for the Kyalla Formation: (a) TOC content vs S2 yield; (b) Tmax vs HI

HC = hydrocarbons; HI = hydrogen index; S2 and Tmax = Rock-Eval pyrolysis parameters; TOC = total organic carbon; wt% = weight as a percentage; %EqVR = vitrinite reflectance maturity
Source: modified from Jarrett et al. (2019)
Data: Revie and Normington (2018); Pangaea NT Pty Ltd (2019)
Element: GBA-BEE-2-052

Table 26 Present day net organically rich ratio (NORR) of the Kyalla Formation shales in the Beetaloo Sub-basin and surrounds

Beetaloo Sub-basin region	Well	Net organically rich ratio (fraction)	Total formation thickness (m)	Total thickness of organically rich section (m)
Eastern	Beetaloo W1	0.01	787	5
Western	Birdum Creek 1	0.37	249	93
Western	Tarlee 1	0.42	98	41
Western	Tarlee 2	0.42	95	40
	Average	0.30	307	45

Data: Revie and Normington (2018)

4.2.2.5 Shale reservoir characteristics

4.2.2.5.1 Petrophysical properties

Porosity, permeability and fluid saturation are three of the key petrophysical input parameters required for characterising shale plays. Based on laboratory tests (as-received basis) on 14 Kyalla Formation shale rock samples from 3 wells the Beetaloo Sub-basin and surrounds, the Kyalla Formation shales have an average total porosity (helium porosity of dry samples) of 5.9%, average as-received bulk density of 2.59 gm/cc, average water saturation of 61.5%, average oil saturation of 5.9%, average gas saturation of 32.6%, average gas-filled porosity of 1.95% and average permeability (as-received samples) of 7.9 x 10^{-5} mD. Table 27 and Figure 37 show the details of above parameters in different wells in the Beetaloo Sub-basin and surrounds.

Table 27 Average laboratory measured as-received shale rock properties of Kyalla Formation for key wells in the Beetaloo Sub-basin

Well	Number of tests	A-R Bulk Density (g/cc)	Dry Helium Porosity (% of BV)	A-R Water Saturation (% of PV)	A-R Oil Saturation (% of PV)	A-R Gas Saturation (% of PV)	A-R Gas - Filled Porosity (% of BV)	A-R Press Decay Permeability (mD)
Elliott 1	1	2.935	3.50	71.49	0.86	27.65	0.97	1.100 x 10^{-5}
Jamison 1	5	2.578	5.65	55.56	10.07	34.36	1.98	4.772 x 10^{-5}
Shenandoah 1/1A	8	2.603	6.08	67.50	1.64	30.85	1.91	1.107 x 10^{-4}
Average		2.590	5.87	61.53	5.86	32.61	1.95	7.923 x 10^{-5}

A-R = as received basis; BV = bulk volume; g/cc = grams per cubic centimetre; mD = milliDarcy; PV = pore volume
No distinction has been made between the properties of reservoir versus non-reservoir units.
Data: Revie and Normington (2018)

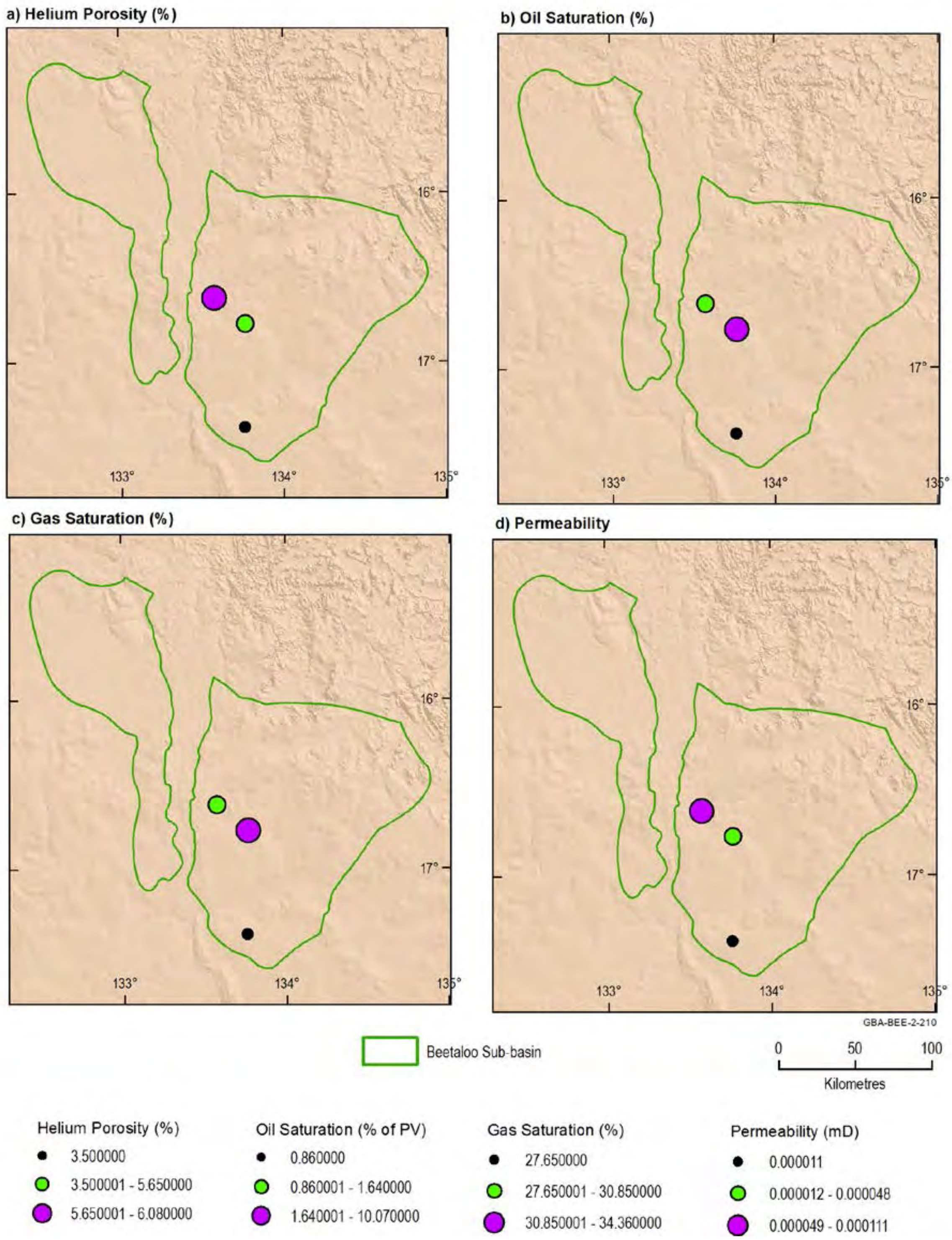

Figure 37 Petrophysical properties of the Kyalla Formation: (a) averaged dry helium porosity, (b) as-received oil saturation, (c) gas saturation and (d) pressure decay permeability

mD: millidarcies; PV = pore volume
Data: Revie and Normington (2018)
Element: GBA-BEE-2-210

4.2.2.5.2 Total gas content and total gas storage capacity

Gas in shale is stored as adsorbed gas on the organic matter, free gas stored in the pore spaces and dissolved gas in the formation water. Seven air-dry core samples from the Kyalla Formation shales in Shenandoah 1/1A and Tarlee 1 (Falcon Oil and Gas, 2012; Pangaea NT Pty Ltd, 2019) were tested for gas content analysis, resulting the averaged total gas content of the Kyalla Formation shales of 2.82 scc/g in Shenandoah 1/1A and 1.29 scc/g in Tarlee 1 (Table 28).

Table 28 Desorbed gas content test results of the lower Kyalla Formation shales in Shendandoah 1/1A and Tarlee 1

Sample ID	Top (m)	Bottom (m)	Lost Gas Content (scc/g)	Measured Gas Content (scc/g)	Crushed Sample Gas Content (scc/g)	Total Gas Content (scc/g)
Shenandoah 1/1A	1586.7	1587	0.76	0.83	0.48	2.07
	1589.7	1590	1.23	0.98	1.62	3.83
	1592.7	1593	0.82	0.96	0.79	2.57
	Average		0.94	0.92	0.96	2.82
Tarlee 1	670.8	671.15	0.13	0.43	0.26	0.82
	701.05	701.35	0.15	1.26	0.42	1.84
	721.05	721.35	0.10	1.05	0.38	1.53
	742.3	742.6	0.16	0.52	0.29	0.97
	Average		0.14	0.82	0.34	1.29
Average (2 wells)			0.54	0.87	0.65	2.06

scc/g = cubic centimetre at standard condition per gram
No distinction has been made between the properties of reservoir versus non-reservoir units.
Source: Falcon Oil and Gas (2012); Pangaea NT Pty Ltd (2019)
Data: Revie and Normington (2018)

In addition to the direct desorbed gas content test, the methane isotherm test data were collected for 7 Kyalla Formation shale samples from Shenandoah 1/1A, Tanumbirini 1 and Tarlee 1 (Table 29). These data were used to describe the adsorbed gas storage capacity of shales, which provides an approximation for adsorbed gas content.

The adsorbed gas storage capacity of the Kyalla Formation shales is much smaller than that of the Velkerri Formation shales (Table 18). However, the methane isotherm test of the lower Kyalla Formation shale sample from Tanumbirini 1 between 2050–2055 m (measured depth) shows that the adsorbed gas storage capacity (as-received) could be up to 2.02 scc/g (Table 29).The averaged total organic content (wt%), crushed sample density (g/cc), and adsorbed gas storage capacity (as-received, scc/g) of the Kyalla Formation shales are respectively 1.854 wt%, 2.625 g/cc and 0.73 scc/g.

Table 29 Methane isotherm test data of 7 Kyalla Formation shale samples from Shenandoah 1/1A, Tanumbirini 1 and Tarlee 1 in the Beetaloo Sub-basin and surrounds

Well	Top (m)	Bottom (m)	Total Organic Content (wt%)	Crushed Sample Density (g/cc)	Langmuir Storage Capacity, As-Received (scc/g)	Langmuir Pressure (kPa)	Adsorbed Gas Storage Capacity, As-Received (scc/g)
Shenandoah 1/1A	1585.0	1585.1	1.25	2.65	0.43	3604	0.37
	1590.3	1590.4	1.22	2.628	0.38	7740	0.27
	1595.4	1595.5	1.55	2.63	0.60	4397	0.49
	1593.1	1593.1	1.1	2.67	0.79	25804	0.34
	Average		1.28	2.64	0.55	10386	0.37
Tanumbirini 1	1785.0	1790.0	0.34	2.68	0.97	45698	0.42
	2050.0	2055.0	1.41	2.68	3.20	22953	2.02
	Average		0.87	2.68	2.085	34326	1.22
Tarlee 1	721.35	721.45	3.41	2.55	1.36	10639	0.59
Average (3 wells)			1.85	2.625	1.33	18450	0.73

g/cc = grams per cubic centimetre; kPa = kilopascals; scc/g = cubic centimetre at standard condition per gram; wt% = weight %
No distinction has been made between the properties of reservoir versus non-reservoir units.
Data: Revie and Normington (2018), Pangaea NT Pty Ltd (2019)

Two samples from the Kyalla Formation shale in Shenandoah 1/1A were tested and analysed for total gas storage capacity. Table 30 shows the averaged gas storage capacities of different storage mechanisms and total gas storage capacity of the Kyalla Formation shale in Shenandoah 1/1A. The main gas storage mechanism is the free gas storage in the Kyalla Formation shale in the Shenandoah 1/1A, and the total gas storage capacity of the two Kyalla Formation shale samples is 1.266 scc/g.

Table 30 Averaged gas storage capacities of different storage mechanisms of two Kyalla Formatino shale samples from Shenandoah 1/1A in the Beetaloo Sub-basin

Formation	Gas storage capacity
Dissolved Gas-in-Water Storage Capacity (scc/g)	0.012
Dissolved Gas-in-Water Fraction (vol%)	1.12
Free Gas Storage Capacity (scc/g)	0.951
Free Gas Fraction (vol%)	74.56
Adsorbed Gas Storage Capacity (scc/g)	0.303
Adsorbed Gas Fraction (vol%)	24.32
Total Gas Storage Capacity (scc/g)	1.266

scc/g: cubic centimetre at standard condition per gram; vol% = volume percent
Data: Revie and Normington (2018)

4.2.2.6 Mineralogy and brittleness

The mineral assemblage and brittleness of the Kyalla Formation shales were described using XRD analyses of 61 shale samples from seven wells in the Beetaloo Sub-basin (Table 31) (Revie and Normington, 2018).

The Kyalla Formation is composed of quartz, clay minerals, feldspar and carbonate minerals (Table 31) with minor contents or traces of pyrite, barite, anatase, apatite, jarosite, gypsum, pyroxene/diopside and magnetite. The main clay minerals include kaolinite, illite/muscovite, chlorite and mix layer illite/smectite. The carbonate minerals could be calcite, dolomite, ankerite and siderite.

Figure 38 shows a ternary plot of the dominant mineral content of the Kyalla Formation shales, including contents of total clay, carbonates and other, and the “other” included all the minerals other than clay or carbonate minerals (Revie, 2017c).

The brittleness index (BI) was calculated from mineral content using the method of Jarvie et al. (2007). This assessment indicates that the Kyalla Formation shale is classified as ‘less brittle’, with an average BI of 0.406 (Table 31) (Perez Altamar and Marfurt, 2014). However, recent petrophysical, core and geomechanical analyses demonstrate that the Kyalla Formation completion quality more is favourable than that suggested by mineralogy alone (Altmann et al., 2018; Baruch et al., 2018).

Table 31 Main mineral assemblage statistics of the Kyalla Formation analysed by XRD and average brittleness indices estimated from mineral assemblages using the method of Jarvie et al. (2007)

Well	Number of samples	Quartz (wt%)	Clays (wt%)	Carbonates (wt%)	Others (wt%)	Brittleness index (fraction)
Balmain 1	5	35.00	59.00	0.80	5.20	0.370
Burdo 1	6	49.83	42.33	1.83	6.00	0.537
Chanin 1	1	36.00	59.00	1.00	4.00	0.375
Elliott 1	10	36.50	49.20	2.00	12.40	0.427
Jamison 1	14	26.84	67.52	1.16	4.45	0.283
Ronald 1	3	36.67	47.33	2.00	14.00	0.432
Shenandoah 1/1A	22	38.91	53.32	1.48	6.50	0.420
Average		37.11	53.96	1.47	7.51	0.406

wt% = weight as a percentage
Data: Revie and Normington (2018)

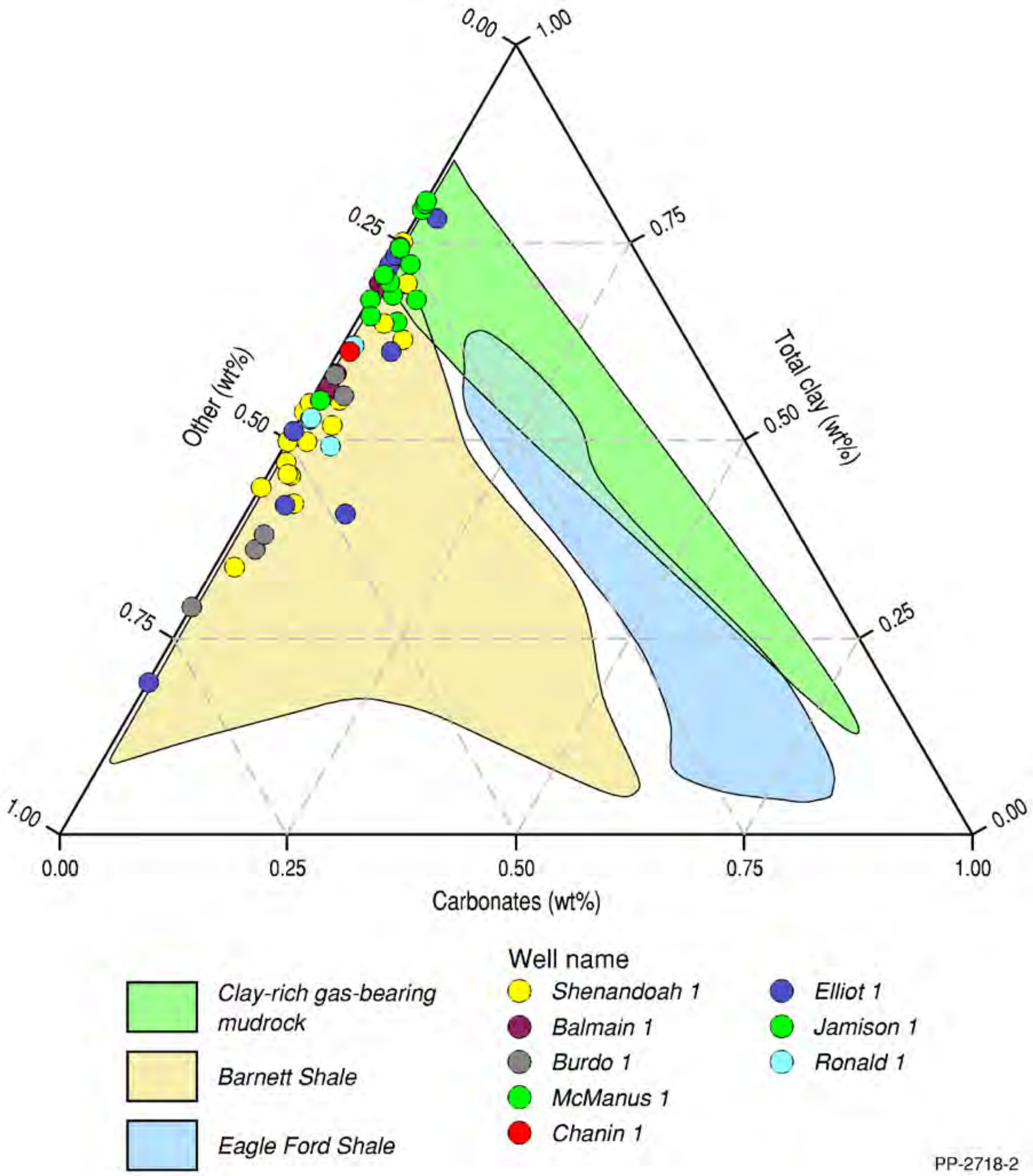

Figure 38 Ternary plot of XRD mineral content (wt% fraction) for shales of the Kyalla Formation in the Beetaloo Sub-basin

For comparison producing USA shale plays (the Barnett and Eagle Ford shales) are shown after Passey et al. (2010)
Source: updated from Revie (2017c)
Data: Revie and Normington (2018)
Element: GBA-BEE-2-355

4.2.2.7 Gas composition

Two desorbed gas samples from the lower Kyalla Formation shales in Shenandoah 1/1A were tested with gas chromatography (Revie, 2017a; Falcon Oil and Gas, 2012). Table 32 shows the results of gas composition.

Table 32 Integrated contaminant-corrected gas composition of Kyalla Formation shale

Mid-depth (m)	Methane (mol%)	Ethane (mol%)	Propane (mol%)	Oxygen (mol%)	Nitrogen (mol%)	Carbon dioxide (mol%)	Hydrogen (mol%)
1589.8	40.42	21.23	34.14	0	0	4.21	0
1592.8	48.6	18.02	30.29	0	0	3.08	0
Average	44.51	19.63	32.22	0	0	3.65	0

mol% = molar fraction of total gas component
Source: Falcon Oil and Gas (2012)
Data: Revie and Normington (2018)

Mud logging entails gathering qualitative and semi-quantitative data from hydrocarbon gas detectors that record the level of natural gas returned to the surface in the drilling fluid (mud). Chromatographs are used to determine the chemical makeup of the gas by separating the gas stream into fractions according to molecular weight. Table 33 shows the averaged hydrocarbon (gas) composition of the Kyalla Formation from mud logging data in the Beetaloo Sub-basin (Origin Energy, 2015b, 2015a, 2016a; Santos Ltd, 2014; Falcon Oil and Gas, 2012).

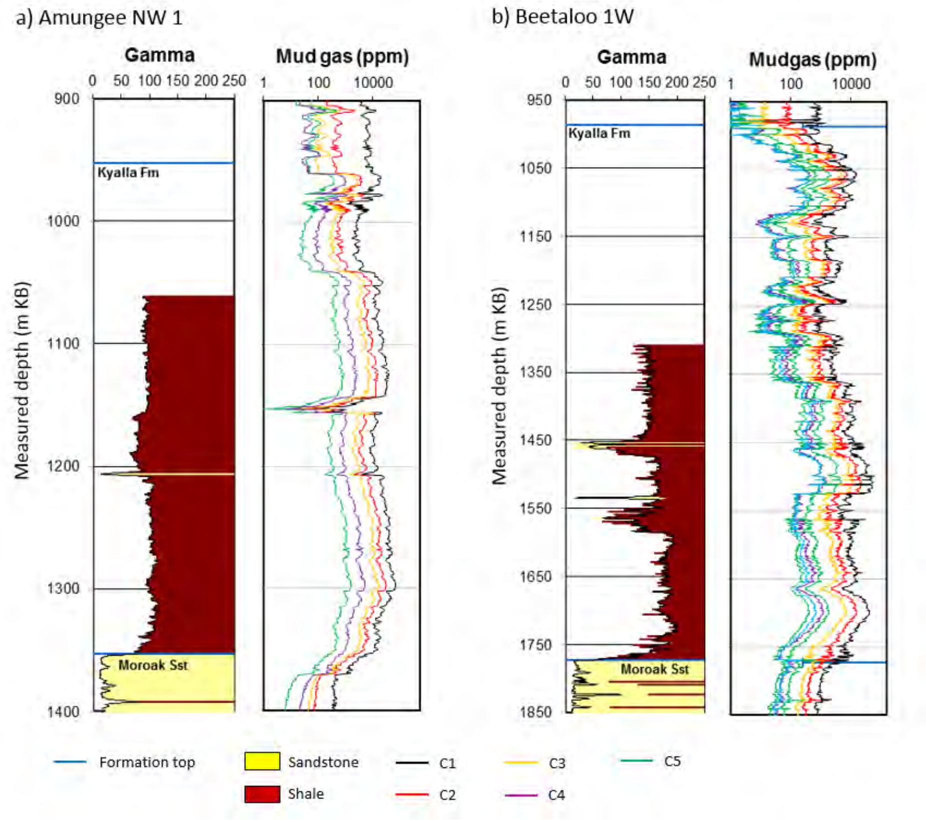

Figure 39 Kyalla Formation mud gas data for a) Amungee NW-1 and b) Beetaloo W1

ppm = parts per million
Data: Revie and Normington (2018)
Element: GBA-BEE-2-198

Table 33 Averaged hydrocarbon (gas) compositions (mole %) of the whole Kyalla Formation derived from mud logging data in the Beetaloo Sub-basin

Well	Methane (%)	Ethane (%)	Propane (%)	Isobutane (%)	n-Butane (%)	Isopentane (%)	n-Pentane (%)
Kalala S1	62.01	18.69	11.33	1.54	3.93	1.33	1.16
Amungee NW1	56.08	22.93	12.83	1.43	4.22	1.26	1.25
Beetaloo W1	56.14	22.78	12.58	1.79	4.15	1.38	1.17
Shenandoah 1A	56.90	24.21	11.74	1.96	3.35	1.12	0.71
Tanumbirini 1	77.68	13.99	4.83	1.32	1.22	0.32	0.64
Average	61.76	20.52	10.66	1.61	3.37	1.08	0.99

Source: Falcon Oil and Gas (2012); Origin Energy (2015b, 2016a, 2015a); Santos Ltd (2014)
Data: Revie and Normington (2018)

Three canister desorbed gas samples from the Kyalla Formation shales in Tarlee 1 were analysed by gas chromatography (Pangaea NT Pty Ltd, 2019). The average gas compositions include 26.20% methane, 14.85% ethane, 16.03% propane, 42.23% heavier hydrocarbon (butane plus) and 0.68% carbon dioxide (Table 34).

