The North West Shelf, Western Australia's super basin, in the twenty-first century

Peter Purcell and Ian Longley

ABSTRACT

The North West Shelf of Australia, extending some 2400 km along the continent's northwestern coast, is the nation's premier hydrocarbon province, and is rivaled only by Qatar as the world's leading liquified natural gas exporter. It is underlain by four large sedimentary basins, the Northern Carnarvon, Roebuck, Browse, and Bonaparte Basins, respectively, from southwest to northeast: all contain significant reserves of hydrocarbons. These basins constitute the Westralian Super Basin, but industry has used the term North West Shelf as a geographic term of convenience for decades, covering not only the continental shelf but also adjacent deep-water regions. Sediment thickness reaches a maximum of nearly 20,000 m, with superimposed Paleozoic, Mesozoic, and Cenozoic successions. At the end of 2021, the estimated proven and probable production available from the historical, current, and sanctioned developed fields in the North West Shelf basins was 138 TCF of gas, 3100 million bbl of oil, and 2600 million bbl of condensate. Discovered undeveloped resources are currently estimated to be 97 TCF of gas, 350 million bbl of oil, and 1600 million bbl of condensate. The challenge for industry is to commercialize the undeveloped gas fields and to discover new oil and gas resources. New concepts and processes will be required to ensure exploration and production success, almost certainly in the face of increased public and political opposition. That success is vital for Australia's future and for the health of the economy and the people of the Australasian region. Gas, which was once seen as the curse of the North West Shelf but proved to be its fortune in the late twentieth century, must continue to provide for the nation and her neighbors well into the century ahead.

Manuscript received March 16, 2022; provisional acceptance April 11, 2022; revised manuscript received June 14, 2022; revised manuscript provisional acceptance August 8, 2022; 2nd revised manuscript received October 9, 2022; final acceptance October 15, 2022.
DOI:10.1306/02072322035

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ACKNOWLEDGMENTS

The authors acknowledge the valuable assistance provided by IHS Markit, now part of S&P Global, and thank them for the access provided to their database on the North West Shelf. Also acknowledged is Perth-based company GIS-Pax, whose regional geological mapping and evaluation software "Player" was used to generate many of the graphs and images presented in the figures included in this paper (see www.gis-pax.com for details). Special thanks to Andrew Murray for his input and advice on geochemical aspects. Thanks also to colleagues Peter Baillie, John Gorter, Robert Seggie, and Fred Wehr, who provided useful comments on the draft paper. We are especially grateful to Steve Moss and Darren Ferdinando for their generous time and major efforts in formally reviewing the paper for the AAPG editors. We benefitted greatly from their many suggestions. We also express our thanks to Nick Ellis of Ellis Drafting Pty. Ltd. for drafting support and advice.

INTRODUCTION

The North West Shelf (NWS) petroleum province extends approximately 2400 km along the northwestern coast of Australia from near Exmouth in the southwest to near Darwin in the northeast (Figure 1). The NWS is not a physiographic province but a geographic term of convenience, used by the industry for decades and covering not only the Australian continental shelf but also adjacent deep-water provinces such as the Exmouth Plateau. The NWS is underlain by four large sedimentary basins, the Northern Carnarvon, Roebuck, Browse, and Bonaparte Basins, respectively, from southwest to northeast (Figure 2); all contain significant reserves of hydrocarbons. The maximum thickness of sediment in the basin is locally nearly 20,000 m, composed of superimposed Paleozoic, Mesozoic, and Cenozoic successions. Approximately 2060 wells have been drilled in these basins since the mid-1950s: 935 exploration wells, 430 appraisal wells, 720 development wells, and 76 stratigraphic or service wells. This regional basin system is properly known as the Westralian Super Basin (Yeates et al., 1987) but is ubiquitously referred to by industry as the NWS. In *AAPG Memoir 40*, Forrest and Horstmann (1986) noted the many, then recent, oil and gas discoveries on the NWS and predicted the region would become a major petroleum province in the future. Nearly 40 yr later, it is appropriate that another AAPG publication should acknowledge the accuracy of that prediction.

By the 1980s, it was clear that the discovery and development of the oil and gas resources of the NWS would be vital to Australia's security and welfare in the twenty-first century (Purcell and Purcell, 1988). Much of that imperative has been accomplished. At the turn of the century (specifically, at the end of 2000), the discovered and developed reserves on the NWS were approximately 30 and 10.2 billion BOE, respectively. By the end of 2021, the discovered reserves had increased by more than 56% to 47 billion BOE, with developed reserves soaring 280% to 36 billion BOE. Australia had become the world's largest liquified natural gas (LNG) exporter and is now a near second to Qatar (Australian Petroleum Production and Exploration Association, 2021). The oil and gas fields of the NWS and the associated pipelines and processing facilities are shown on Figure 2, which identifies all fields mentioned in this paper. The impact of the NWS's oil and gas production on the national economy and well-being is clear. Sixty-five percent of Australia's power supplies in 2020 came from oil (39%) and gas (26%). The national trade surplus in oil and gas/LNG in 2019 to 2020 was nearly A$30 billion, courtesy of the A$50 billion worth of LNG exports, 70% of which came from the NWS. Australia's near-balance of crude oil imports/exports also comes largely from the NWS, which produces 67% of the nation's annual 48 million bbl of oil production and 89% of the annual condensate production (Australian Petroleum Production and Exploration Association, 2021). In addition, there are annual taxation, rent, and royalty payments to the federal and state governments of nearly A$6 billion, based on the 2018–2019 Australian Petroleum Production and Exploration Association (APPEA) Financial Survey.

This paper follows the major review of the NWS at the end of the twentieth century by Longley et al. (2002) and chronicles the main exploration and development activity in the initial decades of the twenty-first century. The distinction between twentieth and twenty-first century activity is highlighted on the discovery history plots discussed later, but the twentieth century activity is discussed only where it provides context for the recent developments. Only summary comments on the history of exploration and the petroleum geology of the region are provided. Both are the subject of voluminous publications, notably by the APPEA (previously, the Australian Petroleum Exploration Association) and the Petroleum Exploration Society of Australia, as well as Geoscience Australia (and predecessor organizations) and the Geological Survey of Western Australia. Key publications include Wilkinson (1983), Australian Petroleum Exploration Association (1988), Barber (1988, 2013), Purcell and Purcell (1988), Australian Geological Survey Organization North West Shelf Study Group (1994), and Kopsen (2002). A detailed summary of the known petroleum geology of the NWS at the end of the twentieth century has been provided by Longley et al. (2002).

In the decades ahead, the Australian petroleum industry on the NWS faces challenges arising from the region itself and from the First World's commitment to a 2050 net-zero carbon target. Local issues include the gas-prone nature of the basins, the enormous remaining volumes of undeveloped gas (currently estimated to be 97 TCF), the costs of development projects, and well-funded, aggressive environmental activism. All are impediments to exploration and development, especially for smaller local companies. Regardless of the development of alternate energy sources, it is increasingly clear that gas will remain an important element of future global power supplies, and the gas resources of the NWS will be an important part of that supply. A key objective of this paper is to understand the lessons of the recent past exploration on the NWS and to derive, where possible, some insight into the plays and the significant exploration potential that remain untested across this vast region.

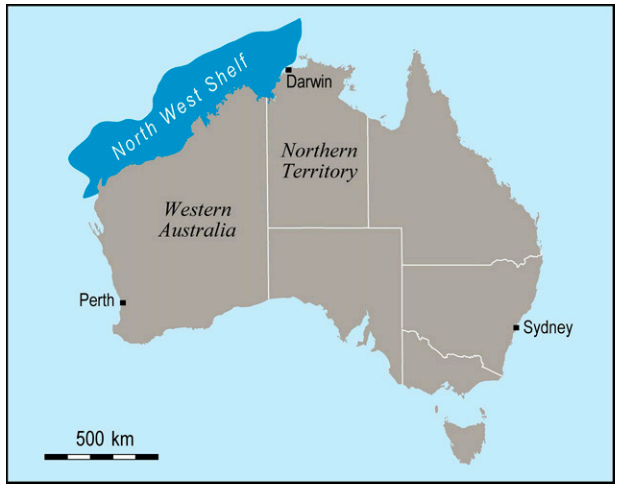


Figure 1. Location map of the North West Shelf in Australia.

GEOGRAPHY AND PHYSIOGRAPHY

The term NWS has been used by the industry for more than 60 yr for the offshore region along Australia's northwestern margin. Being a term of convenience, it is neither rigorously defined nor officially designated, and opinions differ about its limits and even its value as a term. In its conception and more popular usage, the term applies only to regions within Australian waters and ends at the Timor Trench, previously interpreted as a crustal discontinuity between the Australian continental plate and the Indonesian volcanic arc (Hamilton, 1979). Subsequent recognition that the Australian continent extends beyond the trench (Chamalaun et al., 1976; Bowin et al., 1980; Baillie et al., 2004) complicated that simple definition and was given political expression in the 2018 Maritime Boundary Treaty between Timor-Leste and Australia. An alternate, more recent definition of the NWS emphasizes that geological continuity with Timor-Leste and allows the NWS term to incorporate part of the Banda Arc province of Indonesia and Timor-Leste, albeit by surrendering its "Australian" identity (Longley et al., 2002). In this paper, we have accepted the NWS as essentially an Australian province, albeit including an area recently ceded to Timor-Leste.

The vastness of the NWS and its distance from the main cities and infrastructure hindered early

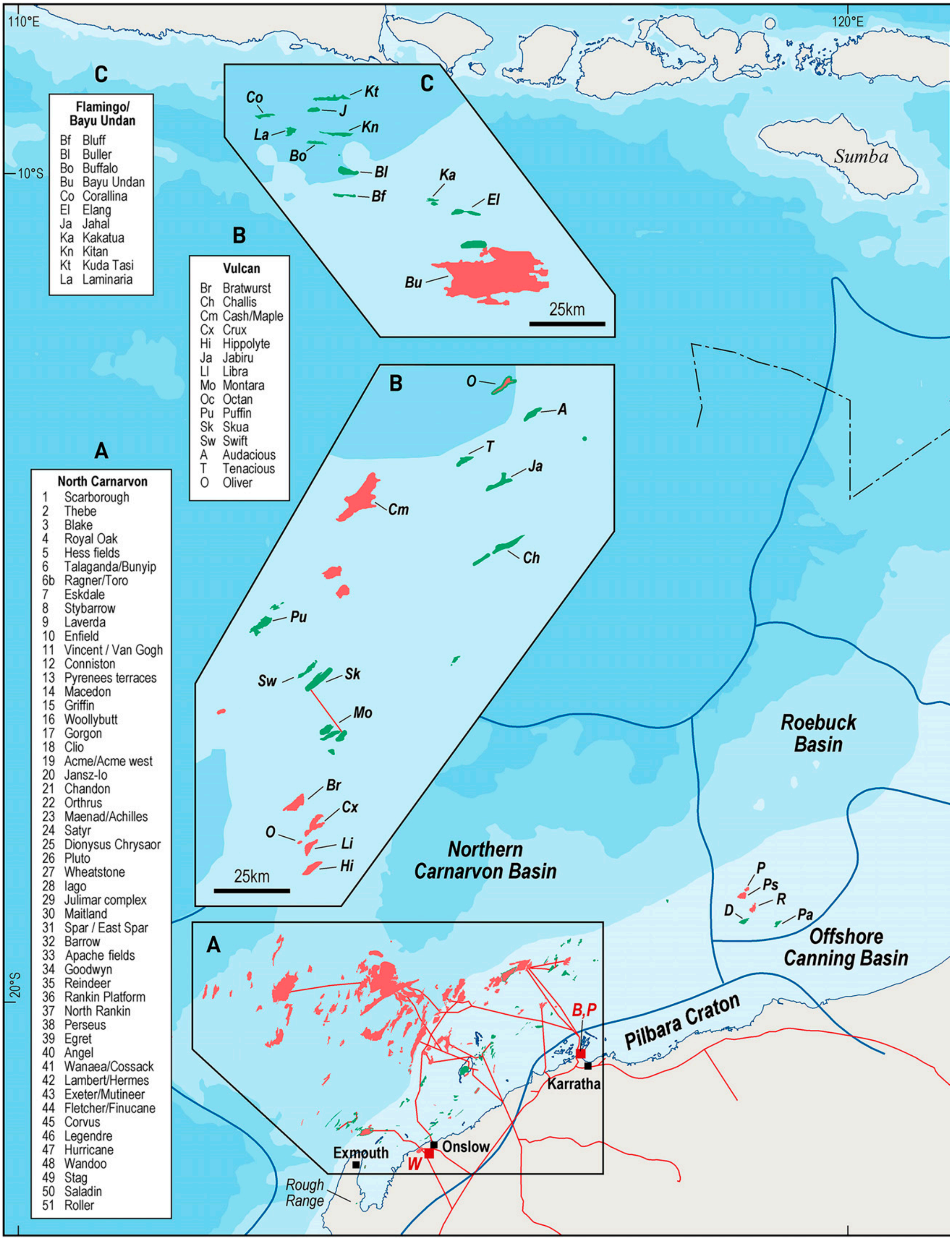


Figure 2. A map of the North West Shelf showing bathymetry, oil and gas fields, pipelines, and liquified natural gas (LNG) processing facilities. All fields referred to in the text are identified on the main map or on the enlarged insets (North Carnarvon (A), Vulcan (B), and

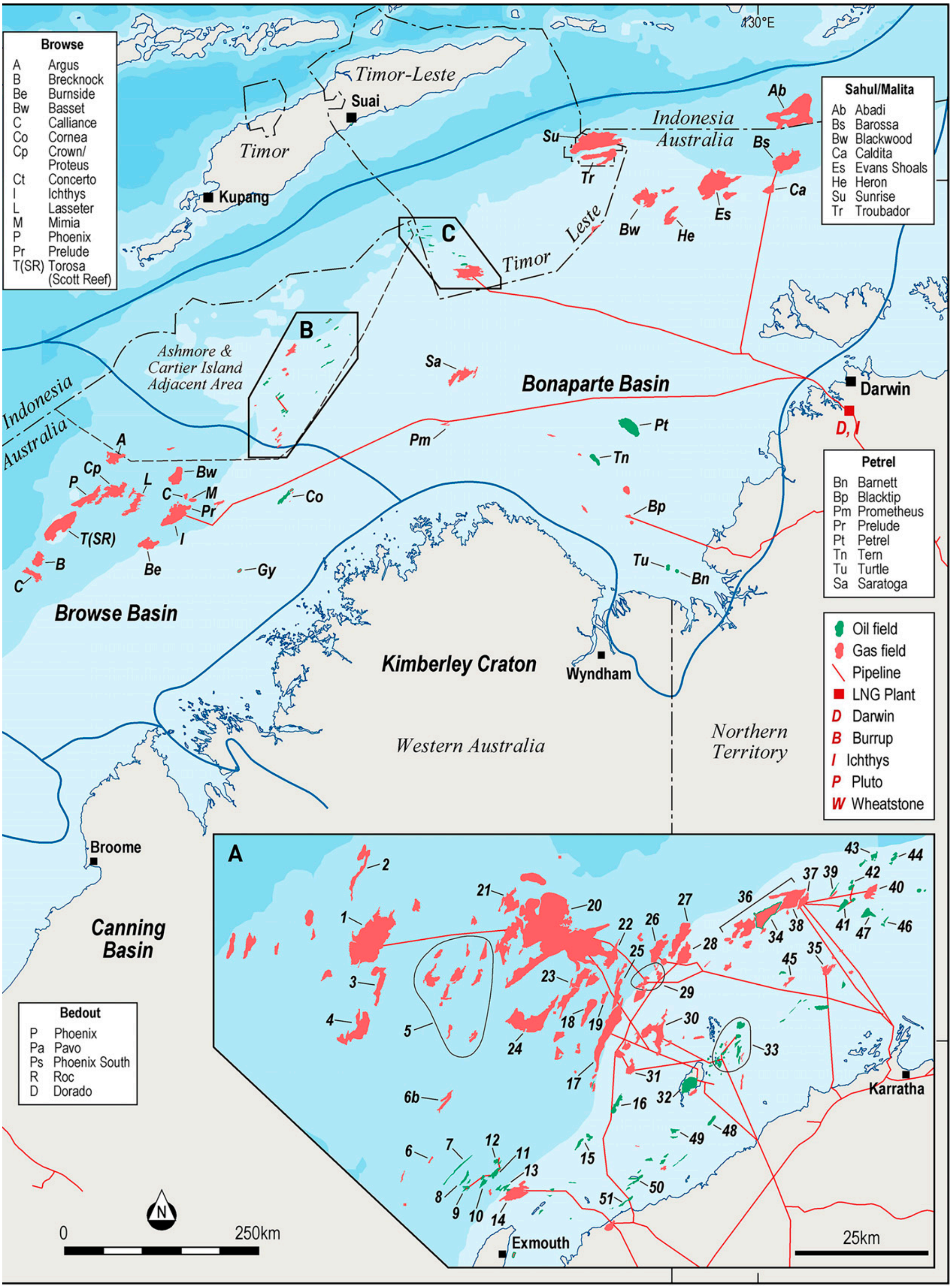


Figure 2. Continued. Flamingo/Bayu-Undan (C)) of parts of the Northern Carnarvon and Bonaparte Basins. This map includes content supplied by IHS Markit (Copyright © IHS Markit, 2022. All rights reserved).

exploration. Covering more than 700,000 km^2 and with an average width of approximately 300 km, the NWS begins 1200 km north of Western Australia's capital city of Perth and extends over 2400 km to near Darwin, the capital of the Northern Territory. To illustrate that enormity for London-based Burmah Oil Company (B.O.C.) management, the operator for the Woodside joint venture (JV) in the early years commonly drew a same-scale image of Great Britain alongside their permit maps. For a long time, the gas fields at Scott Reef on the edge of the continental shelf were dubbed "the loneliest gas in the world." In the 50 yr since, the infrastructure established in Perth and Darwin and at the industrial development centers of Karratha and Port Hedland have somewhat pacified the tyranny of distance, to use the famous Australian expression, but operating in such a remote and vast region continues to challenge industry operationally and economically.

The NWS has enormous environmental, cultural, and social value for Australians. The waters along the Kimberley coast fringing the Browse Basin are winter birthing grounds of humpback whales and the spectacular fringing reefs at Ningaloo in the Exmouth Sub-basin are world famous for whale sharks. Many islands, atolls, and shallows host unique marine wildlife and are recreational destinations for Australian and international visitors. Onshore, endless beaches and rugged ranges and gorges are equally spectacular, and the landscape itself has cultural importance for its Aboriginal connections, including the Murujuga petroglyphs of the Burrup Peninsula and the Wandjina and Gwion (or Giro-giro) art of the Kimberley caves. Considerable government and social focus is on protecting this unique environment from damage: the North West Marine Region is subdivided into various provinces, each with regulations protecting its specific ecological features, such as ancient coastlines, isolated reefs, and aerially extensive shoal complexes. Much of the scientific knowledge that underpins those protective policies and procedures comes from studies conducted by the oil industry, which has operated there for nearly 70 yr with very few incidents and no lasting detrimental impact.

Details of the physiography are provided by Carrigy and Fairbridge (1954), Fairbridge (1955), Phipps (1967), and Van Andel and Veevers (1967) and are summarized along with aspects of the culture and nomenclature in Purcell and Purcell (1988).

BASIN DEVELOPMENT

The northwest margin of the Australian continental plate formed during the fragmentation of Gondwana along the "southeast" Tethys ocean margin during the late Carboniferous to Early Cretaceous. A series of microcontinents were progressively rifted and rafted away from Gondwana during that time and are now sutured together in the tectonic "jigsaw" of Southeast Asia (Metcalfe, 1999, 2013). In their wake, the Westralian Super Basin developed along the margin, with four large basins, from southwest to northeast, the Northern Carnarvon, Roebuck, Browse, and Bonaparte Basins, respectively, as shown on Figures 2 and 3. Figure 2, like many of the other maps and displays on figures in this paper, includes content supplied by IHS Markit (Copyright © IHS Markit, 2022. All rights reserved). The basin boundaries shown on these maps and other maps in this paper conform generally to most NWS basin classifications but differ in local detail. These comments on basin development are a brief summary only and much greater detail is available in the cited references.

The rifting of different blocks along the Westralian Super Basin margin can be conceptually divided into Oxfordian and younger rifting events, for which the oceanic spreading history is recorded and preserved in the magnetic striping in the Argo and Gascoyne ocean basins and older rifting events for which the oceanic record has been subducted and "lost" under the Banda Arc system (Heine and Muller, 2005). These earlier events are consequently less well constrained and more open to differing interpretations.

The recognition of the importance of both the Mesozoic rift system and the late Paleozoic precursor rifting in determining the hydrocarbon resources of the Westralian basins coincided with the emergence of plate tectonic concepts in the late twentieth century and underwrote an industry perception of the NWS as a "passive" rifted margin: rift basins formed during continental breakup and were overlain by sag basins, which formed as the new margins collapsed. This view was occasionally criticized as simplistic (for example, Etheridge and O'Brien, 1994) and has slowly yielded to change under the influence of higher-quality seismic reflection data and new tectonic concepts. Of particular relevance was the discovery of the relative "dearth of extensional faults" (Australian Geological Survey Organization North West Shelf Study Group, 1994,

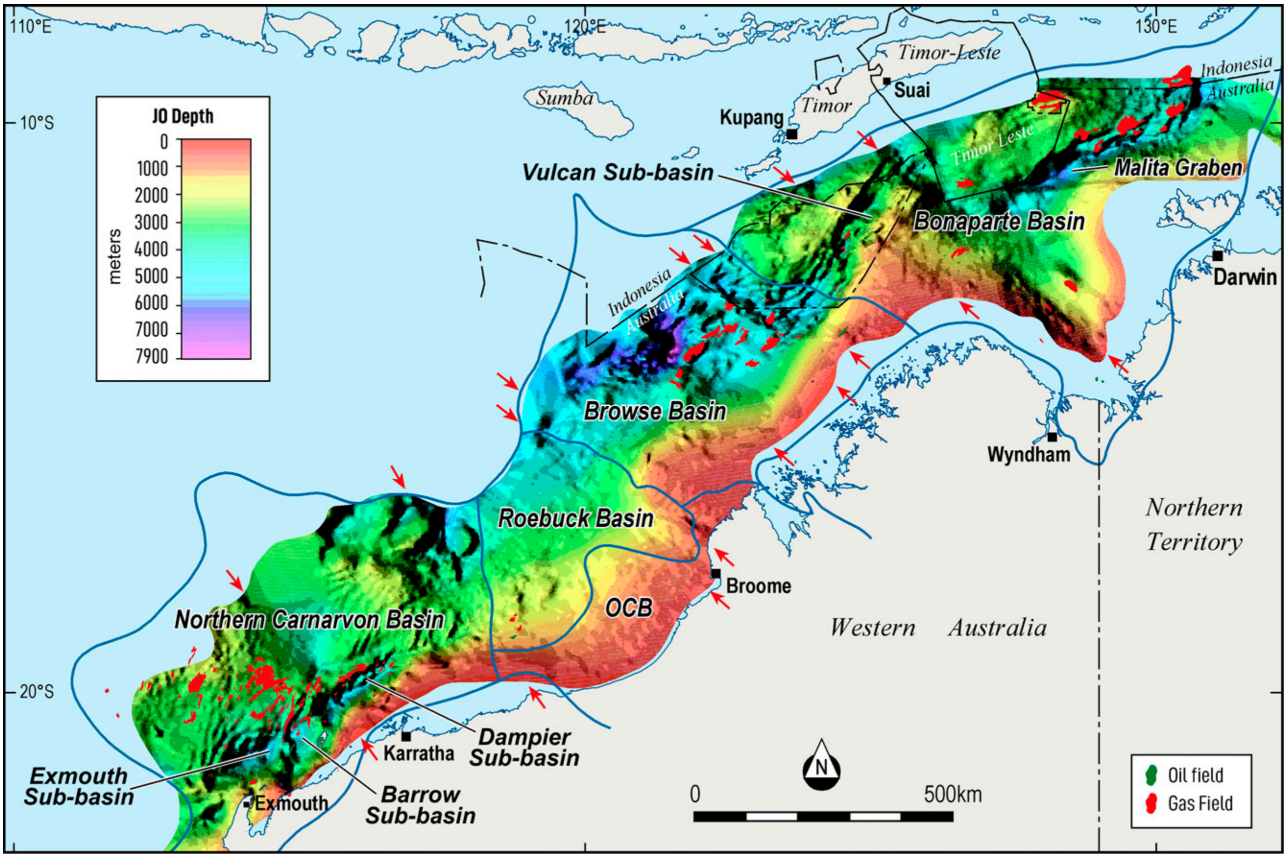


Figure 3. Upper Jurassic (Oxfordian) (JO) three-dimensional depth–structure map showing basin outlines. The prominent Upper Jurassic Exmouth, Barrow, Dampier, and Vulcan rifts are highlighted. Several basin-bounding Precambrian lineaments are marked by red arrows. Modified from figure 4 in Longley et al. (2002).

p. 72) in the sedimentary section, other than on the inboard flanks of the Northern Carnarvon and Bonaparte Basins particularly. Basin subsidence in the Westralian Super Basin was primarily related to thinning events in the lower crust, identifying the NWS as an upper plate margin (Stagg et al., 1999).

Current models of the tectonic development of the Westralian Super Basin present the Permian–Carboniferous, Triassic, and Jurassic rifting as consequent to the separation from Gondwana of various microcontinental fragments. These blocks are recognized today as geological terranes within Southeast Asia, and their specific paleolocations along the Australian continental margin are largely conceptual. Correspondingly, there is general agreement on the timing of events but considerable variation in the names and paleolocations assigned to the blocks. In the late Carboniferous, when the Cimmerian strip of continental fragments began to separate from Gondwana (Sengor, 1987), the Sibumasu block, essentially Cimmeria's eastern part (or partly so), separated from the "Australian region." Further continental rupture, commencing in the Late Triassic and extending into the Jurassic, is commonly linked to the separation of the Lhasa Block (now in Tibet) from various paleolocations against the northwest Australian and Indian continental margins. The rift tectonism along the NWS in the Late Jurassic is commonly attributed to separation of the Argo, West Burma, and Woyla microcontinental blocks (Metcalfe, 2013), but the definitions and paleolocations of these blocks vary considerably (Hall, 2012). The Argo Block, for instance, is shown by Baillie et al. (2004) as originally extending along the entire NWS but is considered by Longley et al. (2002) to have occupied only the region between the Exmouth and Scott Plateaus. The general concept of microcontinents rifted away from Gondwana to form the northwest Australian continental margin is not in dispute, of course, and future studies can be expected to resolve many of the current uncertainties.

The factors controlling the location of the interrelated zones of rifting, basin formation, and continental breakup are also subjects of ongoing research and debate. The Australian Geological Survey Organization North West Shelf Study Group (1994) envisaged a major Proterozoic shear zone, which they named the NWS megashear, as the controlling crustal substructure for the continental breakup and the formation of the Westralian basins. This concept was further developed by Pryer et al. (2002)—though their correlation with the Limpopo mobile zone in South Africa does not accord with most current reconstructions of Gondwana (for example, Jablonski and Saitta, 2004; Heine et al., 2005). All stressed the importance of the underlying Precambrian fabric in controlling basin development. Belgarde et al. (2020) proposed that the rift patterns were a product of "lithospheric inheritance": (1) crustal thinning of the cratonic blocks such as the Pilbara craton occurred along a narrow "necking" zone, its location inherited from the underlying Proterozoic fabric; (2) thick rift successions accumulated on the thinned crust, as on the Exmouth Plateau, for example; and (3) subsequent Jurassic rifting developed along the necking zones, with only minor deformation in the thinned-crust domain.

Arguably, the most enigmatic aspect of the rifting along the northwest Australian continental margin is the apparent absence of any evidence of precursor rifting along the continent–ocean margin itself. Seismic reflection profiles show no evidence of Permian, Triassic, or Jurassic rift basins at or near the continent–ocean boundary (Australian Geological Survey Organization North West Shelf Study Group, 1994; Belgarde et al., 2020). It seems unlikely that all continental rupture along this margin was associated with half-graben rifting controlled by west-facing faults along which the drifting continental blocks slid away. The thick volcanic succession now recognized along the Browse margin might prove to be rift basin-fill, but this does not explain the absence of precursor rifting along, for example, the Exmouth Plateau, where the Triassic Mungaroo Formation successions abuts seawater. Further speculation is beyond the scope of this discussion, but the authors suggest it is a subject deserving of more attention by future explorers.

The geological histories of the NWS basins reveal many similarities that are expressed in the regional pattern of stratigraphy, as shown on Figure 4, but there are also some very significant differences that are critical to the local hydrocarbon prospectivity. These differences can be related to varying Archean and Proterozoic fabric underlying the region, with northeast-, north-south–, and northwest-trending structures reactivated during various tectonic episodes (Pryer et al., 2002). The Roebuck Basin (historically referred to as the Offshore Canning Basin) and the Bonaparte Basin are underlain by northwest-southeast–trending Paleozoic basins, which were truncated by and buried beneath the overall northeast-southwest–trending Westralian complex of Permian, Triassic, and Jurassic rift systems. Northwest-southeast– and north-south–trending Precambrian lineaments controlled major offsets in these rift systems and determined much of the "compartmentalization" of the NWS into basins and subbasins (O'Brien et al., 1999).

The Permian to Jurassic rift episodes, be they extensional or transtensional in origin, are fundamental elements of the main petroleum systems in the NWS basins, determining the presence of structure, reservoir, and source. The main Jurassic oil fairways, for example, are in the Exmouth, Barrow, Dampier, and Vulcan Sub-basins, where algal-rich Oxfordian–Kimmeridgian shales were deposited in the rifts. These grabens can be seen clearly on the three-dimensional (3-D) image of the Oxfordian unconformity depth structure shown on Figure 3. By contrast, the Roebuck Basin was an unrifted, west-deepening shelf during the Late Jurassic and is devoid of Upper Jurassic source rocks or significant Jurassic structure (Smith et al., 1999). The Roebuck Basin does, however, have an oil-rich petroleum system in the Bedout Sub-basin, associated with the Early Triassic rifting, as discussed further below. Triassic and Early Jurassic rift basins also accommodated the voluminous deposits of, respectively, the Mungaroo and Legendre deltas, providing both source and reservoir for many fields.

Mid-Carboniferous to early Permian rifting, commonly associated with the onset of rifting of the Cimmerian continental blocks, including Sibumasu, was the formative event for the NWS, as recognized by Australian Geological Survey Organization North West Shelf Study Group (1994) and Metcalfe (1999). Recent studies, some integrated with deep seismic data, have provided detailed insights into this East Gondwana Interior rift, which not only established the (current) northeast-southwest orientation of the Westralian basin system but extended deep into eastern Gondwana to the Southern Carnarvon and Perth Basins and beyond (Harrowfield et al., 2005;

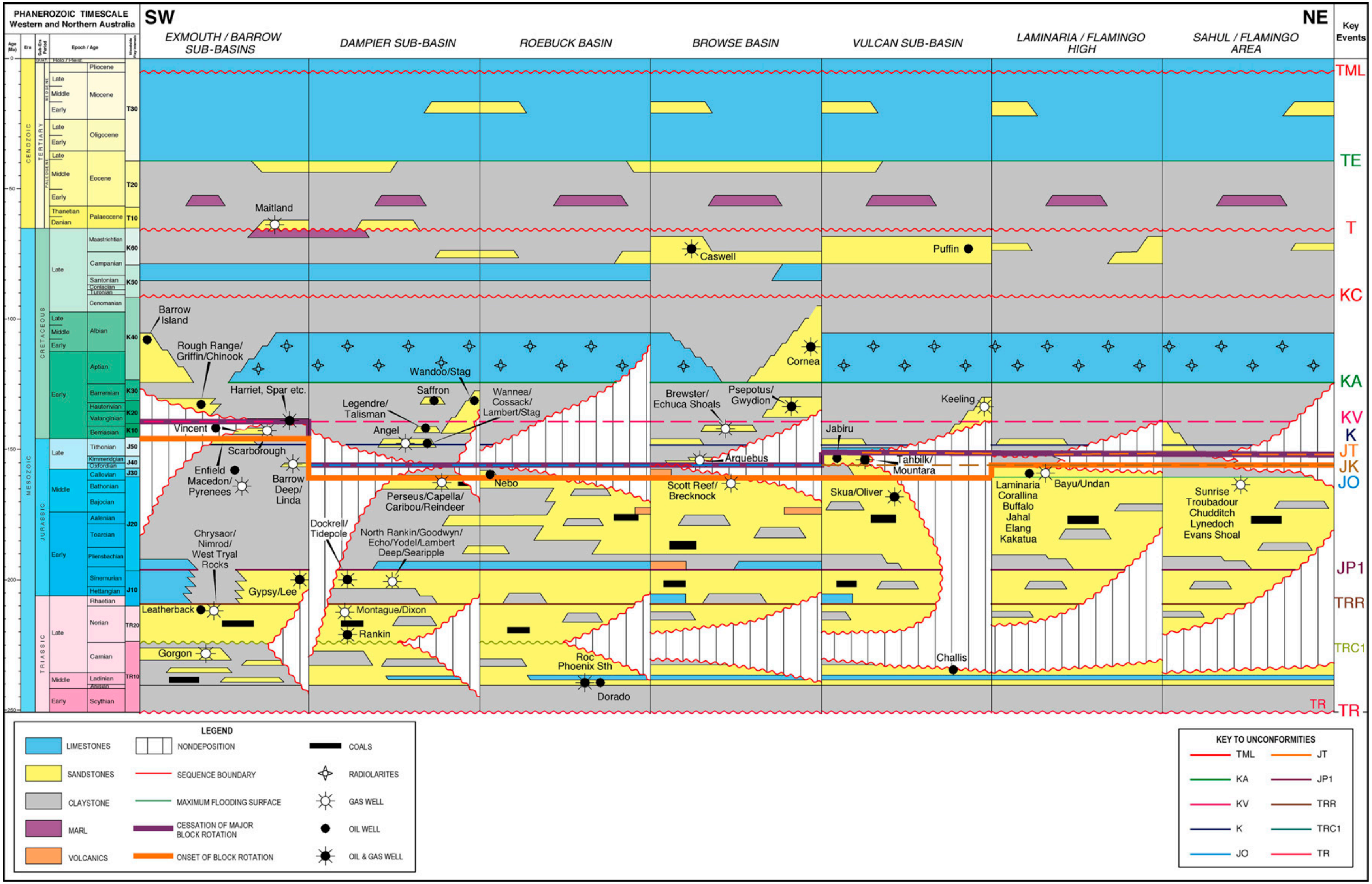


Figure 4. Generalized stratigraphic column for the North West Shelf basins showing the regional lithostratigraphic patterns across the basins. Modified from figure 9 of Longley et al. (2002).

