Global Infracambrian petroleum systems: a review

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Abstract: This review covers global uppermost Neoproterozoic–Cambrian petroleum systems using published information and the results of studies undertaken by the Geological Survey of Western Australia (GSWA) on the Neoproterozoic Officer Basin. Both production and hydrocarbon (HC) shows sourced from, and reservoired in, uppermost Neoproterozoic–Cambrian successions occur worldwide, and these provide ample incentive for continuing exploration for these older petroleum systems. However, the risks of charge volume, timing of generation–migration v. trap formation and preservation of accumulation are significantly higher than in conventional Phanerozoic petroleum systems. Therefore, the location and assessment of preserved HC accumulations in such old petroleum systems presents a significant exploration challenge.

Organic-rich metamorphosed Proterozoic successions of SE Greenland, the Ukrainian Krivoy Roy Series, the Canadian Upper Huronian Series and the oil shales of the Russian Onega Basin are known as the world's oldest overmature petroleum source rocks. The oldest live oil has been recovered from the McArthur Basin of Australia (*c*. 1.4 Ga; Ga is 10^9 years), followed by the Nonesuch oil of Michigan. Numerous other petroleum shows have been reported from Australia, Canada, China, India, Morocco, Mauritania, Mali, Oman, Pakistan, Venezuela and the USA. These demonstrate that generation and migration of Proterozoic petroleum has occurred worldwide. The Siberian Lena–Tunguska province, the Russian Volga–Ural region and the Middle Eastern south Oman petroleum fields exemplify the productive potential of uppermost Neoproterozoic–Cambrian successions, where petroleum generation, migration and trapping were either late in the geological history (Palaeozoic–Mesozoic, Oman) or where accumulations have been preserved beneath highly effective super-seals (Lena–Tunguska). The total resource potential of the Lena–Tunguska petroleum province is estimated to be 2000 Mbbl (million barrels) oil and 83 Tcf (trillion cubic feet) gas. The equivalent proven and probable reserves derived from Neoproterozoic–Early Cambrian source rocks and trapped in Late Neoproterozoic (Ediacaran), Palaeozoic and Mesozoic reservoirs in Oman are at least 12 bbbl (billion barrels) of oil and an undetermined volume of gas.

The recovery of 12 Mcf (million cubic feet) of Precambrian gas from the Ooraminna-1 well in the Amadeus Basin in 1963, together with the occurrence of numerous HC shows within the Australian Centralian Superbasin, triggered the initial exploration for Proterozoic hydrocarbons in Australia. This included exploration in the Neoproterozoic Officer Basin, which is reviewed in this paper as a case study. Minor oil shows and numerous bitumen occurrences have been reported from the 24 petroleum exploration wells drilled in the Officer Basin to date, indicating the existence of a Neoproterozoic petroleum system. However, the potential of the Neoproterozoic petroleum system in the vast underexplored Officer Basin, with its sparse well control, remains unverified, but may be significant, as may that of many other 'Infracambrian' basins around the world.

The stratigraphic terminology and the position of key events used in this study are summarized in Figure 1, using numerical ages of the unit boundaries available from 2008 updated from International Commission on Stratigraphy web: http://www.stratigraphy.org/gssp.htm.

According to the presently known stratigraphic record, the conditions required for the deposition

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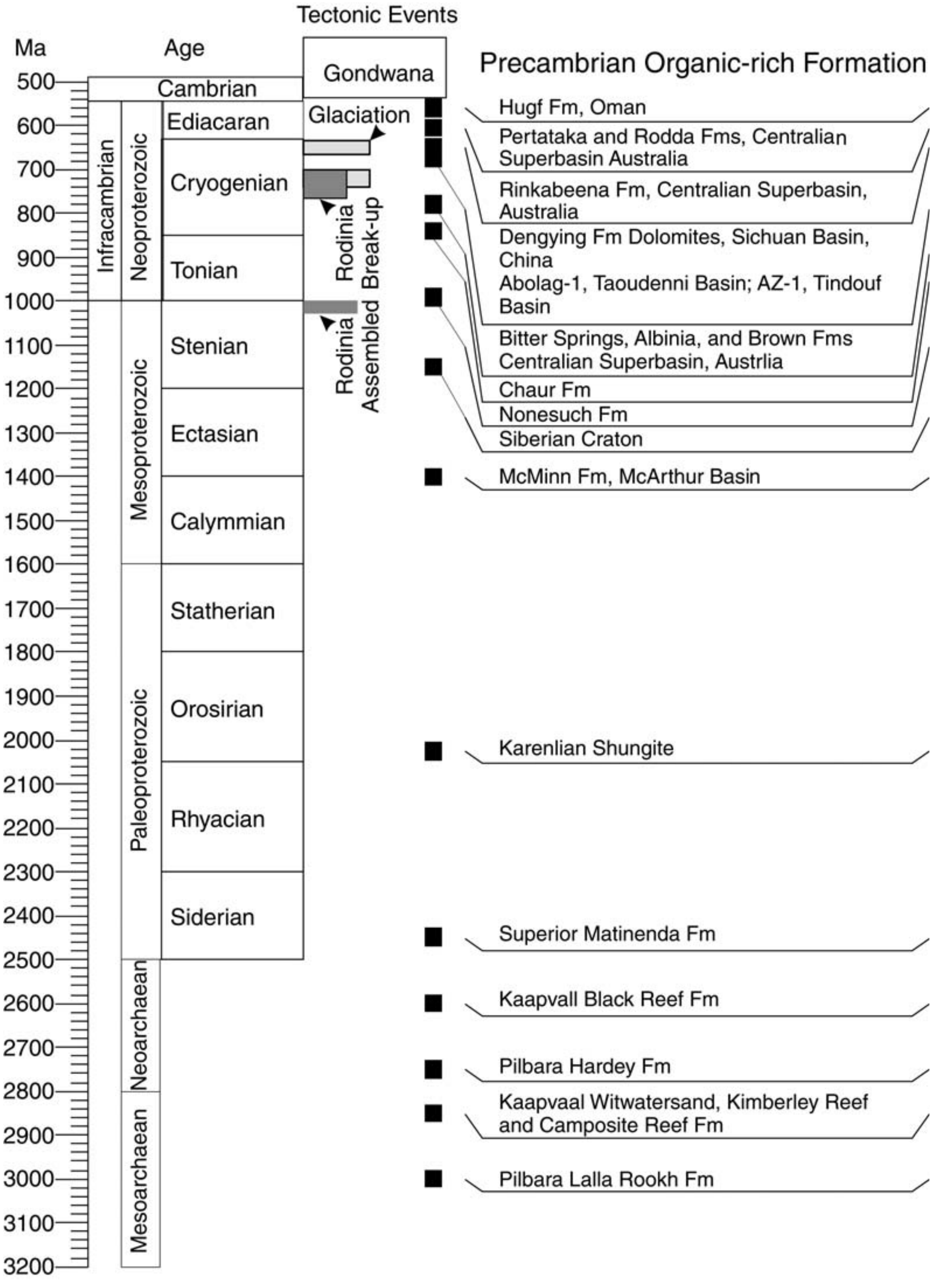

Fig. 1. Precambrian stratigraphic terminology and events used in this study.

of organic-rich sediments have occurred locally since Archaean time, but their frequency increased substantially during the Proterozoic and drastically during the Phanerozoic. The quality and richness of organic matter preserved in sediments increases in accordance with the evolution of the archea and eubacteria (prokaryotes) and the eukarya (eukaryotes or higher organisms) from the Archaean to the Present. The resulting organic-rich sediments are the source of most of the world's oil and gas reserves. These reserves are not evenly distributed either spatially or temporally. Globally, conditions for the deposition of source rocks were most conducive during the Mesozoic Era. This review provides a summary of the geographical and stratigraphic position of global Neoproterozoic–Early Cambrian petroleum systems from published information, followed by a summary of the results of studies undertaken by the Geological Survey of Western Australia (GSWA), on the Neoproterozoic Officer Basin, as a more detailed case study.

Petroleum system concept

Petroleum geochemistry has played the key role in developing the petroleum system concept since the early 1970s as discussed by Dow (1974), Demaison (1984), Meissner *et al.* (1984), Ulmishek (1986), Perrodon (1992), Bradshaw (1993), Magoon & Dow (1994), Magoon (1995), Magoon & Beaumont (1999) and Peters *et al.* (2005). The principal objective of the petroleum system approach is to define the three basic risk factors in evaluating effective petroleum systems: (1) magnitude of petroleum charge, which depends on source rock organic richness and facies, thickness and maturity; (2) trap, which depends on reservoir porosity, permeability, geometry, and seal quality; and (3) timing of charge v. trap formation. These three basic factors are essential to define the geographical boundaries of oil and gas occurrence, and to predict the location of areas that may have potential petroleum systems.

Precambrian petroleum systems

Precambrian sourced and reservoired oil and gas accumulations worldwide have been differentiated geochemically from equivalent Phanerozoic-sourced petroleum systems on the basis of their unusual biomarkers and light carbon isotopic signatures (McKirdy & Imbus 1992). The first prerequisite for petroleum formation is the deposition of organic-rich petroleum source rocks that are enriched in hydrogen and are exposed to sufficient heat that they generate and expel hydrocarbons. Most of the world's major petroleum source rocks have a total organic carbon (TOC) content of at least 2–3%, even after they have passed through the oil-generating stage. Such organic-rich sediments have been well documented from many Precambrian successions. The oldest of these potential or proven Precambrian source rocks include the metamorphosed Proterozoic succession of the Canadian Upper Huronian Series, broadly equivalent age successions in SE Greenland, the Ukrainian Krivoy Series and the oil shales of the Russian Onega Basin (Hunt 1996).

The commercial accumulations of indigenous Proterozoic-sourced petroleum in Siberia (Meyerhoff 1980), Oman (Al-Marjeby & Nash 1986; Alsharhan & Kendall 1986) and China (Korsch *et al.* 1991) demonstrate the economic viability of these 'old' petroleum systems. These commercial accumulations, which include several giant fields [>500 Mbbl (million barrels) of oil and/or 3 Tcf (trillion cubic feet) of gas] together with the widespread occurrence of hydrocarbon (HC) shows in Precambrian successions worldwide, have provided significant impetus for the exploration of other Proterozoic petroleum systems in recent years. However, a better understanding of the stratigraphy and structural history of Proterozoic sequences worldwide is required to encourage future exploration. Organic-rich rocks of Archaean–Palaeoproterozoic age (3.80–1.60 Ga; Ga is 10^9 years) have long been studied for their scientific interest, but organic-rich rocks of Mesoproterozoic–Neoproterozoic age (1.60–0.54 Ga) are also becoming of increasing interest from a commercial perspective.

Archaean–Palaeoproterozoic

The oldest recognizable petroleum source rocks were deposited in anoxic environment where methylotrophic bacteria played a key role in the production of oil-prone organic matter highly enriched in light ^{12}C. The oldest (*c.* 2 Ga) and organically richest rocks are reported from the Upper Zaonezhskaya Formation near Lake Onega, NW Russia. This includes a 600 m-thick sequence that contains shungite, a nearly pure carbonaceous material, averaging about 25% TOC (Melezhik *et al.* 1999; Peters *et al.* 2005). Relict Archaean petroleum systems are also recognized within the Pilbara Craton, Australia, and Kaapvaal Craton, South Africa, on the basis of pyrobitumen nodules of migrated oil and oil fluid inclusions (Buick *et al.* 1998; Dutkiewicz *et al.* 1998; Peters *et al.* 2005). Palaeoproterozoic rocks contain abundant microfossils and hydrocarbons. (Burlingame *et al.* 1965). The associated biomass, largely consisting of prokaryotes, was sufficient to produce organic-rich source rocks, while veins of pyrobitumen provide evidence of oil migration (Mancuso *et al.* 1989; Peters *et al.* 2005).

Mesoproterozoic–Neoproterozoic

Mesoproterozoic successions containing lacustrine and marine shales with source potential are reported from the Siberian Craton, central North America, and also from the McArthur Basin of Australia, where preserved Mesoproterozoic petroleum systems indicate the potential for commercial production of oil and gas (Peters *et al.* 2005). The Mesoproterozoic rocks of the McArthur Basin of Australia contain the world's oldest (*c.* 1.4 Ga) live oil, which flowed from black mudstone of the Velkerri Formation in BMR well Urapunga No. 4 (Muir *et al.* 1980). The Mesoproterozoic Nonesuch Formation (*c.* 1.05 Ga) of central North America contains oil seeps within the White Pine copper deposit, Michigan, USA (Imbus *et al.* 1988; Pratt *et al.* 1991; Mauk & Hieshima 1992; Price *et al.* 1996). The source of the eastern Siberian Precambrian oils is also believed to be organic-rich shales of Mesoproterozoic (Riphean) age (Ulmishek 2001). The Neoproterozoic was a period of Earth history during which one or more continental-scale, or even global-scale, glaciations affected the evolution of life (Hoffman *et al.* 1998; Hoffman & Schrag 2002: Halverson *et al.* 2005). Source rock deposition occurred between the pulses of glaciation during periods of prolonged oceanic anoxia and high rates of accumulation of organic matter in marine sediments, with TOCs locally as high as 20–30% (McKirdy & Imbus 1992). Rich Neoproterozoic source rocks and the world's oldest commercial oil and gas accumulations occur on the Siberian Platform (Lena–Tunguska region) and on the Arabian Shield (Oman). In the former Late Riphean and Vendian, siliciclastic and carbonate rocks are overlain by thick Lower Cambrian salt deposits that form an effective superseal to the petroleum system (McKirdy & Imbus 1992; Ulmishek *et al.* 2002). The giant Weiyuan gas field in the Sichuan Basin of eastern China produces from peritidal dolomitic carbonate rocks of the Sinian Period (Neoproterozoic), which include both basal argillaceous source rocks and the main reservoirs (Hao & Liu 1989). Countries currently producing Proterozoic oil and gas, and those that are being actively explored for Precambrian petroleum, are shown in Figure 2. Productive and potential Proterozoic petroleum systems are briefly reviewed later in this chapter.