Table 34 N_2 and O_2 set to zero gas compositions of the desorbed gas samples from the Kyalla Formation shales in Tarlee 1

Sample number	Top (m)	Bottom (m)	Methane (mol%)	Ethane (mol%)	Propane (mol%)	Butane plus (mol%)	Carbon dioxide (mol%)
TL1_DS1	670.8	671.15	25.13	10.62	16.15	47.28	0.83
TL1_DS2	701.05	701.35	28.12	17.20	15.88	38.16	0.65
TL1_DS4	742.3	742.6	25.37	16.74	16.07	41.25	0.57
Average			26.20	14.85	16.03	42.23	0.68

mol%: molar percentage
Data: Pangaea NT Pty Ltd (2019)

The hydrocarbon resource in the Kyalla Formation shales is mainly liquid-rich wet gas in the eastern part (Table 32 and Table 33) and light oil in the western part of Beetaloo Sub-basin (Table 34).

4.2.3 Hayfield sandstone member

Key characteristics of the Hayfield sandstone member are summarised below in Table 35.

Table 35 Key features of the Hayfield sandstone member

Unconventional play type	Tight oil/ condensate and liquids-rich gas (Côté et al., 2018)
Age	Neoproterozoic; maximum depositional age 1092±15 Ma (Munson et al., 2018)
Base depth	-193–964 m MSL
Gross formation thickness	Poorly determined
Lithology	Mudstone interbedded with siltstone and sandstone
Depositional environment	Bathyal/abyssal to continental shelf
TOC	Not a source rock
Mean original HI	Not a source rock
Thermal maturity	Not a source rock
Average permeability	No data – unassessed
Average porosity	No data – unassessed
Average water saturation	No data – unassessed
Average oil saturation	No data – unassessed
Average gas saturation	No data – unassessed
Average brittleness [a]	Brittle (0.472)
Pressure regime	No data

MSL = mean sea level

[a]The brittleness index (BI) was calculated from mineral content using the method of Jarvie et al. (2007)

4.2.3.1 Age and stratigraphic relationships

The age of the Hayfield sandstone member of the Hayfield mudstone is poorly constrained and was first dated by Munson and Revie (2018) as having a maximum depositional age of 1092 ± 15 Ma. The Hayfield mudstone is conformably underlain by the Jamison sandstone.

4.2.3.2 Extent, depth and gross formation thickness

The Hayfield mudstone is widely intersected in wells drilled in the Beetaloo Sub-basin namely in Amungee NW 1, Balmain 1, Beetaloo West 1, Burdo 1, Chanin 1, Jamison 1, Mason 1, Ronald 1, Shenandoah 1, Shortland 1, Tanumbirini 1, Tarlee 1 and Tarlee 2. It is reinterpreted as present in McManus 1 (Munson, 2016) and it is potentially in Kalala South 1. The extent of the Hayfield sandstone member remains more poorly defined, although well intersections indicate it is restricted to the central part of the eastern sub-basin (Côté et al., 2018).

The depth to the base of the Hayfield mudstone (equivalent to the top of the Jamison sandstone) ranges from -194 m to 964 m below sea level (Figure 40). The Hayfield sandstone member occurs about 60 m above the base of the Hayfield mudstone and reaches a maximum thickness of approximately 12 m in Shenandoah 1 (Munson, 2016).

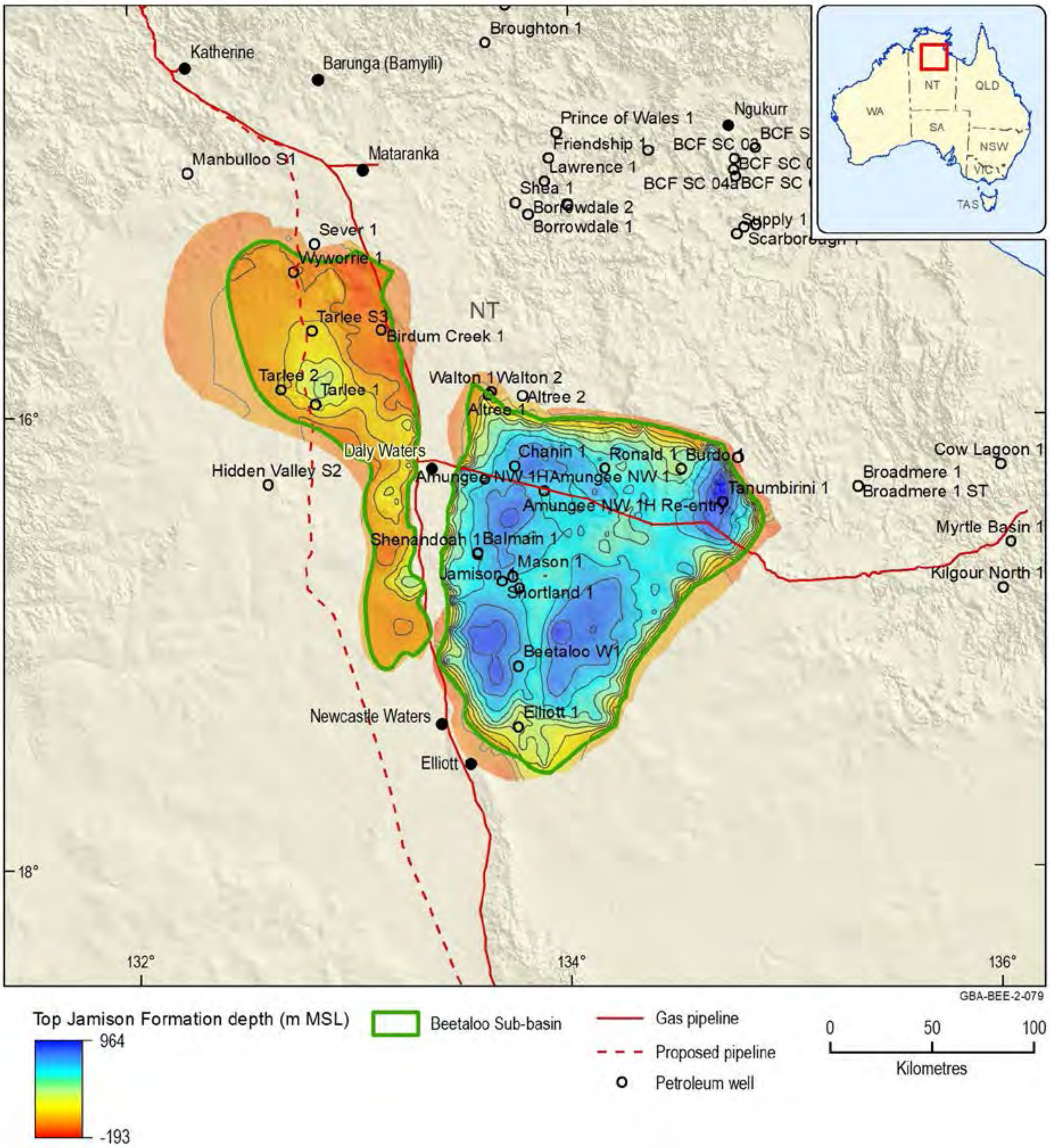

Figure 40 Jamison sandstone top depth (m), equivalent to base of the Hayfield mudstone

Source: Orr et al. (2020)
Data: Geological and Bioregional Assessment Program (2019b); GBA derived dataset based on Williams (2019) and (Northern Territory Government, 2018b)
Element: GBA-BEE-2-079

4.2.3.3 Lithology and palaeoenvironment

The Hayfield mudstone is a mudrock-rich unit. It comprises claystone with thinly interbedded siltstone and sandstone (Munson, 2016). Sandstone is more common towards the base of the unit. A laterally persistent sandstone interval dominates lower part of the Hayfield mudstone, about 60 m above the base, informally termed the “Hayfield sandstone member” (Munson, 2016). It comprises medium- and fine-grained sandstone, siltstone and minor claystone; the sandstone is similar to the Jamison sandstone, with a feldspathic component similarly indicating immaturity relative to the underlying Roper Group (Munson, 2016).

The fine-grained nature of the Hayfield mudstone, and the presence of glauconite and marine palynomorphs, indicate a sub-tidal shallow-marine shelf setting (Munson, 2016). The thicker sandstone intervals, such as the Hayfield sandstone member, indicate shallowing to a nearshore environment (Munson, 2016). Both fining- and coarsening-upward sediment cycles indicate variations in water depth through the Hayfield mudstone (Munson, 2016).

4.2.3.4 Source rock characteristics

The Hayfield mudstone is not a petroleum source rock. Instead, the origin of oil and gas in the Hayfield sandstone member is thought to be the result of migration from source rocks in either the Kyalla or Velkerri formations (Côté et al., 2018).

4.2.3.5 Reservoir characteristics

The thin but regionally extensive Hayfield sandstone member forms the reservoir of Hayfield sandstone member oil/condensate play (Côté et al., 2018). There was insufficient public domain well data available to characterise the porosity, permeability, gas and oil saturation of the Hayfield sandstone member reservoir.

The mineral assemblage and brittleness of the Hayfield sandstone member were described using XRD analyses from 3 shale rock samples from 1 well (Revie and Normington, 2018). The Hayfield sandstone member comprises quartz, kaolinite, mica/illite, feldspar, chlorite, siderite, rutile and anatase. The Hayfield sandstone member has a high degree of quartz overgrowths. Although these overgrowths reduce the porosity and permeability, secondary porosity networks and natural fractures partly compensate for this reduction (Côté et al., 2018).

Average brittleness indices (BI) were calculated from the mineral composition using the method of Jarvie et al. (2007). Limited available data indicates the Hayfield sandstone member is classified as ‘brittle’, with a total average BI of 0.472 Table 36.

Table 36 Main mineral assemblage statistics of the Hayfield sandstone member analysed by XRD and average brittleness indices estimated from mineral assemblages using the method of Jarvie et al. (2007)

Well	Quartz (wt%)	Clays (wt%)	Carbonates (wt%)	Others (wt%)	Brittleness Index (fraction)
Shenandoah 1/1A (3 samples)	37.67	40.67	1.67	20.67	0.472

wt%: weight percent
Data: Revie and Normington (2018)

4.2.3.6 Trap and seal

Although not fully understood, the play’s trapping mechanism is considered to be a structural-stratigraphic trap, sealed by the overlying Hayfield mudstone (Côté et al., 2018).

4.2.3.7 Gas composition

Mud logging entails gathering qualitative and semi-quantitative data from hydrocarbon gas detectors that record the level of natural gas returned to the surface in the drilling fluid (mud).

Chromatographs are used to determine the chemical makeup of the gas by separating the gas stream into fractions according to molecular weight. Table 37 shows the averaged hydrocarbon (gas) compositions of the Hayfield mudstone from mud logging data in the Beetaloo Sub-basin (Origin Energy, 2015b, 2016a).

Table 37 Averaged hydrocarbon (gas) compositions (mole %) of the Hayfield mudstone derived from mud logging data in the Beetaloo Sub-basin

Well	Methane (%)	Ethane (%)	Propane (%)	Isobutane (%)	n-Butane (%)	Isopentane (%)	n-Pentane (%)
Amungee NW1	84.51	8.03	3.61	0.83	1.51	0.81	0.70
Beetaloo W1	78.10	15.55	4.24	0.35	1.10	0.27	0.39
Average	81.31	11.79	3.92	0.59	1.30	0.54	0.55

Data: Revie and Normington (2018)

4.3 *Source rock maturity*

4.3.1 Introduction

The burial and thermal history of 18 wells across the Beetaloo Sub-basin was reviewed to better constrain the likely distribution of the oil, wet gas and dry gas windows for the Velkerri and Kyalla formation plays.

Only limited burial and thermal history modelling has been undertaken on the Roper Group succession of the Beetaloo Sub-basin. Burial history models have been published for McManus 1, Jamison 1 (Silverman et al., 2007) and Kalala 1 (Faiz et al., 2016; Faiz et al., 2018) in the eastern sub-basin and Tarlee 3 in the western sub-basin (Hoffman, 2016). These results indicated that the Amungee Member source rocks reached the oil to wet gas window during the Mesoproterozoic depositional event with additional primary and secondary cracking of hydrocarbons during the Neoproterozoic and/or Cambrian-Ordovician. However, while these one-dimensional modelling studies provide important insights into the source rock maturity and generation history, the spatial variation of source rock maturity across the Velkerri and Kyalla formations remains poorly constrained.

4.3.2 Input data

One-dimensional burial and thermal history models were set up for 18 wells across the Beetaloo Sub-basin (Figure 41), using the Zetaware Inc. Genesis (version 5.6x) software (Zetaware, 2019). The input parameters used to construct the burial history models (i.e. the time-depth history of the basin) include age, present day thickness and lithology of the stratigraphic units, information on major unconformities and the amount of missing section (Allen and Allen, 2005). Basin architecture, stratigraphic ages and lithologies are based on the three-dimensional geological model, stratigraphic chart and associated stratigraphic unit descriptions in Orr et al. (2020). The timing of major erosion events included in the model are shown in Table 38.

The thermal or time-temperature history was constrained from the subsidence history, taking into consideration changes in surface temperature through time, lithospheric structure changes through time and the thermal properties of the sediments and crust (Allen and Allen, 2005; Beardsmore and Cull, 2001; Hantschel and Kauerauf, 2009; Peters et al., 2012). The thermal model used for burial and thermal history modelling was 'transient, fixed temperature at base lithosphere' using a temperature of 1330°C (Zetaware, 2019). A constant mean average surface temperature of 26°C was applied (Bureau of Meteorology, 2019). Upper crustal radiogenic heat production was estimated from Frogtech Geoscience (2018). A heat flow pulse was applied to the late Mesoproterozoic to correspond with the Derim Derim Dolerite sill emplacement at 1324 Ma, as modelled by Hoffman (2015).

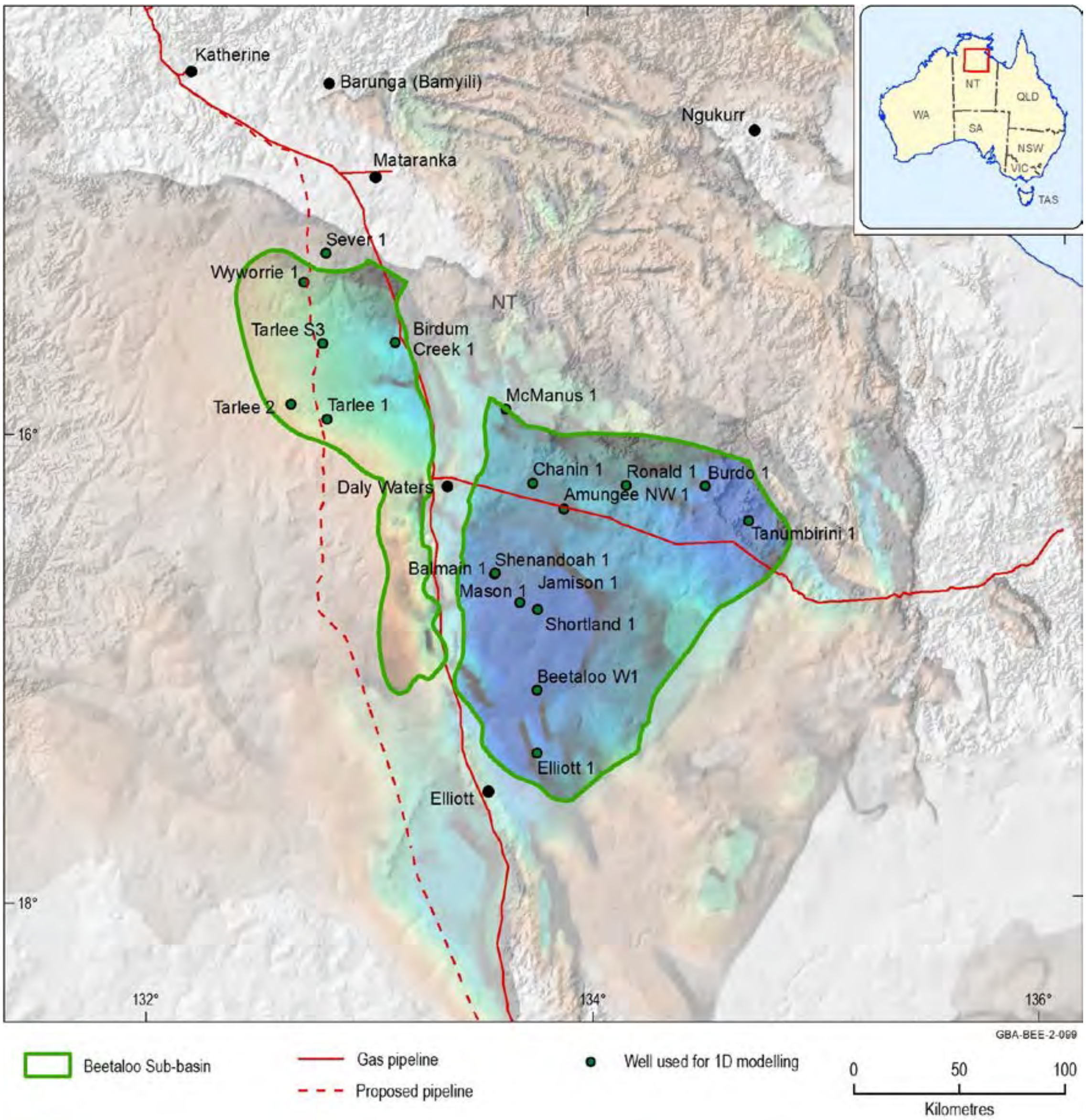

Figure 41 Location of wells used for the burial and thermal history modelling review

Source: depth to base Roper Group from Frogtech Geoscience (2018)
Element: GBA-BEE-2-099

Table 38 Amounts of erosion for major unconformities of the Beetaloo Sub-basin at modelled well locations

Unconformity	Estimated erosion amount
Mesoproterozoic unconformity (Top Roper Gp)	500 m
Neoproterozoic unconformity (Top Hayfield mudstone)	500 m
Paleozoic unconformity (Top Georgina Basin)	1200–1500 m
Mesozoic unconformity (Top Carpentaria Basin)	500 m

Source: Unconformities are sourced from the stratigraphic chart and associated references presented in Orr et al. (2020). Estimated erosion amounts are discussed in the methods snapshot below.

Methods snapshot: modelling erosion and maximum burial depth

Erosion events are modelled for the following unconformities: top Mesoproterozoic, top Neoproterozoic, Paleozoic, and Mesozoic (Table 38). The amount of erosion associated with each event, determines when source rocks reached their maximum depth of burial and hence the timing of hydrocarbon generation and maturation.

In this study, the maximum erosion and hence maximum depth of burial was modelled to occur in the Paleozoic based on the most recently published burial history model presented in Faiz et al. (2018). This is consistent with the presence of hydrocarbons in the Bukalara Sandstone in the well Walton 1 which indicates significant migration occurred in post-Mesoproterozoic times. An estimated erosion amount of 1500 m from Faiz et al. (2018) was used as a starting point for each one-dimensional model, which was then adjusted for each well to better fit the observed calibration data. Constant erosion amounts of 500 m were applied to the Top Roper Group and Mesozoic unconformities (Faiz et al., 2018).

Other models have been proposed which place maximum depth of burial at different times in the sub-basin's history. Dutkiewicz et al. (2007) estimated that the most significant oil migration episode for the Roper Group occurred in the Mesoproterozoic, following compaction, cementation and contact metamorphism during structural inversion between about 1300–1000 Ma. In contrast, a reinterpretation of the burial history of the Roper Group, based on two-dimensional seismic data and paleothermal studies (Duddy et al., 2003; Silverman and Ahlbrandt, 2010) indicates that peak hydrocarbon generation may have occurred in the early Mesozoic, much later than reported in these previous studies and this would greatly increase the potential for preservation of conventional traps. However, further work is required to test these scenarios and their impact on source rock maturation and generation.

4.3.3 Model calibration

Model input parameters were adjusted to calibrate the results with observed temperature and maturity data. All one-dimensional models were calibrated using present day bottom hole temperature measurements sourced from the OZTemp database (Holgate and Gerner, 2010) and supplementary data supplied by Pangaea NT Pty Ltd (2019). Wherever possible temperature data was Horner corrected to provide the best estimate of subsurface conditions undisturbed by drilling (Beardsmore and Cull, 2001).

Thermal maturity in the Proterozoic rocks of the Beetaloo Sub-basin cannot be determined by conventional vitrinite reflectance because these predate the evolution of land plants from which vitrinite is derived. Alginite has been identified as the dominant maceral present in the Kyalla and Velkerri formations, with minor occurrences of telalginite and fluorescing lamalginite are also present (Revie, 2017c). These macerals are derived from sapropelic algal organic matter, deposited in subaquatic muds under oxygen-restricted conditions (Revie, 2017c). Bitumen occurrences are also common in the Roper Group petrographic samples (Revie, 2017c).

For this study, a compilation of alginate and bitumen reflectance (Pangaea NT Pty Ltd, 2019; Revie and Normington, 2018) was converted relative to equivalent vitrinite values using the equation of Jacob (1989) as a measure of source rock maturity.

The Rock-Eval pyrolysis parameter Tmax, used in conjunction with Hydrogen Index and Production Index, has also been used as a proxy for the level of thermal maturity with some degree of success (Revie and Normington, 2018; Pangaea NT Pty Ltd, 2019). However, Tmax is prone to suppression (Summons et al., 1994). Down well Tmax profiles in the Beetaloo Sub-basin results are highly variable (Jarrett et al., 2019).

