2014 EDITION

Western Australia's

Petroleum and Geothermal Explorer's Guide

Government of **Western Australia**
Department of **Mines and Petroleum**

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Advanced Energy Group's drill rig, the Crusader 405, on location at Ungani 3 in the Canning Basin (photo courtesy of Buru Energy)

PURPOSE OF THIS GUIDE

Information in this guide relates to petroleum and geothermal energy resources activity in the State of Western Australia, its onshore and State Waters areas including islands, which are administered under the *Petroleum and Geothermal Energy Resources Act 1967*, the *Petroleum (Submerged Lands) Act 1982*, the *Petroleum Pipelines Act 1969* and the *Petroleum Act 1936*. All petroleum and geothermal operations must comply with all relevant legislation.

This publication is designed particularly to provide general information and guidance on the legislative framework for companies considering exploring and investing in Western Australia's upstream petroleum and geothermal energy industries and for companies currently involved in those industries. It may also be a reference for the public and other Government agencies.

The Department of Mines and Petroleum is a lead agency for the State, responsible for coordinating proposed project approval processes, ensuring that mining, petroleum and dangerous goods operators comply with regulatory requirements, and enforcing regulation and conditions of approvals.

This guide is divided into two sections: information and regulation. The information section contains information about:

- role of Government
- exploration and production of conventional petroleum resources
- exploration for tight gas, shale gas and shale oil
- regional geology of Western Australia's sedimentary basins considered to be prospective for hydrocarbons
- geological information relevant to geothermal energy resources
- transport, infrastructure and pipelines
- greenhouse gas storage projects in Western Australia
- accessing data.

The regulation section contains information and guidance on:

- petroleum and geothermal legislation
- resource management and administration regulations
- native title
- land access
- environmental assessment and legislation
- occupational safety and health
- taxation and commercial aspects relating to petroleum production
- Perth and Western Australia.

The content of this document is intended as information only and is not intended to be a substitute for understanding the statutory requirements of any of the petroleum acts and regulations, or any other relevant legislation.

In the event of disagreement between this guide and current legislation, regulations, directions or guidelines, the latter will prevail. Readers are invited to consult with the Department of Mines and Petroleum (DMP) for further clarification.

PART 1

GOVERNMENT'S ROLE

PETROLEUM EXPLORATION, PRODUCTION AND DEVELOPMENT

PETROLEUM PROSPECTIVITY OF WESTERN AUSTRALIA'S SEDIMENTARY BASINS

GEOTHERMAL ENERGY RESOURCES

CARBON CAPTURE AND STORAGE

ACCESS TO DATA

History of Australia's Offshore Legal Jurisdiction

Australia's offshore jurisdiction includes Commonwealth, State and Northern Territory areas and is regulated by the laws in place offshore. Up until the mid-1960s, general Commonwealth legislation encouraged exploration and exploitation of petroleum and minerals but there was no legislation with specific jurisdiction over offshore areas.

The *Petroleum (Submerged Lands) Act 1967* was the outcome of Commonwealth–State negotiations in relation to the legislative basis for offshore petroleum exploration and production. The Act provided that the Commonwealth and the States would each introduce complementary legislation to establish a regime in which offshore petroleum exploration could be carried out and royalties would be shared. However, the 1967 agreement had avoided addressing issues about the respective constitutional powers of the Commonwealth and the States. This led to the enactment of the *Seas and Submerged Lands Act 1973,* which asserted the Commonwealth's sovereignty over the continental shelf and landward as far as the low-water mark in waters outside State limits. This was upheld by the High Court in 1975.

On 29 June 1979, the Commonwealth and the States completed an agreement for the settlement of various contentious and complex offshore constitutional issues, including issues related to offshore petroleum resources. The result was that rights were returned to each State over the territorial sea adjacent to its coast, limited to three nautical miles from the baseline (nominal low-water mark), and the Commonwealth would administer the waters beyond that area.

Straight forward jurisdictional boundaries now apply. Activities outside the three nautical mile zone are primarily regulated by the Commonwealth Government and activities within this zone are regulated by the State Government of Western Australia.

Figure 1 shows part of Western Australia's coastline and offshore waters, and indicates the various legislative zones. Petroleum exploration and development in Western Australia's onshore areas is accommodated by way of the *Petroleum and Geothermal Energy Resources Act 1967* (PGER Act). The PGER Act also applies to the State's coastal waters landward of the baseline from which Australia's territorial sea is measured (area 1 on Figure 1). There is a notable exception to the application of the PGER Act in this area and that is in respect to the area of titles which were present when the area was the subject of previous legislation. Those titles, where they remain current, come within the *Petroleum (Submerged Lands) Act 1982* (PSL Act) (area 2).

In the remainder of Western Australia's coastal waters (the three nautical mile zone seaward of the baseline) petroleum exploration and development is regulated by the PSL Act (area 2). Barrow Island is regulated under the *Petroleum Act 1936* (area 3).

All waters beyond State and Northern Territory (NT) coastal waters are regulated under the Commonwealth's *Offshore Petroleum and Greenhouse Gas Storage Act 2006* (OPGGS Act) (area 4). In the offshore area of Western Australia, these areas continue to be regulated by a Joint Authority arrangement between the Offshore Resources Branch (ORB) of the Department of Industry (DoI) and the Western Australian Department of Mines and Petroleum (DMP). The National Offshore Petroleum Titles Administrator (NOPTA) is responsible for titles administration functions and the National Offshore Petroleum Safety and Environmental Management Authority (NOPSEMA) regulates environment and safety matters. All decisions in respect to greenhouse gas storage in the Commonwealth jurisdiction are solely the responsibility of the Commonwealth Minister.

Figure 2 shows the demarcation of the maritime zones described above as determined under the United Nations Convention on the Law of the Sea in 1982. Those zones are: waters within the limits of a State or Territory, coastal waters, territorial sea, contiguous zone, exclusive economic zone, and the continental shelf.

State Regulation

The ownership of Australia's petroleum and geothermal resources is vested in the Crown as is the right to provide access to those resources. For petroleum and geothermal resources within the limits of Western Australia (its onshore areas including islands and coastal waters), that ownership is administered by the Government of Western Australia.

Through legislation, the Western Australian Government provides an orderly and equitable system by which the rights to explore for and produce petroleum and geothermal resources are awarded to the private sector.

Western Australian Department of Mines and Petroleum (DMP)

The State Government provides support to assist industry in the exploration and development of the State's resources and has maintained a healthy and welcoming environment for responsible exploration and development.

DMP oversees Western Australia's A$113.8 billion resources industry (2013 calendar year) by attracting investment, and advancing the State's mining, petroleum and geothermal energy industries while ensuring community standards are met.

Among the department's central functions are the management of the State's petroleum, geothermal and mineral titles; regulation of safety for workers and the environment within the resources industry; collection of mineral and petroleum royalties; and development and provision of world-class geological information (Figure 3).

DMP's responsibilities in regulating the upstream petroleum and geothermal energy industries are described in the following section.

DMP's Petroleum Division

The Petroleum Division's responsibilities under State legislation are to:

- encourage and facilitate responsible exploration, development and production of petroleum and geothermal energy resources;
- administer and control petroleum and geothermal energy exploration and production in accordance with the relevant Acts and the regulations and directions pertaining to those Acts;
- administer and negotiate future act *Native Title Act 1993* (Cwth) (NT Act) requirements for petroleum title applications under State legislation;
- engage with the petroleum and geothermal energy industries to resolve issues pertaining to timelines of Aboriginal cultural heritage survey and Reserve Land activity associated with exploration operations;
- make available areas for exploration and make recommendations on the grant, renewal or cancellation of permits and licences;
- evaluate all technical matters relating to drilling, formation evaluation, resource management and production in accordance with good industry practice;
- advise on exploration evaluation and assess all permit and work applications;
- record and register all documents dealing with permits, titles, applications and general procedural matters;
- maintain title registers including title spatial data;
- spatially ascertain, in respect to petroleum and geothermal activities, other land tenures and interests that may be impacted by these activities; and
- support the WA Minister for Mines and Petroleum in all State petroleum and geothermal resource matters and also, in his capacity as the State's member of the Western Australian-Commonwealth Joint Authority, for decisions in Commonwealth waters offshore the State of Western Australia.

GOVERNMENT'S ROLE

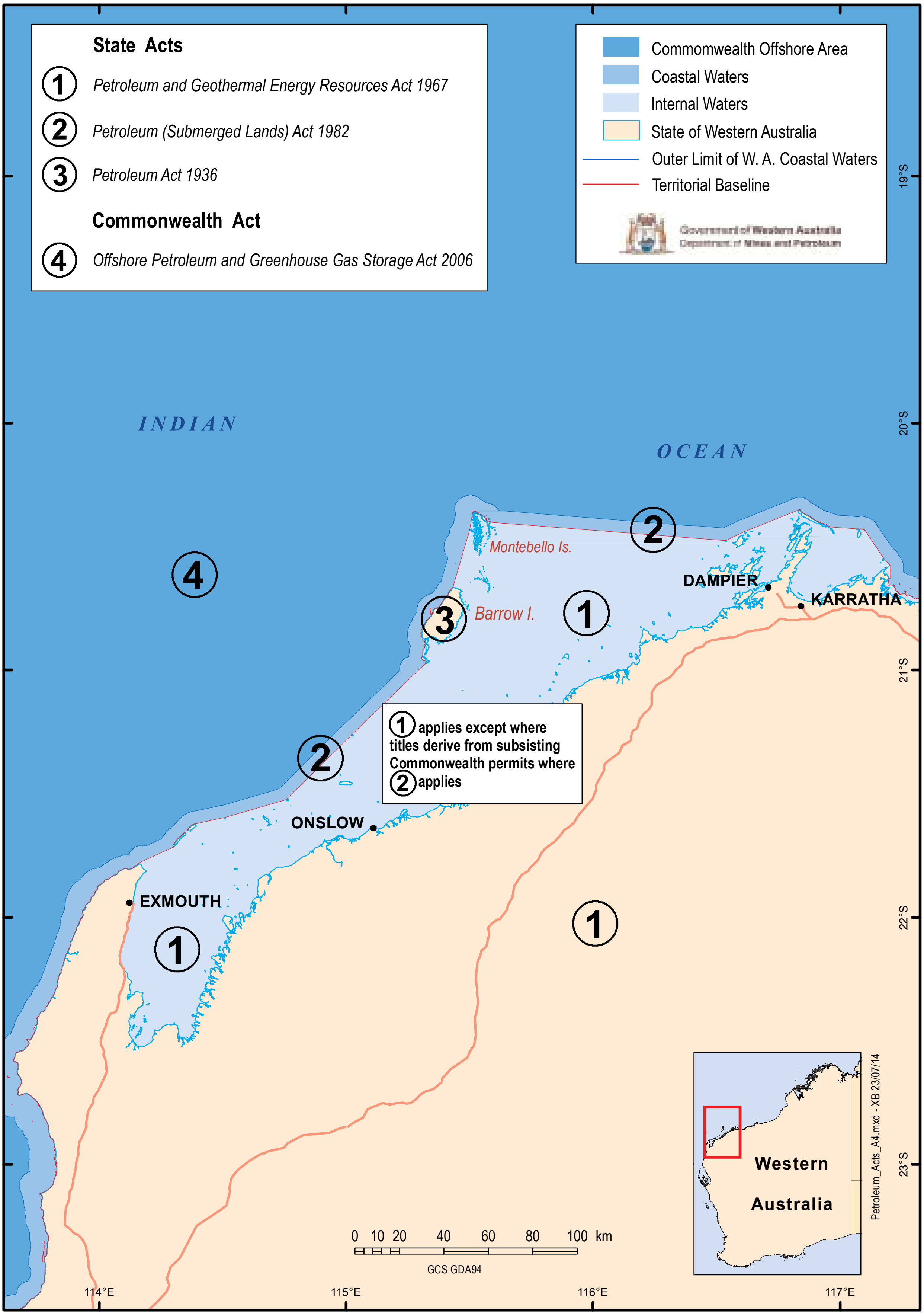

Figure 1. Example of where Commonwealth and State petroleum and geothermal Acts apply

Joint Authority Role
Under delegation, the Executive Director of the Petroleum Division represents the State's member of the Western Australian-Commonwealth Joint Authority for Joint Authority functions in waters offshore the State of Western Australia and, as such:

- receives information and advice from the National Offshore Petroleum Titles Administrator (NOPTA);
- provides fully informed advice on Commonwealth title approvals to the State Minister;
- ensures that the State Minister is kept fully informed and advised on all policy matters relating to Commonwealth offshore activities; and
- ensures that Commonwealth offshore activities do not adversely impact on activities in State areas.

DMP's Geological Survey of Western Australia (GSWA)
GSWA systematically records and interprets the geology of Western Australia and provides this information to Government, industry and the general public to assist the exploration, development and conservation of the State's petroleum, geothermal and mineral resources.

GSWA actively assesses and promotes the prospectivity of oil, gas, and geothermal energy in the sedimentary basins of Western Australia. The main focus is to develop regional geological frameworks of different onshore and nearshore tectonic units. The assessment is based on interpretation of existing and newly supplemented data on geology, geophysics, geochemistry, and temperature. GSWA is currently focused on the Neoproterozoic – Paleozoic Amadeus and Paleozoic Canning Basins, which are vastly underexplored with proven petroleum systems, and on the geothermal energy potential of Western Australia.

DMP's Strategic Planning and Royalties Branch
The Royalties Branch administers the collection of mineral, petroleum and geothermal energy royalties from State areas for the long-term benefit of all Western Australians. The Royalties Branch continues to collect royalties payable on specified petroleum titles in the North West Shelf on behalf of the State by virtue of the *Offshore Petroleum (Royalty) Amendment Act 2011*. The branch is also responsible for developing and providing royalty policy advice and implementing royalty policy and legislation.

DMP's Environment Division
DMP promotes responsible practices in the petroleum industry to ensure the protection of the environment through administration of the *Petroleum (Submerged Lands) (Environment) Regulations 2012, Petroleum and Geothermal Energy Resources (Environment) Regulations 2012* and the *Petroleum Pipelines (Environment) Regulations 2012*. DMP's Environment Division interacts with numerous Government agencies and industry groups to obtain advice and guidance on environmental management in Western Australia. Proponents are encouraged to review the *Guidelines for the Preparation and Submission of an Environment Plan* available on the DMP website and to contact the Environment Division prior to submitting an application for approval. They can assist by clarifying specific requirements related to individual operations and their locations, and provide advice on contacting other agencies where appropriate.

The role of the division is to:

- administer the environmental provisions of WA State petroleum and geothermal legislation;
- monitor and maintain a record of industry environmental performance;
- promote environmental best practice in the petroleum and geothermal industries; and
- meet community standards in the management of risk to the environment.

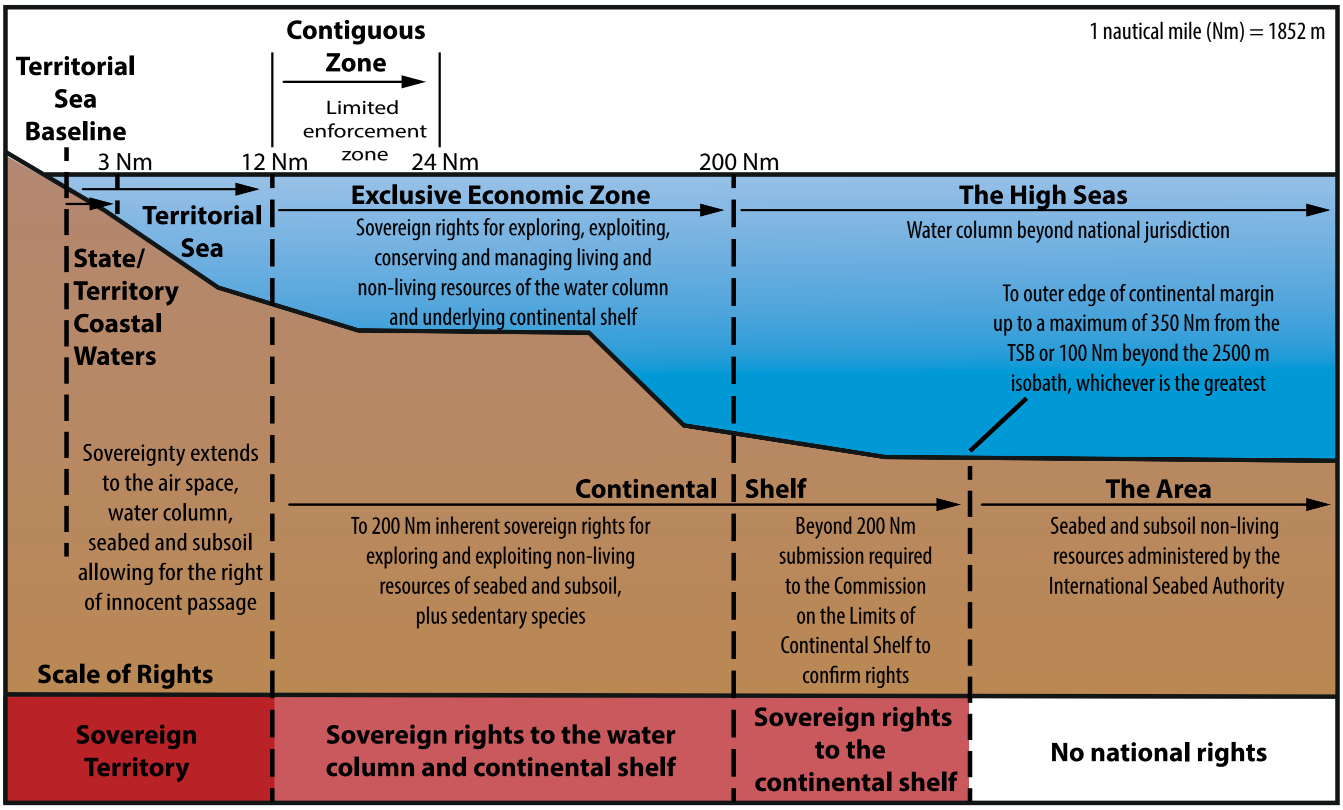

Figure 2. Maritime zones and rights under the 1982 United Nations Convention on the Law of the Sea (UNCLOS)
Source: Geoscience Australia 2009

GOVERNMENT'S ROLE

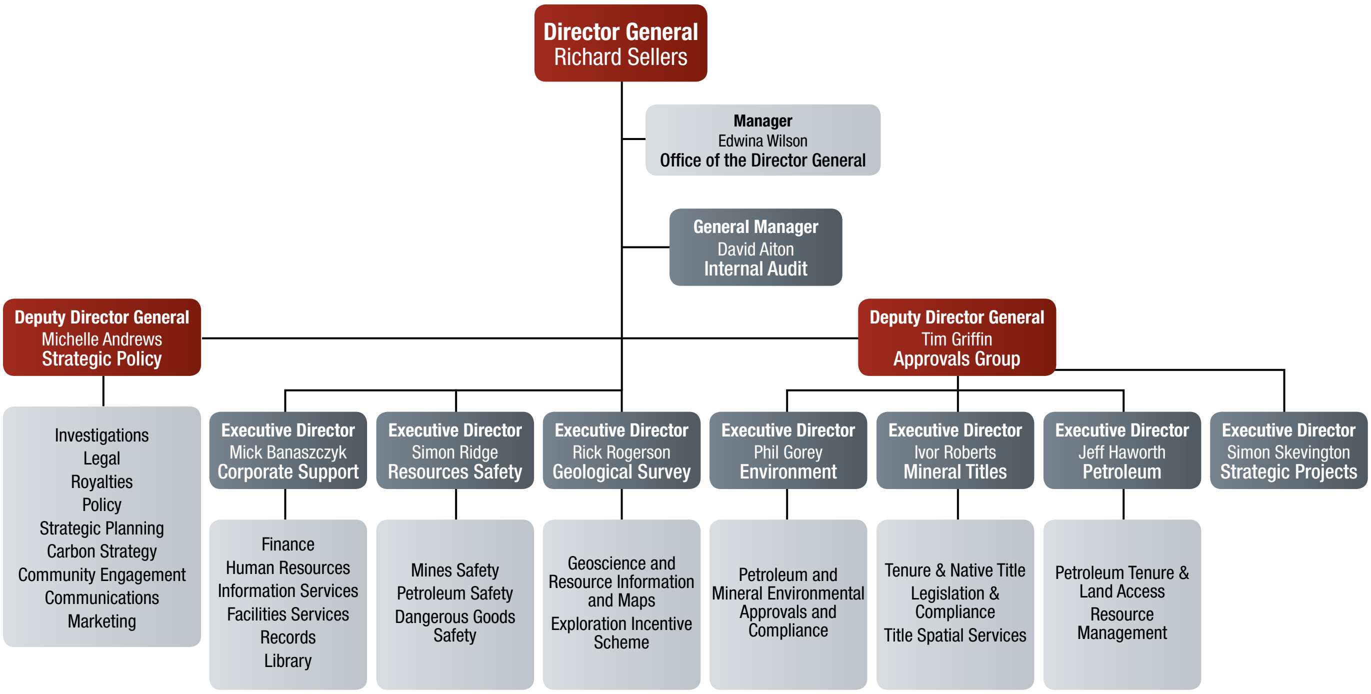

Figure 3. Divisional structure of the Western Australian Department of Mines and Petroleum as of August 2014

Resources Safety Division

DMP's Dangerous Goods and Petroleum Safety Branch of the Resources Safety Division is responsible for the management and administration of occupational safety and health under the *Petroleum and Geothermal Energy Resources Act 1967*, the *Petroleum (Submerged Lands) Act 1982* and the *Petroleum Act 1936*. The Dangerous Goods and Petroleum Safety Branch has the responsibility for the day-to-day administration of the listed occupational safety and health (OSH) laws contained in the submerged lands legislation that applies to all State coastal waters from the mean low-water mark on the mainland to the three nautical mile limit. This legislation applies to all offshore petroleum and diving operations including vessels engaged in such activities.

The role of the Dangerous Goods and Petroleum Safety Branch in respect to upstream petroleum and geothermal energy exploration and development is to:

- ensure all occupational safety and health risks in the petroleum and geothermal industries are properly controlled;
- administer petroleum and geothermal energy occupational safety and health provisions of the legislation; and
- promote a legislative framework that encourages continuous improvement in the management of occupational safety and health in the petroleum and geothermal industries.

The Resources Safety Division also administers the *Dangerous Goods Safety Act 2004*, which applies to manufacture, storage, handling, transport and use of dangerous goods, including the operation of major hazard facilities in Western Australia.

Other State Agencies

As lead agency responsible for coordinating the whole application approval process, DMP can initiate contacts with other agencies on behalf of the applicant. The involvement of DMP can assist in obtaining timely input from other agencies. Other Western Australian agencies that play a role in regulating petroleum and geothermal activities in State areas include the Environmental Protection Authority, the Department of Environment Regulation, the Department of Parks and Wildlife, the Department of Water, and the Department of Aboriginal Affairs.

Environmental Protection Authority (EPA)

EPA is an independent authority whose operations are governed by the *Environmental Protection Act 1986* (EP Act) which stipulates that the objective of the EPA is to 'use its best endeavours – a) to protect the environment; and b) to prevent, control and abate pollution and environmental harm'. The EPA conducts environmental impact assessments, prepares policy for environmental protection, publishes guidelines for managing environmental impacts, and provides advice to the Minister for Environment. Consult the EPA's website for further information www.epa.wa.gov.au.

Department of Environment Regulation (DER)

DER is responsible for works approvals and licensing, compliance and response, enforcement and other major environmental initiatives within Western Australia. The department aims to work with industry and the community to protect the environment, by encouraging operation beyond compliance in industry regulation. DER is the regulatory agency responsible for administering the following environmental legislation: *Environmental Protection Act 1986* (EP Act), *Contaminated Sites Act 2003*; and *Waste Avoidance and Resource Recovery Act 2007*. For more information visit the website www.der.wa.gov.au.

Department of Parks and Wildlife (DPaW)

DPaW has primary responsibility for managing the State's national parks, marine parks, State forests and other reserves, for conserving and protecting native animals and plants, and for managing many aspects of the access to and use of the state's wildlife and natural areas. It is also responsible for conserving flora and fauna throughout the State. The *Conservation and Land Management Act 1984 (CALM Act)* does not generally protect land managed by DPaW from mining or development projects. Section 4 of the CALM Act provides that nothing in the Act shall take away from the operation of any Act relating to minerals or petroleum or any Agreement Act for a development project (except in marine nature reserves and certain zones in marine parks, which are protected from petroleum drilling and production). For more information, go to www.dpaw.wa.gov.au.

Department of Water (DoW)

DoW is the government agency responsible for Western Australia's water resources by managing the availability and quality of water sustainability. DoW licenses water used by mining and industry for State development and should be consulted for guidelines for use of groundwater in petroleum and geothermal projects. For more information, go to www.water.wa.gov.au.

Department of Aboriginal Affairs (DAA)

DAA engages with Indigenous Western Australians and all levels of Government to improve delivery of services, and to facilitate the development of policy and programs, which deliver sustainable economic, environmental and social benefits to Indigenous communities. Under the *Aboriginal Heritage Act 1972 (AH Act)*, DAA works with Indigenous people to protect and manage places of significance. DAA also provides advice to the public and private sectors and the community about Aboriginal heritage management and maintains a Register of Aboriginal Sites. DAA's Land Branch can provide information on land tenure and Aboriginal lands. For more information, go to the "Land Access – Aboriginal Affairs" chapter in this guide and www.daa.gov.wa.au.

Commonwealth Regulation

Department of Mines and Petroleum (DMP)

The Petroleum Division acts on behalf of the WA member of the Joint Authority for Joint Authority functions in Commonwealth waters offshore the State of Western Australia. The Petroleum Division ceased undertaking the day-to-day administrative functions under the *Offshore Petroleum and Greenhouse Gas Storage Act 2006* (Cwth) in January 2012 with the inception of the National Offshore Petroleum Titles Administrator (NOPTA).

Department of Industry (DoI)

Responsibility for Australia's offshore areas beyond three nautical miles from the territorial sea baseline rests with the Australian Government.

Offshore Resources Branch (ORB)

ORB, a branch of DoI, acts for the Commonwealth delegate of the State-Commonwealth Joint Authority for Joint Authority functions.

National Offshore Petroleum Titles Administrator (NOPTA)

NOPTA, a branch of DoI, is responsible for the day-to-day administration and management of all petroleum titles in Commonwealth waters under the *Offshore Petroleum and Greenhouse Gas Storage Act 2006* (OPGGS Act). NOPTA provides advice to all Joint Authority members on title related applications requiring a Joint Authority decision.

National Offshore Petroleum Safety and Environmental Management Authority (NOPSEMA)

NOPSEMA is a Commonwealth Statutory Agency with responsibilities in Commonwealth waters to:

- ensure all occupational health and safety risks in the offshore petroleum industry including offshore greenhouse gas storage operations are properly controlled;
- administer offshore petroleum occupational health and safety legislation;
- ensure structural integrity of facilities and environmental management within Commonwealth waters is maintained;
- promote a legislative framework that encourages continuous improvement in the management of occupational health and safety in the offshore petroleum industry.