Proterozoic petroleum production

The Sultanate of Oman salt basins, the Siberian Lena–Tunguska province of Russia and the Sichuan Basin of China all produce commercial volumes of oil and gas from the Meso-Neoproterozoic–Lower Palaeozoic petroleum systems, along with their Mesozoic–Cenozoic petroleum systems. The Meso-Neoproterozoic sourced petroleum systems of these areas are reviewed briefly here, together with their approximate stratigraphic position in relation to the latest International Geological Timescale (Gradstein *et al.* 2004; International Commission on Stratigraphy 2008).

Sultanate of Oman basins

The Sultanate of Oman is located on the southeastern margin of the Arabian plate. Figures 3 and 4

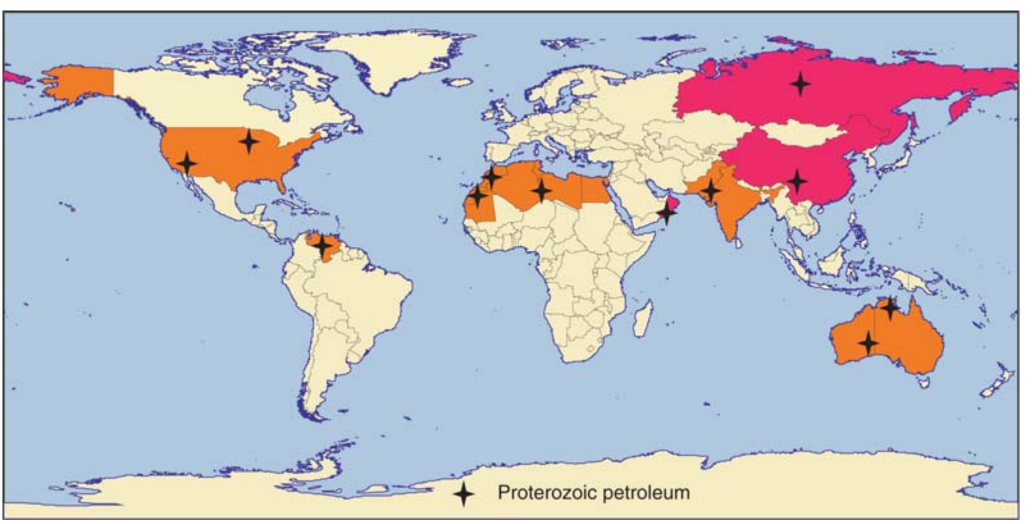

Fig. 2. Countries either producing (red) or potential to produce (orange) Proterozoic oil and gas.

summarize location, stratigraphy and petroleum systems of the Sultanate of Oman, which were compiled from various publications including: Pollastro (1999), Terken *et al.* (2001), Al-Lazki *et al.* (2002) and Al-Lazki (2003). The best estimate on the age of the Huqf Supergroup is 725–540 Ma, with the young constraint being the age of the Angudan unconformity (Allen 2007). The Huqf Supergroup is the oldest sedimentary sequence in Oman (Fig. 4), and consists of alternating clastic, carbonate and evaporitic units (Gorin *et al.* 1982; Pollastro 1999). It has been extensively studied for both commercial and scientific interests as it is a prolific petroleum producer, and provides critical information on the geological evolution of the Arabian–Persian Gulf region during the Neoproterozoic and constrains the Sturtian (740–700 Ma) and Marinoan (665–635 Ma) glacial episodes of the Neoproterozoic (Amthor 2006; Summons *et al.* 2006; Allen 2007).

The Huqf Supergroup contains several clastic and carbonate source rocks of exceptional quality, and these sourced the primary petroleum systems that produce hydrocarbons throughout Oman. The latest Neoproterozoic–earliest Cambrian Ara Group is a carbonate- and evaporate-dominated sequence containing salt deposits up to 1000 m thick (the Ghaba, South Oman and Fahud salt basins). The Ara evaporites were deposited in geographically restricted basins during periods of low relative sea level where stratified, anoxic conditions prevailed and organic-rich sediments and salt were deposited (Mattes & Conway-Morris 1990; Edgell 1991). Source rocks and reservoirs are widespread both geographically and stratigraphically in Oman (Fig. 4). The main source rocks have been identified in the Neoproterozoic Huqf Supergroup, the Silurian Safiq, the Upper Jurassic Sahtan (Diyab Formation), and the Cretaceous Kahmah (Bab Formation) and Wasia (Natih Formation) groups (Terken *et al.* 2001). Oil and gas derived from the Huqf Supergroup, which is believed to be the source of about 12 bbbl (billion barrels) of oil and an undetermined amount of gas, accumulated in Ediacaran and the overlying Palaeozoic and Mesozoic reservoirs (Grantham *et al.* 1987; Fritz 1989; Edgell 1991).

Five geochemical types of crude oil are recognized in Oman, including South and North Oman Huqf oils, 'Q' oils, Natih oils and Tuwaiq oils. These are correlated to four main source rocks. Of these, the South and North Oman Huqf oils and 'Q' oils are correlated to the Huqf Supergroup source rocks. The existence of prolific Ediacaran–Early Cambrian petroleum systems in Oman is one of the key drivers for the exploration of potentially equivalent petroleum systems within Precambrian successions elsewhere in the world.

Russian basins

The Lena–Tunguska Mesoproterozoic–Palaeozoic petroleum superprovince is located on the Siberian Craton in northern Russia between the Yenisey and Lena rivers (Fig. 5a). The region comprises three petroleum-bearing provinces: the Lena–Tunguska, Lena–Vilyuy and Yenisey–Anabar provinces. The Yurubchen–Tokhom Zone in Lena–Tunguska province is potentially the most important oil-producing area in the superprovince (Clarke 1985; Kontorovich *et al.* 1990; Kuznetsov 1997). The Siberian Craton rifted in the Riphean, and the rift basins were filled by thick synrift sedimentary sequences (Ulmishek *et al.* 2002). These are mainly overlain by Palaeozoic platform successions (Ulmishek *et al.* 2002). The petroleum-bearing sedimentary sequences are Riphean, Vendian, upper Vendian–Lower Cambrian, Cambrian, Ordovician–Devonian and Carboniferous–Triassic in age (Fig. 5b). The Riphean petroliferous sequences are particularly important in the Baikit and Predpatoma regions. The Vendian petroliferous sequences are commercially important in the Baikit, Katanga, Angara–Lena, Nepa, Botuoba and Predpatoma regions. The Vendian–Cambrian petroliferous sequences contain oil, oil and gas, and gas pools in the South Tunguska, Nepa–Botuoba, Baikit and Predpatoma regions. The Cambrian petroliferous sequences produce gas in the South Tunguska and Angara–Lena region and the Turukhan–Norilsk area (Kontorovich *et al.* 1990).

The Yurubchen–Tokhom productive area provides the most extensive geophysical and drilling database with over 100 wells. The first oil was tested in 1977. In 1982 it was proved to be light oil (42°–45°API) of low sulphur content (0.2–0.3%) and can be produced commercially. Major petroleum discoveries include the Jurubchenskoe, Kujumbinskoe, Talakanskoe, Chayadinskoe, Verkhne–Viluchanskoe, Kovyktinskoe and Verkhnevilyuy fields. Verkhnevilyuy is one of the largest fields in the region with proven plus probable reserves of 10.5 Tcf of gas and some 260 Mbbl of condensate (Meyerhoff 1980). The total resource potential of the Lena–Tunguska petroleum province is estimated to be 2.0 bbbl oil and 83 Tcf gas (Meyerhoff 1982). The principal source and reservoir rocks are within the Meso-Neoproterozoic succession. A thick Cambrian salt succession provides a regional super-seal that facilitated the preservation of hydrocarbons, which are considered to have been generated in pre-Devonian times.

The oldest petroleum systems on the Siberian Craton are unusual in that the kitchen areas were partially or fully destroyed by post-depositional tectonism in early Palaeozoic time (Ulmishek *et al.*

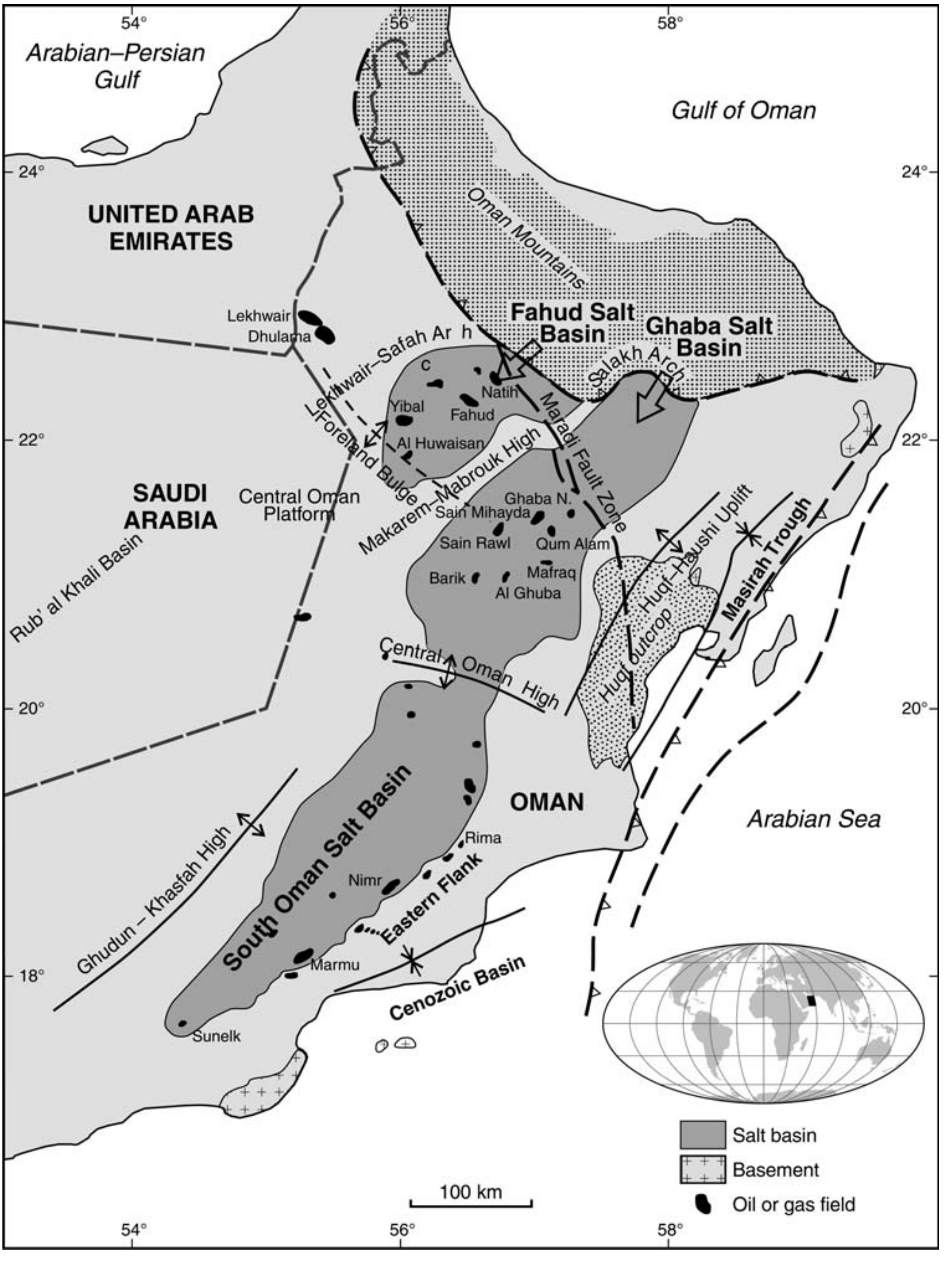

Fig. 3. Location of sedimentary basins of the Sultanate of Oman modified from Pollastro (1999).