4.3.4 Maturity windows

Vitrinite reflectance can be generally correlated to the stage of oil and gas generation, where maturity is the main control on oil vs gas (i.e. where all other factors are constant). A variety of generic phases defining empirical relationships for primary oil and gas generation have been published (Hantschel and Kauerauf, 2009). However, the kinetics of oil and gas generation (i.e. the relationship between temperature and transformation of organic matter to hydrocarbons) can vary significantly by basin so this generic correlation may not always be appropriate.

A compilation of bulk kinetics for the Beetaloo Sub-basin sourced from Revie and Normington (2018) were analysed by Jarrett et al. (2019) to show the relationship between transformation ratio and maturity (Figure 42). The Beetaloo Sub-basin specific kinetic relationships indicate that the onset of generation, represented by a transformation ratio of 10%, occurs at maturities between 0.44 %EqVR and 0.82 %EqVR (mean value 0.73 %EqVR). This shows that in the Beetaloo Sub-basin the onset of oil generation occurs at higher maturities than indicated by the generic value of 0.5 %EqVR presented for Type I and/or Type II kerogens (Pepper and Corvi, 1995).

The Beetaloo Sub-basin specific kinetics data also indicate that peak generation occurs between 0.51 % Ro and 1.37 % Ro and an average value of 0.95 %EqVR was used in this study to represent the end of the peak oil window. This is slightly higher the generic value of 0.9 %EqVR presented for Type I and/or Type II kerogens.

The Beetaloo Sub-basin kinetic relationships are used to customise the generic Type I and Type II oil and gas maturity windows used by Weatherford Laboratories (2017), to be more appropriate to the characterisation of source rocks of the Beetaloo Sub-basin.

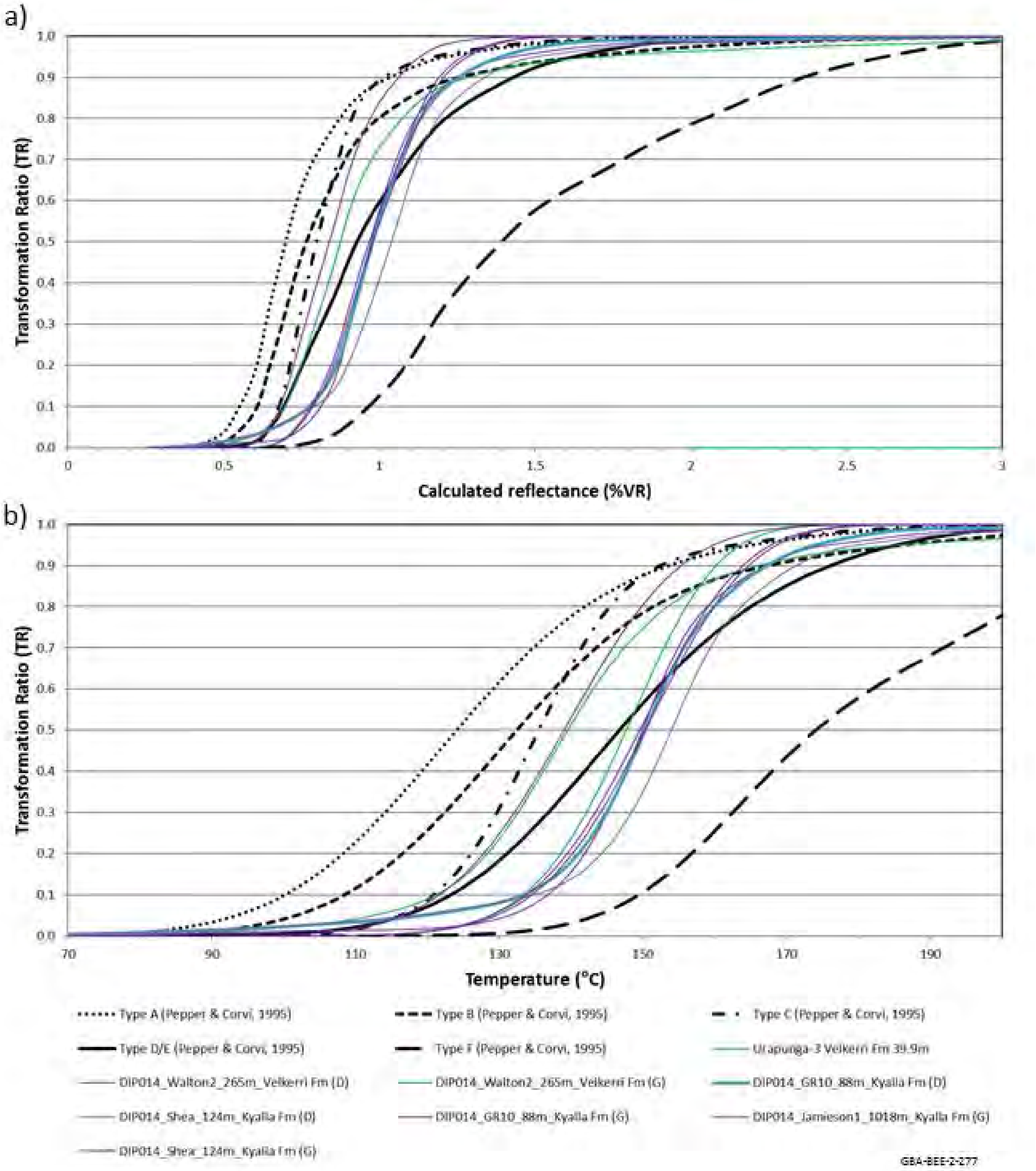

Figure 42 Transformation ratio (TR) curves calculated using bulk kinetics. A) TR plotted against maturity (calculated vitrinite reflectance equivalent; %VR) and B) TR plotted against temperature (°C)

TR = transformation ratio; %VR = calculated vitrinite reflectance maturity
Source: Generic kinetics (type A-F) from Pepper and Corvi (1995)
Data: Beetaloo Sub-basin specific kinetics from Revie and Normington (2018)
Element: GBA-BEE-2-277

Table 39 Thermal maturity windows

Maturity window	Thermal maturation for generic Type I and Type II kerogen (Weatherford Laboratories, 2017)	Maturity windows - this study	Source of value used in this study
Immature	< 0.5 %EqVR	< 0.73 %EqVR	< 10% TR (Figure 39)
Early oil	0.5–0.65 %EqVR	0.73–0.8 %EqVR	10–20% TR (Figure 39)
Peak oil	0.65–0.9 %EqVR	0.8–0.95 %EqVR	20–50% TR (Figure 39)
Late oil	0.9–1.1 %EqVR	0.95–1.1 %EqVR	50–90% TR (Figure 39); Weatherford Laboratories (2017)
Liquids-rich gas	1.1–1.4 %EqVR	1.1–1.4 %EqVR	Weatherford Laboratories (2017)
Dry gas	> 1.4 %EqVR	> 1.4 %EqVR	Weatherford Laboratories (2017)

TR = transformation ratio; %EqVR = vitrinte reflectance maturity

4.3.5 Results

Figure 43, Figure 44 and Figure 45 show examples of the calibrated burial and thermal history modelling results for Tarlee 3, Birdum Creek 1 and Jamison 1. Maximum depth of burial was reached in the early Paleozoic, placing the Kyalla Formation in the liquids-rich gas window (1.1–1.4 %EqVR) and the Amungee Member of the Velkerri Formation in the dry gas window (> 1.4 %EqVR). The model also shows the effect of emplacement of the Derrim Derrim sill on the maturity of the adjacent sediments.

Maturity maps were generated from the one-dimensional modelling results by extracting the modelled maturity for each well at the mid-depth of the stratigraphic unit of interest and interpolating between points using the respective depth grids from the three-dimensional geological model as trending surfaces.

The Amungee Member maturity map is shown in Figure 46. The Amungee Member is in the dry gas window across the majority of the central eastern sub-basin and over about half of the western sub-basin. The flanks of the eastern sub-basin and the majority of the western sub-basin sit within the liquids-rich gas windows. These results are consistent with the observations made in previous one-dimensional modelling studies (Hoffman, 2016; Faiz et al., 2016; Faiz et al., 2018; Silverman and Ahlbrandt, 2010). Côté et al. (2018) note that the organic matter within the A, B and C shales are derived from similar biomass of low biotic diversity. As a result, these source maturity variations are likely to have a stronger control on the liquids potential of the Amungee Member play than variations in organic matter type.

The Kyalla Formation maturity map is shown in Figure 47. The Kyalla Formation reaches the liquids-rich gas window in the central part of the eastern sub-basin and around Birdum Creek 1 in the western sub-basin. Elsewhere the Kyalla Formation sits within the oil window.

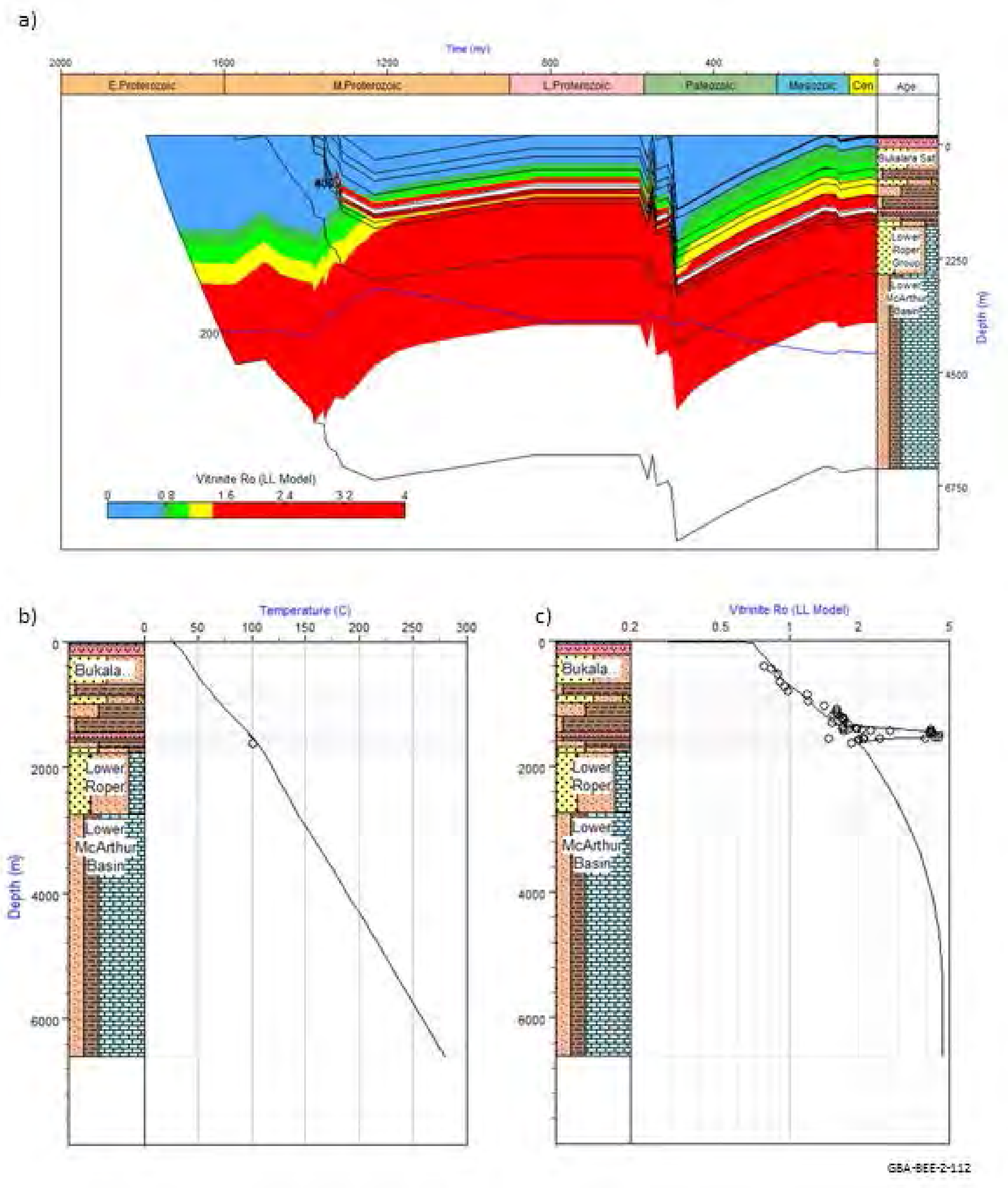

Figure 43 Modelled burial history for Tarlee 3 a) burial history, showing temperature contours and coloured by thermal maturity; b) modelled present day temperature-depth profile, with bottom hole temperature measurement; c) modelled maturity-depth profile. Bitumen reflectance data converted to equivalent vitrinite reflectance values using the conversion equation of Jacob (1989)

Source: modified from Hoffman (2015)
Data: Pangaea NT Pty Ltd (2019); Revie and Normington (2018); Holgate and Gerner (2010)
Element: GBA-BEE-2-112

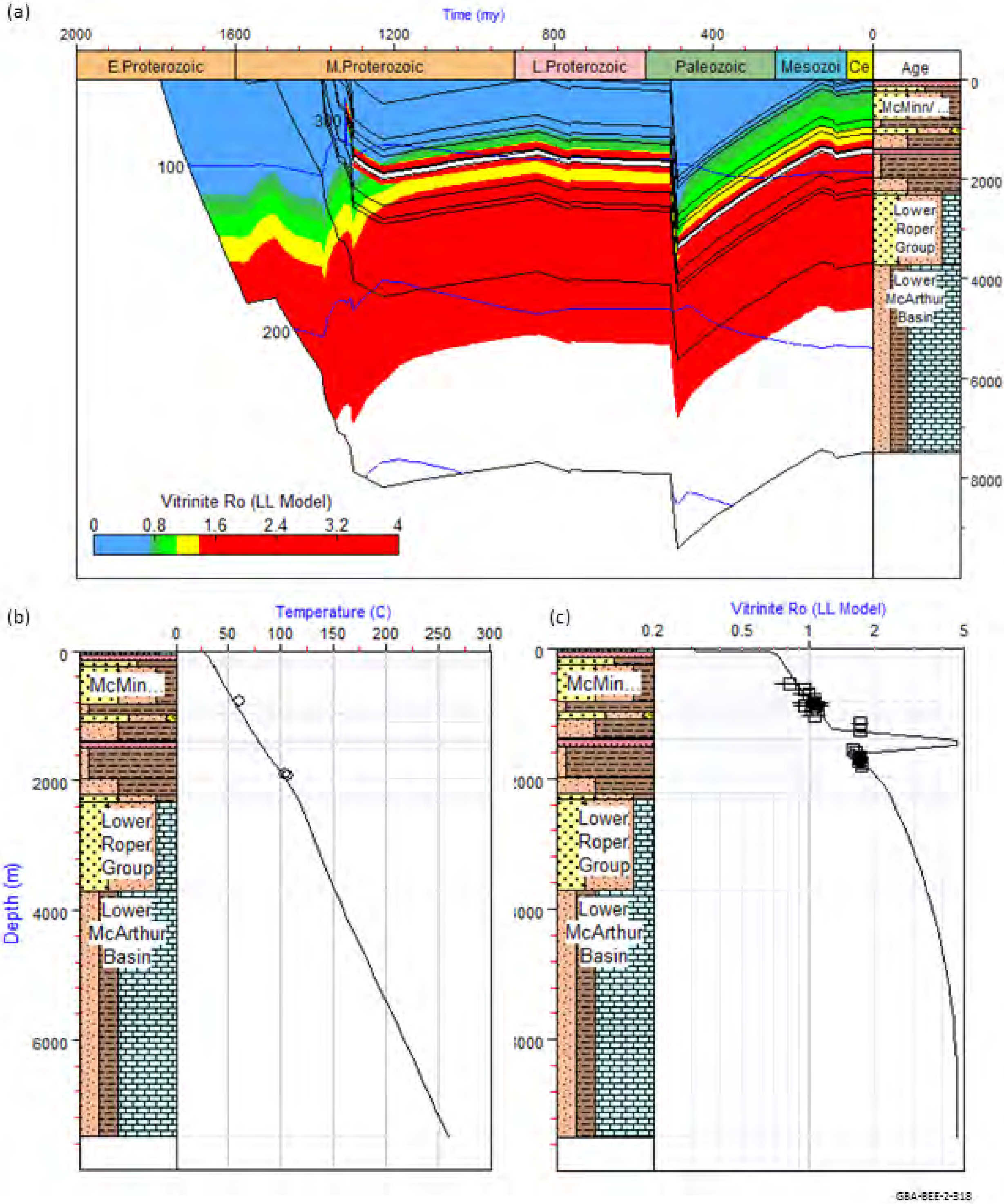

Figure 44 Modelled burial history for Birdum Creek 1 a) burial history, showing temperature contours and coloured by thermal maturity; b) modelled present day temperature-depth profile, with corrected bottom hole temperature measurement; c) modelled maturity-depth profile, with measured bitumen reflectance data converted to equivalent vitrinite reflectance values using the conversion equation of Jacob (1989)

Data: Pangaea NT Pty Ltd (2019); Revie and Normington (2018); Holgate and Gerner (2010)
Element: GBA-BEE-2-318

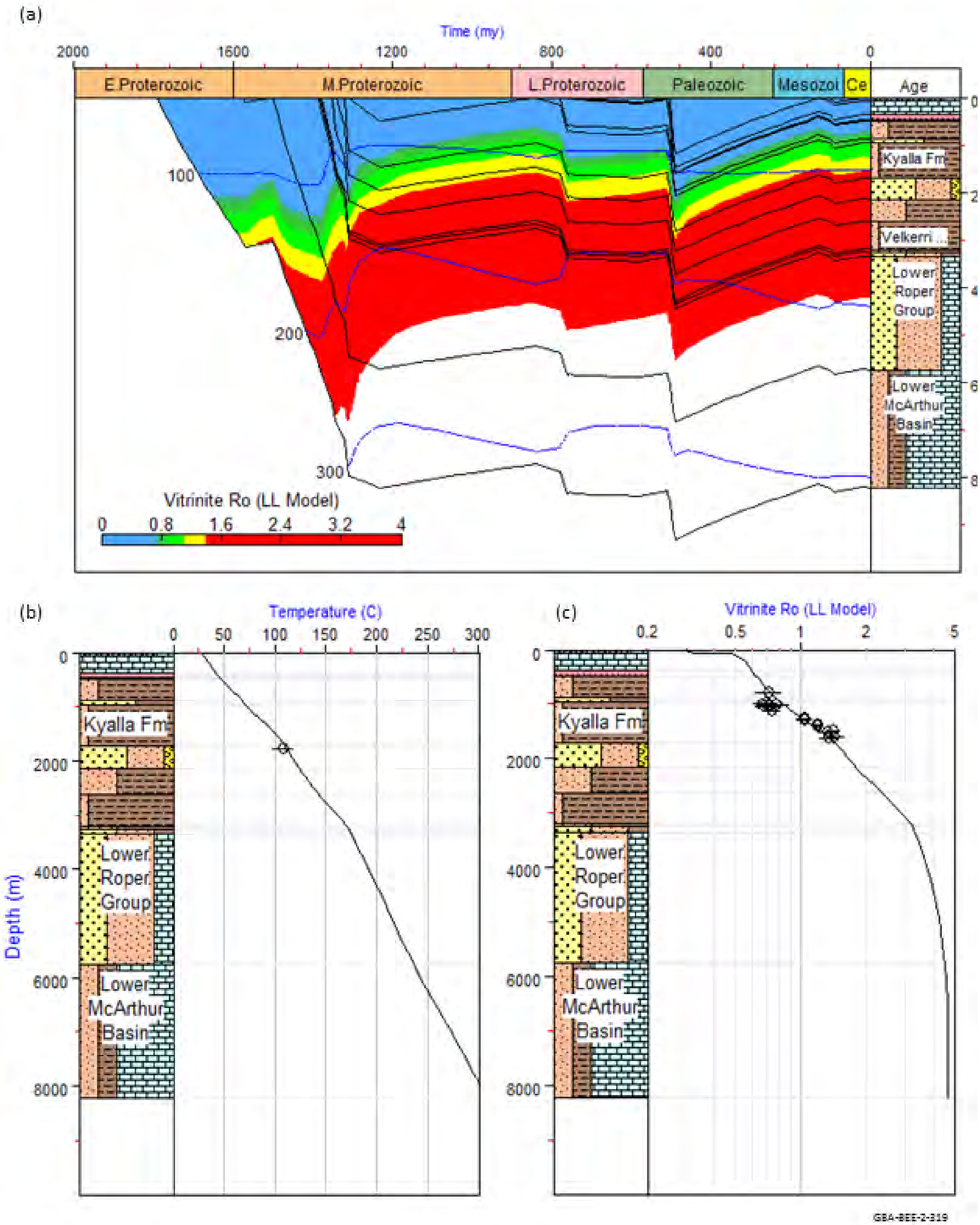

Figure 45 Modelled burial history for Jamison 1 a) burial history, showing temperature contours and coloured by thermal maturity; b) modelled present day temperature-depth profile, with correct bottom hole temperature measurement; c) modelled maturity-depth profile, with measured bitumen reflectance data converted to equivalent vitrinite reflectance values using the conversion equation of Jacob (1989)

Data: Revie and Normington (2018); Holgate and Gerner (2010)
Element: GBA-BEE-2-319