Haig et al., 2017; Belgarde et al., 2020). As seafloor spreading commenced, Neo-Tethys formed behind the drifting Cimmerian continent and Paleo-Tethys closed ahead of it. Major crustal extension occurred across the entire NWS during the late Carboniferous–early Permian rifting, and dwarfs the extension associated with the later Mesozoic rifting (Etheridge and O'Brien, 1994).

Warming temperatures in the late Carboniferous led to melting of ice sheets across the NWS region. Fluvio-glacial and glacio-marine sediments were widespread but, by the Sakmarian, carbonates were forming in the rift axes, especially in warmer, more northern waters (Haig et al., 2017). The Permian and older successions are mainly encountered in wells on basin-margin terraces but are widespread in the Petrel Sub-basin where the underlying Paleozoic succession includes salt deposits that have mobilized and formed several prospective structures. Renewed rifting in the mid-Permian restructured the Northern Carnarvon Basin (NCB) region and aligned its form and future development within the Westralian Super Basin complex. Prograding and back-stepping geometries on seismic data in the upper Permian succession in the Roebuck Basin have been interpreted as a carbonate bank system (Paschke et al., 2018) and, alternatively, as a lava-delta complex (MacNeill et al., 2018). Interbedded upper Permian carbonate deposits and siliciclastic/volcanoclastic units have been mapped in Timor-Leste (Haig et al., 2017), and a similar interlayering might also characterize the Roebuck Basin succession.

Several pulses of transpressional structuring occurred in the middle Permian to Early Jurassic (Australian Geological Survey Organization North West Shelf Study Group, 1994; Etheridge and O'Brien, 1994). The upper Permian period of uplift, transpression, and igneous activity, known as the Bedout movement, is most pronounced in the Roebuck Basin where the volcanism, uplift, and erosion are seen on the Bedout high. Further structuring occurred in the Middle Triassic, notably in the Browse Basin, where prospective structures such as the Scott Reef trend formed along the faulted shelf edge. The Late Triassic to Early Jurassic structuring (ca. 210 Ma) is known as the Fitzroy movement and was part of an Australia-wide tectonic event. Major faulting, both extensional and compressional, triggered the formation of the inboard Jurassic depocenters in the NCB and crustal buckling in the Vulcan Sub-basin. Upper Triassic sediments, eroded from the uplifted hinterland, were deposited across the Carnarvon Basin by the Mungaroo delta and are the key to that region's vast gas resources.

The Middle to Late Jurassic rifting cycles within the NWS basins varied in intensity across the region: Hettangian–Sinemurian rifting was more developed in the south; Tithonian rifting, in the north; whereas the Callovian–Oxfordian rifting occurred extensively along the entire margin, albeit with varying rift geometries that significantly influenced prospectivity (Longley et al., 2002). Shale units deposited in the sediment-starved rifts and sags during the Oxfordian are the main oil-prone source rocks, whereas mass-flow sandstones deposited during tectonic or eustatic events constitute important reservoirs.

Overall, much of the stratigraphy and prospectivity of the NWS is determined by the location, paleogeography, and interaction of three major delta systems. The oldest and thickest complex is the Upper Triassic Mungaroo delta: it covers the entire NCB and is more than 10 km thick across the Exmouth Plateau area (Longley et al., 2002). The Mungaroo Formation provides the main Triassic sandstone reservoirs for the NCB's vast gas accumulations, and where present, the interbedded coaly mudstones are effective source rocks. The Legendre/Plover delta systems of Middle Jurassic age are the products of uplift and erosion of clastic successions in the onshore regions. In the south, the Legendre delta flowed from the onshore Canning Basin area into the NCB, covering the Beagle Sub-basin and filling the northern end of the proto-Lewis trough, where it provides reservoir and source for local discoveries. In the north, the Middle Jurassic Plover delta flowed from the northern Kimberley region and filled the Browse and Bonaparte Basins, providing both reservoir and coal-rich gassy source rocks over large areas. The youngest major delta is the Lower Cretaceous Barrow delta, which flowed northward from the Perth Basin rift into the southern Exmouth and Barrow Sub-basin areas of the NCB, providing source and reservoir units for many Barrow and Exmouth Sub-basin fields.

The separation of Greater India from Australia began in the Valanginian–Berriasian, terminating the supply of clastics into the Barrow delta and causing regional marine flooding and the deposition of the shales that form the "regional seal" for most of the oil and gas fields of the NWS. In the Early Cenozoic, as Australia drifted northward into tropical latitudes, thick carbonate sediments formed on the margin, infilling the remnant topography and providing a thermal blanket that was critical for source maturity in many areas. Minor tectonism in the NCB in the Late Cretaceous, commonly thought to be associated with the onset of the Tasman spreading system along the east coast of Australia, had both positive and negative impacts on the hydrocarbon potential: oil- and gas-bearing inversion structures such as Barrow Island, Woollybutt and John Brookes formed at this time, but tilting (down to the northwest) caused redistribution and spilling of other oil and gas accumulations. In the Late Miocene to Neogene, the Australian continent collided with the Java-Banda Arc system to its north (Keep et al., 2007), triggering widespread reactivation of faults, breaching many oil fields that "lost" billions of barrels of oil to the seafloor. This major tectonic event was stronger in the Timor Sea/Bonaparte Basin area, producing compressional anticlines and widespread fault inversion and reactivation. In the more distal NCB area to the south, this event is expressed mainly as tilting with only isolated local fault reactivations.

The geochemistry of the oil and gas source units and the many accumulations have been extensively studied, though not all with modern techniques and concepts. The most comprehensive review was the GeoMark Research/Geoscience Australia project (Edwards and Zumberge, 2005). This study, like most others at the time, relied heavily on high boiling-point biomarker compounds for oil–source correlation. This creates an intrinsic bias toward liquid generative source components in any mixed oil- and gas-prone petroleum system (Murray and Peters, 2021). In the context of the NWS, this has exaggerated the significance of the relatively rare and poorly developed oil-prone source rocks in the Jurassic rift grabens. More recent analyses are focused on the complexity of the mixed source systems on the NWS (e.g., Grosjean et al., 2016; Palu et al., 2017).

Notwithstanding these limitations, the petroleum sourcing systems present along the NWS can be divided into two main types:

1. Anoxic oil-prone marine shales deposited in the Upper Jurassic deep-water axial troughs of the Barrow/Dampier/Exmouth rift system and the contemporaneous equivalents in the Vulcan Sub-basin and the Northern Bonaparte Basin. These type B and type B/D/E (Pepper and Corvi, 1995) kerogen-containing shales can be locally oil prone but are more commonly mixed oil/gas prone. They are neither thick nor extensive and cannot be considered as "world class" in comparison with, for example, the Upper Jurassic source rocks of the United Kingdom/Norway North Sea or the Gulf of Mexico. This is the principal reason that undersaturated, medium gravity oils are very rarely found on the NWS (Murray et al., 2021) despite these being common in other super basins.
2. Nonmarine source rocks (coals and carbonaceous shales) deposited in deltaic environments developed within the Upper Triassic Mungaroo Formation, Early–Middle Jurassic Legendre and Plover Formations, and other smaller deltaic packages. These source rocks are type D/E/F (Pepper and Corvi, 1995) and dominantly gas prone, but those of Lower–Middle Jurassic age can also produce significant volumes of liquids (either as oil or condensate). Oil accumulations can occur where the reservoirs are shallow enough to be below the fluid saturation pressures and where gas has been lost via top seal failure or by water washing. Biodegradation can also result in separation of heavy oil from a light, gas-rich charge (for example, on the Yampi shelf of the Browse Basin).

A third type of liquids-prone source rock gave rise to the volatile oil and rich gas condensates recently discovered in the Bedout Sub-basin (Minken et al., 2018; Thompson et al., 2019, and references cited therein). These source rocks, of Middle Triassic age, are fluviolacustrine and the kerogens are best described as "D/E/C" (Pepper and Corvi, 1995). The extent of this petroleum system and the presence/absence of analogues elsewhere on the margin are as yet unknown.

The presence of extensive volcanism along the northwest continental margin has become well recognized in recent decades (Symonds, et al., 1998). Volcanics were encountered in many early wells on the NWS, dating from the first well drilled, Ashmore Reef-1 (B.O.C./1967 [This format of company/year is used throughout for wells to identify the operator and drilling date. Well completion reports are not referenced in the text, except where quoted directly;

these reports are available by name in the Australian National Offshore Petroleum Information Management Site, www.ga.gov.au/nopims]), but the widely separated intersections were more commonly seen as evidence of isolated events rather than widespread distribution. Seminal 1970s papers such as Veevers and Cotterill (1978) noted the few known volcanic occurrences but did not attribute fundamental significance to them; Falvey and Mutter (1981) concluded that rift-phase volcanism was not a major factor in the northwest margin formation, being evidenced in "only about one percent of hundreds of exploration wells" (Falvey and Mutter, 1981, p. 24). This perception began to change in the 1980s, driven largely by deep sea drilling and dredging on the marginal plateau (von Rad and Exon, 1983). Subsequently, the increasingly common volcanic intersections in exploration and deep marine research wells, the clear evidence on 3-D seismic profiles of intrabasin volcanism, including seaward-dipping reflections, and the better understanding of passive margin formation have underwritten a revised understanding of volcanism on the NWS (Symonds, et al., 1998; Krassey et al., 2013; McClay et al., 2013; MacNeill et al., 2018; Curtis et al., 2021). Significant events in this revision from the explorationist's perspective included the discovery of extensive volcanism in the Seringapatam Basin and the disappointing impact of volcanism on the hydrocarbon potential of the outer Roebuck Basin and along the gas-rich Greater Ichthys and Scott Reef trends of the Browse Basin. That said, current descriptions of the central NWS as a Large Igneous Province (Rollet et al., 2019a) might prove to be an overstatement.

HISTORICAL OVERVIEW

Exploration for oil and gas on the NWS began in the mid-twentieth century based on the then prevailing geosynclinal concept of basin formation and the expectation that the Timor geanticline, with its extensive oil seeps, would be replicated with progressively diminishing magnitude to the southwest, down what was then called the Westralian geosyncline (Teichert, 1939; Boutakoff, 1963). West Australian Petroleum's (WAPET's) 1964 major oil discovery on the broad dome of Barrow Island, with an estimated in-place 1.25 billion bbl of oil and 1.1 TCF of gas (Ellis et al., 1999), leant support to this concept and several of B.O.C./Woodside's first wells were drilled on analogous structures. In line with "fixist" concepts of the time, basin structure and sedimentary successions were initially projected from the onshore geology (Carrigy and Fairbridge, 1954) and many early wells dramatically rewrote the local and even regional geology. North Rankin-1 (B.O.C./1971), for instance, was conceived as a Jurassic oil play, then reinvented as a Cretaceous reef prospect, and ultimately discovered a giant gas accumulation in Triassic sandstones (Purcell, 2011). By the 1970s, although drilling was confirming the prospectivity of structures such as Scott Reef on the continental margin, early seismic surveying was revealing that these features were faulted uplifts, not compressional folds—a discovery that coincided with worldwide recognition of the new concept of plate tectonics and hastened its acceptance among Australian geologists (McDonald, 2001).

After Barrow Island, most of the major discoveries in the 1970s were gas and, at that time, nobody wanted gas. "Not more gas," B.O.C.'s exploration manager Dave McDonald is said to have yelled in frustration at yet another multi-TCF discovery along the Rankin platform—a story which, even if only archetypal, summed up the mood among explorers. The perception that the NWS, especially the NCB, was "too gassy" persisted as a negative reputation for decades, but by the end of the twentieth century, that gas had become a great asset and will remain so for decades to come.

New offshore petroleum legislation in 1967 and mandatory relinquishments in the 1970s changed the pattern of exploration on the NWS. Many smaller blocks were gazetted, and a multitude of smaller Australian and international companies acquired them. New ideas and enthusiasm and smaller-scale economics led to successful drilling of prospects such as Harriet (Occidental/1983). Oil discoveries such as WAPET's 1985 Saladin-1 (100 million bbl) and Roller-1 (45 million bbl) shifted the focus inboard in the NCB, just as Heywood-1, Gwydion-1, and Cornea-1 did in the Browse Basin, albeit less successfully. Development of many of the oil and gas fields on the eastern NCB margin was facilitated by the construction of processing and storage facilities on nearby islands, notably Varanus, Airlie, and Thevenard. Woodside's Wanaea-1/Cossack-1 (1988/1989, 280 million bbl) was to prove the largest discovery on the NWS for the next 30 yr. (But for an unrecognized velocity gradient, B.O.C.'s Madelaine-1 (1969), drilled as a Barrow Island analogue, would have discovered this field 20 yr earlier (di Toro, 1994) and might have forestalled the basin's gas-prone reputation).

During the initial decades of exploration on the NWS, a major handicap was the persistence of seismic reflection multiples generated by the Cenozoic carbonate layer and commonly masking or distorting the deeper data at objective levels (Ramsden et al., 1988). Through all the exploration cycles, the Neogene collision of the Australian plate with the Indonesian Arc complex proved a constant frustration for explorers, particularly in the northern basins and especially in the Vulcan Sub-basin and along the Laminaria/Kelp high trend. Many large oil deposits leaked to the seafloor where they "fed" the coral colonies that grew above the depleted fields. Well after well found residual columns or, at best, diminished accumulations: Keppler-1 (BHP/1994) had a residual column of more than 450 m in high-quality reservoirs and may have originally held several billion barrels of oil. Residual oil columns suggest the Buffalo oil field has lost approximately 450 million bbl, approximately 88% of the original charge (Newell, 1999).

The economics of gas were changing through the 1970s, but the development of Woodside's massive gas reserves, whereas it finally loomed as possible, was still economically marginal. In 1979, Western Australia's Premier Sir Charles Court committed to a take-or-pay deal with Woodside for domestic gas for Western Australia and thereby underpinned the LNG development project (Murray, 1991). Japanese customer companies joined Woodside and the LNG era began. Coincidentally, WAPET discovered the giant 12 TCF Gorgon gas field along the same structural trend, but its development was delayed for decades, largely because of its lower condensate–gas ratio (CGR) and higher CO_2 gas content. By the 1990s, the demand for LNG supplies in rapidly developing Asian countries drove the so-called "dash for gas," with many major gas discoveries and multiple LNG projects in the Northern Carnarvon, Browse, and Bonaparte Basins, as discussed below.

From an explorationist's perspective, the twentieth century petroleum exploration on the NWS has been subdivided by Longley et al. (2002) into four phases: 1953–1969, early years; 1970–1979, "big gassy fish in a barrel"; 1980–1994, two-dimensional (2-D) seismic oil; and 1995–2001, 3-D seismic oil. Looking back from 2022, it is tempting to recast this scheme to better emphasize the important role of seismic technology in determining the play concepts and objectives in recent decades. Overall, the period 1970–1990 was characterized by the search for and drilling of anticlinal and fault-block prospects defined by 2-D seismic surveys and without reference to amplitude analyses. The 1990–2010 period was marked by the acquisition of 3-D seismic surveys, with increasing emphasis on amplitude-support and quantitative analyses. The period 2010–2020 is essentially an extension of that phase but with a greater focus on deep-water prospects, notably within the NCB.

TWENTY-FIRST CENTURY PLAYS, SUCCESSES AND FAILURES

Explorers on the NWS in the twenty-first century have pursued many of the well-established plays but have also taken some new and innovative exploration ideas into new areas and different stratigraphic successions. Results have been mixed. Major successes for oil explorers in the Bedout Sub-basin and the NCB have occurred, specifically the Exmouth Sub-basin, but arguably little substantial economic reward elsewhere. In contrast, the exploration for gas resources has been very successful, with many major fields discovered and several major LNG development projects commissioned, though many of the smaller gas discoveries remain undeveloped.

On the cusp of the twenty-first century, the NWS had proved to be what its history had long intimated: a world-class gas province with "minor oily sweet spots" (Longley et al., 2002). The region's future gas potential was clear; estimated reserves in undeveloped fields and remaining reserves in developed fields were then in excess of 150 TCF. The Australian Geological Survey Organization (AGSO) estimated remaining undiscovered gas resources (50% probability [P50]) of 28 TCF (Powell, 2001), with the US Geological Survey World Energy Assessment Team (2000) proposing a more optimistic 107 TCF. The remaining oil potential was less clear, and many observers considered estimates of 1330 million bbl and 4721 million bbl by AGSO and US Geological Survey, respectively, to be optimistic, the latter imaginatively so (Longley et al., 2002).

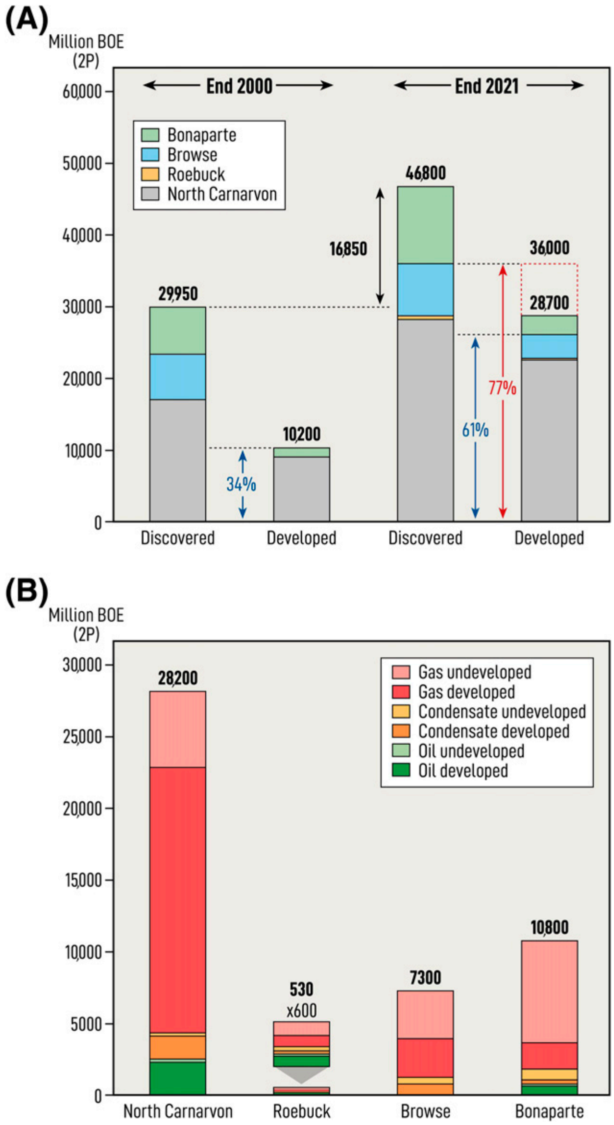


Figure 5. (A) A histogram showing the discovered and developed proven and probable (2P) hydrocarbon volumes at end 2000 and end 2021. (The Dorado field, with final investment decision originally scheduled for 2022, was included in the end 2021 developed volumes category.) (B) A histogram showing developed versus undeveloped 2P hydrocarbon volumes at end 2021 by basin and commodity. The dashed red box shows the impact of development of the Abadi, Sunrise, and Scott Reef fields.

The exploration and development activities of the past two decades have further confirmed the reputation of the NWS as a super basin. The gas resources discovered since 2000 have been impressive, with more than 87 TCF of gas reserves discovered. During that period, 95 TCF of gas reserves have been developed, involving both pre-2000 as well as post-2000 discoveries. Also, since 2000, 900 million bbl of oil have been discovered and 1100 million bbl developed, again involving both pre- and post-2000 discoveries. A comparison of discovered and developed proven and probable (2P) hydrocarbon volumes on the NWS, expressed in millions of barrels of oil equivalent at the end of 2000 versus the end of 2021 is shown on Figure 5A. (The Dorado field was included in the 2021 statistics because the final investment decision [FID] was expected by the time of publication.) The total developed resources versus discovered resources in millions of barrels of oil equivalent at the end of 2021 are shown by basin on Figure 5B. The twenty-first century is clearly seen as a period of major development projects: at the end of 2000, the discovered resources in the NWS basins were nearly 30,000 million BOE, with approximately 34% developed; by the end of 2021, however, the discovered resource had grown to nearly 47,000 million BOE, with 61% developed or committed to development projects. The percentage of the developed resources will increase to 77% at 36,000 million BOE when the Sunrise, Abadi, and the Scott Reef fields (Brecknock, Calliance, and Torosa) are developed in the future as shown in Figure 5B. The summary statistics from which these plots are derived are shown in Table 1.

The development activity on the NWS this century has been spectacular, with eight new LNG trains established. (Trains are processing facilities to purify and liquify natural gas from the gaseous phase produced from the reservoir.) New LNG facilities were established for the Gorgon, Pluto, Bayu-Undan, and Wheatstone gas fields and new trains were added to Woodside's North Rankin hub, Chevron's Barrow Island facilities, and the Inpex and Santos Darwin plants. The locations of the LNG facilities are shown in Figure 2. The development of several of the large gas discoveries of the last century, notably the giant Gorgon and Io-Jansz fields, discovered in 1980 and 2000, respectively, involved massive industry activity and expenditure and established the NWS as a world-leading LNG producer. Details of each of the LNG projects, including those at FID and pre-FID stage in 2021, are shown in Table 2.

The relative sizes of the twentieth and twenty-first century discoveries are shown on Figure 6A for the Northern Carnarvon and Roebuck Basins and Figure 6B for the Bonaparte and Browse Basins. As in many basins worldwide, most of the largest fields were discovered early in the exploration cycle. The exception on the NWS was the giant Jansz-Io gas

Table 1. Summary of Discovered Resources on the North West Shelf by Basin and Phase at End 2001 and End 2021

	At End 2000			End 2000 to end 2021		At End 2021					
Basin	Total 2P Discovered, million BOE	Total 2P Developed, million BOE	Percentage Developed	Discovered between End 2000 and End 2021, million BOE (2P)		Discovered 2P Oil, million bbl	Discovered 2P Cond. million bbl	Discovered 2P Gas, TCF	Discovered, million BOE	Developed, million BOE	Percentage Developed
North Carnarvon	16,950	8876	52%	11,205	66%	2492	1819	143	28,155	22,445	80%
Roebuck	83	0	0%	441	3%	150	102	2	525	287	55%
Browse	6311	0	0%	996	6%	35	1187	37	7307	3324	45%
Bonaparte	6610	1335	20%	4213	25%	762	1102	54	10,822	2644	24%
Total	29,954	10,211	34%	16,854	100%	3438	4210	235	46,808	28,700	61%

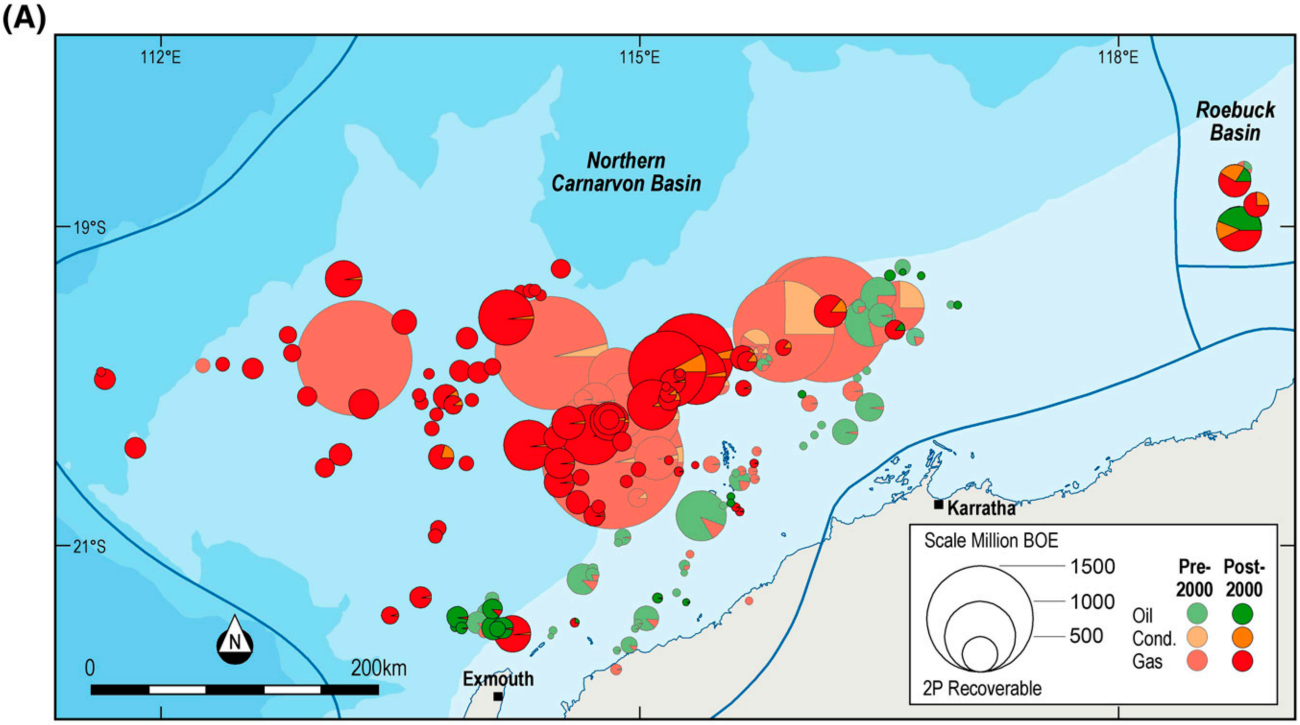
Both the end 2001 data (Longley et al., 2002) and the end 2021 tabulations include content supplied by IHS Markit (Copyright © IHS Markit, 2022. All rights reserved).
Abbreviations: 2P = proven and probable; Cond. = condensates.

discovery in the NCB and the Abadi discovery in Timor Sea—actually in Indonesia but included here because it is within the broader NWS/Westralian Super Basin. Many gas discoveries have been made since 2000, but the average size is considerably smaller. These maps also usefully illustrate the predominance of gas in the basins, with oil trends limited to the eastern flank of the NCB and Roebuck Basins and the Vulcan Sub-basin and Sahul syncline areas of the Bonaparte Basin. The clusters of large discoveries in the early 1970s and late 1980s and 1990s can be seen on Figure 7, the hydrocarbon discovery history for the NWS, expressed in billions of barrels of oil equivalent (oil equivalent, where 6 BCF = 1 million BOE) and color-coded for phase, with several of the main discoveries indicated. Discoveries are shown at the time of the discovery well even if its scale and significance were not recognized until later, as at Brewster-1 (Woodside/1980) for the Ichthys gas field and North Rankin-4 (Woodside/1972) for the Perseus

Table 2. Liquified Natural Gas Projects on the North West Shelf

LNG Project	Main Field(s)	Year	Other Fields	Status	Type	Operator	Trains	MTPA	FID	Start	Years to Production
Sunrise	Sunrise	1974	Troubadour	Pre-FID	Unknown	Woodside	1	5	2025	2030	56
Abadi LNG	Abadi	2000		Pre-FID	Platform	Inpex	2	9.5	2025	2030	30
Browse LNG	Brecknock/Calliance	1979	Torosa	Pre-FID	Platform	Woodside	0	10	2024	2028	49
Scarborough	Scarborough	1979	Thebe, Jupiter	FID	Platform	Woodside	1	5	2021	2025	46
Barossa	Lynedoch	1973	Caldita	FID	Platform	Santos	0	3.7	2021	2025	52
Prelude	Prelude	1980	Concerto, Mimia	Producing	FLNG	Shell	1	3.6	2011	2018	38
Ichthys T1 and T2	Ichthys	1980		Producing	Platform	Inpex	2	8.9	2012	2017	37
Wheatstone T1 and T2	Wheatstone	2004	Iago, Julimar, Brunello	Producing	Platform	Chevron	2	8.9	2011	2017	13
Gorgon T1–T3	Gorgon/Jantz/Io	1981	Chrysaor, Dionysus, Geryon, Spar, West Tryal Rocks	Producing	Platform	Chevron	3	15	2009	2014	33
Pluto T1	Pluto	2005	Zena	Producing	Platform	Woodside	1	4.3	2007	2012	7
NWS T5	North Rankin/ Goodwyn/Perseus	1971	Angel	Producing	Platform	Woodside	1	4.8	2005	2008	37
Darwin	Bayu-Undan	1994		Producing	Platform	Santos	1	3.4	2002	2006	12
NWS T4	North Rankin/ Goodwyn	1971		Producing	Platform	Woodside	1	4.3	2002	2004	33
NWS T1–T3	North Rankin/ Goodwyn	1971		Producing	Platform	Woodside	3	7.7	1985	1989	18

The final investment decision (FID) and start dates for Sunrise and Abadi are estimates only. Brecknock, Scarborough, and Barossa will be backfill for North West Shelf (NWS) venture (Burrup), Pluto 1, and Darwin liquified natural gas (LNG) respectively. This tabulation includes content supplied by his Markit (Copyright © IHS Markit, 2022. All rights reserved).
Abbreviations: FLNG = floating liquified natural gas; MTPA = million tonnes per annum.



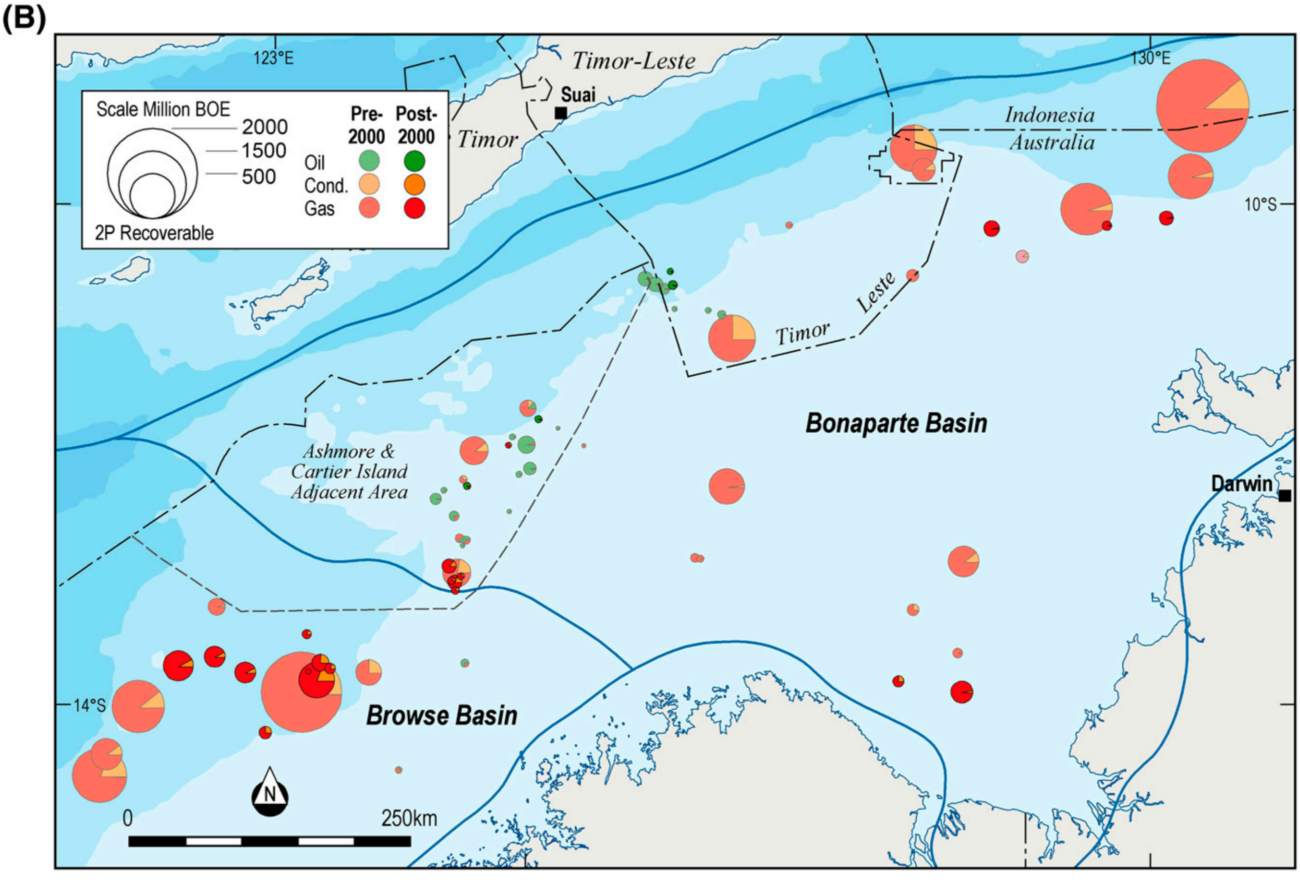


Figure 6. (A) Bonaparte and Browse Basins oil and gas fields displayed as size-based discs, showing a comparison of the sizes of fields discovered pre-2000 and post-2000. (B) Northern Carnarvon Basin and Bedout Sub-basin oil and gas fields displayed as size-based discs, showing a comparison of the size of fields discovered pre-2000 and post-2000. This map includes content supplied by IHS Markit (Copyright © IHS Markit, 2022. All rights reserved). 2P = proven and probable; Cond. = condensate.