References

Offshore Petroleum Bill 2005 Explanatory Memorandum. The Parliament of the Commonwealth of Australia, House of Representatives.

White, Michael, 2011, Australia's offshore legal jurisdiction: Part 1 – History and development. Australian and New Zealand Maritime Law Journal, 25 1, 3-18.

Drilling Ungani 1 in the Canning Basin (photo courtesy of Buru Energy Ltd)

Exploration History

Western Australia is the largest State in Australia, comprising about one third of the country. Its sedimentary basins, including its continental shelf, cover an area of approximately 2.5 million km^2. The State has seven major sedimentary basins: the Bonaparte, Browse, Canning, Northern Carnarvon, Southern Carnarvon, Officer and Perth Basins, as well as several minor basins, including the Amadeus Basin which is prospective for petroleum (Figure 4).

Exploration for oil in Western Australia commenced in the early 1900s, with the last 40 years in particular seeing significant exploration, production and marketing developments. Prospectivity for petroleum has been demonstrated across large onshore and offshore areas of the State, and commercial quantities of hydrocarbons have been found in the Northern Carnarvon, Perth, Canning, Browse and Bonaparte Basins.

Exploration in Western Australia began in 1902 when the first petroleum exploration well was drilled near the Warren River in the State's southwest. Traces of oil were found in a water bore near Fitzroy Crossing in 1919. The Australian Motorists Petrol Company (AMPOL) was one of the first to carry out formal exploration in Western Australia, commencing in 1946. That same year, the Bureau of Mineral Resources (BMR) initiated survey work for the Australian Government.

AMPOL was awarded the first two Western Australian Exploration Permits near Exmouth in 1947. They then formed a joint venture with Standard Oil and called the new company West Australian Petroleum (WAPET). WAPET made the first discovery of oil in the State at Rough Range in 1953. The Rough Range 1 well produced oil at a rate of 87 kL/d (550 bbl/d), but the field was too small for commercial development at the time. 59 years later, in 2012, a Production Licence was awarded over the Rough Range oilfield. The field is no longer producing.

Commercial quantities of oil were first discovered in 1964 at Barrow Island, located 56 km off the northwest coast, in the Northern Carnarvon Basin, and brought into production by WAPET in 1967. Production from the Barrow Island oilfield continues to this day. Over 127 GL (800 MMbbl) remain unrecovered from the Barrow Island oilfield. In 1966, WAPET discovered commercial quantities of natural gas near Dongara in the Perth Basin, leading to completion of the Western Australian Natural Gas (WANG) pipeline (now called the Parmelia pipeline) in 1971.

In 1967, the North West Shelf became the focus for offshore exploration. Although the search was initially for oil, gas shows were encountered as early as 1968. Major discoveries of gas were made throughout the 1970s such as Goodwyn, North Rankin, Angel and Scarborough, but several major oil discoveries such as Harriet and South Pepper in the 1980s changed the perception that the North West Shelf was particularly gas-prone. Numerous oil discoveries since then have been made in the Northern Carnarvon Basin.

The Northern Carnarvon (Figure 5) and northern Perth Basins (Figure 6) have seen record levels of exploration and production activity. The Triassic to Cretaceous sandstones of the offshore Northern Carnarvon Basin, the Triassic to Cretaceous sediments of the Browse Basin and the Permian to Jurassic sandstones of the northern Perth Basin are currently recognised as the most prospective areas for conventional oil and gas exploration in the State, although the Late Permian formations of the Bonaparte Basin are now generating considerable interest. Shale gas and shale oil potential in the northern Perth Basin is also being investigated, with dedicated shale gas wells now being drilled and pilot testing of hydraulic stimulation commenced.

The Canning Basin has a long history of greenfields petroleum exploration, with over three hundred wells, mainly exploration wells and stratigraphic boreholes, while the Officer Basin in the southeast of the State is poorly explored, with limited seismic coverage and only 31 stratigraphic holes and exploration wells drilled as of July 2014. For the Officer Basin, this means one well has been drilled per 10,000 km^2.

In the early 1980s, numerous small oil accumulations were discovered in the Canning Basin and brought onto production on the Lennard Shelf, including the Blina, Sundown, West Terrace and Boundary oilfields (Figure 7). More recent exploration has led to the discovery of oil at Ungani 1 and gas at Valhalla and Yulleroo 2. A Production Licence application over the Ungani oilfield is pending, anticipated to be awarded upon conclusion of native title procedures under the *Native Title Act 1993* (Cwth).

Tight Gas

Western Australia's sedimentary basins also hold the potential to deliver an additional energy supply to the State's domestic gas market through the development of its tight gas resources. Tight gas is trapped in ultra-compact reservoirs characterised by very low porosity and permeability. The rock pores that contain the gas are minuscule, and the interconnections between them are so limited that the gas can only migrate through them with great difficulty. Higher permeability is one of the parameters by which conventional gas reservoirs can be distinguished from tight formations. Tight gas is known in the onshore Perth and Canning Basins and is found in low permeability and low porosity sandstone and limestone. The Perth Basin is estimated to hold more than 283 Gm^3 (10 Tcf) of tight gas resources, enough to meet Western Australia's domestic needs for 30 years.

Basin Centred Gas Accumulations (BCGA)

BCGAs are a category of tight gas accumulation that typically:

- are abnormally pressured;
- have continuous gas saturation;
- lack a down-dip water contact; and
- comprise low permeability (less than 0.1 millidarcy) and porosity reservoirs.

BCGA reservoirs lack traditional seal or trapping mechanisms. The only proposed BCGA in Western Australia that is being explored is the Laurel Formation in the Canning Basin.

Shale Gas Exploration

The State's onshore frontier basins offer perhaps the best opportunities to discover a new petroleum province in the Asia–Pacific Region. There are emerging opportunities in other petroleum resources such as shale gas and shale oil, as small independent explorers lead the way exploring the potential of the State's shale plays. International companies, including Apache, ConocoPhillips, Hess, Mitsubishi and PetroChina, are now entering these plays by forming JV partnerships with the smaller independents in the Canning Basin. Shale gas plays often cover large contiguous areas, and it is believed that shale gas resources are spread across the onshore Perth, Carnarvon and Canning Basins. There has also been recent industry interest in the shale gas potential in the Officer Basin.

Shale gas occurs within the mudstones and siltstones that commonly serve as traditional oil and gas sources, and forms at depths below 2000 m. Gas is contained in miniscule pores between the grains that make up the rock matrix. Shales have low matrix permeability; the permeability values of gas shales are as little as one one-thousandth of the permeability of tight gas formations, and require the presence of extensive natural or engineered fracture systems to sustain commercial production rates.

To produce shale gas, a rock formation needs to undergo stimulation, typically hydraulic fracture stimulation, to release gas and enable recovery. Hydraulic fracturing of the rock increases its permeability (e.g. the ability for fluids to flow into the wellbore). Hydraulic stimulation activities may also be associated with conventional oil and gas development wells to enhance recovery.

An assessment of world shale gas resources by the United States Energy Information Agency (EIA) ranked Australia seventh after the US in terms of recoverable shale gas resources, with the Canning and Perth Basins holding 7.6 Tm^3 (268 Tcf) of technically recoverable resource (EIA, 2013). This is approximately twice the amount of gas held in Western Australia's offshore areas.

PETROLEUM EXPLORATION, PRODUCTION AND DEVELOPMENT

Figure 4. Western Australia's sedimentary basins

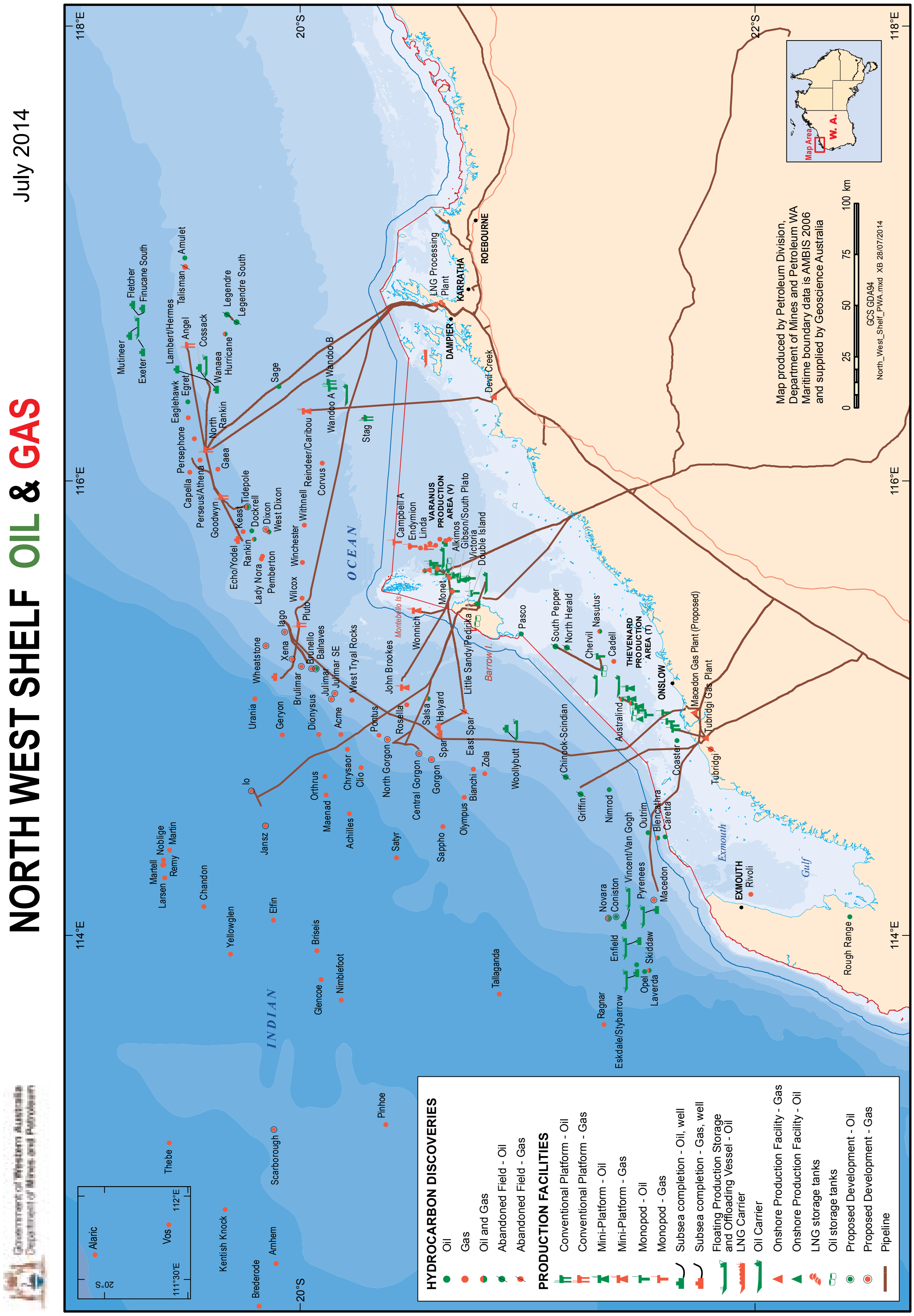

Figure 5. North West Shelf production facilities and significant hydrocarbon discoveries

PETROLEUM EXPLORATION, PRODUCTION AND DEVELOPMENT

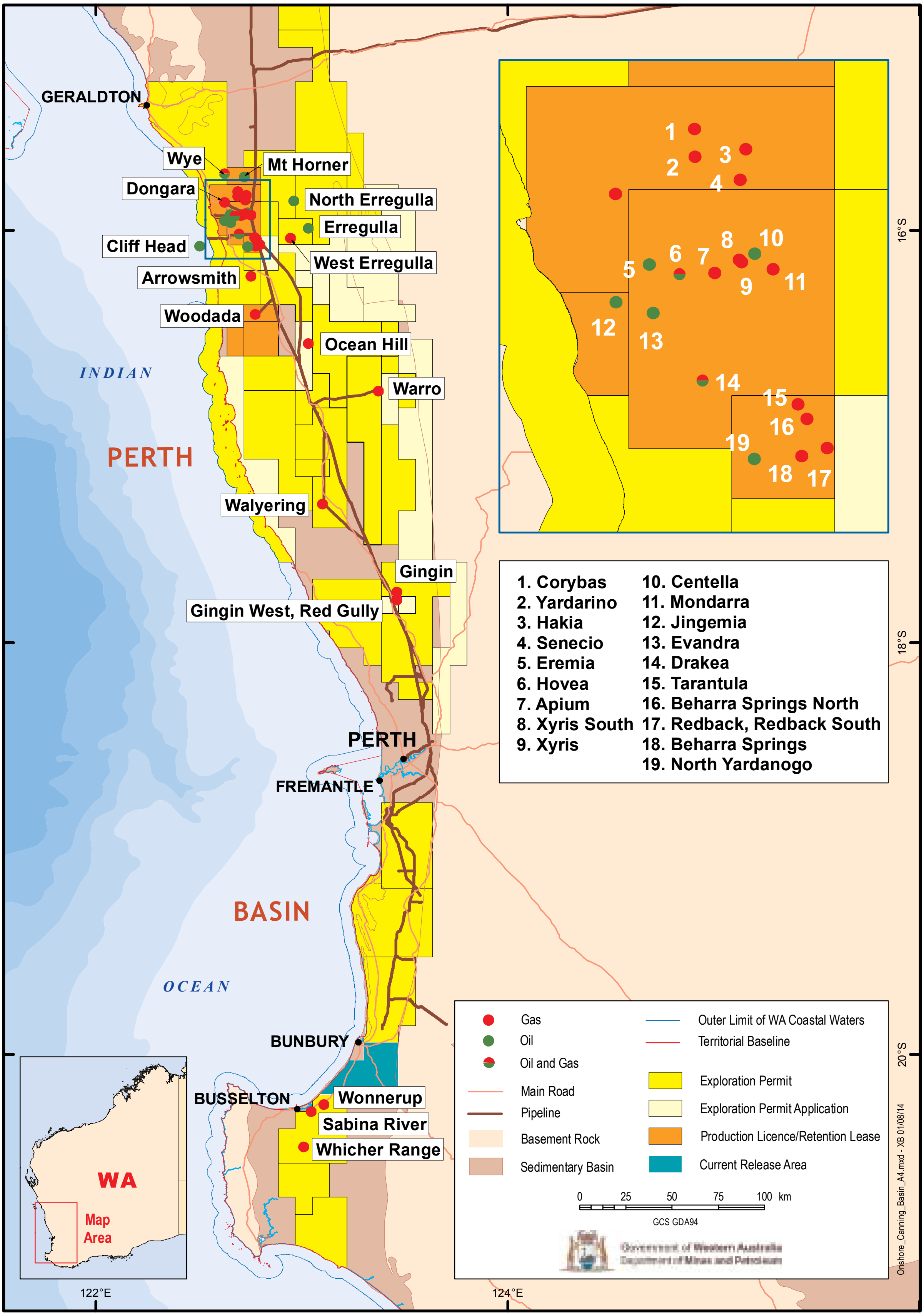

Figure 6. Significant hydrocarbon discoveries in the Perth Basin

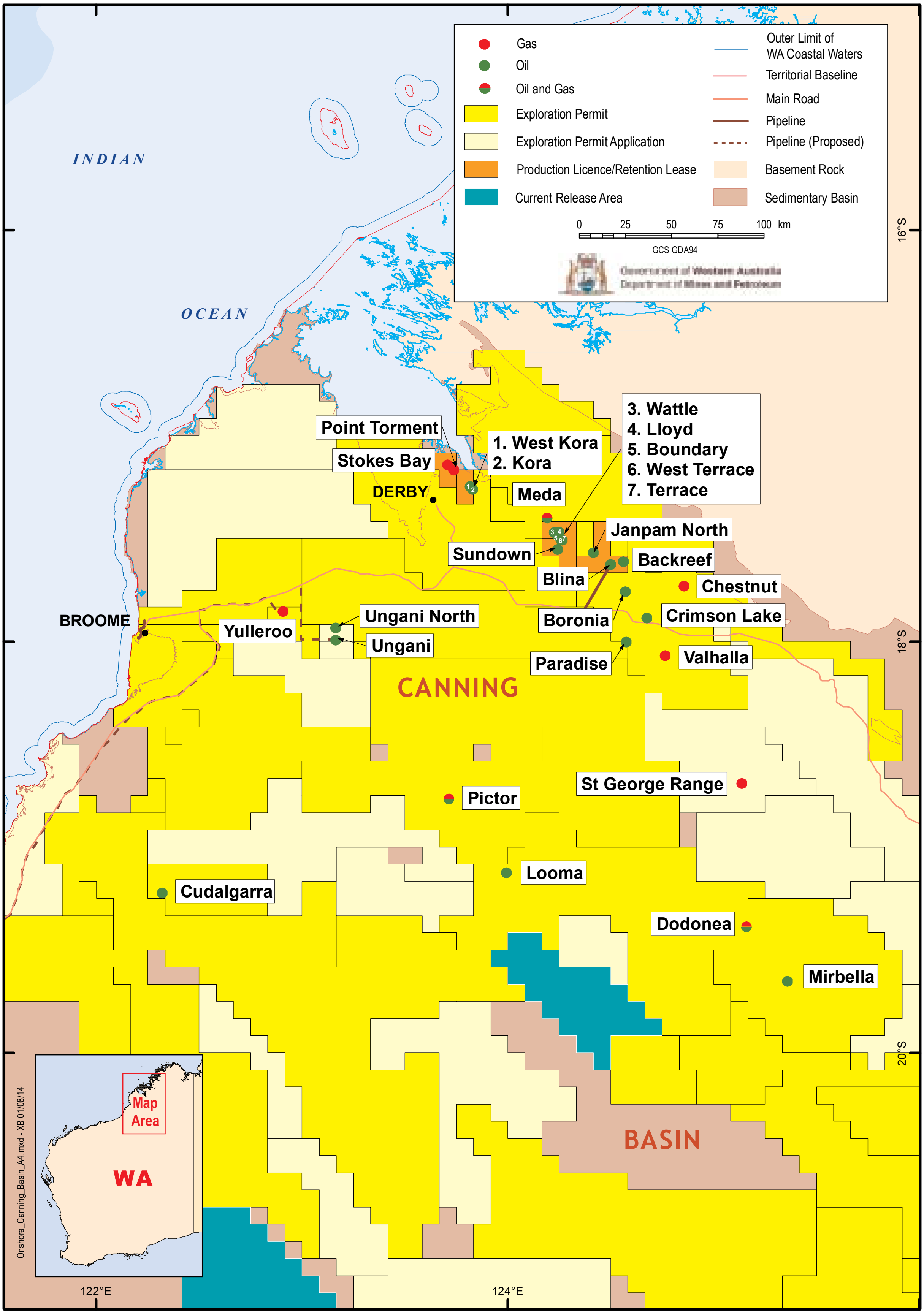

Figure 7. Significant hydrocarbon discoveries in the Canning Basin

PETROLEUM EXPLORATION, PRODUCTION AND DEVELOPMENT

It is estimated that Western Australia's shale and tight gas resources could provide enough energy to power a city of one million people for more than 500 years. Present indications suggest that shale gas and tight gas, particularly shale gas, is likely to become an important part of Western Australia's energy future, with a likely increase in the number of natural gas projects being developed.

The vastness and variety of the geology in Western Australia provides a challenge to applying new technologies in the search for petroleum in this underexplored State.

Coal Seam Gas (CSG)

Coal bed methane (also known as coal seam gas) is natural gas obtained form coal seams. It is found predominately close to the surface, generally between 300 and 1000 m. The gas is adsorbed on the surface of coal particles or stored in the natural cleats (fractures) of coal seams. Western Australia currently has no known potentially commercial CSG resources, because of the State's geology and character of its coals.

Some Statistics

By the end of 2013, a total of 3429 exploration wells have been drilled (1843 in State onshore, 302 in State waters and 1284 in Commonwealth waters).

During the modern era of petroleum exploration (1965–2013), approximately 1,581,149 line km of 2D seismic were recorded (155,420 line km onshore, 295,667 line km in State waters and 1,130,062 line km in Commonwealth waters), along with more than 237,788 km^2 of 3D seismic (3827 km^2 onshore, 5297 km^2 in State waters and 228,664 km^2 in Commonwealth waters).

Petroleum exploration expenditure in Western Australia amounted to more than A$2.1 billion, or around 56 per cent of the total petroleum exploration expenditure in Australia, in 2012. This includes exploration in Commonwealth areas. Western Australia's sedimentary basins hold approximately 80 per cent of Australia's discovered natural gas resources, despite being one of the least explored areas in the world, with one exploration well per ~3000 km^2 offshore (one well per ~100 km^2 on the North West Shelf) and one well per ~2600 km^2 onshore. This can be contrasted with Texas, where one well is drilled per 2 km^2.

Hydrocarbon Production and History

Western Australia is well established nationally and internationally as a significant hydrocarbon bearing and productive area. It leads the nation in gas and LNG production, and petroleum (crude oil, condensate and natural gas) is one of the leading contributors to the State's resources sector, largely due to the resources of the North West Shelf. In 2013, there was hydrocarbon production from 35 fields onshore and in State waters. For information on production from Commonwealth waters, visit www.nopta.gov.au.

Production for the year to 31 December 2013 was 487.5 ML (3.06 MMbbl) of liquids and 529.3 Mm^3 (18.6 Bcf) of gas. Reserves and contingent resources for fields onshore and in State waters at 31 December 2013 were 13.06 GL (82.14 MMbbl) of oil, 0.67 GL (4.26 MMbbl) of condensate and 54.22 Gm^3 (633.51 Bcf) of gas.

Onshore

Western Australia has been producing crude oil since 1967 and condensate, (a liquid co-produced with gas), since 1972. The discovery of commercial quantities of natural gas near Dongara in the Perth Basin in 1966, and the subsequent development of this field for industrial use led to the construction of the Parmelia pipeline, the first gas pipeline in the State, to supply heavy industry at Kwinana, south of Perth. The gas was transported to Perth and Pinjarra by a pipeline constructed by West Australian Natural Gas (WANG), but which is now owned by APT Parmelia. The Yardarino gasfield, discovered in 1964, came onto production in 1978 and produced until 2010. The Woodada gasfield was discovered in 1980 and was connected to the WANG pipeline in 1982. It produced for 28 years. The Beharra Springs gasfield was discovered in April 1990, commenced production in January 1991 and is still on production.

The Mt Horner oilfield, in the northern Perth Basin, commenced oil production in 1984 and ceased in January 2011, when the field failed a controlled pressure test and was shut in. The field produced 298,141 kL (1.87 MMbbl) of oil. The Jingemia oilfield was discovered in 2002 and started production in 2003. The Jingemia field produced a cumulative 745,616 kL (4.7 MMbbl) of oil and 36,542,900 m^3 (1.29 Bcf) of gas over a 10-year period. Other small Perth Basin fields such as Apium, Eremia, Tarantula and Xyris were in production for a short period.

Gas was produced from the Tubridgi field in the onshore Northern Carnarvon Basin from 1991 until 2005 when the field was depleted. In 2012, all of the Tubridgi wellheads were plugged and the field was decommissioned. The depleted Tubridgi field remains an opportunity for gas storage. The Mondarra gas storage facility began operating in 1994 and currently continues to store and supply gas to the Perth market.

In the Canning Basin, the Blina oilfield, discovered in 1981, became the first commercial onshore oilfield since the Barrow Island field in 1967. Production began in September 1983 and continued to February 2013 when Blina went under care and maintenance. Several other small oilfields in the Lennard Shelf area (Boundary, Lloyd, Sundown, West Kora and West Terrace) have produced oil as well but are now all under care and maintenance. As at 31 December 2013, these fields produced a combined total of 467,690 kL (2.9 MMbbl) of oil.

State Waters

Airlie Island

The South Pepper oilfield was discovered in 1982, followed by North Herald and Chervil in 1983. Production commenced in 1989 from the Chervil monopod. Airlie Island provided the base for the processing and storage of oil produced from these three fields. The North Herald and South Pepper fiel ds were decommissioned in 1997. Chervil field was decommissioned in 2002. The island infrastructure includes oil-processing and water-separation facilities, currently under care and maintenance, two 24 million litre (ML) storage tanks, pipelines, a power generation plant and a flare tower. Airlie Island is located 35 km north of Onslow.

Varanus Island

Approximately 120 km west of Dampier, Varanus Island provides the base for the Harriet Joint Venture gas-gathering and oil export projects, which are now heading towards decommissioning. The project saw minor production from the Agincourt, Bambra, Lee, Linda, and Rose fields in the first half of 2014.

The island infrastructure includes an oil processing plant, oil tanks and tanker export facilities, three gas trains, condensate stabilisation facilities, water treatment and injection facilities, pipelines and a power station. The total gas-processing capacity on Varanus Island is 390 TJ/d.

Thevenard Island

Thevenard Island provided the base for the processing and storage of hydrocarbons produced from the Saladin, Roller, Skate, Yammaderry, Crest and Cowle fields. However, the current operator, Chevron Australia, has indicated their intention to cease operations on Thevenard Island and have met with DMP to discuss decommissioning requirements. Consent to cease to operate the Thevenard Island facilities and associated pipelines was granted on 22 January 2014. On 12 April 2014, the Thevenard Island Asset ceased production, with final offtake in June 2014.

The island infrastructure includes facilities capable of handling up to 19 ML/d (120,000 bbl/d) of mixed oil–water production and 500,000 m^3 (17.6 MMcf) of gas per day, three 55.6 ML (350,000 bbl) oil tanks, water treatment and disposal facilities, pipelines, three gas turbine generators, a gas treatment plant, a 55 m^3 (1942 cf) capacity slug catcher/separator vessel and gas compression units.

Fluid produced from these six fields was piped to Thevenard Island, where it was separated into oil, water and gas. The water was re-injected into the reservoirs while the oil was processed and blended together before being stored in tanks. It was then transported via a 610-mm, 7-km pipeline to offshore tankers berthed at a 10-point spread mooring system. The crude was sold to refineries in Australia and overseas.

The Saladin field was discovered in June 1985 and commenced production in November 1989. An estimated 8.7 GL (55 MMbbl) oil-in-place, with potential recoverable oil of 3.3 GL (21 MMbbl) are contained in the Mardie Greensand Formation. The Saladin field continued to produce in 2014. The Roller field was discovered in January 1990 and commenced production in May 1994. The field consists of four production wells and one gas injection well, which are linked to three unmanned monopods. Roller ceased production in 2013, with a cumulative total of 7,211,390 kL (4.53 MMbbl) of oil and 793,215,000 m^3 (28 Bcf) of gas produced. Discovered in October 1991, the Skate field commenced production in July 1994. Skate ceased producing in 2012. Cumulative production from the field amounted to 266,950 kL (1.68 MMbbl) of oil, 8873 kL (55.8 Mbbl) of condensate and 178,287,000 m^3 (6.3 Bcf) of gas.

Yammaderry and Cowle were each developed as single-well fields linked to separate offshore unmanned monopods. Discovered in July 1988, the Yammaderry field commenced production in March 1991. Production continued in 2013 from this well, at a very low rate, with a cumulative total of 858,332 kL (5.4 MMbbl) of oil and 142,396,000 m^3 (5 Bcf) of gas. The Cowle field was discovered in December 1989 and commenced production in May 1991. It was shut-in in 2013. Cumulative production from the field totalled 537,068 kL (3.38 MMbbl) of oil and 91,871,000 m^3 (3.2 Bcf) of gas.