2002). However, the source rocks reached maturity, and HCs were expelled and migrated into platform traps before the original HC kitchens were destroyed. The exceptionally long preservation of HCs was facilitated by the existence of the undeformed Cambrian salt super-seal. The undiscovered volumes of both oil and gas on the Siberian Craton, as assessed by United States Geological Survey (USGS), range from 2.8 bbbl of oil and 48.9 Tcf of gas (Masters *et al.* 1997) to 11.3 bbbl of oil and 175 Tcf of gas (Ulmishek 2001). The main reason for the difference in the assessments is the

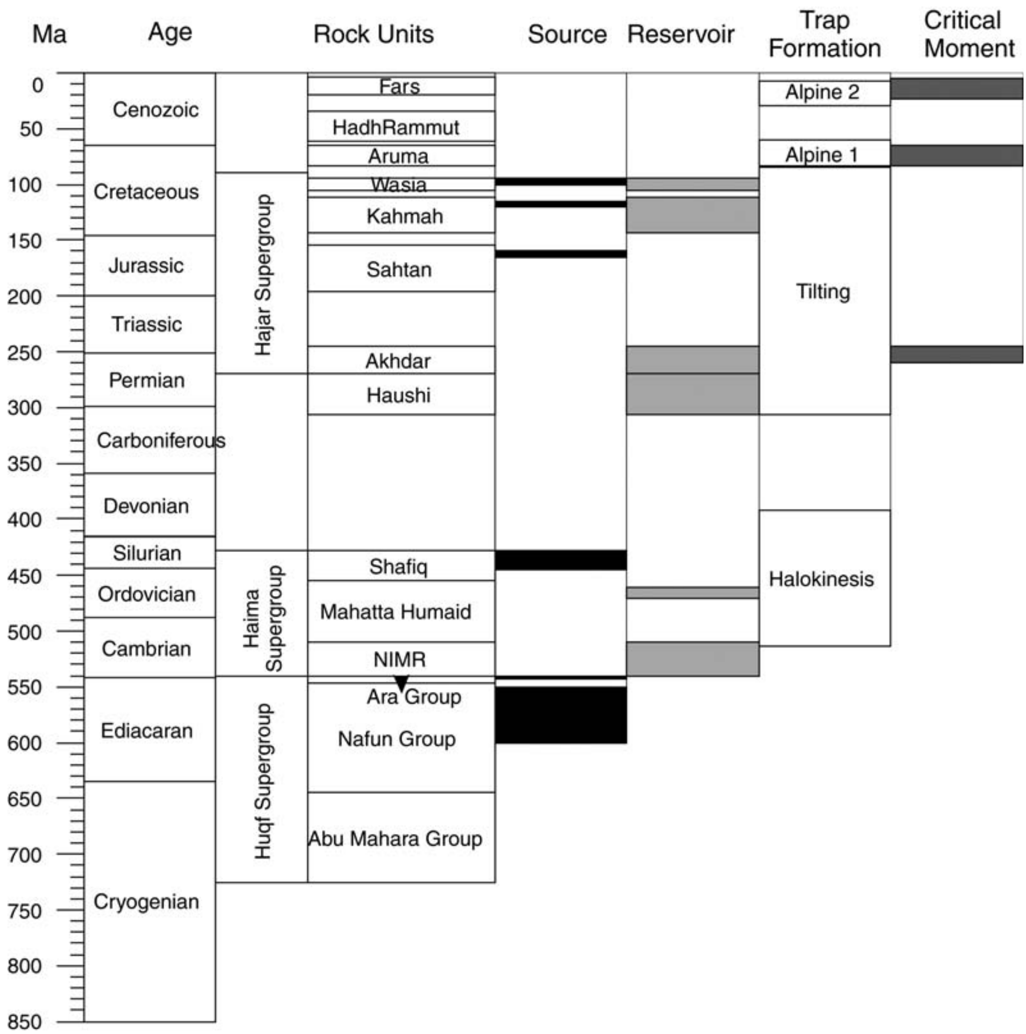

Fig. 4. Generalized stratigraphy and petroleum systems of the Sultanate of Oman.

assumption that much of undiscovered resources will be accounted for by reserve growth in two discovered giant fields, the Yurubchen–Takhoma oil field and the Kovykta gas field. In the 2000 assessment, field growth was considered separately (Ulmishek *et al.* 2002). There are more than 30 discoveries (mostly gas and condensate) in the Lena–Tunguska region. At least two of these are considered to be giant fields. Modelling of HC generation suggests that significant additional petroleum is yet to be discovered in the region. The principal HC prospective areas are related to zones of Riphean–Vendian reservoir rocks along palaeo-rift zones that contain thick source rock development in their central parts (Postnikov & Postnikova 2006).

Chinese basins

Sinian (Neoproterozoic) sourced and produced HCs occur in the Sichuan Basin of SW China (Fig. 6a), a large intracratonic sedimentary basin, covering an area of 180 000 km^2 in the western part of the Yangtze Craton. The relationship of the Yangtze Craton to the assembly and break-up of Rodinia and correlations with other continents are discussed by Li *et al.* (2003, 2005) and Greentree *et al.* (2006), The Yangtze Block sedimentary province is an important petroleum producing area with over 60 gas fields and 10 oil fields (Korsch *et al.* 1991). The basin contains up to 12 000 m of Neoproterozoic–Cenozoic sediments, deposited in a Neoproterozoic–middle Mesozoic

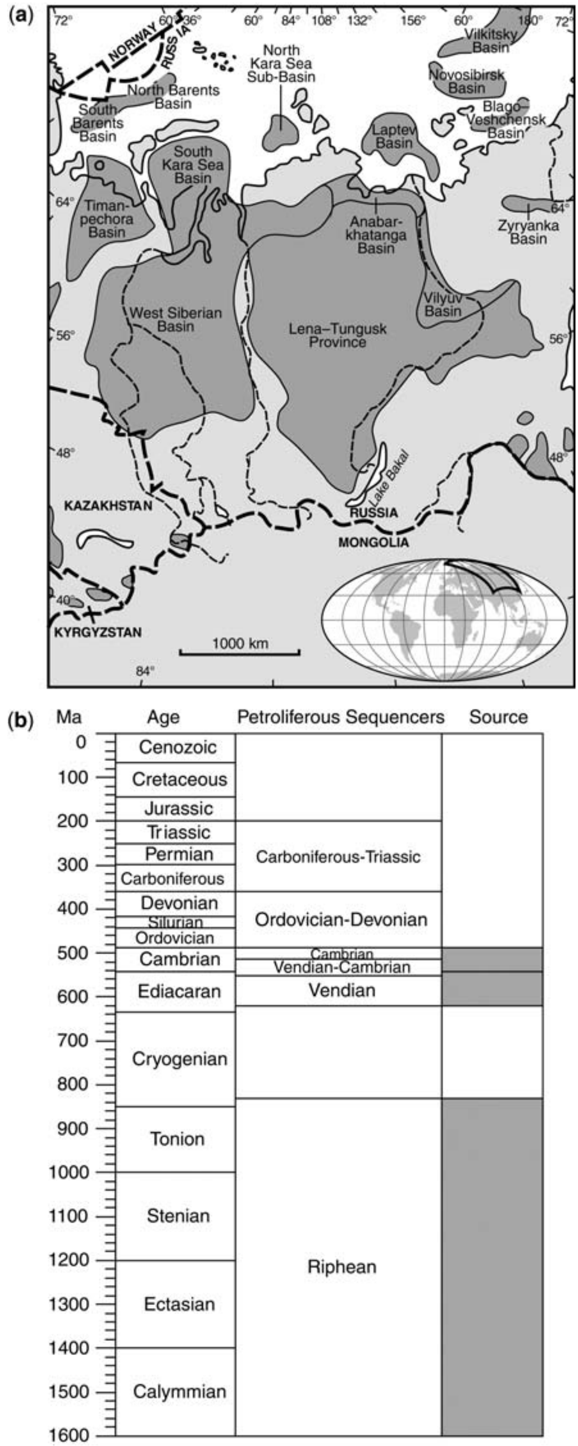

Fig. 5. Proterozoic of Russia: (**a**) location of sedimentary basins; and (**b**) petroliferous sequences and petroleum source rocks.

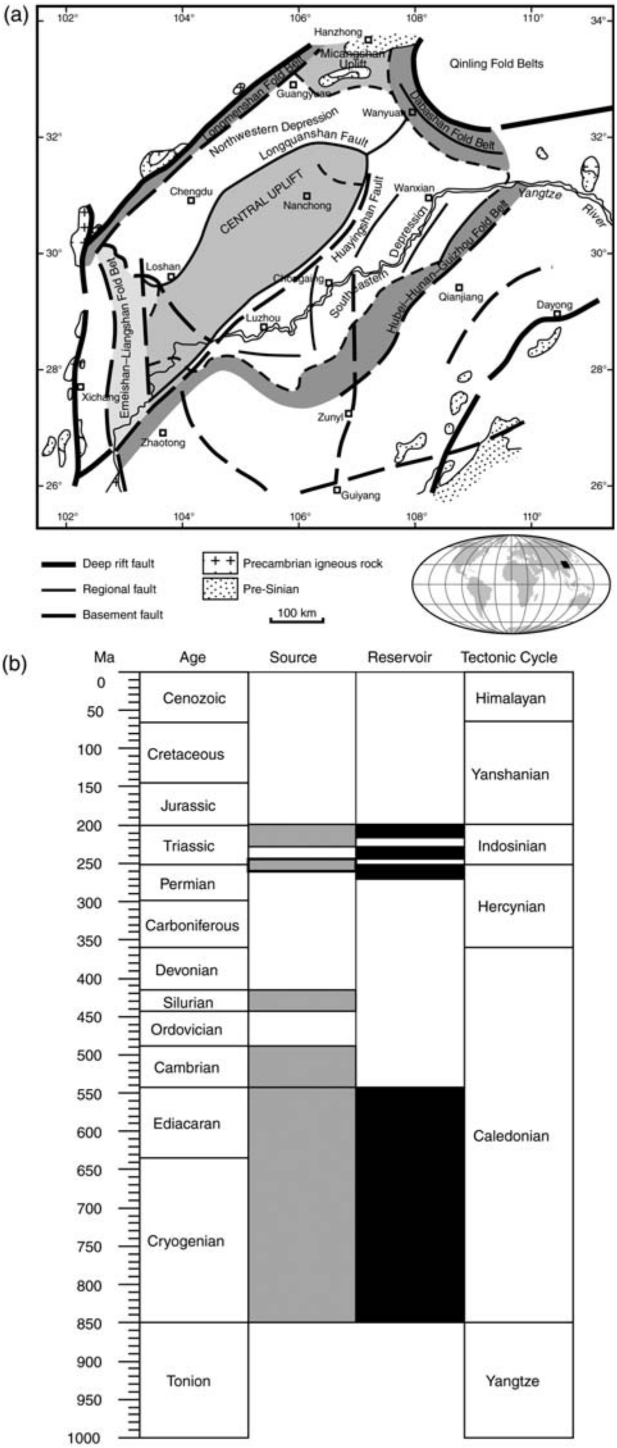

Fig. 6. The Sichuan Basin of China: (**a**) location; and (**b**) petroleum systems.

passive margin basin overlain by a late Mesozoic–Cenozoic foreland basin. The basin has three major subdivisions: the northwestern depression; the central uplift; and the southeastern depression. The central uplift is separated from the northwestern depression by the Longquanshan fault in the west and from the southeastern depression by the Huayingshan fault in the east (Ma *et al.* 2007).

The Sichuan Basin is a prolific petroleum province with an upside resource potential of 178 Tcf of gas and 26.18 bbbl of oil. Since 1950 over 245 gas and 15 oil pools had been discovered. The basin contains over 21 producing gas and oil reservoirs, distributed within the Sinian–Jurassic succession (Fig. 6b) at depths ranging from 7157 m (Guanji well) to a few hundreds of metres (Zhou 1996). The Weiyuan Gas Field within the Neoproterozoic–Palaeozoic succession of the Sichuan Basin is one of the largest gas fields in China, with estimated total reserves of up to 1.41 Tcf (Korsch *et al.* 1991). The gas is produced primarily from dolomite in the Sinian Dengying Formation and was generated chiefly from the microbial dolomite of the same Neoproterozoic sequence. Other major gas fields in the Sichuan Basin include the Wulunghou, Shiyougou, Luzhou, Shendengshan, Zigong, Huanchiachan, Tengchingkuan, Huangkuanshan and Yenkaohsi fields. Gas fields are located predominantly in the south of the basin, whereas oil fields occur predominantly in the centre and east. Other fields in Sichuan have an estimated ultimate recovery of 1.06 Tcf of gas. The oil and gas is predominantly reservoired in carbonate sequences deposited on a stable platform extending in time from the Neoproterozoic to the Jurassic.

The Bohai Bay Basin in northern China also has significant petroleum prospectivity within the Neoproterozoic succession. The Renqiu Oil Field in the Bohai Bay Basin is one of the largest oil fields in China. The oil in this field is produced primarily from dolomite in the Meso-Neoproterozoic Wumishan Formation, but was generated mainly from source rocks in the Oligocene Shahejie Formation. However, there is a possibility that the oil was also partly sourced from the Meso-Neoproterozoic rocks, since many oil and gas shows have been reported in the Meso-Neoproterozoic rocks of the Yanshan foldbelt at the northern margin of the Bohai Bay Basin. According to organic geochemical studies, the Meso-Neoproterozoic rocks in the area have good potential for HC generation, and conditions for the generation of HCs should exist in the Bohai Bay Basin and the nearby Yanshan Fold Belt. These Precambrian producing carbonate formations account for a considerable portion of the reserves and production in China (Hao & Liu 1989).