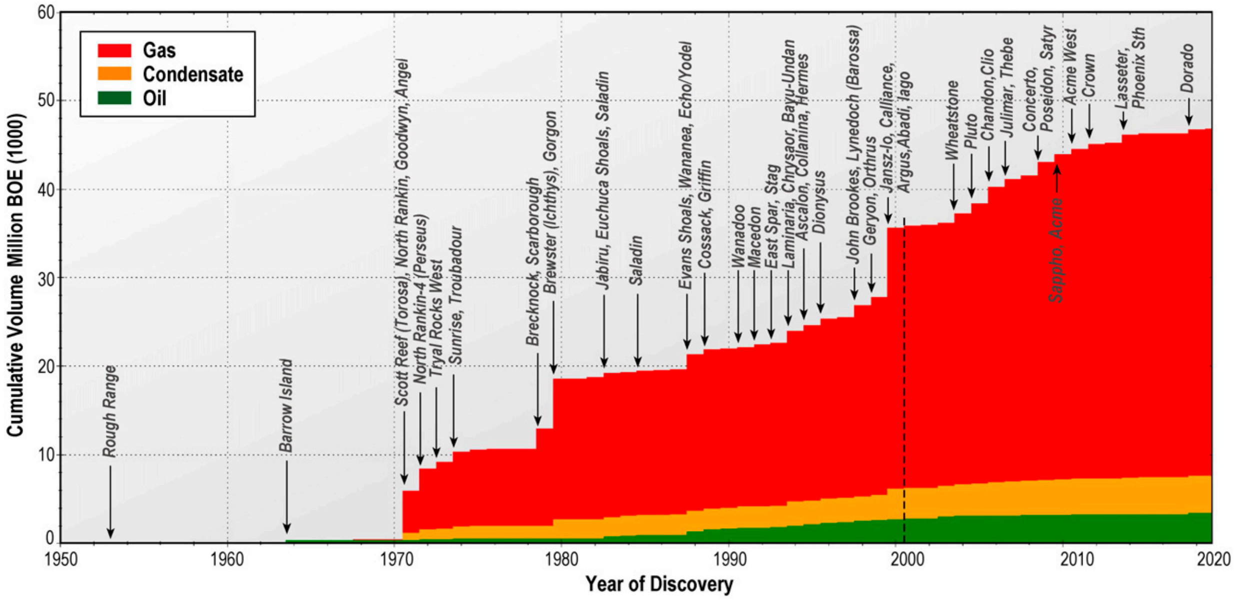


Figure 7. The North West Shelf creaming curve in millions of barrels of oil equivalent (shown by phase).

gas field. Most of the twenty-first century discoveries in the Northern Carnarvon, Browse, and Bonaparte Basins occurred in the first decade, and the subsequent decline in discoveries reflects in large part the dramatic decline in exploration drilling in recent years.

By comparison to the gas discoveries, the oil discoveries on the NWS this century have been less than world-scale but were locally significant. The Exmouth Sub-basin discoveries in the early 2000s and the Dorado discovery in the Roebuck Basin in 2018 distinguish an otherwise flattening creaming curve for the super basin (Figure 8). It bears noting, however, that this flattening comes after the substantial exploration success of the 1990s, when discovered oil reserves almost doubled in the NWS basins. Nonetheless, the flattening curve was in line with the expectations of many explorers. Longley et al. (2002) noted that only the Exmouth Sub-basin was still manifesting a rising discovery trend in 2000 and

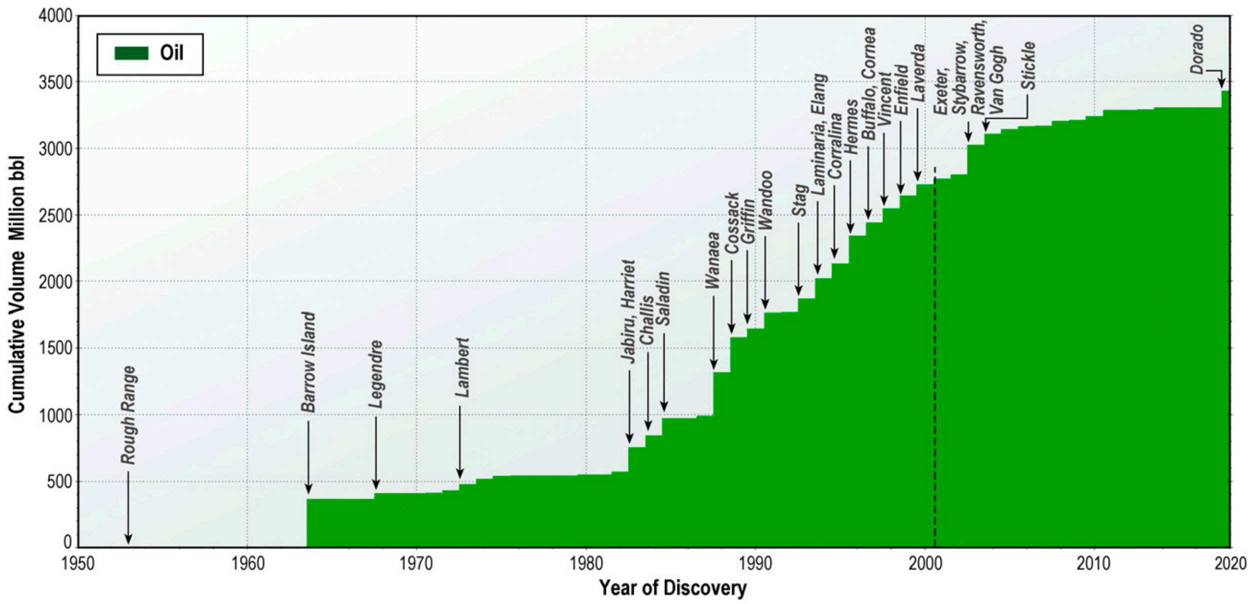


Figure 8. The North West Shelf oil discoveries' creaming curve in millions of barrels.

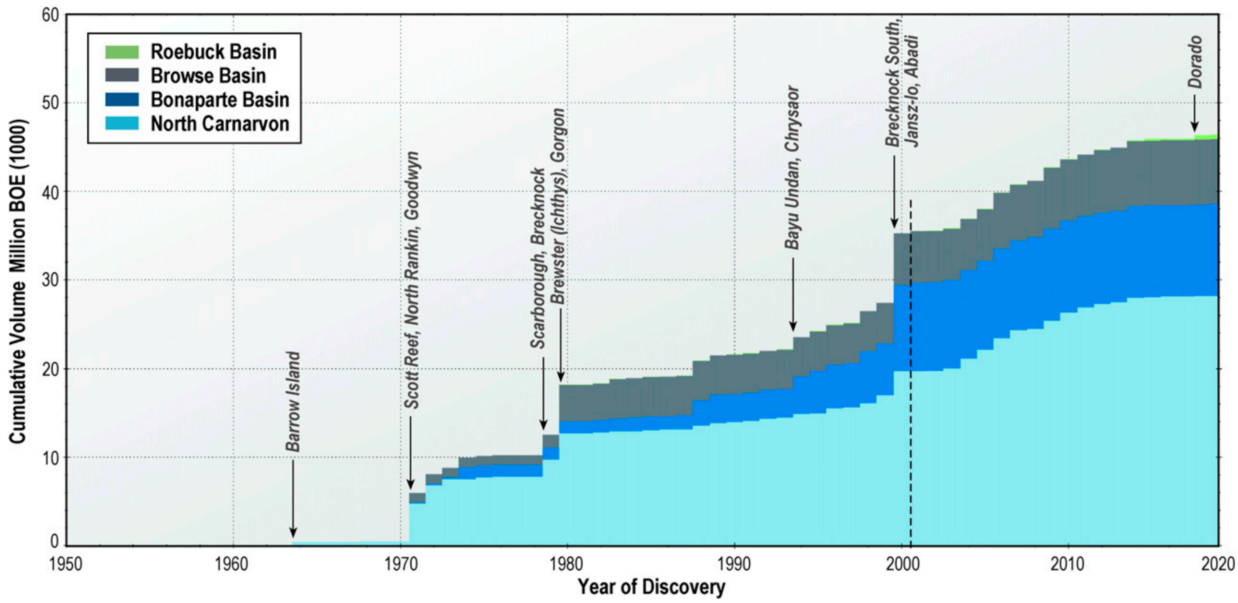


Figure 9. The North West Shelf creaming curve in millions of barrels of oil equivalent (shown by basin).

suggested that remaining potential in known "oily areas" appeared relatively low by international standards. Seismic data showed that there were no untested Upper Jurassic rift basins with marine anoxic source intervals on the NWS, and successful exploration outside these basins would require the presence of alternate Jurassic source models, such as deltaic Lower to Middle Jurassic units. The probability of discovering a new oily subbasin or province along the NWS margin appeared to be low and the prospect of discovering large oil accumulations in the known basins was considered fair at best.

The "flaw" in this widely accepted analysis was its focus on the Upper Jurassic succession as the only significant oil-producing strata on the NWS. It was not that the Triassic succession was ignored; on the contrary, it was recognized as one of the most important hydrocarbon systems on the NWS but seen to be characterized by major gas generation and entrapment. The discovery of Triassic oil in the Roebuck Basin (Bedout Sub-basin) in 2014 and the large Dorado discovery in 2018 in a canyon-wall trap surprised many explorationists on the NWS and served as a useful reminder that oil fields yet to be found might not accord with prevailing wisdom.

The exploration in the years 2000–2020 was spread across the NWS from Palta-1 (Shell/2012) in the far southwest to Blackwood-1 (MEO Australia Limited [MEO]/2008) in the Timor Sea in the far northeast. Several major themes are evident. Notable in the NCB, beginning in the late 1990s, was the so-called dash for gas, with amplitude-driven exploration in the deeper waters along the Rankin-Alpha trend and across the Exmouth Plateau, and the oil "boom" in the southern Exmouth Sub-basin. High-quality 3-D data was obtainable in both areas because of the deep-water settings and the lack of thick Cenozoic carbonates, providing companies with a large inventory of amplitude-supported traps, both simple and complex, and many discoveries. Because of this, the NCB has continued to be the preeminent oil and gas basin of the NWS, as seen on the basin-by-basin creaming curves of Figure 9. The predominance of the gas discoveries in deeper water in recent decades is seen clearly on the bathymetry-based creaming curve of Figure 10. The pursuit of gas in the Browse Basin occupied both decades, with several major discoveries and LNG developments at the Ichthys and Prelude gas fields. The return of exploration interest in the Roebuck Basin—focused on the Triassic petroleum system there—was another distinguishing theme of the period, providing spectacular success in the inner Bedout Sub-basin and disappointing failure in the outer Rowley Sub-basin. The failure of the new 3-D programs to reduce risk in areas of pronounced Neogene fault reactivation in the Bonaparte Basin was an ongoing frustration—though some failures might relate more to lack of oil charge, as discussed later.

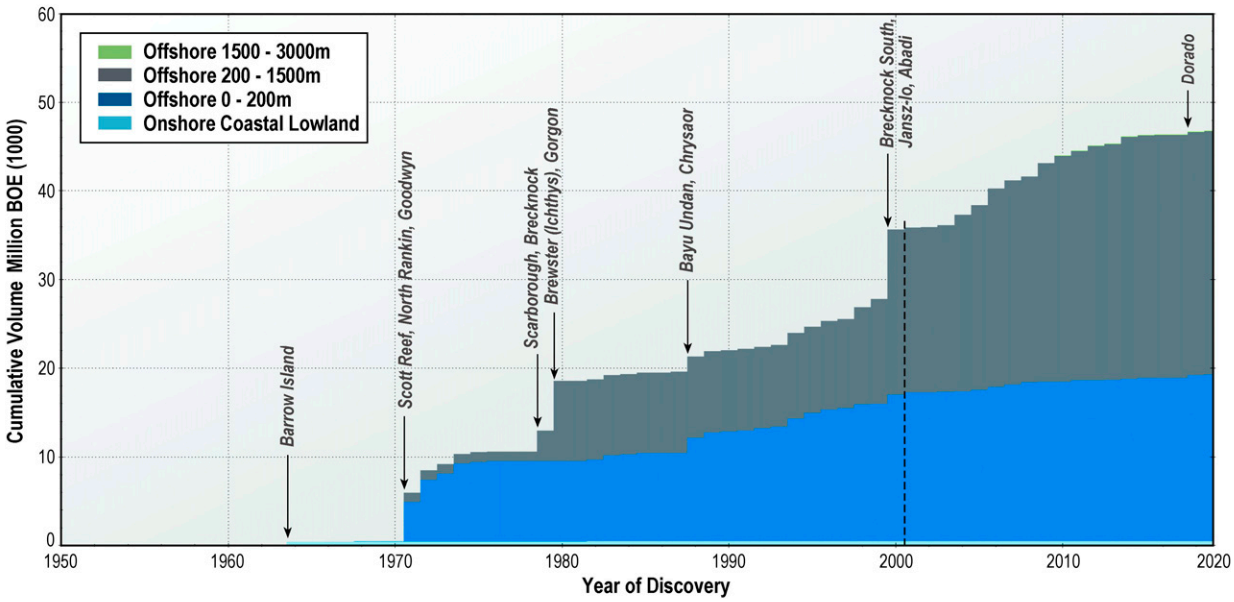


Figure 10. The North West Shelf creaming curve in millions of barrels of oil equivalent (shown by water depth).

In general, the availability of better-quality seismic data has been a key element of the twenty-first century exploration, providing new insights into the complexity of major structures and trends, such as along the Alpha arch, and further expanding the extensive use of seismic attribute mapping and analyses. This led to successful revisiting of some early uncommercial discoveries such as Lambert (B.O.C./1973) and Hilda (WAPET/1974) in the Dampier and Barrow Sub-basins, respectively. It was equally important in identifying new gas prospects in the Petrel Sub-basin and revitalizing drilling in the Vulcan Sub-basin, albeit without commercial success in the latter. The 3-D data were also a major assistance in field development planning, such as at Gorgon, where band-limited elastic impedance seismic processing and displays greatly aided reservoir mapping and development drilling (Maftei et al., 2013).

Events on the NWS this century also served to dramatically alter government regulations concerning petroleum industry activity in commonwealth waters, with the federal government terminating its agreement with state and territory regulators and creating new federal agencies to administer exploration and production activity. Other major changes to the administration of exploration and development in areas of the Bonaparte Basin occurred as a result of agreement between the Australian and Timor-Leste governments regarding the relocation of their maritime boundary. Changes to the boundary between commonwealth and Western Australia state waters at the Scott Reef atoll above the Torosa gas field will have a major impact on the distribution of future royalties between the commonwealth and state treasuries.

The following sections review the main exploration activity and results in the four basins, as well as the development of the newly and previously discovered oil and gas fields. Exploration and development activities prior to 2000 are discussed where they provide context for the recent activity.

Bonaparte Basin

The Bonaparte Basin at the northeast end of the NWS is a complex basin with numerous subbasins and structural elements, as shown in Figure 11 and the enlarged areas in Figure 11A and B. The Petrel Sub-basin, which occupies the Joseph Bonaparte Gulf, extends northwestward from lower Paleozoic outcrops onshore, having formed initially during northeast-southwest–directed extension. To the northwest, it is overprinted by the northeast-southwest–trending Mesozoic basins but retains some expression of the Paleozoic trend in the Mesozoic sags of the Flamingo and Sahul synclines. The basin axis is occupied by the Vulcan rift basin and the Malita graben, the latter extending northward into the Calder graben. The southeast margin of the basin comprises the Darwin shelf and the vast Londonderry high, whereas the northwest region is dominated by the Ashmore and Sahul platforms. Numerous petroleum systems are functioning to varying degrees within the Bonaparte Basin, notably in the late Permian and Jurassic–Triassic (Barrett et al., 2004) successions. Detailed discussions about the petroleum geology and exploration history of the Bonaparte Basin are provided by Mory (1988), Ambrose (2004), Cadman and Temple (2004), and references therein.

This section discusses exploration and development activity in the Bonaparte Basin in recent decades by reference to the various subbasin areas. The basin has seen several recent large gas discoveries at Blacktip and Barossa/Caldita, with Blacktip now supplying the majority of the Northern Territory's gas requirement and Barossa/Caldita scheduled for first gas in 2025. Oil and condensate discoveries pre-2000, notably in the Vulcan Sub-basin and on the Laminaria high, have been substantial, though modest on a world scale, but recent commercial discoveries have been few. The hydrocarbon resources discovered in the Bonaparte Basin in 2000–2021 were 94 million bbl of oil, 280 million bbl of condensate, and 23.0 TCF of gas, a total of 4212 million BOE, approximately 25% of the hydrocarbons discovered in the NWS in the period. Creaming curves for the Bonaparte Basin, subdivided by phase and subbasin, are shown on Figure 12, as is a histogram of the annual well count. The demise of exploration in the Bonaparte Basin is pronounced: drilling activity peaked in 1990 and has progressively declined, albeit with diminishing pulses of activity. Drilling activity in the 5 yr to 2020 is the lowest since exploration began in the 1960s, reflecting both the considerable gas resources currently undeveloped and the perception that no large oil fields remain to be found.

Vulcan Sub-basin

The southwest region of the Bonaparte Basin comprises the complex rift-within-rift structure of the

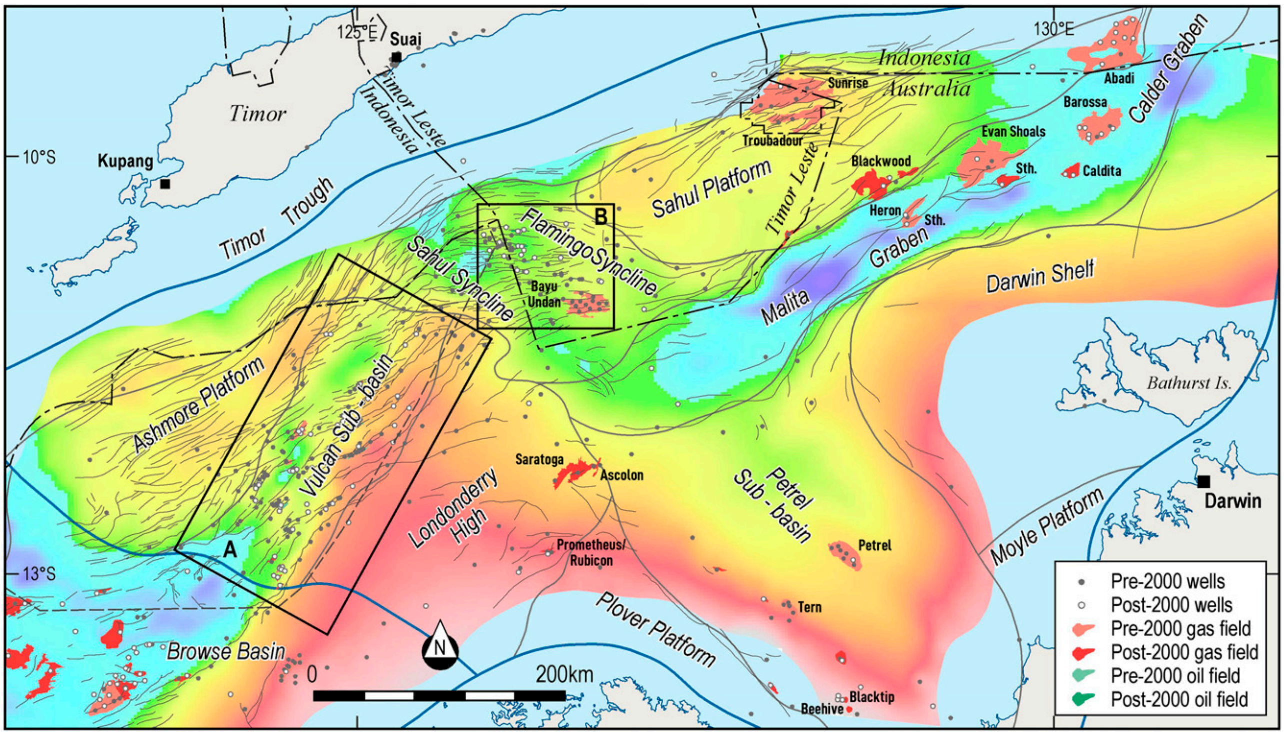


Figure 11. Bonaparte Basin Upper Jurassic (Oxfordian) (JO) structure maps showing subbasin regions and pre- and post-2000 wells and discoveries and identifying wells mentioned in the text. (A) Vulcan Sub-basin JO structure map showing fields and wells mentioned in the text. (B) Sahul syncline area Elang Formation depth structure map showing wells and fields mentioned in text (faulting is after figure 2 of Preston and Edwards, 2000). The underlying JO structure map for this figure is based on Longley et al. (2002), with superimposed base Cretaceous faults from P&R Geological Consultants' (2010) North West Shelf base Cretaceous structure map. This map includes content supplied by IHS Markit (Copyright © IHS Markit, 2022. All rights reserved). Is. = Island.

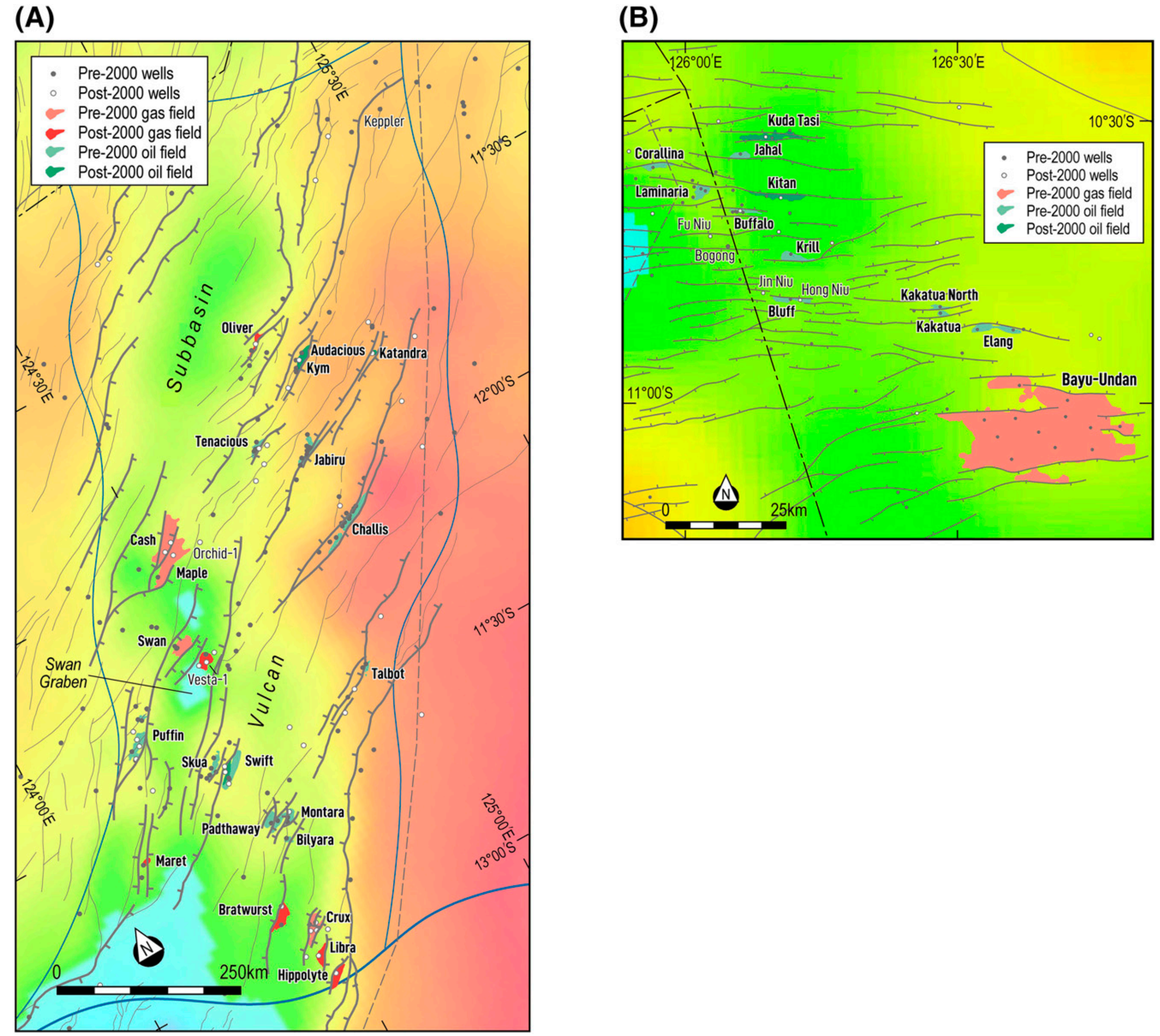


Figure 11. Continued.

Vulcan Sub-basin, which is flanked by the broad Ashmore platform to the northwest and the extensive Londonderry high along the southeast (Figure 11A). The subbasin contains discovered reserves (2P) of 360 million bbl of oil, 87 million bbl of condensate, and 3.2 TCF of gas (Data courtesy of IHS Markit [Copyright © IHS Markit, 2022. All rights reserved]). The main source unit is the anoxic oil-prone marine shale of the Upper Jurassic lower Vulcan Formation (*Wanaea spectabilis* palynozone), which was deposited in the narrow deep rift system that developed between the Oxfordian open marine shelves of the central Bonaparte and Browse Basins (Longley et al., 2002) (Figure 14). The Vulcan Formation succession is thickest in Swan graben, which is the main source kitchen for the subbasin. Kopsen (2002) estimated potential oil generation from this Vulcan Formation source of 98 billion bbl. The main reservoirs are Triassic and Jurassic fluvio-deltaic sandstones and Jurassic and Cretaceous turbidite sandstones. The traps have been mainly horsts and tilted blocks within the tightly faulted horst-and-graben complex and commonly have an hourglass structure. The seal is provided by shales overlying the Valanginian unconformity. In theory, the hourglass structuring should create a plethora of traps and, given the presence of multiple reservoirs and a good oil source, numerous and large oil fields in the Vulcan Sub-basin might be

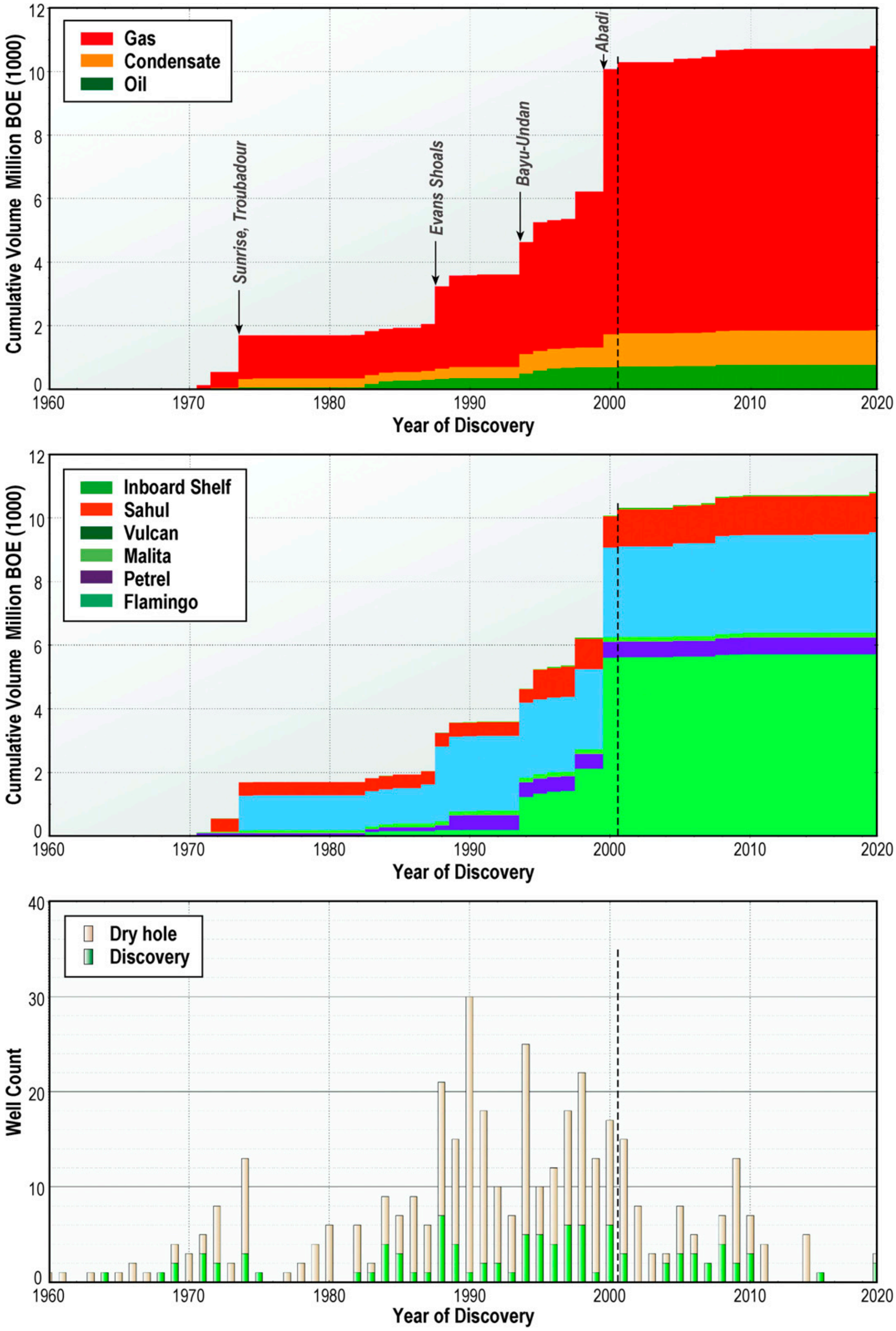


Figure 12. Bonaparte Basin discovery history showing creaming curves by subbasin (top) and phase (center), and the annual well count color coded for discoveries and dry holes (bottom).

expected. It has not proved that simple, however, and the subbasin is, to date, only a modest oil province. The widespread Neogene shearing and fault reactivation caused by the collision of the Australian continent with the incipient Banda Arc has effectively demolished what had been a world-scale oil province.

Exploration in the basin has also been hampered by problems of effective seismic imaging, even on modern 3-D surveys. As Figure 12 illustrates, the creaming curve has remained relatively flat across recent decades, with no significant uptick yet in discovery volumes from the improved 3-D seismic data (post-Onnia 1998 3-D survey), even though there have been more than 20 exploration wells in the post-2000 era. Explorers are hopeful that the recent Bratwurst-1 (Shell/2018) and Orchid-1 (PTT Exploration and Production [PTTEP]/2019) discoveries, drilled on the Cygnet 3-D regional data set, will prove to be the start of a more successful exploration cycle. Bratwurst-1 was a satellite discovery to Crux; Orchid-1 was the first of long-planned appraisal drilling on the Cash-Maple gas field, after Coastal's 2002 Cash-1 and PTTEP's 2011 Cash-2 and Maple-2 encouraged commitment to a gas development project, with possible gas-in-place of 3.5 TCF (Wilkinson, 2020).