The onshore Crest field was discovered in February 1994 when the deviated Crest 1 well encountered hydrocarbons under Thevenard Island. The well was placed on an extended production test in June 1994. In 1998, Crest 1 was plugged and Crest 6 was drilled horizontally into the overlaying Mardie Greensand reservoir. Crest 6 produced oil at low rates and was shut-in in October 1998 pending application for a Production Licence. Two licences were granted over Thevenard Island (Production Licences L12 and L13) and production recommenced in December 2002 from the Mardie Greensand horizontal well Crest 6. Production ceased in 2013. The Crest field produced a total of 275,808 kL (1.73 MMbbl) of oil, 108 kL (679 bbl) of condensate and 65,773,000 m^3 (2.3 Bcf) of gas.

Barrow Island

The Barrow Island oilfield was discovered in July 1964 beneath the 233 km^2 island located 88 km north of Onslow, in State waters. It is the largest onshore oilfield in Australia with over 900 wells drilled and over 50.5 GL (318 MMbbl) of oil produced. Production commenced in April 1967 and peaked at 7950 kL/d (50,000 bbl/d) in 1970. Barrow Island was originally expected to have 30 years of production, but as a result of careful management of the reservoirs using more than 800 oil and water-injection wells, the expected life of the field has been extended until 2031.

The joint venture estimates that the field will have produced 54.5 GL (343 MMbbl) of oil by 2031, approximately one third of the known oil-in-place. In the majority of producing wells, oil is pumped to the surface using beam pumps (nodding donkeys). The remaining producing wells use gas-lift or are on natural flow. The Barrow Island field contains at least 30 different reservoirs of oil and gas. Currently there are 12 oil-producing formations, with the Windalia sandstone reservoir containing 95 per cent of known reserves.

Barrow Island is also the site of the new gas processing facility for the Gorgon Project and will be the largest commercial CO_2 geosequestration project in the world. Pipeline Licence PL 93 has been granted for CO_2 injection at Barrow Island.

Domestic Natural Gas Supply

Offshore

John Brookes

The John Brookes field lies offshore in 45–70 m of water in WA-29-L, in Commonwealth waters. The field was discovered in 1998 by the John Brookes 1 exploration well which intersected an 80 m gross hydrocarbon column. First production began in September 2005. The field has four production wells producing from an unmanned platform. Raw gas is sent to the Varanus Island processing facility via a 55 km multiphase pipeline where condensate is removed and stored. The raw gas is processed and sent to mainland Western Australia via two sales gas pipelines, which connect into the DBNGP and Goldfields Gas Transmission trunklines.

Reindeer Field

The Reindeer gasfield was discovered in 1997–98 however, development drilling didn't take place until 2008. The development project consists of an unmanned offshore platform in 62 m water depth with a pipeline connecting the platform to the two-train onshore processing facility at Devil Creek, which then ties into the Dampier to Bunbury Natural Gas Pipeline (DBNGP).

The Devil Creek plant is located 40 km southwest of Dampier and will have the capacity to supply up to 215 TJ/d into the domestic market. Initially gas will be supplied into the Devil Creek facility from the Reindeer field located in the offshore block WA-209-P. Gas is reservoired in the Middle Jurassic Legendre Formation. The project will supply all of its production to the domestic market. Production commenced from the field on 6 December 2011. The field has a life expectancy of 20 to 30 years. Apache (the operator) holds a 55 per cent interest and Santos has a 45 per cent interest in the Reindeer field and Devil Creek.

Halyard and Spar Fields

The Halyard gasfield is located in Commonwealth permit WA-13-L in the Carnarvon Basin. Spar is situated in permit WA-45-L, about 70 km west of Varanus Island and 2 km from Halyard. Gas and condensate is produced at the Halyard 1 discovery well. Gas is reservoired in Lower Cretaceous sandstones (Flacourt Formation and Halyard Sandstone).

Production from the Halyard well is through an existing pipeline to the East Spar field facilities and through to Apache's Varanus Island hub. The development of the Spar field, located in adjacent licence WA-45-L, is expected to follow when additional capacity becomes available at Varanus Island. The combined recoverable reserves at Halyard and Spar are estimated at 335 PJ, with production forecast to 2025. Apache holds 55 per cent equity and is the operator of both fields. Santos holds the remaining 45 per cent equity.

Macedon

The Macedon gasfield was discovered in 1992 at the West Muiron 3 well. Approximately 34 Gm^3 (1.2 Tcf) of gas is reservoired in the Upper Barrow Group sandstones. In September 2010, BHP Billiton approved the US$1.57 billion development of the Macedon gasfield located 50 km north of Exmouth in Production Licence WA-42-L in Commonwealth waters. The Macedon development involves four offshore production wells and a gas treatment plant at Ashburton North, 17 km southwest of Onslow. Gas from the facility is fed via a sales gas pipeline into the DBNGP to supply up to 220 TJ/d the State's domestic gas market. The plant has a production capacity of approximately 5.6 Mm^3 (200 MMcf) of natural gas per day. First production into the DBNGP for the domestic market occurred in August 2013 and is anticipated to continue for 10-15 years.

Onshore

Corybas

Corybas 1 was drilled south of Dongara in the northern Perth Basin in 2005 by ARC Energy and flowed modest volumes of gas from a sandstone interval in the Irwin River Coal Measures. In May 2009, AWE conducted a fracture stimulation of the vertical well, increasing gas flow rates. This was sufficiently encouraging to undertake a long-term production test and a pipeline link was installed from the Corybas 1 well to the nearby Dongara gasfield's processing facility. The field underwent an extended production test from April to September 2010, resulting in a recoverable reserves estimate of 82 Mm^3 (2.9 Bcf). The only confident way to define these reserves will be by a long-term production test (~12 months). A production flow test was conducted over the period 6 March to 30 June 2011 and another extended production test in December 2011 for 7 days. It was shut in until October 2012. In November 2012, the field produced 2.8 kL (17.6 bbl) of condensate and 244 km^3 (8.6 MMcf) of gas. It was shut in again between December 2012 and March 2013. Since April 2013, this field has been put on extended production test again. It was still on production in August 2014.

PETROLEUM EXPLORATION, PRODUCTION AND DEVELOPMENT

Redback Terrace

The Origin-operated Redback gasfield (L11), located approximately 2.2 km northeast of the Beharra Springs Gas Plant, was discovered in 2009 following a production test at Redback 2 and Redback South 1. Gas is reservoired in the Wagina Sandstone and is similar in composition to the Beharra Springs gasfield. Production testing was extended in 2014 to obtain further data and better understand the reservoir. At present, Redback field is the largest gas producer onshore WA, with a cumulative total of 450 Mm^3 (16 Bcf) of gas produced as at 31 December 2013.

Red Gully

The Red Gully Gas and Condensate Facility in the northern Perth Basin is operated by Empire Oil and Gas and processes hydrocarbons from the Gingin West and Red Gully gasfields. Facility commissioning commenced in May 2013. Gas is reservoired in the Cadda Formation and Cattamarra Coal Measures. Gingin West 1 had the largest gas flow in the area and is the closest discovery to the Perth metropolitan area. The facility has an initial operational processing capacity of up to 0.3 Mm^3/d (10 MMcf/d) of gas and 79 kL/d (500 bbl/d) of condensate. This could be doubled with an additional train. Gas is transported in the DBNGP, approximately 2.8 km away via a 3.2 km export pipeline. Empire estimates recoverable gas resources at 849 Mm^3 (30 Bcf) and condensate of 238–318 ML (1.5–2 MMbbl).

Warro

The Warro Gas Project is contained within Exploration Permits EP 407 and EP 321. Warro 1 was drilled in 1977 by WAPET and intersected a substantial gas column. Follow-up drilling at Warro 2 confirmed a 390 m gas column. The Warro gasfield is estimated to contain a P50 recoverable resource of 31 Gm^3 (1.1 Tcf) in the Yarragadee and Cadda Formations. The field is 31 km from both the Dampier-to-Bunbury and Parmelia pipelines, which provide easy access to gas consumers both to the north and the south of the field. Warro is partly funded by Alcoa, which has taken up to a 65 per cent stake in the Warro field in return for spending up to A$100 million on appraisal and development activities. Transerv Energy has retained a 35 per cent stake in the field and is the current operator. Applications for Retention Leases have been received covering the Warro field.

Domestic Gas Sourced From LNG Projects

Domestic Gas Reservation Policy

In the past, the WA Government has used State Agreements to facilitate domestic gas reservation requirements. State Agreements are essentially contracts between the Government and proponents of major resource projects that are ratified by an Act of Parliament. For example, domestic gas commitments can be found in the State Agreements for both the North West Shelf Project and the Gorgon Project.

In 2006, the State Government announced a policy requiring that future developers of export gas projects set aside 15 per cent of the reserves in each gasfield for domestic use within the State. This policy replicated the initial State Agreement for the North West Shelf Project, and was intended to secure the State's long-term energy needs. The equivalent of 15 per cent of Liquefied Natural Gas (LNG) production from export gas projects will now be required to be reserved for domestic use as a condition of access to WA land for the location of processing facilities.

The target of 15 per cent reflects current estimates of future gas needs, estimated gas reserves and forecast LNG production. As these estimates could change over time the target will be subject to periodic review.

The policy contains flexibility, allowing negotiations between the State and LNG project proponents to occur on a case-by-case basis regarding the method by which proponents fulfil their domestic gas commitments, including from alternative sources.

More than half of the new domestic gas processing capacity under construction is the direct result of domestic gas reservation, namely Gorgon (300 TJ/d) and Wheatstone (200 TJ/d). Without domestic gas reservation, it is likely that neither of these projects would supply the WA market (Domgas Alliance, 2013).

North West Shelf Gas Project

The North West Shelf Joint Venture (NWSJV) was Australia's largest natural resource development until the Gorgon Project achieved Final Investment Decision (FID) (see below). It is located about 130 km north of Karratha in northwestern Australia in Commonwealth waters. It produces LNG, condensate and oil for export and gas for Western Australia's domestic market from its vast offshore fields. Gas and condensate are produced from the North Rankin, Goodwyn, Perseus–Athena, Angel, Searipple and Echo–Yodel fields via the Goodwyn and North Rankin production platforms. The gas is then transported by two subsea pipelines to the NWSJV onshore gas plant at Withnell Bay on the Burrup Peninsula 20 km north of Karratha. The plant currently produces LNG, natural gas, Liquefied Petroleum Gas (LPG) and condensate.

In June 2005, the Woodside-operated NWSJV announced it would proceed with its A$2 billion Phase 5 expansion to increase production capacity to 16.3 Mt of LNG a year. First LNG deliveries from Train 5 occurred in September 2008.

The A$1.6 billion Angel project has a platform over the Angel field operated remotely from the North Rankin platform and tied into the first trunkline to shore. Angel started production in October 2008.

The North West Shelf Project currently supplies 54 per cent of the gas for the domestic market.

Gorgon Project

The Gorgon Project is operated by Chevron. It is a joint venture of the Australian subsidiaries of Chevron (approximately 47.3 per cent), ExxonMobil (25 per cent), Shell (25 per cent), Osaka Gas (1.25 per cent), Tokyo Gas (one per cent) and Chubu Electric Power (0.417 per cent). The Gorgon Project will develop the Gorgon and Jansz/Io gasfields, located within the Greater Gorgon Area, about 130 km off the northwest coast of Western Australia, and will apply new technology to sequester the CO_2 produced from the gasfields into the Dupuy Formation under Barrow Island. The project includes the construction of a 15.6 Mtpa LNG plant on Barrow Island and a domestic gas plant. While the focus has been on producing LNG for export from the Greater Gorgon Area gasfields, which contain about 1326 Gm^3 (40 Tcf) of gas, and injecting the produced CO_2 into the Dupuy Formation, the Gorgon Project will also progressively provide up to 300 TJ/d of domestic gas to Western Australia. This gas will be delivered through a tie in to the existing DBNGP, with delivery of 150 TJ/d, for the first six months, expected to begin in mid-2015.

Pluto Project

Woodside's Pluto Project is the first project to fall under the Domestic Gas Reservation Policy. While Pluto is subject to a 15 per cent domestic gas reservation commitment, the obligation to supply only arises five years after first LNG exports (which commenced in 2012) and only if commercially viable. Woodside produces the Pluto gasfield to the Burrup LNG Park on the Burrup Peninsula. The Pluto field was discovered in April 2005 and has been producing since April 2012. The field is in the Carnarvon Basin, in Production Licence WA-34-L about 190 km northwest of Karratha and is owned 90 per cent by Woodside, with a 5 per cent interest each to Kansai Electric and Tokyo Gas. Water depth at the field ranges from about 400 m to about 1 km. The field is estimated to contain 130 Gm^3 (4.6 Tcf) of dry gas in the Upper Triassic Mungaroo Formation. A smaller field, Xena, has also been discovered in this permit, with an estimated 14.1 Gm^3 (0.5 Tcf) of dry gas.

The development includes an offshore production system, offshore platform and a pipeline of about 200 km to the new onshore Burrup LNG Park. The Burrup LNG Park includes a gas processing plant, storage facilities and an export jetty. The LNG plant has a production capacity of 5–6 Mtpa.

Wheatstone Project

The Wheatstone Project will include an onshore facility located at Ashburton North Strategic Industrial Area, 12 km west of Onslow in Western Australia's Pilbara region to process gas from the Wheatstone and Iago fields operated by Chevron, and Julimar and Brunello fields operated by Apache. The foundation project will include two LNG trains with a combined capacity of 8.9 Mtpa and a domestic gas plant. The Western Australian Government has negotiated with Chevron and its joint venture partners to formalise the implementation of the Western Australian Domestic Gas Policy for gas feeding into the Wheatstone Project for domestic use. Wheatstone will provide up to 200 TJ/d into the domestic market commencing in 2016.

Infrastructure

Western Australia has significant established infrastructure including modern seaports, and international airports to support its abundant and reliable supplies of energy. Western Australia has several major pipelines to deliver natural gas from offshore or onshore processing facilities to the State's industrial, mining and domestic markets.

Pipelines

The petroleum pipeline industry in Western Australia is largely linked with the development of major petroleum production projects and energy intensive industries. Natural gas was first supplied to domestic and industrial consumers from the Dongara field in 1970 through the Parmelia pipeline. As at July 2014, there are 120 Pipeline Licences (live titles) in WA, covering a total pipeline length of more than 8680 km, in addition to a significant quantity of flowlines and gas lift lines constructed within production facilities in the State.

The **Dampier to Bunbury Natural Gas Pipeline** *(DBNGP)* runs entirely underground and is the longest natural gas pipeline in Australia, at 1789 km. There are ten compressor stations located at approximately 150 km intervals along the length of the pipeline; these stations provide the pressure needed to move the natural gas. The DBNGP has undergone several expansions, the most recent saw the construction of 11 loops that required 440 km of parallel pipe to be installed along almost 1600 km of the route, effectively creating a second pipeline.

The **Goldfields Gas Transmission** (GGT) pipeline is a 1426 km natural gas pipeline that transports gas from the Carnarvon Basin and Northwest Shelf producers to mining customers in the Pilbara, Murchison and Goldfields mining regions of Western Australia for industrial use and power generation. The second longest pipeline in Western Australia, it services a number of mines between Yarraloola in the Pilbara and Kambalda along with the township of Kalgoorlie. The pipeline also transports gas to the 340 km **Kambalda to Esperance Pipeline** (separately owned) for the Esperance region. The GGT assets include maintenance bases at Karratha, Newman, Leinster and Kalgoorlie. Four compressor stations have been installed to boost the capacity of the GGT.

The **Parmelia Gas Pipeline** (PGP) is a 364 km long pipeline that transports gas from both the Perth Basin gasfields at Dongara, south of Geraldton, and the Carnarvon Basin fields via the Dampier to Bunbury pipeline, to industrial markets in the wider Perth area. The Parmelia Gas business includes the Mondarra storage facility near Dongara.

The **Pilbara Energy Pipeline** (PEPL) is a 215 km pipeline connecting the Carnarvon Basin with power stations located in Karratha and Port Hedland, as well as industrial and mining operations in the Pilbara region that are located on the Port Hedland to Telfer gas pipeline. The 24 km Burrup Extension Pipeline connects the PEPL to Woodside's North West Shelf processing plant at Dampier. The 80 km Wodgina Lateral connects PEPL to the Sons of Gwalia tantalum mine at Wodgina.

The **Mid West Pipeline** transports gas from the Dampier to Bunbury Pipeline near Geraldton (Eradu) to power generators for mining processes in the Windimurra and Mt Magnet region. The **Telfer Gas Pipeline** extends for 422 km from the end of the Pilbara Energy Pipeline at Port Hedland to the Telfer Mine.

The **Kalgoorlie Kambalda Pipeline** transports gas from the Kalgoorlie South outlet from the Goldfields Gas Pipeline to Kambalda.

The **Macedon Domgas Pipeline** consists of a subsea pipeline from the Macedon gasfield (100 km west of Onslow) to bring gas to shore, a 15 km wet gas pipeline which connects from the shoreline crossing to the onshore gas treatment and compression plant at Ashburton North (15 km southwest of Onslow), and a 67 km domestic sales gas pipeline connects the onshore facility to the DBNGP.


Construction of the LNG plant on Barrow Island for the Gorgon Project is continuing through 2014 with first gas expected in mid-2015 (photo courtesy of Chevron Australia)

PETROLEUM EXPLORATION, PRODUCTION AND DEVELOPMENT

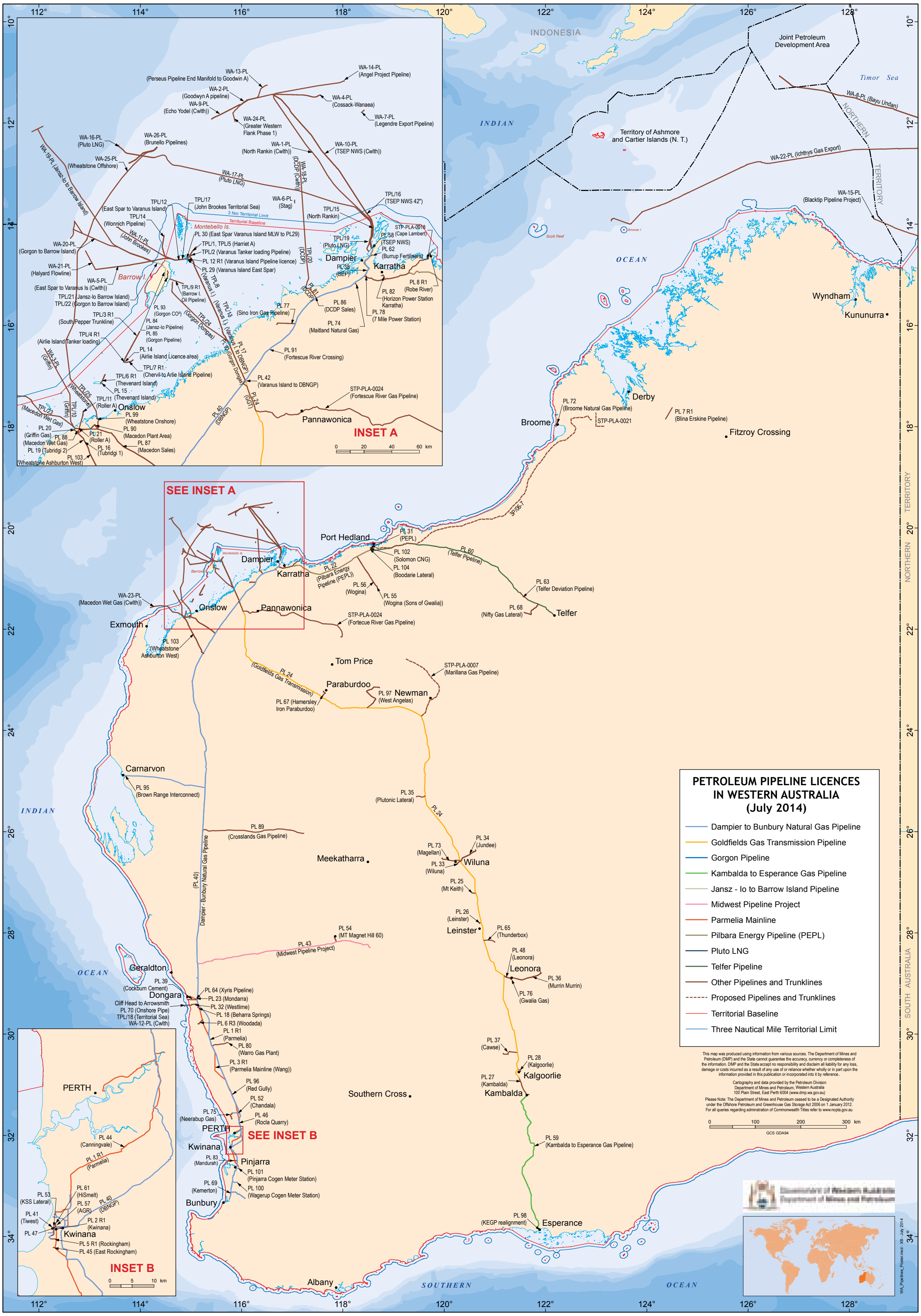

Figure 8. Petroleum pipeline licences in Western Australia as at August 2014

Under construction is the **Gorgon Domgas Pipeline** which will transport gas from the Gorgon Project to a connection to the DBNGP near its compressor station 1.

Under construction is the **Wheatstone Ashburton West Pipeline** which will transport gas from the Wheatstone Project to a connection to the DBNGP near its compressor station 2.

The major pipelines within Western Australia are shown in Figure 8.

Mondarra Gas Storage Facility

The Mondarra Gas Storage Facility near Dongara is located adjacent to the two pipelines servicing Perth and the South West, including APA's Parmelia Gas Pipeline. Wholly owned by APA Group, the Mondarra Gas Storage Facility is currently the only commercial underground gas storage facility in Western Australia. In response to peak gas demand, APA has expanded this facility.

Gas Processing Plants

The Karratha Gas Plant processes gas for the North West Shelf Venture. Located 1260 km north of Perth, the plant includes five LNG processing trains, two domestic gas trains, six condensate stabilisation units, three LPG fractionation units, and storage and loading facilities for LNG, LPG and condensate. The plant has the capacity to produce 16.3 Mtpa of LNG, 600 TJ/d of domestic gas and 20,668 kL (130,000 bbl) per day of condensate.

The Varanus Island Processing Hub was built in 1987. The facility produces around 1271 kL/d (8000 bbl/d) of oil and 375 TJ/d of gas and accounts for more than one third of the estimated 28,316,846 m^3/d (1 Bcf/d) of gas consumed in the State of Western Australia.

The Devil Creek Gas Plant was the State's third domestic natural gas processing hub and the first new plant in more than 15 years. It was commissioned in 2012. The two train plant is designed to process 5.6 Mm^3/d (200 MMcf/d) of gas from the Apache-operated Reindeer field.

The Macedon Gas Plant, built for BHP Billiton at Onslow, was commissioned in 2013, with first gas on 16 August. The plant was officially opened in September 2013. The plant has a production capacity of up to 200 TJ/d and will supply 20 per cent of Western Australia's domestic gas for consumers and industry. Gas from the Macedon plant is exported to the DBNGP for sale into the WA market.

James Price Point was initially selected as the preferred location for the Browse LNG development which includes the Torosa, Brecknock and Calliance fields. It is located approximately 42 km north of Broome. This proposal failed to achieve FID and the Woodside led Joint Venture is reviewing the commerciality of a FLNG development. Compulsory acquisition of James Price Point by the WA State Government has been completed and the Government intends for it to be developed into a supply base and a gas processing hub in future.

Reference

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Western Australia has a network of pipelines to provide gas to industrial sites and the domestic market

Strike ridges of latest Neoproterozoic to early Cambrian Ellis Sandstone, western Amadeus Basin

Amadeus Basin

The Amadeus Basin is exposed over about 170,000 km^2 in central Australia. The majority of the basin lies within the Northern Territory (NT), but about 30,000 km^2 extends into Western Australia (WA). Whereas the eastern part of the basin is relatively accessible, well studied, and has an existing petroleum industry infrastructure, the western portion is poorly explored and access is difficult. Unsealed highways (Great Central Road and Gary Junction Road) lie along the southern and northern margins of the WA Amadeus Basin, linked near the WA–NT border by the north–south oriented Sandy Blight Junction Track (Figure 9).

Geological Setting

The Amadeus Basin overlies Paleo-to Mesoproterozoic metamorphic and igneous basement domains of the Arunta Province (north) and Musgrave Province (south), and locally contains up to 14 km of Neoproterozoic and Paleozoic sedimentary rocks (Figure 10). It is overlain to the west by late Paleozoic (Permian) rocks of the Canning Basin. Remnants of a latest Mesoproterozoic sedimentary and volcanic rift phase are also present locally, but by definition are excluded from the Amadeus Basin succession. The present basin margins are mainly of tectonic origin, the Neoproterozoic component of the Amadeus Basin being one of several remnants of the hypothetical Centralian Superbasin. This is perceived as a much larger intracratonic depositional system that was progressively fragmented by major convergent tectonic events including the latest Neoproterozoic to earliest Paleozoic Petermann Orogeny, and the mid to late Paleozoic Alice Springs Orogeny.

The sedimentary fill of the Amadeus Basin is mainly of shallow-marine origin, apart from significant fluvial clastic wedges shed from the uplifted basin margins during orogenic events. A widespread salt unit within the Gillen Member of the Bitter Springs Formation, near the base of the Neoproterozoic succession, has exerted significant influence over the structural style of the basin via halotectonics. The remainder of the Neoproterozoic succession comprises alternating carbonates and fine to coarse siliciclastics, including two widespread glacial phases that can be correlated throughout the Centralian Superbasin and Adelaide Rift Complex.

During the Cambrian, shallow marine conditions prevailed in the east, including the deposition of abundant carbonates and a significant Lower Cambrian salt unit, with thick, marginal marine to non-marine clastics in the west. In Western Australia, the stratigraphic extent of Cambrian sedimentation is uncertain in the absence of biostratigraphic data. The thick, predominantly clastic, shallow-marine Larapinta Group (latest Cambrian to Ordovician) is almost entirely restricted to the Northern Territory part of the basin. Small outcrops mid-Ordovician in age are known in Western Australia, but on present evidence appear to be very thin and localised. All Silurian and Devonian strata are of non-marine (fluvial and eolian) origin, and reflect repeated uplift events and clastic input, culminating in the Alice Springs Orogeny. This succession is likely preserved in Western Australia, but its distribution is uncertain due to the absence of chronostratigraphic data.

