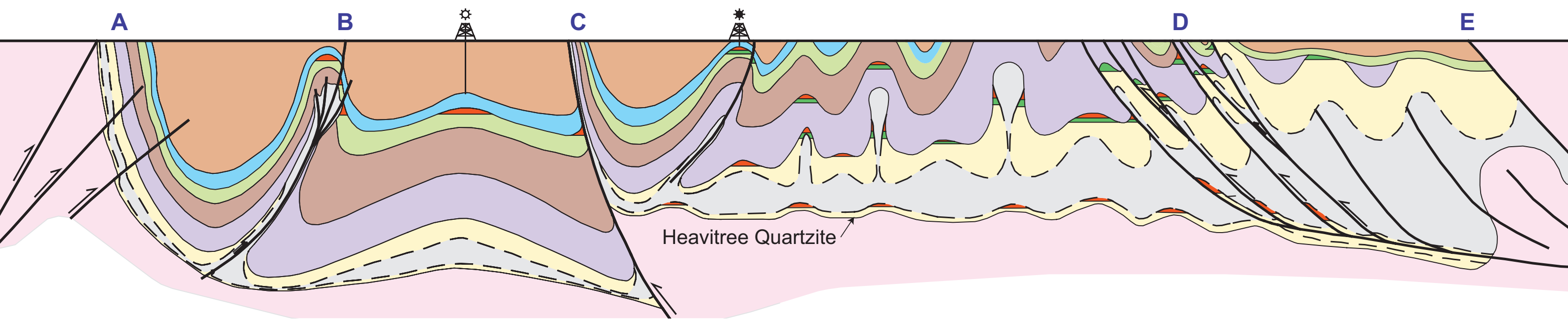
Overview of known conventional and unconventional petroleum potential in the Northern Territory

Information brief for the Scientific Inquiry into Hydraulic Fracturing in the Northern Territory



Northern Territory Geological Survey

Updated version May 2017

NORTHERN TERRITORY GOVERNMENT

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INTRODUCTION

The Northern Territory has over thirty years of continuous oil and gas production, with all production to date sourced from conventional reservoirs in the Amadeus Basin. Despite this long history of production, values of total historical production in the Territory are relatively modest, with around 400 Bcf (billion cubic feet) of gas and 17 mmbbl (million barrels) of oil produced. Current levels of production are around 3.7 Bcf of gas and 0.28 mmbbl oil per year.

Many of the Territory's petroleum-bearing basins remain very underexplored by Australian and global standards; as a result, the level of geological knowledge of the basins is highly variable. The Amadeus Basin, south of Alice Springs, has seen the highest levels of exploration, but most of this exploration has been focussed near the producing fields in the northern part of the basin, with large areas elsewhere in the basin underexplored. The Amadeus Basin remains the most prospective basin in the Territory for conventional gas and oil accumulations, with a number of proven petroleum systems. Exploration has expanded in recent years into the southeastern part of the basin in the search for large sub-salt, helium-rich conventional gas plays.

The other basin where oil and gas exploration is relatively advanced is the Beetaloo Sub-basin of the McArthur Basin. Exploration over the past five years in the Beetaloo Sub-basin has demonstrated the existence of a substantial shale gas resource, with original gas-in-place likely to be in the order of hundreds of trillion cubic feet (Tcf). Drilling of the prospective shales of the middle Velkerri Formation has demonstrated the consistent presence of gas-saturated, quartz-rich source rocks that are mature for gas over extensive areas, and which appear to meet all of the physical and chemical parameters for a successful shale gas play. The Beetaloo Sub-basin is now at a stage of transition from early stage exploration into an appraisal and testing phase. Further drilling and testing will be required to fully define the dry and wet gas maturity windows, optimise flow rates, and demonstrate whether large scale shale gas and liquids production is economically viable. The Beetaloo Sub-basin is the subject of a separate, more detailed briefing.

The McArthur Basin extends at depth over large areas of the northern part of the Territory. A number of prospective areas for shale gas within the basin remain untested, the most notable being the Walker Fault Zone in eastern Arnhem Land. Also in the McArthur Basin, the Batten Fault Zone area near Borroloola has an active petroleum system, with defined small conventional resources and large potential shale gas resources associated with the Barney Creek Formation shale.

The onshore extension of the Bonaparte Basin, adjacent to the Western Australia border has proven petroleum potential, with a small conventional gas resource defined at Weaber. There is also relatively untested shale gas potential.

The southern Georgina Basin, northeast of Alice Springs, has twenty wells drilled within the Territory. This basin has a productive shale source rock with evidence for generation of significant hydrocarbons. Despite the presence of substantial oil and lesser gas in the basin, exploration to date has not yielded commercial flows of hydrocarbons.

In the Simpson Desert area, the Pedirka Basin is a time correlative of the petroleum-rich Cooper Basin. It has substantial Permian to Triassic coal and shale formations that have potential to generate significant conventional and unconventional petroleum plays. However, to date no substantial flows of hydrocarbons have been generated from the wells drilled in the basin.

A number of other basins in the Territory have limited geological information and have undergone little or no petroleum exploration: most notably the Wiso Basin, South Nicholson Basin and Lawn Hill Platform. A major collaboration between Geoscience Australia, NT Geological Survey (NTGS) and the Geological Survey of Queensland under the Commonwealth's *Exploring for the Future* program will lead to new seismic data and stratigraphic drilling in the South Nicholson Basin and Lawn Hill Platform in 2017–2020.

Other basins in the Northern Territory, such as the Ngalia Basin, Eromanga Basin and Arafura Basin, have some hydrocarbon potential but are not a focus of current exploration and are not discussed further in this paper.

Historical overview

The first significant petroleum exploration campaigns occurred in the Territory in the 1960s, and included the Amadeus, Georgina, Pedirka/Eromanga and Bonaparte basins; with lesser exploration in the Ngalia and Wiso basins. The first significant technical discovery in the Territory was in the Amadeus Basin in 1963, when drillhole Ooraminna-1 encountered a sub-commercial gas flow. This was followed up by the discovery in the same basin of the Mereenie oil and gas field in 1963 and Palm Valley gas field in 1964. Low oil prices hampered the development of these discoveries, and further exploration in the Amadeus and other Territory basins was greatly reduced through the 1970s.

Increased levels of exploration activity occurred in the 1980s and early 1990s, resulting in the discovery of the Dingo gas field in the Amadeus Basin (1981), Weaber gas field in the Bonaparte Basin (1982) and several other technical discoveries. Extensive exploration programs were also conducted in the Georgina, McArthur, Pedirka/Eromanga and Ngalia basins at this time. The Palm Valley and Mereenie fields were brought into production in 1983 and 1984 respectively, and remain in production.

The most recent phase of significant exploration activity commenced in the 2000s, with a steep increase in activity around 2010. This has been largely driven by the opportunity presented by developments in petroleum engineering allowing for development of unconventional resources such as shale gas and oil. Exploration since 2010 has totalled $505 million (**Table 1**), including 46 wells and more than 10 000 km of 2D seismic, with around 50% of that amount expended in exploring the shale plays of the Beetaloo Sub-basin. Most other exploration was committed to the Amadeus, Georgina and McArthur basins. Additional

Table 1. Summary of wells, seismic acquisition and actual reported expenditure on onshore exploration in the Northern Territory, 2010-2016.

Year	# of wells	2D seismic survey (line km)	Actual expenditure
2010	7	1791.84	$47,800,571
2011	3	382.09	$23,607,806
2012	4	3531.38	$26,860,680
2013	4	4181.65	$92,152,018
2014	18	0	$117,943,495
2015	6	386.11	$136,745,858
2016 *	4	0*	$60,168,662
Total	**46**	**10273**	**$505,279,090**

*1300 km 2D seismic by Santos in the Amadeus basin commenced November 2016

but limited exploration has also occurred in the Pedirka and Bonaparte basins. This phase of development has also included the discovery and short-term development of the Surprise oil field, and the development of the Dingo gas field, both in the Amadeus Basin.

Figure 1 shows the distribution of known prospective areas for oil and gas in the Territory, **Figure 2** shows wells, seismic lines and producing fields in the Territory, and **Figure 3** shows existing granted tenure relative the geological basins in the Territory.

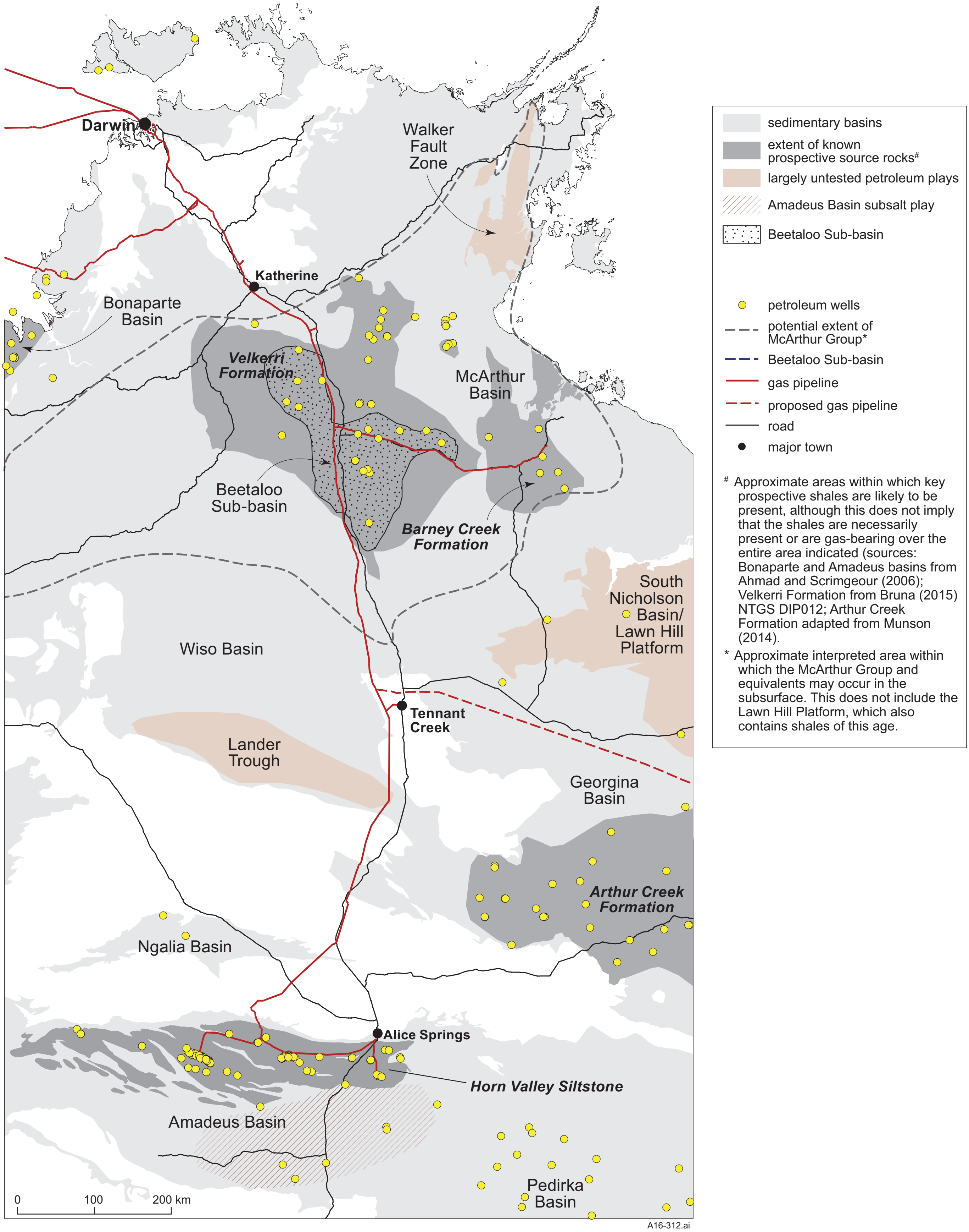


Figure 1. Distribution of known prospective areas for oil and gas in the Northern Territory.