Proterozoic petroleum potential

Meso-Neoproterozoic sourced petroleum systems are reported from basins in North Africa, India, Pakistan, North America and Australia, but their commercial viability needs further systematic evaluation. These basins include: the Taoudenni Basin overlying the West African platform, the Bikaner–Nagaur Basin of India and the Punjab Platform of Pakistan, the Midcontinent Rift system and Grand Canyon areas of the United States, and the McArthur Basin and Centralian Superbasin of Australia. The potential of these Meso-Neoproterozoic sourced petroleum systems is briefly reviewed here.

North Africa basins

The Maghreb Petroleum Research Group (MPRG) at University College London, supported by the National Oil companies of Libya, Algeria and Morocco and by the Eni Exploration and Production Division, is actively assessing the potential for Mesoproterozoic and Neoproterozoic–Cambrian petroleum systems in North African basins. Their published and unpublished studies provided the basis for this review. The recovery of gas from 'Infracambrian' carbonates in the Taoudenni Basin and the success of Neoproterozoic–Early Cambrian plays globally provided the incentive to research and explore the prospectivity of Precambrian petroleum systems in North Africa, where Palaeozoic petroleum systems are already well established. The recovery of gas (480 million cubic feet day^{-1} (Mcfd)) from the Infracambrian succession of the Abolag-1 well within the Mauritanian part of the Taoudenni Basin in 1973 confirms the existence of a viable Infracambrian petroleum system in northwestern Africa. The Taoudenni Basin developed over part of the West African platform covering areas of present-day Mauritania, Mali and Algeria (Fig. 7). Deposition started at about 1000 Ma and continued until the end of the Carboniferous, producing a sedimentary succession with an average thickness of 3000 m. The Neoproterozoic–Carboniferous succession is exposed on the flanks of the basin, but is covered by a thin sequence of Mesozoic–Cenozoic rocks in centre of the basin.

The Infracambrian–earliest Palaeozoic petroleum potential of North African basins is summarized here based on detailed published field, laboratory and research reports, and unpublished data available from MPRG, including: Lüning *et al.* (2004, 2005), Geiger *et al.* (2004), Kolonic *et al.* (2004), Thusu *et al.* (2004) and Craig *et al.* (2008). According to these studies, polyphase evolution of the North African basins started during the Huqf Supergroup East African Orogeny

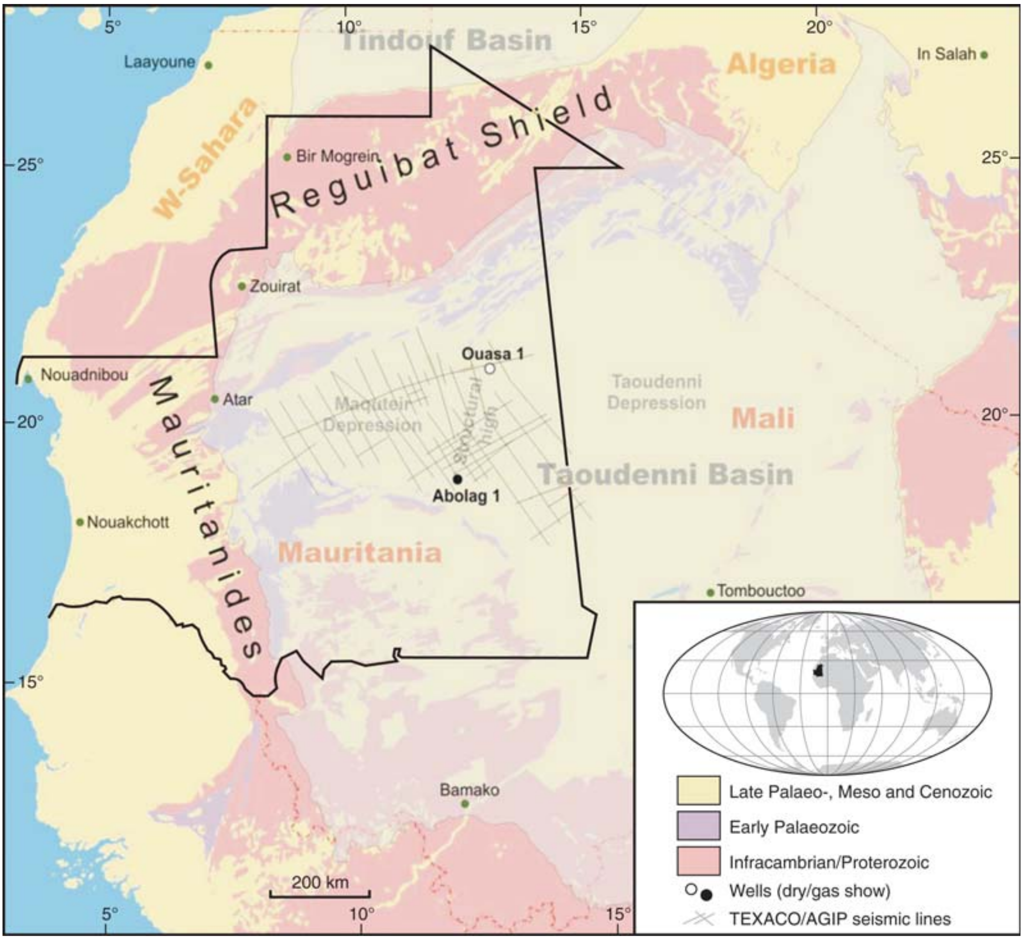

Fig. 7. Locations of outcrops, wells and seismic lines, and the extent of the Taoudenni Basin across Mauritania, Mali and Algeria.

(*c*. 650 Ma: Collins & Pisarevsky 2005) and involved at least seven major tectonic phases up to the final Oligocene–Miocene tectonic event associated with the development of the Red Sea, Gulf of Suez and Gulf of Aqaba rift systems. The effect of these different tectonic events varies greatly across the North African region (Craig *et al.* 2008).

Currently, Infracambrian organic-rich and/or black pyritic sediments in North Africa are known from the Taoudenni Basin, the Anti-Atlas and the Ahnet Basin. Field studies, laboratory analysis and synthesis indicate that Neoproterozoic and Lower Palaeozoic successions in the north-western African basins can be correlated through Morocco, Algeria, Libya and Egypt to Jordan and Oman. With the exception of the uppermost Neoproterozoic–Early Cambrian salt basins of Oman, the petroleum potential of the Neoproterozoic successions in the basins of North Africa and the Middle East is poorly known (Craig *et al.* 2008).

The Neoproterozoic–Early Cambrian plays in most of these basins are at the frontier stage of exploration with limited seismic data and very few wells. In Mauritania (Fig. 7), only two-dimensional (2D) seismic surveys, totalling 6268 km, have been acquired in the Mauritanian sector of the Taoudenni Basin, and only two wells have been drilled: Abolag-1 (Texaco: 1974) and Ouasa-1 (Agip: 1974). Texaco completed the Abolag-1 well in April 1974, and recorded gas shows at depths between 2300 and 3000 m. A drillstem test recorded the equivalent of 480 Mcfd from Infracambrian limestones at about 3000 m depth. In October 1974 Agip completed the Ouasa-1 well, but failed to reach the Infracambrian objective tested by Texaco. It is likely that Ouasa-1 did not test a valid closure. However, despite the Abolag-1 gas discovery, no further exploration has occurred since 1974 (Kolonic *et al.* 2004). New palynological and geochemical analyses on core and cutting samples from the Abolag-1 well indicate an age for the gas-bearing sequence ranging from Tonian to Early Cryogenian, with low organic richness and high maturity within the gas condensate window (Kolonic *et al.* 2004). A Tonian–Early Cryogenian age for this sequence is consistent with available radiometric dates of approximately 750–1000 Ma for the broadly equivalent carbonates of the Atar Group that crop out on the northern margin of the Taoudenni Basin (Deynoux 1980; Clauer & Deynoux 1987). In Morocco, gas shows in the AZ-1 well reported from a similar Infracambrian limestone succession on the northern margin of the Tindouf Basin, indicate the possible existence of another viable petroleum system in the Infracambrian Tata and Taroudant groups in this basin (Geiger *et al.* 2004). The Infracambrian–earliest Palaeozoic petroleum potential of North African basins is discussed in detail by Lüning *et al.* (2009).

Indian and Pakistani basins

The Bikaner–Nagaur Basin of India and its extension across the Punjab Platform of Pakistan contains a proven Infracambrian petroleum system (Fig. 8). Heavy asphaltic oil was first produced from fractured dolomite within the Infracambrian Salt Range Series at Karampur-1 on the Punjab Platform in 1959; and the first major heavy oil discovery was made at Baghewala-1 in the Bikaner–Nagaur Basin in 1991. Only some 7 bbl of 17.6° API gravity oil was originally produced from sandstone reservoirs (1103–1117 m) within the Infracambrian Jodhpur Formation in Baghewala-1. However, good shows were also reported from many other wells in the region including Bijnot-1 on the Punjab Platform, and Kalrewala-1 and Tavriwala-1 in the Bikaner–Nagaur Basin (Fig. 8). The geochemistry of the crude oil obtained from Baghewala-1 and Karampur-1 is very similar to that of oils and source rocks from the Neoproterozoic–Early Cambrian Huqf Supergroup of Oman, thus providing both strong evidence that viable Infracambrian sourced petroleum systems are present in the Bikaner–Nagaur Basin and Punjab Platform, and the rationale to further explore these basins (Peters *et al.* 1995; Sheikh *et al.* 2003).

The Baghewala-1 oil is non-biodegraded, heavy, sulphur-rich and considered to be sourced from organic-rich laminated dolomites within the Neoproterozoic–Early Cambrian Bilara Formation, based on the source and age-diagnostic biomarkers (Peters *et al.* 1995). Regionally, there are two different source rock types within the Neoproterozoic–Early Cambrian petroleum system. The 'laminated dolomitic beds' produce heavy, high sulphur oil (17°–25° API) during early maturation, while associated 'oil shales' produce low sulphur, light oil (42°–50° API), but require higher levels of maturation for oil expulsion. The light oil phase is more dominant in the Punjab and Potwar regions of Pakistan, but there are also unconfirmed rumours that light oil has been encountered in at least one well in the Indian portion of the Bikaner–Nagaur Basin. The reported reserves for the Baghewala Field are 628 Mbbl of oil; with the oil contained in four separate reservoirs. The oldest reservoir consists of sandstones within the Ediacaran Jodhpur Group, with a porosity of 16–25% and oil saturation ranging from 65 to 80%. The Early Cambrian Upper Carbonate Formation dolostone forms the youngest reservoir with porosities ranging from 7 to 15% (Peters *et al.* 1995; Sheikh *et al.* 2003).

The thick evaporite sequences of the Punjab Platform, the Bikaner–Nagaur Basin, and the Ghaba, Fahud and South Oman salt basins were deposited in a series of basins that formed during a period of latest Neoproterozoic–earliest Cambrian rifting and/or transtension (Pollastro 1999) from India and Pakistan across the Arabian Shield to central Iran. Plate-tectonic reconstruction suggests that these restricted marine-evaporite rift basins formed in close proximity on a broad carbonate shelf along the northern margin of the Gondwana supercontinent (Gorin *et al.* 1982; Lawyer & Scotese 1987; Husseini & Husseini 1990; McKerrow *et al.* 1992; Collins & Pisarevsky 2005). Of these salt basins, the Ghaba and Fahud Salt basins of Oman currently contain the most prolific Infracambrian petroleum systems. The Infracambrian plays on the Punjab Platform and in the Bikaner–Nagaur Basin are still very underexplored. However, the similarity of their depositional and tectonic history to the salt basins of Oman and the geochemical similarity of the oils encountered with those from the Neoproterozoic–Early Cambrian Huqf Supergroup, which is believed to be the source of about 12 bbbl of oil and an undetermined amount of gas in Neoproterozoic and overlying Palaeozoic and Mesozoic reservoirs in Oman (Grantham *et al.* 1987; Fritz 1989; Edgell 1991), provide a strong incentive for further systematic exploration for Neoproterozoic and Early Cambrian petroleum systems in the Infracambrian basins of India and Pakistan.