Figure 9. The Amadeus Basin in Western Australia and Northern Territory, showing exploration wells, fields, and pipelines

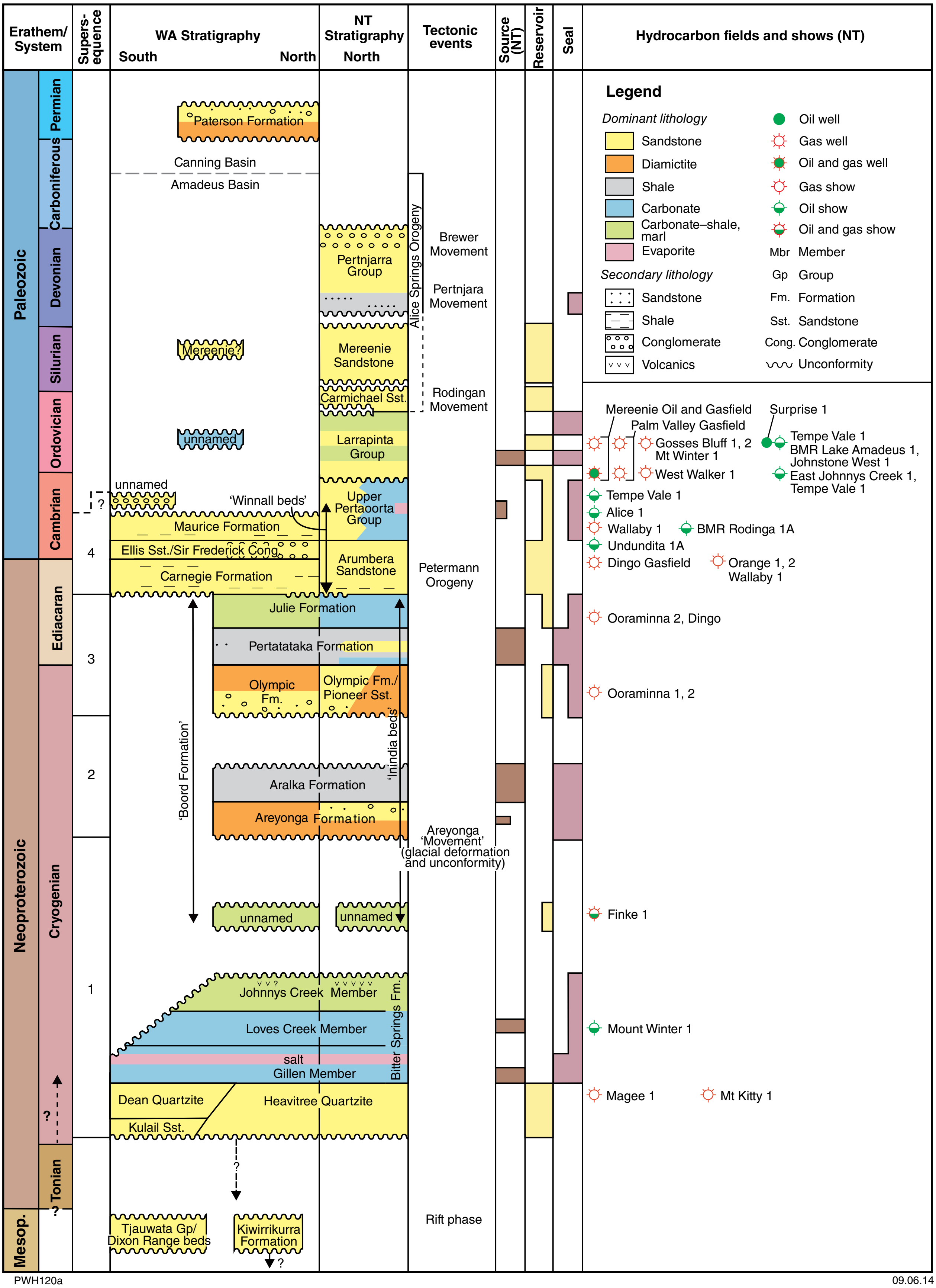


Figure 10. Stratigraphy, tectonic events, and hydrocarbon systems of the Amadeus Basin. Western Australian stratigraphy is compared with the northern Amadeus Basin stratigraphy of the Northern Territory. Source rock intervals are based on Northern Territory data. Exploration drilling is restricted to the Northern Territory

The basin fill is folded into predominantly east–west oriented synclines and anticlines, with many of the latter likely salt cored, and there is evidence of large scale thrusting over decollement surfaces in the Gillen Member salt. Thinning of stratigraphy onto some anticlines is evidence for growth of that anticline during deposition. Unlike the well-studied northeastern part of the basin where the Alice Springs Orogeny was the most important tectonic event, the Petermann Orogeny was apparently the most significant event in Western Australia. Although there is considerable sand cover in the Western Australian part of the basin, structural trends can be mapped using geophysics, particularly the available aeromagnetic data. Structural trends from the Amadeus Basin can be carried west for some distance beneath the thin cover of the Canning Basin.

Exploration History

Petroleum exploration in the Amadeus Basin has been almost entirely restricted to the better studied and more accessible Northern Territory portion. The first exploration well was drilled in 1963, with the large Mereenie oil- and gasfield and Palm Valley gasfield being discovered in 1964 and 1965, respectively. Both fields have been producing since the mid-1980s, via an oil pipeline to Alice Springs and gas pipelines to Alice Springs and Darwin. Early exploration was focused on prominent surface anticlines, with later exploration focusing on seismically defined targets beneath cover. Other discoveries include the Dingo gasfield (discovered 1981), and significant shows have been encountered in other wells. The Dingo gasfield is now operated by Central Petroleum Pty Ltd and proposed to commence production in 2015, supplying gas via pipeline to the Alice Springs power station. When this happens it will be the first commercialisation of Precambrian reservoired hydrocarbons in Australia.

No exploration wells have been drilled in Western Australia. Beach Petroleum NL held PE 153 H over much of the Western Australian Amadeus Basin in the 1960s, but the title was farmed out to Australian Aquitaine Petroleum in 1965; the work by Australian Aquitaine included outcrop studies and some shallow stratigraphic drilling, although no reports of the latter are held by the Geological Survey of Western Australia (GSWA).

Two lines of the Hickey Hills seismic survey, shot for Australian Aquitaine in 1972, lie in the area west of the surficial Canning Basin – Amadeus Basin boundary, where Amadeus Basin rocks are interpreted to lie beneath those of the former basin at relatively shallow depths (a few hundred metres or less); however, this seismic data is of very poor quality. More recently, Central Petroleum Ltd held SPA 7/04-5 AO over most of the Western Australian Amadeus Basin to conduct an airborne geophysical survey. The recent oil discovery of Surprise 1 by Central Petroleum, located about 100 km east of the WA/NT border, shows that new fields continue to be discovered. Surprise 1 commenced production in March 2014 and is producing oil at a rate of 35 kL/d (220 bbl/d).

Petroleum Prospectivity

Studies of the Northern Territory portion of the Amadeus Basin have identified at least four petroleum systems. The youngest, the Ordovician Larapintine petroleum system, is associated with the large, producing Palm Valley gasfield and the Mereenie oil- and gasfield, and is responsible for significant shows elsewhere across the northern half of the basin. However, this petroleum system is not considered to be prospective in the Western Australian Amadeus Basin because Ordovician strata are thin, only locally preserved, and the Horn Valley Siltstone source unit is not recognised west of the border. The older petroleum systems are all related to Neoproterozoic sources. These systems are associated with one gasfield proposed to come on stream in 2015 (Dingo) and significant oil and gas shows in a number of wells, and are the target of ongoing exploration in the Northern Territory.

The oldest petroleum system involves gas prone source rocks in the lower Gillen Member of the Bitter Springs Formation. Sandstone of the underlying Heavitree Quartzite, or its equivalents, is perceived as the most likely reservoir, whereas a widespread salt unit in the upper Gillen Member provides a seal. This 'Gillen petroleum system' has been tested by two wells, Magee 1, which flowed 1784 m^3 (63,000 cf) of gas per day from a thin (6 m), and relatively tight, sandstone equated with the Heavitree Quartzite, and Mt Kitty 1, which flowed 14,158 m^3/d (500,000 cf/d) over 19 m, but is yet to be fully tested. The presence of 6.2 per cent basement sourced helium in Magee 1, as well as 9 per cent helium in Mt Kitty 1, attests to the integrity of the salt seal, and has further economic implications for the system. The lateral distribution of the Gillen petroleum system is poorly constrained. The Gillen Member, with evidence of contained salt, has recently been confirmed in Western Australia by GSWA fieldwork.

The second Neoproterozoic petroleum system, lying above the Gillen Member salt seal, involves potential source rocks in the upper Bitter Springs, Areyonga, and Aralka Formations, plus correlatives within the Inindia beds in the south. Source intervals in the Loves Creek Member of the Bitter Springs Formation are mainly oil prone (total organic carbon (TOC) $\leq$1.1%), whereas black shales of the Aralka Formation are mainly gas prone (TOC$\leq$3.4%).

This system is likely responsible for gas flows in the Ooraminna 1 and 2 wells (the latter flowed 4304 m^3 (152,000 cf) of gas per day from the tight Pioneer Sandstone), and oil shows in Mount Winter 1 and Finke 1. Finke 1 contains a probable paleo-oil column, based on grain fluorescence studies conducted by the Commonwealth Scientific and Industrial Research Organisation (CSIRO).

The third Neoproterozoic petroleum system involves source rocks in the shaly Pertatataka Formation (TOC $\leq$1%, gas and oil prone), with the latest Neoproterozoic to Cambrian Arumbera Sandstone as a reservoir. This system is most convincingly demonstrated in the Northern Territory by the Dingo gasfield (0.37 Gm^3 or 13 Bcf gas), and gas shows at the same level in Orange 1 and 2. The Pertatataka Formation has recently been confirmed in the Western Australian part of the basin, and thick equivalents of the Arumbera Sandstone, including the Carnegie Formation, may provide a suitable reservoir, although an overlying seal is problematic.

In the absence of drillhole information, the source and reservoir potential, and maturity of rocks, within the Western Australian Amadeus Basin remains speculative. However, the recent recognition that the stratigraphy and facies of the Western Australian Amadeus Basin have much more in common with the eastern succession than previously thought raises the possibility that some, or all, of the Neoproterozoic petroleum systems and plays may be present.

Bonaparte Basin

The Bonaparte Basin, consisting of the Northern Bonaparte and Southern Bonaparte Basins, is the most northerly sedimentary basin in Western Australia, straddling the border between the Northern Territory and Western Australia. Most of the basin is offshore, covering 250,000 km^2 compared to just over 20,000 km^2 onshore (Figure 11).

To date, offshore production development has relied on stand-alone infrastructure, such as those established since the 1980s at Challis–Cassini, Jabiru, Laminaria, Corallina, and Blacktip. A combined development plan for the Petrel, Tern and Frigate gasfields has been proposed but is yet to be approved.

Geological Setting

The Bonaparte Basin adjoins the Browse Basin to the west and the Money Shoals Basin to the northeast. The Timor Trough defines its northern boundary. The basin developed as a v-shaped, north-opening rift during the Devonian to Early Carboniferous. Exploration in the area defined a sedimentary succession that dips regionally to the north, with the oldest strata outcropping in the south. The dominant structural element of the basin is the north-northwesterly-oriented Petrel Sub-basin, which preserves up to 17 km of Paleozoic to Cenozoic sedimentary fill. This sub-basin contrasts with the northern sub-basins (the Ashmore and Sahul Platforms, Vulcan Sub-basin, Londonderry High, and Malita Graben), where the predominantly northeasterly fault trends lie orthogonal to those of the Petrel Sub-basin, and the sedimentary fill is dominantly Mesozoic to Cenozoic. This change in orientation is related to the Late Jurassic breakup of Gondwana.

In the Southern Bonaparte Basin, two periods of sediment deposition are recognised (Figure 12). The initial period (Late Devonian to Early Carboniferous) was associated with the remnants of a rift system controlled by numerous north-northwesterly-oriented normal faults. During the second period, Upper Carboniferous and younger sedimentary rocks draped the earlier rift blocks and onlapped Proterozoic rocks, forming the flanking shelves. This latter part of the succession is relatively unfaulted. In the northern part of the basin, where the structural configuration is dominated by the Late Jurassic breakup that formed northeasterly oriented fault blocks, the oldest part of the succession known from drilling is Late Permian in age. However, the presence of an even older section is indicated by rare salt-related structures similar to those at the southern end of the Petrel Sub-basin.

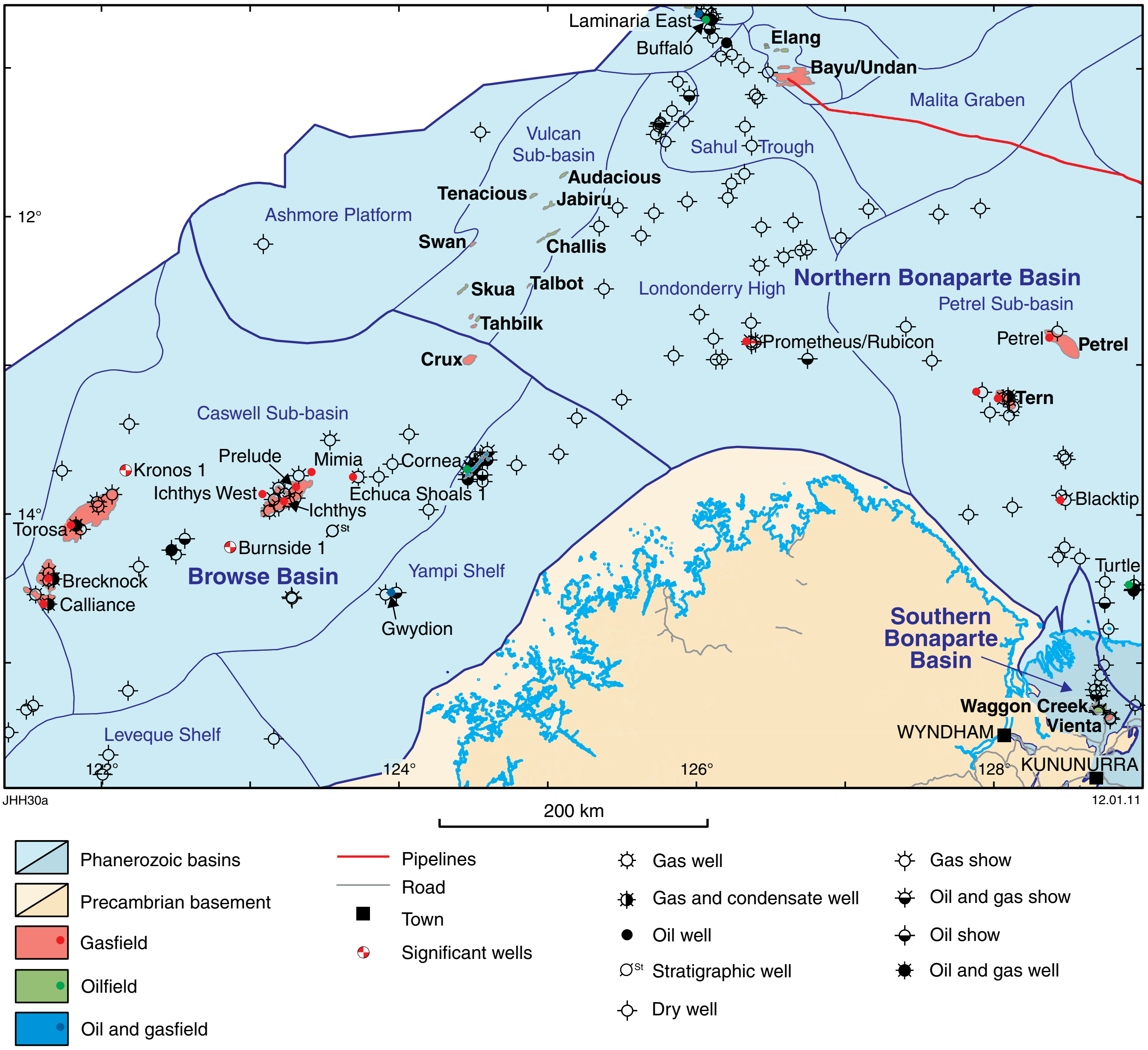


Figure 11. The Bonaparte Basin, showing tectonic units, exploration wells, pipelines and petroleum fields

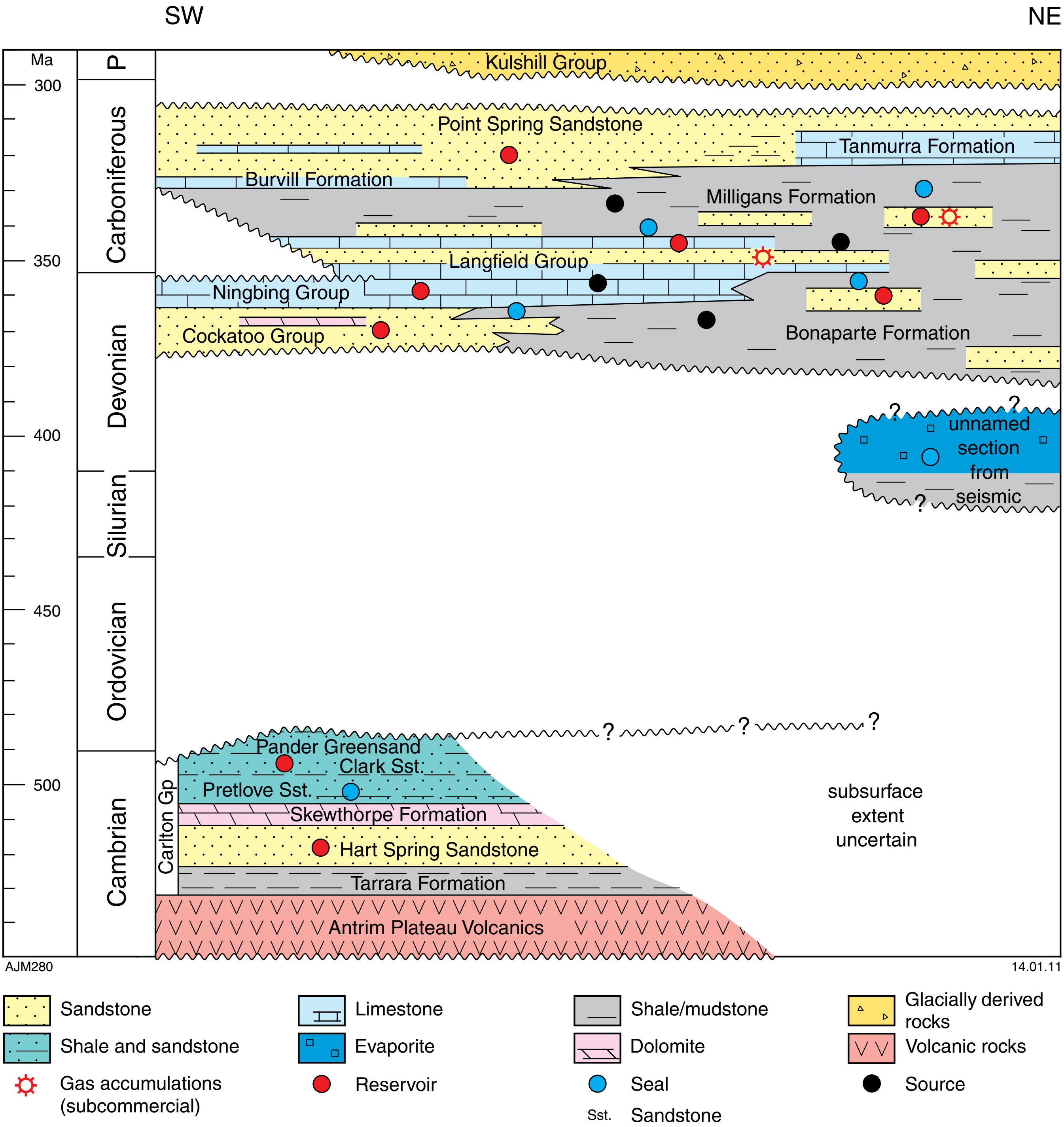


Figure 12. Stratigraphy and petroleum systems of the onshore Bonaparte Basin

PETROLEUM PROSPECTIVITY OF WESTERN AUSTRALIA'S SEDIMENTARY BASINS

In the Cenozoic, a prograding wedge of carbonates was deposited across the western passive margin of Australia, including the Bonaparte Basin. Middle Miocene collision with the Indonesian Plate to the north rejuvenated faults and produced small anticlines.

Exploration History

Petroleum exploration of the Bonaparte Basin commenced in the late 1940s, with reconnaissance work in the onshore area. In 1963, Bonaparte 1, the first well in the Western Australian portion of the basin, was spudded by Alliance Oil Developments. Since then, 92 offshore and 12 onshore wells have been drilled in the Western Australian area. Seismic exploration in the Western Australian Bonaparte Basin to date includes more than 200,000 line km of 2D and 19,084 km^2 of 3D seismic offshore and 6650 line km of 2D onshore.

Petroleum Prospectivity

The prospectivity of the Bonaparte Basin is evident from known oilfields and gasfields, particularly those in the northwestern Timor Sea. Subcommercial gas accumulations in lower Paleozoic strata indicate that even the older sedimentary rocks have hydrocarbon potential.

Onshore, the units considered mostly likely to generate hydrocarbons are the predominantly shaly Lower Carboniferous Milligans Formation (TOC up to 2.2%, and S1+S2 up to 4.5 mg/g rock) and the Upper Devonian Bonaparte Formation (Figure 12). Vitrinite reflectance measurements suggest that these units are immature to mid-mature in the onshore part of the basin, apart from near the Pincombe Inlier, where Devonian rocks are in the gas generation window, possibly as a result of high heat flow in this area. Gas discoveries in the Western Australian onshore area are Vienta, Waggon Creek and Bonaparte.

In the Western Australian portion of the basin offshore, there are five known gas accumulations (Blacktip, Tern, Petrel, Frigate, and Penguin), two oil and gas accumulations (Buffalo and Laminaria East), inferred currently sub-commercial oil accumulation (Turtle), and several extensive residual oil columns (Avocet, Barita, Drake, and Lacrosse).

The Waggon Creek 1 and Vienta 1 wells underwent abbreviated well tests in 2011. Waggon Creek 1 flowed at a stabilised rate of 30,281 m^3/d (1.07 MMcf/d) from the Lower Carboniferous Milligans Formation.

Potential shale plays and tight gas plays in the onshore Southern Bonaparte Basin include shale gas in the lower Milligans Formation and tight gas sandstone and limestone reservoirs in the Langfield Group. All such plays remain untested in the Bonaparte Basin; to date only Milligans Formation gas sands have successfully flowed gas. Vienta 1 encountered over pressured shales and sandy limestone with high gas saturations in the Langfield Group. Marine shales with up to 2.2% total organic carbon (TOC) have been sampled from wells in the Southern Bonaparte Basin. Limited geochemical data indicates that this part of the basin is mature for wet gas and oil to depths of 1400 m and overmature (dry gas generating) below 1400 m.

Table 1 indicates the reservoirs for the accumulations and shows in the onshore portion of the basin.

Table 1. Oil and gas discoveries in the Western Australian onshore portion of the Bonaparte Basin

YEAR	FIELD/DISCOVERY	OIL/GAS	FORMATION	FORMATION AGE
1963	Bonaparte	gas	Milligans Formation	Early Carboniferous
1995	Waggon Creek	gas and oil	Milligans Formation	Early Carboniferous
1998	Vienta	gas	Ningbing Group Milligans Formation	Late Devonian Early Carboniferous

Browse Basin

The Browse Basin covers an area of approximately 140,000 km^2 and lies entirely offshore, north of Broome. The basin is bounded by the Leveque Shelf in the south, the Kimberley Block to the east, and the Ashmore Platform and Scott Plateau in the north, and grades into the offshore Canning Basin to the southwest. The area can be serviced from Broome and Derby, which have port and air facilities. The economics of development operations in the Browse Basin are often adversely affected by the isolation of the area and by the fact that the majority of the basin lies in waters more than 200 m deep (Figure 13). Currently the only State interests in the Browse Basin are associated with the Torosa gasfield over Scott Reef as it has Retention Leases TR/5 (regulated under the PSL Act) and R2 (regulated under PGER Act). The recent discovery of small islands in the Scott Reef area by Geoscience Australia may lead to a revision of the boundaries between WA and Commonwealth jurisdictions, resulting in the WA administered area increasing.

Geological Setting

The Browse Basin, which forms part of the Westralian Superbasin, is a northeast-trending depocentre containing up to 15 km of Paleozoic to Cenozoic sediments. The oldest sediments in the basin, assumed to be Permian in age, are identified along the southeastern basin margin in the Rob Roy 1 and Yampi 1 wells, suggesting that sedimentation commenced during rift initiation along the North West Shelf.

The sedimentary succession of the Browse Basin is divided into two episodes, Late Permian to Jurassic, and Late Jurassic to Cenozoic (Figure 14), with a regional Jurassic unconformity terminating the first episode. The sediments below this unconformity are substantially block-faulted and buried to approximately 4000 m.

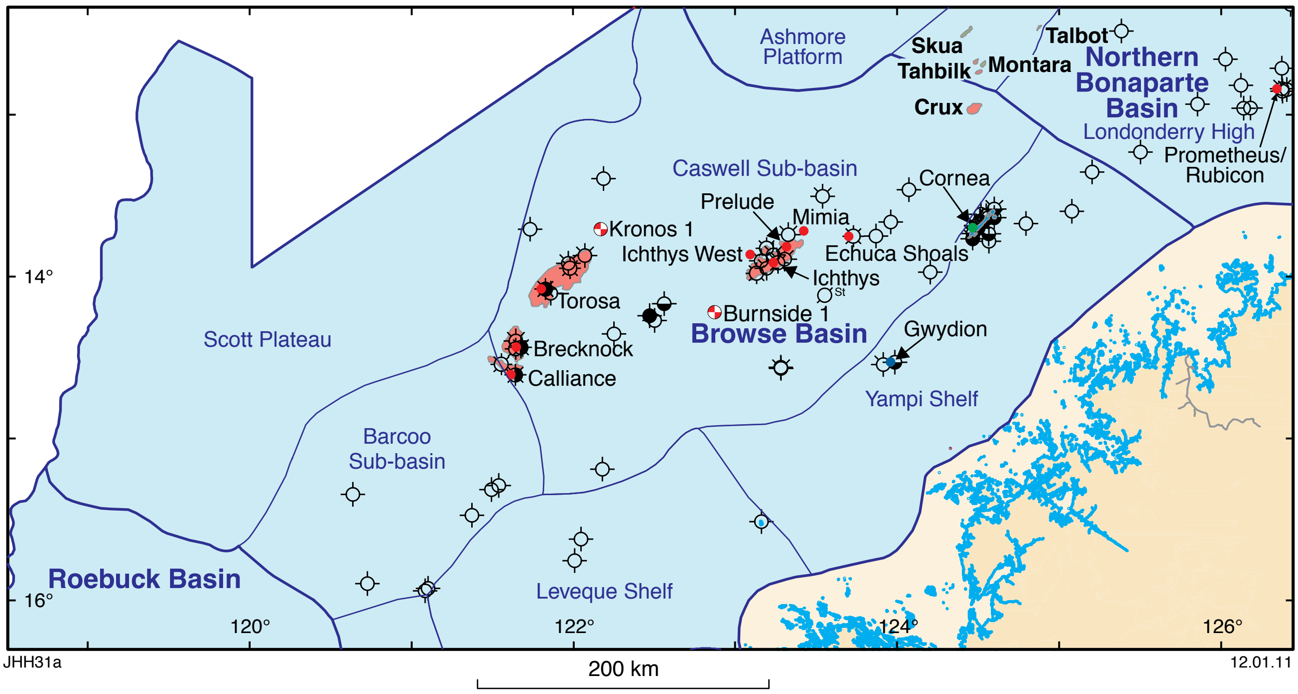
Following the breakup of Gondwana, the North West Shelf as a whole, and the Browse Basin in particular subsided, ending the existence of the Browse Basin as a separate entity, as it merged with the Westralian Superbasin. Up to 4000 m of relatively undisturbed Upper Jurassic to Cenozoic marine sediments were then deposited above the main Jurassic unconformity. Minor fault reactivation, fault reversal, and broad spectrum parasitic anticline development resulted from the subsequent Late Cenozoic collision of the Eurasian and Australasian plates.