Exploration in the Vulcan Sub-basin is relatively mature by NWS standards, with all the large seismically defined horsts and tilted fault blocks drilled. Consequently, much of the recent activity has been a follow-up to earlier discoveries or encouraging shows, including the appraisal and development of fields discovered as far back as the 1970s. Some efforts were more successful than others. Arguably, the least successful was the development of the Puffin oil field, discovered by ARCO in 1972. Puffin-1 had recovered oil from previously unknown (Puffin) sandstones in the Maastrichtian carbonates and Puffin-2 tested 4600 bbl/day of 48° API oil, but from a different sand. These early exploration results at Puffin were to prove typical of many Vulcan fields: complex faulting, rapid velocity changes, and poor seismic definition, leading to faulty well prognoses and disappointing outcomes. In 2000, Australian junior AED Oil Ltd. (AED) drilled Puffin-5, encountered a 9 m oil column, tested 2580 bbl/day, estimated 100 million bbl of oil reserves, and committed to development. In 2008 Sinopec paid A$600 million for 60% of the project and other AED assets (Sinopec, 2008). What followed was the all-too-common Vulcan experience: seven appraisal wells, ending with Puffin-13 (2008), showed the field to be three separate small accumulations. Production ceased in 2009 and the field was abandoned in 2013, having produced only 2.2 million bbl (Wilkinson, 2015).

The most impactful twenty-first century venture in the Vulcan Sub-basin was the Montara Project: the development of the Montara, Swift, and Skua fields discovered by BHP in the 1980s. The Australian company Coogee Resources acquired the fields in 2003 and were well advanced with the development program at end 2008 when they sold the project to Thailand's state oil company PTTEP. On August 21, 2009, a blowout in Montara-H1ST1 resulted in an uncontrolled flow of oil into the sea for 74 days, ruining the industry's 40 yr record of environmentally safe drilling on the NWS. (The only prior blowout occurred in ARCO's Petrel-1 in August 1969. The rig fire was quickly extinguished, and the gas boil was finally stopped in January 1971, after a kill well was drilled by legendary Red Adair. No oil spill occurred.) Operations were suspended for 3 yr while a major inquiry was held and remedial action taken. The Montara Commission of Inquiry found that the blowout was caused by PTTEP's failure to comply with proper well-operating procedures and standards. The commission also asserted that the regulator, the Northern Territory Department of Resources, had not provided "sufficiently diligent" oversight of the company's procedures (Borthwick, 2010, p. 6).

These findings had major and lasting impacts on the oil industry in Australia. The environmentalists seized on the event to argue against drilling offshore anywhere, especially in the Great Australian Bight. The federal authorities argued that the commission's findings warranted their assuming control of administrative and operational management of all petroleum-related activities in commonwealth waters. The long-standing but commonly strained agreement whereby the state/territory authorities administered all exploration and production activity in state/territory waters and the adjacent commonwealth waters (state territory includes water within 3 nautical mi of the coastline, which can take in bays and islands; all waters beyond that are commonwealth territory) was scrapped, and the Federal National Offshore Petroleum Titles Administrator and the

National Offshore Petroleum Safety and Environment Management Authority bureaucracies were established.

PTTEP eventually resumed the field developments, with first oil flowing in 2013. In September 2018, they sold the assets to United Kingdom–listed Jadestone, which currently operates the fields. The Montara fields produced an average of 7,647 bbl/day in 2021. As of December 31, 2020, the Montara fields had proven plus probable reserves of 23.4 million bbl of oil (Jadestone Energy, 2021).

In the 1990s, a major focus on seismic hydrocarbon-related diagenetic zones and aerial seep surveys sought to identify patterns of fault leakage and better evaluate the risks of trap integrity in the Vulcan Sub-basin and, more generally, the Bonaparte and Browse Basins (O'Brien and Woods, 1995; O'Brien et al., 1998, and references therein). Coincidentally, improved seismic data quality, particularly from prestack depth migration, led to follow-up drilling on structures where early wells had encountered oil shows. Unfortunately, all discoveries proved too small for commercial development: Tenacious-1 (Cultus/1997), for example, found only approximately 6 million bbl and 14 BCF. This disappointing pattern continued in the twenty-first century. Audacious-1 (OMV/2001), drilled updip to Kym-1 (Cultus/1996), was thought to have discovered approximately 20 million bbl in the Plover Formation reservoir but appraisal wells were low to prognosis and showed the accumulation was actually two small uneconomic pools. Small discoveries were made in wells drilled on structures defined by the new 3-D seismic data but were technical successes only; none were commercially significant. Katandra-1 (OMV/2004), for example, found approximately 1 million bbl of oil in place (OIP) in Valanginian sandstones, with the objective Vulcan reservoir being low to prognosis. Follow-up drilling on BHP Petroleum's (BHPP) small Oliver-1 discovery (1987; 15 million bbl, 500 BCF), based on the new Oliver 3-D seismic survey, was also disappointing: Stuart Petroleum's Oliver-2 (2009) targeted 53 million bbl of oil and 810 BCF of gas, but found only minor gas in a separate fault compartment, significantly downgrading the accumulation.

Eni's Vesta-1 (2005) tested a new play concept for the area: turbiditic Upper Jurassic sandstones within a structural closure in the Swan graben, sourced and sealed by encasing Lower Vulcan Formation shales. Petrophysics showed Vesta-1 encountered 17 m of oil, but drill-stem tests (DSTs) recovered oil, gas, and water. Vesta-2 (Eni/2007) found only a small gas column. Geochemical analyses revealed several hydrocarbon charge episodes with an initial oil charge displaced by a later gas influx (Ellis, 2012). The potential for a new round of exploration based on Upper Jurassic to Lower Cretaceous-confined turbidites in settings such as the Swan graben has been highlighted recently, with analogies drawn to North Sea fields (Ferdinando et al., 2019).

Modern broadband 3-D seismic data has substantially improved imaging of the complex crestal faulting of Vulcan Sub-basin structures and should encourage a revisiting of the potential of this area.

Malita and Calder Grabens

The Malita graben trends northeast-southwest between the shallow Darwin shelf to the southeast and the Sahul platform to the northwest and extends southeast across the northwest-southeast–trending Petrel Sub-basin as seen in Figure 11. At its northeastern end, the graben arcs to the north and is known as the Calder graben. To the east of the Calder graben, the Money Shoals Basin is taken here as the northeast limit of the NWS. Large structures on the northern rift shoulder of the Malita and Calder grabens were recognized on seismic data in the late 1960s, but ARCO's Heron-1 (1971) and Shell's Lynedoch-1 (1973) encountered only gas in tight Jurassic reservoirs. Evans Shoals-1 (BHP/1988) was drilled for oil objectives, but the high geothermal gradient confirmed that the Plover Formation source unit was below the oil window and the Malita graben was dismissed as another "unwanted" gas province. That changed in the late 1990s when the developing gas industry in Northern Territory waters encouraged a return to the Malita gas play, although the poor quality of the Plover reservoirs and the high concentrations of CO_2 remained challenging.

Caldita-1 (ConocoPhillips/2005), located between the Evans Shoals and Lynedoch structures, encountered gas-saturated sandstones in the Flamingo Group and the Elang and Plover Formations. Porosity remained <10% in the 264-m gas column but flows of up to 33 MMCF gas/day were achieved from the Flamingo reservoir, albeit with 12%–13% CO_2. Nearby, Barossa-1 (ConocoPhillips/2005) tested more than 30 MMCF gas/day from the Elang, with 16% CO_2. Eni successfully revisited the Evans

Shoals gas field in 2013 when Evan Shoals North-1 flowed 30 MMCF gas/day. The Evans Shoals wells are in hydraulic communication and the field is estimated to have original gas in place (OGIP) between 8 TCF and 10.3 TCF, the latter based on IHS Markit estimates (6.6 TCF recoverable 2P). In March 2021, having purchased Phillips' interests, Santos announced the A$3.6 billion Barossa Project to develop the Barossa and Caldita fields. First gas is expected in 2025 and will be delivered by pipeline to the Darwin LNG facility, significantly extending its life. A Memorandum of Understanding between Santos and Eni to collaborate in northern Australia and Timor-Leste will see the Evans Shoals field developed as feedstock for a new train at the Darwin LNG facility (Evans, 2021b). Environmental opposition to the Barossa development has taken an international turn, with court action in South Korea seeking to prevent the Export Bank of Korea and the Korean Trade Insurance Corporation from funding loans for the project. In late 2022, Santos's drilling at Barossa was halted by the Federal Court of Australia on the grounds that, despite agreement with all representative bodies of the Tiwi Island "traditional owners," they had not consulted with each individual (Petroleum Australia, 2022). The appeal against this ruling was unsuccessful and Santos has initiated a new round of consultations with traditional owners and other affected parties.

By contrast, MEO's nearby Heron-2 (2007) found only 300 BCF of gas, with 50% CO_2, and Heron South-1 (2012) yielded only minor flows. Heron-2 was also targeting gas in the Windalia Radiolarite, but there was no recovery on testing. The MEO's Blackwood-1 (2008), on the fault block behind the Heron wells, discovered approximately 0.5 TCF but with more than 30% CO_2; Blackwood-2 (Eni/2013) failed to recover gas from the tight reservoir. The MEO's innovative development scheme envisaged an LNG processing and storage facility constructed on the nearby shallow submarine platform of Tassie Shoals, along with a methanol plant to "sequester" the CO_2. Environmental approvals were obtained for use of the Tassie Shoals site but, without the expected Heron/Blackwood gas supply, construction did not proceed. The new owners, Melbana Energy, promote the Tassie Shoals facility as a possible way to commercialize stranded gas offshore northern Australia (Melbana Energy, 2021b).

Sahul Platform and Sahul Syncline

Flanking the Malita/Calder grabens on the northwestern side is the vast Sahul platform, which, in various definitions, extends to the edge of the continental shelf or to the collision zone in the axis of the Timor Trench. Thin Lower Jurassic and Cretaceous strata overlie Permian units across most of the platform. At its southwestern end, locally called the Kelp high, the platform is bounded by a broad northwest-trending trough commonly referred to as the Sahul syncline (Mory, 1988), but the terminology differs among companies and authors. This trough contains two prominent high blocks, the Laminaria high in the northwest and the Flamingo high in the southeast, connected by a discontinuous structurally high zone. The synclines flanking this high trend are known as the Flamingo syncline to the northeast and the Nancar trough or the Sahul syncline to the southwest. Exploration along this high trend, which is extensively cut by east-west–trending faults, has been very successful, with the Laminaria and Corallina oil fields in the northwest and the Bayu-Undan gas/condensate field in the southeast, and several commercial oil fields in between, as shown on Figure 11B.

Two giant gas fields occur on the Sahul platform: Sunrise-Troubadour, now in Timor-Leste waters, and Abadi (Nagura et al., 2003), in Indonesian waters. Both fields are being charged mainly from thermally mature Jurassic strata in the Malita graben to the southeast. The Sunrise-Troubadour gas/condensate field was discovered by Woodside's Troubador-1 (1974) and Sunrise-1 (1975). Both wells were targeting oil, which was confidently expected because of proximity to the oil seeps onshore in (then) Portuguese Timor. The discovery of an interpreted 0.5–1 TCF of dry gas in the Jurassic Plover Formation reservoirs was, at the time, a major disappointment for the companies.

Subsequent to the Sunrise/Troubadour discoveries, exploration in this region of the Bonaparte Basin was delayed for many years by disputes over marine jurisdiction. An international boundary coincident with the Timor Trench axis had been agreed to by Indonesia and Australia in 1972 but was rejected by (then) Portuguese Timor. After Timor-Leste was annexed by Indonesia in 1975, a zone of cooperation (ZOCA) with Australia was negotiated in 1989, with varying revenue-sharing arrangements depending on a field's location relative to the Timor Trench and the median line between the countries. This arrangement continued after Timor-Leste became independent in 2001 but was modified in 2006 by agreement between Timor-Leste and Australia, whereby Timor-Leste gained 90% of revenues from the renamed Joint Petroleum Development Area. In 2017, Australia and Timor-Leste commenced negotiations regarding a permanent international boundary, reaching agreement in 2018 (Schleich, 2018; La'o Hamutuk, 2020). Consequently, exploration and development activities in a large area formerly considered to be in Australian waters now fall under Timor-Leste jurisdiction, subject to existing permit holders being guaranteed the same regulatory and financial regime as had previously applied under the Australian administration.

A rarely discussed aspect of the boundary disputes in the Timor Sea is the decision by the Indonesian government not to ratify the 1972 Australia/Indonesia agreement, thereby leaving open the possibility of default on the agreement. A maritime boundary based on the midline between the countries, similar to the 2018 Timor-Leste/Australia agreement, would have advantages for Indonesia, ceding them large areas that have remaining hydrocarbon potential. These maritime boundaries have become a nationalistic issue in recent Indonesian presidential elections (Chen, 2014). Negotiations between Australia and Indonesia about their maritime boundaries, which recommenced in 2019 but stalled because of the COVID pandemic, are concerned with the 1997 agreement regarding the Economic Exclusive Zone boundary, not the Timor Sea petroleum rights boundary (Strating, 2021). Ultimately a tripartite agreement between Indonesia, Australia, and Timor-Leste is needed to finally settle the boundary issue.

The 1989 creation of the ZOCA allowed exploration in the area to recommence after a two-decade hiatus and led immediately to a flurry of significant discoveries. This success was primarily owing to the learnings during that hiatus from exploration in the areas surrounding the ZOCA, and to the vast improvement in seismic acquisition and processing technology. Elang-1 and Kakatua-1 (BHP/1994) both discovered oil in the Oxfordian–Callovian Elang Formation (also known locally as the Montara Formation or, informally, the Montara beds) in tilted east-west–trending fault blocks. Exploration also resumed on the Flamingo high where Bayu-1 (Phillips/1994) and Undan (BHP/1995) discovered the major Bayu-Undan gas field, with 4 TCF of very wet gas (60 bbl/MMSCF) in reservoirs in the Elang and Plover formations. A residual oil column shows that Bayu-Undan was originally charged with oil but was not full to capacity. Modern seismic data reveal that ARCO's Flamingo-1 (1971), which encountered both gas and oil shows, narrowly missed the structural closure at the reservoir levels. ConocoPhillips became the operator for the unitized field that was developed by pipeline connection to an LNG plant built near Darwin. The first LNG shipment was in 2006, with peak production in 2008 of 500 MMSCF/day, as well as 65,000 bbl/day of oil and 37500 bbl/day of natural gas liquids (Offshore Technology, 2021). Interestingly, the Sahul platform also contains significant helium resources that have been extracted from Bayu-Undan tail gas from the LNG plant. This is likely sourced from widespread radiometrically hot granites such as those intersected in Troubadour-1.

Bayu-Undan has been in relatively steady decline since 2011 (Offshore Technology, 2021) and a possible cessation of production as early as 2022 was announced (ConocoPhillips, 2019). This declining production had major implications for Timor-Leste for whom Bayu-Undan had provided revenue exceeding US$22 billion by mid-2019. Because of the declining revenue, Timor-Leste's Petroleum Fund, which is effectively the national treasury, was projected to be bankrupt by 2028 (Scheiner, 2019). However, in 2020, Santos bought ConocoPhillips interests in the field and the Darwin LNG and became the operator. An infill drilling program, initiated in 2021, was very successful, with the first well adding 178 MMSCF/day and 11,350 bbl/day of oil (Santos, 2021a), significantly extending the life of the field. Santos has also announced that, in conjunction with Eni, they are investigating options to repurpose the Bayu-Undan facilities, including as a carbon capture and storage project. This project now has the agreement of the Timor-Leste government, for whom it will provide critical revenue (Evans, 2021a).

At Sunrise and Troubadour, the resumption of exploration in the 1990s allowed 3-D surveying, which, with proper depth conversion, revealed the accumulations to be much larger than initially estimated (Seggie et al., 2000), with combined recoverable reserves of 8.35 TCF and 298 million bbl of condensate (Office of Environment and Heritage, 2003). The recognition of the substantial condensate reserves significantly improved the economics for any development. After extensive engineering studies highlighted complexities regarding reservoir distribution and resource estimates, Sunrise-3 (Woodside/2008) was drilled to provide additional data on these and other issues: it flowed 44 MMSCF/day of gas from the Plover Formation. The Sunrise and Troubadour structures have been in place for less than 12 m.y., probably less than 5 m.y., and the charge is both active and recent, mainly from the southeast and from the trough between the fields. The high heat flow caused by the shallow radiogenic Precambrian basement means that the Plover Formation source rocks, which are interbedded with the reservoir, are mature immediately off-structure. Such a relatively small fetch area has been able to provide the 8+ TCF of gas reserves because of the coal-rich source material and the gas expansion in the shallow reservoir. The relatively low maturity also ensures a high liquids content, including the likely oil rim that remains undrilled (A. Murray, 2022, personal communication).

As a result of the 2018 Marine Boundary Treaty, Sunrise-Troubadour now lies entirely within Timor-Leste waters but, as part of that agreement, the Woodside JV is guaranteed exclusive rights to develop the fields and market the gas and condensate. Both Australia and Timor-Leste have the right of "in principle" approval of the development plan, and there is a long-standing disagreement between them: Woodside argues that a floating LNG scheme best suits the reserve's size and the benign metocean conditions in the Timor Sea; Timor-Leste wants a "floating pipeline" across the Timor Trench to an LNG processing plant to be built at the coastal town of Nova Beaco. To better pursue that development plan, Timor-Leste paid A$484 million in late 2018 for Conoco Phillips' 30% share of the Greater Sunrise asset (Dziedzic, 2018). The income from Sunrise-Troubadour had been projected as budget-sustaining revenue for Timor-Leste after Bayu-Undan ceased production in 2024 or earlier, and consequently, the delayed development at Sunrise had potentially serious financial implications (La'o Hamutuk, 2015). That concern has been alleviated by the Barossa field development and the phase 2 development at Bayu-Undan and its repurposing for carbon capture and storage, which will now provide substantial replacement revenue (Evans, 2021a).

Timor-Leste has cast their Sunrise development plan as a symbol of national sovereignty and financial development, but it remains without support from the companies. Woodside has qualified its commitment to the Greater Sunrise development project by insisting on the need for the "fiscal and regulatory certainty necessary for commercial development to proceed" (Woodside, 2022c). Geopolitics has already come into play: newly elected Timor-Leste president, Ramos-Horta, has announced that, in the absence of Australian government intervention and support, he will seek a multibillion-dollar investment from China to develop the field. Given the national and regional security implications, the Australian government is actively negotiating with the Timor-Leste authorities and the JV parties.

Abadi (Inpex/2000), a tilted fault block updip from the Timor imbricated trough succession (Nagura et al., 2003), contains 18.5 TCF of gas and 330 million bbl of condensate. The field is in Indonesia and sensu stricto not part of the Australian NWS region. It is included briefly in this discussion because it is the largest gas field in the Bonaparte Basin. A pre-front-end engineering design (FEED) development plan for the Masela LNG Project, as it is known, has been approved by the Indonesian government based on an integrated floating production storage and offloading (FPSO) facility and an onshore LNG facility on Nustual Island north of the field. The FEED work is proceeding and looking toward the first shipment of LNG later this decade (Inpex, 2021).

Controversy also engulfed the Laminaria/Corallina oil fields on the Laminaria high. This structure was not in the contested marine area, but its adjacency thereto and concerns about breaching by recent east-west faulting served to limit exploration interest for many years. The Laminaria field was discovered by Woodside in 1994, commenced production in 1999 using the FPSO Northern Endeavor, and ultimately produced 112 million bbl (Data courtesy of IHS Markit [Copyright © IHS Markit, 2022. All rights reserved]). The nearby Corallina oil field (Woodside/1995) was developed by tie-back to the Laminaria FPSO and ultimately produced 102 million bbl (Data courtesy of IHS Markit [Copyright © IHS Markit, 2022. All rights reserved]). Residual oil columns showed these fields were originally part of a giant gas-condensate accumulation, and the substantial volumetric reduction in the original accumulation is generally attributed to fault leakage, although water washing has also been proposed (Newell, 1999).

Both fields and the associated facilities were sold in 2015 to the private Australian company, Northern Oil and Gas Australia (NOGA), who became the operator. Production was approximately 3000 bbl/day at the time of sale and future income from the field was expected to be adequate to cover the decommissioning costs, estimated to be more than US$200 million. In 2019, however, after maintenance issues forced a halt to production, NOGA went bankrupt and the federal government, having approved the transfer to NOGA and indemnified Woodside against future costs, became liable for the decommissioning costs. After considerable discussion with the oil industry, largely through APPEA, the federal government announced in mid-2021 the imposition of a levy on all offshore oil production to pay for the decommissioning (Lepic, 2021). This served to impose taxation on companies who have never been involved in production in the Bonaparte Basin and was vigorously but unsuccessfully opposed by industry.

Drilling on the high trend between Laminaria and Bayu-Undan in the mid-1990s was initially very successful. In addition to Woodside's Laminaria and Corallina in the northwest and BHP's Elang and Kakatua in the southeast, there were discoveries at Buffalo-1 (BHP/1995) and Jahal-1 (Woodside/1996). Jahal was considered uncommercial, but Buffalo-1 encountered a 45-m live oil column in the Elang Formation, with an initially estimated 36 million bbl OIP, later revised to 64 million bbl (Begg et al., 2002). Typical of the area, a large residual oil column (120 m) indicated a much larger original in-place resource of approximately 500 million bbl (Newell, 1999). Buffalo-2 (BHP/1997) confirmed recoverable reserves of 20 million bbl and development planning commenced immediately. Thereafter, the drilling results in the area were disappointing: several wells encountered residual oil columns, and only Bluff-1 (BHP/1998) had a live oil column (21 m), indicating approximately 10 million bbl recoverable. It also had a possible 129-m residual oil column, evidencing another substantial accumulation "lost" because of a combination of water washing and fault seal failure. Nexen purchased BHP's interests in 2000, but their three development wells in 2002 met with mixed success—as had BHP's original development drilling program—and the field was decommissioned in 2003 after producing just over 20 million bbl.

Exploration of the faulted structures in this area has faced two major challenges. First, seismic data interpretation is hampered by enormous velocity pull-ups associated with shallow-water carbonate buildups, many thought to be indicative of oil leakage from reservoirs in underlying structures, and by the lack of significant acoustic impedance at the objective Elang and Plover Formation levels. Second, the Neogene reactivation of faulting caused by the collision of the Australian continent with the Indonesian Arc was no less destructive of the oil resources in this area, with billions of barrels of oil leaking to the seafloor. Many wells encountered only minor shows or small accumulations but commonly had significant residual oil columns. Since 1995, drilling on fault-bound prospects has had a 35% technical success rate but only 13% commercial success.

Woodside's Kuda Tasi-1 (2001) discovery raised hopes of a development project that would also exploit the nearby Jahal field, but appraisal drilling was disappointing, and the fields remain undeveloped, with combined reserves estimated at approximately 25 million bbl. Eni's Kitan-1 (2008), drilled east of Laminaria on the same bounding fault, was more successful, discovering an oil pool estimated at approximately 35 million bbl recoverable. This structure had been mapped for some time but had not been drilled because of concerns about fault leakage. Kitan-2 (Eni/2008) confirmed the field, the Timor-Leste authority approved the development in 2010, and first oil flowed in 2011. Early notions of a tie-in of the Jahal and Kuda Tasi fields did not materialize.

Several wells have been drilled along the high trend to follow up on earlier discoveries or oil shows but with little success to date. The China National Offshore Oil Corporation (CNOOC) Australia drilled Jin Niu-1 (2009) and Hong Niu-1 (2009) on the Bluff structure, targeting a thicker oil column than in Bluff-1, but both wells were low to prognosis. Their Fu Niu-1 (2009) was seeking a live oil column updip from Bogong-1 but found only residual oil. More recently, the Australian company Carnarvon Petroleum remapped the abandoned Buffalo field using full-waveform inverted data (McGee et al., 2019) and drilled Buffalo-10 (2022), targeting an undrilled attic in the central area with mapped resources of 31 million bbl (Carnarvon Petroleum, 2017). The well encountered the Elang Formation reservoir 80 m low to prognosis (Carnarvon Energy, 2022b).

Industry's perception is that a pervasive charge system exists in the Sahul syncline and, whereas it is not hard to find where oil has previously accumulated, it is hard to find where oil has been retained: 93% of wells drilled in this area encountered an oil column, either paleo or current, and 80% of the current accumulations have a large paleooil column. Some of the loss of hydrocarbons was the result of water washing by high salinity waters pushed southward by the Neogene plate collision (Newell, 1999), but the principal cause of trap failure is generally believed to be fault reactivation, as discussed previously. Trapping appears to require that the high-side fault that provides the critical reservoir seal within the tilted block has not been significantly reactivated. Based on these criteria, a recent proprietary analysis of 38 structures where existing or residual oil columns proved charge, predicted the retention/loss of seal/oil in 80% of cases (Ascendience Geoscience, 2021). It is hoped that progressively improving 3-D seismic quality will allow more accurate mapping of the faulting and permit better predrill evaluation of the risk of fault-seal failure.

It is also possible that source rock distribution is a contributing issue to some well failures; specifically, that the effective source facies in the Elang and Plover Formations are limited spatially to the northeastern flank of the Flamingo syncline area. Longley et al. (2002) noted that algal-rich, delta-top ponding models, as favored for this area, predict effective source facies development only on the landward side of the prograding delta systems: in this instance, in the northeast. Lower quality source facies develop more broadly and generate minor hydrocarbon volumes, but these source pods are limited in size by a combination of structural position and depositional facies.

Petrel Sub-basin

The Petrel Sub-basin is located in the Joseph Bonaparte Gulf (Figure 11) and contains superimposed Paleozoic rift and sag basins, in turn overlain by Triassic and Jurassic sag-basin successions. Broad swell structures and diapirs were readily mapped in the subbasin on late 1960s seismic data, and the absence of associated magnetic anomalies was correctly interpreted as evidence of salt-cores. ARCO's ill-fated Petrel-1 (1969) and -2 (1970) discovered an estimated 2 TCF of gas and 14 million bbl of condensate in the upper Permian Hyland Bay Formation, whereas Tern-1 discovered 350 BCF in the top Hyland Bay unit, in a sandstone uncharged at Petrel. The accumulations were predominantly methane, and in 1971, there was no commercial interest in gas. Subsequent wells in the 1980s showed that the accumulations were in different reservoirs in each well, and Petrel-6 (Santos/1995) downgraded Petrel's reserves to approximately 600 BCF, making development unlikely in the short term at least. Exploration continues nearby, however: Santos has recently received regulatory approval for 3-D seismic surveys over areas covering the Tern gas field and the nearby Breakwater and Sparrowhawk prospects (Skopljak, 2022).

In 2000, a new round of exploration began in the Petrel Sub-basin focused on amplitude-supported prospects. Prometheus-1 and Rubicon-1 (Kerr McGee/2000) discovered an uncommercial 370 BCF of gas in adjacent fault blocks on the western margin. Blacktip-1 (Woodside/2001) was the subbasin's first commercial discovery, with 1150 BCF of gas and 4 million bbl of condensate at multiple levels in the Permian Keyling Sandstone, all correctly predicted based on sharp amplitude anomalies. Eni bought out JV partner Woodside in 2005 and proceeded to drill the successful appraisal Blacktip-2 (2007) after Blacktip North-1 (2006) found only residual oil shows on a separate structural closure. Production commenced in 2009, with a pipeline to the Yelcher processing plant onshore and a connection into the Amadeus Gas Pipeline to Darwin, where the gas supplies the domestic market. The Yelcher plant is near the Aboriginal township of Wadeye, and construction was linked to the social, environmental, and economic program negotiated by Eni with the community. Several wells (for example, Weasel-1 in 2003) targeting amplitude-supported prospects were unsuccessful, with the anomalies proving to be related to lithology. Gorter et al. (2008) have highlighted the glaciogene nature of the Permian succession in the Petrel Sub-basin, pointing to the giant fields of the Murzuk Basin in Libya as motivation for renewed exploration efforts.

The Petrel Sub-basin hosts the small Turtle (Western Mining/1984) and Barnett (Elf/1985) oil fields, where Permian and Carboniferous reservoirs have been charged with oil from either the anoxic marine shales of the upper Tournaisian–Viséan Milligans Formation (Cadman and Temple, 2004) or the lower Tournaisian Langfield Group (Gorter et al., 2004). Given the mid-Tournaisian tectonism, identification of the active source unit is critical for modeling of source maturity and migration. Numerous wells targeting this play, both onshore and offshore, have encountered oil and gas shows and small accumulations. The most recent test was Sandbar-1 (Woodside/2001), on a four-way dip-closed anticline in the extreme south nearshore area: neither reservoir nor source units were encountered.

The wild card for the Petrel Sub-basin is the drilling of the giant Beehive prospect, touted as one of the largest undrilled hydrocarbon prospects in Australia, with potential OIP of 1.4 billion bbl. The feature was recognized and mapped by Woodside in the early 2000s, when it was known as Whitetip (being beside Blacktip!). Beehive has been interpreted as a large Viséan carbonate buildup (180 km^2, 400 m vertical relief) overlying a lower Carboniferous source unit, which also blankets an underlying Ordovician closure. The Beehive "reef" is sometimes considered analogous to the giant Tengiz field in the Caspian Basin (Melbana Energy, 2021a), but has also been interpreted as an eroded carbonate platform (Gorter et al., 2005). The project was developed by Australian junior Melbana but sold to private American oil company, EOG Resources Inc., in 2021 after both Total and Santos declined drilling options. Even a modest commercial discovery would stimulate exploration interest in the carbonate play. Permit terms require drilling before August 21, 2023.

Browse Basin

The Browse Basin in the central NWS has two main subbasins, the Caswell and the Barcoo, in the northeast and southwest, respectively, and the adjacent Seringapatam Sub-basin, a volcanic deep-water plateau that has historically also been called the deep-water Browse or the outer Browse Basin. The Browse Basin's proven 2P potential reserves of approximately 50 TCF and 1200 million bbl of condensate (Data courtesy of IHS Markit [Copyright © IHS Markit, 2022. All rights reserved]) are all located within the Caswell Sub-basin; neither the Barcoo nor the Seringapatam Sub-basins have demonstrated an operating petroleum system. In the period 2001–2021, the discovered resources in the Browse Basin were 18 million bbl of oil, 503 million bbl of condensate, and 2.8 TCF of gas, a total of 996 million BOE, approximately 6% of the total of the NWS discoveries during the period. Figure 13 shows the Caswell Sub-basin Jurassic (Oxfordian) structure, with fields color coded to distinguish pre- and post-2000 discoveries. The discovery history for the entire Browse Basin is shown in Figure 14. The basin's remoteness, relative even to the NCB and Bonaparte Basin, is one of the main reasons that the multi-TCF gas–condensate discoveries, beginning with Scott Reef-1 (B.O.C./1971) 50 yr ago, remain undeveloped. Modest condensate yields and higher CO_2 values have also been factors in this delay.

Much of the exploration activity in the Browse Basin during the period 2001–2021 was focused on appraising past and new discoveries (Scott Reef trend, Ichthys, Prelude, and Crux) and testing satellite and on-trend structures, many of which were long-known leads and concepts. Multiple gas and condensate discoveries were made. Additionally, the deep-water Seringapatam Sub-basin was drilled, and several exotic play concepts were tested. Volcanics were encountered in the Lower Jurassic section in several wells and proved to be a frustrating blight on several exploration concepts and trends. Development of the Ichthys and Prelude discoveries saw the first hydrocarbon production in the basin.