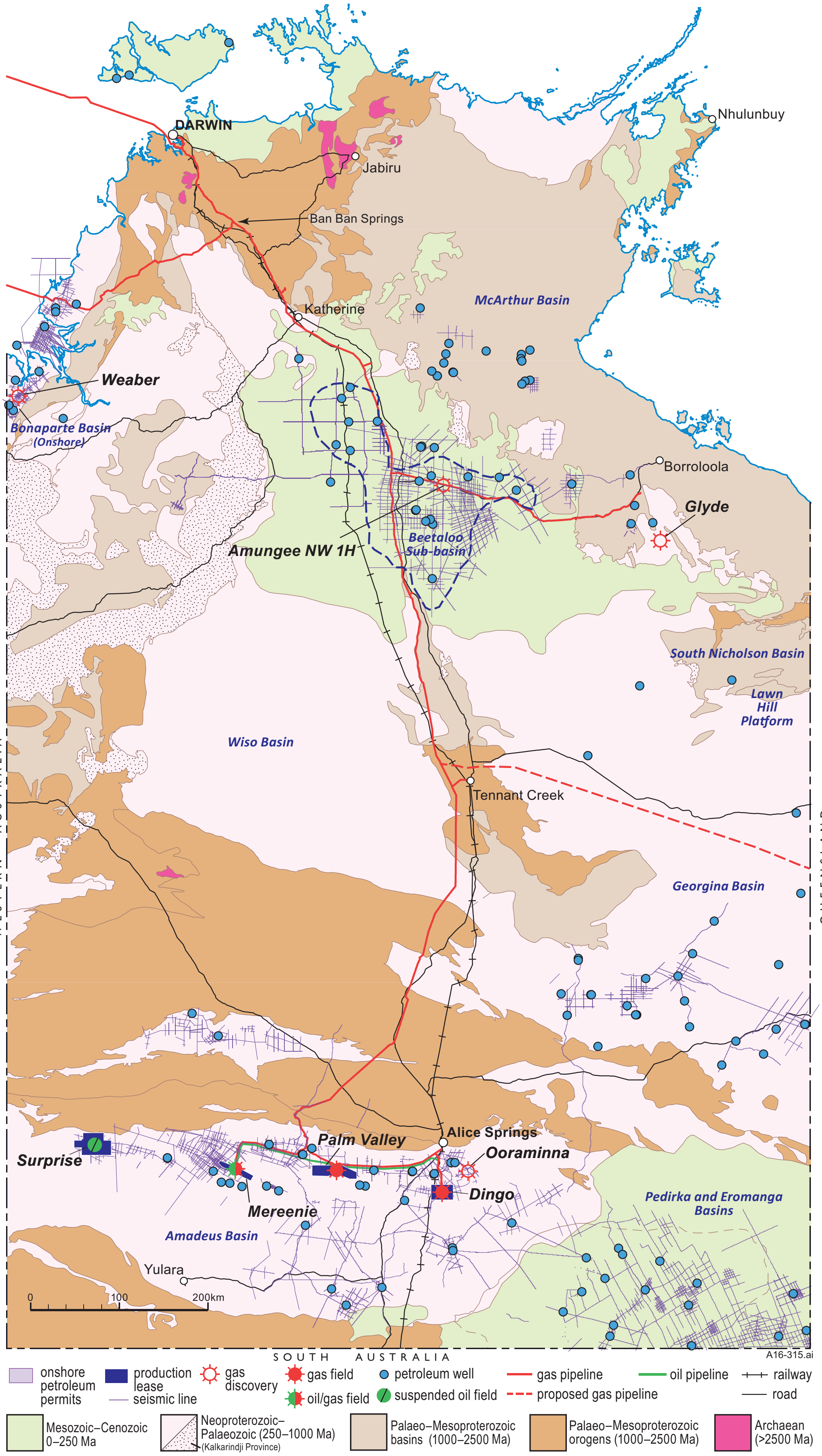


Figure 2. Petroleum wells, seismic lines and producing fields in the Northern Territory.

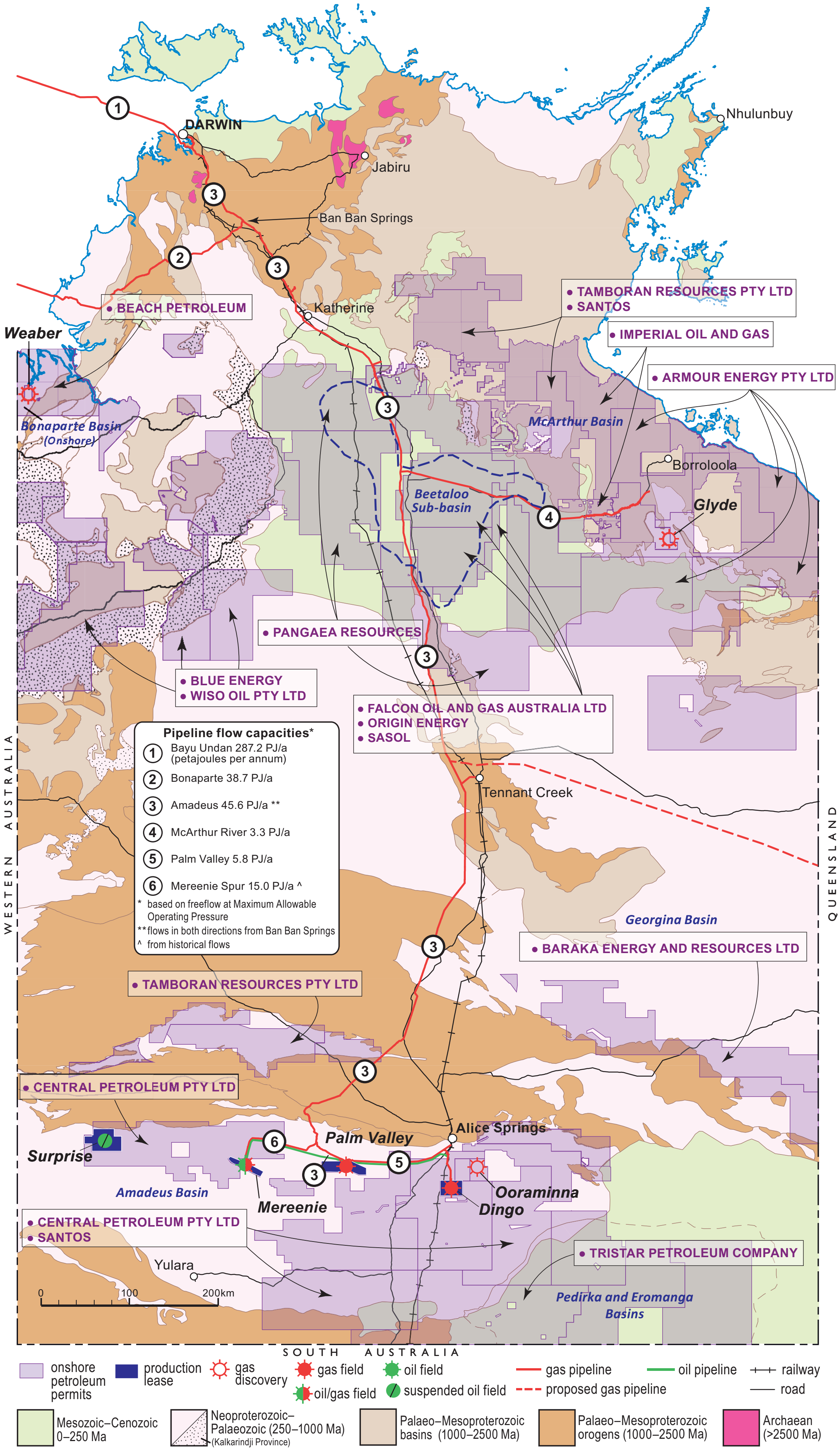
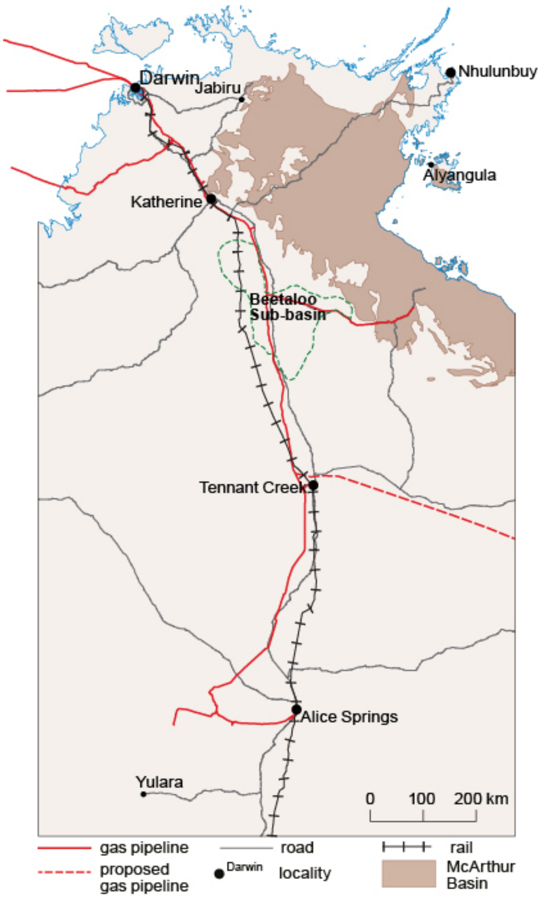


Figure 3. Existing granted tenure relative to geological basins in the Northern Territory.