Exploration History

Exploration commenced in the Browse Basin in 1967, when Burmah Oil Company Australia Ltd (BOCAL, now Woodside) acquired 1600 km of regional seismic data. Since that time, over 180,000 km of 2D and 46,000 km^2 of 3D seismic data has been acquired, some of which is now on open file.

The fourth well drilled in the basin, Scott Reef 1 (completed in 1971), was significant in discovering Australia's potentially largest gasfield (now named Torosa) (Table 2). Since then, a further 102 wells have been drilled and there have been 19 hydrocarbon discoveries. Recent discoveries include the Toccata, Fortissimo, Ichthys North, Ichthys West, Poseidon, Mimia, Burnside and Kronos wells.

Although the combined gas reserves of these fields total over 900 Gm^3 (33.4 Tcf), none has been developed, mainly as a result of their isolated location, almost 300 km from the mainland, in waters 300–500 m deep. Final investment decision (FID) has been achieved for the Prelude (2011) and Ichthys (2012) gas-condensate fields but is delayed for the Brecknock, Calliance and Torosa fields.



Phanerozoic basins
Precambrian basement
Gasfield
Oilfield
Oil and gasfield
Pipelines
Road
Town
Significant wells
Gas well
Gas and condensate well
Oil well
Stratigraphic well
Dry well
Gas show
Oil and gas show
Oil show
Oil and gas well

Figure 13. The Browse Basin, showing tectonic units, exploration wells and petroleum fields

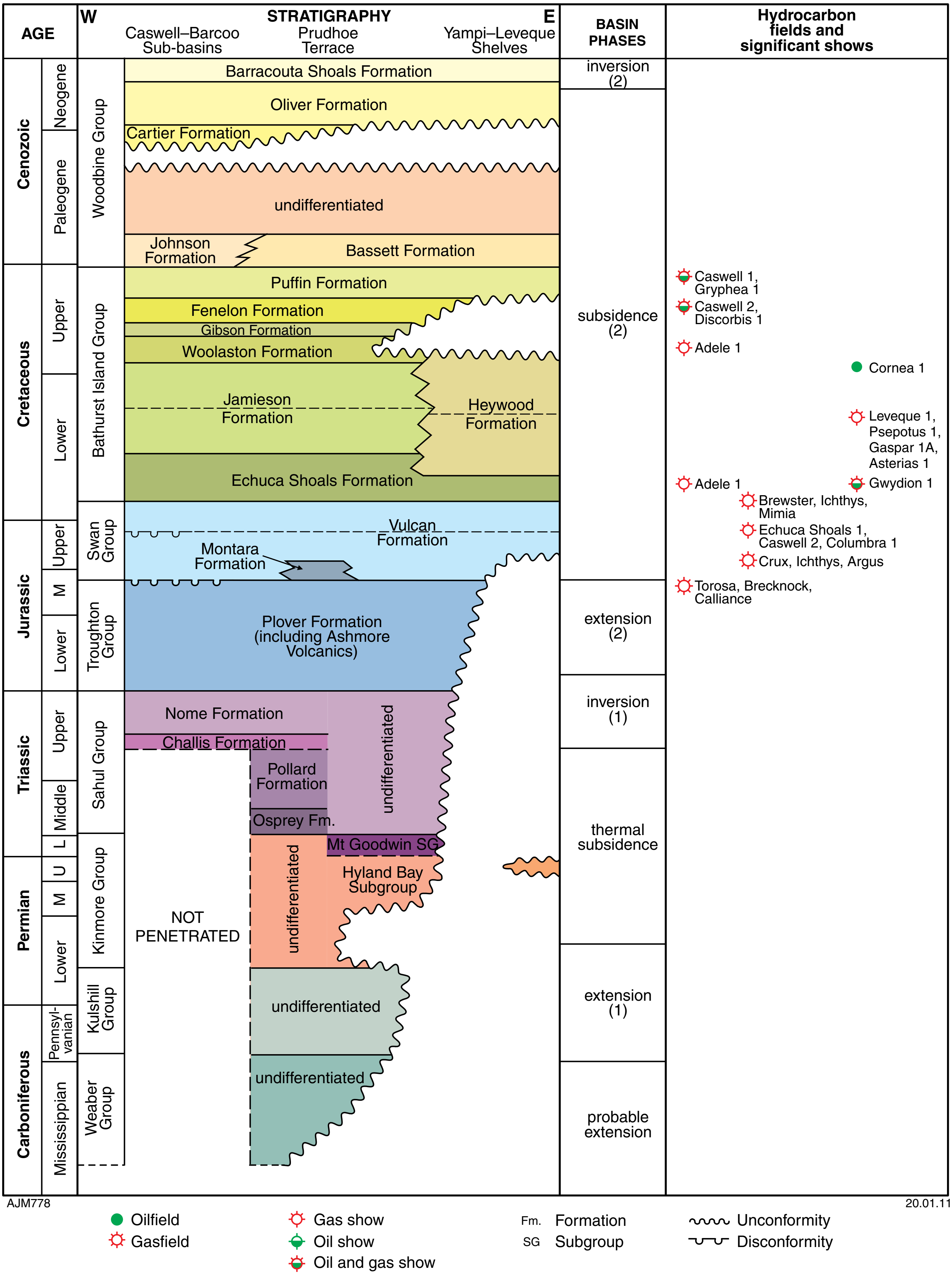


Figure 14. Stratigraphy, depositional settings, and petroleum geology of the Browse Basin

Petroleum Prospectivity

Although the Browse Basin has had limited exploration, the hydrocarbon discovery rate is extremely favourable. Reservoirs are identified at depths of between 4000 and 5000 m, or between 3000 and 3500 m on the basin margins, where stratigraphic play concepts may be valuable. Several structures and potential stratigraphic plays remain undrilled in the basin. The logistics of operating in such a remote area and within deep water are major hindrances to economic discoveries. As such, the Browse Basin is considered both a high-risk and high-reward area.

Table 2. Oil and gas discoveries in the Browse Basin in which the State holds an interest

YEAR	FIELD/DISCOVERY	OIL/GAS	FORMATION	FORMATION AGE
1971	Scott Reef (Torosa)	gas	Plover Formation	Middle to Lower Jurassic

Drilling in the Browse Basin (photo courtesy of Woodside Energy Ltd)

PETROLEUM PROSPECTIVITY OF WESTERN AUSTRALIA'S SEDIMENTARY BASINS

Canning Basin

The onshore Canning Basin covers an area of about 530,000 km^2 in central-northern Western Australia, and extends offshore for a total basin area of more than 640,000 km^2, of which 110 000 km^2 is in State waters (Figure 15). The succession in the onshore basin ranges in age from Ordovician to Cretaceous, but is predominantly Paleozoic. World-renowned Devonian reefs exposed on the Lennard Shelf in the northeast part of the Canning Basin provide excellent insight into the subsurface carbonate geology. The Blina oilfield produces from these reefs.

Two urban centres, Broome and Derby, have shipping and air support and service the Canning Basin. Broome serves as the shipping terminal for crude oil, while minor pipeline grids lie mainly near Derby. Major roads service parts of the basin, particularly near the coast and along the northern margin, where there are settlements and pastoral leases. Remote drilling locations have specifically prepared roads to facilitate operations. Much of the central and southern areas of the basin remain remote and unsettled, however, with a regional network of unmaintained, or poorly maintained, tracks providing the only access.

The West Kimberley Power Project provides remote area electricity generation. Liquefied natural gas (LNG) from Karratha is trucked to storage facilities in Broome, Derby, Halls Creek, Fitzroy Crossing and Looma. Gas-fired generators provide electrical power for each of these local communities. Initial generating capacity was 61 MW. Buru Energy plans to build the Great Northern Pipeline to transport gas from their Yulleroo and Valhalla discoveries and, to underpin this, has undertaken a Gas Supply Agreement with Alcoa of Australia.

Geological Setting

The Canning Basin initially developed in the Early Paleozoic as an intracratonic sag between the Precambrian Pilbara Craton and the Kimberley Basin (Figure 15). The basin contains two major northwesterly-trending troughs separated by a mid-basinal arch and flanked by marginal shelves. The northern trough comprises the Fitzroy Trough and the Gregory Sub-basin, which are estimated to contain up to 15 km of predominantly Paleozoic rocks. The southern trough includes the Kidson and Willara Sub-basins, which are formed by thinner sedimentary successions (4–5 km thick) of predominantly Ordovician to Silurian and Permian-aged sediments with extensive Mesozoic cover. The central arch is divided into the Broome and Crossland Platforms, with structural terraces that downstep into the troughs on either side. The subdivisions of the basin are based on presently expressed structural elements; however, the troughs developed and were active at different times, with some elements forming through growth faulting.

The basin succession consists of continental to marine-shelf, mixed carbonate and clastic sedimentary rocks (Figure 16). Major evaporitic basins were present from the Late Ordovician to earliest Silurian. Significant tectonic events affected the basin in the Early Ordovician (extension and rapid subsidence), Early Devonian (compression and erosion), Late Devonian (extension and subsidence), Middle and Late Carboniferous–Permian (compression, then subsidence), and Early Jurassic (transpressional uplift and erosion).

The southern Canning Basin is less intensively deformed than the northern part, with major fault block movements absent in the south.

The offshore Canning Basin contains about 6000 m of Permian and younger sedimentary rocks, with a thick Jurassic to Early Cretaceous section.

Exploration History

Petroleum exploration activity began in the Canning Basin in the early 1920s, when the Freney Oil Company encountered asphaltic shows in drillholes on the Lennard Shelf. Minor exploration continued with Associated Australian Oilfields later joining the search in the 1950s, and exploration intensified again in the 1960s and 1970s when the Bureau of Mineral Resources (BMR, now Geoscience Australia) and West Australian Petroleum Pty Ltd (WAPET) conducted gravity, magnetic, and seismic reflection surveys. Since then, 287 onshore

View north of Millijiddee, WA in the Kimberley region of the Canning Basin and 14 offshore wells have been drilled in the region, accompanied by acquisition of 175,591 km of 2D seismic data, of which 89,587 km is onshore and 86,004 km is offshore.

Up until the mid-1980s, exploration largely focused on the northern and central parts of the Canning Basin. Primary exploration targets were Devonian and Permian strata. Many exploration wells had shows, especially of oil, but few yielded commercial hydrocarbons. Oilfields were first discovered on the Lennard Shelf in 1981. The Blina field was discovered first, followed by the Sundown, Lloyd, Boundary, West Terrace, and West Kora oilfields; the Point Torment gas discovery occurred in 1992. The sub-salt Ordovician section was later targeted by companies such as Shell, who, in 1996, recovered hydrocarbons in the southern Canning Basin well Looma 1.

In 2009, Buru Energy completed the first 3D seismic survey in the Canning Basin, the Bunda Survey. Buru Energy conducted a drillstem test on the Yulleroo 2 well in 2010, which flowed gas and condensate to the surface. In 2011 Buru discovered oil in dolomites at Ungani 1, which achieved initial peak flow rates of 254 kL/d (1600 bbl/d) and is currently undergoing further testing. This was the first significant oil discovery in the basin since the 1980s. In the same year, Buru Energy appraised the wet gas accumulation at Valhalla with two wells. Appraisal at Ungani 2 confirmed more oil for Buru and partner Mitsubishi. The Ungani 3D seismic survey was completed in October 2013. To date, Buru has aquired 669.27 km^2 of 3D seismic data.

Table 3 lists producing fields and wells with substantial recoveries in the Canning Basin, as well as a selection of additional wells with flow tests or shows. To summarise, the Canning Basin remains substantially underexplored, with few wells drilled to date, of which only a small percentage serve as valid structural tests.

Petroleum Prospectivity

The Fitzroy Trough and the Lennard Shelf were long considered the most prospective areas of the Canning Basin, owing to their thick sedimentary successions, reefal carbonate buildups along a half-graben hingeline to the north, and structural development in the southwest. Shows in the area confirm petroleum generation and migration.

Other prospective areas of the Canning Basin include the Broome Platform and the Kidson Sub-basin. The Ordovician, subsalt Looma discovery first proved the presence of mature, migrated oil from a source pod in the southern Canning Basin and thereby provided a new exploration play.

In the south of the basin, there is potential for gas generation from the Permian and Ordovician carbonaceous shales and for oil expulsion from shales in the Ordovician Goldwyer Formation.

Potential reservoirs are the Nita Formation (Ordovician), the Devonian reef complexes, the Tandalgoo Formation (Devonian), and Permian sandstones. Salt diapirism is evident in the region and may provide traps in areas that lack major block faulting.

Permian, Triassic, and Jurassic fluvio-deltaic sandstones are considered the primary objectives of the offshore Canning Basin. The producing units of the onshore area are deeply buried in the offshore, however, and possess lower reservoir quality. Thick Lower Triassic and Cretaceous shales do provide adequate seals.

Analogues for parts of the Canning Basin include the Paradox Basin of North America, where the Paradox Formation is similar to the Goldwyer, Nita, and Carribuddy shales. Fractured Ordovician Nita and Goldwyer Formations may be analogous to the Cambrian–Ordovician Ellenburger Dolomite of West Texas. In addition, exploration models from the Devonian reefs of Canada have been applied to those on the Lennard Shelf of the northern Canning Basin.

Permian–Carboniferous clastic rocks may be analogous to those in Saudi Arabia. In Oman, the eastern flank of the South Oman Salt Basin, at or near the edge of the Cambrian Ara Salt, has more than 1.9 billion kilolitres (12 billion barrels) of proven oil in-place in analogous Paleozoic to Permian reservoirs.

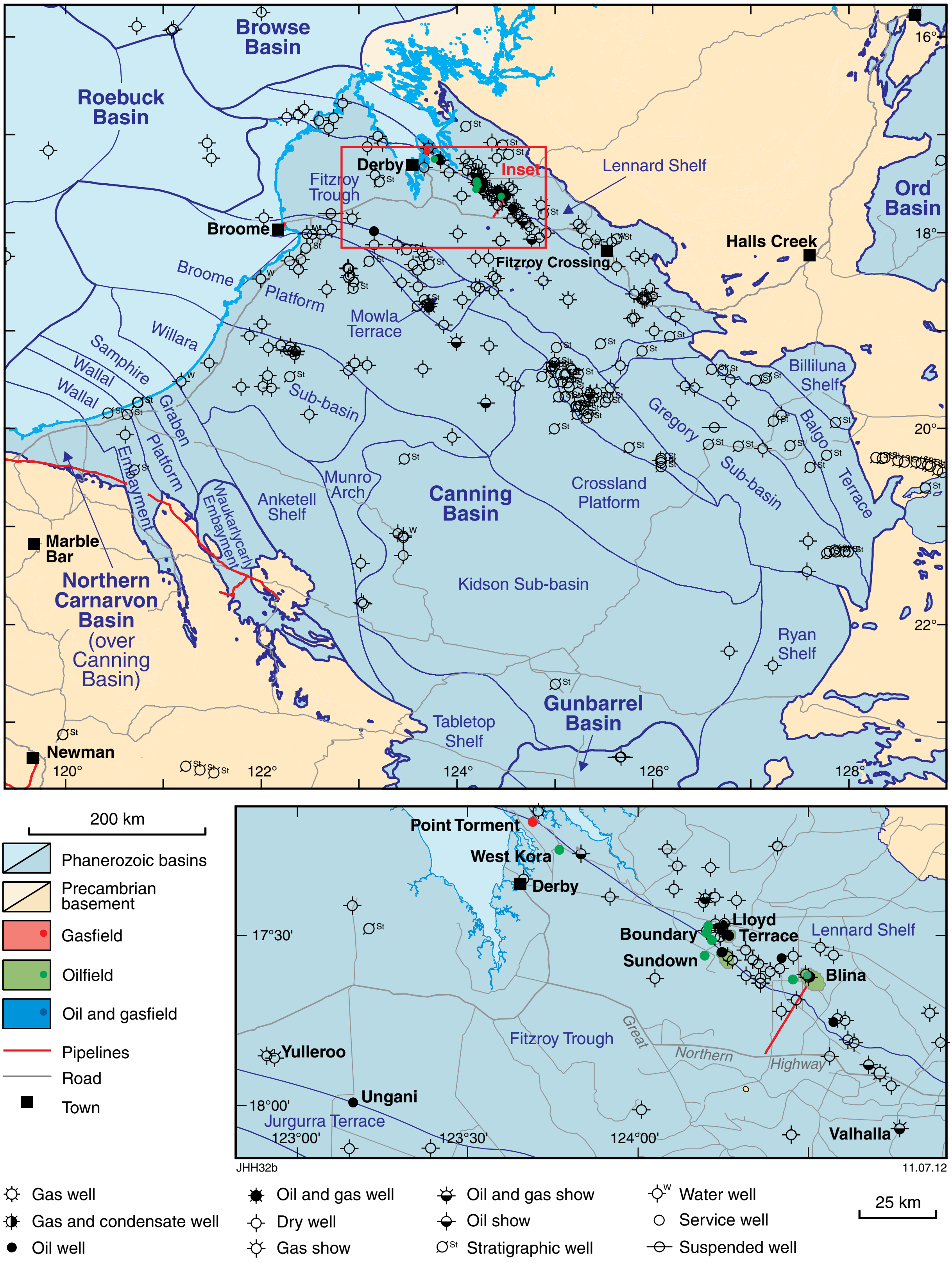


Figure 15. The Canning Basin, showing tectonic units, pipelines, fields and petroleum wells

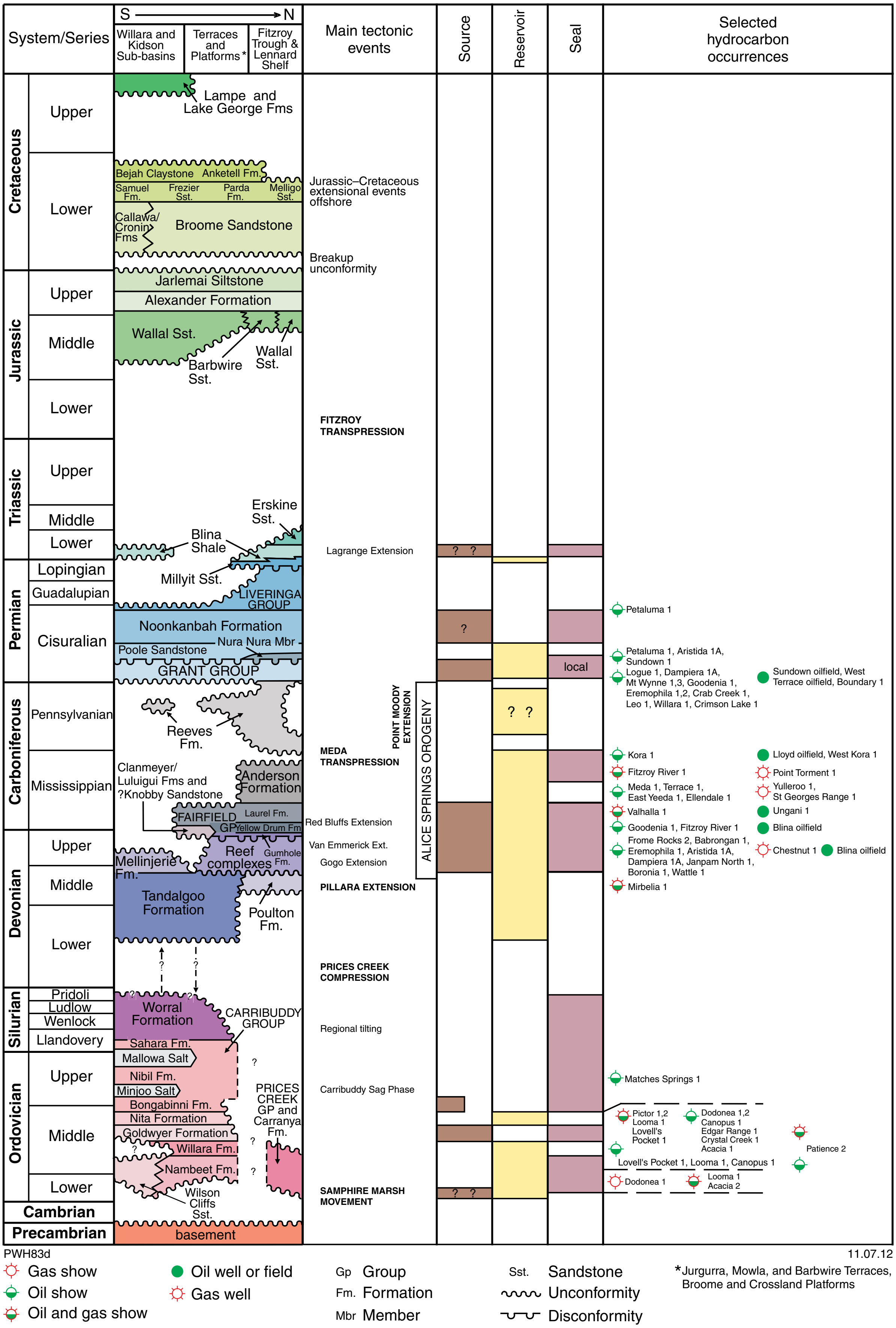


Figure 16. Stratigraphy and petroleum systems of the onshore Canning Basin

Table 3. Fields and significant discoveries in the onshore Canning Basin

YEAR	FIELD OR WELL NAME	OIL/GAS	RESERVOIR(S)	AGE OF RESERVOIR
1958	Meda 1	oil	Laurel	Carboniferous
			Nullara	Upper Devonian
1959	Frome Rocks 2	oil	Fairfield	Devonian–Carboniferous
1965	St George Range 1	gas	Laurel	Carboniferous
1967	Yulleroo 1	gas	Laurel	Carboniferous
1973	Mimosa 1	oil and gas	Pillara	Upper Devonian
1979	Ellendale 1	gas	Laurel	Carboniferous
1981	Blina	oilfield	Nullara	Upper Devonian
			Yellow Drum	Lower Carboniferous
1982	Sundown	oilfield	Grant	Permian–Carboniferous
1982	Boronia 1	oil	Pillara	Upper Devonian
1983	Cycas 1	oil	Noonkanbah	Permian
			Grant	Permian–Carboniferous
			Anderson	Carboniferous
1984	West Kora	oilfield	Anderson	Carboniferous
1984	Pictor 1	oil and gas	Nita	Ordovician
1984	Cudalgarra 1	oil and gas	Carribuddy	Silurian
			Nita	Ordovician
1985	Mirbelia 1	oil	Mellinjerie	Devonian
1985	West Terrace	oilfield	Grant	Permian–Carboniferous
1985	Dodonea 1	gas and oil	Goldwyer	Ordovician
1985	Kennedia 1	oil and gas	Nita	Ordovician
1987	Lloyd	oilfield	Anderson	Lower Carboniferous
1987	Janpam North 1	oil	Nullara	Devonian
1988	Crimson Lake 1	oil	Grant	Permian–Carboniferous
1990	Boundary	oilfield	Grant	Permian–Carboniferous
1992	Point Torment 1	gas	Anderson	Carboniferous
1994	Wattle 1	oil	Yellow Drum	Lower Carboniferous
1996	Looma 1	oil	Acacia	Ordovician
		oil and gas	Nita, Nambeet	Ordovician
2011	Ungani	oilfield	Laurel	Carboniferous
2011	Valhalla 2	gas	Laurel	Carboniferous

Table 4. Comparison of volumetric estimates for shale gas in the Canning Basin in Tm³ (Tcf volumes in brackets)

	GOLDWYER III		GOLDWYER FM			LOWER LAUREL		LAUREL FM
	Triche and Bahar 2013		ACOLA 2013	EIA 2013	EIA 2011	Triche and Bahar 2013		ACOLA 2013
	Deterministic	Probabilistic				Deterministic	Probabilistic	
GIIP	22.2 (783.9)	24.5 (867.4)	730.6 (2580)*	706.8 (2496)*	721.2 (2547)*	5.5 (193.6)	7.7 (271.5)	11.9 (420)*
Recoverable Resource	3.3 (117.6)	3.7 (130.1)	10.9 (387.0)	10.6 (374.4)*	10.8 (382.1)*	0.8 (29.0)	1.2 (40.7)	1.8 (63.0)
Risked GIIP [50% RF]	11.1 (392.0)	12.3 (433.7)	365.2 (1290)*	353.3 (1248)*	360.6 (1273.5)*	2.7 (96.8)	3.8 (135.8)	5.9 (210)*
Risked GIIP [30% RF]	6.6 (235.2)	7.4 (260.2)	21.9 (774)	21.2 (748.7)	21.6 (764.0)	1.6 (58.1)	2.3 (81.5)	3.6 (126)*
Risked Recoverable Resource [30% RF, 15% ReF]	1.0 (35.3)	1.1 (39.0)	3.3 (116.1)*	3.2 (112.3)*	3.3 (114.6)*	0.2 (8.7)	3.5 (12.2)	5.4 (18.9)

RF: Risk Factor
ReF: Recovery Factor
*extrapolated here from published data

Four petroleum systems have been identified in the onshore Canning Basin. Proven Ordovician source-rock intervals exist within the Goldwyer and Bongabinni Formations. Source-rock intervals in the Devonian (Givetian and Frasnian) include the fossiliferous Gogo Formation. These shales sourced the Blina oilfield, the first commercial discovery in the basin. The basinal facies of this formation contains the highest source potential in the Devonian section, matched only by the anoxic carbonaceous lithofacies of the back-reef Pillara Limestone. The Lower Carboniferous section includes effective source rocks in the Laurel and Anderson Formations, which likely sourced the Lloyd 1, West Kora 1, and Point Torment 1 hydrocarbon accumulations. Permian sequences include globally distributed source rocks in the upper Grant Group shales and in the Noonkanbah Formation.

The Ordovician and Devonian petroleum systems (Larapintine 1, 2, and 3) are considered to provide the best prospects for liquid hydrocarbons, with the potential to generate hundreds of billions of litres of oil. Devonian carbonates are productive for oil on the Lennard Shelf (Blina oilfield), whereas the Lower Carboniferous section has produced mainly oil and minor gas (Lloyd, Sundown, West Kora 1, Point Torment 1). There are also several small oilfields (Boundary, Sundown, and West Terrace) in the Gondwanan-system (Permian) reservoirs, although the oil is thought to be from Larapintine 3 source rocks of the Laurel Formation.