An uplifted and faulted Jurassic and Triassic topography in the Browse Basin region was bevelled by erosion in the Oxfordian, and subsequent subsidence of the western basin margin created a west-dipping, monoclinal basin geometry at Upper Jurassic and younger levels. Three main source intervals exist in the Browse Basin, more specifically, within the Caswell Sub-basin: the Lower to Middle Jurassic (J10–J20) Plover Formation (source for Plover Formation gas on both sides of basin), the Upper Jurassic to Lower Cretaceous (J30–K10) Vulcan Formation (source of wet gas in Brewster Member sandstones in the Ichthys and nearby gas fields), and the Lower Cretaceous Echuca Shoals Formation (source of the oils

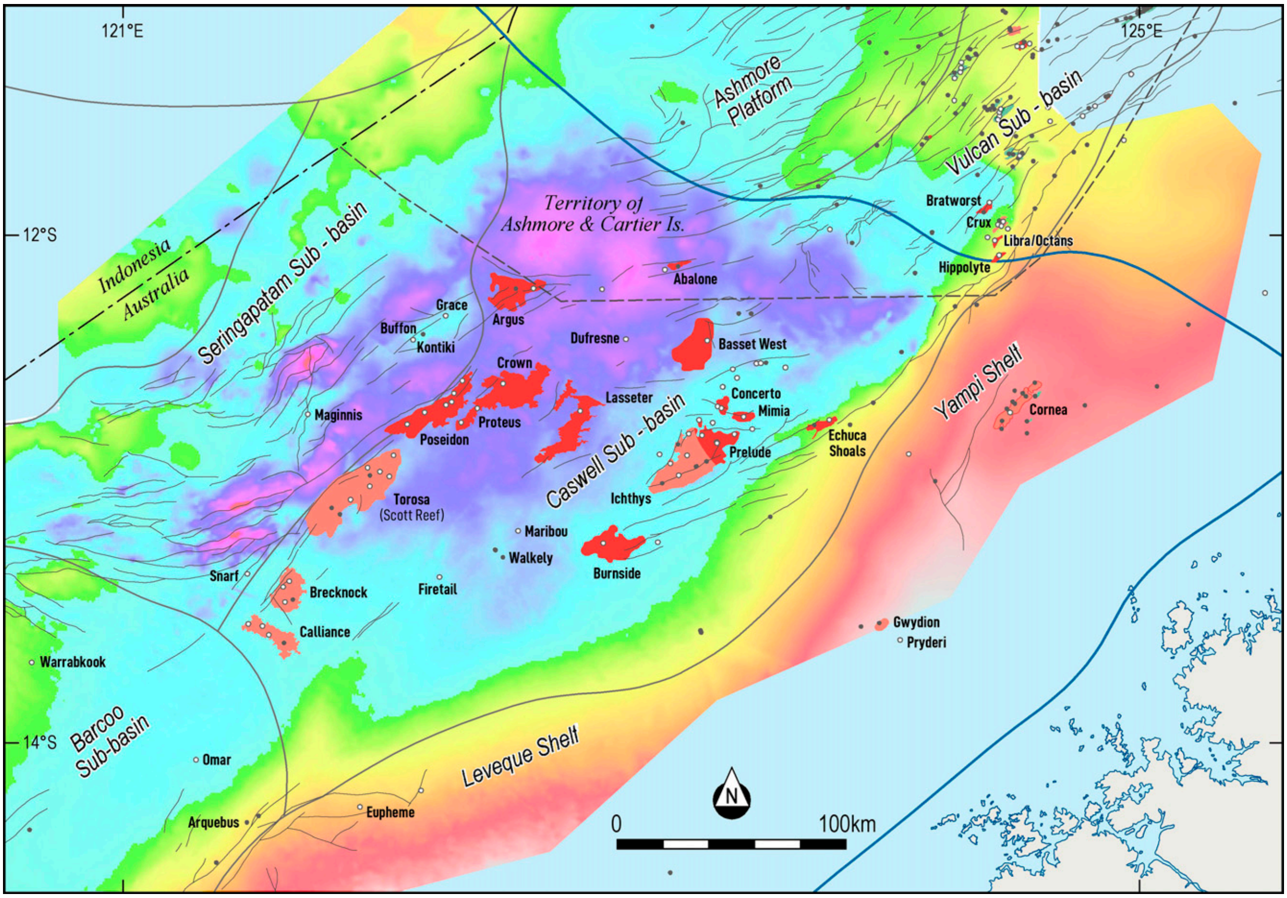


Figure 13. Browse Basin Oxfordian structure map showing subbasin regions and pre- and post-2000 wells and discoveries and identifying wells mentioned in the text. The underlying JO structure map for this figure is based on Longley et al. (2002), with superimposed base Cretaceous faults from P&R Geological Consultants' (2010) North West Shelf base Cretaceous structure map. This map includes content supplied by IHS Markit (Copyright © IHS Markit, 2022. All rights reserved). Is. = Island.

along the eastern margin) (Edwards et al., 2014; Grosjean et al., 2016; Rollet et al., 2019b).

Caswell Sub-basin

The western edge of the Caswell Sub-basin is marked by the Scott Reef trend, an extensive tilted horst block system that is manifest as a broad dome at the seafloor at 200- to 500-m water depth and is capped in several places by modern reefs. The bathymetric high had attracted Woodside's geological adviser Nicholas Boutakoff to the area in the 1950s (Purcell et al., 2015; Butcher et al., 2018), and the reefs made possible the early drilling after seismic surveys confirmed the structure at depth. Scott-Reef-1 (B.O.C./1971) discovered gas and condensate in the Lower Jurassic Plover Formation and gas in the Triassic Nome Formation. Brecknock-1 (Woodside/1979), along trend, discovered gas in the Plover Formation, as did North Scott-Reef-1 (Woodside/1982). However, these fields were 250 km from shore, where there was no infrastructure anyway, and the discoveries were largely ignored for decades.

No further drilling occurred on the fields until 2000, when Woodside's South Brecknock-1, on a depth closure mapped on new 3-D seismic data, discovered 4 TCF of gas and 85 million bbl of condensate. Several fields were renamed around this time: South Brecknock became Calliance and Scott Reef became Torosa. Although the Torosa rebadging was seen by some as Woodside seeking a less environmentally sensitive name, the reality is that Woodside's extensive environmental research and monitoring over many years has established Scott Reef as the best documented reef complex along Australia's northwest continental margin (Gilmour et al., 2013). Appraisal drilling on the fields continued through 2009, with 11

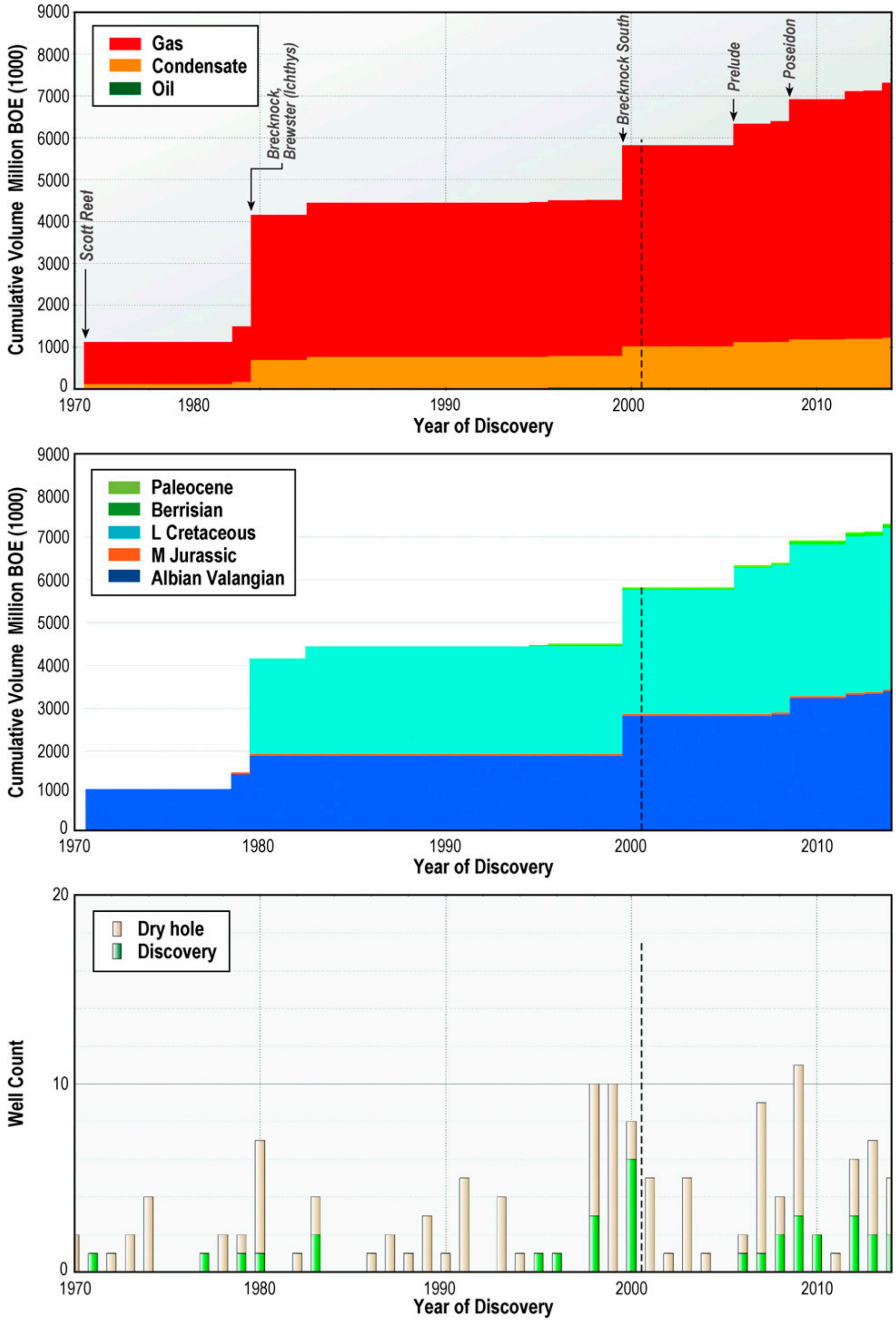


Figure 14. Browse Basin discovery history showing creaming curves by subbasin (top) and phase (center), and the annual well count color coded for discoveries and dry holes (bottom). L = Lower; M = Middle.

wells drilled. Reserves at Torosa (2P) are estimated as 6 TCF of gas and 120 million bbl of condensate; at Brecknock, 2.0 TCF and 47 million bbl of condensate; and at Calliance, 5.9 TCF and 223 million bbl of condensate (Data courtesy of IHS Markit [Copyright © IHS Markit, 2022. All rights reserved]).

In 2008, Woodside proposed to develop the Torosa and Calliance fields by piping the gas ashore to an LNG facility to be built at James Price Point on the coast north of the town of Broome. This proposal caused major divisions within the local and national society. Aboriginal native title holders were important parties to the negotiations with Woodside and the state government and, although there was some dissent, they generally supported the project, which was expected to provide approximately A$1.5 billion for Aboriginal communities in the area. Environmental activists successfully exploited local concerns regarding pollution risk and social disruption, and considerable publicity was generated by FIFO (Australian colloquial term meaning "fly in, fly out") activist celebrities. In April 2013, Woodside announced that the project was no longer considered economically viable, and they would instead investigate a floating LNG option with Shell. No mention was made of any reputational cost, but that too was likely deemed prohibitive by the Board. Plans for the A$40 billion floating LNG project were dropped in 2016. A proposal to deliver the Browse gas to the Burrup hub in the NCB through a 900-km pipeline is currently in the concept-development phase (Woodside, 2022a).

Commonwealth and state "ownership" of the Torosa field changed in 2014 when it was discovered that the 2004 Cyclone Fay had heaved a large block of submarine reef up onto the North Scott Reef atoll and, because this block was visible at high tide, it became legally Western Australia land, and a large surrounding area was reclassified as part of the state of Western Australia. Thereby, the area of Torosa field in Western Australia state waters increased from 20% to 70%, and the corresponding increase in Western Australia's share of future royalties will be worth billions of dollars to the state coffers.

Exploration elsewhere along the Scott Reef trend was also successful, albeit to varying degrees and diminished by commonly encountered volcanics. Argus-1 (BHP/2000) at the north-northeast tip of the Scott Reef trend found 40 m of gas in the Oxfordian Montara Formation, but the Plover Formation intersection was primarily volcanics. Poseidon-1 (Karoon/2009), drilled on a large multielement fault block northeast of the Scott Reef accumulations, encountered 95 m of volcanic flows and tuffs in the upper Plover Formation, but underlying sandstones had nearly 11% porosity and a gross 317-m gas column, extending down into the Triassic Nome Formation. This feature had been known to Woodside as the Colbert Structure since the 1980s but went undrilled because of its target depth and its proximity to Buffon-1 (Woodside/1980), which had encountered a thick volcanic-prone Plover Formation succession. Kronos-1 (ConocoPhillips/2010), on the crest of the Poseidon block, proved a total gas column of more than 500 m and tested 26 MMCF gas/day with 9 bbl/MMSCF of 48° API condensate. ConocoPhillips also revisited the Buffon trend, but their Kontiki-1 (2009) and Grace-1 (2013) wells encountered 960 m and 1176 m, respectively, of volcanics and thin interbedded siliciclastics. Woodside's Snarf-1 (2007) was drilled on a fault block west of the main Scott Reef trend, but the objective Jurassic section was missing below the Cretaceous unconformity.

Karoon estimated P50 reserves in the Poseidon gas field of 7 TCF and envisaged an LNG/condensate development project with the gas to be taken by pipeline to an LNG plant built on an island off the Western Australia coast. Karoon sold their 40% interest in the field to Origin Energy in 2014 for A$600 million plus staged uplifts. Origin had expected the field to be developed as backfill for Darwin LNG, but that will now be provided by the Barossa gas field development. ConocoPhillips's 40% interest was sold to Santos in 2019 as part of the larger sale of their NWS assets. Santos is currently the operator of Greater Poseidon and has listed the 2P resources as 410 million BOE (Santos, 2019b). The field remains undeveloped and will likely remain so for some time: Origin's book value has been written down to zero (Letts, 2017).

On the eastern side of the basin, the main exploration effort and success was following up on Woodside's Brewster-1 (1980) discovery, which had gas shows in the Lower Cretaceous (Berriasian) Brewster Member and the Upper Jurassic Plover Formation. Producibility was uncertain and drilling costs very expensive, and the permit was relinquished. Inpex acquired the block in 1997, reportedly based on perceived oil potential in several local closures. Their Dinichthys-1, Gorganichthys-1, and Titanichthys-1 wells (2000) confirmed the gas accumulation, with 65 to 220 m of gas pay in the Brewster Member and Plover Formation sandstones, with all reservoirs at each level in communication. Ichthys-1 and -2 (Inpex/2003) confirmed the high CGR of 40+ bbl/MMSCF in the gas accumulation, which Inpex renamed the Ichthys gas field. This appraisal drilling also revealed that a tilted paleohydrocarbon–water contact in the Brewster Formation had preserved better porosity in the northwestern part of the field, relative to that encountered in the tight sandstones to the southeast in the Woodside's Brewster-1 discovery well (Nakanishi et al., 2014). The Echuca Shoals Formation and Lower Vulcan Formation mudstones are the source for the Brewster Member gas, with Lower Vulcan and Plover Formation claystones charging the Plover Formation sandstones. Appraisal drilling established P50 reserves of 12 TCF and 500 million bbl of condensate. Inpex planned to use development facilities on a coastal island but abandoned this in the face of government approval delays and the inevitability of activist-orchestrated opposition. Several Japanese and Chinese companies and Total joined Inpex at the development stage, which involved condensate processing and export through the Ichthys Venturer FPSO and the piping of gas almost 900 km to the dual-train Ichthys LNG facility built at Darwin. Production commenced in 2018, with projected annual production of 8.9 million t of LNG, 1.6 million t of LPG, and 100,000 bbl/day of condensate (Inpex, 2022).

Shell's adjacent WA-35-P permit, which contained a significant extension of the Ichthys structure, had expired in 2005, forcing Shell to compete for the regazetted block, which they won with an aggressive 12-well bid. Prelude-1 (2006) confirmed the extension of the Ichthys accumulation, discovering gas in the Brewster Member sandstones (Upper Swan Formation, in Shell terminology). Subsequent wells, Toccata-1 (2007) and Fortissimo-1 (2007), confirmed further extensions of the Ichthys accumulation at the Brewster reservoir but encountered volcanics in the Plover Formation. Concerto-1 (Shell/2007), drilled on a separate structure to Ichthys/Prelude, discovered gas in the Brewster Member and in the fluvio-deltaic Plover Formation, which was devoid of volcanics. Combined reserves in the Prelude fields are 3 TCF and 120 million bbl of condensate. The 2019 Bratwurst-1 discovery in the Vulcan Sub-basin will also be tied back to Prelude.

Prelude might usefully have been developed as part of a "Greater Ichthys" project, with combined reserves of 15 TCF and 620 million bbl of condensate, but Shell proceeded independently, building the world's first floating LNG plant to develop the field. Inpex (17.5%), Korean Gas Corporation (10%), and CPC Corporation (5%) joined the Prelude Project in 2012. Prelude has not been a successful venture to date. Initial costs were projected at approximately A$12 billion, but final costs through 2019 are estimated to have been A$17–A$19.3 billion. Operational and safety problems, notably a near catastrophic fire in 2021, have limited production time to less than 25% in recent year, and have recently been added to by a prolonged industrial dispute. In 2021, Shell announced that it is unlikely ever to pay Petroleum Rent Resource Tax to the Australian government for the gas produced from Prelude (Milne, 2020a, 2022).

A gas development project centered on Nippon's Crux discovery (2000) has recently been announced. Crux-1, drilled on a poorly defined faulted structure, found both the (Oxfordian) Montara and (Jurassic) Plover Formation objectives missing but serendipitously encountered 252 m of gas in two sandstones in the Lower Jurassic–Upper Triassic Nome Formation, flowing 33 MMCF gas/day and 960 bbl/day of condensate. Australian junior Nexus Energy acquired the permit in 2005 and sold the gas rights to Shell in 2006. Crux-2, -3, and -4 (2006–2008) encountered gas columns in the Jurassic Montara and Plover Formations above the Nome Formation. Very poor seismic data made mapping difficult and predicting of the subunconformity section very imprecise. Shell acquired 80% of the project in 2012 and drilled several wells looking for additional gas reserves. Octans-1 (2008), on an extension of the Crux field, and both Libra-1 (2008) and Hippolyte-1 (2010), on adjacent fault blocks, encountered gas in multiple reservoirs. Gas-filled Tithonian sandstones in Hippolyte-1 established a new objective in the area. In 2020, Shell received approval to develop Crux as backfill for the Prelude floating LNG facility, based on an unmanned platform and a 165 km pipeline to Prelude. First gas was projected for 2025 but has been delayed because of the COVID pandemic (Hunt, 2020).

Several wells in the northeast Browse Basin tested more exotic play concepts. Braveheart-1 (Hawkstone/2010) on the Prudhoe Terrace targeted a Barremian submarine fan of *Muderongia australis* age within the Echuca Shoals Formation, but the strong amplitude versus offset (AVO) anomaly proved to be related to the unexpectedly high porosity in the objective sandstones, not hydrocarbons. Fossetmaker-1 (Shell/2007), a follow-up to the uncommercial gas "discovery" in Upper Vulcan Formation sandstones in Echuca Shoals-1 (Woodside/1984), found the Brewster Member sandstone water wet and poor reservoir quality in the primary Tithonian target zone. Both cases showed the difficulty of accurately predicting reservoir facies and hydrocarbon content, even on good 3-D seismic data in areas with close well control.

On the eastern Yampi shelf, Gwydion-1 (BHPP/1995) discovered 11 million bbl of OIP and 77 BCF of gas, proving long-range migration onto the shelf of oil from the Echuca Shoals Formation source kitchen in the basin center. It was, however, the next well, Cornea-1 (Shell/1997), which set the industry into a frenzy about this new play concept in the basin and was to have serious repercussions for the offshore exploration regulatory regime. Cornea was a small closure over a local basement knoll on a long basement ridge and, like Gwydion-1, it had large coincident amplitude anomalies (Stein et al., 1998). Cornea-1 encountered an 18-m oil column and appeared on the 2-D data to be coincident with a flat spot that extended continuously over the entire 50-km-long structure. Estimated OIP was 1 billion bbl. Additionally, there was a plethora of numerous smaller structures nearby, all eroded basement knolls with draping Cretaceous and Cenozoic sandstones, and many with amplitude anomalies. "Ducks on a pond" was the consensus industry view. Cornea-1 was drilled as a "tight hole" because the adjacent acreage, into which the Cornea ridge extended, had been gazetted for application and work program bids were due. With the benefit of the Cornea-1 results, including several sidetracks, the Cornea JV (Shell, Chevron, and Cultus) successfully bid 42 wells on the adjacent blocks, albeit at a commitment cost of only A$30 million. Thereafter, it all went wrong. A 3-D seismic survey showed that neither the structure nor the flat spot was continuous, and several early wells failed to encounter any oil at all. Where the oil rim was present, it was thin, with high viscosity, and the reservoir was poor. After drilling 11 wells, Shell concluded that "even under the most optimistic assumption, the production of oil from horizontal wells in the Albian reservoir in Cornea would never be significant" (Ingram et al., 2000, p. 64).

The JV successfully applied to the government for permission to terminate the exploration program without drilling the remaining 31 wells in their firm work program. Outwardly this seemed the simple and logical thing to do but it served to compromise the entire Federal work program bidding system, which until then, had always been sacrosanct: the work program bid in years 1–3 was "firm" and without any possibility of relief. To remedy this breakdown, the government introduced a penalty system whereby the money not spent on the firm drilling program had to be spent by the companies (split by equity share) on frontier blocks that industry had "rejected" (that is, blocks that had been gazetted but had not attracted bids) or they could take a 5-yr ban from the bidding rounds and be in "bad standing" during that time. Shell took the frontier exploration expenditure penalty; Chevron and Cultus took the 5-yr ban. The current arrangement is that companies seeking relief from firm work commitments must enter into a confidential Good Standing Agreement (GSA) with the government whereby the amount to be spent is agreed at the outset. Inevitably, this results in low well costs being specified in work program bids, given that the application bids are graded on the well count, not the proposed expenditure, whereas GSAs are based on the unspent expenditure.

While all this unfolded, Woodside drilled Psepotus-1 (1998) on a Cornea-like basement knoll on the Leveque shelf to the southeast, also looking for oil below a seismic "flat spot," but found only a small (10 BCF) gas accumulation. Nexen tried to develop this play by aggregating multiple small structures and pinchout traps, but the prospects went undrilled. A decade later, Octanex sought to revive the Cornea play, arguing that new amplitude studies had better defined Torithe oil rim and indicated potential for more than 400 million bbl original OIP, albeit with a 7% recovery factor (Octanex, 2008). Cornea-3 (2009) encountered oil-bearing Albian sandstones, but the producibility was questionable. Further drilling planned for 2018 did not eventuate (Octanex, 2016). Australian junior IPB Petroleum developed a play updip from Gwydion-1, based on an interpretation of amplitude anomalies associated with channel-filling sandstones. Prideri-1 (Calenergy/2014) tested the interpreted oil segment but found only minor residual oil and poorly developed sandstones. No permits are currently active along the Browse eastern margin.

The potential for stratigraphic traps in turbidite and channel features in the near monoclinal Cretaceous succession of the Caswell Sub-basin had been proven by Caswell-2 (Woodside/1983) and became the focus of a detailed exploration effort by Santos through the late 1990s (Benson et al., 2004), culminating in the drilling of the Carbine and Marabou prospects in 2001. Carbine-1 was a complex mound feature on the Campanian shelf edge and thought to be a slump-filling sand body that had been molded by differential compaction; it appeared analogous to the 800 million bbl OIP Alba oil field in the North Sea. Unfortunately, no shows were encountered in Carbine-1, which likely had no access to charge from the deeper Echuca Shoal source section. Maribou-1 tested a "ponded" turbidite with small structural closure in the Campanian Puffin Formation and a shallower stratigraphic trap but found only minor gas shows in the Puffin Formation closure. Firetail-1 (Woodside/2002) marked a return to more conventional features, targeting basin-floor fan sandstones draped over a large structural high, but found the sandstones shaled-out and a younger fan-sandstone was water wet. Success came with Burnside-1 (Santos/2009), something of a mini-Ichthys analogue play, which found a possible 52-m gas column in Brewster Member sandstones draped over a complexly faulted horst block and pinching out updip. Appraisal drilling is not scheduled until 2025.

By 2000, seismic data quality was adequate to map multiple deep Plover Formation structures in the basin center between the giant gas trends at Ichthys and Scott Reef. Crown-1 (Santos/2012), drilled on a large northeast-trending structure en echelon to the Poseidon discovery, encountered a 62-m gas column in the Vulcan, Plover, and Malita Formations. Lasseter-1 (Santos/2014), drilled in the central area on a horst block with fault-dependent closure at Vulcan Formation and Plover Formation reservoir levels, found 84 m of gas pay. Plover Formation reservoirs in both wells were low porosity, averaging 7%–9%. Efforts to locate the Plover Formation gas play farther north at Basset West (Total/2012) and Dufresne (Total/2013) were unsuccessful, with the entire Plover Formation section missing at the Valanginian unconformity. These two wells were disappointing, highlighting again the difficulty of predicting thin reservoir units, even with relatively good quality 3-D seismic data.

Many of the recent wells in the Caswell Sub-basin have involved deep targets (some >5 km) and encountered overpressured shales within and below the regional seal, a combination that makes many wells difficult to drill and expensive (>US$100 million): Dufresne-1 and Basset West-1 both took more than 6 months to drill. The limited size of the discoveries, the high CO_2 content, and the relatively low CGRs are added hurdles to economic development. Had Woodside's James Price Point LNG hub been established, the option to tie in such smaller accumulations to the cross-basin pipeline would have significantly improved the economics of these fields and facilitated earlier development.

Seringapatam Sub-basin

The Seringapatam Sub-basin is located beyond the continental shelf, west of the Caswell Sub-basin. The outline of the basin varies with different authors, as does its relationship with the Scott Plateau, a physiographic feature. We have followed BHP (Jason et al., 2004) in viewing the basin as a northeast-southwest–trending "graben" complex downfaulted from the Scott Reef trend.

The Seringapatam Sub-basin was the focus of an extensive evaluation program by BHP in 1997–2003 (Hoffman and Hill, 2004). Structures were very large, ranging to 1600 km^2, with the potential to hold sufficient reserves to warrant the high costs involved in drilling and development, but there were major uncertainties regarding both reservoir and source. BHP's program to mitigate the source risk involved an extensive hyperspectral, airborne slick detection survey, a follow-up multibeam bathymetry survey, and a seabed coring program. Approximately 50 oil slicks, mostly coincident with heavily faulted areas, were identified and nearly 400 fault zone targets were defined bathymetrically. Several cores did yield low thermogenic oil concentrations, but the significance vis-à-vis a mature source succession was equivocal. Reservoir risk was associated with the potential presence of volcanics in the objective Plover Formation sandstones, a common problem on the adjacent Scott Reef trend, and flagged here by volcano-like structures and the Plover seismic signature seen on 2-D seismic profiles. Analysis of data from shipborne magnetic and gravity surveys and a vast aeromagnetic survey led to the interpretation of deep, large magnetic bodies, possibly magma chambers, and a widespread thin volcanic layer below which Plover Formation sandstones were predicted.

The Maginnis structure, downfaulted from the Buffon structure on the Scott Reef trend, was selected for a first test because the magnetic anomaly was smaller than at Buffon-1, and prospective Plover sandstones were predicted below thin volcanics. In contrast, however, Maginnis-1 (BHP/2002) encountered a thick succession of volcaniclastics and altered basalts below the Cretaceous unconformity. The absence of an associated major magnetic anomaly was attributed to weathering of the basaltic unit, which was dated as Oxfordian to Kimmeridgian (154 Ma). Review of the seismic data led to recognition of a thick and widespread seaward-dipping volcanic succession across the region and downgraded the basin.

BHP drilled a second well, Warrabkook-1, on the large (1600 km^2) Narrowmine structure to test a shallow amplitude-supported closure in the Cenomanian to middle Aptian Jamieson Formation, with a secondary objective in the underlying Plover Formation tilted fault block. On most basin classifications, this well is actually within the Barcoo Sub-basin but is included here because it was part of the BHP Seringapatam Sub-basin program. The amplitude anomaly proved to be the product of diagenetic opal PT phase change alteration of the Windalia Radiolarite, not hydrocarbons, and the Plover Formation consisted entirely of interbedded tuffs and basaltic flows. A 3-D detailed survey of the Larrikin prospect showed that the objective Plover Formation section was continuous with the seaward-dipping volcanic wedge and drilling plans were abandoned.

The presence of the thick Lower Jurassic volcanic complex and the lack of any indication of a mature oil source brought interest in the Seringapatam Sub-basin to an unhappy end, and it is unlikely to see a return of exploration interest in the foreseeable future, unless new seismic data identifies a convincing direct hydrocarbon indicator. A first step will be a better understanding of the extensive Jurassic fluvio-volcanic terrain of the Seringapatam Sub-basin and the Browse Basin generally. The potential of the prevolcanic or even Triassic successions remains a long-term proposition.

Barcoo Sub-basin

The Barcoo Sub-basin was an early disappointment for explorers, and it has continued in that vein this century. Lynher-1 (B.O.C./1970), the first well drilled in the Browse Basin, was located on a wrench-faulted, inverted anticlinal feature on the eastern basin margin but did not encounter any significant shows. Several rounds of drilling along this trend have yielded only minor gas shows and some questionable oil indications in Arquebus-1 (Amoco/1991). In 2004, Magellan's Galapagos South-1 was based on amplitude anomalies in the Upper Cretaceous and Plover Formation successions along the same trend, but both reservoirs were devoid of shows. The substantial faulting that cuts through the Upper Cretaceous succession, extending to the seafloor and linking to Jurassic faults at depth, raises questions about trap integrity.

The Woodside JV's early prize target in this subbasin had been the Barcoo prospect on the western margin, seemingly a clear analogue of the Scott Reef discovery, but it went undrilled until 1979 because of the 720-m water depth. Barcoo-1 had no shows: the Upper Jurassic section was missing, and the Triassic succession contained interbedded volcanics. Woodside's Omar-1 (2012), targeting a large, faulted anticline to the northeast, found tight water-wet Jurassic reservoirs and a nonreservoir carbonate Upper Triassic (Norian) succession.

The lack of significant hydrocarbons in any of the Barcoo Sub-basin wells may well point to a basic lack of source material, given that Jurassic succession is in the oil- and gas-maturity windows over vast areas. However, the presence of local source pods cannot be discounted. This logic underpinned Pathfinder Energy's exploration concept in this area, with Triassic half grabens seen as the potential source kitchen for reservoirs on large adjacent fault blocks (Pathfinder Energy, 2018).

Roebuck Basin

The Roebuck Basin, the smallest of the Westralian basins, consists of three main subbasin areas, as shown on Figure 15: the Rowley Sub-basin in the deeper water to the north, the Bedout Sub-basin in the southwest, and the Oobagooma Sub-basin in the northeast. The Roebuck Basin has historically been called the Offshore Canning Basin by industry, but that term is now mainly used for the extensive shallow coastal shelf where a thin Mesozoic and Cenozoic succession overlies the offshore extensions of fault-bounded elements of the Canning Basin. The Offshore Canning Basin is not considered to be part of the Roebuck Basin, but it is part of the NWS. As noted at the outset, the basin terminology on the NWS is not always clear or consistent!

Exploration in the Roebuck Basin in the twenty-first century has proved to be a tale of two very

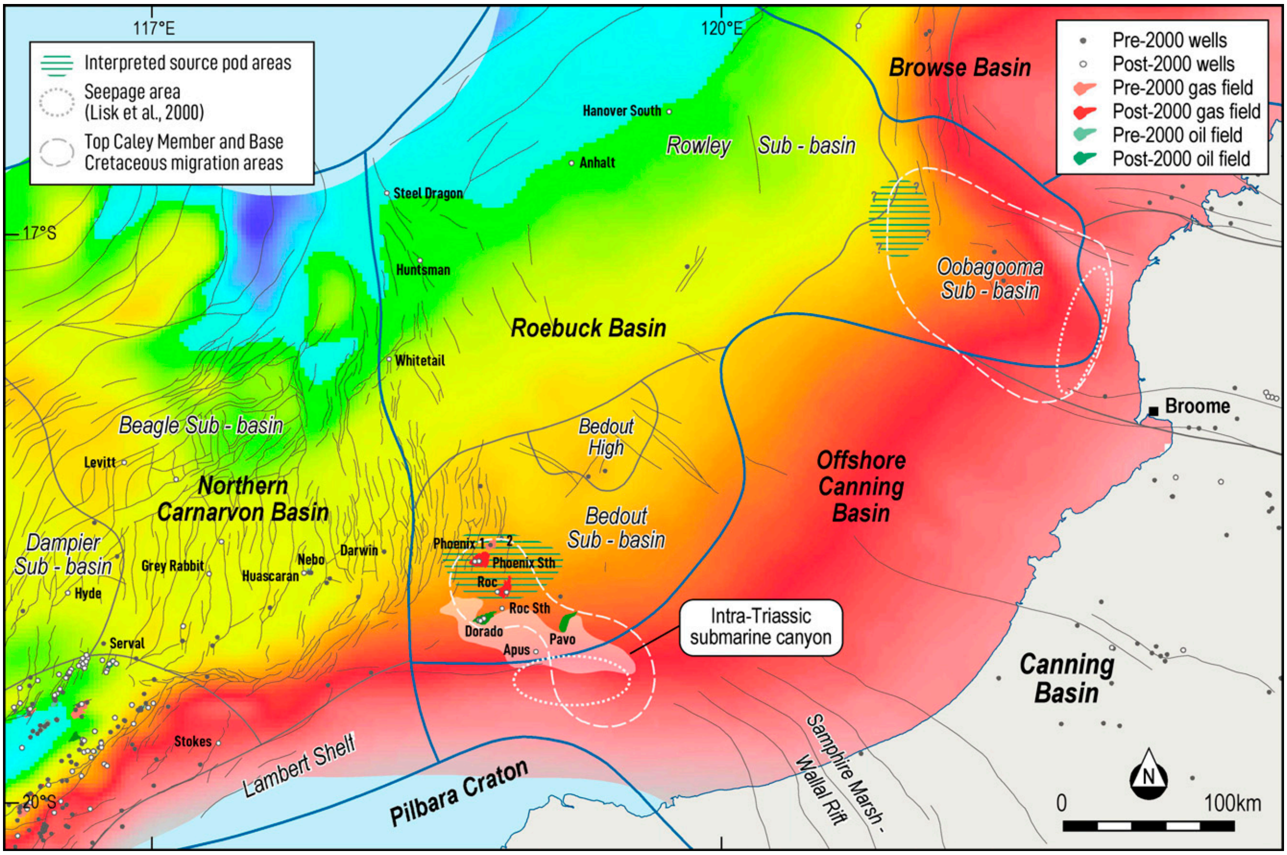


Figure 15. Roebuck Basin and Beagle Sub-basin Oxfordian (JO) structure map, showing subbasins, pre- and post-2000 wells and discoveries and identifying wells mentioned in the text. The underlying JO structure map for this figure, is based on Longley et al. (2002), with superimposed base Cretaceous faults from P&R Geological Consultants' (2010) North West Shelf base Cretaceous structure map. This map includes content supplied by IHS Markit (Copyright © IHS Markit, 2022. All rights reserved).

different outcomes: in the Rowley Sub-basin, exploration for Middle Jurassic, Triassic, and Permian objectives on potentially new deep prospective trends found no significant shows of oil or gas and downgraded the area; whereas the Bedout Sub-basin was the site of the largest oil discovery on the NWS in 30 yr. No exploration has occurred for decades in the Oobagooma Sub-basin, which has more structural and stratigraphic affinities with the contiguous onshore Fitzroy trough, of which it is effectively the northwest continuation.