North American basins

Several areas in North America contain proven or potential Precambrian petroleum systems (Fig. 9). These include the Midcontinent Rift system, the Grand Canyon area in northern Arizona, the Unita

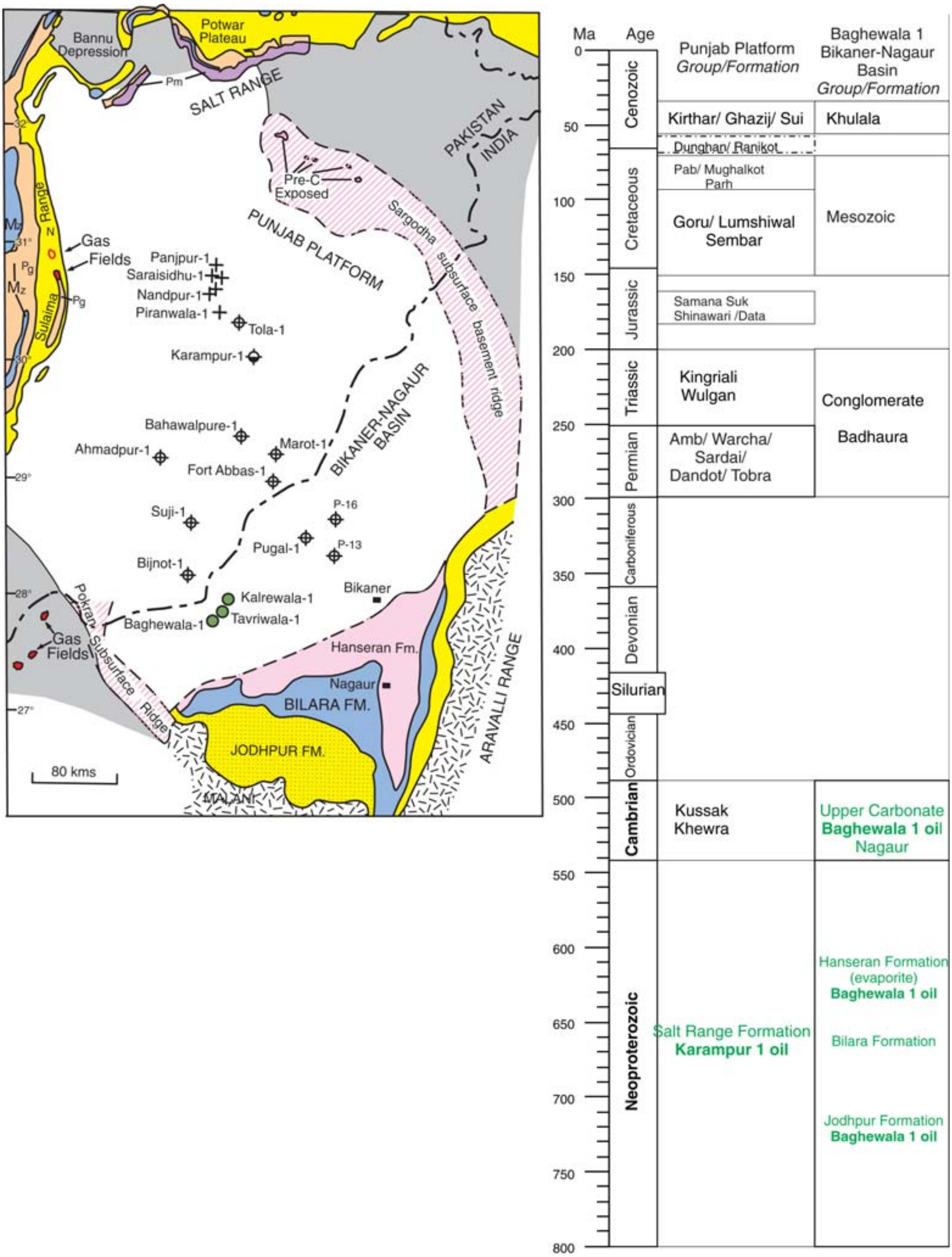

Fig. 8. Location and stratigraphy of the Bikaner–Nagaur Basin of India and the Punjab Platform of Pakistan.

Mountains and the Rocky Mountain overthrust belt of northwestern Montana. Of these, the best producing potential appears to be in the Meso-Neoproterozoic Oronto Group of the Midcontinent Rift system and in the Neoproterozoic Chuar Group of the Grand Canyon (Fig. 10). However, the potential of source rocks in these regions is poorly known, but they may have generated and expelled HCs that were subsequently trapped in Neoproterozoic–Palaeozoic reservoirs (Palacas 1997). The 1.1 Ga

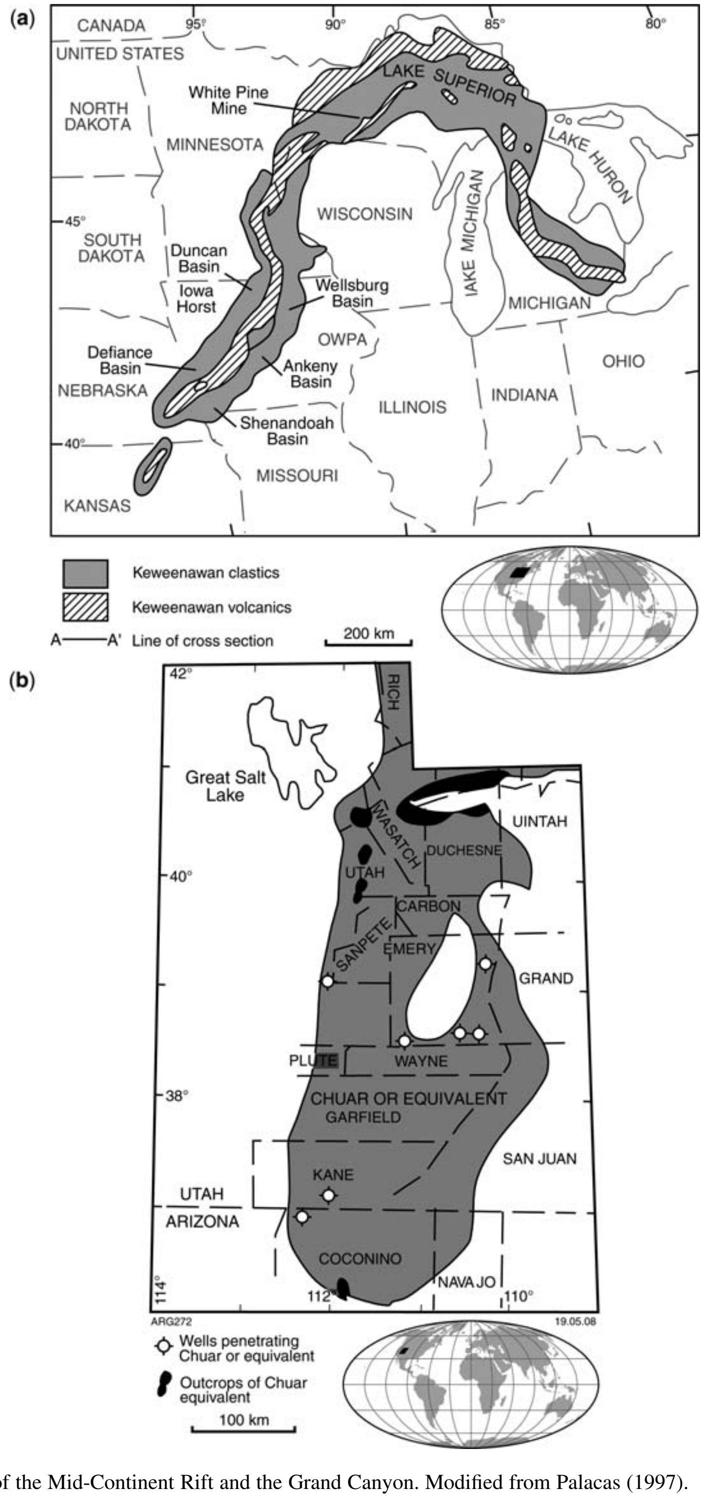

Fig. 9. Location of the Mid-Continent Rift and the Grand Canyon. Modified from Palacas (1997).

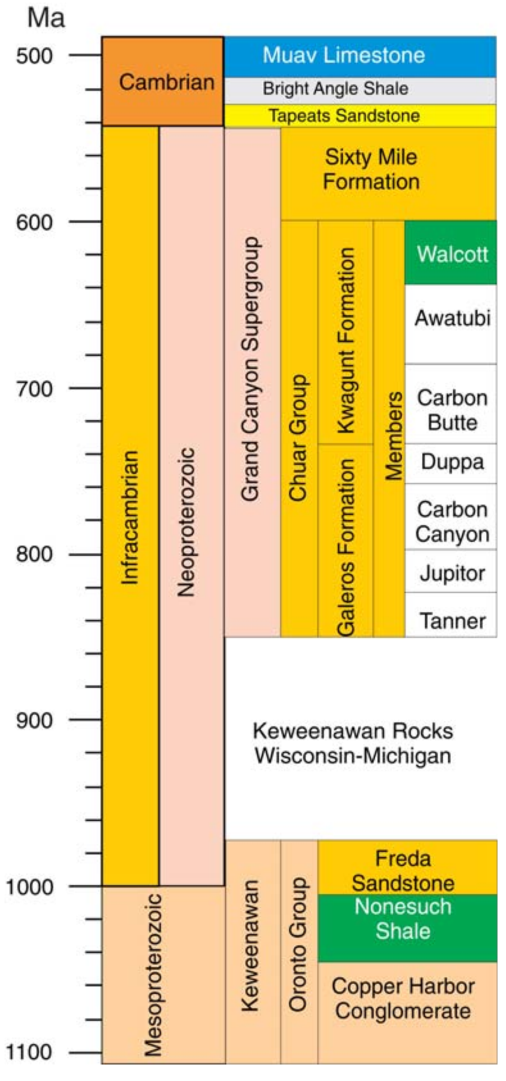

Fig. 10. Stratigraphic position of the Nonesuch Formation (Mid-Continent Rift) and the Chuar Group (Grand Canyon). Geographic positions are shown in Figure 9.

Midcontinent Rift system is a major structure in the North American Craton that is infilled with up to 15 km of dominantly mafic volcanic rocks, overlain by up to 10 km of clastic sedimentary rocks (Green 1983; Van Schmus & Hinze 1985; Mauk & Burruss 2002). These rocks crop out in the Lake Superior region of Michigan, northern Wisconsin and Minnesota, and extend in the subsurface through Minnesota, Iowa, Nebraska and into northeastern Kansas. The 1500 km-long Midcontinent Rift system is a failed rift, characterized by a series of asymmetric basins filled with a clastic succession up to 10 km thick (Anderson 1989) belonging to the Meso-Neoproterozoic Keweenawan Supergroup, which is subdivided into a lower Oronto Group and an upper Bayfield Group. The Copper Harbor Conglomerate and the Nonesuch and Freda formations together form the Oronto Group (Daniels 1982; Elmore *et al.* 1989).

In the Lake Superior area of the Midcontinent Rift system, indigenous oil seeps are present within thin intervals of silty shales in the Nonesuch Formation (1.05 Ga). These shales contain up to 3.0% TOC and are marginally mature to mature with respect to the zone of oil generation. Petroleum seeps and shows from the White Pine mine have been typed to the Nonesuch Formation (Pratt *et al.* 1991; Mauk & Hieshima 1992). The Neoproterozoic Chuar Group of the eastern Grand Canyon, Arizona, contains the organically richest, thermally mature source rocks with TOC contents of up to 10%. The generation potential of these source rocks is locally as high as 16 mg of HC per gram of rock and extractable organic matter contents of up to 4000 ppm. These organic-rich units of the Chuar Group may be the source of economic accumulations of gas and oil in Neoproterozoic–Palaeozoic reservoirs in northern Arizona and southern Utah (Palacas 1997).

The high risks of exploring Precambrian basins are well known, and hence careful evaluation of available geological, geophysical and geochemical data is essential in order to identify the most promising areas for the accumulation of HCs sourced from the Mesoproterozoic Nonesuch Formation of the Midcontinent Rift system and the Neoproterozoic Chuar Group of the Grand Canyon areas (Fig. 10).