Play types vary geographically and stratigraphically. Fracture systems, associated with transfer faults connecting the Lennard Shelf to the deeper Fitzroy Trough, control migration and permeability in the carbonate reservoirs of the Lennard Shelf. Effective intraformational seals control accumulations in the siliciclastic reservoirs on the Lennard Shelf. Unconformity-related traps in rotated fault blocks, draping reservoirs developed over such fault blocks, downthrown rollovers, inversion folds, subsalt traps, and stratigraphic traps all remain to be tested within this large, underexplored basin.

The search for shale gas resources in the Canning Basin is in the early exploration phase. However, similarities exist between the Ordovician Goldwyer Formation and gas shales of the United States (US). Table 4 summarises the findings from several studies evaluating the shale gas resources of the Canning Basin. A recent Petroleum Division assessment of the Canning shales (Triche and Bahar, 2013) examined the basal member of the Goldwyer Formation and the Lower Laurel unit of the Laurel Formation, where initial gas in-place was estimated to be 24.5 Tm³ (867 Tcf) and 7.67 Tm³ (271 Tcf), respectively. The recoverable gas based on a 30% risk factor and 15% recovery factor is 1.1 Tm³ (39 Tcf) for the Goldwyer III and 0.34 Tm³ (12.2 Tcf) for the Lower Laurel unit. The EIA (2013) estimated that the Goldwyer Formation, which covers approximately 124,000 km² of prospectivity, could contain 70.7 Tm³ (2496 Tcf) gas in-place and a risked recoverable shale gas resource estimated at 3.18 Tm³ (112.3 Tcf), using the same parameters for risk and recovery factors. These numbers are based on the entire formation but are believed to be highly uncertain. A study of the Laurel Formation by Cook et al. (2013) with an estimated gas in-place of 11.9 Tm³ (420 Tcf) would have a risked recoverable resource of 0.53 Tm³ (18.9 Tcf), which includes both the Upper and Lower Laurel Formation.

The Goldwyer Formation lies at an average depth of 1330 m, has an average thickness of 350 m and TOC values ranging up to 6.4%. It is thickest in the Fitzroy Trough and Willara Sub-basin, but new exploration undertaken by New Standard Energy with ConocoPhillips indicates that the Goldwyer shales may be prospective in the Kidson Sub-basin as well. This area remains highly underexplored. Figure 17 shows the maturity data for the Goldwyer III unit. There is also potential for shale oil in this unit. Figure 18 shows the maturity data for the Laurel Formation, which appears to have a greater prospectivity for shale oil than the Goldwyer III.

The Carboniferous Laurel and Devonian Gogo Formations could possess additional shale gas potential in the deeper parts of the Canning Basin, such as the Fitzroy Trough. Gas shows in some wells that failed to produce from these formations may in fact be tight gas reservoirs; however, this assertion will need further investigation. Initial data indicates that the Laurel Formation contains TOC measurement up to 4.8% and a thermal maturity (R_o) of 1.95%, while the Gogo has shown TOC values of 4% and maturity of 0.8%. Thermal maturity and TOC values for all three formations are comparable to, or better than, those shown in successful US shale gas plays.

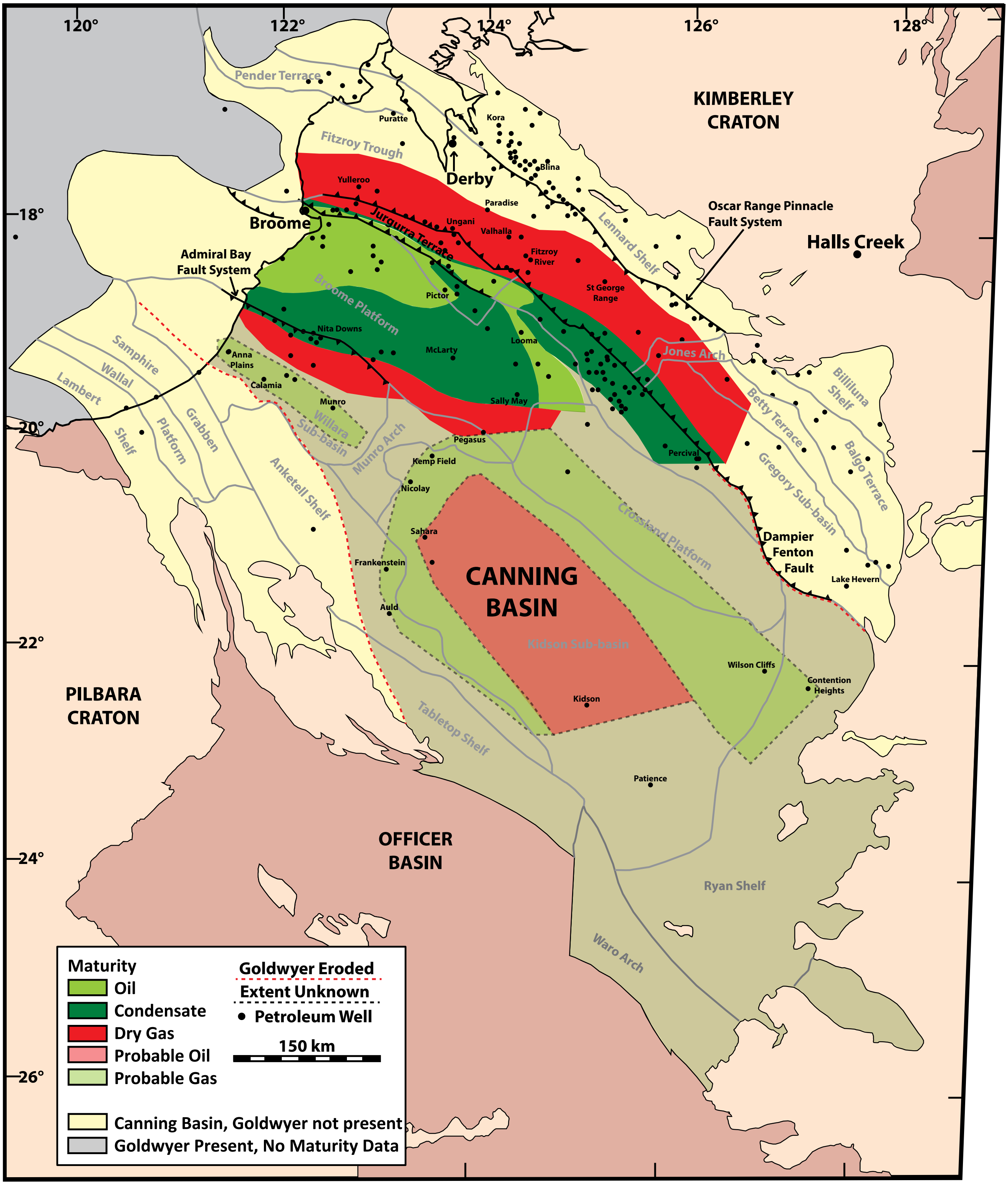


Figure 17. Thermal maturity and prospectivity of the Goldwyer Formation

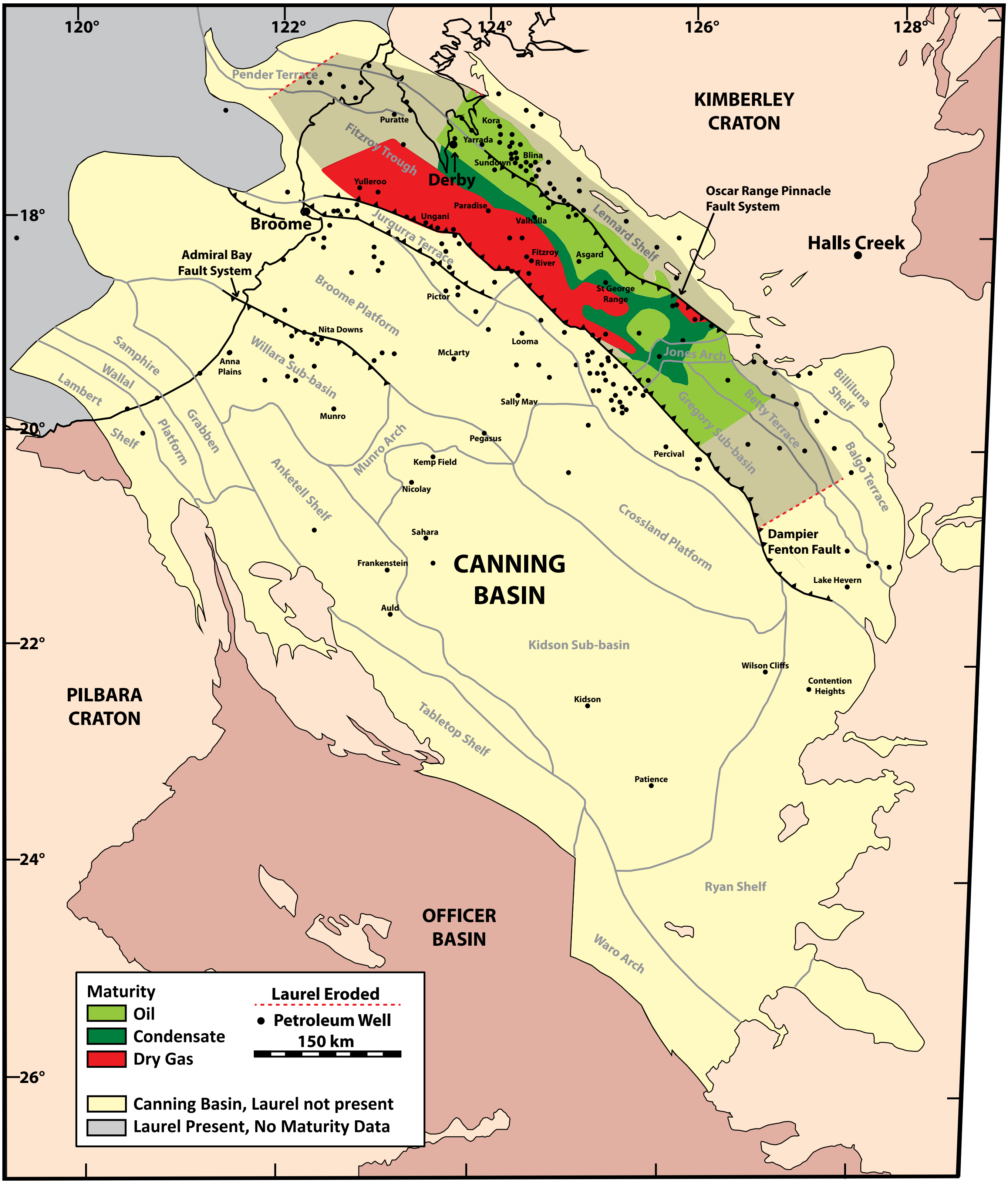


Figure 18. Thermal maturity and prospectivity of the Laurel Formation

Northern Carnarvon Basin

The Northern Carnarvon Basin, and in particular the Barrow and Dampier Sub-basins, is regarded as the premier hydrocarbon basin of Australia, and is one of the more intensely explored areas of the country. The basin lies mainly offshore, extending north from the Pilbara Craton to the continental–oceanic crust boundary, and covers about 500,000 km^2.

The Northern Carnarvon is transitional to and overlies the predominantly onshore Southern Carnarvon Basin (Figure 19). Several islands provide excellent locations for production facilities and bases in the basin (e.g. Barrow Island, Airlie Island, Varanus Island and Thevenard Island).

Barrow Island, host of significant oil reserves, is the site of the Gorgon LNG and domestic gas plant. Construction on the plant began in 2009, and first gas is expected in mid-2015. A carbon capture and storage (CCS) project will sequester carbon dioxide (CO_2) naturally present in Gorgon gas beneath Barrow Island, an important test of CCS technology.

The onshore part of the Northern Carnarvon Basin is readily accessible from the North West Coastal Highway. The towns of Carnarvon, Exmouth, Onslow, Dampier, Karratha and Port Hedland provide excellent support facilities for offshore exploration and development. Karratha is the loading terminal for Woodside's LNG exports and a processing centre for supplying gas to domestic markets including Perth, Bunbury and the Eastern Goldfields. The Pluto LNG plant began exports in early 2012 and the newly opened Devil Creek plant has begun supplying domestic gas. The Ashburton North LNG and domestic gas plant is under construction near Onslow.

Geological Setting

The Northern Carnarvon Basin is dominated by a southwest-trending set of troughs — the Exmouth, Barrow, Dampier and Beagle Sub-basins. These are the major depocentres of the southern North West Shelf, containing up to 15 km of Mesozoic sedimentary rocks. In these sub-basins, Mesozoic and Cenozoic successions overlie (commonly at considerable depth) Paleozoic sedimentary rocks that extend north from the Southern Carnarvon and Canning Basins. The Peedamullah Shelf and Lambert Shelf flank the depocentres shoreward, while a mid-basin arch consisting of the Rankin Platform and the Alpha Arch flank them seaward. The Kangaroo Trough, Dixon Sub-basin, and Investigator Sub-basin lie further offshore.

The breakup of Gondwana controlled the evolution of the Northern Carnarvon Basin. Prior to breakup, several sedimentary sequences were deposited from the Ordovician to the Permian in an elongate basin between the Archean Pilbara Craton and continental blocks to the northwest (Figure 20). At the end of the Paleozoic, rapidly subsiding, northeast-trending troughs developed in the Northern Carnarvon Basin to form its present-day framework, followed by faulting and breakup in the Jurassic. Thick siliciclastic sequences accumulated in offshore marine to continental settings. Final continental separation occurred in the Early Neocomian, further offshore than the aborted rifts along the axis of the Barrow and Dampier Sub-basins, resulting in a trailing-edge, passive margin basin. After breakup, in the late Cretaceous, global oceanic circulation patterns changed and deposition shifted from siliciclastic to carbonate-dominated, resulting in the formation of a thick carbonate wedge across the entire offshore basin.

Exploration History

Oil was discovered in the first modern well drilled in the Carnarvon Basin, Rough Range 1, at the eastern edge of the Exmouth Sub-basin, in 1953. Follow-up discoveries of oil at Barrow Island (1964), and of gas in North Tryal Rocks 1 (1971), established the Northern Carnarvon Basin as a major hydrocarbon province. The level of exploration activity increased following a steep decline in 2001 and 2002. Table 5 lists the oilfields and gasfields in State waters and onshore areas of the Northern Carnarvon Basin.

The offshore portion of the basin has a reasonable regional and detailed seismic grid, mainly north of Exmouth Gulf where 3D surveying is now a common tool in both exploration and development scenarios. Some offshore areas still receive only minimal exploration, especially in the south, with exploration remaining sparse over most of the onshore basin, except for the Rough Range – Cape Range area. The nearshore is highly prospective but largely unexplored owing to the difficulty of conducting seismic and drilling operations in a shallow-water, environmentally sensitive zone.

Petroleum Prospectivity

Numerous oilfields and gasfields in the Northern Carnarvon Basin demonstrate the petroleum potential of the region, particularly offshore.

Oil is produced primarily from the Barrow Group and sandy intervals (Windalia Sand, Mardie Greensand and Birdrong Sandstone) of the lower Winning Group, all of which occurred post-breakup. The Lower Cretaceous Barrow Group has excellent reservoir characteristics, and Middle Miocene faulted anticlines provide structural traps. The main source rock for post-breakup accumulations is considered to be the Upper Jurassic Dingo Claystone. This source is estimated to have the capacity to expel 1.27 TL (8 Bbbl) of oil, just over 10 per cent of which has been discovered within the Barrow Sub-basin. The sub-basin margins, such as the Peedamullah Shelf, Rankin Trend, Exmouth Gulf, and the sub-basin axes, may hold the key to a major portion of the undiscovered reserves.

Within the Dampier Sub-basin, production of gas, condensate, and associated minor oil, is primarily from pre-breakup sandstones of the Upper Jurassic to mid-Upper Triassic Angel, Brigadier and Mungaroo Formations. Truncation and fault traps control the pre-breakup accumulations, which are probably sourced by the Triassic Locker Shale and intra-Mungaroo shales.

Although parts of the Northern Carnarvon Basin are intensely explored, further discoveries continue to be made at various intervals, both within the proven hydrocarbon-rich Barrow and Dampier Sub-basins and in the less explored surrounding sub-basins. Successful exploration includes different play types and extensions of known discoveries and models. The support facilities now present in the Carnarvon Basin also allow the development of offshore fields with less than 1.5 GL (10 MMbbl) of recoverable resources.

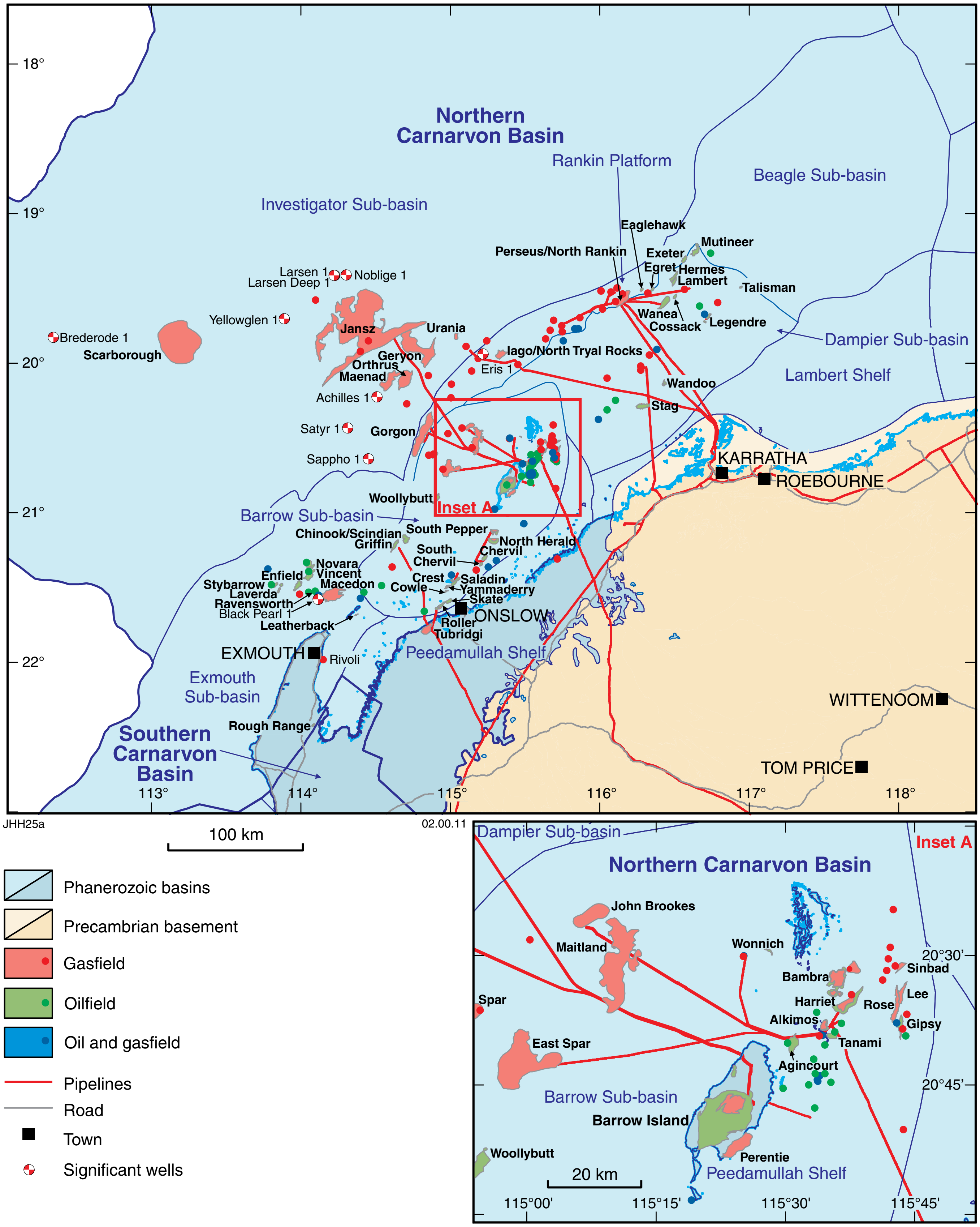


Figure 19. The Northern Carnarvon Basin, showing tectonic units, pipelines, fields and petroleum wells

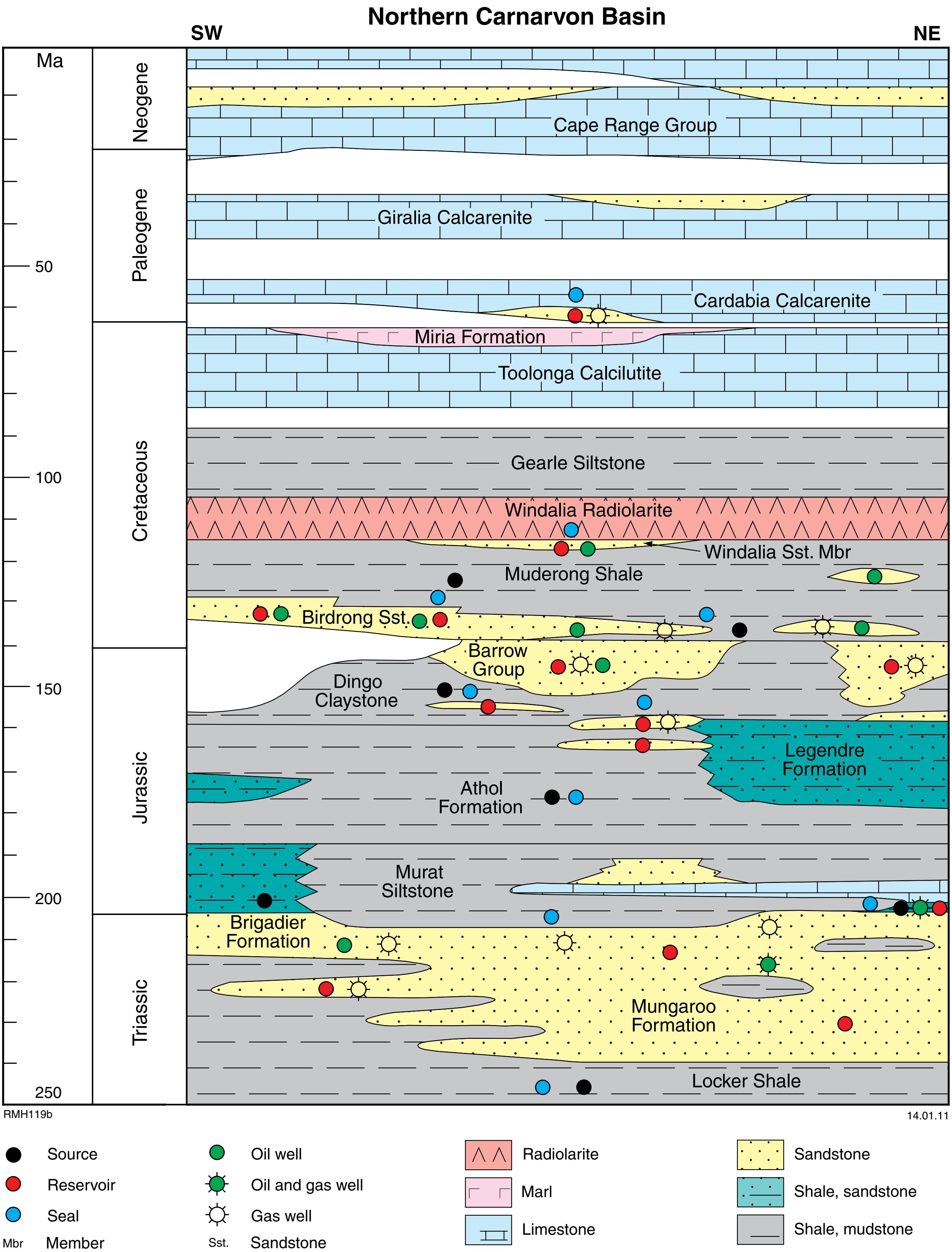


Figure 20. Stratigraphy and petroleum systems of the onshore Northern Carnarvon Basin

Table 5. Fields and significant discoveries in State areas of the Northern Carnarvon Basin					
FIELD	YEAR	RESERVOIRS	AGE OF RESERVOIR	HYDROCARBON TYPE	STATUS*
Agincourt	1996	Flag Sandstone	Lower Cretaceous	gas, oil, condensate	producing
Albert	2005	Flag Sandstone	Lower Cretaceous	gas, oil, condensate	depleted
Alkimos	1994	Flag Sandstone	Lower Cretaceous	gas, oil	depleted
Artreus	2005	Double Island Sandstone	Lower Cretaceous	gas, oil, condensate	depleted
Australind	1993	Barrow Group	Lower Cretaceous	gas, oil	undeveloped
Baker	2000	Brigadier Formation Mungaroo Formation	Upper Triassic	gas	undeveloped
Bambra	1983	Flag Sandstone	Lower Cretaceous	gas, oil, condensate	producing
Bambra East	1985	Flag Sandstone	Lower Cretaceous	gas	undeveloped
Barrow Island	1966	Windalia Radiolarite Mardie Greensand Mbr Muderong Shale Gearle Siltstone Flacourt Formation Dupuy Formation	Lower Cretaceous Lower Cretaceous Early Cretaceous Mid Cretaceous Lower Cretaceous Upper Jurassic	gas, oil	producing
Blencathra	1995	Barrow Group	Lower Cretaceous	oil	undeveloped
Cadell	1999	Mungaroo Formation	Upper Triassic	gas	undeveloped
Campbell	1979	Flag Sandstone	Lower Cretaceous	gas, condensate	depleted
Chervil	1983	Flacourt Formation	Lower Cretaceous	oil	depleted
Coaster	1999	Mardie Greensand Mbr Barrow Group	Lower Cretaceous Lower Cretaceous	oil	undeveloped
Cowle	1990	Mardie Greensand Mbr Flacourt Formation	Lower Cretaceous Lower Cretaceous	gas, oil	depleted
Crest	1994	Mardie Greensand Mbr Flacourt Formation	Lower Cretaceous Lower Cretaceous	gas, oil	depleted
Cyrano	2003	Mardie Greensand Mbr Airlie Sandstone	Lower Cretaceous Lower Cretaceous	gas, oil	undeveloped
Doric	1996	Flag Sandstone	Lower Cretaceous	gas	depleted
Double Island	2002	'Double Island sandstone member"	Lower Cretaceous	oil, gas	depleted
Endymion	2002	Flag Sandstone	Lower Cretaceous	gas, condensate	depleted
Flinders Shoal	1969	Birdrong Sandstone	Lower Cretaceous	gas, oil	undeveloped
Gibson	2003	Flag Sandstone	Lower Cretaceous	oil	depleted
Gipsy	1998	North Rankin Formation Brigadier Formation Mungaroo Formation	Lower Jurassic Upper Triassic Upper Triassic	gas oil	depleted
Gudrun	2001	Flag Sandstone	Lower Cretaceous	oil	depleted
Harriet	1983	Flag Sandstone	Lower Cretaceous	oil	producing
Hoover	2002	Flag Sandstone	Lower Cretaceous	oil	depleted
Josephine	2000	North Rankin Formation Brigadier Formation Mungaroo Formation	Lower Jurassic Upper Triassic Upper Triassic	gas	undeveloped
Leatherback	1991	Mungaroo Formation	Upper Triassic	oil	undeveloped
Lee	1999	North Rankin Formation Brigadier Formation Mungaroo Formation	Lower Jurassic Upper Triassic Upper Triassic	gas, condensate	producing
Linda	2000	Linda Sandstone Member	Upper Jurassic	gas, condensate	depleted
Little Sandy	2002	Flag Sandstone	Lower Cretaceous	gas, oil	depleted
Mardie	2000	Intra-Muderong Sands	Lower Cretaceous	gas	undeveloped
Mohave	2005	Flag Sandstone	Lower Cretaceous	gas, oil	depleted