Rowley Sub-basin

Exploration in the Rowley Sub-basin during the period was unsuccessful and served to downgrade several exploration concepts developed for the region. Woodside's Whitetail-1 (2003) and Huntsman-1 (2006) tested large fault block closures for Middle and Lower Jurassic objectives, respectively, but reservoirs in both wells were water wet and devoid of shows. An unexpected very low geothermal gradient (vitrinite reflectance, 0.4%) meant that predicted Triassic (Keraudren Formation) and Lower Jurassic (Athol Formation) source units were immature for oil and wet-gas generation. Exploration interest shifted west, based on the potential for mature-oil source units in that area, where multiple deep large structures had been mapped on 2-D seismic data. Woodside acquired three contiguous blocks along the trend in the 2010 gazettal round, with a firm work program bid of eight wells, and were joined by Shell (50%) as part of a broader deal aligning their equities in various Browse Basin projects. Woodside's interest in these blocks was presumably also influenced by their being located along the likely pipeline route from the Scott Reef gas fields in the Browse Basin to the Burrup Peninsula LNG hub in the NCB. The first well, Anhalt-1 (2014), encountered water-wet Lower Jurassic Bedout Formation without any hydrocarbon shows, overlying Upper Triassic carbonates, and

(?)Middle–Lower Triassic volcanics. In Steel Dragon-1 (2014), all Upper Triassic Mungaroo Formation reservoirs were devoid of shows, whereas Hannover South-1 (2014) encountered a nonreservoir Upper Triassic carbonaceous claystone succession overlying thick Triassic volcaniclastics. These volcanic successions had formed on a broad plain and contained interfingering fluvial deposits, lava flows, and ash falls. The failure of these three wells effectively discredited the play concepts and led Woodside to abandon the eight-well program, for which they paid an A$13 million penalty. The lack of any evidence of charge or deep source in these wells removed most industry interest in the western area of the basin.

Bedout Sub-basin

The exploration success in the Bedout Sub-basin this century was in stark contrast to the Rowley Sub-basin disappointments, with Apache and Quadrant making a series of oil and gas discoveries commencing with Phoenix South-1 (2014) and culminating in Dorado-1 (2018), the latter selected by Wood Mackenzie as the worldwide "Discovery of the Year." In the period from end 2000 to end 2021, the hydrocarbon resources discovered in the Bedout Sub-basin were 150 million bbl of oil, 102 million bbl of condensate, and 1.14 TCF of gas, a total of 441 million BOE, as shown on Table 1.

The Bedout Basin has, until recently, been best known for the massive and enigmatic subcircular Bedout high (Figure 15), variously interpreted as a basement block, a volcanic dome, and a meteor impact crater (Lipski, 1994; Jablonski et al., 2019; Rollet et al., 2019a; Yule and Spandler, 2022). In the preferred interpretation, the Bedout high is seen as a major extrusive volcanic center within the Eastern Gondwana Interior rift, which subsequently has evolved into a "rising igneous cored high" (Minken et al., 2019). This magmatic complex appears to be located at the intersection of northwest- and northeast-trending branches of the Permian–Triassic rift.

The hydrocarbon potential of the subbasin was noted early, when BP's deep Phoenix-1 (1980) encountered a 767-m gas column (110 m net) in Middle Triassic sandstones of the Keraudren Formation. Oil shows were noted on the mudlogs and indicated from gas chromatograph data, and oil was observed in the cores. However, porosity in the thin streaky sandstones was only 4%–15% and permeabilities averaged 5 md; the well was not tested because of operational issues. In the follow-up Phoenix-2 (1982), the reservoir quality was worse, and the "discovery" was set aside as noncommercial. The poor reservoir quality of the sandstones was attributed to their provenance in the volcanic flows known from early drilling on the Bedout high.

There was no further drilling in the Bedout Sub-basin until Apache's Darwin-1 (1995) targeted Jurassic objectives on the Beagle Sub-basin boundary: all reservoirs were water wet. No other exploration occurred until junior Australian explorers Finder Energy and Carnarvon Petroleum successfully bid for four permits over the main basin area in 2009. A farmout to Apache and JX Nippon in 2014 was based on several gas prospects with multi-TCF gas resource potential, with the oil indications in Phoenix-1 largely overlooked. Improved Triassic reservoir quality was predicted because of greater distance from the Bedout high volcanics to the north and increased quartz sand input from the southeast. Ultimately, it was the southeastern sand provenance rather than distance from the Bedout volcanics that would prove significant. What followed has been described as a rollercoaster ride for the exploration teams—finding oil when expecting gas, finding gas when expecting oil, finding primary targets dry but discovering new deeper hydrocarbon accumulations and, in the process, discovering several large fields, several different plays, and a major new hydrocarbon province (Thompson et al., 2018; Thompson, 2020).

Phoenix South-1 (Apache/2014) encountered elevated gas readings and fluorescence in low porosity reservoirs in the Lower Triassic Keraudren Sandstone and appeared to be a subcommercial tight gas discovery, similar to Phoenix-1. Disappointment swiftly became elation, however, when Schlumberger's Saturn probe recovered 46° API oil to the surface: the well had unexpectedly encountered a 151-m oil column, encompassing five sandstone reservoirs.

Roc-1 (Apache/2015) targeted oil in the same sandstone unit, newly named the Barret Member, but found the sandstones water wet with minor gas shows. (Postwell analyses suggested this was most likely the result of poor lateral seals on associated faults.) Because of persisting elevated gas readings, Quadrant deepened the well in search of stacked sandstones known from the nearby Keraudren-1 well (BHP/1974) and were rewarded with a 40-m wet-gas column in a high porosity sandstone unit. which was named the Caley Member. Gas shows were also found in sandstones of the Milne Member at total depth. Significantly, the older, more mature Caley sandstones exhibited superior reservoir quality compared with the younger, more immature sandstones (Thompson et al., 2019).

In 2016, seeking to refocus on North American shale gas ventures, Apache sold their Australian business unit to private equity investors who had formed Quadrant Energy and who also purchased the interests of Finder and JX Nippon. Roc-2 (Quadrant/2016), drilled to test the Caley Member and deeper reservoirs on the structural crest, encountered a 45-m gas column that was seen on pressure data to be a separate accumulation to Roc-1. Test flows of 51.2 MMCF gas/day and 2943 bbl/day of condensate were excellent but, with the gas–water contact encountered 55 m higher than predicted, the volumetrics were marginal. Follow-up drilling at Phoenix South was also disappointing, with Phoenix South-2 (Quadrant/2016) encountering the objective sandstone structurally higher but water wet, albeit with shows. Hydrocarbons were discovered in the deeper Caley Member, but the high-pressure gas influx prevented logging and hydrocarbon sampling. Field reserves were estimated as 490 BCF and 57 million bbl of condensate, but Phoenix South-3 (Quadrant/2018) came in at the lower end of expectations and downgraded this accumulation.

The Triassic delta system prograding northwest down the Samphire/Wallal rift in the southwest Canning Basin into the Bedout Basin is the key to the Bedout Sub-basin petroleum system. Mature sandstones were eroded from the uplifted Canning Basin area, then reworked and deposited by high-energy systems in the Bedout rift, notably in the Caley Member but also in the deeper Crispin and Milne Members. The source rocks interbedded with the Caley Member were deposited in swamp or lagoonal delta-top ponds, a mix of land plant and algal material (Pepper and Corvi's, 1995, organofacies D/E/C), with the algal content determining the liquid component. The temperature regime is described as "goldilocks: hot enough for proximal generation but not too hot so as to degrade reservoir quality" (Woodward et al., 2018, p. 881).

Data from the 2015 Capreolus 3-D multiclient seismic survey greatly improved structural and stratigraphic mapping and focused attention on a large, shale-filled canyon system updip from the Roc field and potentially a major stratigraphic trap. Extensive reprocessing, notably full-waveform inversion-driven migration and inversion, sharpened the imaging and understanding of the trap, with amplitude anomalies in multiple sand units leading to a confident 41% chance-of-success prediction. Dorado-1 (Quadrant/2016) encountered a 132-m net oil column in the Caley (80 m), Baxter, Crespin, and Milne Members; all sandstones had 13%–20% porosity. Condensate yields were 190–245 bbl/MMSCF in the Caley, Crispin, and Milne Members and 70–90 bbl/MMSCF in the Baxter Member. Several weeks after the Dorado discovery was made public, Santos announced the purchase of Quadrant, which was completed in November 2018. The discovery and well evaluation of Dorado-1 had taken place during intense financial negotiations between Santos and the Quadrant owners.

Appraisal drilling began in mid-2019 with Dorado-2 (Santos/2019), 2.2 km northeast and downdip of the discovery, finding oil and condensate-rich gas in the Caley Member and gas/condensate in the Baxter and Milne Members. Dorado-3, drilled later in 2019 in the western part of the field, flow-tested both the Baxter and Caley Formations, with the Caley flowing more than 11,000 bbl/day from an 11-m interval, confirming the excellent reservoir quality. The pre-FEED development planning commenced soon thereafter. Dorado is considered to have 2P reserves of 344 million BOE including 162 million bbl of light oil. Testing of Dorado-3 indicates potential flow rates of 30,000 bbl/day (Carnarvon Petroleum, 2019, 2021).

The Dorado development proposal involves an initial phase of liquids production from Dorado and future nearby tie-backs, with gas reinjection to optimize liquids recovery ahead of a future phase of gas export. The relatively shallow-water depth (<100 m) will allow development with a wellhead platform and an FPSO capable of processing 100,000 bbl/day and gas reinjection capacity of 235 MMSCF/day over 20 yr (National Offshore Petroleum Safety and Environment Management Authority, 2021). The need to reinject the gas early in the production phase is believed to make this a relatively high carbon intensity development. The FID, initially scheduled for 2022, has been postponed because of the perceived high risk of cost escalation resulting from "current regional inflationary pressures and supply chain challenges" (Carnarvon Energy, 2022c, p. 1). First oil is now unlikely before 2027.

One unsuccessful near-field wildcat along the Dorado trend (Roc South-1 [Santos/2019]) was drilled in 2019. Santos drilled two eroded canyon spur structures in early 2022, both sealed laterally by the shale-filled canyons. Pavo-1, testing the northern culmination of the structure, encountered a 46-m oil column (net oil pay) of 52° API oil in the Caley Member, with an estimated 2P resource of 43 million bbl. A similar resource is expected in the southern culmination, based on similar reservoir volumes and amplitude signatures. These fields will be developed as part of the Dorado project (Santos, 2022b). In disappointing contrast, Apus-1, estimated to have gross mean in-place resources of 250 million bbl (Carnarvon Petroleum, 2021), encountered only minor hydrocarbon indications in the Caley and Milne Members, with limited charge considered to be the likely explanation (Carnarvon Energy, 2022a).

Oobagooma Sub-basin

There has been no drilling during the period 2000–2020 in either the Offshore Canning Basin or the Oobagooma Sub-basin. As noted earlier, the Oobagooma Sub-basin is sometimes classified as part of the Offshore Canning Basin, rather than the Roebuck Basin (Totterdell et al., 2014).

Northern Carnarvon Basin

The main subbasin elements of the NCB are shown in Figure 16, as are the locations of Figure 16A and B, which show, respectively, the main discoveries and wells in the southern Exmouth Sub-basin and the Barrow/Dampier Sub-basins. Most of the basinal subdivisions are not discrete geological boundaries and are more industry consensus, albeit with some historic underpinnings: the separation of the Barrow and Dampier Sub-basins, for example, reflects in part the original WAPET and Woodside permit boundaries. The degree of detail of the subbasin elements shown on Figure 16 reflects the broad overview perspective of this paper. For simplicity's sake and in line with common industry usage, the Exmouth Plateau is treated here as a subbasin province.

The NCB has enjoyed multiple large gas discoveries in the opening decades of the twenty-first century, including several giant fields (>5 TCF) and numerous significant oil discoveries. The creaming curves in Figure 17, categorized by subbasin and phase, respectively, illustrate the considerable new resources discovered this century, being 66% of the new resources found on the NWS: 665 million bbl of oil, 480 million bbl of condensate, and 60.3 TCF of gas—a total of 11,200 million BOE, as shown on Table 1. Multiple major gas discoveries were made along the Rankin/Gorgon/Alpha structural high trend on the western margin of the Jurassic rift system and on structures within the complex faulted terrain flanking it. Major production continued along this structural trend and the development of earlier discoveries such as Gorgon commenced. Many other gas discoveries were made on the Exmouth Plateau, including the giant Jansz-Io stratigraphic trap with recoverable reserves of 20 TCF. Multiple oil discoveries were made in the Exmouth Sub-basin in both prograding and channel sandstones near the base and top of the Barrow Group. As has been the case historically, the paleogeography of the Lower Cretaceous Barrow Group delta complex and its depositional and erosional limits have been major determinants of the successes and failures of recent exploration in the Barrow and Exmouth Sub-basins. An equally important determinant of prospectivity in the basin has been the presence, quality, and maturity of the Upper Jurassic (Oxfordian) synrift shales of the Dingo Claystone. The distribution of oil generated from these shales has been significantly affected by the westward tilting of the basin in the Cenozoic, both on a subbasin scale and a field scale, as at the Griffin/Chinook fields (Tindale et al., 1998).

Exploration in the NCB in recent decades has been focused on the same basin elements that have dominated the exploration history since the early years: the Triassic Mungaroo delta prograding west-northwest across the basin, the Jurassic Legendre delta prograding west and southwest, the organic-rich shales of the Late Jurassic rift basin, and the northward-prograding Lower Cretaceous Barrow delta. The interaction between these systems controls much of the NCB prospectivity: the Legendre delta, for example, provides the wet-gas source for the

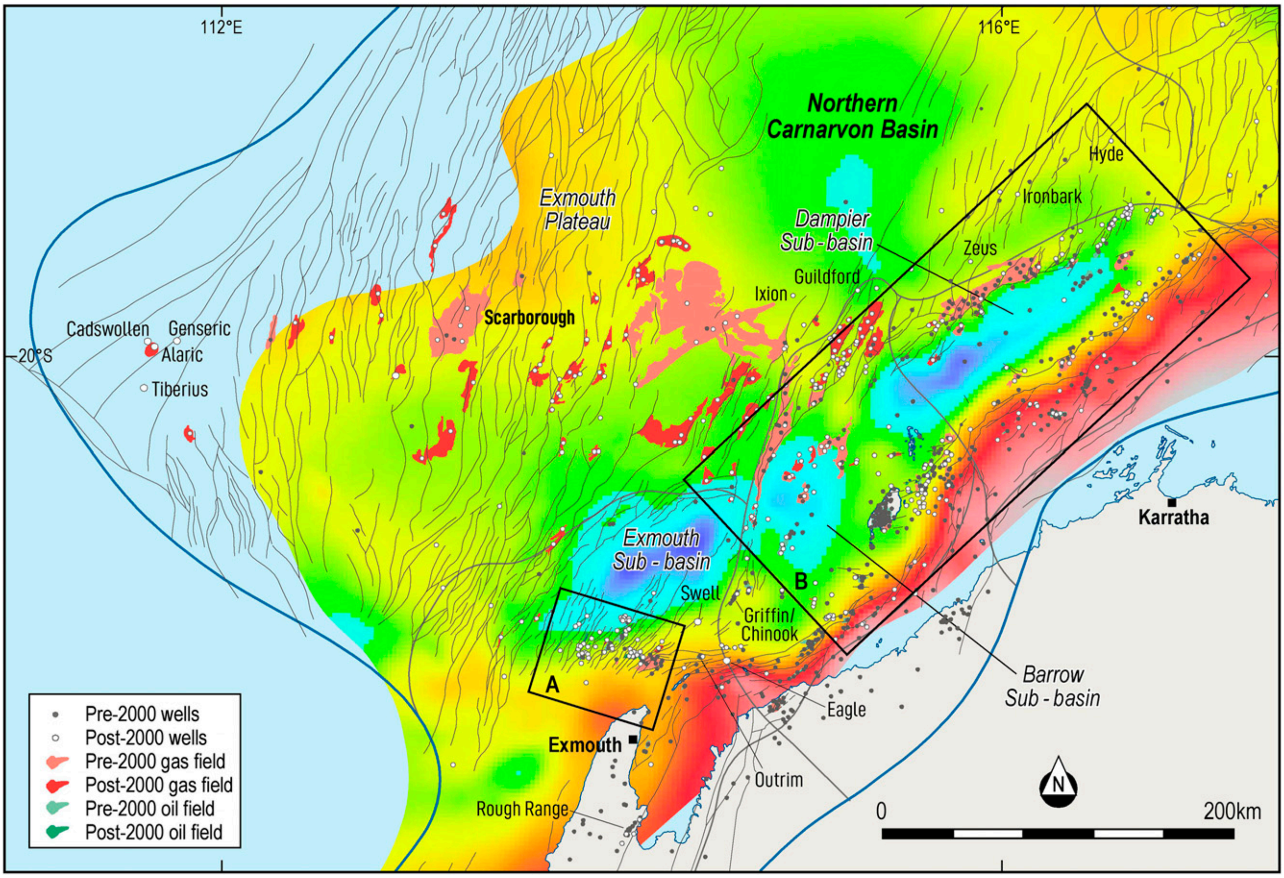


Figure 16. North Carnarvon Basin Oxfordian (JO) structure map showing subbasin regions and pre- and post-2000 wells and discoveries and identifying wells identified in the text. The labeled black boxes show the locations of (A) and (B). (A) Southern Exmouth Sub-basin JO structure map showing pre- and post-2000 wells and discoveries mentioned in the text. (B) Barrow and Dampier Sub-basins JO structure map showing pre- and post-2000 wells and discoveries mentioned in the text. The underlying JO structure map for this figure is based on Longley et al. (2002), with superimposed base Cretaceous faults from P&R Geological Consultants' (2010) North West Shelf base Cretaceous structure map. This map includes content supplied by IHS Markit (Copyright © IHS Markit, 2022. All rights reserved). Is. = Island.

Rankin platform fields, as well as reservoirs for many fields in the basin. Barrow Group strata are reservoir and seal in many fields but can also act as thief zones where they overlie the Mungaroo Formation reservoirs. The improved seismic surveying and processing technologies, notably with 3-D data, providing better velocity control on prospects and allowing detailed amplitude and QI analyses (where QI refers to quantitative interpretation of seismic data to estimate porosity and likely hydrocarbon fill) have been a major factor in the exploration success during the period.

Exmouth Sub-basin

Exploration commenced in the Exmouth Sub-basin in the early 1950s with the newly formed WAPET, a JV of Ampol Exploration, Shell, Chevron, and Texaco. The first well, located onshore at the southern end of Exmouth Gulf, was the Rough Range-1 oil discovery (1953), which is of no commercial significance in itself but is now legendary for sparking the rapid growth of Australia's embryonic oil exploration industry. No other wells at Rough Range or environs in those early years were successful. Considerable early attention was focused on the structural features north of Cape Range and thought initially to be an extension of the Alpha arch on which WAPET would later discover the giant Gorgon gas field in 1981. A second round of exploration in the 1980s, dominantly by BHP (Tindale et al., 1998), led to a variety of hydrocarbon discoveries and indications ranging from light oil with gas caps (Chinook/1989) to light oil (Griffin/1989) to heavy oil (Novara/1982) to dry gas (Macedon/1994) and revealing a complex multicharge history and diagenetic alteration within the accumulations.

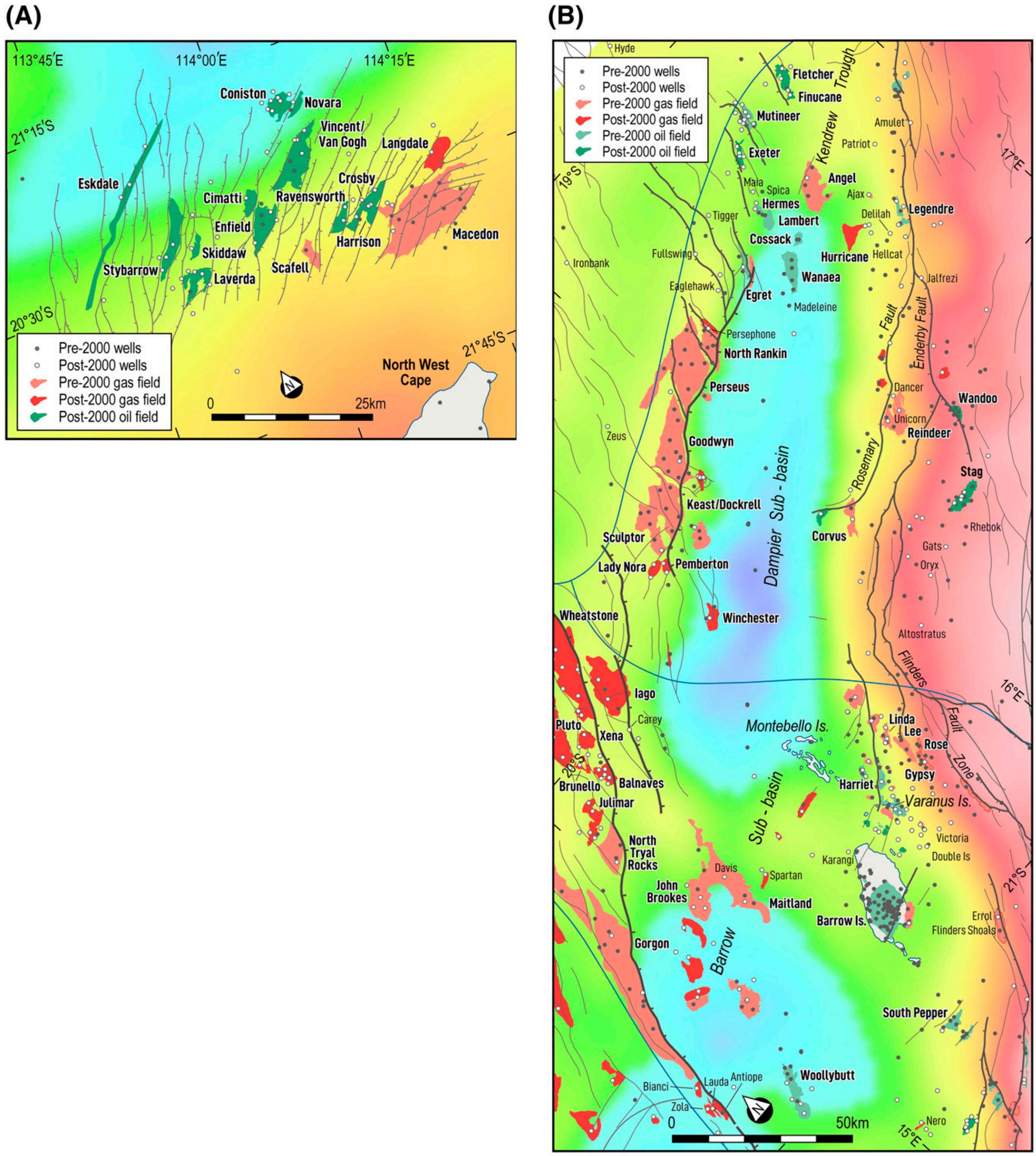


Figure 16. Continued.

As would prove to be the case elsewhere on the shelf, residual columns showed that Griffin-Chinook had been a much larger field (500 million bbl) prior to regional tectonism that spilled the oil to the east (Brincat et al., 2006)

Beginning in the late twentieth century and continuing into recent decades, the identification of complex velocity fields, which allowed more accurate depth mapping and fault delineation, and the emergence of amplitude analyses as a standard and increasingly reliable technique, further refined the exploration processes in the Exmouth Sub-basin, as elsewhere on the NWS. In particular, amplitude mapping on new high-quality 3-D seismic in the southern Exmouth Sub-basin proved the key to unlocking the oil play in this area, when the Vincent and Enfield discoveries sparked the Exmouth Sub-basin "oil rush." A plethora of pronounced amplitude anomalies at upper and basal Barrow Group levels were mapped across the area, providing clear evidence of hydrocarbons in low-side fault closures, tilted fault blocks and faulted channel systems. The main oil discoveries this century are shown in Figure 16A.

Woodside had entered the Exmouth Sub-basin in 1997, venturing for the first time into the WAPET/Chevron domain, presumably because this was an oil play. (Shell was an early partner in both the WAPET and Woodside JVs, and there was an agreed unofficial demarcation line to avoid Shell "competing with itself.") In 1998, Woodside's Vincent-1, drilled on a faulted closure at the Top Barrow Group, with a conformable amplitude anomaly, encountered 19 m of 17° API oil below a 13-m gas cap, and flowed 4300 bbl/day. The recognition that the oil was 12–16 cP in the reservoir and producible finally overcame the prejudice against this southern area because of the heavy oil (13.9°–16.7° API) encountered previously in Novara-1 (Esso/1982). Apache's Van Gogh-1 (2003) confirmed the extension of the Vincent accumulation into the adjacent permit. Development drilling on the 73 million bbl Vincent field began in 2007–2009, with first oil delivered in 2008; at Van Gogh, development drilling began in 2008, leading to first oil in 2010. Misalignment between the two JVs and the unwillingness of the regulator to force a joint development resulted in the suboptimal deployment of two FPSOs for a single field.

A few months after the Vincent discovery, Woodside's Enfield-1 flowed 4800 bbl/day of 22° API oil (17 cP) from the Macedon Member sandstone near the base of the Barrow Group. Enfield was a tilted fault block, defined by excellent 3-D seismic data and with a very detailed conformable amplitude anomaly indicative of gas over an oil leg over water, as confirmed by the well. Appraisal drilling proved reserves of 127 million bbl OIP and development commenced in 2004, delivering first oil in 2006. The exquisite seismic imagery and amplitude displays allowed detailed mapping of the channel systems, including the main and splay channels, the overbank spill facies, and the basin-floor fans (O'Halloran et al., 2013). Woodside's Laverda-1 (2000) encountered a 61-m oil column in a faulted channel complex in the Macedon Member. Other early discoveries included BHP's Stybarrow-1 (2003, 59 million bbl) and Eskdale-1 (2004), in fault-sealed horst and truncated channel sand plays, respectively (Jitmahantakul and McClay, 2013). Laverda appraisal drilling commenced in 2011 and the field was developed as part of the Greater Enfield project, along with more recent discoveries at Cimatti (2011) and Norton (2012), and tied back to the Vincent facilities by pipeline (Offshore Technology, 2016). Ultimately, the amplitude anomalies, which had so successfully mapped the detailed internal structure of the channels and lobes, were used to monitor production in the fields (Hurren et al., 2013).

The oil play in the Exmouth Sub-basin also extended to the east, with multiple discoveries by BHP in the Pyrenees terraces on the western side of the large Macedon structure (Scibiorski et al., 2005). This Triassic horst, draped with a Cretaceous succession, had been drilled unsuccessfully in the early 1970s, but BHP's West Muiron-3 and -4 in the 1990s, based on detailed depth conversion and supported by amplitude anomalies, discovered gas in basal Barrow Group sandstones. When West Muiron-5 (BHP/1993) unexpectedly found a 32-m oil leg on a downfaulted terrace to the northwest, it was seen as a breakthrough, but BHP's 1994 Pyrenees-1 and -2 were unsuccessful, and exploration declined again (Tindale et al., 1998). In the early 2000s, improved 3-D and AVO analyses calibrated against nearby oil and gas columns led to immediate success for BHP: Ravensworth-1 (2003, 45 million bbl), Crosby-1 (2003, 46 million bbl), Harrison-1 (2004, 4 million bbl, 200 BCF), and Stickle-1 (2004, 34 million bbl) were discovered on terraces downfaulted progressively to the west. In most cases, the gas–oil contacts and oil–water contacts were accurately predicted. The interpreted source for all the Exmouth Sub-basin oil discoveries is the underlying Oxfordian *W. spectabilis* anoxic marine shale section, the main synrift oil-prone source in the NCB. All oil accumulations (and associated minor gas) were in the Pyrenees Sandstone Member of the basal Barrow Group succession, with the underlying shaley Muiron Member providing base and cross-fault seals. The oils were

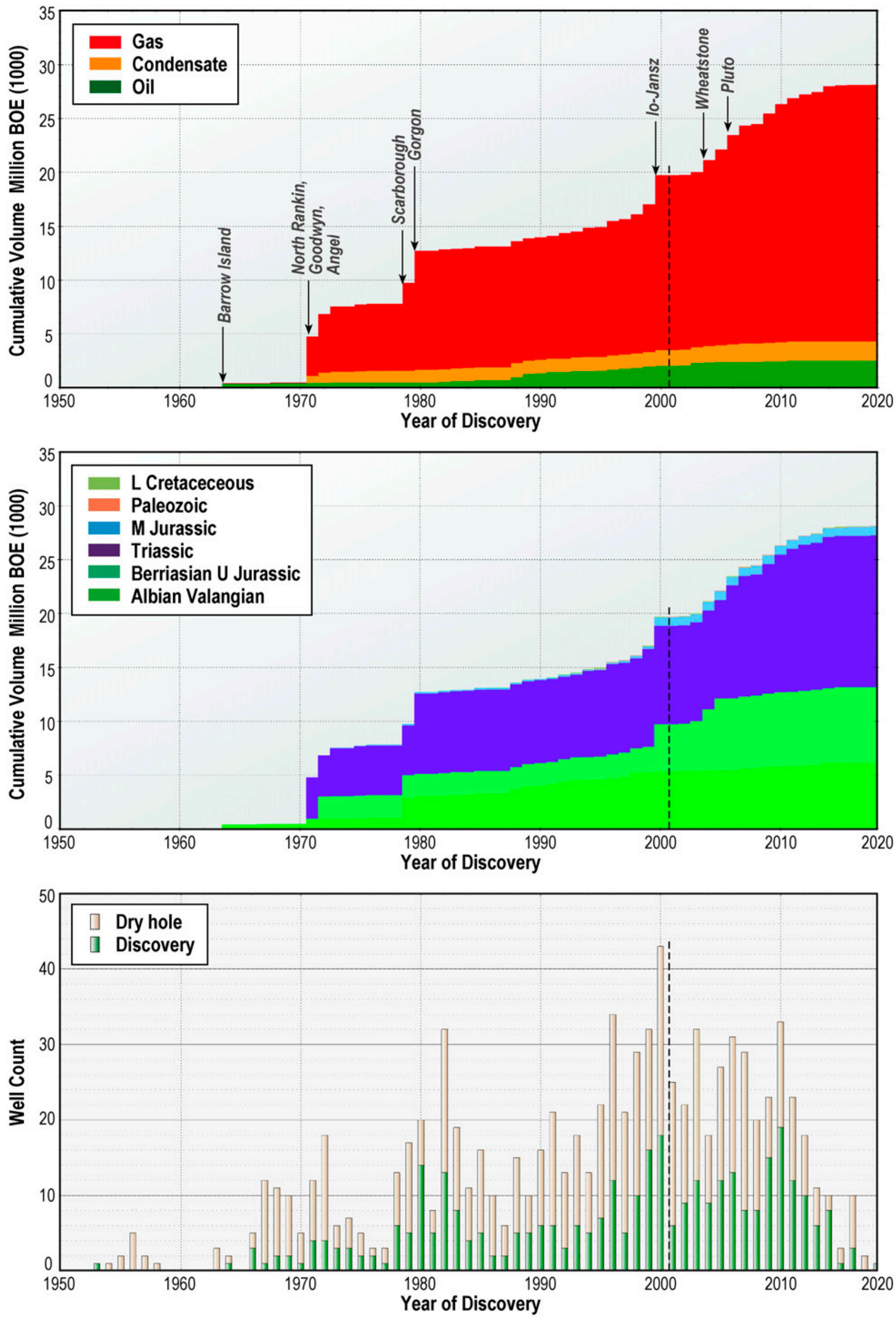


Figure 17. North Carnarvon Basin discovery history showing creaming curves by subbasin (top) and phase (center), and annual well count color coded for discoveries and dry holes (bottom). L = Lower; M = Middle; U = Upper.

biodegraded at approximately 19° API and in relatively thin columns, but viscosity was low (8–11 cP), reservoir quality was excellent, and there was a strong bottom water drive. The Ravensworth, Crosby, and Stickle fields were developed jointly, with a complex subsea completion system tied to an FPSO near Stickle and gas for injection drawn from the nearby Macedon gas field (Slate et al., 2010).