MCARTHUR BASIN



The Palaeo- to Mesoproterozoic McArthur Basin contains an unmetamorphosed and relatively undeformed succession of sedimentary and minor volcanic rocks with a preserved thickness of up to 15 km in the northeastern Territory. There are a number of stacked basins in the McArthur Basin with varying petroleum potential. The youngest succession, the Roper Group is Mesoproterozoic in age (1500–1300 Ma) and forms the Beetaloo Sub-basin, which contains the Territory's most advanced shale gas play. There are older petroleum systems in the McArthur Basin, including demonstrated conventional and unconventional petroleum systems in the McArthur Group, and a more conceptual petroleum system in the underlying Tawallah Group. A map showing all wells and seismic in the McArthur Basin is shown in **Figure 4.**

The Beetaloo Sub-basin has a well demonstrated shale gas play associated with the middle Velkerri Formation, and a secondary play in the Kyalla Formation. The geology, exploration history and resource characteristics of the Beetaloo Sub-basin are provided in detail in a separate briefing paper to this Inquiry.

McArthur Group and equivalents

The Batten Fault Zone is a north-trending zone within the McArthur Basin, 50 km wide and 250 km in exposed length, west of Borroloola (**Figure 5**), which has only attracted serious attention as a potential gas province since 2010. The most important potential source rock and shale gas play within this part of the McArthur Basin is the Barney Creek Formation, which also hosts the McArthur River zinc deposit. Thick sections greater than 500 m with good source rock characteristics occur within small fault-bounded sub-basins, particularly within in the southern Batten Fault Zone. Away from these sub-basins, the formation is thinner and may be less prospective. In the Batten Fault Zone, the Barney Creek Formation is oil-mature at surface and is predicted to be wet-gas mature from 350 m to 2400 m, and dry-gas mature at depths greater than 2400 m. Shales within the unit have an average total organic carbon (TOC) of 2% and an oil-prone organic matter type.

Exploration history

The first indication of significant hydrocarbons within the McArthur Group in the Batten Fault Zone was a mineral exploration drillhole (GR79-9) that flowed gas to surface at such a rate that it had to be plugged with cement. Between 1981 and 1984, work by a joint venture between Amoco Australia Petroleum Company and Kennecott Copper Corporation [then owned by Standard Oil of Ohio (SOHIO)] included field mapping, stratigraphic drilling and geophysical surveys.

Exploration for oil and gas effectively ceased in the area until Armour Energy Pty Ltd (Armour) commenced exploration around 2010, targeting conventional and unconventional gas resources in the McArthur Group. This program has been focussed in the area of the Batten Fault Zone near Borroloola, with most exploration to date occurring in the period 2011-2013. A summary of the leads and prospects defined by Armour's exploration is shown in **Figure 5.** This program included the drilling of five wells, plus a sidetrack well. In 2012, Armour reported gas in two wells in the McArthur River district, to the north and south of the McArthur River mine. The northern occurrence is of unconventional shale gas in drillhole Cow Lagoon-1, whereas the southern (Glyde-1) is a shallow conventional accumulation within brecciated dolostone that flowed gas to surface. Glyde-1 intersected a continuous vertical section of 132 m of gas-charged, naturally-fractured Barney Creek Formation before intersecting the Coxco Dolostone Member. A highly deviated lateral well (Glyde-1 lateral) was drilled from within Glyde-1 and flowed 3.33 million standard cubic feet per day equivalent (mmscf/d) at 125 psi pressure during a 45 minute flow test, from a reservoir within fractured Coxco Dolostone Member. Armour have concluded that both prospects reservoir potentially economic quantities of gas. In late 2013, Armour drilled the Lamont Pass-3 vertical well 25 km north of Glyde-1, and reported multiple oil and gas shows in a 520 m-thick interval of Barney Creek Formation shale from 260 m to 780 m depth. Armour interpreted the results of the hole to indicate that the oil window in the area is more extensive than was previously recognised.

Armour have announced a prospective P50 resource of shale gas in place of 13 Tcf in the Batten Fault Zone; Imperial Oil and Gas have a prospective P50 resource of 8.7 Tcf west of the Batten Fault Zone. Armour also has a contingent conventional resource at Glyde of 6 Bcf gas, and a Best Estimate Prospective Resource of 2.2 Tcf for conventional resources in the Coxco Dolostone Member.

Imperial Oil and Gas Ltd has exploration tenure to the west of the Batten Fault Zone and extending north into the

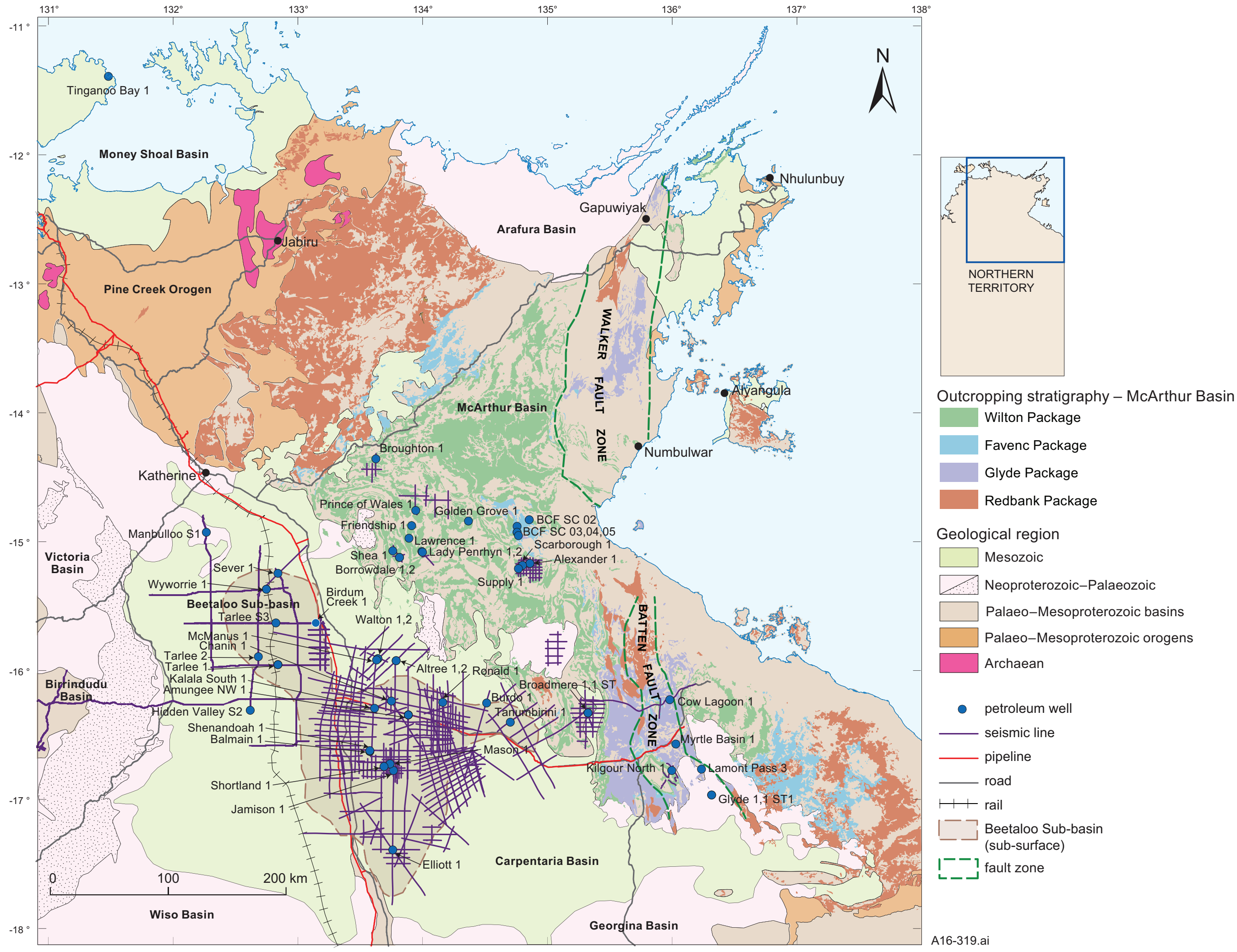


Figure 4. Location of petroleum wells and seismic lines within the McArthur Basin overlain on map of NT regional geology.

Walker Fault Zone in eastern Arnhem Land. The Walker Fault Zone is a 250–300 km-long, 60 km-wide, strongly faulted zone that extends from the north coast near Gapuwiyak to the gulf coast south of Numbulwar (**Figure 4**). Due to an almost complete lack of drilling or seismic data in east Arnhem Land, information on the petroleum prospectivity of this area can only be undertaken on the basis of correlations between mapped surface outcrops in the area and the well documented Batten Fault Zone to the south, which is interpreted to be an extension of the same geology.

The most prospective units within the Walker Fault Zone are in the Balma Group (and correlative Hapgood Group), which include interpreted correlatives of the gas-bearing formations in the Batten Fault Zone near Borroloola. The unit of particular interest is the Vaughton Siltstone, which outcrops poorly and for which no drill core exists. NTGS have interpreted that the Vaughton Siltstone is a likely correlative of the Barney Creek Formation in the Batten Fault Zone. Field observations by NTGS in eastern Arnhem Land in 2016 noted that the Vaughton Siltstone is a thick carbonaceous shale, suggesting that the unit has high prospectivity for shale gas and/or oil, although there is no data to date on hydrocarbon maturity. Imperial's application in east Arnhem Land are currently subject to negotiations under the *Aboriginal Land Rights Act (NT).*

The shales of the McArthur Group are regarded as a higher risk exploration play than the Beetaloo Sub-basin, largely due the evidence for variability of the thickness and organic content of the shales. NTGS is currently compiling a comprehensive dataset of properties of the shales through the Batten Fault Zone to support future decision-making.