Table 5. Fields and significant discoveries in State areas of the Northern Carnarvon Basin continued

FIELD	YEAR	RESERVOIRS	AGE OF RESERVOIR	HYDROCARBON TYPE	STATUS*
Monet	2004	Flag Sandstone	Lower Cretaceous	oil	depleted
Monty	1999	North Rankin Formation Brigadier Formation Mungaroo Formation	Lower Jurassic Upper Triassic Upper Triassic	gas, condensate	undeveloped
Narvik	1999	Birdrong Sandstone	Lower Cretaceous	gas	undeveloped
Nasutus	1999	Mardie Greensand Mbr Upper Barrow Group	Lower Cretaceous Lower Cretaceous	gas, oil	undeveloped
North Alkimos	2000	Flag Sandstone	Lower Cretaceous	oil	depleted
North Gipsy	1999	North Rankin Formation Brigadier Formation	Lower Jurassic Upper Triassic	gas, oil	depleted
North Herald	1983	Upper Barrow Group	Lower Cretaceous	gas, oil	depleted
North Pedirka	2003	Flag Sandstone	Lower Cretaceous	gas, oil	depleted
Pasco	1967	Barrow Group	Lower Cretaceous	gas, oil	undeveloped
Pedirka	2002	Flag Sandstone	Lower Cretaceous	gas, oil	depleted
Rivoli	1989	Birdrong Sandstone	Lower Cretaceous	gas	undeveloped
Roller	1990	Mardie Greensand Mbr Flacourt Formation	Lower Cretaceous Lower Cretaceous	gas, oil	depleted
Rose	1998	North Rankin Formation Brigadier Formation Mungaroo Formation	Lower Jurassic Upper Triassic Upper Triassic	gas, condensate	producing
Rosette	1987	Flag Sandstone	Lower Cretaceous	gas, condensate	depleted
Rough Range	1955	Birdrong Sandstone	Lower Cretaceous	oil	undeveloped
Saladin	1985	Mardie Greensand Mbr Flacourt Formation	Lower Cretaceous Lower Cretaceous	gas oil	depleted
Simpson	2000	Flag Sandstone	Lower Cretaceous	gas oil	depleted
Sinbad	1990	Flag Sandstone	Lower Cretaceous	gas, condensate	depleted
Skate	1991	Mardie Greensand Mbr Flacourt Formation	Lower Cretaceous Lower Cretaceous	gas, oil	depleted
South Chervil	1983	Mardie Greensand Mbr Barrow Group	Lower Cretaceous Lower Cretaceous	gas, oil	undeveloped
South Pepper	1983	Mardie Greensand Mbr Barrow Group	Lower Cretaceous Lower Cretaceous	oil	depleted
South Plato	2001	Flag Sandstone	Lower Cretaceous	oil	depleted
Tanami	1991	Flag Sandstone	Lower Cretaceous	oil	depleted
Tubridgi	1981	Birdrong Sandstone Flacourt Formation Mungaroo Formation	Lower Cretaceous Lower Cretaceous Upper Triassic	gas	depleted
Ulidia	1992	Flag Sandstone	Lower Cretaceous	gas	undeveloped
Victoria	2002	'Double Island sandstone member'	Lower Cretaceous	oil	depleted
West Cycad	2006	Flag Sandstone	Lower Cretaceous	oil	depleted
Wonnich	1995	Flag Sandstone	Lower Cretaceous	gas, condensate	producing
Wonnich Deep	2007	Flag Sandstone	Lower Cretaceous	gas, condensate	undeveloped
Yammaderry	1988	Mardie Greensand Mbr Flacourt Formation	Lower Cretaceous Lower Cretaceous	oil, gas	depleted
Zephyrus	2006	'Double Island Sandstone'	Lower Cretaceous	oil	depleted

NOTES:
Mbr Member
Formation names in quotations are informal company designations

Southern Carnarvon Basin

The onshore, primarily Paleozoic, Southern Carnarvon Basin has seen minimal exploration compared to the adjoining Perth and Northern Carnarvon Basins. The Southern Carnarvon extends west from the Precambrian shield to the Mesozoic offshore Perth and Northern Carnarvon basins, and covers approximately 200,000 km^2 (Figure 21).

The basin is readily accessible from the North West Coastal Highway, and the Dampier to Bunbury gas pipeline runs through its eastern portion. In addition, large pastoral leases provide a network of roads and tracks, although these may close briefly after heavy rain.

Vegetation consists of open to dense shrub land and spinifex grassland. Mangroves and salt lakes are present in some coastal areas.

Geological Setting

The northerly elongate Southern Carnarvon Basin is composed of two principal structural elements: the Gascoyne Platform to the west, and the Merlinleigh and Byro Sub-basins to the east. The Gascoyne Platform contains gently folded Ordovician to Devonian strata, unconformably overlain by a veneer of Mesozoic and younger rocks. In comparison, the Merlinleigh and Byro Sub-basins are characterised by a thick Upper Carboniferous to Permian section, underlain by a Lower Carboniferous–Devonian section (Figure 22), and unconformably overlain by a veneer of Cretaceous and younger rocks. The Paleozoic section is up to 7 km thick and is covered by Triassic rocks in the North. Northerly and northwesterly-trending faults are also present.

Seismic data indicate that the breakup of Gondwana during the Mesozoic had the greatest impact on the structural evolution of the area. This tectonism produced wrenching that resulted in faulting and long-wavelength folds. The collision of the Australian plate with Timor in the Miocene caused structural inversion and reverse movement on many faults previously dominated by normal movement.

Exploration History

Petroleum exploration commenced in the Southern Carnarvon Basin in the 1930s, after WG Woolnough first drew attention to the prospectivity of the Wooramel River area, and when hydrocarbon shows were encountered in shallow water bores in the northern part of the region. WAPET was the first company with serious exploration programs in the 1950s and 1960s, following its oil discovery at Rough Range. After early exploration near Rough Range and other onshore coastal anticlines proved noncommercial, the main exploration activity moved north to the offshore Northern Carnarvon Basin. To date, 105 onshore (including 57 stratigraphic tests) and five offshore wells are drilled in the Southern Carnarvon Basin. No fields or accumulations have yet been discovered (Table 6).

The Pleistocene aged limestone Zuytdorp cliffs extend for about 150 km along the coast in the Southern Carnarvon Basin

Petroleum Prospectivity

The northernmost part of the Southern Carnarvon Basin is characterised by three large Cenozoic anticlines: the Rough Range, Giralia, and Marrilla Anticlines. Several smaller anticlines of the same age are exposed along the eastern and western shores of Lake MacLeod, in the central part of the basin, and similar anticlines underlie the peninsulas and islands of the Shark Bay region.

There are only a few valid tests for hydrocarbon plays in the region. Lower Cretaceous sandstone, which has excellent reservoir characteristics, is the main objective for oil exploration in the northern part of the basin, but seal adequacy and distance from effective source rocks are risks. Source rocks are present in Lower Permian, Upper Devonian, and Silurian strata (Larapintine 2 and 3, Transitional, and Gondwanan petroleum systems). Lower Permian source rocks are regionally immature to marginally mature, and are mostly gas prone. In comparison, Devonian–Silurian source rocks are shown to have good potential for both oil and gas generation, although Silurian source beds are thin. The Cretaceous succession may still offer some potential for hydrocarbon generation and for an oil discovery (Austral petroleum system). The Devonian succession offers the most challenging, yet untested objective. Untested structural highs exist adjacent to major faults (mainly along the eastern edge of the Gascoyne Platform) that may have provided vertical conduits for migrating hydrocarbons.

In the Southern Carnarvon Basin, the Permian Wooramel Group and Byro Group shales are as yet untested for their gas potential. These shales are of similar age to northern Perth Basin shales, feature high levels of TOC, and lie partly in a mature gas window.

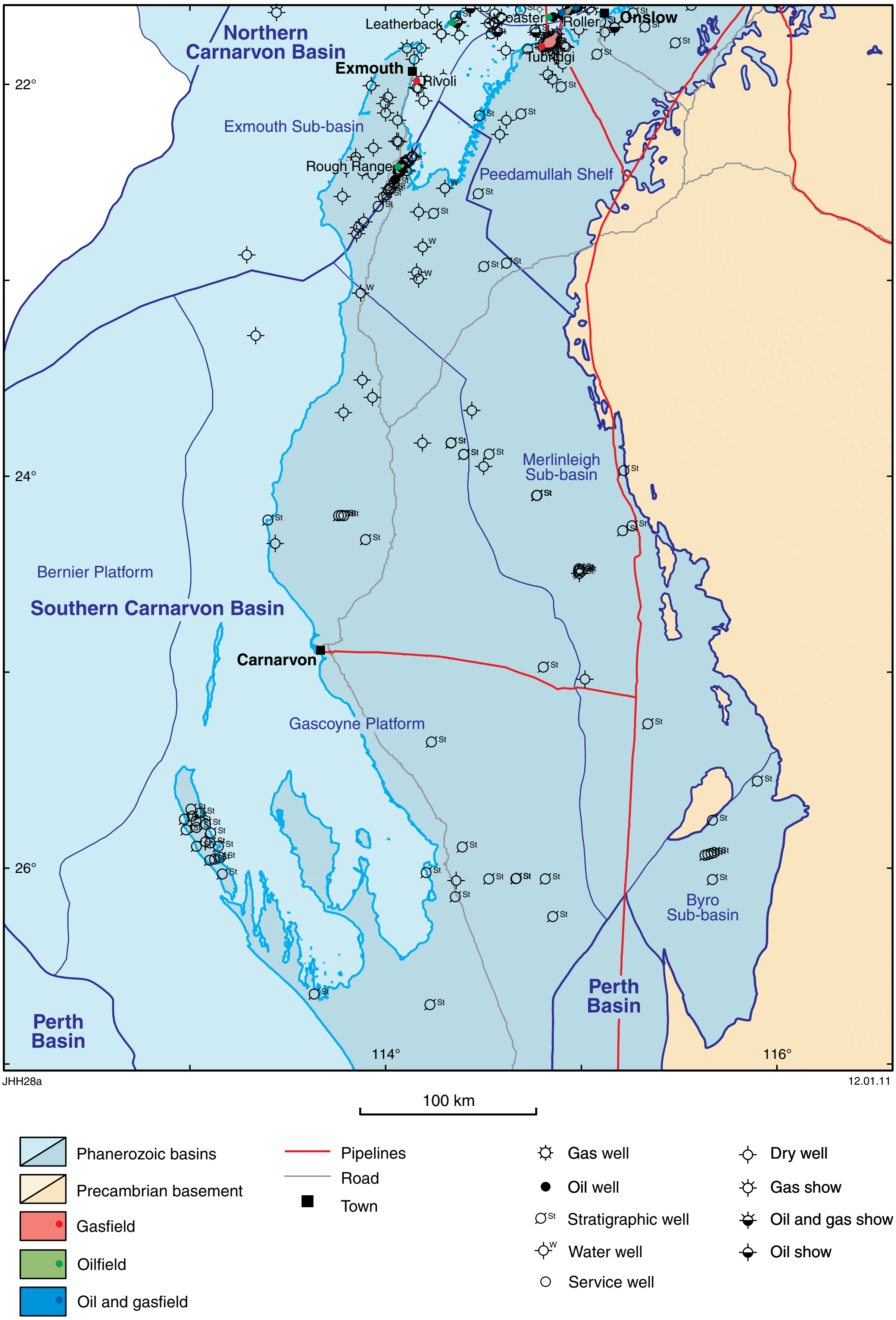


Figure 21. The Southern Carnarvon Basin, showing tectonic units, pipelines, fields and petroleum wells

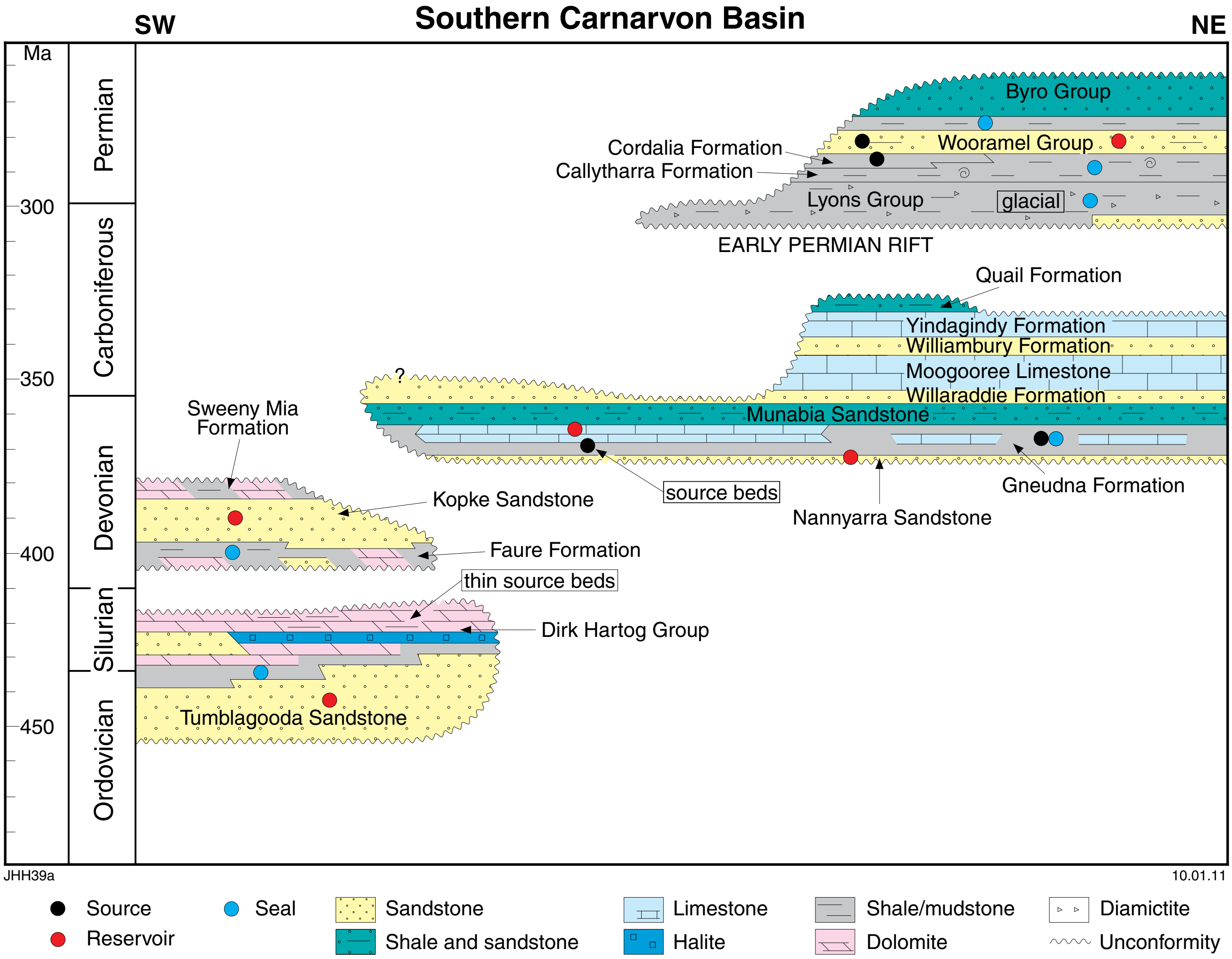


Figure 22. Stratigraphy and petroleum systems of the Southern Carnarvon Basin

Table 6. Hydrocarbon shows, onshore Southern Carnarvon Basin

YEAR	WELL	QUALITY OF SHOW	FORMATION	FORMATION AGE
1962	Wandagee 1	Poor gas show	Tumblagooda Sandstone	Ordovician
1963	Quail 1	Trace oil	Gneudna Formation	Devonian
1966	Kennedy Range 1	Fair gas shows	Moogaloo Formation (Wooramel Group)	Lower Permian
1984	Quobba 1	High background C_4	Gneudna Formation	Devonian

Officer Basin

The Officer Basin extends 1500 km from the southeastern flank of the Pilbara Craton to the central-western part of South Australia and, within Western Australia, occupies an area of about 310,000 km^2 (Figure 23).

The basin contains five major westerly and northwesterly-trending depocentres. The basin fill is predominantly Neoproterozoic, overlying older Proterozoic to Archean sedimentary, igneous and metamorphic rocks. The Gunbarrel Basin, an overlying succession of Cretaceous and younger strata, influences the maturity of source rocks in Officer Basin petroleum systems.

Recent work, including stratigraphic coring and re-evaluation by the Geological Survey of Western Australia (GSWA), has contributed to the understanding of this frontier basin. To date, a few thin, good to excellent source rocks have been identified in each of the main stratigraphic units. Reservoirs in siliciclastic rocks are good to excellent. Seals include salt, other evaporites, shale and siltstone. Potential traps are present from the Latest Neoproterozoic to the Paleozoic.

Most of the basin is sparsely settled desert, with only a regional track grid and a few major through roads. However, access to the basin is reasonable for exploration because topographic relief is minor. No production facilities currently exist in the basin. The Goldfields Gas Transmission Pipeline, which passes about 200 km west of the Officer Basin, was completed in 1996. This pipeline runs south from the North West Shelf to Kalgoorlie, and supplies gas to mine sites and processing facilities. Potential markets for discoveries in the basin include mining centres, Alice Springs in central Australia, and export via the coast, which is 250 to 600 km from the basin.

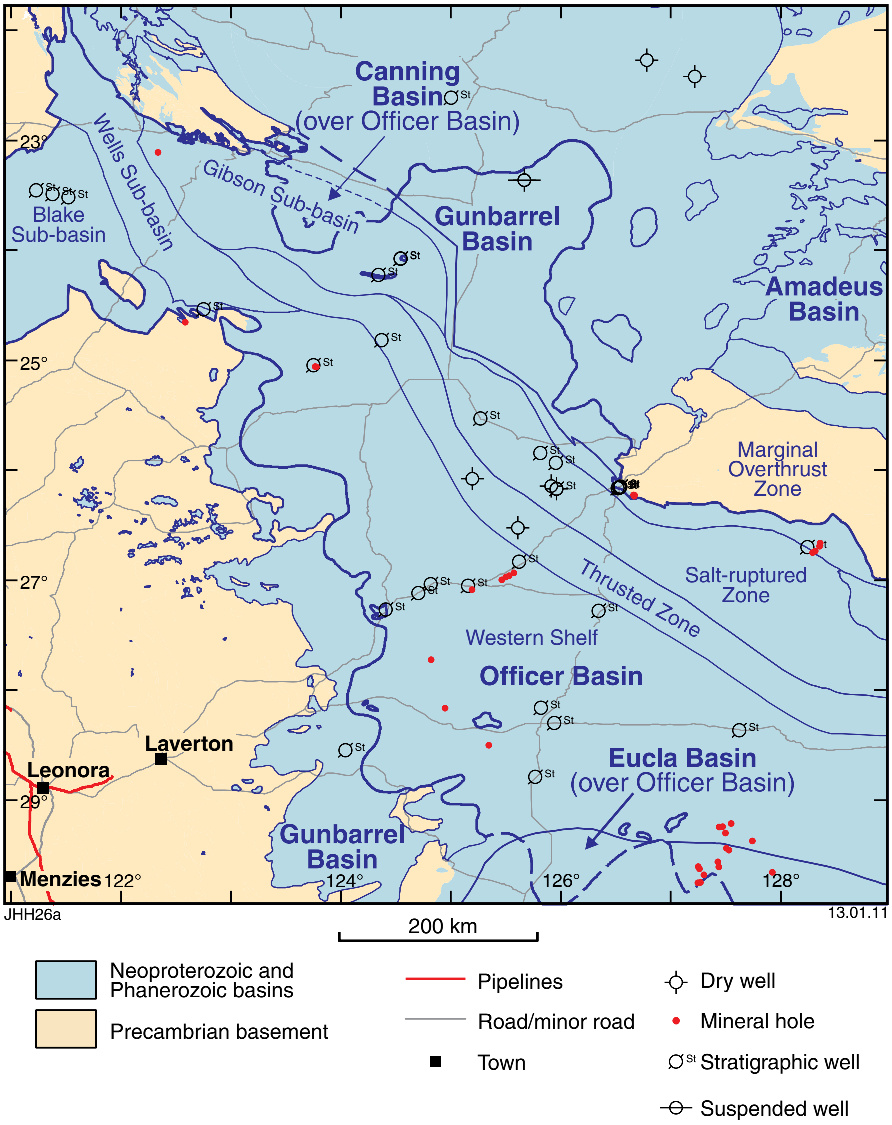


Figure 23. The Officer Basin, showing tectonic units and exploration drillholes of interest

Geological Setting

The Officer Basin is a Neoproterozoic intracratonic basin with a total sedimentary thickness of up to 8 km. The basin infill is a mixed carbonate, silty and sandy siliciclastic, and evaporitic succession dominated by shallow marine to coastal deposition. The Officer Basin sedimentary succession preserves three of the four supersequences common to central Australian Neoproterozoic basins. Only the second supersequence appears to be absent in Western Australia, except near the South Australian border.

The structural configuration of the basin is largely determined by major salt deposits, which mobilised during several tectonic episodes. Four distinct structural zones are present in the main part of the basin in Western Australia: a Marginal Overthrust Zone along the northeastern margin of the basin adjacent to the Musgrave Complex; an adjoining Salt-ruptured Zone; a central Thrusted Zone; and a Western Shelf (Figure 24). The basin has a complex history with several tectonic episodes, the most significant of which are the Areyonga Movement, when major salt mobilisation occurred, and the Paterson–Petermann Orogeny (Figure 24), when major uplift of the Paterson Orogen and Musgrave Complex shed large volumes of coarse siliciclastic rocks into the basin.

Exploration History

There have been several periods of stratigraphic and exploration drilling in the Officer Basin since 1965. A consortium including Hunt Oil drilled five wells in 1965–66, encountering minor oil and gas shows within the Browne Formation in Browne 1 and 2. Shell Australia drilled three wells in 1980–84, and found an algal-sourced oil show in Kanpa 1. Eagle Corporation Limited and others drilled two stratigraphic wells in 1982 in the northwest of the basin. Subsequent exploration drilling in the Amadeus Basin and in the Officer Basin in South Australia led to several oil and gas shows, and the discovery of the Dingo gasfield in the Northern Territory.

Approximately 6500 km of good-quality seismic data were acquired between 1980 and 1984. The Japanese National Oil Company (JNOC) reprocessed most of the modern seismic data in the Yowalga area in 1996. Geoscience Australia gravity data cover the basin on an 11km grid, and GSWA acquired semi-detailed gravity surveys on 2–3 km grids over parts of the Savory and Waigen areas in 1995 and 1998, respectively.

Geoscience Australia's regional aeromagnetic data cover the basin on a 1.5-km line spacing.

Mining interests and JNOC acquired more detailed surveys; the latter covers the central part of the Yowalga area.

From 1995 until 2003, GSWA performed a program of stratigraphic drilling with Trainor 1, Empress 1 and 1A, Vines 1 and Lancer 1. Amadeus Petroleum drilled three exploration wells in 1997 (Akubra 1, Mundadjini 1, and Boondawari 1). In 2011, Geoscience Australia and GSWA acquired a deep seismic line over the western Officer Basin.

Petroleum Prospectivity

Neoproterozoic sedimentary rocks are known to have sourced commercial accumulations of oil and gas in Russia, Oman, and in the Amadeus Basin in west-central Australia. Hydrocarbon shows (in the form of minor oil staining and bitumen in intergranular pores, fractures and vugs) are recorded in the northwest Officer Basin in Mundadjini 1, Boondawari 1, and LDDH 1, and in the adjoining Paleoproterozoic Scorpion Group in OD 23. Elsewhere in the western Officer Basin, hydrocarbon shows are recorded in NJD 1, Kanpa 1A, Browne 1, Browne 2, Dragoon 1, Hussar 1, and Vines 1 (Table 7).

Results from these wells indicate reservoirs with porosity greater than 20%, and permeabilities of hundreds of millidarcies. Halite beds more than 10 m thick in the Browne Formation, and shales more than 10 m thick in the Browne, Hussar, Kanpa, and Lupton Formations, provide potentially effective seals. Thin, but potentially effective, source rocks are found in the Browne, Kanpa, and Hussar Formations. The close association of laminae-scale source rocks with good quality reservoir and seal horizons indicates the presence of at least the basic physical elements of a petroleum system. Geochemical modelling indicates that most potential source rocks in the Officer Basin first entered the oil-maturation window after formation of substantial structural traps, and much of the section remains in that window today.

Play types in the Officer Basin vary geographically and stratigraphically. Subsalt minibasin plays, similar to current exploration targets in the Gulf of Mexico, may be present, particularly in the Gibson area. Such plays are higher risk for reservoir and source, although the sealing capacity of the halite beds remains an attraction. Suprasalt plays include folded four-way dip closures resulting from low-amplitude, broad, open folds, and isoclinal to overturned thrust folds. Many of the larger folds are cored by salt diapirs, but opportunities for flanking traps or lateral truncation traps remain unexplored. Stratigraphic traps in the subsalt and suprasalt section remain untested.