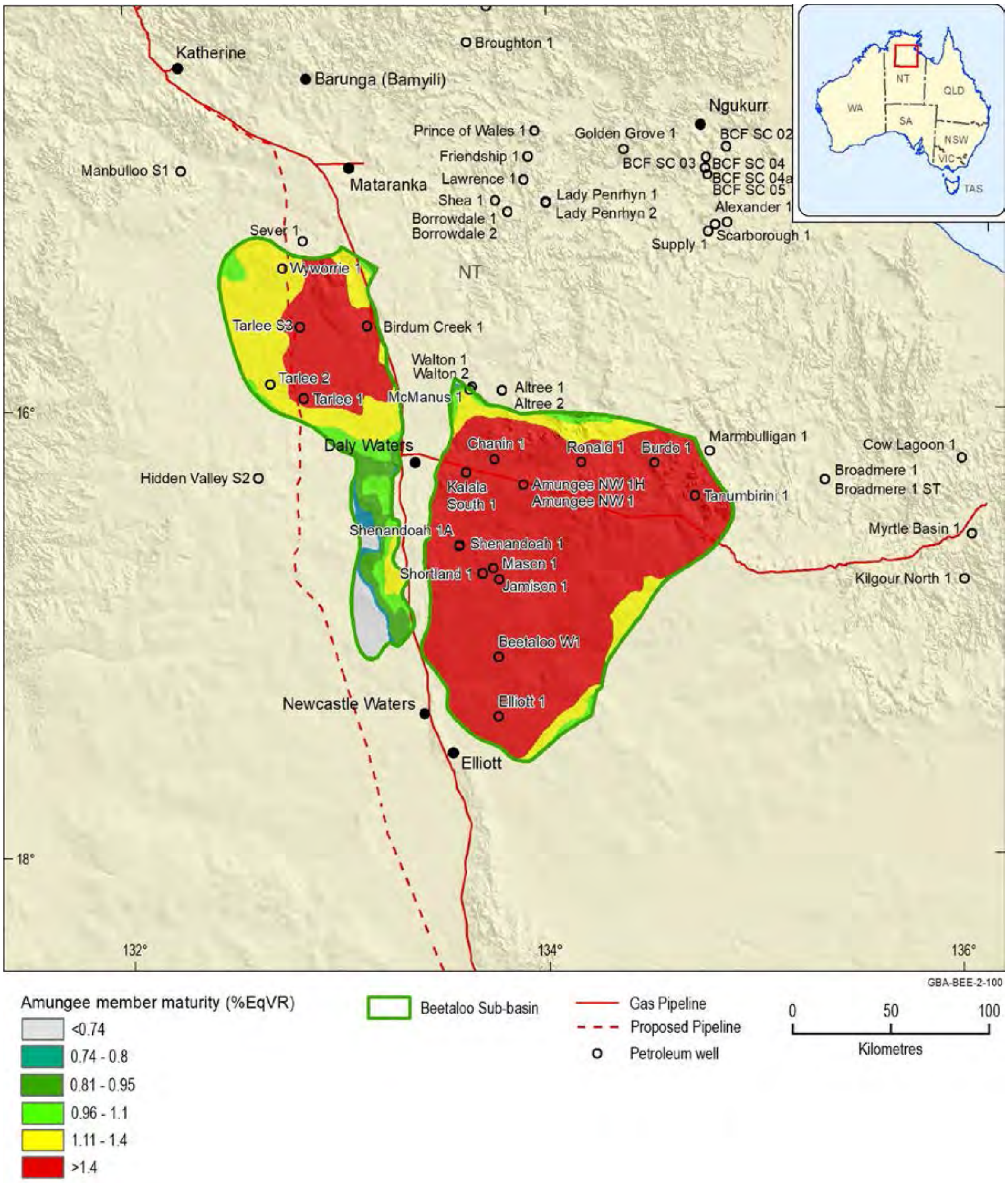

Figure 46 Source rock maturity map for the mid-depth of the Amungee Member of the Velkerri Formation

Data: Geological and Bioregional Assessment Program (2019a)
Element: GBA-BEE-2-100

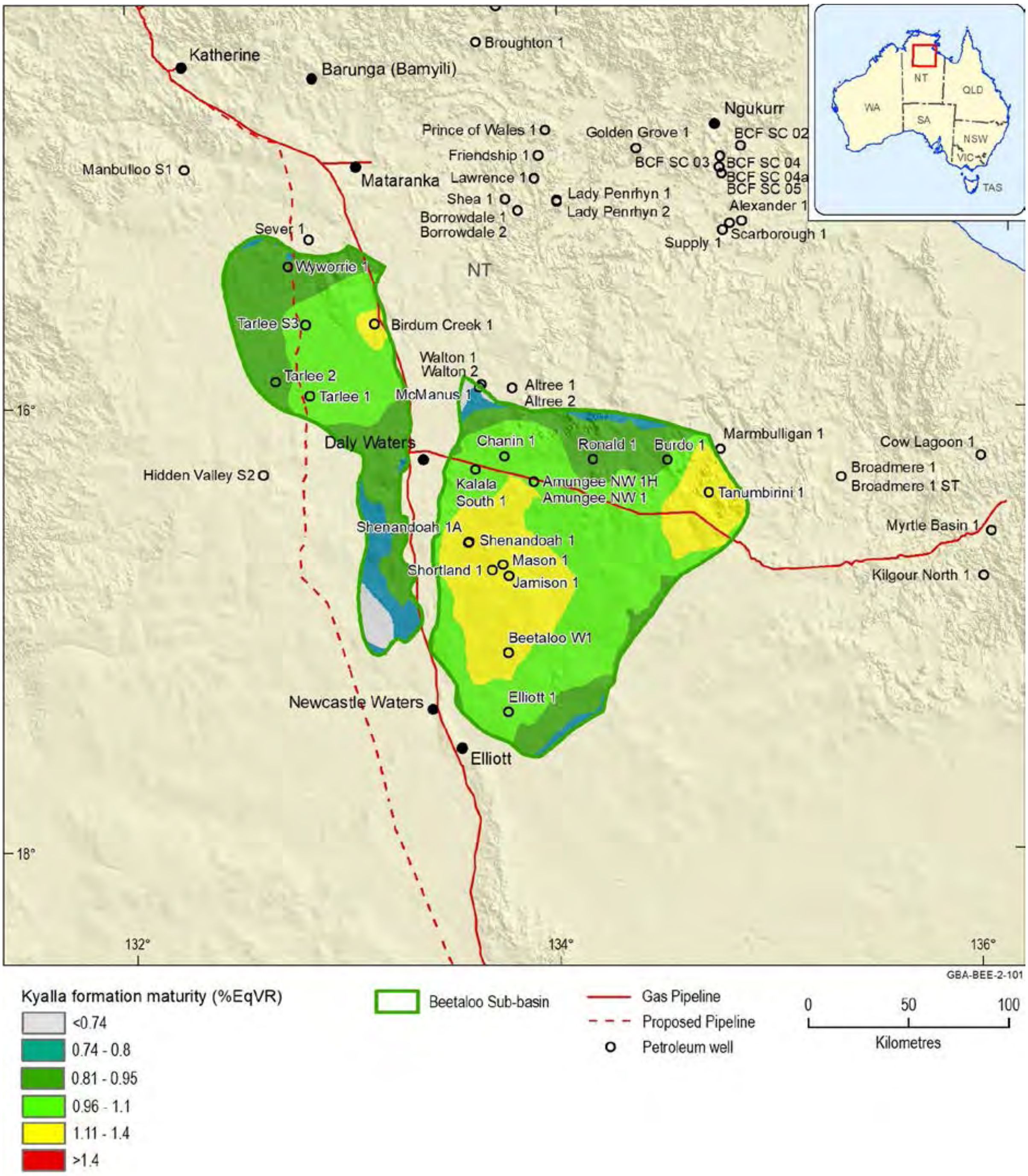

Figure 47 Source rock maturity map for the mid-depth of the Kyalla Formation

Data: Geological and Bioregional Assessment Program (2019a)
Element: GBA-BEE-2-101

4.3.6 Uncertainties

Due to the complex nature of burial-thermal histories in the Beetaloo Sub-basin, modelling uncertainties are high. Uplift and erosion estimates, and hence maximum burial depths, are poorly constrained. In addition, hydrothermal events may have resulted in erratic maturity reflectance profiles at local scale. The one-dimensional modelling approach presented here is useful in areas of minimal data where rapid assessment is required to predict the timing of thermal maturity of the source rock and petroleum generation as a function of depth. However this modelling cannot properly predict migration pathways, the locations and volumes of accumulations, or three-dimensional lateral heat transfer. To more accurately represent the full petroleum system, a more detailed three-dimensional modelling study of the basin would be required.

4.4 Regional stress and overpressure

4.4.1 Regional stress regime

Contemporary patterns of tectonic stress in the brittle crust act as a control over neotectonic deformation and seismicity, and acts as a primary control over both the formation and propagation of natural fractures and of hydraulically induced fractures (Bailey et al., 2017; Bell, 1996b, 2006; Fisher and Warpinski, 2012; Hillis et al., 2008; King et al., 2010; Lund Snee and Zoback, 2016; Olsen et al., 2007; Palano, 2014; Palmer, 2010; Pitcher and Davis, 2016; Rajabi et al., 2017; Sandiford et al., 2004; Seeber and Armbruster, 2000; Sibson, 1992; Sibson et al., 2012; Sibson et al., 2011; Stein, 1999). The extraction of fluids from low-permeability reservoirs, such as shales and tight sandstones, typically requires the creation of fracture pathways through hydraulic stimulation in order to enable adequate flows of hydrocarbons from the reservoir to the well (Bell, 1990; Bell and Babcock, 1986).

Tectonic stress regimes are defined by the relative orientations and magnitude of three orthogonal principal stresses, namely a maximum ($\sigma 1$), minimum, ($\sigma 3$), and intermediate ($\sigma 2$). One stress is generally vertical due to the mass of overburden (σv), constraining the two remaining stresses to the horizontal plane (Anderson, 1951; Bell, 1996b; Sibson, 1977; Zoback, 2007). These are referred to as the maximum (σH) and minimum (σh) horizontal stresses (Bell, 1996a) (Figure 48), and are usually expressed in terms of stress gradients at a given depth (e.g. MPa/km or psi/ft).

Under a given stress regime, the type of failure defined by that regime will typically dominate, though pre-existing structures can exhibit hybrid failure modes (Heidbach and Höhne, 2008; Sibson, 1977). For further information regarding the definition of lithospheric stresses, see: Bell (1996b, 1990, 1996a); Chan et al. (2014); Couzens-Schultz and Chan (2010); Plumb et al. (2000); (Zoback, 2007). Stress patterns in the Beetaloo Sub-basin are reviewed to determine what impact the present day stress regime may have on potential hydraulic stimulation of formations for gas exploration.

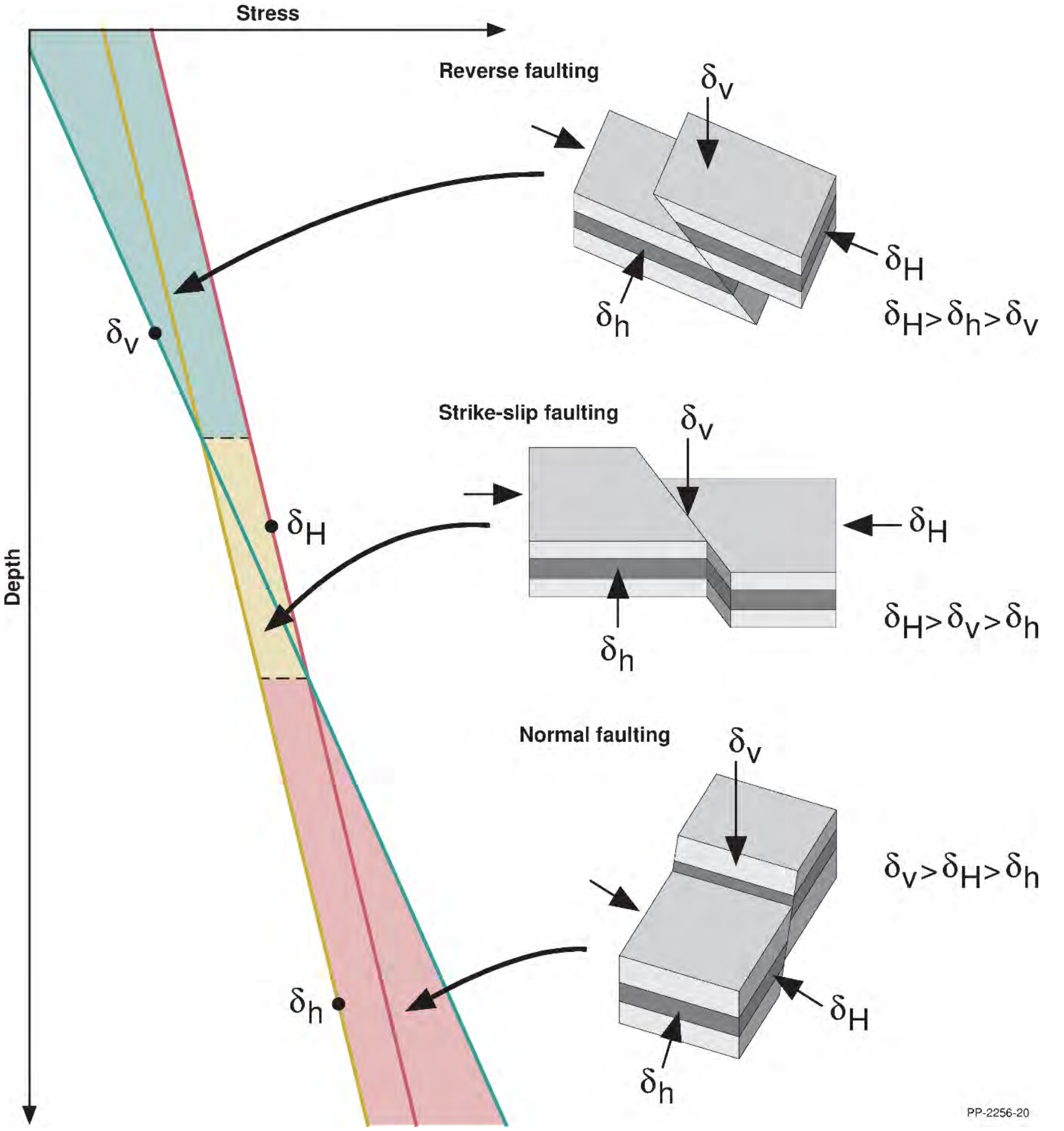

Figure 48 Tectonic stress regimes as defined by Anderson (1951), highlighting the relative magnitudes of the three principle stresses. Vertical stress is shown in green, maximum horizontal stress in red, and minimum horizontal stress in brown

Source: After Brooke-Barnett et al. (2015)
Element: GBA-BEE-2-059

4.4.2 Present day stress in the Beetaloo Sub-basin

Currently, there is no regional-scale understanding of present day stresses within the Beetaloo Sub-basin. Limited stress data are available from within the Beetaloo Sub-basin and it has to date been considered only as a part of the greater McArthur Basin in continent-scale stress studies. Given the nature of recent interest in the Beetaloo Sub-basin as a potential shale gas province, increasing amounts of stress data are being acquired and analysed. Many of the petroleum exploration wells drilled within the Beetaloo Sub-basin feature modern wireline logs, including image logs, and well tests that allow for a reasonable understanding of present day stresses to be assembled.

The published literature includes little on the regional stress regimes in the Beetaloo Sub-basin, instead focusing on those within the target intervals. For example, the middle Velkerri is interpreted by Close et al. (2017b); Close et al. (2017a) as hosting a strike-slip or normal stress regime. More detail is provided in the Santos Ltd (2017) submission to the Scientific Inquiry in to Hydraulic Fracturing in the Northern Territory, which discusses the stress state interpreted at the Tanumbirini 1 well location. Tanumbirini 1 is a shale gas exploration well drilled in 2014 by Santos Ltd in the Beetaloo Sub-basin to a depth of 3946.0 m. The primary aim of the well was to provide control for the Roper Group shale play, by targeting the basin centre in order to maximise overpressures in the middle Velkerri Formation target and to intersect the full shale section of the Kyalla Formation (Santos Ltd, 2014). As a shale-specific exploration well, extensive suites of data were acquired over the target intervals that allow for interpretation of geomechanical properties and an assessment to be made of the present day stress state.

The stress state within the sedimentary section intersected by Tanumbirini 1 is interpreted as a thrust regime transitioning to borderline thrust to strike-slip with depth (Santos Ltd, 2017); consistent with the analysis of regional-scale stress regimes within the overlying Georgina Basin undertaken by Bailey et al. (2017). However, significantly reduced stress anisotropy is interpreted within the Velkerri shale unit, resulting in the interpretation of a normal faulting stress regime. This is consistent with the stress states modelled for similar shales in the McArthur Basin (Johnson and Titus, 2014; Mildren et al., 2013) and in the Isa Superbasin (Bailey et al., 2019; Johnson and Titus, 2014) , as well as previous studies within the shale units of the Beetaloo Sub-Basin (Close et al., 2017b; Close et al., 2017a; Theologou, 1991).

4.4.3 Maximum horizontal stress azimuth

The Australian Stress Map project includes the Beetaloo Sub-basin within the McArthur Region stress province, one of the 30 defined stress provinces for continental Australia and Papua New Guinea (Figure 49). The McArthur Region stress province is characterised by a σH orientation of 026°N, in line with much of northern Australia where NE-SW to NNE-SSW σH orientations are observed on the continental-scale (Figure 49). Close et al. (2017a) note that average breakout orientations observed in image log data indicate a σH orientation of 045°N, or NE-SW. This is reinforced by interpretation of fracture orientations on image log data, with the primary direction of fracture growth observed to align with breakout orientation (Close et al., 2017a). These results are consistent with previous geomechanical studies within the region; Bailey et al. (2017) interpret a σH orientation of 044°N within the overlying Georgina Basin and its surrounds and Theologou (1991) demonstrate an approximately 020°N σH orientation from hydraulic fracture tests within the Velkerri Formation.

4.4.4 Implications for fracture propagation

Mechanical properties control the amount of stress which can be supported by a given lithology (Figure 50). The concept of mechanical stratigraphy, where variation in rock properties of a given lithology can be defined by discrete mechanical properties, is noted as a significant control over the formation and propagation of fractures within the subsurface (Laubach et al., 2009). Where there are contrasts between these mechanical units, natural barriers to fracture propagation are formed (Zoback, 2007). Typically, a significant change in stresses from unit to unit will result in the termination of fracture propagation.

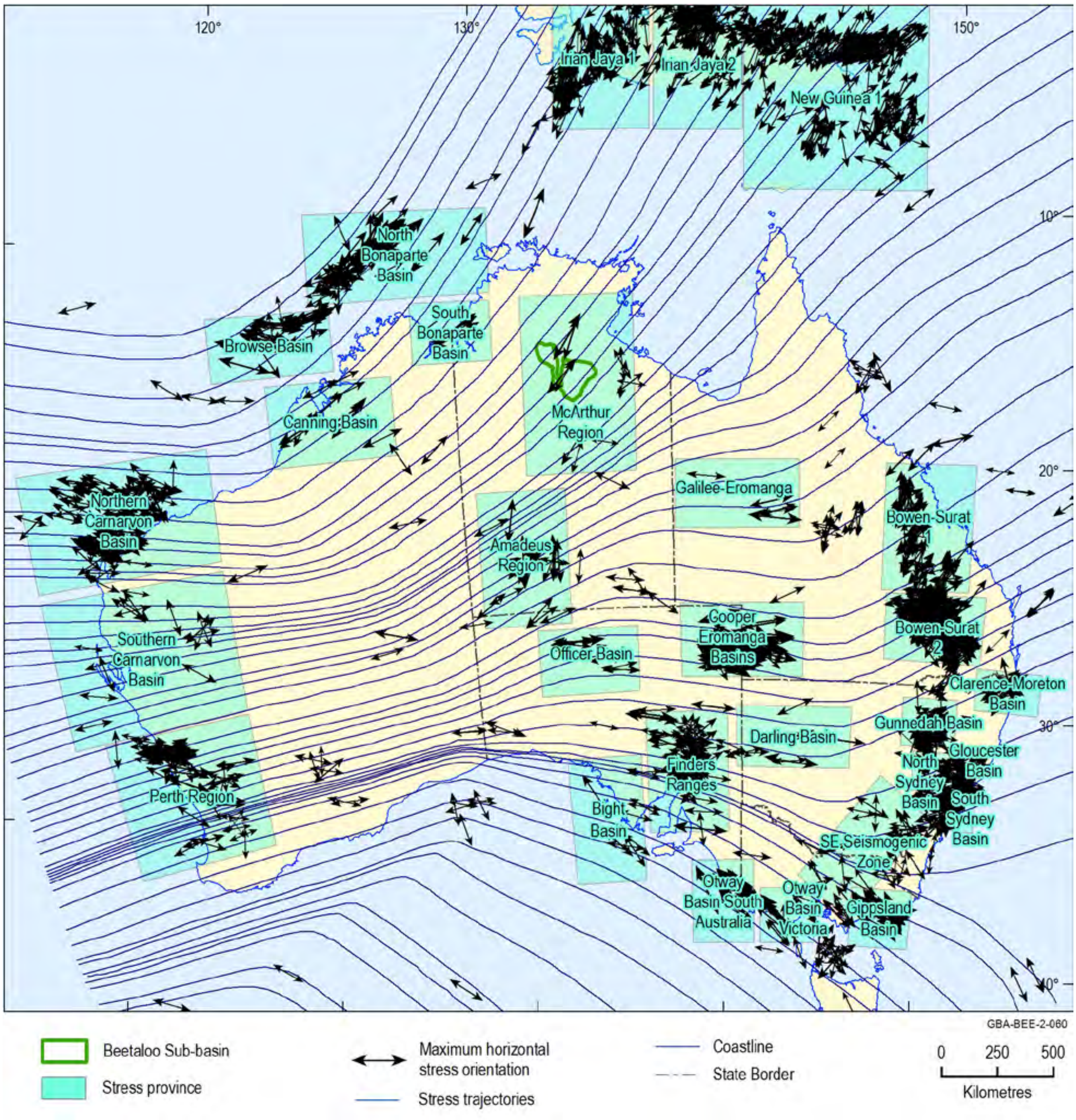

Figure 49 Australian Stress Map data (Rajabi et al., 2017) showing the 30 defined stress provinces and continent-scale stress orientations. The location of the Beetaloo Basin, as well as local stress orientations not currently provided in the ASM, are also displayed

Source: Rajabi et al. (2017)
Element: GBA-BEE-2-060

Fundamentally, low Poisson's Ratio rocks with a high Young's Modulus support anisotropic horizontal stresses (i.e. lower magnitudes in the minimum horizontal stress direction and elevated magnitudes in the maximum horizontal stress direction); whereas rocks with a high Poisson's Ratio and low Young's Modulus are incapable of supporting those anisotropic stresses and so tend towards more isotropic stresses (i.e. higher magnitudes in the minimum horizontal stress direction and lower magnitudes in the maximum horizontal stress direction) (Plumb et al., 2000) (Figure 50). Typically, it is grain-supported facies such as sandstones or carbonates that exhibit anisotropic horizontal stresses and clay supported facies such as mudstones and shale that approach isotropic stress conditions (Plumb et al., 2000; Zoback, 2007) (Figure 50). An understanding of mechanical stratigraphy, and the variation of in-situ stresses that results from varying mechanical properties, allows for induced fractures to be naturally constrained.