Tawallah Group

The Tawallah Group is the lowermost group in the McArthur Basin, and occurs extensively between the Batten Fault Zone and the Queensland border. The petroleum prospectivity of the Tawallah Group is regarded as being less than that of overlying successions (McArthur and Roper groups), but these Tawallah Group successions are very underexplored. There is recognised source potential in some units (McDermott and Wollogorang formations), and coarse clastic units with reservoir potential occur at a number of levels. There has been no systematic petroleum exploration in the Tawallah Group, but both Armour Energy and Imperial Oil and Gas have announced prospective undiscovered shale gas resources for the Tawallah Group, based on analysis of the shales from existing drill core. Armour has announced the largest resources, with Best Estimate Recoverable Resources of 6.9 Tcf for the Wollogorang Formation and 10.1 Tcf for the McDermott Formation within their tenure. However, these estimates have very high uncertainties and given the lack of exploration, should be treated with caution.

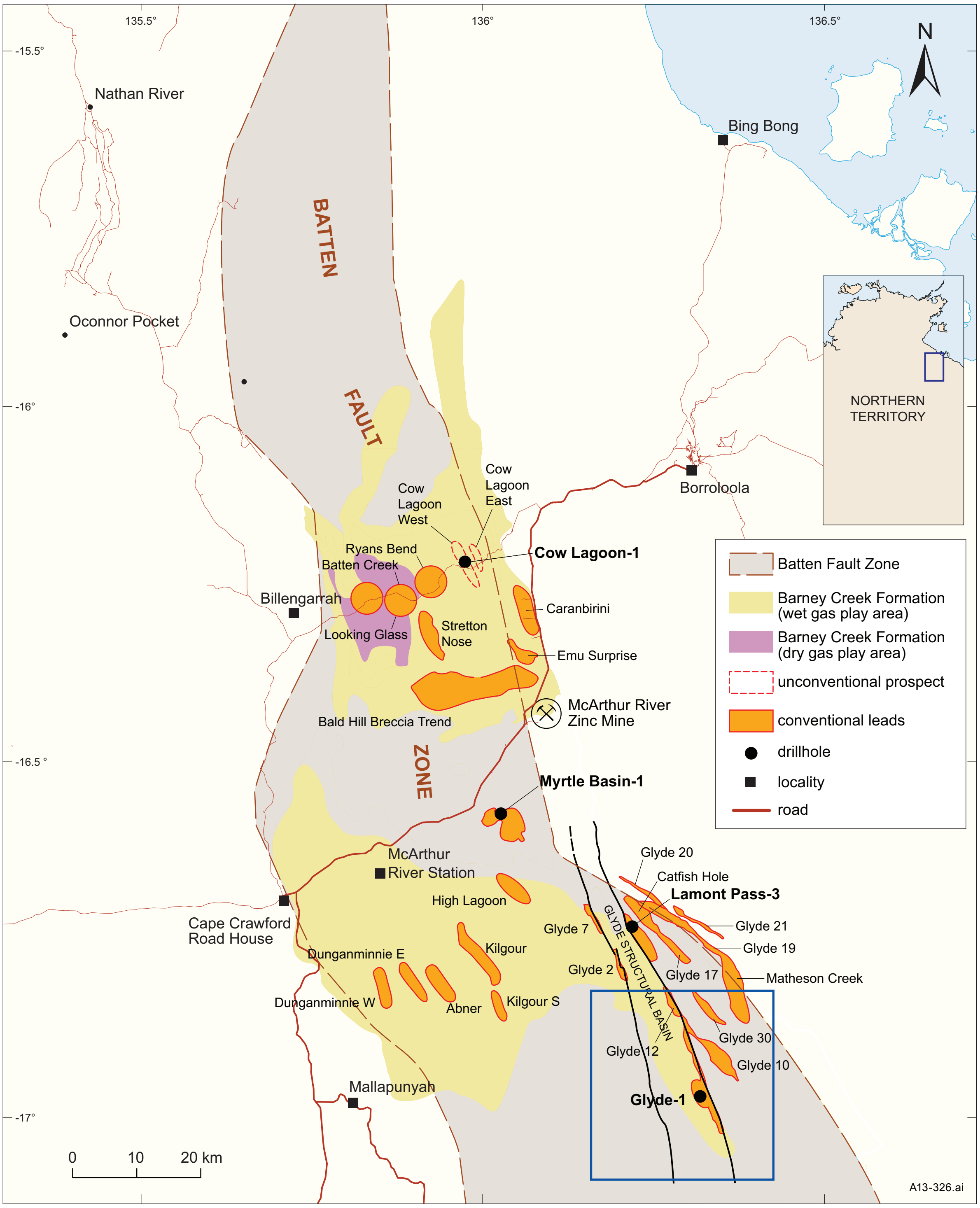
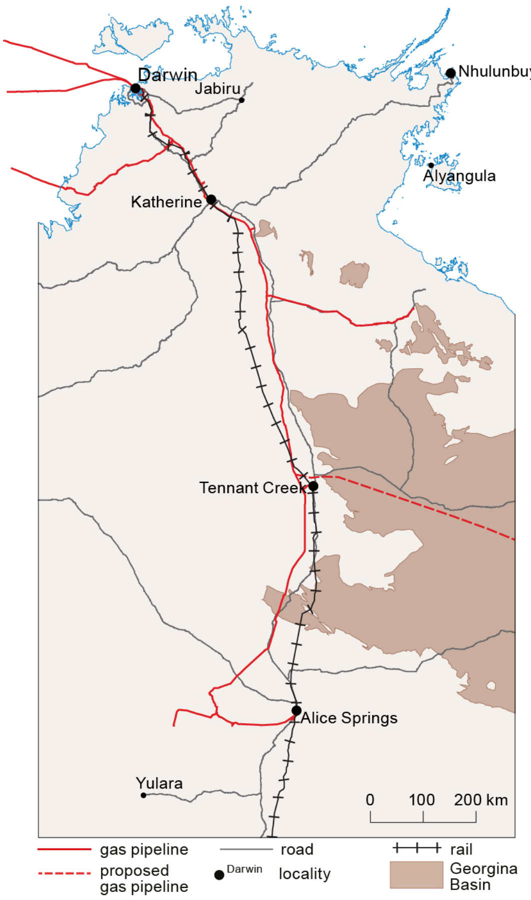


Figure 5. The Batten Fault Zone showing the Barney Creek Formation and summary of leads and prospects, as defined by Armour Energy Ltd.

GEORGINA BASIN



Overview

The southern part of the Georgina Basin is among the most prospective onshore areas in the Territory for oil and gas, but exploration is still at the frontier stage. The basin has 20 petroleum wells distributed across it, but the seismic coverage is relatively sparse and there is a large spacing between wells (**Figure 6**) meaning that any estimates of potential resources remain poorly constrained.

Despite world-class shale source rocks and multiple hydrocarbon shows in wells from across the southern Georgina Basin, disappointing exploration results in recent years have downgraded perceptions of the basin's potential. Much of the southern Georgina Basin in the Territory is now vacant in regards to exploration tenure, after relinquishments of tenure by Petrofrontier Corp and Baraka Energy. However, the basin remains very underexplored and there remains potential for both conventional and unconventional discoveries.

Geological understanding

The Georgina Basin is a Neoproterozoic to Devonian basin in the central-eastern Territory extending to western Queensland that is prospective for petroleum at a number of stratigraphic levels. There have been no commercial discoveries in the basin to date, but the potential of the southern part of the basin for both conventional and large-scale unconventional hydrocarbon accumulations has been demonstrated. The thick sedimentary succession in the southern Georgina Basin contains organically rich source rocks, reservoirs with effective vertical seals at various stratigraphic levels, and a variety of potential stratigraphic and structural traps. Middle Cambrian rocks are the main target for both conventional and unconventional accumulations; there is also some potential for economic conventional petroleum in the late Cambrian–Ordovician succession. The main petroleum potential in the southern Georgina basin is associated with the lower Arthur Creek Formation, which has been well documented as a world-class prospective petroleum source rock.

The petroleum prospectivity of the relatively thin limestone successions in the central to northern Georgina Basin is considered to be minimal. However, high-quality source rocks locally occur in the underlying McArthur Basin or South Nicholson Basin; there is some evidence that hydrocarbons were generated and migrated/remigrated from these sources into the overlying Georgina Basin. Therefore, although there has only been limited petroleum exploration activity in central to northern Georgina Basin to date, its prospectivity cannot be ruled out.

Exploration history

Hydrocarbons were first noted within the Georgina Basin as early as 1910. A number of wells were drilled in the basin from 1962 to 1983, but the only well to flow sizeable volumes of hydrocarbons was Ethabuka-1, which was drilled in the Toko Syncline in Queensland in 1974. Between 1988 and 1992, Pacific Oil and Gas conducted an exploration campaign over the southern Georgina Basin that included 675 line km of seismic data, and eight exploration wells in the Territory and two in Queensland. Although minor hydrocarbon shows were recorded in all these wells, there were no significant discoveries.

The most recent phase of exploration commenced in the mid-2000s and focussed on exploration for unconventional, as well as conventional petroleum. Petrofrontier Corporation undertook an exploration program that included the acquisition of 1302 line km of seismic data in 2009–2011, and three vertical wells (Baldwin-2, MacIntyre-2 and Owen-3) in 2011–2012. These three wells were re-entered and extended into the prospective lower Arthur Creek Formation as horizontal wells (Baldwin-2Hst1, MacIntyre-2H, Owen-3H). An attempt at hydraulic stimulation in these wells in 2012 met with mixed success. Good gas shows were recorded in all three horizontal wells; oil seepage was also reported in Owen-3 and oil fluorescence in Owen-3H, which penetrated a thermally less mature and therefore oil-prone part of the formation. Stimulation of Owen-3H resulted in the retrieval of fluids approximately equal to the amount injected during stimulation and 90% of the amount lost during drilling. However, no hydrocarbons were recovered.