Australian basins

Australia was the part of the Rodinia supercontinent until about 750 Ma when rifting occurred along both margins of the continent as Rodinia broke up. Australia then collided with India to form a major component of Gondwana as it finally amalgamated at around 530 Ma (Collins & Pisarevsky 2005). The assembling of Gondwana towards the end of the Precambrian and its Precambrian sedimentary record is similar to that of other Precambrian basins around the world. Three potential Proterozoic petroleum supersystems are recognized in Australia: the Palaeo-Mesoproterozoic McArthur, the Mesoproterozoic Urapungan and the Neoproterozoic Centralian systems (Bradshaw *et al.* 1994). As yet, there is no HC production from these Proterozoic sequences, but organic-rich rocks and significant oil and gas shows confirm the existence of Proterozoic petroleum systems. There is a significant gas accumulation at Dingo in the Amadeus Basin

(Ozimic *et al.* 1986; Bradshaw *et al.* 1994). The Palaeo-Mesoproterozoic McArthur Basin, the Neoproterozoic Centralian Superbasin and the Adelaide Rift Complex have been studied for scientific and commercial purposes since 1960 (Fig. 11). The Centralian Superbasin includes the Neoproterozoic fill (840–545 Ma) of the Amadeus, Georgina, Ngalia and Officer basins, which developed as a single depositional system but separated into different structural units mainly during the Petermann (600–540 Ma) and Alice Springs (400–300 Ma) orogenic events (Walter *et al.* 1992, 1995; Walter & Gorter 1993). The McArthur Basin covers an area of about 200 000 km^2 and contains four lithostratigraphic sequences (Tawallah, McArthur, Nathan and Roper groups) separated by regional unconformities (Plumb *et al.* 1980; Crick *et al.* 1988). The Tawallah group is mostly overmature. The McArthur and Nathan Groups consist mainly of evaporitic and stromatolitic cherty dolostones interbedded with dolomitic siltstone and shale that were deposited in a variety of marginal marine, lacustrine and fluvial environments. The Roper Group consists of quartz arenite, siltstone and shale deposited in a stable marine setting. The most organic-rich source rocks in the Palaeo-Mesoproterozoic McArthur Basin are reported from the lacustrine Barney Creek Formation (*c.* 1640 Ma) in the McArthur Group and from the marine Velkerri Formation (*c.* 1440 Ma) in the Roper Group (Jackson *et al.* 1986; Womer 1986; Rawlings 1999). Source rocks with comparable thickness and potential to Phanerozoic source rocks are present in these sequences with TOC of up to 7% containing type I and II kerogen, with thermal maturities ranging from overmature to marginal mature (Crick *et al.* 1988). Weeping oil and gas blowouts occurred in several shallow wells drilled in the McArthur Basin for lead–zinc exploration in the mid-1970s. Two different oil types have been observed: a heavily biodegraded oil containing associated galena, sphalerite and barite, which was probably generated and migrated during the phase of lead–zinc mineralization; and a 'golden honey colour', very volatile oil generated during the later tectonic events (Wilkins 2007). The Roper Group of McArthur Basin was one of the oldest sequences currently explored for HCs in Australia due to the

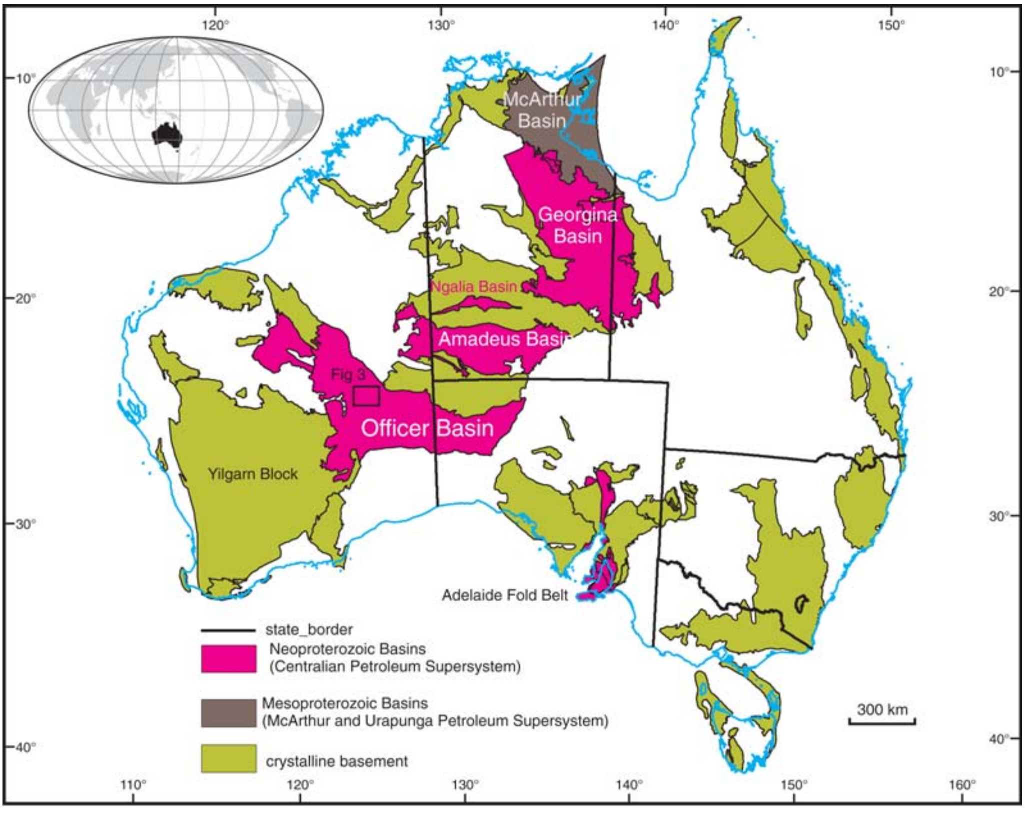

Fig. 11. Location of Australian basins containing prospective Mesoproterozoic and Neoproterozoic sequences.

presence of extensive oil and gas shows reported in stratigraphic and petroleum exploration wells drilled during the 1980s (Jackson *et al.* 1988).

The Neoproterozoic Centralian Superbasin contains four supersequences (Walter *et al.* 1995; Grey *et al.* 2005). Deposition of Supersequence 1 (early Cryogenian: Fig. 12) commenced with a thick sheet of sand, overlain by dolomites, limestones, evaporates and fine siliciclastics, which reach a total thickness of more than 3000 m in the Officer Basin (Yowalga area), as discussed later. This sequence is considered to be the most prospective for oil and gas exploration. The base of Supersequence 2 (mid to late Cryogenian: Fig. 12) is defined by the Sturtian glaciation deposits (Cryogenian), which are overlain by widespread igneous sills and by shales with interbedded carbonates and sandstones. This supersequence is mainly developed within the Amadeus Basin. The base of Supersequence 3 (late Cryogenian: Fig. 12) is defined by the Marinoan glaciation deposits, which are continent-wide (Preiss & Forbes 1981), and may be coeval with extensive tillites found over much of the globe (Knoll & Walter 1992; Hoffman & Schrag 2002) and the products of a period of global glaciation. Comparable glacigenic successions are reported from the Sinian of China (Yin 1985), the latest Proterozoic of Svalbard (Knoll 1992), the Vendian of Siberia (Moczydlowska *et al.* 1993) and the Cryogenian of Oman (Allen 2007).

The basal part of Supersequence 4 (Ediacaran: Fig. 12) contains an 'Ediacara fauna' and the upper part is Cambrian in age. This supersequence consists predominantly of sandstone, except within the Adelaide Rift complex where there are extensive shales and marls (the Brachina, Bunyeroo and Wonoka formations). A prominent central ridge existed in the Centralian Superbasin at this time (Paterson Province–Musgrave Block) and provided the main provenance for sand deposited on deltas building out into the northern basins. The northernmost part of the Centralian Superbasin remained marine at this time, while most of the southern region may have been emergent.

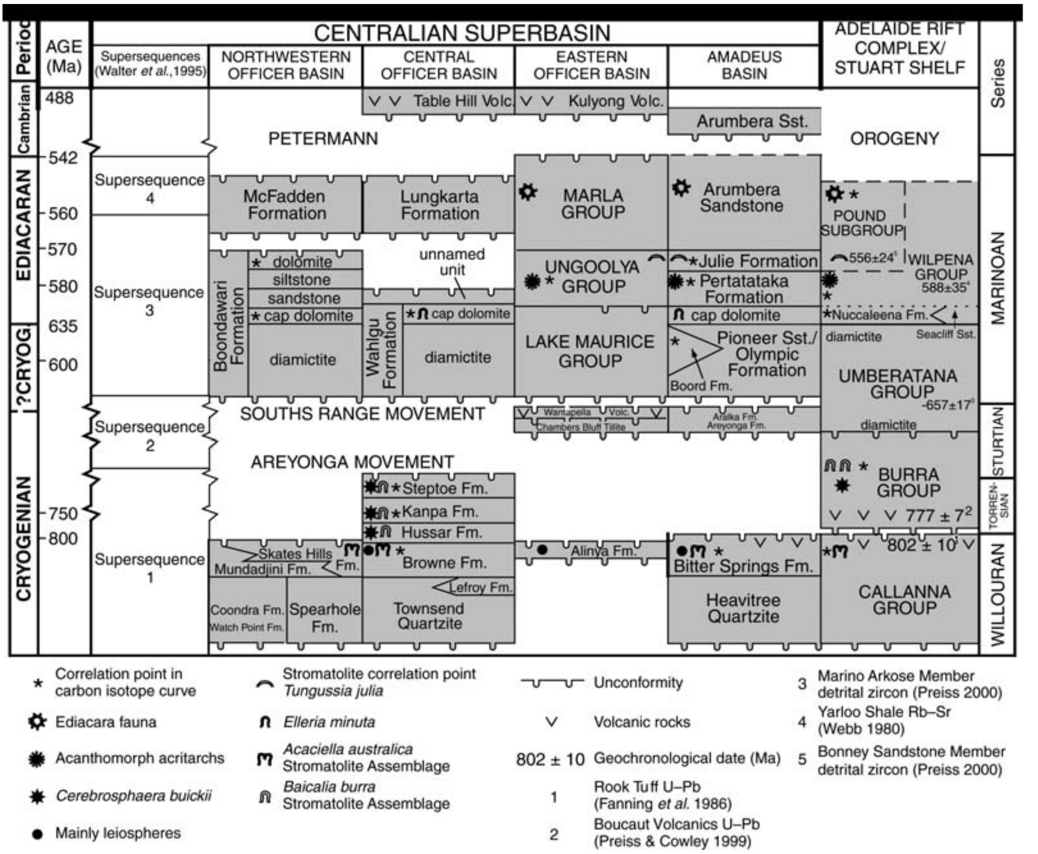

Fig. 12. Generalized stratigraphy of the Centralian Superbasin of Australia (after Grey *et al.* 2005).

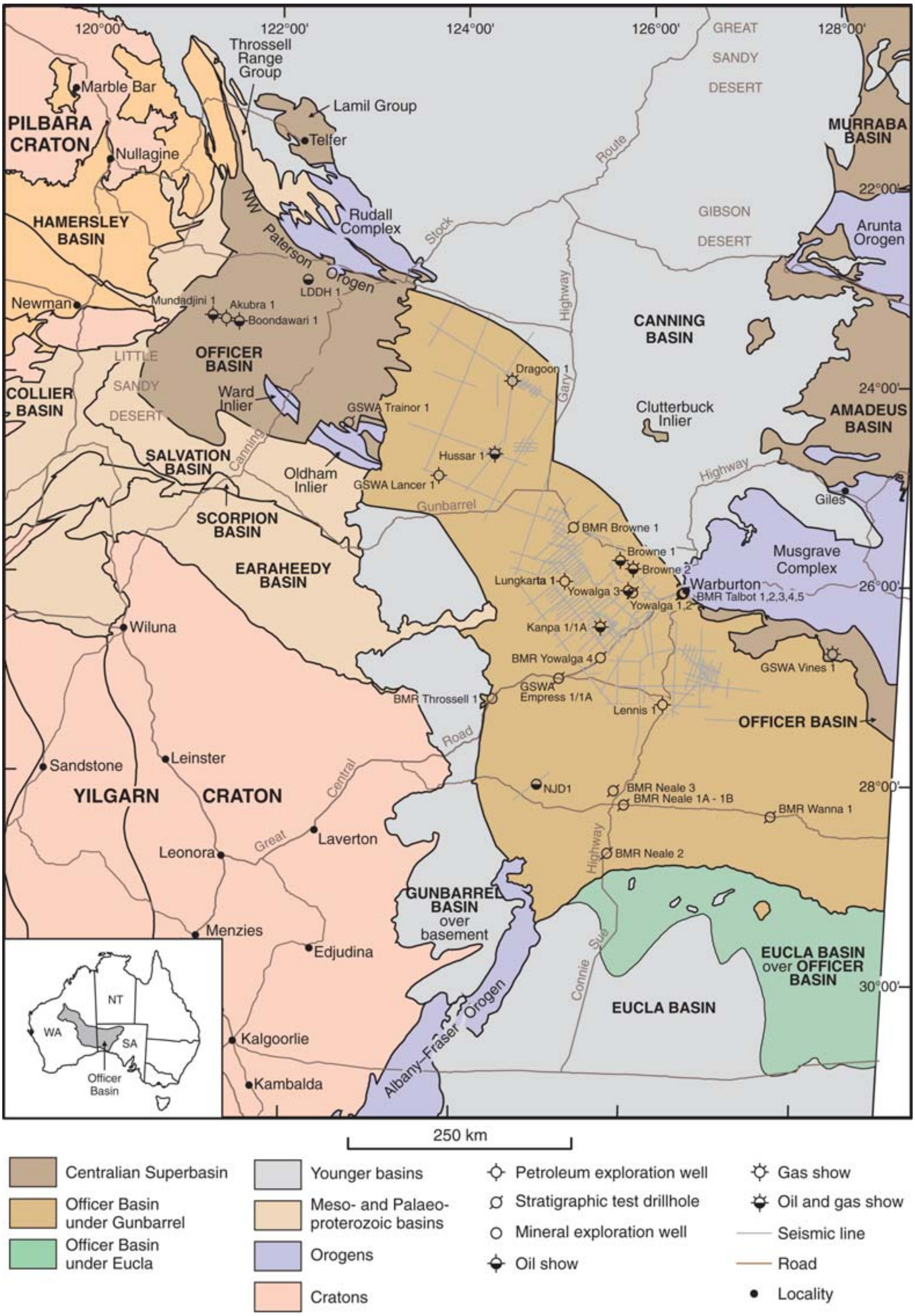

Fig. 13. Structural units, wells, seismic survey and petroleum shows in the Officer Basin, Western Australia.