Several wells were drilled east of West Muiron complex for various objectives along the east-west–trending Long Island fault zone, but only Outtrim-1 (Esso/1985) had any significant success, testing 5276 bbl/day of oil and 2.2 MMCF gas/day from the Birdrong Sandstone. Appraisal wells, including Outtrim East-1 (Quadrant/2016) showed the Outtrim accumulation to be of uneconomic size, as was the case with other small-legacy discoveries nearby. A deep test of the Mungaroo section along this trend at Eagle-1 (Supora OMV/2021) has recently been unsuccessful.

Occasionally, the amplitude anomalies were misleading, as at Vucko-1 (Woodside/2012) and Falcone-1 (Woodside/2005), commonly because of unexpectedly high porosity or other lithologic factors. In general, however, they proved reliable guides to gas accumulations and gas-capped oil legs—though many discoveries, such as Woodside's Ragnar-1 (2011) and Toro-1 (2014) and BHP's Tallaganda-1 (2012) and Bunyip-1 (2014), are stranded because of noncommercial size. All of the significant DHIs in the Exmouth Sub-basin have now been drilled, and this play is mature. Deeper tests have been attempted but did not intersect the predicted reservoir. Less convincing amplitude-driven stratigraphic traps that have been mapped in the northwestern, more basinward part of the Macedon Member depositional system remain undrilled. Some potential clearly remains but in riskier opportunities.

Exmouth Plateau

The Exmouth Plateau has been seen, since the 1970s at least, as a subsided continental block, separated from the Australian continent along the deep Exmouth and Barrow rifts. More recently, Belgarde et al. (2020) have proposed that the plateau is underlain by thinned continental cratonic crust as a result of extension during Permian rifting. The total sediment thickness on the plateau is possibly 20,000 m: above nearly 10 km of Permian strata is the thick (5+ km) Triassic Mungaroo delta succession, which is, in turn, overlain by thin, faulted wedges of Jurassic strata and a "thermal blanket" of Cretaceous and Cenozoic strata. The Barrow delta succession is present in the southern area. Large gas reserves are present in Mungaroo Formation and Barrow Group reservoirs.

The Exmouth Plateau "play" took a long time to recover from the boom-to-bust experience of the late 1970s/early 1980s, when 11 wells were drilled for Barrow Group and Triassic objectives in what was widely touted as a promising new oil province. None of those wells encountered significant oil shows, but several discovered gas in Triassic and Cretaceous sandstones. At the time, however, even the large Scarborough dry gas discovery (Esso/1979, 7.3 TCF) in Barrow Group basin-floor clastic fans was uncommercial. The predicted thick Jurassic oil source was not present and there was no oil charge from Lower Triassic shales. It bears noting that the presence of gas had been predicted in many structures on the basis of flat spot amplitude anomalies, foreshadowing the future highly successful amplitude-based exploration. The early disappointment underwrote decades of industry disinterest in the plateau, but in 1996 several central blocks were taken up, including WA-269-P, where the giant Jansz discovery in 2000 changed the rules. Within a few years, almost the entire region was under permit and the so-called dash for gas was on, not just on the plateau itself but along the horst and graben complex on the western flank of the Rankin-Gorgon trend.

The Jansz prospect had been mapped as an amplitude anomaly by most of the larger companies and consistently interpreted as a thin turbidite sand on the western flank of the Kangaroo syncline. Jansz-1 (Mobil/2000) encountered 29 m of gas pay in an Oxfordian sandstone unit; Io-1 (Chevron/2001) in adjacent WA-267-P found the same sand with 44 m of gas pay. It was not, however, the turbidite sand predicted but a shallow marine deposit, essentially a shoreline unit lapping the aerially exposed Triassic hinterland to the east (Jenkins et al., 2003). Multiple gas discoveries in this faulted Triassic terrain had been made by Chevron in 1995 to 2001, including Geryon and Callirhoe. The Jansz-Io gas accumulation was now found to be in pressure communication with the gas-charged Triassic and Jurassic sandstones in these fields, with the gas leaking up faults and migrating along probable Oxfordian sandstones into the vast (2000 km^2) Jansz-Io stratigraphic trap. The field has a 400-m gas column and reserves of 20 TCF and 89 million bbl of condensate. After appraisal drilling during 2002 to 2009, the field was unitized in 2009 and development as part of the Greater Gorgon Project began in 2012, with first gas delivered into the LNG train in 2015. The Oxfordian shoreline sand was later found to be gas-bearing at Hess's Glencoe-1 (Smallwood et al., 2010), south of Jansz-Io, and Woodside's Pyxis-1 (2015) at the northern end of the Pluto gas field (Slade and Thomas, 2019).

In any "rush for resources" some properties are overvalued or unlucky and some are undervalued: the dash for gas on the Exmouth Plateau was no exception. The WA-356-P (Figure 2) was an undervalued block east of Chevron's Greater Gorgon gas fields, which Apache acquired in 2004, breaking their long-standing policy against deeper water exploration in Australia. A dry hole at Carey-1 (2005), where carbonaceous shales and coals were misidentified as porous gas-bearing sandstones, was followed by extensive inversion and rock physics studies and gas discoveries in Julimar-1 and Brunello-1 in 2007. These accumulations are located in multiple stacked Mungaroo sandstone channels along the horst block system that extends northeast to Wheatstone and Pluto. The Julimar accumulation is on the West Tryal Rocks horst block where wells drilled by WAPET in the 1970s and 1980s narrowly missed the gas-bearing Mungaroo channel system. The critical guiding value of 3-D seismic data and calibrated AVO analysis was well illustrated by Julimar-1 being drilled downdip of a water-bearing sand in West Tryal Rocks-3. Julimar was the "core" field to which other discoveries, including Brunello (300 BCF) and Balnaves Deep (2011; 380 BCF, 20 million bbl of condensate), were tied. All accumulations were well-defined by amplitude anomalies and had a total cumulative resource of 3 TCF of gas and 50 million bbl of condensate. Environmental approvals were obtained in 2011 and development activities proceeded, linked ultimately to the construction of the Wheatstone LNG facility onshore, to which the Julimar gas was contracted by agreement between the Julimar JV and Chevron. In 2015, Woodside purchased Apache's LNG assets in Australia for approximately A$2 billion, including 65% of the Julimar Project and Apache's 13% interest in the Chevron-led Wheatstone LNG project. First gas was delivered from Julimar to the Wheatstone LNG plant in 2017.

In contrast to this, Hess's WA-390-P, within the Exmouth Sub-basin southwest of Jansz-Io (Figure 2), proved to be an overvalued and unlucky block. Hess bid 16 wells for WA-390-P in 2006 and made 15 discoveries in Triassic, Jurassic, and Cretaceous sandstones, including an extension of the Jansz-Io Oxfordian sandstone fairway (Smallwood et al., 2010), but failed economically. Most of the discoveries were in Cretaceous fan sandstones onlapping eroded Mungaroo fault scarps, but all were in the 150 BCF to 500+ BCF range, and there was no core field around which to build a development project. Estimated prebid reserves of 15 TCF were based on amplitude mapping, but discovered reserves proved to be far less, estimated at 2 TCF and 42 million bbl of condensate (Western Gas, 2018), a poor reward for exploration expenditure of approximately A$1.8 billion. By 2017, Hess was facing high expenditures in their major Guyana discoveries and reportedly "sold" the project for US$2 to the newly formed Australian company Western Gas (Milne, 2020b)—though a payment of A$30 million to Western Gas to cover the outstanding well abandonment costs was locally rumored. Western Gas proposes to develop the fields as part of their Equus project, with condensate stripped into an FPSO and gas piped ashore through a third-party line to the Macedon gas plant at Ashburton North, near the town of Onslow. Western Gas developed multiple leads in Jurassic and Triassic reservoirs, with initial focus on the large Sasanof prospect with an estimated P50 OGIP of 24 TCF and 176 million bbl of condensate, based on amplitude anomalies in Cretaceous sandstones (Western Gas, 2021). This feature had been recognized by the Hess geoscience team, who called it Big Juan but did not consider the amplitude anomaly indicative of gas. That view has proved correct: Western Gas (2022) recently announced that Sasanof-1 failed to encounter any significant hydrocarbons in the objective section.

Much of the success of the amplitude-based exploration in the twentieth century was built on the learning of the 1990s, when multiple major gas discoveries demonstrated the reliability of the calibrated AVO technology. This was seen at Chevron's Dionysus and Chrysaor discoveries in the early 1990s (Sibley et al., 1999) and later at their Geryon-1 (1999, 3.3 TCF) and Maenad-1 (2000, 0.3 TCF). This success continued in the new century, with major gas discoveries in Achilles-1 (2009), in multiple Mungaroo Formation sandstone channels in the southern Maenad horst, and in Satyr-1 (2009) within the en echelon Satyr structure. Gas is also present in the overlying Lower Barrow Group section at Satyr, where four appraisal wells have confirmed multi-TCF reserves. Chevron also discovered multiple gas fields in amplitude-defined targets in Mungaroo Formation horst blocks in the Triassic basin-and-range province between Io-Jansz and Gorgon: Clio (2006, 3.2 TCF, 20 million bbl), Acme (2010, 1.5 TCF, 7 million bbl), and Acme West (2011, 1.2 TCF, 6 million bbl), the latter analogous to Perseus in its setting in the syncline between Clio and Acme, with "sand-on-sand" faults sealing. Chandon (2006, 3.8 TCF. 11 million bbl) was a similar Mungaroo discovery further west near Jansz-Io.

The BHP/ExxonMobil JV drilled two appraisal wells on the Scarborough gas field in 2004/2005. Discovered in 1979 in water depths of approximately 900 m, Scarborough's estimated 7.3 TCF of gas is reservoired in two superimposed basin-floor fans within the Barrow Group Flag Sandstone. Scarbough-3 (BHP/2004) was drilled to appraise the upper fan complex; Scarborough-4 (BHP/2005) was drilled to appraise the lower fan complex. A floating LNG development project was contemplated and environmental approvals obtained in 2013, but plans were dropped because of falling oil prices. In 2016, Woodside purchased 50% of BHP's interests in the Scarborough and nearby Thebe and Jupiter fields, estimated to hold a combined 9.2 TCF of dry gas, and in 2018 purchased ExxonMobil's interests and became operator (Offshore Energy, 2018). The proposal to develop the Scarborough gas field as feedstock for Woodside's Pluto LNG facility received environmental approvals from federal and state regulators in 2017. In late 2021, Woodside announced the go-ahead for the A$12 billion Scarborough field development and the related expansion of the Pluto LNG facility onshore near Karratha. First gas is expected in 2023–2025. Predictably, environmental activists have seized on this as their next flagship project, declaring Scarborough "the single-most-polluting fossil fuel development currently proposed in Australia" (Mercer and Borello, 2021). The Conservation Council of Western Australia mounted a legal challenge to the development by claiming the environmental approval process for the associated Burrup LNG facility was inadequate, but the case was rejected by the Supreme Court of Western Australia in March 2022.

The recent decade also saw exploration on the western edge of the Exmouth Plateau in water depths deeper than 1000 m, underpinned by the expectation that more marine facies of the Mungaroo Formation shales in that area might provide a wet gas or oil source. However, Woodside's Genseric-1 (2011) and Cadwollen-1 (2011) found only thin sandstones and poor seals. Alaric-1 (2010) had wet gas shows, seemingly leaving open the possibility of an oil/condensate play, but the thin columns, hosting only 250 BCF and 7 million bbl of condensate, indicated a very high reservoir risk. The other play in this outer plateau region involved Upper Triassic pinnacle reefs, mapped on 3-D seismic data. Woodside's Tiberius-1 (2010) encountered vuggy, even cavernous, porosity but no shows at all, pointing to migration issues or lack of source (Grain et al., 2013). A suite of early-drowned Upper Triassic pinnacle reefs remains untested, but all identified reefs are small and would need to contain oil to be commercial in the near term.

The Mungaroo Formation play, in both the pre- and postamplitude technology eras, has been dominated by WAPET/Chevron and Woodside JVs. In the early decades, Woodside was the leading player, discovering wet gas with low CO_2 levels on the Rankin platform and environs and pursuing multiple field developments and near field exploration. However, they have not enjoyed a repeat on the scale of these early successes, Pluto excepted. In contrast, WAPET/Chevron "warehoused" acreage and delayed exploration expenditure as long as possible, presumably because they lacked the economic offset of operated production in commonwealth waters. The result today is that Chevron has a surplus of gas, whereas Woodside faces a material gas shortage. Woodside's purchase of BHP's and ExxonMobil's interests in the relatively remote and dry Scarborough gas field was driven in large part by the failure of negotiations over access to Chevron's gas fields for feedstock for their Burrup LNG complex. In time, on present indications, Chevron appears destined to replace Woodside as the main LNG exporter on the NWS and become the more significant local gas operator.

In the far south of the Exmouth Sub-basin, Shell drilled Palta-1 (2012–2013) on a Triassic megastructure (1000 km^2). At 5993 m total depth, in 1289-m water depth, this was the deepest well to date on the NWS. Plagued by drilling problems, the well took more than 300 days to drill and cost A$322 million—a very expensive well for Shell and a most unfortunate venture for farminee Mitsui! No shows of oil or gas were encountered, but the well penetrated 630 m of upper Permian limestone at the base of the Triassic Locker Shale. No porosity was observed, but the reported large mud losses hint at possible fracture porosity. If an oil charge can be demonstrated from the basal Locker Shale, as occurs from the Kockatea Shale, the equivalent succession in the northern Perth Basin to the south, this could constitute an interesting play, albeit expensive, for this area, which has long been considered of limited interest.

Barrow Sub-basin

The Barrow Sub-basin is unique on the NWS for being the site of both offshore and onshore exploration and production. It is also the most intensively explored region of the NWS, with approximately 1150 wells in the area encompassing Barrow Island and the adjacent so-called "Harriet Joint Venture" area. Activity on Barrow Island spans the history of the NWS, from exploration in the early 1960s to LNG facilities and CO_2 sequestration today.

Major gas and LNG production commenced in the Barrow Sub-basin in 2016 when the giant Gorgon gas field finally came online, 36 yr after its discovery by WAPET (1980). Gorgon is located on the Alpha arch, the prominent horst block that separates the Barrow and Exmouth Sub-basins and is linked en echelon to the north with the Rankin platform, as seen on Figure 16B, which also shows the main discoveries and selected wells of the post-2000 era. The field had 25–30 TCF gas in place, with combined proven and probable reserves of 17.6 TCF and certified proven reserves of 9.6 TCF, including 12%–15% CO_2 (Data courtesy of IHS Markit [Copyright © IHS Markit, 2022. All rights reserved]). The CGR in Gorgon is low (5–12 bbl/MMSCF) relative to the gas fields of the Rankin platform, some of which are 50+ bbl/MMSCF. Nearby gas fields such as Chrysaor (1994) and Dionysus (1996) will be developed in the future as part of the "Greater Gorgon" project, which has 13.6 TCF of certified reserves. The long delay in the development after the initial appraisal drilling in 1982–1983 saw the emergence of seismic amplitude technology, which was used to plan the development drilling and monitor production. Final environmental approvals for the project were obtained in 2009 and are based on pipeline delivery to nearby Barrow Island where a dual-train LNG facility has been built. Gas reserved for Western Australia domestic use is transported to the mainland by pipeline. Sequestration of the Gorgon CO_2 in saline reservoirs in the Upper Jurassic Dupuy Formation below the Barrow Island oil field was a fundamental element of the development plan. The final environmental approvals require an average of 80% of produced CO_2 reinjected. Production commenced in 2016, but various issues delayed reinjection until 2020. As of July 2021, approximately 15 million t of CO_2 had been delivered to Barrow Island, but only approximately 30% had been injected underground (Milne, 2021).

Several major gas fields, culminating in two new LNG projects, were discovered in the faulted region between the Rankin and Gorgon platforms, within what is here classified as the Barrow Sub-basin. Chevron's Iago-1 (2000, 2 TCF) was followed by the large Wheatstone discovery (2004), which contained 5 TCF and 32 million bbl of condensate. Both fields were developed as part of the Wheatstone Project, with gas piped ashore to a new processing facility near the town of Onslow, comprising a domestic gas plant and two LNG trains with a combined capacity of 8.9 million t per annum. The project was sanctioned in 2011 with the first LNG shipment in 2017. Both fields are in downfaulted terraces of the North Tryal Rocks structure, with the gas-charged reservoir absent by erosion on the crest where WAPET drilled North Tryal Rocks-1 in 1972.

The twenty-first century's geophysical exploration success story of this area—and arguably, of the entire NWS—was Woodside's Pluto discovery (2005), containing 4.6 TCF and 50 million bbl of condensate. The Pluto structure was "hidden" under a steep, extensively canyon-cut continental slope and overlain by numerous high-velocity channels and was revealed only by patient and detailed depth conversion (Tilbury et al., 2009). It has a common gas–water contact with the Wheatstone gas field and the smaller Zena gas field adjacent to the east. Pluto is owned 90% by Woodside, who fast-tracked development with a new LNG train on the Burrup Peninsula and produced first gas in 2012, only 7 yr after the discovery. Subsequently, equally detailed geophysical precision led to the Pyxis-1 gas discovery at the northern end of the Pluto structure in Oxfordian sandstones in an amplitude-defined dip, stratigraphic and fault-bounded trap (Slade and Thomas, 2019). The Pyxis Hub Project, tying Pyxis, Pluto North, and Xena-2 to Pluto and the Pluto LNG train, commenced production in late 2021 (Woodside, 2022b).

Outside the major gas producers, Apache remained the most active explorer in the Barrow Sub-basin. After purchasing Hadson Oil's Barrow Sub-basin assets in 1993, Apache initiated its very successful "string of pearls" strategy, using 3-D seismic surveying and efficient low-cost drilling to aggregate small fields into a very commercial operation. The mapping of small closures on 3-D far stack volumes, commonly derisked by associated amplitude anomalies, led to numerous Flag Sandstone discoveries in small traps south of the Varanus Island facilities in the 1990s and 2000s, including Gibson, South Plato, Double Island, and the Victoria Complex (Apache Energy Ltd., 2002). Apache also successfully drilled multiple prospects along the submeridional Flinders fault zone, pursuing oil and gas in high-side and low-side faulted traps at various stratigraphic levels. The Gypsy and Rose wells (1998) and Lee (1999), for instance, discovered oil and gas in the North Rankin, Brigadier, and Mungaroo Formations, whereas Linda-1 (2000) discovered stratigraphically trapped gas and condensate in channel-filling Oxfordian sandstones (Moss et al., 2003). These fields were developed by tie-back to the Varanus Island facility. As elsewhere on the NWS, some amplitude anomalies proved to be related to higher-than-expected porosity, rather than hydrocarbon presence. Most of the Apache's exploration activity was linked to the paleogeography of the Barrow delta, varying from simple top Barrow Group closures such as Karangi-1 (2003) to complexly faulted slump complexes such as Nero-1 (2005). These Apache assets were purchased in 2016 by Quadrant, which was subsequently acquired by Santos. Most recently, Spartan-1 (Quadrant/2016) discovered gas in a Lower Cretaceous prodelta, sandy debrite mound outboard of the youngest delta foreset. This will be commercialized utilizing the existing infrastructure in what is now production license WA-63-L. Spartan will be the next field developed on the NWS: the FID was taken in February 2021 and first gas is expected in 2023 (Santos, 2021b).

Several significant Barrow Sub-basin discoveries, made in the late 1990s by redrilling of "old" prospects after remapping with modern seismic data, saw appraisal drilling and development in the new century. John Brookes-1 (1998), drilled by Mobil as a follow-up to WAPET's Tryal Rocks-1 (1970), encountered an 85-m dry gas column in turbiditic sandstones in a previously unrecognized channel in the Top Barrow Group strata. However, it was the exploration/appraisal well Thomas Bright-1, drilled in 2003 after Apache became operator, that saw development fast-tracked, with appraisal drilling completed by 2005 and first gas delivered to Varanus Island that year. Recoverable gas reserves are estimated at 1 TCF. Woolybutt-1 (Mobil/1997) was a follow-up to 1980s wells on the West Barrow arch, an extensive anticlinal structure west of the basin axis with only subtle TWT "structural" reversal to the east, making accurate depth mapping critical. Drilled on the northern of two closures, Woollybutt-1 found a 16-m oil column (49° API) in the Top Barrow sandstones, whereas Woollybutt-3 confirmed the southern accumulation (Hearty and Battrick, 2002). After appraisal drilling on both fields, production commenced from the northern field in 2003 and from the southern field in 2008. The field was decommissioned in 2012 after producing approximately 35 million bbl of oil. Not all revisitings of early "discoveries" were successful: Flinders Shoals-1 (WAPET/1969) was thought to have a possible 12–24-m hydrocarbon column, potentially mainly oil, in the top Barrow Group sandstones, but Apache's follow-up Errol-1 (2001) found only a minor hydrocarbon accumulation, estimated at 2 million bbl of oil and 20 BCF of gas.

Drilling on the southern Alpha arch targeted gas in Mungaroo Formation channels on the main horst as well as oil at the top of the Barrow Group. The gas-bearing channels were well delineated by the amplitude anomalies, but Zola-1 (Apache/2010), drilled on the largest feature, found uncommercial gas accumulations at multiple levels, as did Bianchi-1 (Apache/2013). A recent test of the Mungaroo potential further south along the arch at Swell-1 (Woodside/2017) on the Exmouth/Barrow Sub-basin boundary was also unsuccessful. Mapping the Barrow oil play along the crest of the arch proved difficult because of poor velocity control on the subtle structures. The absence of any oil in wells such as Xanthe-1 (BHP/2001) and Lauda-2 (OMV/2005) suggests they were not on valid closures. Residual oil shows at Antiope-1 (BHP/2000) and the small oil accumulation at Lauda-1 (OMV/2005) were interpreted as, respectively, fault leakage and spillage during Pleistocene westward tilting.

Limited progress has been made in recent decades with the Cenozoic play, first proven by Maitland-1 (Western Mining/1992), drilled on an amplitude anomaly near the base of the Cenozoic succession downdip from Tryal Rocks-1 (WAPET/1970)—which, in hindsight, was actually the discovery well. The well encountered 23 m of very fine, friable glauconitic sandstone, which had very high gas reading during drilling and flowed 8.5 MMSCF/day (Sit et al., 1994) when tested. Maitland-2 (Apache/2006) confirmed the gas accumulation and discovered a 10-m oil leg. Davis-1 (Quadrant/2016), drilled to test a satellite structure north of the Maitland field, encountered a 7-m oil leg below 10 m of gas in poor reservoir quality Maitland Sandstone. This resource, estimated at ~150 BCF of gas (Data courtesy of IHS Markit [Copyright © IHS Markit, 2022. All rights reserved]), has not been produced, primarily because of concerns about the low permeability in both the gas and oil legs and the very fine reservoir sand, which would necessitate expensive engineering in development wells. Maitland remains the only material example of a hydrocarbon accumulation within the Cenozoic section along the entire NWS. The Maitland area is not obviously different to adjacent areas, and it remains unclear why hydrocarbons have not been seen in other areas, as is presumed from the lack of amplitude anomalies within the Paleocene section. However, many wells do have shows within this section, and the potential exists for nonamplitude supported accumulations, though discovery may be serendipitous.

Dampier Sub-basin

Exploration in the Dampier Sub-basin (Figure 16B) has been successful from the beginning, though the value of the discoveries was not always seen at the time. The first offshore well, B.O.C.'s Legendre-1 (1968), was an oil discovery, but considered uncommercial until the late 1990s. The first well on the Rankin platform, North Rankin-1 (B.O.C./1971), found gas, not oil, as did many nearby wells. When oil was found along the vast Rankin trend, as at Eaglehawk-1 (B.O.C./1972) in the Rhaetian Brigadier Formation or Egret-1 (B.O.C., 1973) in the Upper Jurassic Angel Formation, it was of uncommercial size. In the twenty-first century, the Dampier Sub-basin is recognized as a highly commercial gas province, with multiple giant fields feeding LNG trains on the adjacent mainland and providing world-leading LNG exports to Asian customers.

An important determinant of the successful exploration in the Dampier Sub-basin, as noted elsewhere on the NWS, has been the progressive improvement in seismic technology. Multiples generated in the shallow Miocene carbonate layer were the geophysicists' bane for many years (Ramsden et al., 1988). The advent of 3-D surveying and improved processing techniques solved much of the problem through the 1990s, and this progress has continued. The Demeter 3-D (2003/2004) survey over the Rankin trend proved superior to earlier 3-D data sets in terms of multiple suppression, expected bandwidth, and signal-to-noise ratio, and guided successful exploration in more subtle and complex traps (Thompson et al., 2009). The data was critical to Woodside's Greater Western Flank Project (GWF), which sought to develop and tie in existing and new discoveries. Even when individually small, the cumulative incremental volumes were economically significant because of proximity to the established infrastructure. Pemberton (2006) and Lady Nora (2007) were both gas discoveries at the southern end of the trend. Sculptor-2 (2006), following-up on the 1995 discovery, confirmed gas and a thin oil column basinward of Pemberton in west-dipping Mungaroo sandstones subcropping the regional Lower Cretaceous Muderong Shale seal. The GWF phase-1 in 2015 involved the subsea tie-back of Goodwyn GH and Tidepole gas fields to the Goodwyn A platform; GWF phase-2 involved tying in the Keast, Dockrell, Sculptor, Rankin, Lady Nora, and Pemberton gas fields. In the north, Persephone (2006) was a larger discovery (~800 BCF gas, 2P recoverable), with a 151-m gas column in Bathonian Legendre Formation sandstones downthrown to the North Rankin block, and a "sand-on-sand" fault seal against the Mungaroo Formation sandstones in the North Rankin field. Production from Persephone began in 2017. Santos's 2013 Winchester-1 revisited the Parker/Webley fault block in front of the main Rankin platform and discovered gas in Angel, Brigadier, and Mungaroo Formation sandstones—the first discovery in this area of the basin, though probably uncommercial.

Farther north along the greater Rankin trend, the results of recent exploration drilling have been mixed. In Egret-3 (2003) the oil accumulations encountered were of uncommercial size and the attempt to tap into deep gas deposits was unsuccessful. At Lambert-Hermes, by contrast, the Demeter 3-D seismic survey identified prospective attics and guided Woodside's successful drilling of Lambert-6 (2004) and -7 (2006). The increased production from these fields contributed to Woodside's decision to establish the new Okha FPSO at the Wanaea/Cossack fields. Farther north again, the Exeter-1 (Santos/2002) oil discovery was a follow-up to the Mutineer oil discovery in 1997, but enigmatic oil distribution served to limit reserves in both fields and frustrated the Santos-led Mutineer–Exeter JV, as did subsequent discoveries such as Fletcher-1 (2007) and Finucane South-1 (2011). All fields were tied into the Mutineer FPSO. Total production from the combined fields was 75 million bbl when production ceased in 2018. Multiple dry holes, including Woodside's Maia-1 (2000), Spica-1 (2000), Tigger-1 (2003), and Japan Energy's Fullswing-1 (2010), were drilled on various horst and inverted structures between the Exeter/Mutineer and North Rankin blocks. The failure of these wells is variously linked to facies changes in the Angel Formation turbidite sandstones, mapping difficulties related to both a lack of acoustic impedance at the top Angel Formation reservoir and complex shallow velocity fields, and the location at the extreme northern end of the Kendrew trough oil charge system.

Exploration success or, more specifically, commercial exploration success on the eastern margin of the Dampier Sub-basin has been far less frequent, historically only 8% as compared to 22% for the Dampier Sub-basin overall and 12% for the entire NWS (Thomas et al., 2004). This margin is subdivided by the north-northeast–trending Rosemary fault into the Legendre (downthrown) and Enderby (upthrown) trends (Longley et al., 2002), both of which have enjoyed modest success. The main oil discoveries have been Legendre (B.O.C./1968), Wandoo (Ampolex/1991), and Stag (Apache/1993); the main gas discovery is Reindeer/Caribou (Apache/1998). Legendre-1 flowed 1014 bbl/day in 1968, but the reservoir was water wet in Legendre-2 (B.O.C./1970). Although the field was considered uncommercial at the time (14-m oil column in tight sandstones), it proved the presence of a Jurassic source in the basin and stimulated exploration. Legendre was not re-evaluated until the early 1990s when 3-D seismic data revealed a lateral velocity gradient that "repositioned" the structure at depth. Jaubert-1 (Woodside/1998), only 3 km from the discovery well, encountered a 37-m oil column and flowed 5867 bbl/day. The revised velocity control and depth mapping defined two separate closures with projected reserves of 40 million bbl (Willetts et al., 1999; Seggie et al., 2003). The field commenced production in 2001 and ceased production in 2011, having produced approximately 50 million bbl (Data courtesy of IHS Markit [Copyright © IHS Markit, 2022. All rights reserved]). Reindeer-1 (Apache/1997) discovered gas in the Legendre Formation and identified a new play for this area of the subbasin. Apache's follow-up wells, Caribou-1 (1998) and Gnu-1 (2006), confirmed a commercial accumulation and development began in 2008, utilizing an unmanned platform tied back to a new onshore gas-processing plant at Devil Creek, 50 km southwest of Karratha. First gas was delivered in 2011. The Devil Creek plant was the third major domestic gas hub established in Western Australia, with gas delivered directly into the Dampier to Bunbury gas pipeline. Exploration efforts to find more gas for the Devil Creek plant have not been successful, most recently with the failure of the Dancer-1 well (Santos/2022).

Commencing in the late 1990s and continuing into the 2000s, extensive drilling programs along the eastern Dampier margin targeted Barremian *M. australis* sandstones, which had previously yielded substantial oil discoveries at Wandoo (Ampolex/1991; 94 million bbl) and Stag (Hadson/1992; 78 million bbl). Three sandstones of different origin and age are involved: a lower basin-floor fan unit and transgressive shelfal unit, a fluvial to shelfal marine unit, and the upper shelfal marine unit (Crowley, 1999). Many companies were involved in the *M. australis* play at different times, but the main players were Woodside and Apache (presumably seeking tie-back increments for their Legendre and Reindeer discoveries, respectively). Seismic definition of the objective zone was difficult, and many wells failed because of invalid traps or missing objective sandstones or both, as in Patriot-1 (2001). Some wells did encounter minor hydrocarbons, but in unpredicted reservoirs or secondary objectives: Oryx-1 (Apache/2000), for instance, found the target *M. australis* sand missing but encountered uncommercial thin oil and gas columns in the Athol Formation secondary target.

An extensive study of the margin by Woodside, Santos, Apache, and other JV partners combined with detailed reprocessing of the multiclient Panaeus 3-D seismic survey led to a new round of drilling in the early 2000s, but results continued to disappoint. The primary objective sandstones were missing or poorly developed in many wells, including Altostratus-1 (Strike Oil/2004) and Apache's Rhebok-1 (2003) and Gats-1 (2005). The reservoir was well developed in Unicorn-1 (Apache/2006) but was dry, presumably being in a migration shadow behind the Reindeer field. Minor accumulations of oil and gas were commonly found in untargeted reservoirs, such as the 11-m oil column in the unpredicted Calypso Formation in Amulet-1 (2006). Arguably, the 1990s was history repeating itself, with plentiful evidence of oil and gas migrating onto the eastern flank but the prediction of the reservoir section and hydrocarbon type proving very difficult. Pay zones, when encountered, were thin: Apache's Jalfrezi-1 (2012) encountered a 13-m gas column over 3 m of oil.

The largest discovery along the eastern margin came from deeper objectives, when Corvus-1 (Apache/2000) found a 63-m gas column in and flowed 14.6 MMSCF/day from Mungaroo Formation reservoirs in a narrow horst structure outboard of the Rosemary fault system. However, the log, core, and DST data all pointed to low permeability—lower than might have been expected from the Mungaroo Formation reservoir at that depth—and despite the column height, raised concerns regarding commerciality. In 2019, Santos drilled the appraisal Corvus-2 and announced 245 m of net hydrocarbon pay, with indications of improved permeability in the Mungaroo Formation reservoir, a gas–condensate ratio ranging to 10 bbl/MMSCF and a CO_2 content of 7% (Santos, 2019a). That initial positive statement has not been followed up, and it remains unclear whether the Corvus-2 results were sufficient to warrant development or even further appraisal. Despite these disappointments, some older fields continue with new life: the Stag 50H Infill Project, designed to revitalize Stag oil field, is currently in the feasibility stage and is expected to commence in 2023.

There has been limited exploration within the axial area of the Dampier Sub-basin. Baleena-1 (Phillips/1993) was the first deliberate test of an Oxfordian turbidite mound in the basin center, but the high hopes for a major basin-floor fan play in the basin (Barber, 1994) were never realized. After several dry holes, including Woodside's Hellcat (1998) and Delilah (2001), Apache's Ajax-1 (2004) and Santos's Hurricane-1 (2005) were oil discoveries but small and uncommercial: Ajax-1 had a 5-m oil column in a debris flow mound, whereas the Hurricane trap contained only 7 million bbl and 30 BCF. Seraph-1 (Woodside/2011) targeted Lower Jurassic Athol and North Rankin Formations below the Angel gas field on the Madeine arch but encountered only thin and tight Athol Formation sandstones with unexpected overpressure that precluded drilling to the deeper Mungaroo Formation target.