As part of joint venture between Petrofrontier and Statoil, a further 304 line km of seismic was acquired in 2013; in 2014, Statoil drilled five wells (OzAlpha-1, OzBeta-1, Oz-Gamma-1, Oz-Delta-1 and Oz-Epsilon-1). Whilst four of the five wells intersected multiple oil shows (at depths between 730 and 1350 m), no oil or gas was produced during testing. These test results suggested insufficient

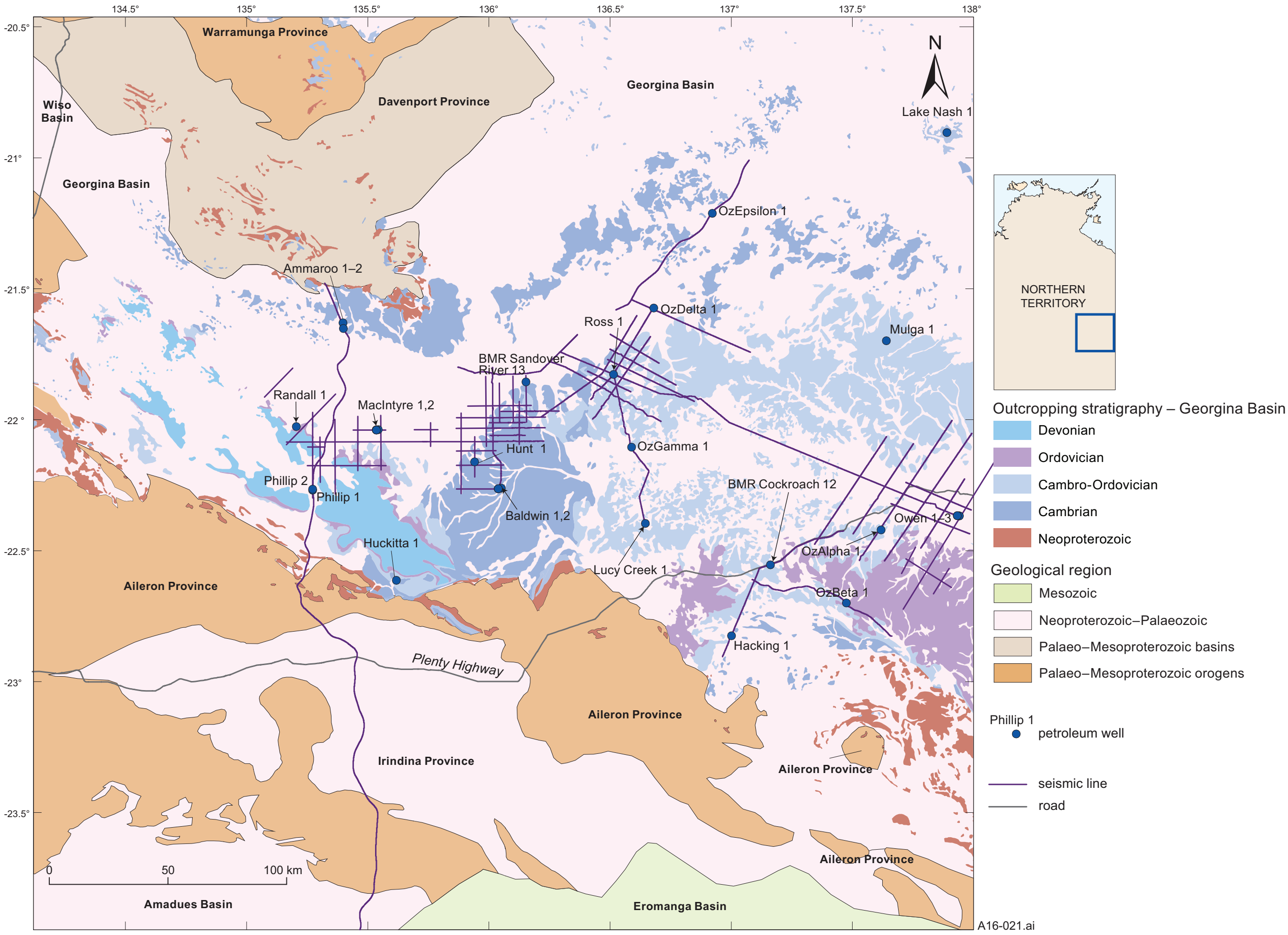
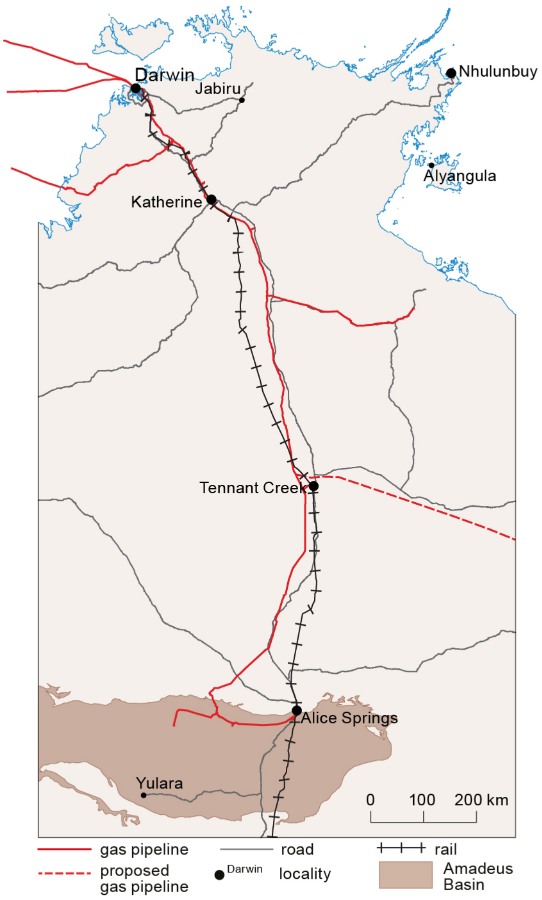


Figure 6. Location of petroleum wells and seismic lines in the Georgina Basin overlain on map of NT regional geology.

reservoir permeability or overpressure to allow hydrocarbon flow. Following the unsuccessful testing of OzBeta-1 and OzDelta-1, Statoil announced that it would not proceed to the next stage of the joint venture. No active exploration has occurred in the southern Georgina Basin in the Territory since that time.

AMADEUS BASIN



The Amadeus Basin is a large (170 000 km^2) complex Neoproterozoic to Devonian basin up to 14 km in thickness, which contains numerous petroleum systems. The Amadeus Basin is the most intensively explored basin in the Territory, with 41 exploration wells and 95 appraisal and development wells, and more than 11 000 km of 2D seismic (**Figure 7a,b**). Since production in the basin commenced in 1983, there has been total production to date of 400 Bcf gas and 17 mmbbl of oil, primarily from the Mereenie and Palm Valley fields. Production from the Surprise oil field commenced in 2014, but has been shut-in since August 2015. The Dingo gas field south of Alice Springs commenced production in 2015.

In 2015, 3.7 Bcf of gas was produced from the Amadeus Basin, comprising 2.4 Bcf from Mereenie, 1.3 Bcf from Palm Valley, and 0.03 Bcf from Dingo. Oil production from the Mereenie field totalled 0.28 mmbbl in 2015.

Geology

The Neoproterozoic to Late Devonian/Early Carboniferous Amadeus Basin contains a sedimentary succession up to 14 km thick that is prospective for petroleum at numerous stratigraphic levels. Detailed summaries of the geology of the Amadeus Basin are in Edgoose (2013) and Munson (2014). Most exploration and production in the basin to date has focussed on conventional petroleum systems, typically related to four-way fold closures within Palaeozoic stratigraphy (**Figure 8**). The basin contains the only producing conventional petroleum fields in the onshore Territory (Mereenie oil and gas and Palm Valley and Dingo gas), with an additional field (Surprise oil) that is currently not in production. There are also a number of other undeveloped fields and prospects. Two petroleum systems are relatively well defined within the basin, and the existence of a number of other poorly defined systems has been demonstrated.

The Ordovician Lower Larapinta Group Petroleum System is main commercially productive petroleum system in the basin and has been the primary target for petroleum exploration. This system includes the Horn Valley Siltstone source rock unit and two principle reservoir units, the underlying Pacoota and overlying Stairway sandstones. It is responsible for the charge of the Mereenie oil-gas, Palm Valley gas and Surprise oil fields. The play fairway for this system is located in the northern part of the basin and it is considered to be oil- and gas-prone with increasing probability for oil westwards. The Horn Valley Siltstone is also prospective for unconventional shale gas and oil, with a Best Estimate Recoverable Resource of 16 Tcf dry gas (Rawsthorn 2013). However, there has been no significant exploration for unconventional oil and gas, and exploration and development in the region is likely to continue to focus on conventional plays.

The oldest petroleum system is a sub-salt play in the basal Neoproterozoic stratigraphy, particularly in the south and southeast of the basin (**Figure 1**). The Gillen Formation provides good source rock characteristics, and regionally extensive evaporites act as a top seal over potential reservoirs in the Heavitree Quartzite. The system has been proved by oil shows within the Gillen Formation and by a stabilised sub-commercial flow of gas from drillhole Magee-1 in the southern part of the basin. This system is being targeted by Santos, who regard it as a potential multi-Tcf gas play; wells into the system to date have intersected 4-9% helium.

Neoproterozoic to Cambrian strata of the basin contain several petroleum systems, none of which have been particularly well defined. Potential source rocks and possible reservoir–seal configurations are present at a number of stratigraphic levels. The principle reservoirs recognised to date are the Pioneer Sandstone, which hosts the Ooraminna gas field; and Arumbera Sandstone, which hosts the Dingo gas field.

Exploration history

Petroleum exploration began in the Amadeus Basin in the 1950s with first discovery of hydrocarbons in the 1960s, culminating in the development of the Mereenie oil and gas field and Palm Valley gas field in the mid-1980s. These are significant fields and both are in the Ordovician Pacoota Sandstone–Horn Valley Siltstone–Stairway Sandstone succession. The Mereenie field was discovered in 1963 and commenced production in 1984; the Palm Valley gas field was discovered in 1965 and developed in 1983; and the Dingo gas prospect was discovered in 1981 and developed in 2015. Initial reserves at Mereenie were 24 mmstb of oil and 462 Bcf of gas; at Palm Valley, 230 Bcf of gas.

In the late 1980s and early 1990s, exploration by Pacific Oil and Gas Ltd (Pacific) focused on the southern half of the basin and included the drilling of two wells. This culminated in the discovery of sub-commercial gas reservoired in the Heavitree Quartzite in Magee-1.