Officer Basin of Western Australia petroleum geology

The petroleum systems of the Neoproterozoic Officer Basin of Western Australia are reviewed here as a case study. The Officer Basin is elongate with a NW–SE trend, and contains over 8000 m of Neoproterozoic strata, overlain by lower Palaeozoic rocks of the Gunbarrel Basin. Subsurface geochemical and geological data comprise 16 wells and 19 seismic surveys undertaken during three phases of petroleum exploration in the late 1960s (five wells) early 1980s (five wells) and the late 1990s (six wells) (Fig. 13). Yowalga-3 is the deepest

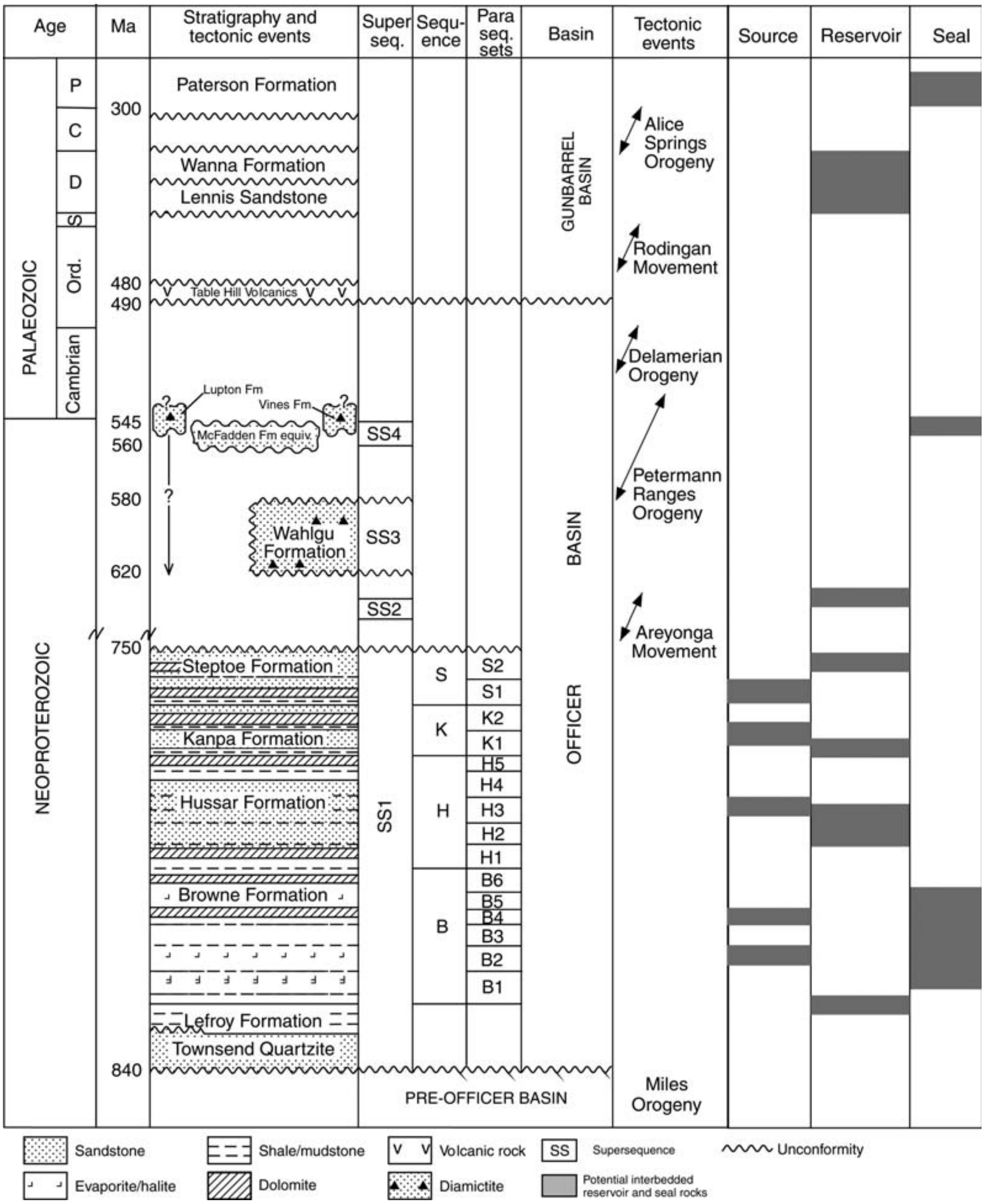

Fig. 14. Generalized time and seismic stratigraphy, tectonic events, source, reservoir and seal rocks for the Officer Basin, Western Australia.

well drilled in the basin. Chronostratigraphy, tectonic events, and the location of source, reservoir and seal rocks are summarized in Figure 14. Minor oil shows and numerous bitumen occurrences have been reported in many of the petroleum exploration wells drilled in the basin (Table 1), confirming the existence of a Neoproterozoic petroleum system. However, given the sparse well control, the ultimate petroleum potential of the vast underexplored Officer Basin remains unverified, but may be significant. Three unconformity bounded sedimentary successions exist throughout most of the Officer Basin in Western Australia (supersequences 1, 3 and 4) and these can be correlated with key tectonic episodes. The Areyonga Movement (Fig. 14) appears to be responsible for the larger structures in the Officer Basin, and separates Supersequence 1 from Supersequence 3. Structural and stratigraphic variations within the overlying supersequences 3 and 4 are attributed to later deformation related to the Petermann Orogeny (Wade *et al.* 2005). The Neoproterozoic traps are associated with faults, unconformities, facies changes and salt tectonics. Episodic salt movement may have resulted in the formation of traps within the younger successions. These younger traps occur throughout the basin, but remain untested. There is little seismic control on the distribution and potential facies of the lower units of Supersequence 1, namely the Townsend Quartzite and Lefroy Formation. However, the overlying units within Supersequence 1 are better understood, and consist of conformable and laterally correlative genetic parasequence units bounded by flooding surfaces. These parasequence units comprise the Browne (B 1–6), Hussar (H 1–5), Kanpa (K 1–2) and Steptoe formations (S 1–2). In most seismic lines Supersequence 1 is characterized by continuous parallel reflectors that are traceable across most of the basin, except where truncated by a younger unconformity (Fig. 15). The presence of mobile salt within the Officer Basin has resulted in a wide range of possible trap configurations. Warren (1989) defined many of the possible salt-related trap styles based on structure and porosity. Many of these traps are related to thrust faults that typically initiated within the Browne Formation salt units, and generate drag rollover structures within the overlying strata. Salt pillows also generate four-way dip closures in the suprasalt section. Unconformity-related traps may have developed where Supersequence 1 strata have been tilted and significantly eroded adjacent to salt injection features and along the basin margins, and extensive karst secondary porosity may have been created within carbonates through leaching of soluble components such as halite, anhydrite and carbonate. Stratigraphic traps may be related to differential subsidence that has resulted in downlap and onlap of units, creating pinch-outs. Additional traps related to facies changes may have developed where halite and anhydrite have been formed in desiccation zones, plugging the porosity of the sediments either during, or after, deposition. Such traps also formed early with respect to charge. Frequent emergence is well documented in Neoproterozoic successions in the Officer Basin, and channels filled with high-energy, reservoir-quality sediments, sealed by the subsequent transgressive shale, are identified as potential exploration targets. The development of structural traps of significant size in the Officer Basin of Western Australia is demonstrated in

Table 1. *Hydrocarbon shows, Officer Basin, Western Australia*

Well	Quality of show	Formation	Formation age
Boondawari-1	40% oil fluorescence in core	Spearhole Formation	Neoproterozoic
Browne-1	Gas cut mud, cut fluorescence, trace oil in core	Paterson Formation Browne Formation	Permian Neoproterozoic
Browne-2	Gas cut mud, cut fluorescence, trace oil in core	Paterson Formation	Permian
Dragoon-1	Mud gas to 10% methane equivalent, including hydrocarbons up to pentane	Browne Formation	Neoproterozoic
Hussar-1	Mud gas readings to 1000 ppm. Possible gas blow On air lift. Trip gas to 4.6% total gas. 72% oil saturation from log analysis	Kanpa Formation Hussar Formation	Neoproterozoic
Kanpa-1A	Dull yellow-orange sample fluorescence, light yellow-white cut fluorescence, brown oil stains in sandstone and dolomite cuttings	Kanpa Formation	Neoproterozoic
LDDH-1	Bitumen in core	Tarcunyah Group	Neoproterozoic
Mundadjini-1	10% oil fluorescence in core	Spearhole Formation	Neoproterozoic
NJD-1	Bleeding oil and bitumen in core	Neale Formation	Neoproterozoic
OD-23	Bleeding oil and bitumen in core	Scorpion Group	Mesoproterozoic
Vines-1	Total gas peaks 25 times background	?Supersequence 1	Neoproterozoic

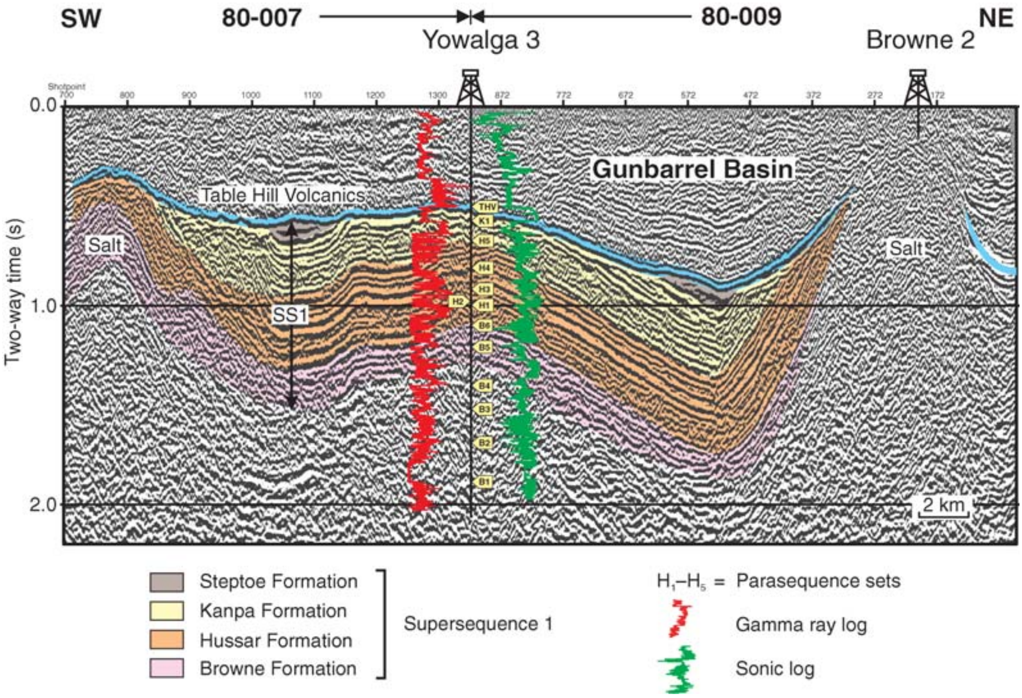

Fig. 15. Composite seismic section of Yowalga-3 and Browne-2 wells, and erosion of Supersequence 1 strata between salt emplacements in the Yowalga area.

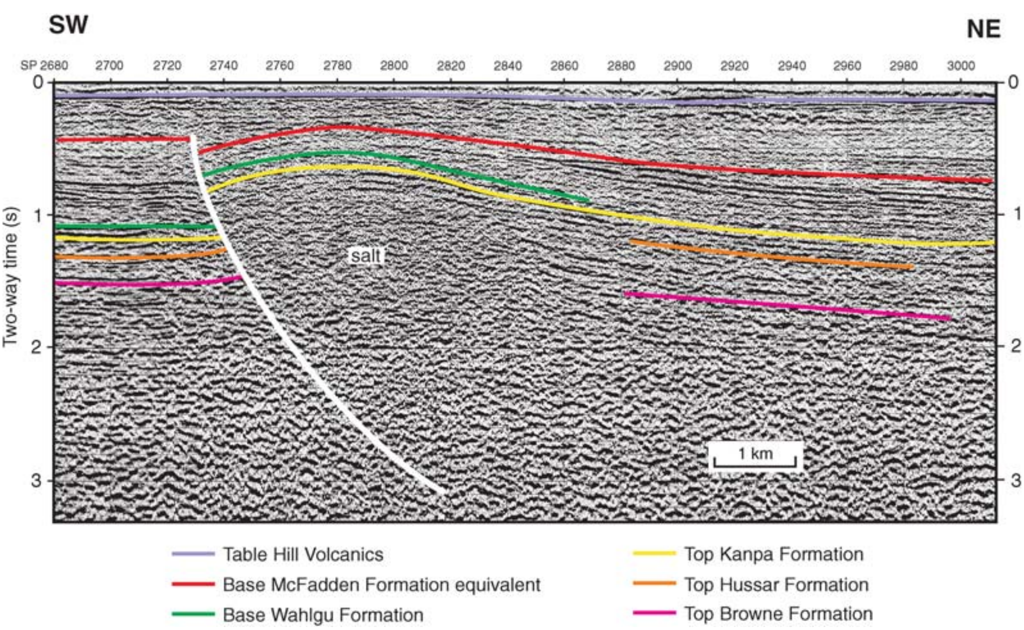

Fig. 16. Seismic line N 83-11 showing an angular unconformity between the Wahlgu and the McFadden Formation equivalent. The Wahlgu Formation is deeply eroded in this location. High-angle reverse faulting associated with salt emplacement resulted in minor displacement of the post-Supersequence 3 unconformity.