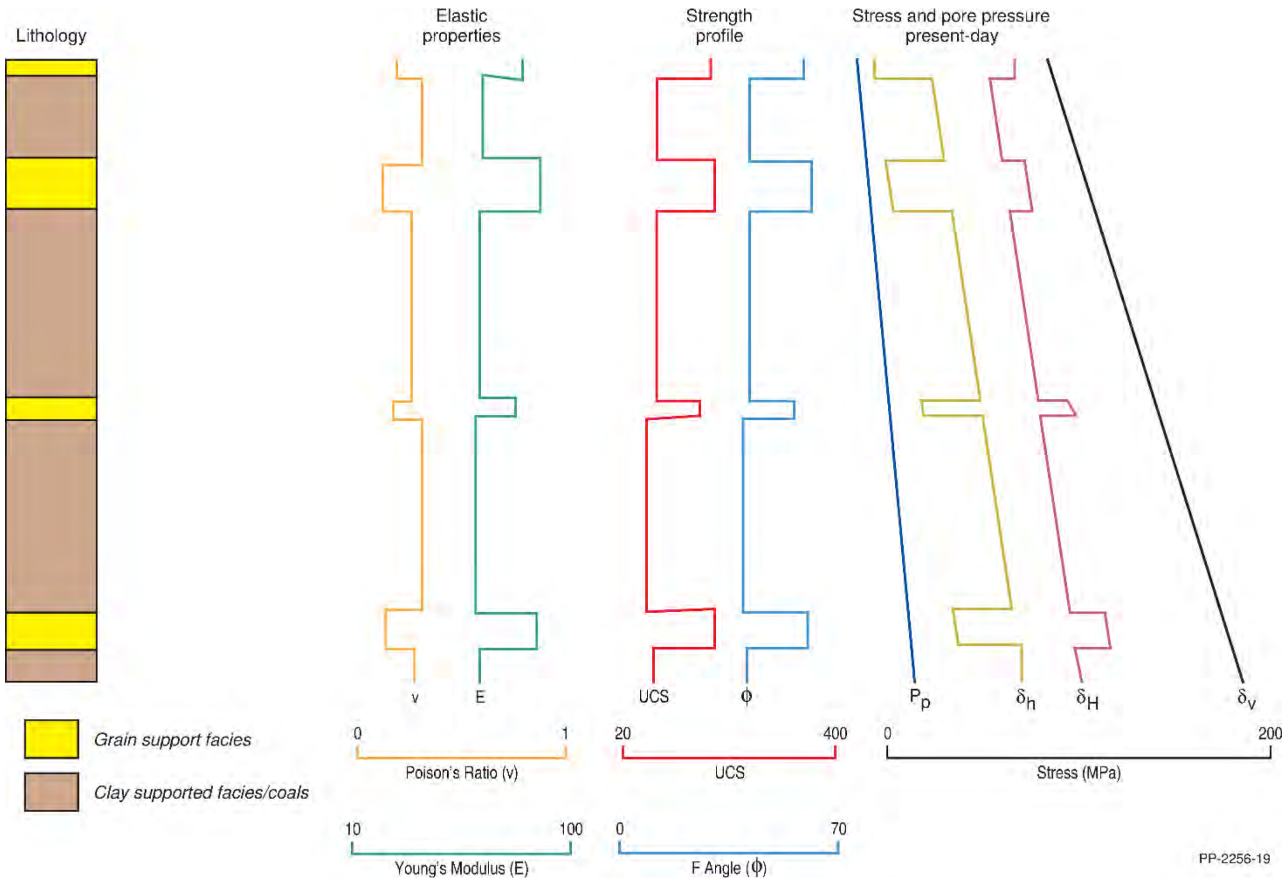

Figure 50 Schematic mechanical earth model showing lithology, mechanical stratigraphy, and calculated stress profiles

Source: After Plumb et al. (2000)
Element: GBA-BEE-2-062

In the Beetaloo Sub-basin, significant variation of stress magnitudes, and possibly stress regime, with depth is likely to act as an impediment to fracture propagation. Given the nature of the target shale intervals, both inter-formational and intra-formation fracture barriers are likely to exist in the form of sand- and siltstone interbeds, particularly within the Velkerri Formation. Mechanical earth models constructed for the well Tanumbirini 1 by Santos Ltd (Figure 51) do not extend over shallow aquifer intervals; however, shallow well tests and regional studies suggest that a reverse faulting stress regime exists from the surface through to the upper Kyalla Formation (Bailey et al., 2017; Santos Ltd, 2017). Below this, significant variations in stress regime are interpreted.

As previously mentioned, any significant change of stress between mechanical units will typically act as a barrier to fracture propagation and these changes are often referred to as stress containment boundaries. The interpreted stress state is dominated by a strike-slip faulting stress regime from the upper Kyalla Formation through to the top of the middle Velkerri Formation, however, there is a modelled interval of reverse faulting stress regime in the overlying upper Moroak Sandstone (Santos Ltd, 2017). Lower horizontal stresses are modelled for the middle Velkerri Formation, resulting in a transition to a normal faulting stress regime through most of the underlying interval. However, where competent sand interbeds exist, variations in stress magnitude and, hence, stress regime, are also observed.

The Tanumbirini 1 one-dimensional MEM (Figure 51) demonstrates that within the Beetaloo Sub-basin both inter- and intra-formational fracture barriers exist that are likely to constrain induced fractures (Santos Ltd, 2017). The organic-rich target intervals of the Kyalla and Velkerri formations are subject to lower stresses than the sandstones and siltstones that bound them and a number of significant stress contrasts exist that are likely to provide containment on any vertical fracture propagation, ensuring that induced fractures remain within the target zone. Flewelling et al. (2013) demonstrated that it is implausible for a hydraulic connection to be created through induced fracturing between deep unconventional formations and overlying shallow potable aquifers due to the limited amount of fracture height growth that is observed at depth, and the containment provided by the rotation of the minimum principal stress to the vertical plane with changing stress regimes.

The Kyalla Formation is subject to a strike-slip faulting stress regime, where fractures will propagate vertically. However, it is overlain by Neoproterozoic to Paleozoic units where a reverse faulting stress regime exists. Under reverse faulting conditions fractures will propagate horizontally, hence, these formations will act as a stress containment boundary and inhibit fracture growth.

The upper Velkerri Formation is overlain by the Moroak Sandstone, which while dominated by a strike-slip faulting stress regime, hosts an interval where high rock strength and high Young's Modulus results in a reverse faulting stress regime. Below this, a strike-slip faulting stress regime is present through to the top Amungee Member, however, an additional stress containment boundary is present within the upper Velkerri Formation in the form of organic-lean siltstones and sandstones with high rock strength and Young's Modulus. A distinct change in horizontal stress magnitude can be observed at the base of these lithologies and this is likely to form an intraformational containment boundary. The primary targets within the Velkerri Formation are the organic-rich A, B, and C shales of the Amungee Member; the Amungee Member is demonstrated to host a normal faulting stress regime and is mechanically contained by the strike-slip faulting stress regime of the overlying Wyworrie Member. Again, organically lean siltstone interbeds are likely to form intraformational seals to further contain fracture propagation (Santos Ltd, 2017).

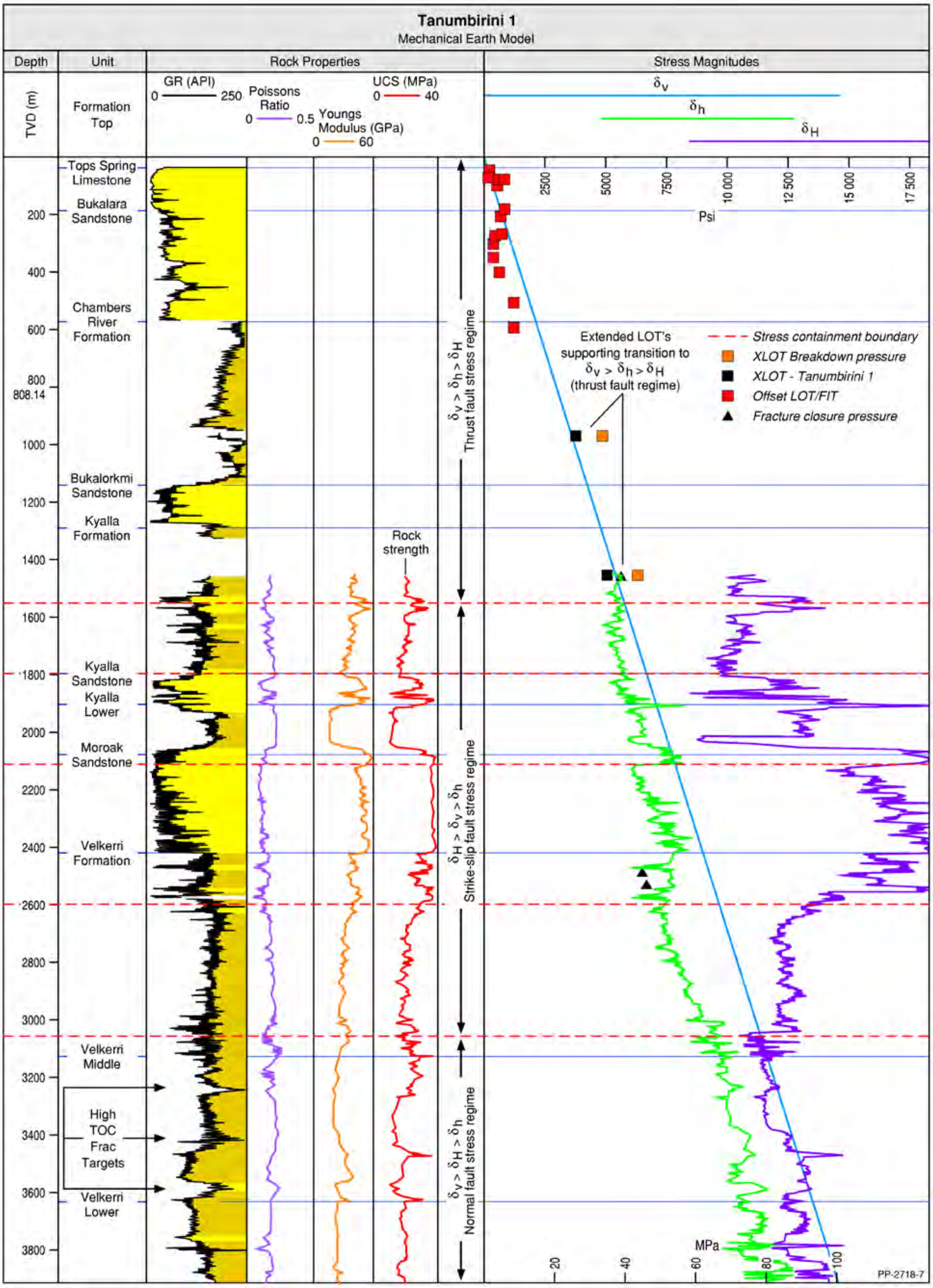

Figure 51 One-dimensional mechanical earth model (1D MEM) constructed for the Santos well Tanumbirini 1 by Santos Ltd., highlighting variations in stress regime within the subsurface as well as significant stress containment boundaries likely to act as natural barriers to induced fracture propagation

Source: After Santos Ltd (2017)

Element: GBA-BEE-2-061

4.4.5 Overpressure

The term overpressure describes an in-situ pore fluid pressure that exceeds the hydrostatic value (Tingate et al., 2001), which ranges from 9.8 MPa/km for fresh water to 11.3 MPa/km for completely salt saturated water. Typically, formation water produced in the Beetaloo Sub-basin has salt concentrations of approximately 50,000 mg/L (range 50,000–150,000 mg/L) (Evans et al., 2020). A reasonable estimate of hydrostatic pore pressure within the Beetaloo Sub-basin is 9.8 to 11.1 MPa/km (0.433 to 0.49 psi/ft), although sample density is quite low. In order to exceed this hydrostatic gradient, a mechanism other than the buoyancy force of a continuous column of static fluid is required (Osborne and Swarbrick, 1997). The most common mechanisms through which this is achieved are: a) disequilibrium compaction, b) generation of hydrocarbons, c) fluid expansion, and, d) tectonic loading (Bowers, 1995; Grauls and Baleix, 1994; Tingay et al., 2003; Tingay et al., 2007, 2009; Wangen, 2001). Knowledge of overpressure and accurate pore pressure prediction is essential to ensure safe drilling, proper well design, and for reservoir planning and reserve estimation (Tingate et al., 2001; Tingay et al., 2009) . Overpressure forms a potential control over seal integrity, fracture reactivation, reservoir quality, and the effective magnitude of in-situ stresses (van Ruth et al., 2004; Zoback, 2007).

To date, there have been no detailed studies of formation pressure within the Beetaloo Sub-basin, published, however, there have been several wells drilled where formation tests were carried out; drill stem tests (DST) suggest a pore pressure gradient mostly in line with the hydrostatic gradient (Figure 52). There are several test results that demonstrate pore pressure gradients as high as 11.79 MPa/km (Figure 52). Both Origin (Close et al., 2017a) and Santos (Santos Ltd, 2017) suggest that there are overpressured formations within the Beetaloo Sub-basin based on interpreted diagnostic fracture injection test (DFIT) data from several wells. Close et al. (2017b) and Close et al. (2017a) report DFIT data from the wells Kalala S-1 and Amungee NW-1 that indicates a pore pressure gradient of 11.8 to 12.4 MPa/km (0.52-0.55 pst/ft) in the middle Velkerri Formation, whereas (Santos Ltd, 2017) report identified pore pressures of 17.0 MPa/km (0.75 psi/ft) from offset wells. Falcon Oil and Gas noted, while drilling Shenandoah 1A that elevated drilling mud densities were required when coring the Velkerri B shale in order to balance increased formation fluid pressures. DFITs carried out prior to the fracture treatments of Shenandoah 1 identified elevated pore pressures in the middle Velkerri Formation that range from 12.6 to 15.0 MPa/km (0.556–0.662 psi/ft). Further DFITs carried out in the Moroak Sandstone (11.2–12.4 MPa/km, or 0.493–0.550 psi/ft) and the lower Kyalla Formation (12.6–14.8 MPa/km, or 0.556–0.653 psi/ft) also indicate overpressure within these formations (Shenandoah WCR). In their assessment of the Kyalla Formation, Altmann et al. (2018) describe efforts by Falcon Oil and Gas (Burgess, 2010) to run a DST over the lower Kyalla Source Rock Reservoir in order to understand pressure and productivity from this interval. The authors note that the packing seat failed after the tool was open and the test was abandoned without assessing reservoir pressures. Due to the lack of reliable direct measurements, Altmann et al. (2018) consider formation pressure to be the most significant technical risk pertaining to the lower Kyalla shale play. Indications from DFITs in both the shale plays of interest, the Velkerri and the Kyalla formations, are that they are overpressured. Overpressure is considered a critical success indicator for North American shale gas plays (Close et al., 2017a).

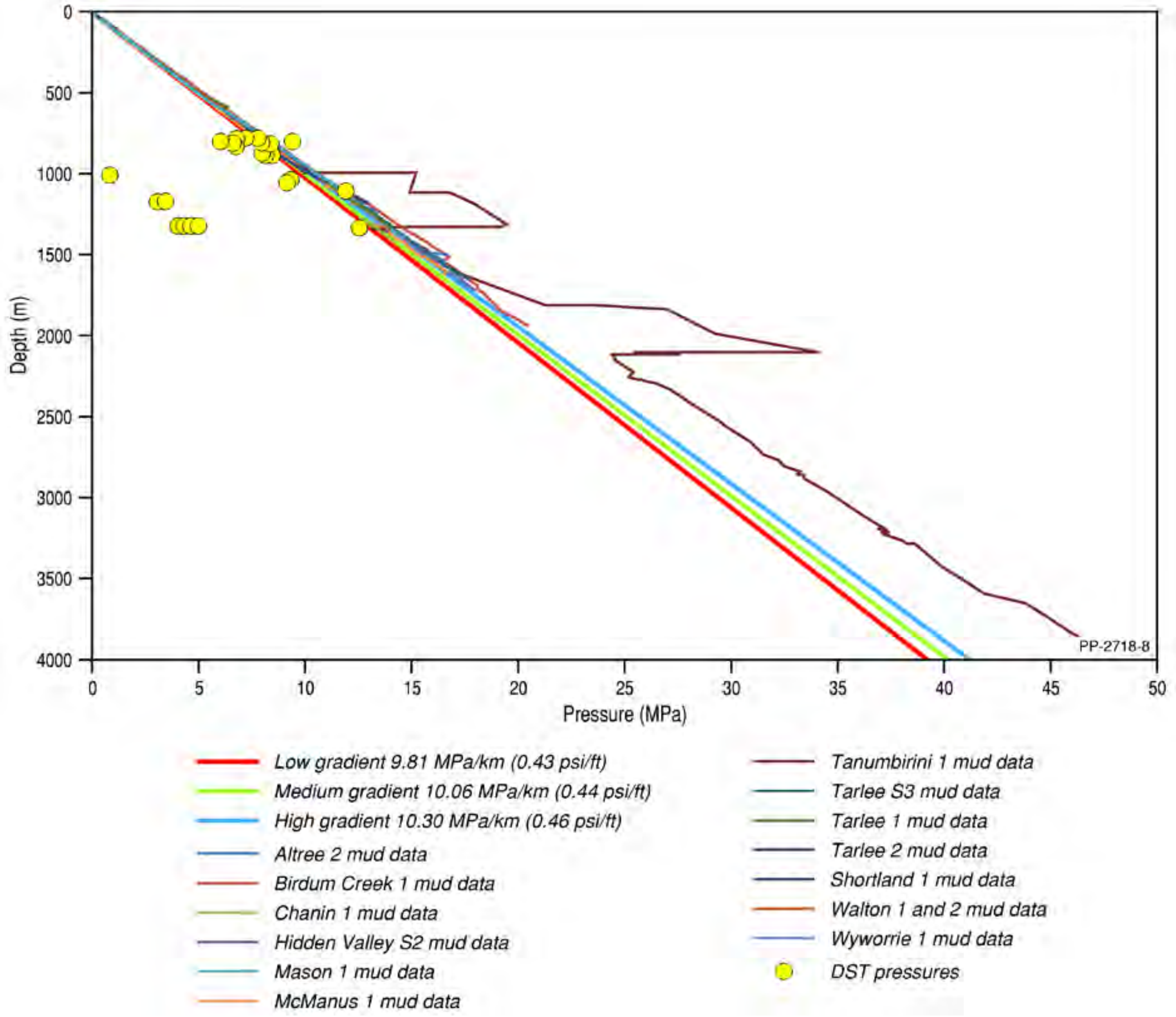

Figure 52 Pore pressure measurements from drill stem tests (DSTs – blue circles) plotted alongside mud weight data from 13 Beetaloo Sub-basin petroleum wells

Also displayed is a range of hydrostatic gradients (red, green, and blue straight lines) showing the likely range of hydrostatic values. Note, diagnostic fracture injection test (DFIT) data discussed in text is not plotted.
Element: GBA-BEE-2-064

5 Prospectivity mapping

Play fairway mapping was used to map the distribution of petroleum plays likely to be developed in a five to ten year time frame. This process aims to address the geological factors likely to assist in identifying whether a viable petroleum play is likely to be present, and makes no attempt to factor economics, politics, or social factors into the assessment.

5.1 Plays to be assessed

The five plays in the Beetaloo GBA region most likely to be developed within the next five to ten years are as follows (Côté et al., 2018):

- Velkerri Shale (Amungee Member) – Dry Gas Play
- Velkerri Shale (Amungee Member) – Liquids-Rich Gas Play
- Kyalla Shale – Liquids-Rich Gas Play
- Kyalla Hybrid Lithology – Liquids-Rich Gas Play
- Hayfield Sandstone – Oil/Condensate Play (possible structural/stratigraphic trap, tight reservoir; requires further exploration and technical viability assessment using a horizontal fracture stimulated well).

Of the above plays, there is only sufficient public domain data available to independently assess the dry and liquids-rich gas plays of the Amungee Member shales of the Velkerri Formation, and the liquids-rich gas in the Kyalla Formation shale.

No additional exploration targets (conventional or unconventional; oil or gas) have been clearly identified and publicly documented, to date, within the sub-basin. Although there is significant oil/condensate potential in the Kyalla Formation, successfully development of this play type would be dependent on further advancements in enhanced oil recovery technology.

5.2 Workflow

The shale play criteria used herein are primarily based on previous work undertaken by US federal agencies, e.g. EIA (2013); Charpentier and Cook (2011), with additional feedback from state government agencies, universities and relevant industry staff (Table 40). Parameters used included formation depth, net source rock thickness and thermal maturity.

Each input parameter was assigned a ranking between zero and one (Zero 0, Med 0.5, High 1). Prospectivity associated with each individual parameter was multiplied together to determine a composite map, highlighting the relative prospectivity of each play across the basin (Figure 53). A workflow was developed for each play type using the equation below to develop the final relative prospectivity confidence maps that are displayed in the results sections for each play type.

$$Prospectivity\ (C) = c_1 \times c_2 \times c_3 \times \ldots \times c_n$$

The results are a reflection of relative prospectivity across the region rather than a statistical probability of success of any play or prospect.

The workflow was set up as a batch task file using the Petrosys software (Petrosys Pty. Ltd., Version 17.7sp6).

Table 40 Summary of shale gas play specific input parameters and classifying criteria used to develop play fairway maps.