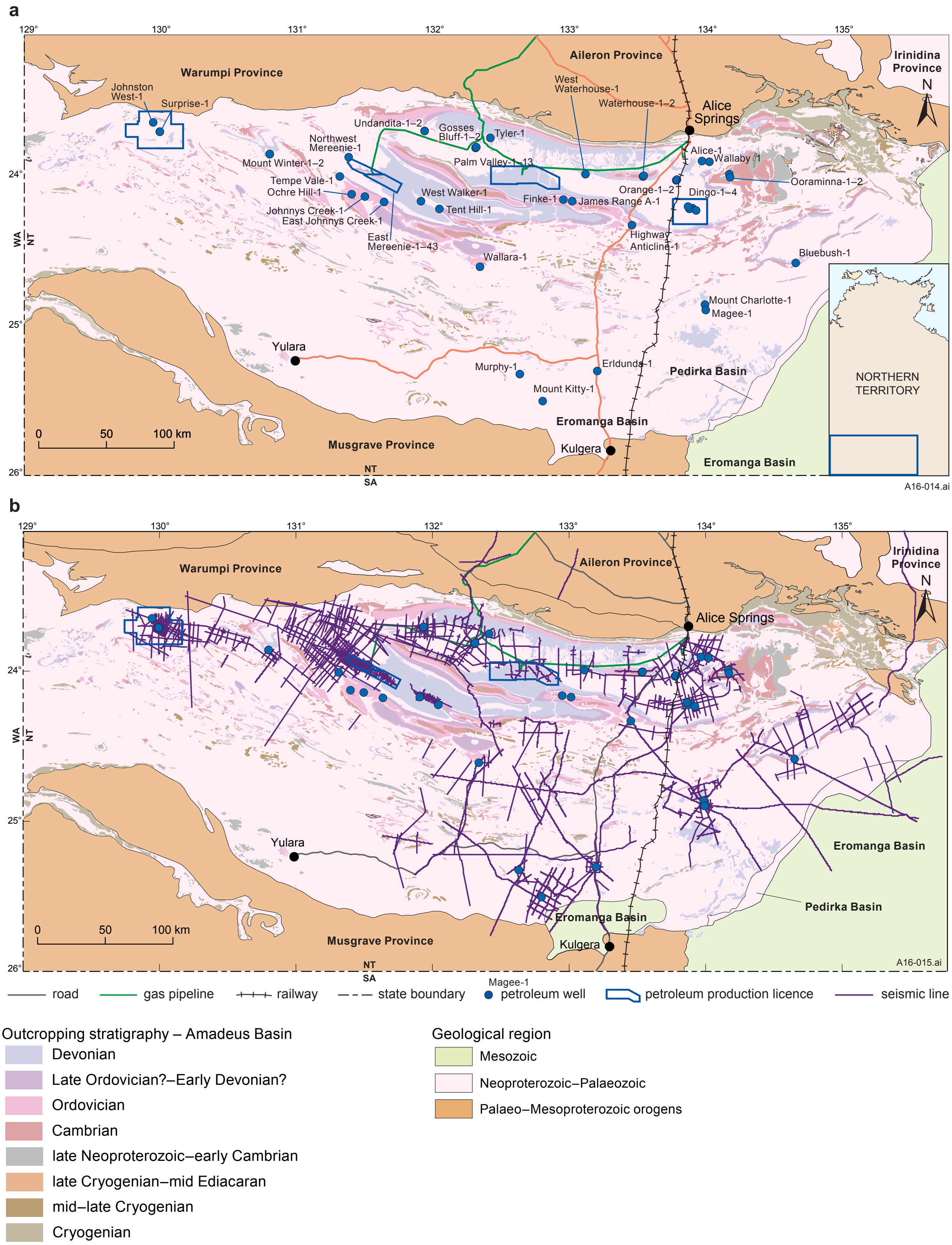


Figure 7. **a**) Location of petroleum wells and (**b**) seismic lines in Amadeus Basin. Base map derived from GA 1:1M geology.

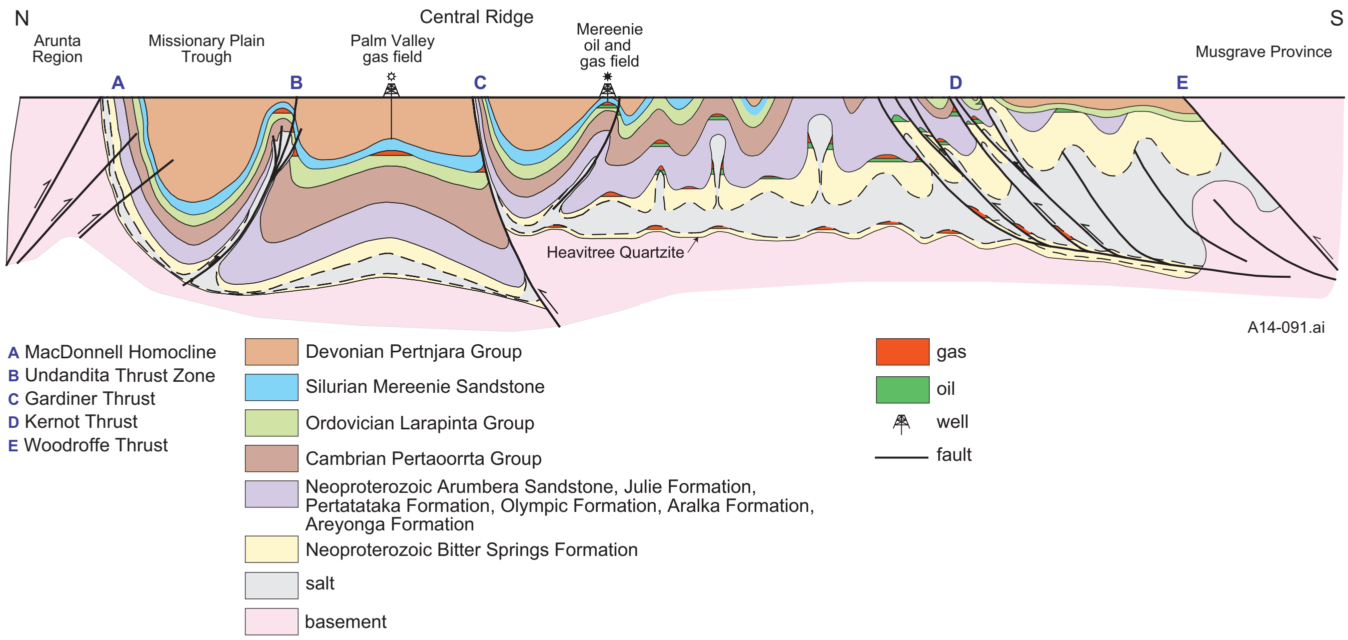
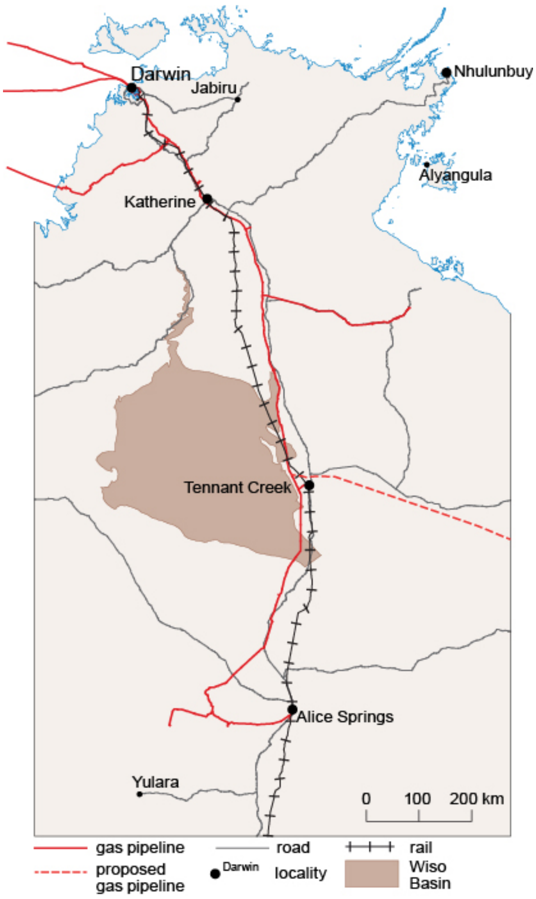


Figure 8. Schematic north–south cross-section through central part of Amadeus Basin (not to scale), showing structural styles and conceptual, conventional hydrocarbon play types (modified after Ambrose 2006a).

Exploration interest in the basin was renewed in the mid-2000s, with Central Petroleum Ltd (Central) embarking on a significant phase of exploration. Several seismic surveys were conducted within their tenements and three wells were drilled. Drillhole Ooraminna-2 flowed gas to surface from a tight reservoir zone in the Pioneer Sandstone (Central Petroleum 2010a). In 2010–2011, Central undertook a drilling program in the previously unexplored west of the basin. Johnstone West-1 confirmed the presence of 'live' oil in the Ordovician section in this area; the nearby wells, Surprise-1 and Surprise-1 REHST1, flowed light sweet crude to surface without pumping (Central Petroleum 2013d). A production licence to develop this discovery as a commercial oil field was granted in February 2014.

As part of a joint venture with Central, Santos commenced regional exploration in 2013, particularly targeting the sub-salt play in the southeast of the basin. The initial phase featured an 1800 line km seismic survey program and one 2140 m exploration well, Mount Kitty-1, in the south of the basin. The well flowed helium-bearing gas; logging of the hole indicated that the Heavitree Quartzite was not encountered in the drilling, and that the gas emanated from fractures within granitic basement. In late 2016, Santos commenced a further 1300 km of 2D seismic to better defined large-scale conventional targets for future drilling.

WISO BASIN



Overview

The Wiso Basin is effectively unexplored for petroleum, although much of the basin is currently covered by exploration permit applications, with the prospective areas held under application by Central. Virtually the entire basin is in Aboriginal freehold land. Given the lack of data and exploration to date, this is arguably Australia's most frontier onshore petroleum basin. The most prospective parts of the basin, in the Lander Trough in the south (**Figure 1**), are covered by applications by Central that are still subject to negotiations under the *Aboriginal Land Rights Act (NT)*.