West of the Rankin platform, exploration has been singularly unsuccessful. The oft-cited hydrocarbon sourcing from the Victoria syncline has not worked. Many experienced NCB explorers refer to a "line of death" in the basin, beyond which no oil or gas accumulations and very few significant shows have ever been found. This line, shown on Figure 18, passes north of Jansz-Io, takes in Woodside's Guilford-1 (2003) and Ixion-1 (2008) and sweeps northeast past Zeus-1 (MEO/2009) to Hyde-1 (Quadrant/2016) in the Beagle Basin and on toward the Barcoo Sub-basin. These prospects included robust horsts (Guilford-1) and synclinal traps analogous to Woodside's nearby giant Perseus gas field (Zeus-1), all qualified by extensively studied amplitude anomalies. In many cases, the anomalous amplitudes proved to be indicative of higher-than-predicted reservoir porosities. The recent lack of significant hydrocarbons in BP's high-profile Ironbark-1 (2021), touted as hosting a potential 15 TCF, has reinforced the line of death concept in the basin.

Beagle Sub-basin

The Beagle Sub-basin, located at the northeastern end of the NCB, as shown on Figure 15, has long been the "poor cousin" among the subbasins. Proximity to the Bedout Sub-basin discoveries gained it a burst of interest and activity in the past decade but without any significant success. At the simplest level, the problem appears to be the absence of the Upper Jurassic source rocks that are critical to the oil generation elsewhere in the NCB. While the Dingo Claystone source units were being deposited in the deep, restricted marine environments in the Barrow, Dampier, and Exmouth rift basins, there was no equivalent-scale rift event in the Beagle Sub-basin: Oxfordian strata are limited to shallow grabens between horsts, and the Tithonian deposition occurred primarily on a shallow, open marine shelf.

No shortage of structures exists in the Beagle Sub-basin. Indeed, the large horst blocks such as Sable and Picard attracted considerable exploration interest in the 1970s. Early wells in the Rankin platform had shown that the liquids content of the gas fields was increasing from southwest to northeast, raising the possibility that the Beagle horsts might be a highly prospective oil trend. That did not prove to be the case, with very few oil shows in any of the wells and no significant gas accumulations. The only discovery was the small Nebo-1 (Kufpec/1993, 2 million bbl), located on a local horst within the Thouin graben. Follow-up wells, Halo-1 (Kufpec/1995) and the more recent Huascaran-1 (2002/IB Resources), had no significant shows and are considered confirmation of a lack of regional oil charge.

In line with exploration strategies elsewhere on the NWS, multiple wells were drilled in recent decades on amplitude anomalies updip from early wells: Woodside, for example, drilled Serval-1 (1999) on the Swift horst and Gray Rabbit-1 (2001) on the Ronsard horst. Neither had significant shows. "No shows" is almost a shibboleth for Beagle Sub-basin wells, as typified this century by Whitetail-1 (Woodside/2002), Wigmore-1 (Kerr-McGee/2003), Levitt-1 (Quadrant/2015), and Hyde-1 (Quadrant/2016). All were valid structures and considered predrill to have access to Lower Jurassic or Triassic source intervals either adjacent or downdip. In many cases, the amplitude anomalies were associated with high porosity water-wet sandstone: predrill studies had underestimated the porosity in the objective sandstone because of the depth of burial. The best result was an indication of hydrocarbons found in sidewall cores by geochemical analyses and organic petrography. The Beagle Sub-basin appears to be, in the vernacular of NWS explorers, across the line of death. Wigmore-1 might be taken as typical, being described frustratedly in the well completion report as having "a total absence of gas and hydrocarbon shows, a total lack of LWD and wire-line log anomalies attributable to a hydrocarbon response, and overall absence of … oil prone source rocks … (confirming) there has been no effective petroleum system operating now or in the past in the Early and Middle Jurassic" (Kerr-McGee NW Shelf Australia Energy, 2003). The Beagle Sub-basin was a "sand-input" zone during the Triassic and Jurassic, and the thin mudstones in the succession do not constitute significant source or sealing units.

The Stokes-1 well (Woodside/2016), drilled near the boundary of the Beagle and Dampier Sub-basins, may be relevant to the debate over upper Permian carbonate banks versus volcanics along this margin. Stokes-1 encountered an upper Permian succession of predominantly calcareous siltstone and sandstone that, below 2225 m at least, probably formed by weathering of mafic rocks, possibly basaltic andesite, and tuffs.

FUTURE PLAYS AND POTENTIAL

The future of the NWS in the twenty-first century will involve the development of known resources and the exploration for and development of new fields. As has been the case in the last 20 yr, the principal short-term focus for activity and expenditure will be the development of the discovered gas resources. Initial attention will be directed to the three giant gas accumulations in the northern region of the NWS, and the competition between them for priority will involve not only their respective technical challenges but also the political and relationship issues in which they are mired.

1. Sunrise-Troubadour (5.1 TCF and 250 million bbl of condensate, 2P recoverable volumes) will depend on agreement between Timor-Leste and the Woodside JV parties regarding a development plan involving either a pipeline to Darwin or a "floating" pipeline across the Timor Trench to an LNG facility onshore Timor-Leste—a dispute already involving significant geopolitical maneuverings by the Timor-Leste, Australian, and Chinese governments, with the outcome of strategic importance for Australia's national security.
2. Abadi, in Indonesia (18 TCF and 330 million bbl of condensate, 2P recoverable volumes) is operated by Inpex, and development will depend on JV alignment and commerciality issues. In 2014, Abadi was originally touted by the JV as the next floating LNG development after Prelude, but the current development plan, effectively dictated by the Indonesian government, involves a pipeline from Abadi to an LNG facility constructed on Nustual Island, north of the field. The JV member Shell has publicly announced plans to sell its equity, based on its view that this development plan is uncommercial.
3. Browse Basin "Scott Reef" fields. Woodside's NWS Venture LNG trains will have exhausted their current NCB gas supply by ca. 2025 and to avoid decommissioning, will need to be backfilled with new gas supplies. The probability is that these new supplies will come from the gas fields along the Scott Reef trend in the Browse Basin, the more so given the recent purchase by Woodside of BHP's petroleum assets. A proposal to deliver the Browse gas to the Burrup

hub in the NCB through a 900-km pipeline is currently in the concept development phase (Woodside, 2022a). The two fields that are likely to supply these volumes are Calliance and Brecknock, which are estimated to have combined recoverable 2P volumes of 7.7 TCF and 270 million bbl of condensate.

Cumulatively, these three projects would see development of ~31 TCF of gas and 850 million bbl of condensate of the discovered but undeveloped resources on the NWS, approximately one-third of the known gas resources and 60% of the condensate resources, amounting to 16% of the currently undeveloped resources on the NWS, as shown in Figure 5B. The condensate resources make these projects competitive in the global LNG market (see Table 2).

The future for new field exploration on the NWS is less clear. In the short term, much of the exploration along the NWS is likely to play a supporting role to the development projects, either finding new gas supplies for existing developments or seeking additional resources to bolster the economic case for unsanctioned projects. On present indications, it appears unlikely that there will be the same substantial levels of frontier exploration investment that the basins enjoyed in the later decades of the last century. Multiple reasons exist for this, not least being the overall demise of the oil and gas industry in Australia. The dozens of Australian and international companies that were once exploring the NWS have dwindled to a handful. At the same time, it has become clear from the past exploration results that large parts of the margin appear to be devoid of effective source rocks, as discussed further below.

The decline in exploration runs counter to the national need for the NWS to play an important role in meeting the demands for energy, fuel, and petrochemical supplies in coming decades, during the transition to more renewable energy sources. To achieve that end, explorers will need to recognize both the potential and the limitations of the basins

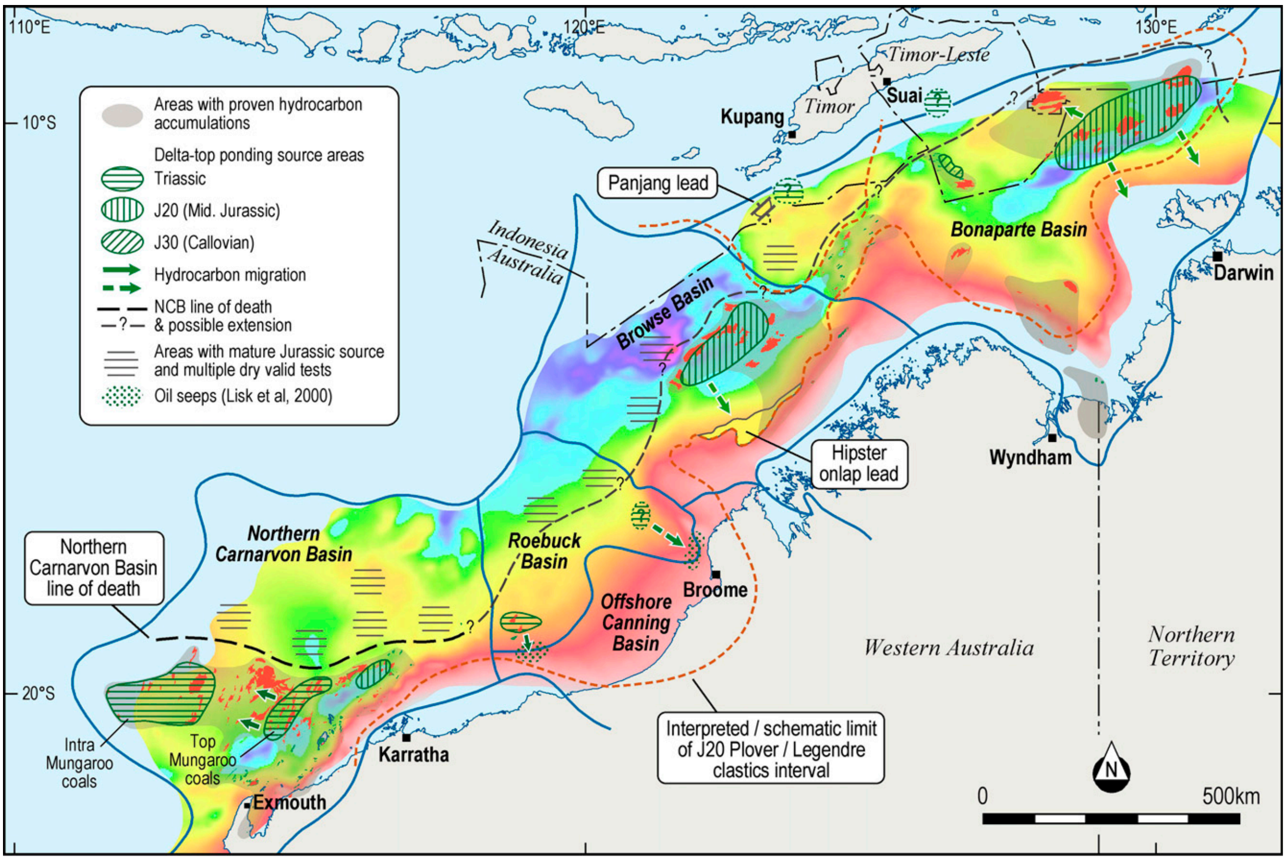


Figure 18. The North West Shelf showing potential future prospective exploration trends and focus areas. Mid. = Middle; NCB = Northern Carnarvon Basin.

and to develop new concepts and processes to ensure exploration and production success, almost certainly in the face of increased public and political opposition. The lessons of past exploration can guide future efforts but must include a recognition of the problems as well as the potential. This section reviews briefly some of the limitations in the NWS petroleum systems and outlines some potential plays and trends for future exploration, as shown in Figure 18.

One of the main limitations vis-à-vis the oil and gas potential of the NWS is the apparent relative paucity of effective source rocks over broad areas, including the northern Exmouth Plateau, the Beagle, Barcoo, Rowley, and Seringapatam Sub-basins, the southern Malita graben, and other areas. This conclusion is based on the multiple exploration wells in these areas that intersected effective reservoir-seal pairs within simple traps that were well-defined by 3-D seismic data and which were adjacent to areas that have potential source intervals within the oil- or gas-maturity windows. It was the failure of numerous wells outboard of the giant Rankin platform—and the predictability of it—that led Woodside explorationists to define a line of death in the NCB beyond which no hydrocarbons were likely to be found. This was explained by various theories at different times, the most popular being that thin Cenozoic burial had resulted in timing/flux limitations. Conversely, the authors suggest that the absence of effective source rocks is an easier and more plausible explanation. Similarly, the failure of some wells in southwest areas of the Flamingo/Sahul region of the Bonaparte Basin might relate to remoteness from the delta-top source pod, rather than trap breaching by Neogene fault reactivation.

To highlight this point, the NCB line of death has been speculatively extended on Figure 18 across other areas of the outboard margin of the NWS where there appears to be a paucity of source rocks. Counterbalancing this, Figure 18 also highlights proven and potential areas of nonmarine source rocks (that is, not the Upper Jurassic *W. spectabilis* marine source rock intervals present in the Barrow, Dampier, Exmouth, and Vulcan rift basins). These Jurassic and Triassic source pods are all considered to be the product of delta-top ponding, as described for the NWS by Longley et al. (2002). This nonmarine deltaic source distribution model is now recognized in the Lower Triassic succession of the Bedout Sub-basin (Minken et al., 2018) and is widely known in southeastern Asian basins (Longley, 2005), as well as, for example, the Gippsland Basin in Australia and the Taranaki Basin in New Zealand. By analogy with the Kutei and Baram deltas in Southeast Asia, it is also suggested that the erosion of source material by later submarine canyoning may well have redeposited source rocks beyond the delta-top ponded source kitchen areas. This is particularly likely in the Bedout Sub-basin.

It is important to note, however, that although large areas of the margin appear to suffer from the absence of effective source rocks and charge, there could be local source kitchens, similar to the Bedout source pod, as yet unidentified in these areas and capable of charging large accumulations, albeit within a relatively limited surrounding area: distance from source may well have been the problem with the Santos/Carnarvon Energy recent undercharged Apus-1 well in the Bedout Sub-basin. Speculative Triassic source pods are shown on Figure 18 in the northwest Bonaparte Basin deep in the Timor Trough and in the Oobagooma Sub-basin. In these frontier or historically unsuccessful areas, the future exploration focus needs to be on finding believable direct hydrocarbon indicators on old or new seismic data and on developing large oil prospects that would, if successful, bypass the issues associated with the complex world of LNG gas development sequencing. In that pursuit, explorers might usefully "follow the spill chain" from existing pools and shows to define lateral migration areas that may have been overlooked. Present-day spill chains have been established from the Barrow Sub-basin to the northwest onto the Exmouth Plateau, in the northern Caswell and Vulcan Sub-basins, and in the Flamingo syncline/Laminaria area. Location along a spill chain will always be a more reliable indicator of potential charge than 3-D charge-modeling software.

Each of the basins of the NWS has its potential and its challenges for explorers in the coming decades.

The Bonaparte Basin, with four major subbasin areas, each with different geology, obviously manifests a wide variety of petroleum systems and plays. The Vulcan Sub-basin is arguably the "oiliest" province on the NWS, courtesy of the thick mature *W. spectabilis* age synrift shales, but its potential has been compromised by the Neogene fault reactivation that breached many large accumulations. Optimism exists that new broadband 3-D seismic data will

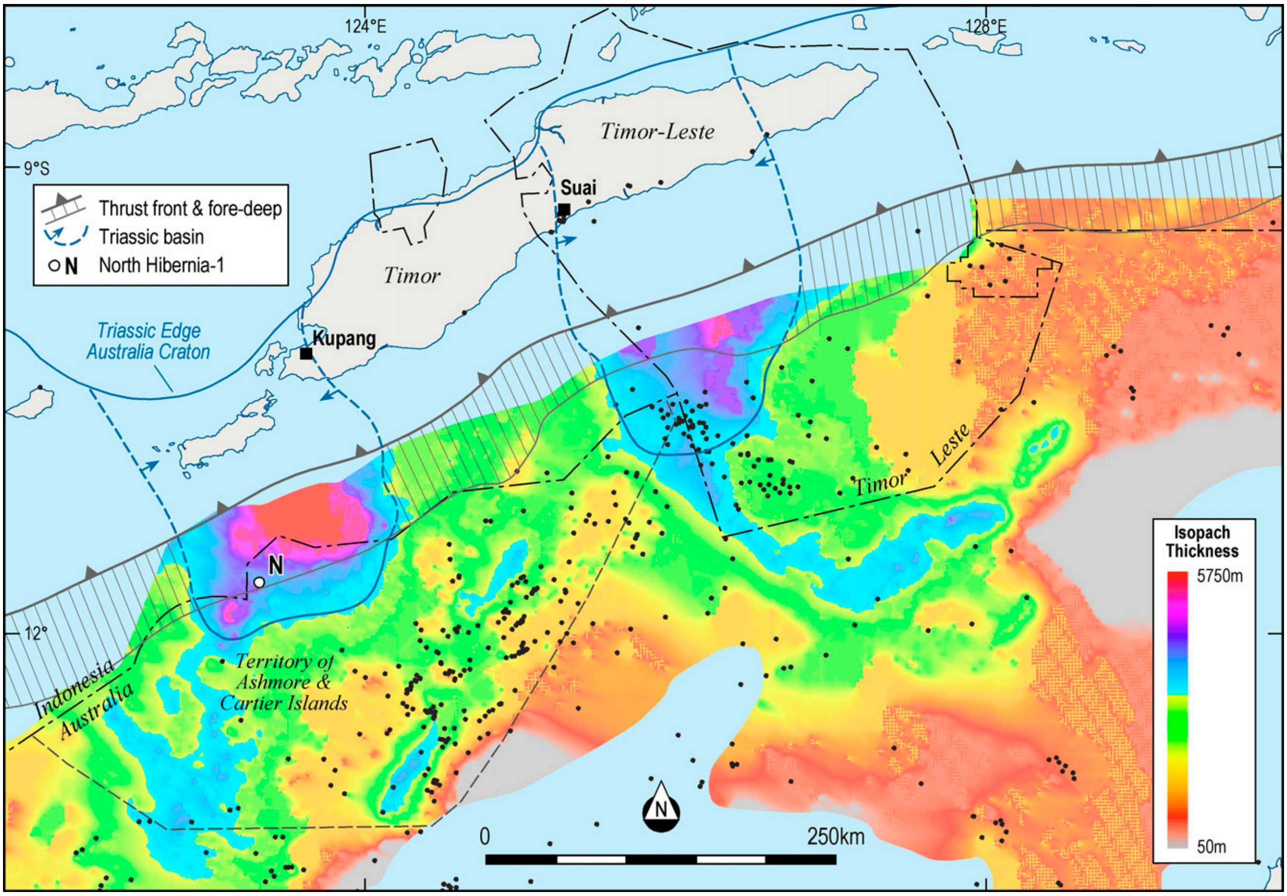


Figure 19. Bonaparte Basin Triassic isopach map of Timor Sea region showing potential Triassic source basins. Black filled circles indicate wells. This map includes content supplied by IHS Markit (Copyright © IHS Markit, 2022. All rights reserved).

deliver new plays and discoveries, including channel plays and deep, complex, salt-related structures, and help define stratigraphic pinchout traps in or near the Swan graben source kitchen (Molyneux and Doyle, 2021).

Along the high trend between the Sahul and Flamingo synclines, some of the faulted structures extending from Laminaria to Bayu-Undan contain oil (degassed) or wet gas from coaly source rocks. Residual oil columns show that many accumulations have been breached but the predominance of discoveries along the northeast side suggests that proximity to a Jurassic delta-top source pod, as shown in Figure 18, might also be a factor. Some abandoned fields and seemingly uncommercial pools could have hidden upside, but the recent failure of Buffalo-10 (Carnarvon Energy, 2022b) will likely limit interest in this play, given the earlier failure of CNOOC step-out wells on the uncommercial Bluff accumulation. Reprocessing vintage 3-D data and acquiring new data sets as technology improves will be important for future exploration.

The northwestern Bonaparte Basin area appears to have deep untested Triassic potential. Figure 19 presents a Triassic–Jurassic isopach constructed from the base Cretaceous and base Triassic maps in Longley et al. (2002), with the Triassic succession considered the main component. Two main basins and the intervening high can be traced into the outcrop geology of Timor and Timor-Leste, albeit obscured onshore by the Neogene overthrusting of the northern margin of the Australian continent. In the southwestern basin, in the Ashmore platform area, Hibernia North-1 (Woodside/1973) intersected Triassic sandstones beneath the regional Cretaceous seals and had deeper weak oil shows. Large untested prospects mapped downdip to the north of this well exist, one of which is highlighted as the Panjang Lead on Figure 18.

Unfortunately, much of this area of deep Triassic potential interest is located in Indonesian waters or subject to long-term uncertainty regarding the Australian/Indonesian boundary, as can be seen from the borders shown in Figure 19.

The Malita graben has additional gas potential, but successful exploration will require commercial flow rates, preferably from Elang Formation reservoirs as shallow as possible. For deeper Plover Formation targets, the high CO_2 content of the gas poses serious restraints unless new technology is developed to solve this challenge. The possibility remains of a shallower Cretaceous hydrocarbon system undetected in the central graben area. Long range migration onto the flanks of the basin may warrant attention in areas such as the Darwin shelf near Bathurst Island and along the southwestern side of the Joseph Bonaparte Gulf.

The Petrel Sub-basin contains several proven petroleum systems, notably involving Carboniferous oil and Permian dry gas source units. The Beehive well will reportedly be testing this potential in the near future. Renewed interest has been shown in recently improved seismic imaging of complex salt-related structures, and shallower Jurassic reservoirs, especially those above the salt diapirs, deserve more attention. The potential of the glaciogenic Permian–Carboniferous succession has also recently been noted (Gorter and McKirdy, 2013).

The Browse Basin is a major gas province with significant undeveloped gas resources and modest liquids potential. As discussed above, the main industry focus will be the development of the large undeveloped fields along the Scott Reef trend. Woodside's proposed pipeline to the NWS LNG facility will offer a development option for other fields, as will tie-backs to Ichthys. Explorers will likely focus on areas with liquids potential, targeting subtle traps that will need improved 3-D seismic data for prospect definition. Based on current data, the future exploration potential appears limited to the Caswell Sub-basin, given the lack of any evidence of a working petroleum system in either the Barcoo or Seringapatam Sub-basins. Cretaceous and Cenozoic plays in the Caswell Sub-basin are compromised by the limited access to hydrocarbons generated in the deep Plover Formation coals and mudstones. Results to date suggest that only minor hydrocarbons are migrating vertically through the thick Cretaceous regional seal, though there is some evidence of leakage up Neogene faults in the central area, as seen in the shallow oil recovery in Caswell-1. Additionally, a deeper Triassic system could be present in the northern Caswell Sub-basin.

On the eastern basin margin, an Upper Jurassic wet gas source is effective in the Heywood graben, where stratigraphic traps updip do not have major migration/leak risks, and the Lower Cretaceous *M. australis* shale is a local and modest oil source. A large stratigraphic trap, shown as the Hipster Lead in Figure 18, is present in the southeast Caswell Sub-basin, where Jurassic sandstones onlap the basin margin in a large embayment updip of the proven kitchen area. The sandstones are overlain by thick marine shales and the basement where penetrated is impermeable and unfractured. Local stratigraphic traps in this area have been recognized by previous explorers (for example, Nexen's Tristram prospect in WA-239-P) but are potentially part of the major Hipster trap—40 × 200 km in size and capable of containing 5+ TCF, with an oil leg likely, given the low pressure and temperature conditions at this shallow depth—assuming the trap is effective. Similar leads might have been overlooked by explorers elsewhere along the margin.

The Roebuck Basin or, more specifically, the Bedout Sub-basin has emerged as the new NWS oil champion of the twenty-first century, courtesy of the Dorado and Pavo oil and gas discoveries in incised canyon stratigraphic traps. Current 2P resources in these fields are approximately 240 million bbl and more than 1.1 TCF (Carnarvon Petroleum, 2021). The basin also has significant potential beyond the current discoveries, with more than 100 prospects mapped within the eastern oil fairway and northwestern gas fairway (Carnarvon Petroleum, 2021). Potential for accumulations also exists in analogous shelf-edge and canyon traps along trend from the Dorado complex. Carnarvon Energy (2022d) estimates their top 20 prospects have potential (P mean) reserves of more than 1500 million BOE.

The source for the Bedout Sub-basin oil and wet gas is a delta-top ponded complex, with the algal content determining the oil/condensate component (Woodward et al., 2018). Assuming that the isopach thick detailed by Minken et al. (2018) (Figure 1) defines the limit of the ponded environment, the Bedout Sub-basin source pod is approximately 60 × 40 km in size. Source pods of this size or smaller could easily be overlooked in areas dismissed because of dry holes. A possible hidden Triassic source kitchen is shown speculatively in the Oobagooma Sub-basin in Figure 18.

Oil seeps have been documented updip from the proposed Bedout source pod and the hypothetical Oobagooma pod (Lisk et al., 2000), suggesting that hydrocarbons have migrated southeastward to the base regional seal level and then to the seabed. Shallow accumulations, such as those found on the Enderby terrace (Stag and Wandoo fields), may well be present in these untested areas that have limited 2-D seismic coverage only. There could also be potential in the extensive upper Permian to Lower Triassic reefs and back-stepping carbonate banks interpreted on seismic data in the Bedout and Oobagooma Sub-basins (Paschke et al., 2018), but this concept is speculative, and the features might prove to be extensive lava delta complexes (MacNeill et al., 2018).

In the Rowley Sub-basin, a possible analogue between its Upper Triassic (Norian/Carnian) paleogeographic setting and the contemporaneous oil-source–rich succession in Timor-Leste has been proposed, with restricted algal-rich basins surrounded by carbonate platforms and fringing reefs, and potentially sourcing both clastic and carbonate reservoirs (Haig et al., 2017; Grosjean et al., 2021). The recent unsuccessful wells in the deep-water outer Roebuck Basin are disappointing because they appear to have disproved the presence in that vast area of a petroleum system charged by a deep Triassic oil-sourcing succession. In this regard, the more tropical setting of Timor-Leste in the Upper Triassic might be a significant factor.

The Carnarvon Basin has 30 TCF+ of discovered/undeveloped gas reserves, and there is little current need or commercial incentive to explore for more big gas. Deep Mungaroo Formation gas prospects under existing fields or near-field amplitude-supported prospects offering minimal tie-backs to infrastructure will be the exception. The focus for future near- to midterm exploration will be on liquids, either oil or high-condensate gas: this will continue until existing LNG developments need ullage/backfill. Gas accumulations with a high-condensate component can "jump the queue" into existing LNG production facilities because the liquids provide an additional income stream. Outboard, toward the northwestern limit of the basin, deep intra-Mungaroo Formation wet-gas potential will require further work, with some incised valley traps—albeit complex but amplitude supported—still untested. Isolated, smaller, deep-water gas accumulations will eventually become economic as long tie-back technology improves.

For oil, the future exploration potential appears on current data to be above and east of the Jurassic rift system, and close to the present-day coastline. The simple anticlinal and fault block structures are all drilled in commonwealth waters, and better/broadband seismic coverage will be needed to identify complex and subtle traps, many of which are likely to be nonamplitude supported and risky. New 3-D broadband surveys should also help unlock any potential upside in known oil fields. In state waters, there might be unidentified large simple structures, but environmental and access issues with nearshore and reefal areas will likely hinder efforts to acquire new 3-D seismic data in search of them. Airborne gravity gradiometry might prove a useful alternate technology, if it can be usefully calibrated with old fields and known structures.

These future development projects and exploration efforts on the NWS will be increasingly bound up in lengthening green and red tape, adding delays and costs to any new developments and to basic oil exploration. Industry can expect little sympathy about these constraints, given that they accord with the carbon-neutral ambitions of the government. It is quite possible, for instance, that the regulator and some customers will require future commercial contracts for LNG shipments to have "carbon-offsets" to ensure "carbon neutrality." In particular, the reality of government carbon emission targets will have a sharp impact on development projects and will increase costs considerably. Currently, CO_2 is vented at all LNG plants except Gorgon, where the CO_2 is injected into the saline reservoirs of the Barrow Island oil field. Obviously, developers of fields with high CO_2 content, such as in the Browse Basin, will face higher scrutiny and costs. The use of other depleted fields for CO_2 injection sites will be an essential component of any future developments and will likely be dictated sooner rather than later for existing projects. In late 2021, responding to industry requests, the commonwealth government announced a bid round for CO_2 disposal-site blocks and has recently awarded permits in the NCB and Petrel Sub-basin to Santos and partners, to form part of their Carnarvon and Northern Australia/Timor-Leste carbon capture and storage hubs, respectively (Santos, 2022a).

CONCLUDING REMARKS

The NWS of Australia emerged as a major petroleum province in the late twentieth century, as predicted by Forrest and Horstmann (1986) in *AAPG Memoir 40*. Generations of geoscientists in companies large and small contributed to that success. Many of them worked or trained in the pioneering companies of WAPET and Woodside, both Australian companies underpinned by international giants, notably Burmah, Chevron, Shell, and Texaco. Many international companies have been important contributors, including Eni from Italy, ExxonMobil, Apache, and ConocoPhillips from the United States, and BP from the United Kingdom. Japanese companies have been foundation partners in many of the major LNG projects, as well as explorers. Large Australian companies such as BHP and Santos have been leading and successful explorers and producers and have trained several generations of explorers. Across most of those decades, the so-called Australian juniors were an important creative force, developing new plays and prospects and attracting funding from the larger companies to test them. Geoscientists in various government agencies, notably Geoscience Australia and its predecessors and the Geological Surveys of Western Australia and the Northern Territory, have also been important contributors to the geological understanding of the region. An important stimulus to exploration has been the extensive open-file databases maintained by commonwealth and state authorities, including open access to seismic data and government-funded surveys. In that regard, the ongoing government agreement to long-term confidentiality of multiclient seismic survey data is viewed by many as an impediment to exploration.

Those efforts have established the NWS as one of the world's super basins for hydrocarbon resources. Within the Westralian Super Basin, the Northern Carnarvon, Browse, and Bonaparte Basins are major LNG exporters and have significant oil and condensate production; the fourth, the Roebuck Basin, has this century seen the largest oil discovery on the NWS in 30 yr. Current (2020) annual gas production from NWS fields is 3.2 TCF, which provides approximately 450 BCF of Northwest Territory and Western Australia domestic gas supplies and 2.75 TCF as feedstock for LNG exports. Oil and condensate production in 2020 were approximately 32 million bbl and 78 million bbl, respectively (Australian Petroleum Production and Exploration Association, 2021). These supplies and exports have been a major sustaining component of the Australian economy for nearly 50 yr.

That said, exploration on the NWS is at a very low level historically: only 10 wildcat wells have been drilled in the 5 yr since 2016, arguably the lowest activity level since drilling began in the late 1960s. This is partly related to the impact of the COVID pandemic but is more broadly related to the current global and national decline in exploration. The number of companies exploring on the NWS (and in Australia in general) is vastly reduced over previous decades, as are the numbers of geoscientists involved in the search. Indeed, the long-term future of the NWS's LNG industry has recently been called into question, based on the diminishing reserves available to some of the major production hubs (Blethune, 2021). That is premature: with discovered undeveloped gas resources of 97 TCF and a yet-to-find estimate, arguably very optimistic, of 95 TCF (Pollastro et al., 2012; P95, adjusted for post-2011 discoveries), there is no shortage of potential supply. The challenge for industry is to develop those resources and to find more. That process is already occurring. Scarborough gas field has recently been approved, as has development of Woodside's Browse Basin gas fields by pipeline link to the North Rankin facilities in the NCB. Other "stranded" gas fields will need to be developed in the coming decade. This exploration and development will be opposed by environmentalists, as already seen with the Scarborough and Barossa projects.

Contrary to the widespread popular perception about the "end of fossil fuels," it is increasingly recognized that the global requirements for oil and gas will be substantial for decades to come, as major sources of power, fuel, fertilizer, and petrochemicals. Gas will be central to any transition to renewables, but oil supplies are also critical. In 2017, the International Energy Agency estimated that oil and gas will constitute approximately 40% of the global energy mix in 2040, much the same as it is today. In Southeast Asia, the main market for the NWS, demand is projected to double by 2050. The political drive to develop renewables will accelerate their development, perhaps substantially so, but oil and gas resources will be needed far into the future, and future discoveries will be needed to offset declining production. The oil supply shortfall in 2040 has recently been estimated to be 30–110 million bbl/day in the absence of new discoveries and production (Equinor Energy, 2021). Exploration expenditure to adequately replace declining reserves must be increased to A$542 billion annually (from approximately A$350 billion currently), according to Moody's (Josyana, 2021), if the world is to avoid another oil supply crisis, with all the attendant financial repercussions. This perspective is longer-term, but the risks of supply shortfall, oil price increase, and global financial repercussions also apply in the near term.

The super basins of the world, including the Westralian Super Basin, will be important in meeting the shortfall in supply. The development of the undeveloped gas fields and the exploration for new oil and gas supplies on the NWS are vital for Australia's future and for the health of the economy and the people of the Australasian region. This will be even more so as a new dynamic develops around government aspirations for greater energy independence, in light of the disruption to supply caused by the Russian invasion of Ukraine. The gas resources, which were once seen as the curse of the NWS but proved to be its fortune in the late twentieth century, will continue to provide for the nation and her neighbors well into the century ahead.

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