Parameter (P)	Zero (0)	Medium (0.5)	High (1)	Map source
Mid-formation depth (m)	< 700 m	700–1000 m	> 1000 m	Three-dimensional geological model (Orr et al., 2019)
Net shale thickness greater than 2 wt% TOC	< 15 m	15–30 m	> 30 m	Gross stratigraphic thickness from three-dimensional geological model (Orr et al., 2019) * net organically rich ratio (Section 3.2 – this report)
Thermal maturity (liquids-rich gas) **OR**	< 1.1 OR > 1.4 %EqVR	n/a	1.1–1.4 %EqVR	Source rock maturity map (Section 3.4 – this report)
Thermal maturity (dry gas)	1.4 %EqVR	n/a	> 1.4 %EqVR	Source rock maturity map (Section 3.4 – this report)

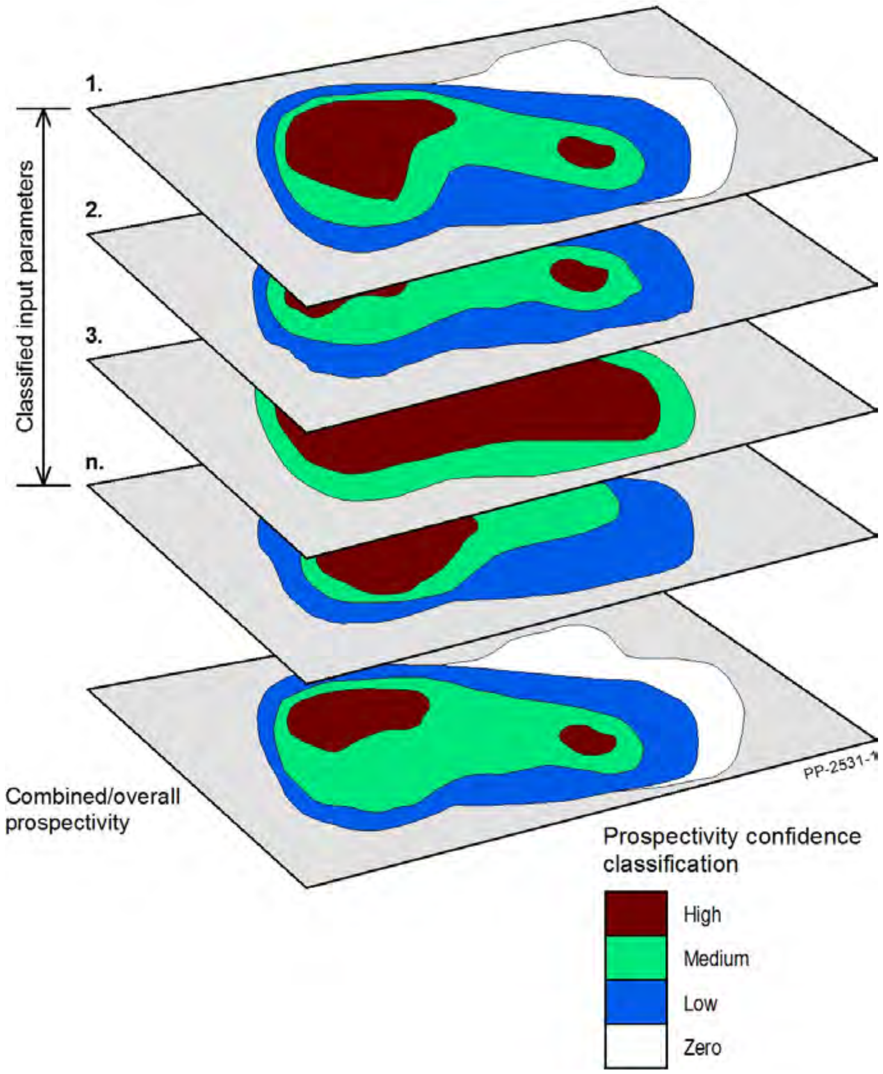

Figure 53 Schematic workflow for combining classified prospectivity confidence input parameter maps to obtain the overall combined relative prospectivity of a formation or play

Element: GBA-BEE-2-199

5.3 Results

5.3.1 Velkerri Formation

5.3.1.1 Amungee Member

Classified individual parameter maps for the Amungee Member shale dry gas play are shown in Figure 54 and the relative prospectivity confidence is shown in Figure 55. The Amungee Member dry gas play is predominantly located in the central part of the eastern sub-basin (Figure 46). The Amungee Member dry gas play extent presented here is very similar to that of the Velkerri dry gas play published by Côté et al. (2018) for the majority of the eastern sub-basin. Minor differences in play extent between this work and Côté et al. (2018) away from the wells, are likely to relate to the variations in seismic interpretation and associated structural surfaces used for each study. A small area around Birdum Creek in the central western sub-basin may also be prospective for dry gas in the Amungee Member.

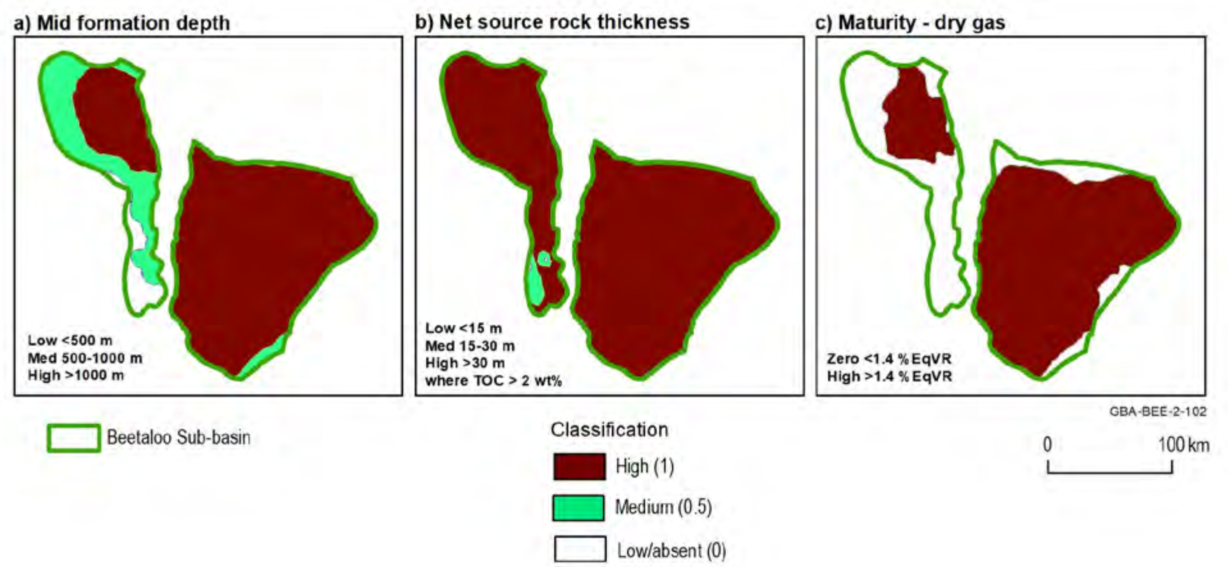

Figure 54 Classified input parameters maps used to generate the Amungee Member shale dry gas play relative prospectivity map

Data: Geological and Bioregional Assessment Program (2019c)
Element: GBA-BEE-2-102

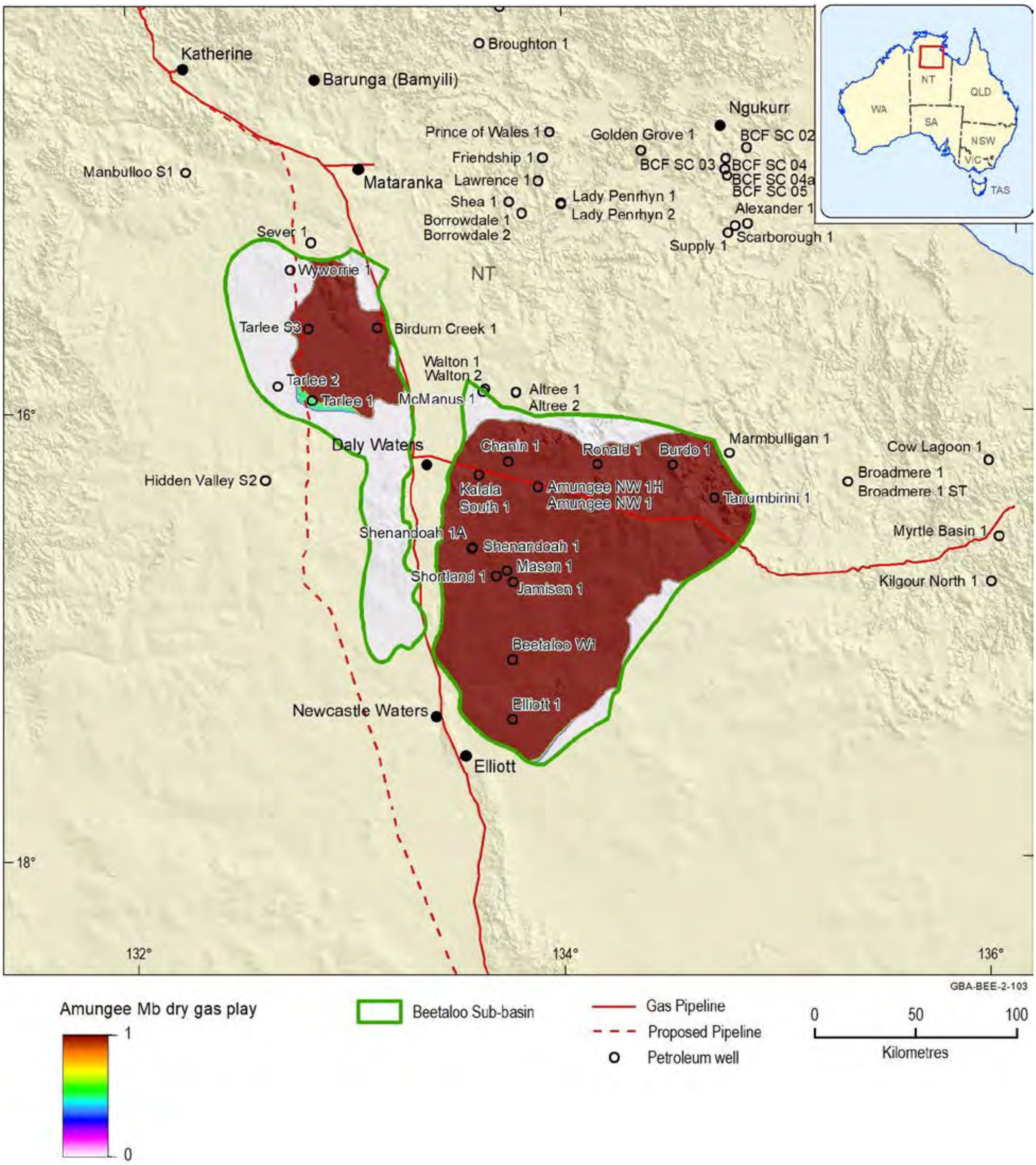

Figure 55 Play fairway map showing the variation in relative prospectivity of the Amungee Member shale dry gas play across the Beetaloo Sub-basin

Data: Geological and Bioregional Assessment Program (2019c)
Element: GBA-BEE-2-103

Classified individual parameter maps for the Amungee Member shale liquids-rich gas play are shown in Figure 56 and the relative prospectivity confidence map is shown in Figure 57. In the eastern Beetaloo Sub-basin, the Amungee Member liquids-rich gas play is located along the northern and south-eastern limits of the sub-basin. Again this follows a similar distribution to the Velkerri liquids-rich gas play of Côté et al. (2018). In the western sub-basin, the liquids-rich play extends across the central part of the depocentre between Tarlee and Birdum Creek 1.

The limiting factor on play extent in the eastern sub-basin is maturity, while net source rock thickness and formation depth restrict play extent in the west.

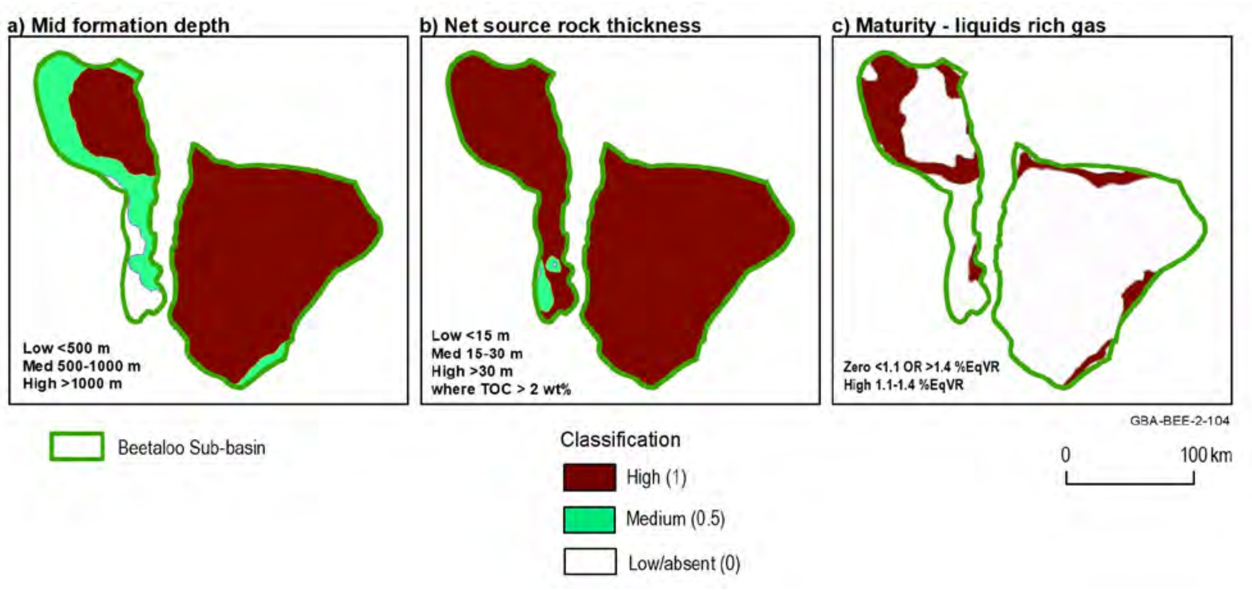

Figure 56 Classified input parameters maps used to generate the Amungee Member shale liquids-rich gas play relative prospectivity map

Data: Geological and Bioregional Assessment Program (2019c)
Element: GBA-BEE-2-104

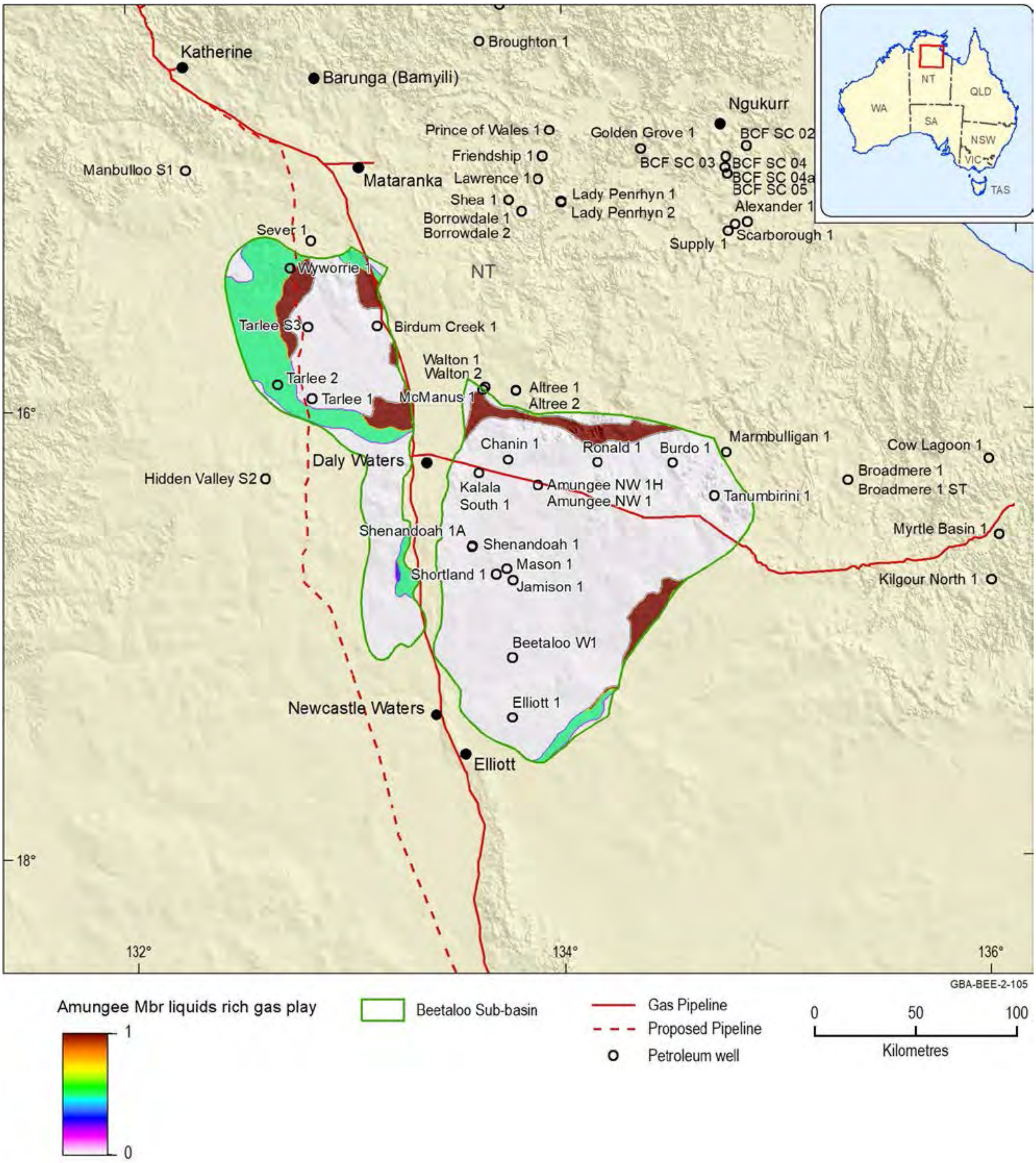

Figure 57 Play fairway map showing the variation in relative prospectivity of the Amungee Member shale liquids-rich gas play across the Beetaloo Sub-basin

Data: Geological and Bioregional Assessment Program (2019c)
Element: GBA-BEE-2-105

5.3.2 Kyalla Formation

Classified individual parameter maps for the Kyalla Formation liquids-rich gas play are shown in Figure 56 and the relative prospectivity confidence map is shown in Figure 57. In the eastern Beetaloo Sub-basin, Kyalla Formation liquids-rich gas play is located in the central part of the sub-basin. Again this follows a similar distribution to the Kyalla Formation liquids-rich gas play of Côté et al. (2018). In the western sub-basin, the liquids-rich play extent is focused around Birdum Creek 1, although the shallow depths result in a lower relative prospectivity in this region.

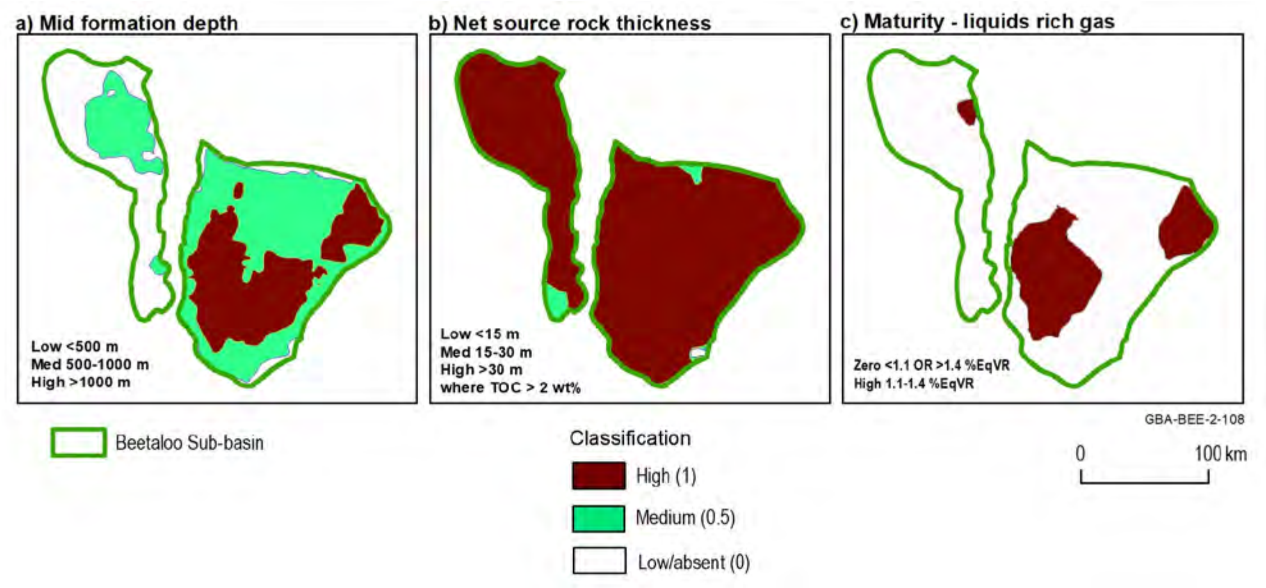

Figure 58 Classified input parameters maps for the Kyalla Formation shale liquids-rich gas play

Data: Geological and Bioregional Assessment Program (2019c)
Element: GBA-BEE-2-108

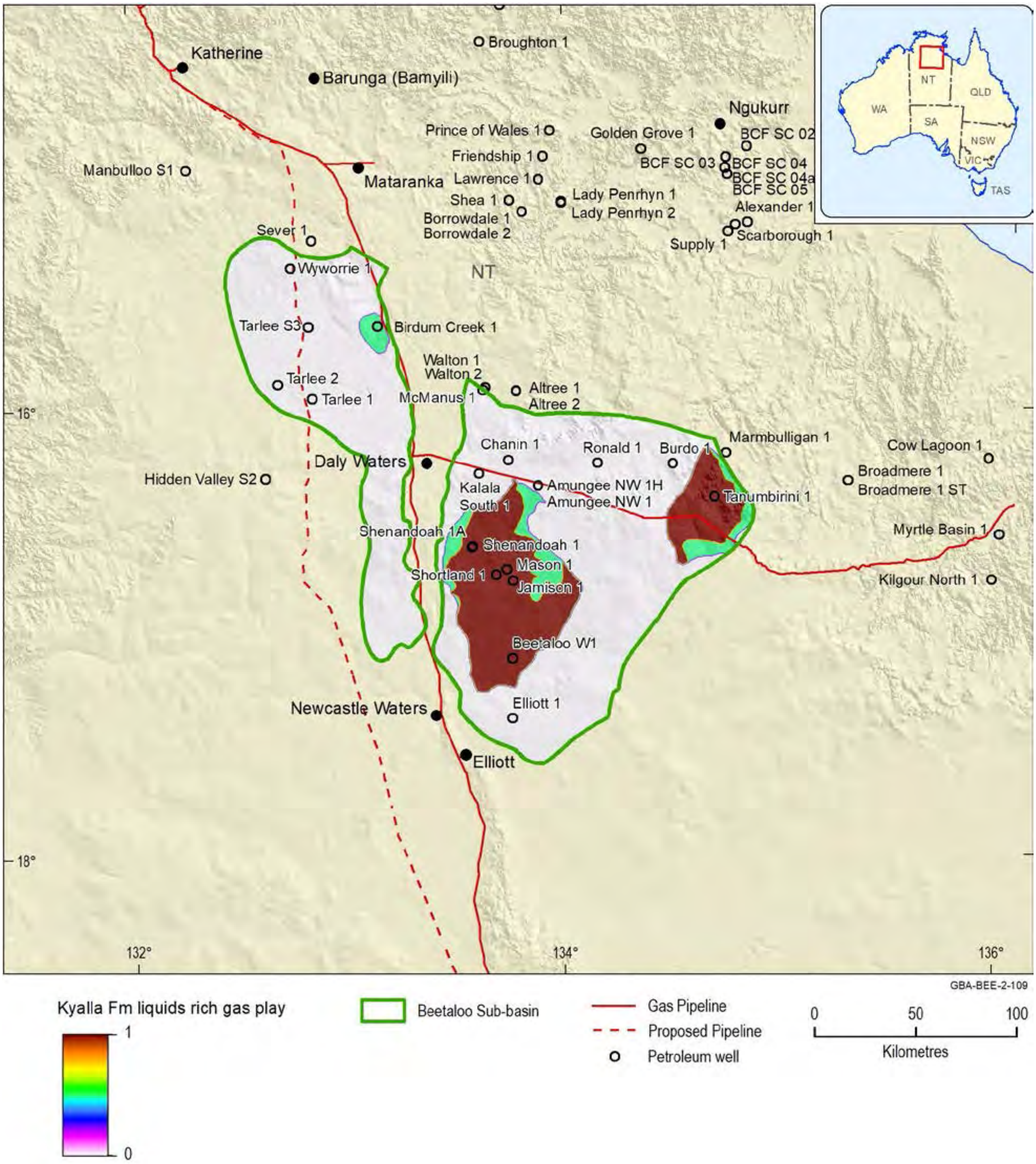

Figure 59 Play fairway map showing the variation in relative prospectivity of the Kyalla Formation shale liquids-rich gas play across the Beetaloo Sub-basin

Data: Geological and Bioregional Assessment Program (2019c)
Element: GBA-BEE-2-109

5.3.3 Hayfield sandstone member

The Hayfield sandstone member liquids play covers a much smaller area than the Kyalla Formation and Amungee Member shale gas plays and is located over the central part of the eastern Beetaloo Sub-basin (Figure 60). This extent is derived from Côté et al. (2018), as there are insufficient public domain data to assess the play distribution.