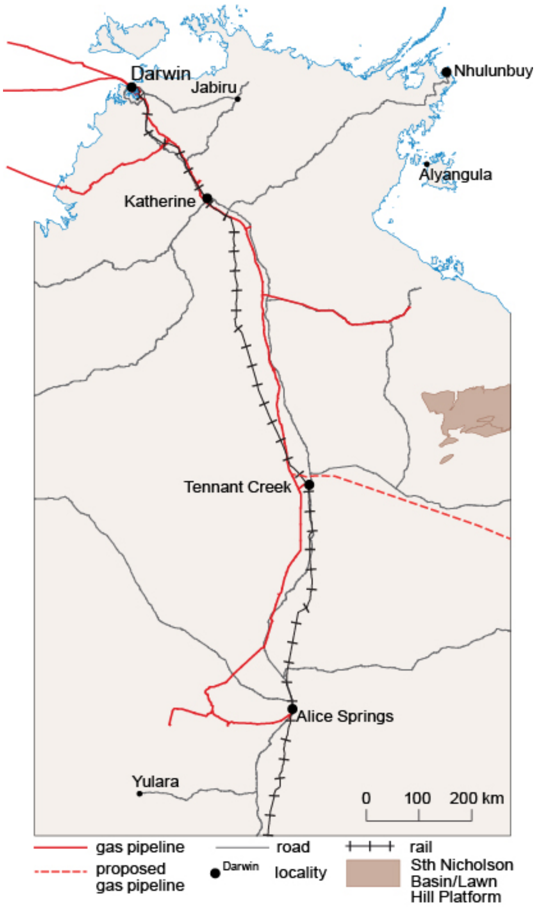
Geological understanding

The level of geological knowledge in the Wiso Basin is low, as the basin is poorly exposed and there have been no petroleum or deep stratigraphic wells drilled anywhere in the basin. A number of shallow mineral exploration and Government stratigraphic holes have been drilled, and minor hydrocarbon shows have been noted in two of the drillholes. The most prospective area is the main depocentre of the basin, the Lander Trough in the south of the basin, but this has not been drill tested. A reconnaissance seismic survey was undertaken in the southeast of the basin in the late 1960s, but otherwise there is no seismic coverage of the basin.

About 80% of the Wiso Basin (central and northern parts) contains less than 500 m of section and is therefore not considered very prospective for hydrocarbons (although in northern areas the basin may overlie older oil- and gas-bearing basins). However, the Lander Trough, with a modelled depth of 2000–3000 m up to a maximum of 4500 m, is significantly more prospective for petroleum. The Lander Trough is on trend with and is believed to be analogous to the prospective parts of the southern Georgina Basin, where significant oil and gas shows have been encountered. It features two main depocentres, separated by a cross-axial high. The succession in these offset depocentres is unknown, but has potential to include middle Cambrian petroleum systems equivalent to the Arthur Creek/Thorntonia petroleum system of the Georgina Basin (Munson 2014).

Maturation modelling by Central has indicated that source rocks in the Lander Trough may range from the early oil window to the early gas window, depending on the depth of burial. A variety of possible conventional structural and stratigraphic traps may be present within the Lander Trough. There is also untested potential for unconventional shale-hosted and basin-centred gas and oil plays.

SOUTH NICHOLSON BASIN AND LAWN HILL PLATFORM



The Lawn Hill Platform and South Nicholson Basin are interpreted stratigraphic correlatives of the McArthur Basin. The South Nicholson Group is correlated with the prospective Roper Group in the Beetaloo Sub-basin of the McArthur Basin, and yet it remains underexplored. The Lawn Hill Platform comprises sedimentary and volcanic strata equivalent to the Tawallah and McArthur groups of the McArthur Basin. Due to correlations to basins with known petroleum systems, plus the lack of exploration to date, makes these basins important frontier exploration targets in the Territory. Large areas of the basin are interpreted to underlie the shallow northern Georgina Basin, although the depth and structure in these areas remains very poorly understood.

Lawn Hill Platform

The Territory portion of the Lawn Hill Platform is unexplored for petroleum, but has potential for both conventional and unconventional hydrocarbons. Active exploration programs in adjacent areas of Queensland have identified two significant intervals (Riversleigh Siltstone and Lawn Hill Formation) that are prospective for shale gas. Based on surface geology maps, seismic interpretation and magnetic data, these shale gas plays have been interpreted to extend into the Territory.

South Nicholson Basin

The South Nicholson Basin has potential to reservoir significant hydrocarbons, particularly given its stratigraphic correlation with the Beetaloo Sub-basin. However, the basin is very underexplored and therefore is regarded as a frontier basin for petroleum exploration. The most promising potential source rock is the Mullera Formation, although it is possible that older source rocks in the underlying Lawn Hill Platform could have also supplied a charge to South Nicholson Basin reservoirs. Potential conventional reservoirs could be present at a number of levels within the succession in the Territory, including the Constance Sandstone, which is reported to have fair to good porosity and permeability in the Queensland portion of the basin. There is also potential for shale gas in organic-rich shales such as the Mullera Formation. The maturity of the basin is poorly understood, and the potential for overmaturity for gas is an unresolved risk for petroleum exploration.

Exploration history

The South Nicholson Basin has received little attention from explorers, and there have been no significant discoveries in either the Territory or Queensland portions of the basin to date. The first petroleum test of the basin in the Territory was Brunette Downs-1, drilled in 1964. The well primarily targeted the younger Cambrian section, but also intersected almost 200 m of the uppermost Mullera Formation. No hydrocarbons were detected. Pacific Oil and Gas investigated the petroleum prospectivity of the South Nicholson Basin in the Territory during the early to mid-1990s. Drillhole DD92SN1 penetrated 430.7 m of what Pacific regarded as Mullera Formation, but due to disappointing generative potentials, overmaturity and levels of extractable hydrocarbons, the program was terminated. However, Rawlings *et al* (2008) suggested that the company had inadvertently drilled the Crow Formation, rather than the Mullera Formation, which therefore remains untested in the Territory.

Future work

It is notable that as part of Geoscience Australia's \$100.5 million, 2016–2020 *Exploring for the Future* program, the South Nicholson Basin and Lawn Hill Platform have been prioritised as the focus area for the energy component of the program in recognition of their frontier status and untested potential for oil and gas. This will commence with around 600 km of 2D seismic during 2017, around two thirds of which will be in the Territory. This will be followed by stratigraphic drilling and analysis. The program, run in collaboration with NTGS and Geological Survey of Queensland, will lead to a greatly improved understanding of basin architecture and the generative potential and maturity of source rocks in the basin. The planned seismic is shown in **Figure 9**.

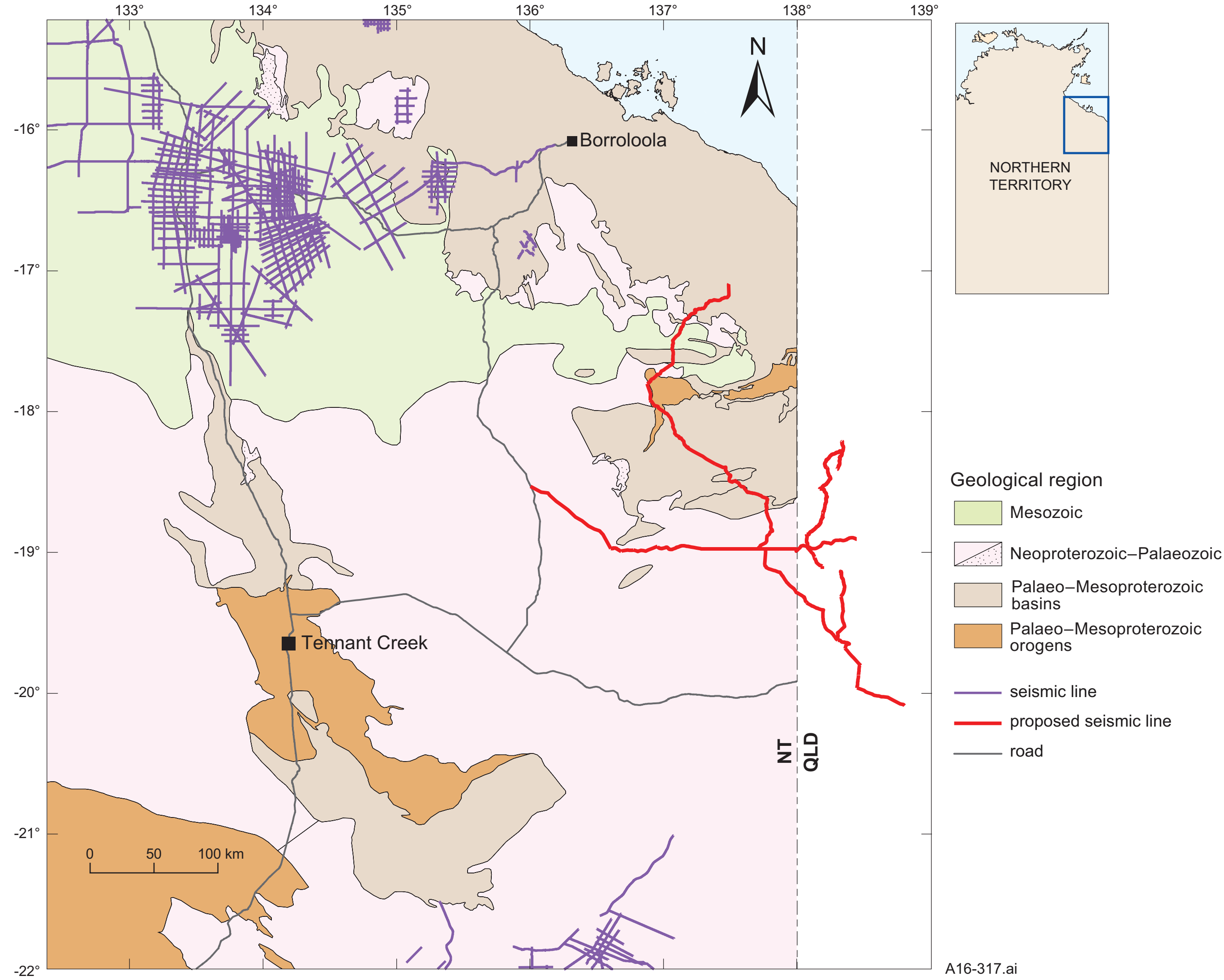
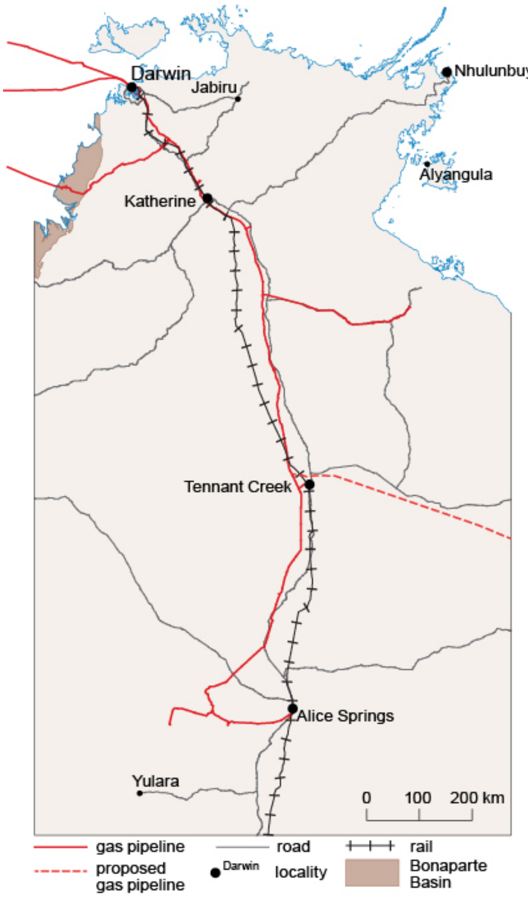


Figure 9. Location of the planned seismic surveys in the South Nicholson Basin and Lawn Hill Platform planned in 2017 under the 'Exploring for the Future' program. Location of existing seismic surveys shown in purple. Base map is the Geological Regions of the NT.