Table 2. *TOC and Rock-Eval data for samples with TOC content over 0.90%*

Well	Depth (m)	Sample	TOC (%)	T_{max} (°C)	S_1	S_2	S_3	$S_1 + S_2$	PI	HI	OI
Empress-1A	587.9	Core	1.38	418	0.43	6.20	0.11	6.63	0.06	449	8
Empress-1A	588.4	Core	1.52	413	0.46	6.44	0.15	6.90	0.07	424	10
Empress-1A	768.2	Core	0.93	421	0.66	4.02	0.44	4.68	0.14	432	47
Kanpa-1A	3412.2	SWC	1.41	436	1.78	4.83	0.75	6.61	0.27	343	53
NJD-1	327.5	Core	6.64	430	0.7	23.47	1.04	24.17	0.03	353	16
NJD-1	328.5	–	3.18	432	0.26	15.83	0.39	16.09	0.02	498	12
NJD-1	400.8	–	1.22	443	0.74	1.27	0.10	2.01	0.37	104	8
NJD-1	502.6	–	21.50	442*	32.11	104.00	1.94	136.11	0.24	484	9
NJD-1	502.7	–	1.10	430*	1.06	4.76	0.45	5.82	0.18	433	41
Normandy LDDH-1	222.8	Core	1.61	450	0.42	2.11	0.32	2.53	0.17	131	20
Normandy LDDH-1	529.6	Core	2.05	471	1.05	1.40	0.07	2.45	0.43	68	3
Throssell-1	184.9	Core	1.37	428	0.35	1.06	0.31	1.41	0.25	77	23
Yowalga-3	1484.0	Cuttings	1.23	421	0.49	3.00	0.47	3.49	0.014	244	38

Notes: TOC, total organic carbon; T_{max}, temperature of maximum pyrolytic yield (S_2); S_1, existing hydrocarbons (HC); S_2, pyrolytic yield (HC); S_3, organic carbon dioxide; $S_1 + S_2$, potential yield; PI, production index; HI, hydrogen index; OI, oxygen index; SWC, side wall core.
*Bitumen-rich samples.

Figure 16. Basin modelling studies indicate that HC generation occurred in the Officer Basin in three main phases, during the latest Neoproterozoic, the Cambrian and the Late Palaeozoic. These phases of oil generation correlate well with initial migration and trap formation during the Areyonga Movement, and late migration and trap formation during the later deformations (Apak *et al.* 2002; Ghori 2002).

Petroleum geochemistry

The available geochemical data indicate the presence of thin source rocks with fair–excellent HC generating potential within the Neoproterozoic successions in the Browne-1 and Browne-2, Empress-1/1A, Hussar-1, Kanpa-1A, LDDH-1, NJD-1, Throssell-1 and Yowalga-3 wells and mineral drill holes. The organic-rich source beds occur in the B2 and B4 parasequences of the Browne Formation, the H3 parasequence of the Hussar Formation, the K1 parasequence of the Kanpa Formation and the S1 parasequence of the Steptoe Formation. Pyrolysis gas chromatography and extract analyses indicate that most of the organic matter in the source beds is oil- and gas-generating type II kerogen (Table 2 and Fig. 17).

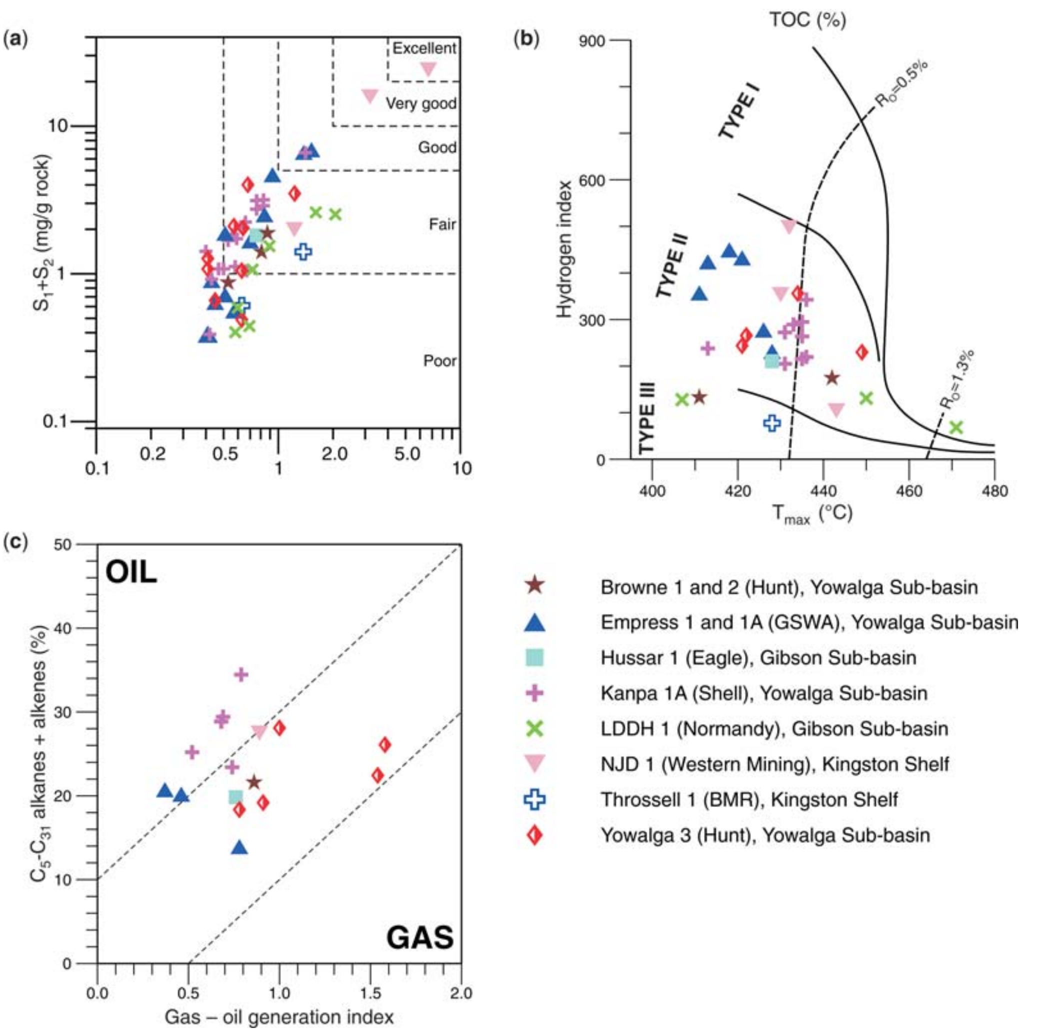

Fig. 17. Source-rock characterization of the Neoproterozoic Officer Basin: (**a**) petroleum-generating potential as a function of organic richness v. potential yield, for samples interpreted as reliable; (**b**) type of kerogen as a function of T_{max} v. hydrogen index, from Rock-Eval pyrolysis; and (**c**) type of kerogen as a function of oil proneness (C5–C31 alkanes + alkenes) v. gas–oil generation index (C1–C5)/C6+) from pyrolysis–gas chromatography.

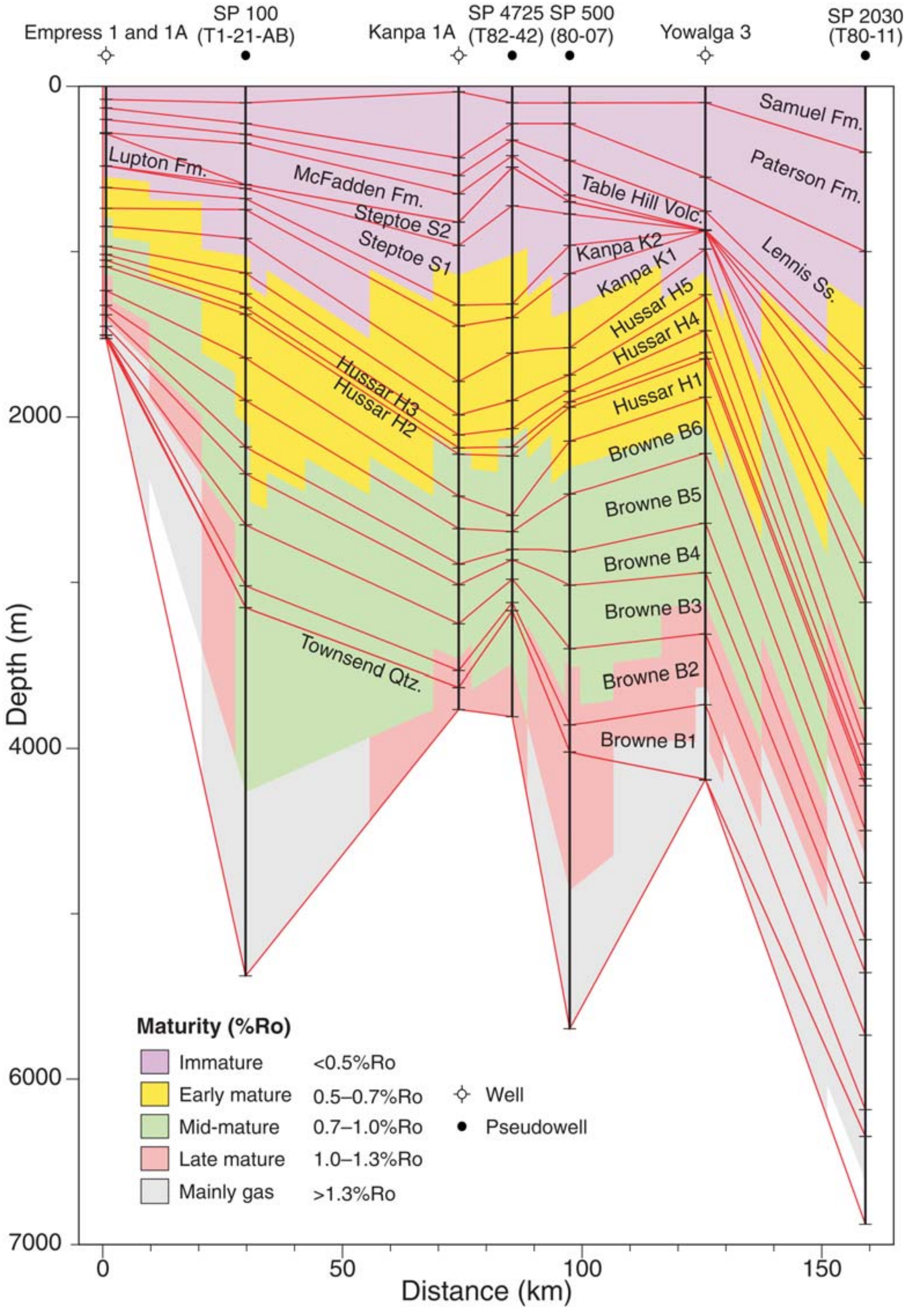

Fig. 18. Present-day maturity across the Yowalga area, from Empress-1/1A in the south to SP 2030 on seismic line T80-11 in the north, based on 2D modelling.

One- and two-dimensional basin modelling studies suggest that the optimum maturity for HC generation within the Browne Formation was reached early in the basin history and that most of the HC generation potential of this formation was exhausted during the Neoproterozoic. However, the Hussar, Kanpa and Steptoe formations were not buried so deeply, and the generation of HCs from these units extends into the Phanerozoic. In parts of the Gibson area (LDDH-1) and over the salt diapirs (Dragoon-1, Browne-1 and Browne-2) the oil-generating window is comparatively shallow, but the oil window is very deep in the Yowalga area (Yowalga-3). The extent and the effects of Mesozoic and Cenozoic tectonic events are poorly understood because the preserved post-Alice Spring Orogeny section is thin and irregularly distributed. Present-day maturity across the Yowalga area is shown in Figure 18. The vast area covered by the western Officer Basin is very poorly explored, and the sparse well control precludes a comprehensive assessment of the source rock potential of the Neoproterozoic succession. The existence of volumetrically significant source rocks of a commercially viable petroleum system cannot be verified with the available dataset. However, the fact that thin, but good-quality, source rocks have been identified in the Browne, Hussar, Kanpa and Steptoe formations, that a significant part of the Neoproterozoic section is presently within the oil window, and that the succession contains good-quality reservoirs and seals suggests that further exploration of this frontier region is warranted.

Conclusions

Oil and gas accumulations will continue to be found in Proterozoic rocks worldwide where organic-rich source rocks and good-quality reservoirs are present, and where the source rocks are not thermally overmature and/or the presence of effective super-seals allows preservation of early generated hydrocarbons. Many of the worlds ‘traditional’ proven petroliferous basins are approaching exploration maturity and much of the ‘easy oil’ has now been found. As a result, significant exploration effort is now being devoted to deep-water and harsh environments worldwide. This review suggests that there is also potential for new discoveries to be made in the Infracambrian (Neoproterozoic–earliest Cambrian age) basins worldwide, including those in Africa, Australia, India-Pakistan and the United States. With further concerted exploration these areas may yet join the already producing Neoproterozoic–early Cambrian basins of China, Russia and the Sultanate of Oman.

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