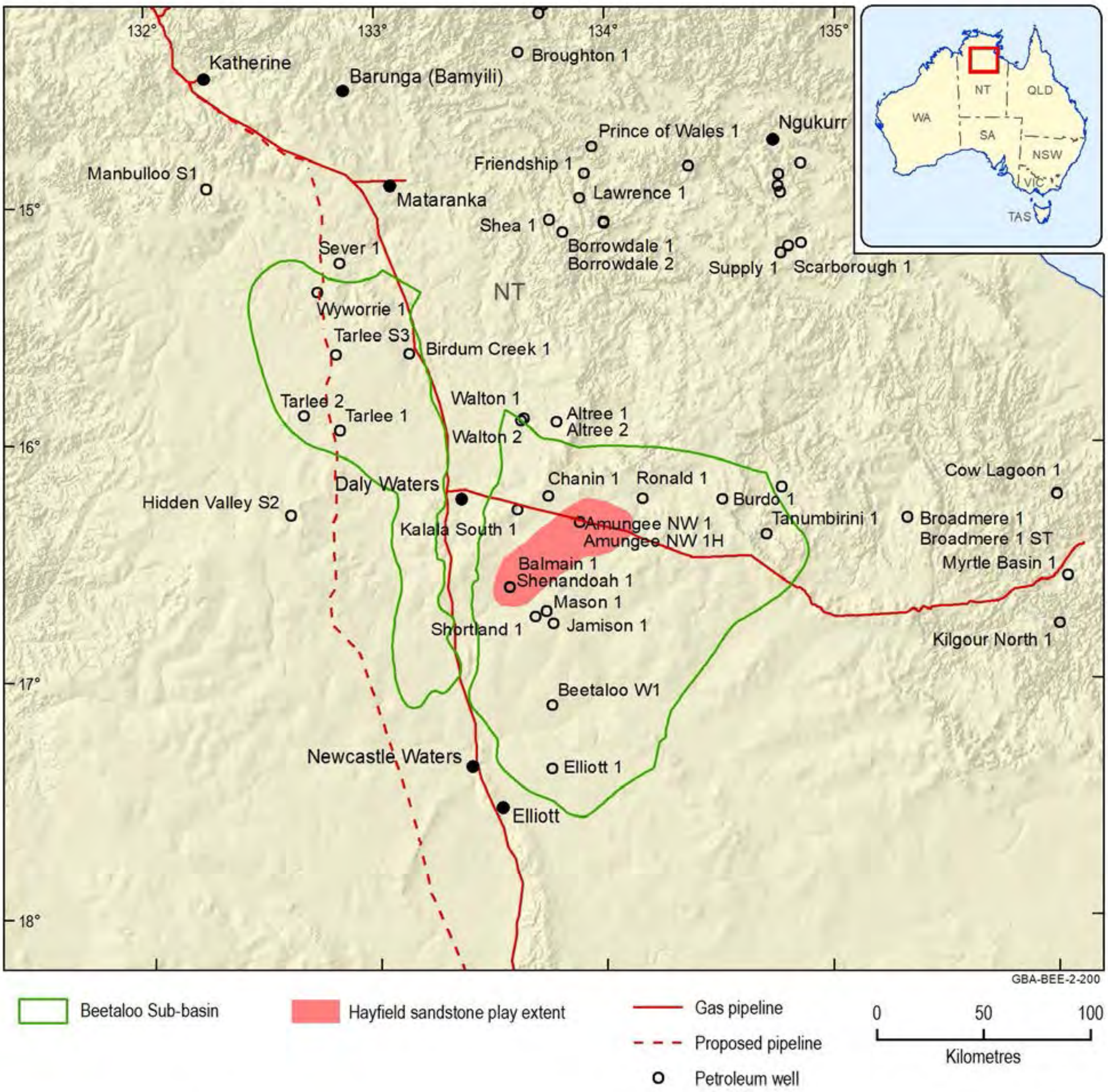

Figure 60 Hayfield sandstone member play extent

Source: Côté et al. (2018)
Element: GBA-BEE-2-200

6 Conclusions

6.1 Key findings

This appendix presents a review of the petroleum prospectivity of the Beetaloo Sub-basin, along with the characterisation and analysis of petroleum plays in the Beetaloo GBA region likely to be targeted for development in a five to ten year time frame. These plays include dry and liquids-rich gas plays within the Velkerri Formation and liquids-rich gas in the Kyalla Formation of the Beetaloo Sub-basin, and liquids-rich gas and oil/condensate in the Hayfield sandstone member in the overlying Neoproterozoic units.

Play fairway analysis has been used to map the relative prospectivity of these play types across the Beetaloo Sub-basin area. Criteria used to map the play fairways are limited to depth, thermal maturity (based on current depth below the surface) and net thickness of organically rich shale.

Key results of the play fairway mapping are as follows:

- The Amungee Member has a high relative prospectivity for dry gas plays across most of the eastern sub-basin, as well as the central part of the western sub-basin.
- The Amungee Member has a high relative prospectivity for liquids-rich gas play along the northern and south-eastern limits of the eastern sub-basin. The area of high relative prospectivity for liquids-rich gas also extends around the shallower regions of the western sub-basin.
- Source rock maturity is the main controlling factor on the Amungee Member play extent in the eastern sub-basin, while net source rock thickness and formation depth restrict play extent in the west.
- The Kyalla Formation has a high relative prospectivity for liquids-rich gas play in the central and western parts of the eastern sub-basin.
- Formation depth and maturity are the main controlling factors on the extent of the Kyalla Formation liquids-rich gas play.
- The Hayfield sandstone liquids play covers a much smaller area than the Kyalla and Amungee shale plays and is located over the central part of the eastern Beetaloo Sub-basin. This is extent is derived from Côté et al. (2018), as there are insufficient public domain data to assess this independently.
- There is also significant oil and condensate potential in the Kyalla Formation, however, successful development of this is dependent on further advancements in enhanced oil recovery technology.

The extents of the petroleum plays defined here inform where those plays are most likely to be located with respect to overlying assets, which in turn aids assessment of potential connectivity to overlying surface water – groundwater systems and associated assets.

6.2 Gaps, limitations and opportunities

A number of limitations and assumptions were identified as part of the Beetaloo GBA region petroleum prospectivity assessment. Data and knowledge gaps, along with potential opportunities for further work, are outlined below.

Only a limited number of petroleum exploration wells have been drilled within the Beetaloo Sub-basin and currently published contingent resource estimate is based on extended production testing for only one well. Future application of new well data, including full wireline log suites as well as geochemical, petrophysical and gas content properties will increase confidence in the petroleum prospectivity of the region. In addition, very few wells penetrate the stratigraphy beneath the Roper Group. Additional drilling would be required before the petroleum prospectivity of the older stratigraphy, equivalent in age to the Isa Superbasin, could be assessed.

Fault systems over the assessment area are relatively complex and somewhat poorly understood three-dimensional structures with multiple phases of reactivation and fluid flow. The role of faults in either locally enhancing shale gas prospectivity through generating zones of enhanced fracture permeability or reducing permeability through producing conduits for mineralisation of organic-rich shales is unknown and not incorporated into the assessment. Acquisition of three-dimensional seismic data within the identified play fairways by industry would help to better understand the enhancing or constraining nature of the faults on prospectivity. In addition, three-dimensional seismic imaging of fault systems may help to identify if there are areas where these structures form potential leakage pathways into groundwater aquifers.

The play fairway analysis was undertaken based on the regional-scale geological conceptualisation detailed in the geology technical appendix (Orr et al., 2020). Results identify areas where further data acquisition and geological modelling could be undertaken. However, this regional analysis is not suitable for individual play or prospect-scale evaluations. Due to local geological variations, which may not be captured by the regional-scale input datasets, not all the areas identified as a having a high relative likelihood of play fairway presence will result in oil or gas discoveries. The maps of source rock total organic content and maturity could be improved with a more detailed burial and thermal history modelling study, incorporating spatial variations of uplift and erosion and facies changes.

Only limited regional stress information is available to frame the Beetaloo Sub-basin within the Australian continent. Acquisition of new data appropriate for assessing the regional stress regime would allow for both a more detailed understanding of in-situ stresses within the Beetaloo Sub-basin and as a broader region within the Australian continent. Acquisition of suitable wireline data and laboratory and field tests as suggested above would allow for a formation by formation assessment of stress magnitudes and, hence, increase the quality of fracture growth and propagation models to assist in understanding natural fracture barriers within the subsurface.

Only limited public domain pore pressure data are available. As a significant component in planning the development of hydrocarbon systems, it is essential to understand formation pressures within the potential plays. This is a limiting factor to understanding the prospectivity of shale gas plays in the Beetaloo Sub-basin.

The play fairway maps use simple geological criteria to assess where shale gas intervals are likely to occur. Limitations to the economic viability or accessibility of these resources are not considered. For example, a maximum depth for economic exploration of shale gas resources has not been used in the selection criteria, as this will vary with time depending on exploration and development technology and energy prices.

Due to the large capital expenditure required to extract these resources, if and how a petroleum play is developed is entirely dependent on its economic viability. Therefore, to inform future development scenarios, associated hazards and impacts, it is essential to consider development of each play in the context of likely economic outcomes. While the prospectivity maps presented in this report inform where the plays are most likely to be located with respect to overlying assets, they do not provide any economic context and hence are insufficient to effectively inform future development scenarios alone. To place this work in an economic context, at a minimum the following additional work is required:

- Resource assessments to estimate of total volume of gas-in-place for priority play types, based on the geological understanding of the plays outlined in this report;
- Estimation of the proportion of gas-in-place that is technically recoverable based on and;
- Economic analysis to understand what would be economic to produce, based on market conditions.

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Glossary

The register of terms and definitions used in the Geological and Bioregional Assessment Program is available online at https://w3id.org/gba/glossary (note that terms and definitions are respectively listed under the 'Name' and 'Description' columns in this register). This register is a list of terms, which are the preferred descriptors for concepts. Other properties are included for each term, including licence information, source of definition and date of approval. Semantic relationships (such as hierarchical relationships) are formalised for some terms, as well as linkages to other terms in related vocabularies. Many of the definitions for these terms have been sourced from external glossaries – several from international sources; spelling variations have been preserved to maintain authenticity of the source.

2C: best estimate of contingent resources

accumulation: in petroleum geosciences, an ‘accumulation’ is referred to as an individual body of moveable petroleum

activity: for the purposes of Impact Modes and Effects Analysis (IMEA), a planned event associated with unconventional gas resource development. For example, activities during the exploration life-cycle stage include drilling and coring, ground-based geophysics and surface core testing. Activities are grouped into ten major activities, which can occur at different life-cycle stages.

adsorbed gas: the gas accumulated on the surface of a solid material, such as a grain of a reservoir rock, or more particularly the organic particles in a shale reservoir. Measurement of adsorbed gas and free gas, which is the gas contained in pore spaces, allows calculation of gas in place in a reservoir.

anticline: an arch-shaped fold in rock in which rock layers are upwardly convex. The oldest rock layers form the core of the fold and, outward from the core, progressively younger rocks occur.

API gravity: a specific gravity scale developed by the American Petroleum Institute (API) for measuring the relative density of various petroleum liquids, expressed in degrees

aquifer: rock or sediment in a formation, group of formations, or part of a formation that is saturated and sufficiently permeable to transmit quantities of water to bores and springs

aquitard: a saturated geological unit that is less permeable than an aquifer, and incapable of transmitting useful quantities of water. Aquitards commonly form a confining layer over an artesian aquifer.

artesian aquifer: an aquifer that has enough natural pressure to allow water in a bore to rise to the ground surface

as-received: a sample (e.g. rock, gas, water) as it is received by the laboratory analysing the sample asset: an entity that has value to the community and, for the purposes of geological and bioregional assessments, is associated with a GBA region. An asset is a store of value and may be managed and/or used to maintain and/or produce further value. An asset may have many values associated with it that can be measured from a range of perspectives; for example, the values of a wetland can be measured from ecological, sociocultural and economic perspectives.

associated gas: a natural gas found in contact with or dissolved in crude oil in the reservoir. It can be further categorised as Gas-Cap Gas or Solution Gas

barrel: a standard unit of measurement for all production and sales of oil. It has a volume of 42 US gallons [0.16 m^3].

basement: the oldest rocks in an area; commonly igneous or metamorphic rocks of Precambrian or Paleozoic age that underlie other sedimentary formations. Basement generally does not contain significant oil or gas, unless it is fractured and in a position to receive these materials from sedimentary strata.

basin-centred gas: a type of tight gas that occurs in distributed basin-centred gas accumulations, where gas is hosted in low permeability reservoirs which are commonly abnormally overpressured, lack a down dip water contact and are continuously saturated with gas. This is also sometimes referred to as 'continuous' and 'pervasive' gas.

bed: in geosciences, the term 'bed' refers to a layer of sediment or sedimentary rock, or stratum. A bed is the smallest stratigraphic unit, generally a centimetre or more in thickness. To be labeled a bed, the stratum must be distinguishable from adjacent beds.

biogenic gas: hydrocarbon gases (which are overwhelmingly (greater than or equal to 99%) methane) produced as a direct consequence of bacterial activity

bore: a narrow, artificially constructed hole or cavity used to intercept, collect or store water from an aquifer, or to passively observe or collect groundwater information. Also known as a borehole or piezometer.

brittleness: a material is brittle if, when subjected to stress, it breaks without significant plastic deformation

brittleness index: brittleness index (BI) is used to calculate the ease at which a shale rock breaks. It can be estimated from the normalised Young's modulus and Poisson's ratio

burial history: the depth of a sedimentary layer versus time, usually corrected for compaction

casing: a pipe placed in a well to prevent the wall of the hole from caving in and to prevent movement of fluids from one formation to another

charge: in petroleum geoscience, a 'charge' refers to the volume of expelled petroleum available for entrapment

cleat: the vertical cleavage of coal seams. The main set of joints along which coal breaks when mined.

coal: a rock containing greater than 50 wt.% organic matter coal seam gas: coal seam gas (CSG) is a form of natural gas (generally 95% to 97% pure methane, CH_4) extracted from coal seams, typically at depths of 300 to 1000 m. Also called coal seam methane (CSM) or coalbed methane (CBM).

compression: lateral force or stress (e.g. tectonic) that tends to decrease the volume of, or shorten, a substance

conceptual model: an abstraction or simplification of reality that describes the most important components and processes of natural and/or anthropogenic systems, and their response to interactions with extrinsic activities or stressors. They provide a transparent and general representation of how complex systems work, and identify gaps or differences in understanding. They are often used as the basis for further modelling, form an important backdrop for assessment and evaluation, and typically have a key role in communication. Conceptual models may take many forms, including descriptive, influence diagrams and pictorial representations.

condensate: condensates are a portion of natural gas of such composition that are in the gaseous phase at temperature and pressure of the reservoirs, but that, when produced, are in the liquid phase at surface pressure and temperature

confined aquifer: an aquifer saturated with confining layers of low-permeability rock or sediment both above and below it. It is under pressure so that when the aquifer is penetrated by a bore, the water will rise above the top of the aquifer.

consequence: synonym of impact

context: the circumstances that form the setting for an event, statement or idea

contingent resources: those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from known accumulations but which are not currently considered to be commercially recoverable

conventional gas: conventional gas is obtained from reservoirs that largely consist of porous sandstone formations capped by impermeable rock, with the gas trapped by buoyancy. The gas can often move to the surface through the gas wells without the need to pump.

Cooper Basin: the Cooper Basin geological province is an Upper Carboniferous – Middle Triassic geological sedimentary basin that is up to 2500 m thick and occurs at depths between 1000 and 4400 m. It is overlain completely by the Eromanga and Lake Eyre basins. Most of the Cooper Basin is in south-west Queensland and north-east SA, and includes a small area of NSW at Cameron Corner. It occupies a total area of approximately 130,000 km^2, including 95,740 km^2 in Queensland, 34,310 km^2 in SA and 8 km^2 in NSW.

crude oil: the portion of petroleum that exists in the liquid phase in natural underground reservoirs and remains liquid at atmospheric conditions of pressure and temperature. Crude oil may include small amounts of non-hydrocarbons produced with the liquids.

crust: the outer part of the Earth, from the surface to the Mohorovicic discontinuity (Moho) dataset: a collection of data in files, in databases or delivered by services that comprise a related set of information. Datasets may be spatial (e.g. a shape file or geodatabase or a Web Feature Service) or aspatial (e.g. an Access database, a list of people or a model configuration file).

deep coal gas: gas in coal beds at depths usually below 2000 m are often described as 'deep coal gas'. Due to the loss of cleat connectivity and fracture permeability with depth, hydraulic fracturing is used to release the free gas held within the organic porosity and fracture system of the coal seam. As dewatering is not needed, this makes deep coal gas exploration and development similar to shale gas reservoirs.

deformation: folding, faulting, shearing, compression or extension of rocks due to the Earth's forces

depocentre: an area or site of maximum deposition; the thickest part of any specified stratigraphic unit in a depositional basin

deposition: sedimentation of any material, as in the mechanical settling of sediment from suspension in water, precipitation of mineral matter by evaporation from solution, and accumulation of organic material

depositional environment: the area in which, and physical conditions under which, sediments are deposited. This includes sediment source; depositional processes such as deposition by wind, water or ice; and location and climate, such as desert, swamp or river.

development: a phase in which newly discovered oil or gas fields are put into production by drilling and completing production wells

disconformity: see unconformity

discovered: the term applied to a petroleum accumulation/reservoir whose existence has been determined by its actual penetration by a well, which has also clearly demonstrated the existence of moveable petroleum by flow to the surface or at least some recovery of a sample of petroleum. Log and/or core data may suffice for proof of existence of moveable petroleum if an analogous reservoir is available for comparison.

dolomite: a rhombohedral carbonate mineral with the formula $CaMg(CO_3)_2$

dolostone: a carbonate sedimentary rock that contains over 50% of the mineral dolomite [$CaMg(CO_3)_2$]

dome: a type of anticline where rocks are folded into the shape of an inverted bowl. Strata in a dome dip outward and downward in all directions from a central area.

drill bit: a drilling tool that cuts through rock by a combination of crushing and shearing drill stem test: an operation on a well designed to demonstrate the existence of moveable petroleum in a reservoir by establishing flow to the surface and/or to provide an indication of the potential productivity of that reservoir. Drill stem tests (DSTs) are performed in the open hole to obtain reservoir fluid samples, static bottomhole pressure measurements, indications of productivity and short-term flow and pressure buildup tests to estimate permeability and damage extent.

drilling fluid: circulating fluid that lifts rock cuttings from the wellbore to the surface during the drilling operation. Also functions to cool down the drill bit, and is a component of well control.

dry gas: natural gas that is dominated by methane (greater than 95% by volume) with little or no condensate or liquid hydrocarbons

effect: for the purposes of Impact Modes and Effects Analysis (IMEA), a change to water or the environment, such as changes to the quantity and/or quality of surface water or groundwater, or to the availability of suitable habitat. An effect is a specific type of an impact (any change resulting from prior events).

effective porosity: the interconnected pore volume or void space in a rock that contributes to fluid flow or permeability in a reservoir. Effective porosity excludes isolated pores and pore volume occupied by water adsorbed on clay minerals or other grains. Effective porosity is typically less than total porosity.

effective water saturation: the fraction of water in the pore space corresponding to the effective porosity. It is expressed in volume/volume, percent or saturation units. Unless otherwise stated, water saturation is the fraction of formation water in the undisturbed zone. The saturation is known as the total water saturation if the pore space is the total porosity, but is called effective water saturation if the pore space is the effective porosity. If used without qualification, the term water saturation usually refers to the effective water saturation.

erosion: the wearing away of soil and rock by weathering, mass wasting, and the action of streams, glaciers, waves, wind, and underground water

exploration: the search for new hydrocarbon resources by improving geological and prospectivity understanding of an area and/or play through data acquisition, data analysis and interpretation. Exploration may include desktop studies, field mapping, seismic or other geophysical surveys, and drilling.

exploration approvals: all operational approvals under the Schedule and all environmental approvals under the Petroleum Environment Regulations granted on an exploration permit for an exploration activity

expulsion: the process of primary migration, whereby oil or gas escapes from the source rock due to increased pressure and temperature. Generally involves short distances (metres to tens of metres).

extraction: the removal of water for use from waterways or aquifers (including storages) by pumping or gravity channels. In the oil and gas industry, extraction refers to the removal of oil and gas from its reservoir rock.

facies: the characteristics of a rock unit that reflect the conditions of its depositional environment

fairway: a term used in geology to describe a regional trend along which a particular geological feature is likely to occur, such as a hydrocarbon fairway. Understanding and predicting fairways can help geologists explore for various types of resources, such as minerals, oil and gas.

fault: a fracture or zone of fractures in the Earth's crust along which rocks on one side were displaced relative to those on the other side

field: in petroleum geoscience, a 'field' refers to an accumulation, pool, or group of pools of hydrocarbons or other mineral resources in the subsurface. A hydrocarbon field consists of a reservoir with trapped hydrocarbons covered by an impermeable sealing rock, or trapped by hydrostatic pressure.

fold: a curve or bend of a formerly planar structure, such as rock strata or bedding planes, that generally results from deformation

footwall: the underlying side of a fault, below the hanging wall

formation: rock layers that have common physical characteristics (lithology) deposited during a specific period of geological time

formation fluid: any fluid within the pores of the rock. It may be water, oil, gas or a mixture. Formation water in shallow aquifers can be fresh. Formation water in deeper layers of rock is typically saline.