ONSHORE BONAPARTE BASIN



The Bonaparte Basin is a large, predominantly offshore, composite polyphase sedimentary basin, extending from onshore coastal areas along the Territory–Western Australia border northward into the Timor Sea. The offshore portion of the basin is a well-established oil and gas province, with proven resources and a number of currently producing fields (eg the Blacktip gas field). In the onshore Territory, the basin comprises the Late Devonian to Middle Triassic clastic and carbonate sediments. The onshore basin in the Territory contains the Weaber gas field; oil and gas shows have also been recorded from a number of wells. A summary of existing seismic and wells in the onshore Bonaparte Basin is given in **Figure 10**.

Multiple conventional petroleum systems have been defined in onshore areas, hosted within Late Devonian to Carboniferous reefal and vuggy/fractured limestones, and marine sandstones. In addition, the onshore Bonaparte Basin has significant unconventional petroleum potential including gas-condensate and shale oil plays in the Carboniferous lower Milligans Formation, and tight gas plays in sandstone and limestone reservoirs.

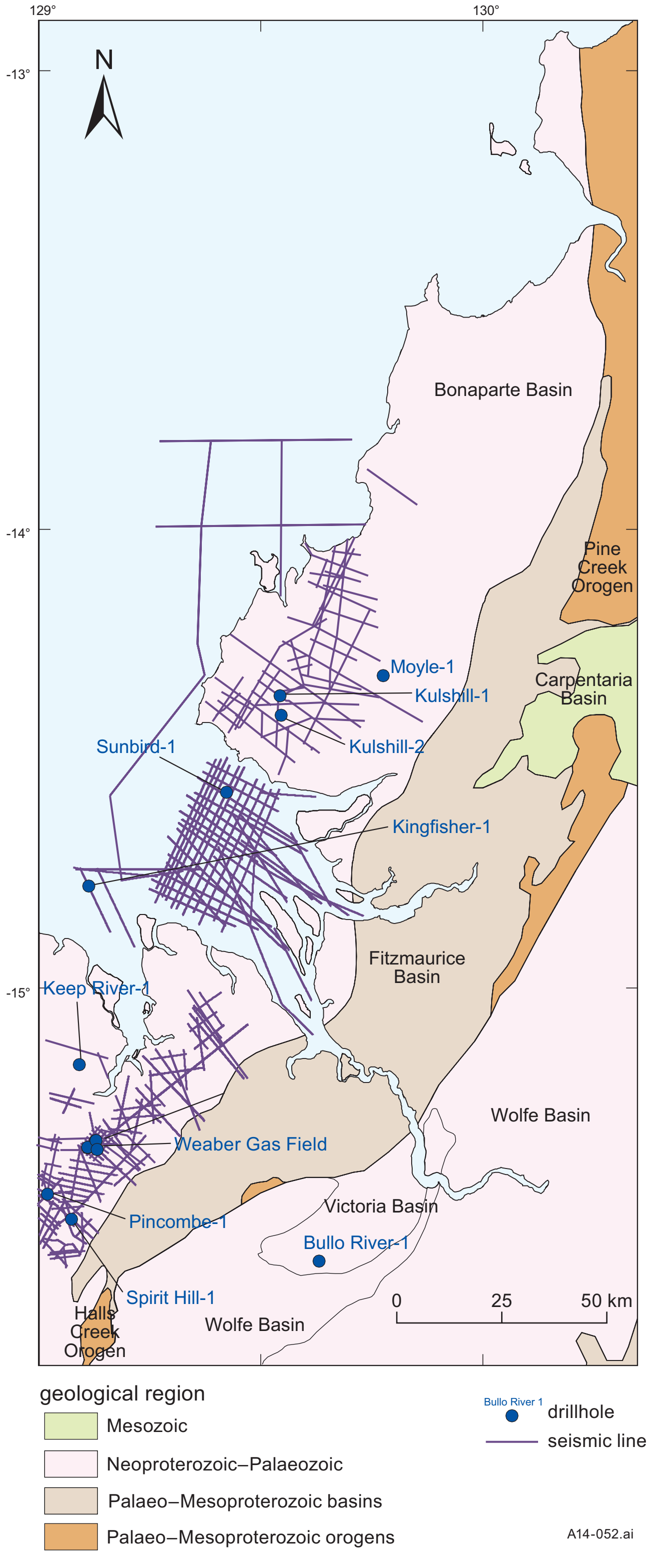


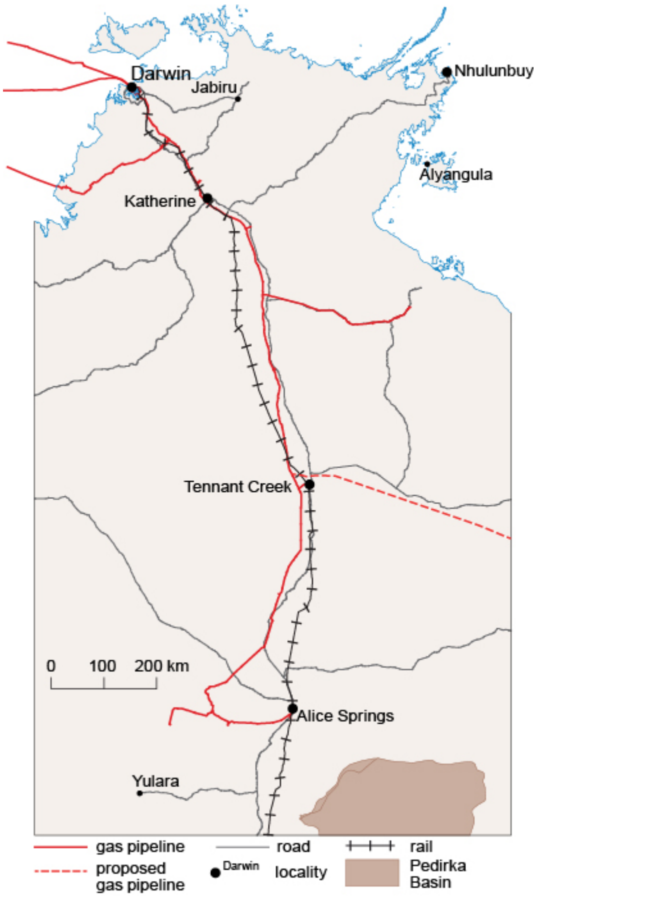
Figure 10. Location of significant NT drillholes and seismic lines from NTGS seismic lines GIS dataset, plotted on map of NT geological regions.

Exploration history

The initial phase of exploration in the onshore Bonaparte basin occurred from 1959 to 1973, with the drilling of a series of exploration wells, some of which encountered encouraging gas and/or oil shows. Seismic exploration recommenced in 1980 and continued until 1984, resulting in the drilling of Weaber-1 in 1982, followed by Weaber-2 and -2A. The Weaber wells encountered significant gas shows, and flowed gas to surface on test. In the early 1990s, appraisal of the onshore Weaber gas accumulation continued, and these wells were re-entered in 2001 for production testing, with both being cased and suspended for future production. At Weaber, gas-bearing sandstone reservoirs have been intersected at depths of about 1300 m and 1400 m in several drillholes. This is a conventional reservoir in a faulted anticlinal structure. The current owner of the field, Advent Energy Ltd, reported a Mean Contingent Resource of 18.4 Bcf gas, and that production testing had resulted in gas flows of 4.5 mmscfd from the field.

Since 2012, Beach Energy Ltd (Beach) has operated most of the exploration tenure in the onshore Bonaparte Basin with the exception of the Weaber gas field. In 2014, Beach drilled the Cullen-1 well to a depth of 3325 m with the primary targets being the Bonaparte Formation and Milligans Formation. The well intersected 1000 m of limestone and interbedded shale with evidence of natural fractures and elevated mud gas readings. In addition, 1600 m of dark grey to black marine shale were intersected with two cores cut for evaluation purposes including gas desorption analyses. The well highlighted the potential of the onshore Bonaparte Basin for both conventional and unconventional accumulations. No on-ground exploration has occurred in the basin since 2014.

PEDIRKA BASIN



The Permian–Triassic Pedirka Basin covers an area in the southeastern corner of the Territory in the Simpson Desert that also extends over areas of adjoining Queensland and South Australia. This largely subsurface intracratonic basin unconformably overlies the Amadeus and Warburton basins, and is unconformably overlain by the Eromanga Basin. It contains a diverse succession of fluvioglacial, fluvial, lacustrine and coal swamp, and continental red bed deposits up to 1.5 km-thick. It has an area of about 100 000 km^2, approximately half of which is in the Territory and the remainder in South Australia, with a small portion in southwestern Queensland. The basin is a similar aged to the highly productive Cooper Basin in South Australia and Queensland although the two are separated by a basement high. Much of the basin reaches depths of greater than 400 m, and maximum depths are in excess of 3000 m at its deepest points in the east (Ambrose *et al* 2007).

No commercial petroleum has been discovered in the Pedirka Basin, but there are good petroleum indications in drillholes. The key source rocks in the Pedirka Basin are the Permian Purni and Triassic Peera Peera formations. Unconventional petroleum potential is provided by extensive Permian and lesser Triassic coal measures and carbonaceous shale, which could theoretically be exploited via coal bed methane drainage and/or underground coal gasification. The Purni Formation is also prospective for shale gas: Rawsthorn (2013) calculated a potential Best Estimate Recoverable Resource from the formation in the Territory and South Australia of 43 Tcf.

Petroleum exploration commenced in the region in 1959 and has continued intermittently until the present. Exploration programs have included a number of aeromagnetic, gravity and seismic surveys, and resulted in the drilling of 18 wells in the Territory portion of the basin. However, only non-commercial conventional hydrocarbon accumulations have been found in this area to date, in basal Jurassic sandstones of the overlying Eromanga Basin.

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