formation water: water that occurs naturally in sedimentary rocks

fracking: see hydraulic fracturing

fracture: a crack or surface of breakage within rock not related to foliation or cleavage in metamorphic rock along which there has been no movement. A fracture along which there has been displacement is a fault. When walls of a fracture have moved only normal to each other, the fracture is called a joint. Fractures can enhance permeability of rocks greatly by connecting pores together, and for that reason, fractures are induced mechanically in some reservoirs in order to boost hydrocarbon flow. Fractures may also be referred to as natural fractures to distinguish them from fractures induced as part of a reservoir stimulation or drilling operation. In some shale reservoirs, natural fractures improve production by enhancing effective permeability. In other cases, natural fractures can complicate reservoir stimulation.

free gas: the gaseous phase present in a reservoir or other contained area. Gas may be found either dissolved in reservoir fluids or as free gas that tends to form a gas cap beneath the top seal on the reservoir trap. Both free gas and dissolved gas play important roles in the reservoir-drive mechanism.

gas cap: part of a petroleum reservoir that contains free gas

gas hydrate: naturally occurring 'ice-like' combinations of natural gas and water that have the potential to provide an immense resource of natural gas from the world's oceans and polar regions. Gas hydrates are known to be widespread in permafrost regions and beneath the sea in sediments of outer continental margins. It is generally accepted that the volume of natural gas contained in the world's gas hydrate accumulations greatly exceeds that of known gas reserves.

gas-in-place: the total quantity of gas that is estimated to exist originally in naturally occurring reservoirs

gas-oil ratio: the ratio of produced gas to produced oil

gas saturation: the relative amount of gas in the pores of a rock, usually as a percentage of volume

geological architecture: the structural style and features of a geological province, like a sedimentary basin

geological formation: stratigraphic unit with distinct rock types, which is able to mapped at surface or in the subsurface, and which formed at a specific period of geological time

groundwater: water occurring naturally below ground level (whether stored in or flowing through aquifers or within low-permeability aquitards), or water occurring at a place below ground that has been pumped, diverted or released to that place for storage there. This does not include water held in underground tanks, pipes or other works.

groundwater system: see water system

hanging wall: the overlying side of a fault, above the footwall

hazard: an event, or chain of events, that might result in an effect (change in the quality and/or quantity of surface water or groundwater)

horizontal drilling: drilling of a well in a horizontal or near-horizontal plane, usually within the target hydrocarbon-bearing formation. Requires the use of directional drilling techniques that allow the deviation of the well on to a desired trajectory.

hydraulic fracturing: also known as 'fracking', 'fraccing' or 'fracture simulation'. This is a process by which geological formations bearing hydrocarbons (oil and gas) are 'stimulated' to increase the flow of hydrocarbons and other fluids towards the well. In most cases, hydraulic fracturing is undertaken where the permeability of the formation is initially insufficient to support sustained flow of gas. The process involves the injection of fluids, proppant and additives under high pressure into a geological formation to create a conductive fracture. The fracture extends from the well into the production interval, creating a pathway through which oil or gas is transported to the well.

hydraulic fracturing fluid: the fluid injected into a well for hydraulic fracturing. Consists of a primary carrier fluid (usually water or a gel), a proppant such as sand and chemicals to modify the fluid properties.

hydrocarbon show: a surface observation of hydrocarbons, usually observed as fluorescent liquid on cuttings when viewed with an ultraviolet or black light (oil show) or increased gas readings from the mud logger's gas-detection equipment (gas show)

hydrocarbons: various organic compounds composed of hydrogen and carbon atoms that can exist as solids, liquids or gases. Sometimes this term is used loosely to refer to petroleum.

hydrogen index: the amount of hydrogen relative to the amount of organic carbon present in kerogen (organic matter). Gross trends of hydrogen indices (HIs) can be used as an indication of maturity.

hydrogeology: the study of groundwater, including flow in aquifers, groundwater resource evaluation, and the chemistry of interactions between water and rock

hydrostatic pressure: equal pressure in all direction, equivalent to the pressure which is exerted on a portion of a column of water as a result of the weight of the fluid above it

immature: a hydrocarbon source rock that has not fully entered optimal conditions for generation of hydrocarbons

impact: the difference between what could happen as a result of activities and processes associated with extractive industries, such as shale, tight and deep coal gas development, and what would happen without them. Impacts may be changes that occur to the natural environment, community or economy. Impacts can be a direct or indirect result of activities, or a cumulative result of multiple activities or processes.

impact cause: an activity (or aspect of an activity) that initiates a hazardous chain of events

impact mode: the manner in which a hazardous chain of events (initiated by an impact cause) could result in an effect (change in the quality and/or quantity of surface water or groundwater). There might be multiple impact modes for each activity or chain of events.

Impact Modes and Effects Analysis: a systematic hazard identification and prioritisation technique based on Failure Modes and Effects Analysis

injection: the forcing or pumping of substances into a porous and permeable subsurface rock formation. Examples of injected substances can include either gases or liquids.

intrusion: the process of emplacement of magma into pre-existing rock

kerogen: insoluble (in organic solvents) particulate organic matter preserved in sedimentary rocks that consists of various macerals originating from components of plants, animals, and bacteria. Kerogen can be isolated from ground rock by extracting bitumen with solvents and removing most of the rock matrix with hydrochloric and hydrofluoric acids.

kerogen type: kerogens are classified into five types: I, II, IIS, III, and IV

kinetics: study of the rates of biological, physical and chemical changes known accumulation: the term accumulation is used to identify an individual body of moveable petroleum. The key requirement to consider an accumulation as known, and hence contain reserves or contingent resources, is that each accumulation/reservoir must have been penetrated by a well. In general, the well must have clearly demonstrated the existence of moveable petroleum in that reservoir by flow to surface or at least some recovery of a sample of petroleum from the well. However, where log and/or core data exist, this may suffice, provided there is a good analogy to a nearby and geologically comparable known accumulation.

life-cycle stage: one of five stages of operations in unconventional gas resource development considered as part of the Impact Modes and Effects Analysis (IMEA). These are exploration, appraisal, development, production, and rehabilitation. Each life-cycle stage is further divided into major activities, which are further divided into activities.

light oil: crude oil that has 35 to 45 ° API gravity

likelihood: probability that something might happen

lithology: the description of rocks, especially in hand specimen and in outcrop, on the basis of characteristics such as colour, mineralogic composition and grain size

lithosphere: the outermost shell of the solid Earth, consisting of approximately 100 km of crust and upper mantle

mantle: the region of the Earth composed mainly of solid silicate rock that extends from the base of the crust (Moho) to the core–mantle boundary at a depth of approximately 2900 km

material: pertinent or relevant

mature: a hydrocarbon source rock that has started generating hydrocarbons

metamorphic rock : a rock formed from pre-existing rock due to high temperature and pressure in the Earth’s crust, but without complete melting

methane: a colourless, odourless gas, the simplest parafin hydrocarbon, formula CH_4. It is the principal constituent of natural gas and is also found associated with crude oil. Methane is a greenhouse gas in the atmosphere because it absorbs long-wavelength radiation from the Earth's surface.

migration: the process whereby fluids and gases move through rocks. In petroleum geoscience, 'migration' refers to when petroleum moves from source rocks toward reservoirs or seep sites. Primary migration consists of movement of petroleum to exit the source rock. Secondary migration occurs when oil and gas move along a carrier bed from the source to the reservoir or seep. Tertiary migration is where oil and gas move from one trap to another or to a seep.

Moho: the Mohorivicic discontinuity (seismic reflector) at the base of the crust

mud gas: gases in the drilling mud that originate from formations in a well

mudstone: a general term for sedimentary rock made up of clay-sized particles, typically massive and not fissile natural gas: the portion of petroleum that exists either in the gaseous phase or is in solution in crude oil in natural underground reservoirs, and which is gaseous at atmospheric conditions of pressure and temperature. Natural gas may include amounts of non-hydrocarbons.

net thickness: the accumulated thickness of a certain rock type of a specified quality which is found within a specific interval of formation

normal fault: a fault in which the hanging wall appears to have moved downward relative to the footwall, normally occurring in areas of crustal tension

oil: a mixture of liquid hydrocarbons and other compounds of different molecular weights. Gas is often found in association with oil. Also see petroleum.

oil-in-place: the total quantity of oil that is estimated to exist originally in naturally occurring reservoirs

oil-prone: organic matter that generates significant quantities of oil at optimal maturity

oil shale: organic-rich shale that contains significant amounts of oil-prone kerogen and liberates crude oil upon heating, as might occur during laboratory pyrolysis or commercial retorting

oil window: the maturity range in which oil is generated from oil-prone organic matter

operator: the company or individual responsible for managing an exploration, development or production operation

organic matter: biogenic, carbonaceous materials. Organic matter preserved in rocks includes kerogen, bitumen, oil and gas. Different types of organic matter can have different oil-generative potential.

outcrop: a body of rock exposed at the surface of the Earth

overpressure: occurs when the pore pressure is higher than the hydrostatic pressure, caused by an increase in the amount of fluid or gas in the rock, or changes to the rock that reduce the amount of pore space. If the fluid cannot escape, the result is an increase in pore pressure. Overpressure can only occur where there are impermeable layers preventing the vertical flow of water, otherwise the water would flow upwards to equalise back to hydrostatic pressure.

P10: in terms of petroleum resource classification, P10 indicates a 10% probability that this volume of oil or gas will be found or exceeded

P50: in terms of petroleum resource classification, P50 indicates a 50% probability that this volume of oil and gas will be found or exceeded

P90: in terms of petroleum resource classifications, P90 indicates a 90% probability that at least this much oil or gas can be found in place

palaeoenvironment: an ancient depositional environment percentile: a specific type of quantile where the range of a distribution or set of runs is divided into 100 contiguous intervals, each with probability 0.01. An individual percentile may be used to indicate the value below which a given percentage or proportion of observations in a group of observations fall. For example, the 95th percentile is the value below which 95% of the observations may be found.

permeability: the measure of the ability of a rock, soil or sediment to yield or transmit a fluid. The magnitude of permeability depends largely on the porosity and the interconnectivity of pores and spaces in the ground.

petroleum: a naturally occurring mixture consisting predominantly of hydrocarbons in the gaseous, liquid or solid phase

petroleum system: the genetic relationship between a pod of source rock that is actively producing hydrocarbon, and the resulting oil and gas accumulations. It includes all the essential elements and processes needed for oil and gas accumulations to exist. These include the source, reservoir, seal, and overburden rocks, the trap formation, and the hydrocarbon generation, migration and accumulation processes. All essential elements and processes must occur in the appropriate time and space in order for petroleum to accumulate.

play: a conceptual model for a style of hydrocarbon accumulation used during exploration to develop prospects in a basin, region or trend and used by development personnel to continue exploiting a given trend. A play (or group of interrelated plays) generally occurs in a single petroleum system.

play fairway analysis: sometimes referred to as play fairway mapping, play fairway analysis is used to identify areas where a specific play is likely to be successful, and where additional work on a finer scale is warranted in order to further develop an understanding of a prospect. The phrasing 'fairway' is used as prospective areas on the map are often visually similar to fairways on a golf course. Play fairway maps are created at a regional scale, often tens to hundreds of kilometres in scale, from multiple input sources that vary based on what information is available and relevant based on the requirements of the creator.

porosity: the proportion of the volume of rock consisting of pores, usually expressed as a percentage of the total rock or soil mass

producing: a well or rock formation from which oil, gas or water is produced

production: in petroleum resource assessments, 'production' refers to the cumulative quantity of oil and natural gas that has been recovered already (by a specified date). This is primarily output from operations that has already been produced.

production well: a well used to remove oil or gas from a reservoir

proppant: a component of the hydraulic fracturing fluid system comprising sand, ceramics or other granular material that 'prop' open fractures to prevent them from closing when the injection is stopped prospective resources: estimated volumes associated with undiscovered accumulations. These represent quantities of petroleum which are estimated, as of a given date, to be potentially recoverable on the basis of indirect evidence but have not yet been drilled. This class represents a higher risk than contingent resources since the risk of discovery is also added.

prospectivity assessment: the assessment of an area to determine the likelihood of discovering a given resource (e.g. oil, gas, groundwater) by analysing the spatial patterns of foundation datasets. The key objective is to identify areas of increased likelihood of discovering previously unrecognised potential. Sometimes referred to as 'chance of success' or 'common risk segment' analysis.

prospectivity confidence: the relative certainty of hydrocarbons being found (on a scale of zero to one) based on prospectivity mapping

prospectivity mapping: mapping or visualisation component of a prospectivity analysis which is used to determine the likelihood of discovering a given resource within a chosen area. See prospectivity assessment.

reserves: quantities of petroleum anticipated to be commercially recoverable in known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial and remaining (as of the evaluation date) based on the development project(s) applied.

reserves, probable: the sum of proved reserves plus probable reserves. Those unproved reserves, which analysis of geological and engineering data suggests are more likely than not (greater than 50% probability) to be recoverable.

reservoir: a subsurface body of rock having sufficient porosity and permeability to store and transmit fluids and gases. Sedimentary rocks are the most common reservoir rocks because they have more porosity than most igneous and metamorphic rocks and form under temperature conditions at which hydrocarbons can be preserved. A reservoir is a critical component of a complete petroleum system.

reservoir rock: any porous and permeable rock that contains liquids or gases (e.g. petroleum, water, CO_2), such as porous sandstone, vuggy carbonate and fractured shale

reverse fault: a fault in which the hanging wall appears to have moved upward relative to the footwall. Common in compressional regimes.

ridge: a narrow, linear geological feature that forms a continuous elevated crest for some distance (e.g. a chain of hills or mountains or a watershed)

risk: the effect of uncertainty on objectives (ASNZ ISO 3100). This involves assessing the potential consequences and likelihood of impacts to environmental and human values that may stem from an action, under the uncertainty caused by variability and incomplete knowledge of the system of interest.

Rock-Eval pyrolysis: a commercially available pyrolysis instrument used as a rapid screening tool in evaluating the quantity, quality and thermal maturity of rock samples sandstone: a sedimentary rock composed of sand-sized particles (measuring 0.05–2.0 mm in diameter), typically quartz

seal: a relatively impermeable rock, commonly shale, anhydrite or salt, that forms a barrier or cap above and around reservoir rock such that fluids cannot migrate beyond the reservoir. A seal is a critical component of a complete petroleum system.

sediment: various materials deposited by water, wind or glacial ice, or by precipitation from water by chemical or biological action (e.g. clay, sand, carbonate)

sedimentary rock: a rock formed by lithification of sediment transported or precipitated at the Earth's surface and accumulated in layers. These rocks can contain fragments of older rock transported and deposited by water, air or ice, chemical rocks formed by precipitation from solution, and remains of plants and animals.

sedimentation: the process of deposition and accumulation of sediment (unconsolidated materials) in layers

seismic survey: a method for imaging the subsurface using controlled seismic energy sources and receivers at the surface. Measures the reflection and refraction of seismic energy as it travels through rock.

shale: a fine-grained sedimentary rock formed by lithification of mud that is fissile or fractures easily along bedding planes and is dominated by clay-sized particles

shale gas: generally extracted from a clay-rich sedimentary rock, which has naturally low permeability. The gas it contains is either adsorbed or in a free state in the pores of the rock.

shear: a frictional force that tends to cause contiguous parts of a body to slide relative to each other in a direction parallel to their plane of contact

sill: a small body of intrusive igneous rock injected between layers of sedimentary rock

siltstone: a sedimentary rock composed of silt-sized particles (0.004 to 0.063 mm in diameter)

source rock: a rock rich in organic matter which, if heated sufficiently, will generate oil or gas. Typical source rocks, usually shales or limestones, contain about 1% organic matter and at least 0.5% total organic carbon (TOC), although a rich source rock might have as much as 10% organic matter. Rocks of marine origin tend to be oil-prone, whereas terrestrial source rocks (such as coal) tend to be gas-prone. Preservation of organic matter without degradation is critical to creating a good source rock, and necessary for a complete petroleum system. Under the right conditions, source rocks may also be reservoir rocks, as in the case of shale gas reservoirs.

spring: a naturally occurring discharge of groundwater flowing out of the ground, often forming a small stream or pool of water. Typically, it represents the point at which the watertable intersects ground level.

stratigraphy: the study of the history, composition, relative ages and distribution of stratified rock strata, and its interpretation to reveal Earth's history. However, it has gained broader usage to refer to the sequential order and description of rocks in a region.

stress: the force applied to a body that can result in deformation, or strain, usually described in terms of magnitude per unit of area, or intensity

stressor: chemical or biological agent, environmental condition or external stimulus that might contribute to an impact mode

strike-slip fault: a type of fault whose surface is typically vertical or nearly so. The motion along a strike-slip fault is parallel to the strike of the fault surface, and the fault blocks move sideways past each other. A strike-slip fault in which the block across the fault moves to the right is described as a dextral strike-slip fault. If it moves left, the relative motion is described as sinistral.

structure: a geological feature produced by deformation of the Earth's crust, such as a fold or a fault; a feature within a rock, such as a fracture or bedding surface; or, more generally, the spatial arrangement of rocks

subsidence: the sudden sinking or gradual downward settling of the Earth's surface with little or no horizontal motion. The movement is not restricted in rate, magnitude, or area involved.

surface water: water that flows over land and in watercourses or artificial channels and can be captured, stored and supplemented from dams and reservoirs

tectonic stress regime: defined by the relative orientations and magnitude of three principal stresses that are orthogonal (at right angles to each other), namely a maximum (σ1), minimum, (σ3) and intermediate (σ2). These are referred to as the maximum (σH) and minimum (σh) horizontal stresses and are usually expressed in terms of stress gradients at a given depth (e.g. MPa/km or psi/ft).

tectonics: the structural behaviour of the Earth's crust

thermal maturity: the degree of heating of a source rock in the process of transforming kerogen (derived from organic matter) into hydrocarbon. Thermal maturity is commonly evaluated by measuring vitrinite reflectance or by pyrolysis.

tight gas: tight gas is trapped in reservoirs characterised by very low porosity and permeability. The rock pores that contain the gas are minuscule, and the interconnections between them are so limited that the gas can only migrate through it with great difficulty.

total organic carbon: the quantity of organic matter (kerogen and bitumen) is expressed in terms of the total organic carbon (TOC) content in mass per cent. The TOC value is the most basic measurement for determining the ability of sedimentary rocks to generate and expel hydrocarbons.

total porosity: total porosity is the total void space in the rock whether or not it contributes to fluid flow (i.e.the total pore volume per unit volume of rock). It is measured in volume/volume, percent or porosity units. The total porosity is the total void space and as such includes isolated pores and the space occupied by clay-bound water. It is the porosity measured by core analysis techniques that involve disaggregating the sample. It is also the porosity measured by many log measurements, including density, neutron porosity and nuclear magnetic resonance logs.

transformation ratio: the difference between the original hydrocarbon potential of a sample before maturation and the measured hydrocarbon potential divided by the original hydrocarbon potential. Ranges from 0 to 1.0.

trap: a geologic feature that permits an accumulation of liquid or gas (e.g. natural gas, water, oil, injected CO_2) and prevents its escape. Traps may be structural (e.g. domes, anticlines), stratigraphic (pinchouts, permeability changes) or combinations of both.

Type I kerogen: in petroleum geochemistry, this refers to highly oil-prone kerogen (organic matter) showing Rock-Eval pyrolysis hydrogen indices over 600 mg hydrocarbon/ g total organic carbon (TOC) when thermally immature. Contains algal and bacterial input dominated by amorphous liptinite macerals. Common in, but not restricted to, lacustrine settings.

Type II kerogen: in petroleum geochemistry, this refers to oil-prone kerogen (organic matter) showing Rock-Eval pyrolysis hydrogen indices in the range 400 to 600 mg hydrocarbon/ g total organic carbon (TOC) when thermally immature. Contains algal and bacterial organic matter dominated by liptinite macerals, such as exinite and sporinite. Common in, but not restricted to, marine settings.

unconfined aquifer: an aquifer whose upper water surface (watertable) is at atmospheric pressure and does not have a confining layer of low-permeability rock or sediment above it

unconformity: a surface of erosion between rock bodies that represents a significant hiatus or gap in the stratigraphic succession. Some kinds of unconformities are (a) angular unconformity – an unconformity in which the bedding planes above and below the unconformity are at an angle to each other; and (b) disconformity – an unconformity in which the bedding planes above and below the stratigraphic break are essentially parallel.

unconventional gas: unconventional gas is generally produced from complex geological systems that prevent or significantly limit the migration of gas and require innovative technological solutions for extraction. There are numerous types of unconventional gas such as coal seam gas, deep coal gas, shale gas and tight gas.

vitrinite: one of the primary components of coal and most sedimentary kerogen. Vitrinite is a type of maceral, where 'macerals' are organic components of coal analogous to the 'minerals' of rocks. It is derived from the cell-wall material or woody tissue of plants.

vitrinite reflectance: a maturation parameter for determining organic matter in fine-grained rocks

volatile oil: type of crude oil that contains a significant portion of dissolved gasses and typically is lower viscosity than other types of crude oil. When produced, dissolved gases separate from the liquid and, hence, volatile oil reservoirs can produce mainly gas with a relatively low liquid content.

water saturation: the fraction of water in a given pore space. It is expressed in volume/volume, percent or saturation units. Unless otherwise stated, water saturation is the fraction of formation water in the undisturbed zone. The saturation is known as the total water saturation if the pore space is the total porosity, but is known as effective water saturation if the pore space is the effective porosity. If used without qualification, the term usually refers to the effective water saturation.

water system: a system that is hydrologically connected and described at the level desired for management purposes (e.g. subcatchment, catchment, basin or drainage division, or groundwater management unit, subaquifer, aquifer, groundwater basin)

watertable: the upper surface of a body of groundwater occurring in an unconfined aquifer. At the watertable, pore water pressure equals atmospheric pressure.

weathering: the breakdown of rocks and other materials at the Earth's surface caused by mechanical action and reactions with air, water and organisms. Weathering of seep oils or improperly sealed oil samples by exposure to air results in evaporative loss of light hydrocarbons.

well: typically a narrow diameter hole drilled into the earth for the purposes of exploring, evaluating, injecting or recovering various natural resources, such as hydrocarbons (oil and gas), water or carbon dioxide. Wells are sometimes known as a 'wellbore'.

well barrier: envelope of one or several dependent barrier elements (including casing, cement, and any other downhole or surface sealing components) that prevent fluids from flowing unintentionally between a bore or a well and geological formations, between geological formations or to the surface.

well integrity: maintaining full control of fluids (or gases) within a well at all times by employing and maintaining one or more well barriers to prevent unintended fluid (gas or liquid) movement between formations with different pressure regimes, or loss of containment to the environment

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