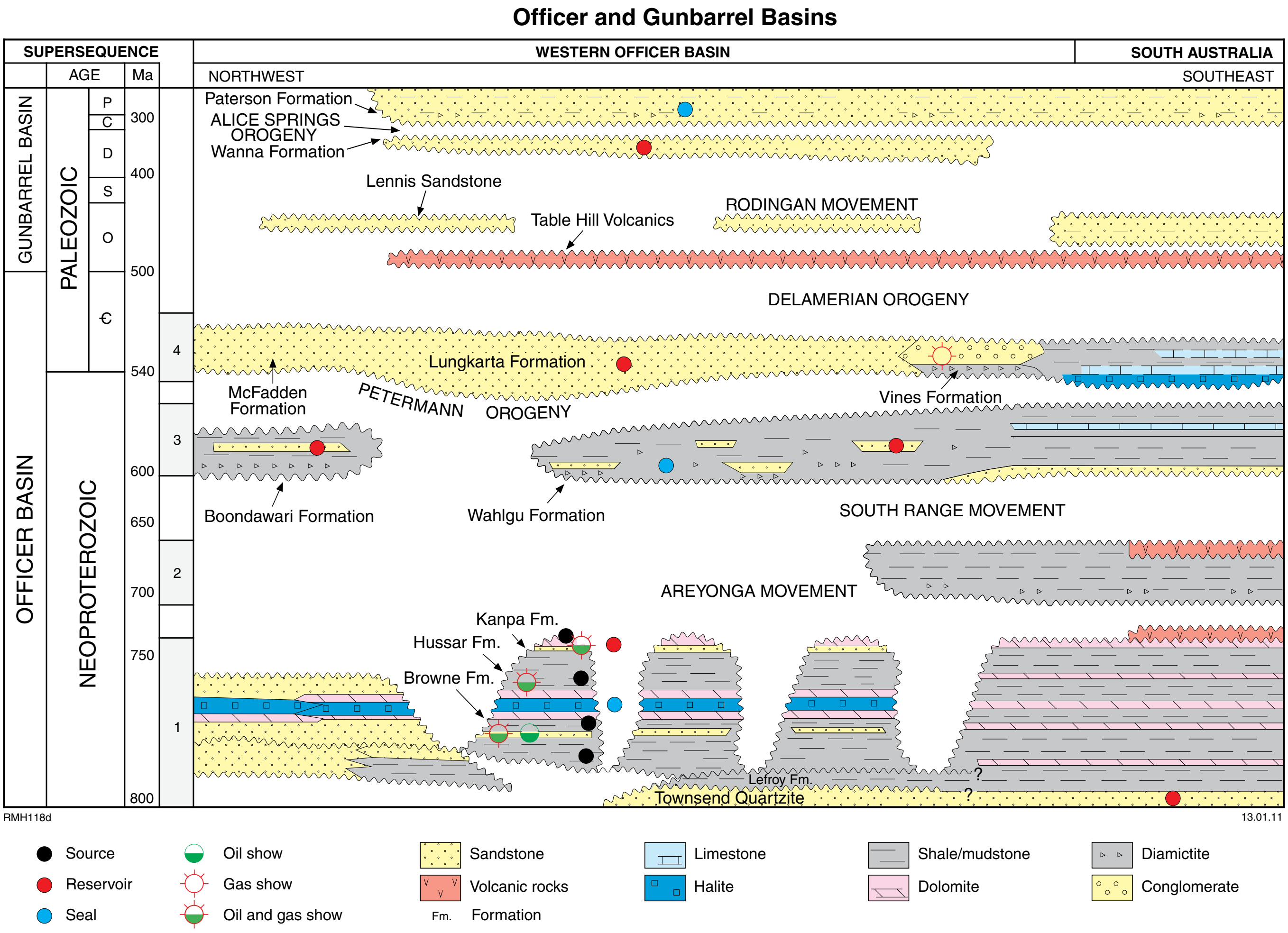


Figure 24. Stratigraphy and petroleum systems of the Officer Basin

Table 7. Hydrocarbon shows in the Officer Basin and adjoining areas, Western Australia

YEAR	WELL	QUALITY OF SHOW	FORMATION	FORMATION AGE
1965	Browne 1	Gas cut mud, cut fluorescence, trace oil in core	Paterson Formation	Permian
			Browne Formation	?Mesoproterozoic
1965	Browne 2	Gas cut mud, cut fluorescence, trace oil in core	Paterson Formation	Permian
1981	NJD 1	Bleeding oil and bitumen in core	Browne Formation	?Mesoproterozoic
1982	Dragoon 1	Mud gas to 10% methane equivalent, including hydrocarbons up to pentane	Browne Formation	?Mesoproterozoic
1982	Hussar 1	Mud gas readings to 1000 ppm. Possible gas blow on air lift.	Kanpa Formation	Neoproterozoic
		Trip gas to 4.6% total gas. 72% oil saturation from log analysis	Hussar Formation	
1982	Kanpa 1A	Dull yellow-orange sample fluorescence, light yellow-white cut fluorescence, brown oil stains in sandstone and dolomite cuttings	Kanpa Formation	Neoproterozoic
1993	LDDH 1	Bitumen in core	Tarcunyah Group	Neoproterozoic
1996	OD 23	Bleeding oil and bitumen in core	Scorpion Group	Paleoproterozoic
1997	Boondawari 1	40% oil fluorescence in core	Spearhole Formation	Neoproterozoic
1997	Mundadjini 1	10% oil fluorescence in core	Spearhole Formation	Neoproterozoic
1999	Vines 1	Total gas peaks 25 times background	Wahlgu Formation	Neoproterozoic


Outcropping of the McFadden Formation sandstones in the Officer Basin

Perth Basin

The Perth Basin extends south from the Southern Carnarvon Basin and covers an area of about 100,000 km^2, from the Yilgarn Craton in the east to the edge of the continental shelf in the west (Figure 25). The onshore area is readily accessible, consisting of farming and shrub land in the central region. The undulating northern portion of the basin has relatively simple access from main roads. In the south, forestry and grazing are the main land uses.

The basin is close to petroleum industry infrastructure, including two major gas pipelines and trucking facilities to an oil refinery 30 km south of Perth. The Parmelia Gas Pipeline provides ready access to market and allows economic exploitation of small discoveries.

A gas storage project at the depleted Mondarra field is undergoing expansion. The Mondarra project is connected to both major gas pipelines and is intended to improve energy security for Perth and surrounding markets.

Geological Setting

The Perth Basin forms a north–south elongate rift–trough along the west coast of Australia. The tectonic framework of the basin is dominated by the Darling Fault and Dandaragan Trough in the east, and the offshore Abrolhos and Vlaming Sub-basins in the west. The Dandaragan Trough is a major depocentre up to 12 km thick.

The basin contains mainly continental clastic rocks of Permian and younger age (Figure 26), deposited in a rift system that culminated with the breakup of Gondwana in the Early Neocomian. Two major tectonic phases are recognised: Permian extension in a southwesterly direction, and Early Cretaceous transtension to the northwest during breakup. Sinistral and dextral movement, respectively, are inferred along the Darling Fault during these phases. The main faults were rejuvenated by breakup tectonism, which also caused horizontal displacements, wrench-induced anticlines, and further faulting.

Exploration History

Petroleum exploration commenced in the Perth Basin in 1951, when the BMR conducted gravity surveys in the northern onshore area. WAPET was the first private company to explore the acreage with gravity and seismic surveys. Both BMR and WAPET drilled stratigraphic wells across the onshore northern Perth Basin in the late 1950s, leading WAPET to drill the basin's first wildcat hole, Eneabba 1, in 1961.

Drilling activity concentrated on the onshore part of the basin, with 320 wells drilled onshore to date, compared with 52 wells offshore. Three-quarters of these wells, and the majority of the known hydrocarbon accumulations, lie in the northern part of the basin.

The exploration of the Perth Basin led to the discovery of 20 commercial oil and gas fields and numerous additional significant discoveries of varying size. WAPET was responsible for the discovery of most of these fields. Other notable discoveries were the Woodada gasfield by Hughes and Hughes Oil and Gas, and the Beharra Springs gasfield by Barrack Energy. Recent discoveries are gas-condensate at Gingin West and gas at Redback South in 2009 and gas-condensate at Red Gully in 2011.

Producing fields in 2014 were Beharra Springs, Beharra Springs North, Corybas, Dongara, Gingin West, Hovea, Red Gully, Redback and Tarantula.

Petroleum Prospectivity

Of the 20 commercial hydrocarbon fields discovered in the northern Perth Basin, Dongara is by far the largest, with 14.3 Gm^3 (508 Bcf) of original in-place gas and 16.6 GL (104 MMbbl) of original in-place oil. Additional discoveries were made both in the northern and southern Perth Basin, some of which are currently being delineated (Table 8).

Petroleum-system analysis of the basin indicates that mature source rocks are widespread, reservoirs are abundant, and structures are well timed for hydrocarbon entrapment. These petroleum systems are defined as Transitional and Gondwanan. The seal is considered to be a critical factor owing to the intense faulting and high sand-to-shale ratio of the post-Lower Triassic succession.

The main source for gas is the Permian Irwin River Coal Measures, with reservoirs in the Upper Permian and Jurassic. The main source for oil is the base of the marine Lower Triassic Kockatea Shale, with reservoirs in Lower Triassic and Permian sandstones. Oil was also recovered from the Lower Cretaceous reservoir immediately offshore from Perth at Gage Roads 1. Before 2001, the success rate of wells drilled in the northern part of the basin was about one in ten. Since then, several discoveries in 2001 and the application of 3D seismic surveys led to a higher success rate. Major play types include Permian–Triassic and Jurassic anticlines, as well as Permian-Triassic tilted fault blocks and stratigraphic traps.

No commercial fields have been discovered to date in the onshore southern Perth Basin, even though hydrocarbon shows were encountered in several wells. Gas flowed on test from the Permian Sue Coal Measures in wells in the Whicher Range field. The Permian to Cretaceous stratigraphic and structural evolution of the southern Perth Basin is similar to that of the northern Perth Basin, but marine intervals are not present in the south, where continental depositional environments dominated until the late Neocomian. Consequently, thick regional shales are absent, and the area may have poor sealing potential. However, potential reservoirs, source rocks for both gas and oil, and anticlinal traps are well documented. There is ongoing interest in the potential for production from known tight gas reservoirs in the area, using enhanced recovery and new production and drilling techniques.

There are many untested hydrocarbon prospects in the Perth Basin. The logistics and economics of potential oil and gas discoveries are very positive, particularly since the deregulation of Western Australian gas markets in 1988.

The northern Perth Basin is being explored for tight gas. The basin has several known tight gasfields, including Warro, Gingin and West Erregulla. DMP estimates that known Perth Basin tight gasfields hold between 0.2 – 0.4 Gm^3 (9 – 12 Tcf) of recoverable gas, located in the vicinity of existing pipelines. The formations with the highest tight gas potential include the Cattamarra Coal Measures, Cadda Formation, Irwin River Coal Measures, Dongara Sandstone, and Willespie Formation; however, little evaluation of these formations has been conducted to date; essentially this is greenfields exploration.

The Perth Basin is undergoing initial testing by AWE and Norwest Energy in the prospective Triassic and Permian marine shale targets. In 2010, AWE drilled the first well with shale gas targets, Woodada Deep 1, to investigate the Carynginia Formation, the Kockatea Shale, and the Irwin River Coal Measures. Initial results of the core testing compared the shales of the middle interval of the Carynginia Formation favourably with US gas shales, and high-graded the formation for further evaluation. Extensive coring programs were carried out at Woodada Deep 1 and Arrowsmith 2 in 2011. In 2012 three shale gas wells were fracced in the northern Perth Basin (Woodada Deep 1, Senecio 2, and Arrowsmith 2).

The Petroleum Division has conducted an evaluation of the northern Perth Basin shale gas resources and has identified the Irwin River Coal Measures, the Carynginia Formation (Figure 27) and the Kockatea Shale (Figure 28) as the most prospective formations. These maps identify areas of thermal maturity and show the potential for both oil and gas from shale resources. Table 10 shows shale gas resources in-place in the northern Perth Basin based on several recent studies of the potential of the Kockatea, Carynginia and Irwin River Coal Measures (Bahar et al., 2011; EIA, 2013; Cook et al., 2013).

In the southern Perth Basin, the Whicher Range gasfield has been known as a potentially productive source of gas since 1968, when the first Whicher Range exploratory gas well was drilled. One of the Whicher Range wells was recently side-tracked (December 2013) using underbalanced oil-based mud to minimise formation damage.

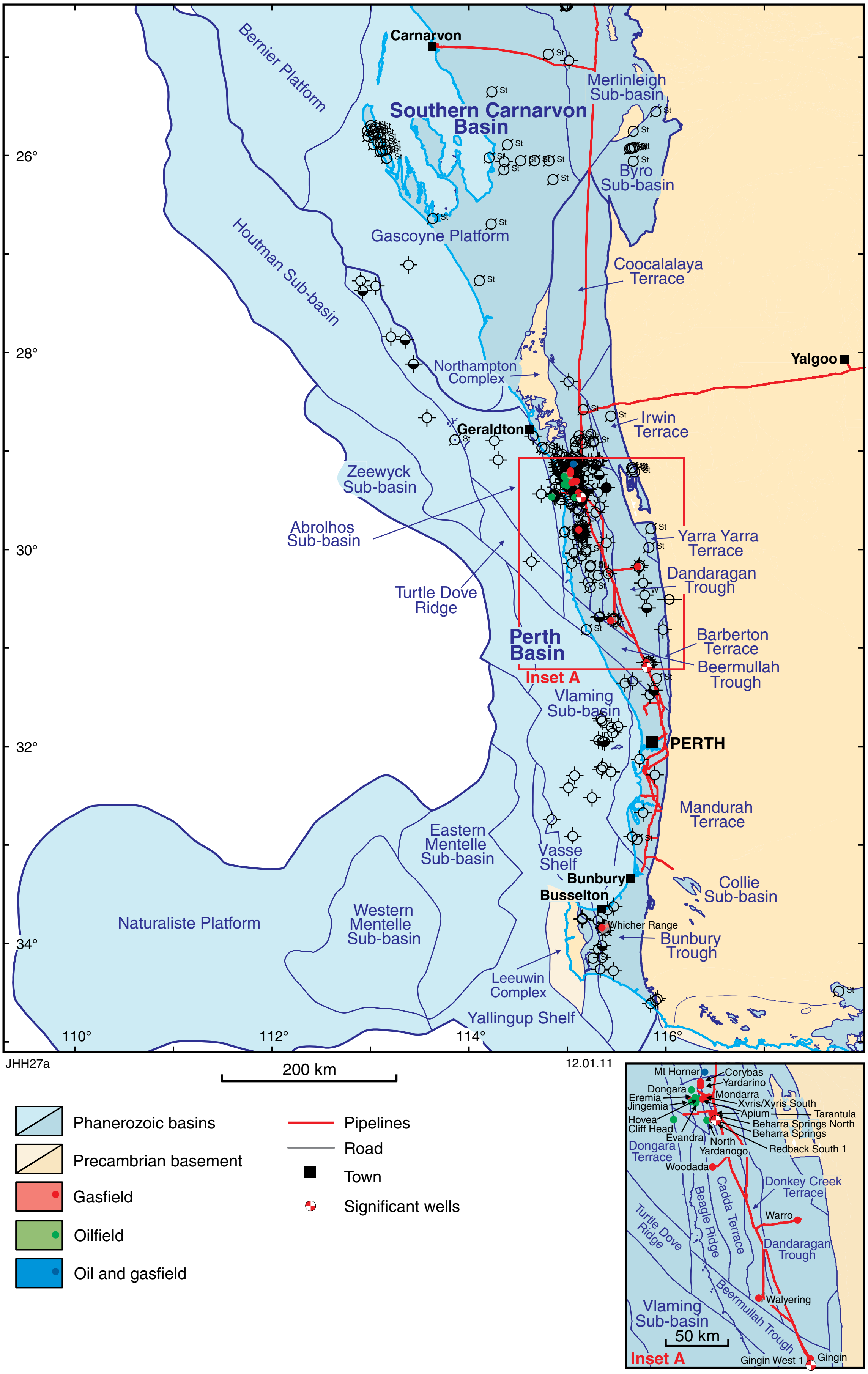


Figure 25. The Perth Basin, showing tectonic units, pipelines, fields, and petroleum wells

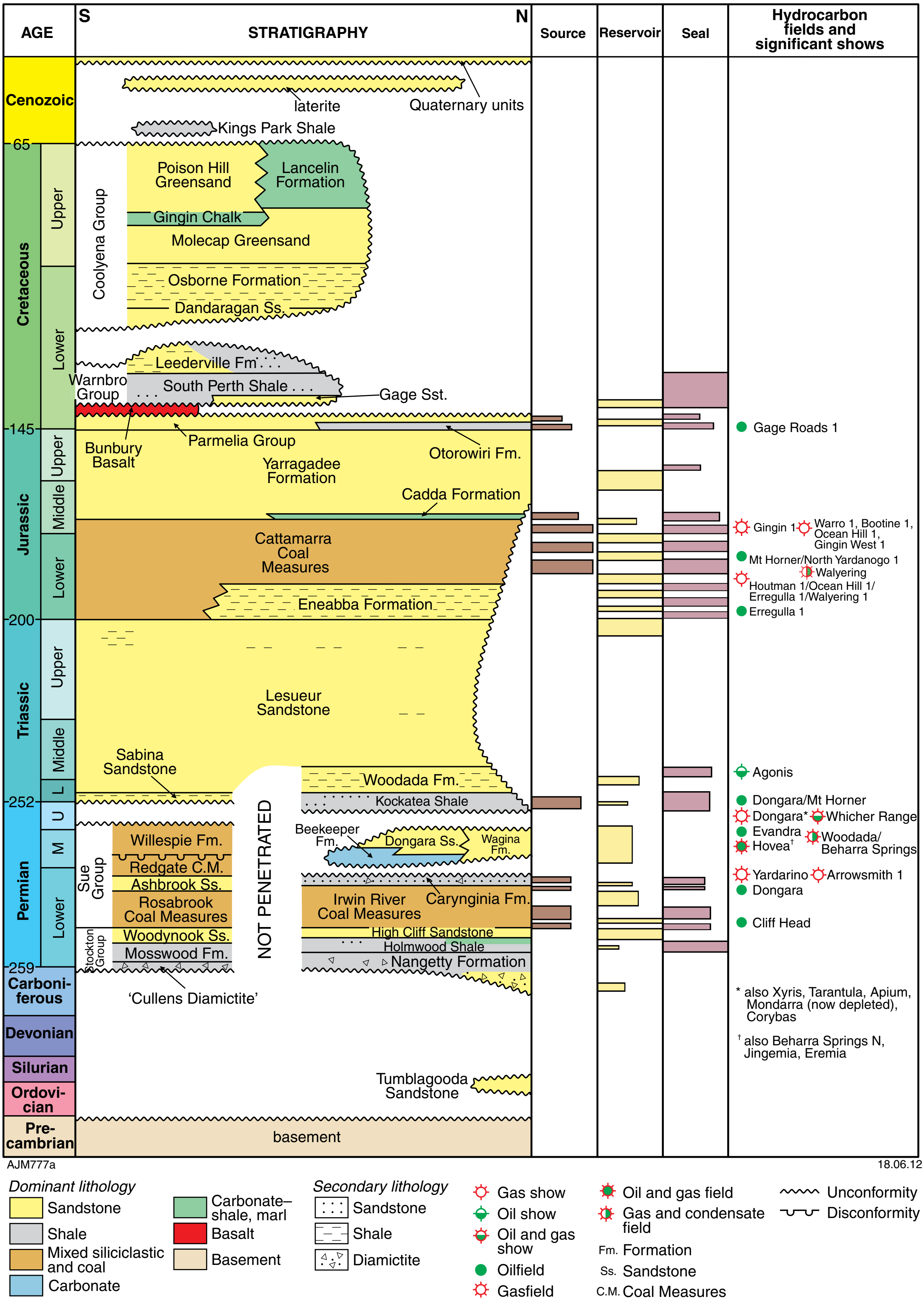


Figure 26. Stratigraphy and petroleum systems of the onshore Perth Basin

Table 8. Fields and significant discoveries in the Perth Basin

YEAR	FIELD/DISCOVERY	OIL/GAS	RESERVOIR	AGE OF RESERVOIR
1964	Yardarino	gas	Dongara	Upper Permian
		oil, condensate	Carynginia/IRCM	Lower Permian
1965	Mount Horner	oil	Cattamarra	Lower Jurassic
			Arranoo	Lower Triassic
			Dongara	Upper Permian
			IRCM	Lower Permian
1965	Gingin	gas, condensate	Cattamarra	Lower Jurassic
1965	Arrowsmith 1	gas show	Carynginia	Lower Permian
1966	Dongara	gas	Dongara	Upper Permian
		oil, condensate	Carynginia/ IRCM	Lower Permian
		oil	Arranoo	Lower Triassic
1966	Erregulla 1	gas shows	Cattamarra/Eneabba	Lower Jurassic
		oil shows	Eneabba	Lower Jurassic
1968	Whicher Range	gas, oil show	Willespie	Lower Permian
1968	Mondarra 1	gas, condensate	Dongara	Upper Permian
		oil show		
1968	Gage Roads 1	oil show	Carnac	Lower Cretaceous
1968	Mondarra 2	gas, condensate	Dongara	Upper Permian
1971	Walyering	gas, condensate	Cattamarra	Lower Jurassic
1977	Warro 1	gas show	Yarragadee/Cadda	Jurassic
1980	Woodada	gas, condensate	Beekeeper	Upper Permian
1981	Bootine 1	gas shows, oil shows	Cadda/Cattamarra	Lower Jurassic
1990	North Yardanogo	oil	Cattamarra	Lower Jurassic
1990	Beharra Springs	gas, condensate	Dongara/Beekeeper	Upper Permian
1991	Ocean Hill 1	gas show	Cadda/Cattamarra	Lower Jurassic
2001	Hovea	gas, oil	Dongara	Upper Permian
2001	Beharra Springs North	gas, condensate	Dongara	Upper Permian
2002	Cliff Head	oil	IRCM	Lower Permian
2002	Jingemia	oil, gas	Dongara	Upper Permian
2004	Redback 1	gas	Wagina	Upper Permian
2004	Xyris	gas	Dongara	Upper Permian
2004	Apium	gas	Dongara	Upper Permian
2004	Tarantula	gas	Wagina	Upper Permian
2004	Agonis 1	gas	Dongara, Wagina	Upper Permian
		oil	Woodada	Triassic
2004	Centella 1	oil	Dongara	Upper Permian
2004	Xyris South 1	gas	Dongara	Upper Permian
2005	Corybas 1	gas	IRCM	Lower Permian

Table 8. Fields and significant discoveries in the Perth Basin continued				
YEAR	FIELD/DISCOVERY	OIL/GAS	RESERVOIR	AGE OF RESERVOIR
2006	Eremia+	oil, gas	Dongara	Upper Permian
2009	Gingin West 1	gas	Cadda/Cattamarra	Lower–Middle Jurassic
2009	Redback South 1	gas	Wagina	Upper Permian
2011	Red Gully 1	gas, condensate	Cadda/Cattamarra	Lower–Middle Jurassic
NOTE: + Determined in 2006 as a separate field to Jingemia, previously regarded as a pool within the Jingemia field+				

Table 9. Comparison of volumetric estimates for shale gas in the Perth Basin in Gm^3 (Tcf volumes in brackets)

	KOCKATEA			CARYNGINIA			IRWIN RIVER COAL MEASURES
	Bahar et al 2011	EIA 2013	ACOLA 2013	Bahar et al 2011	EIA 2013	ACOLA 2013	Triche and Bahar 2013
GIIP	102 (36.0)	125 (44.0)	283 (100.0)	286 (101.0)	351 (124.0)	278 (98.0)	244 (86.0)
Recoverable Resource	152 (5.4)	226 (8.0)	849 (30.0)	425 (15.0)	707 (25.0)	821 (29.0)	37 (13.0)
Risked GIIP [50% RF]	509 (18.0)	623 (22.0)	1415 (50.0)	1430 (50.5)	1755 (62.0)	1387 (49.0)	122 (43.0)
Risked GIIP [30% RF]	306 (10.8)	374 (13.2)	849 (30.0)	858 (30.3)	1053 (37.2)	832 (29.4)	730 (25.8)
Risked Recoverable Resource [30% RF, 15% ReF]	45 (1.6)	57 (2.0)	127 (4.5)	130 (4.6)	159 (5.6)	125 (4.4)	110 (3.9)

RF: Risk Factor
ReF: Recovery Factor
*extrapolated here from published data

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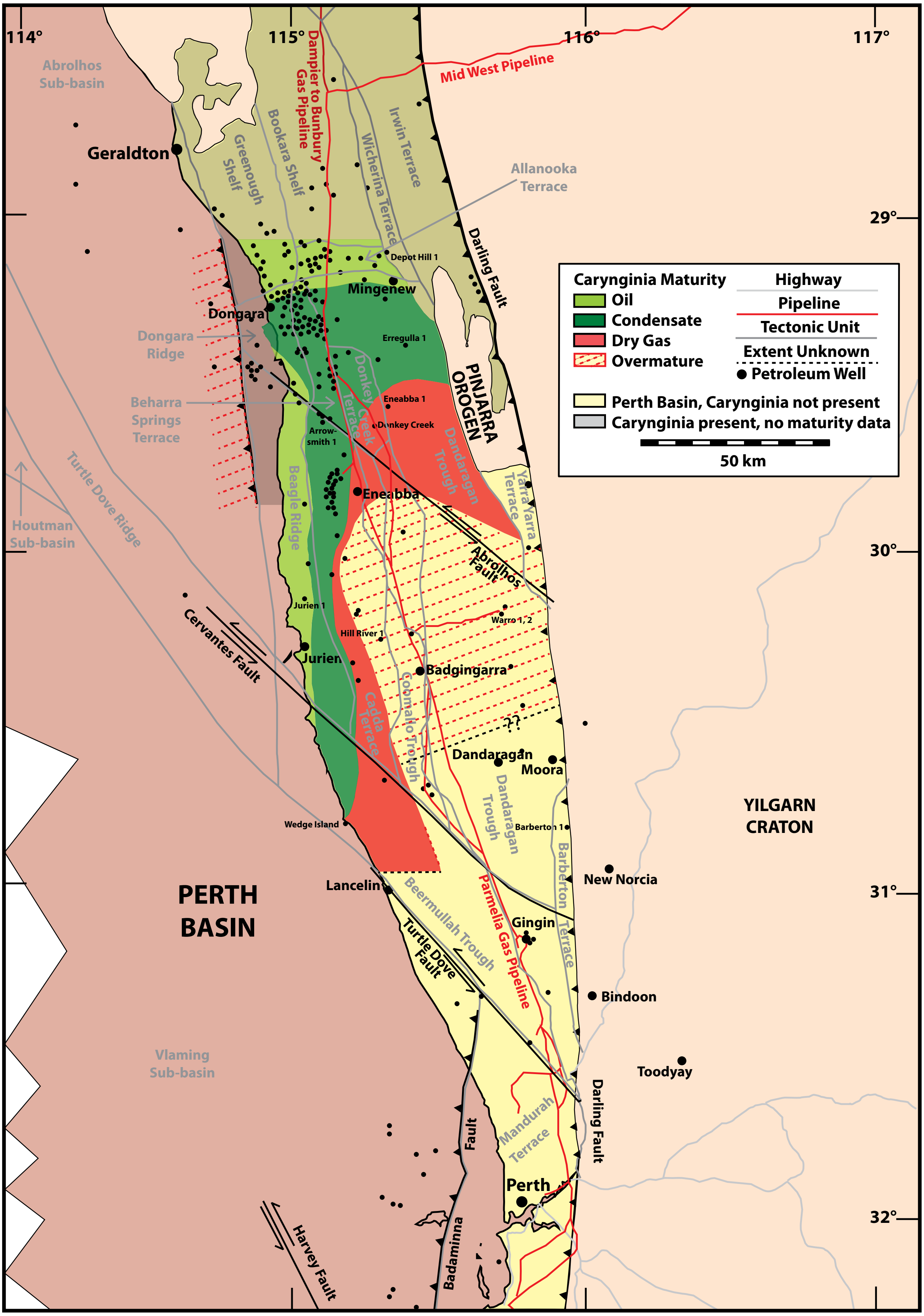

Figure 27. Thermal maturity and prospectivity of the Carynginia Formation

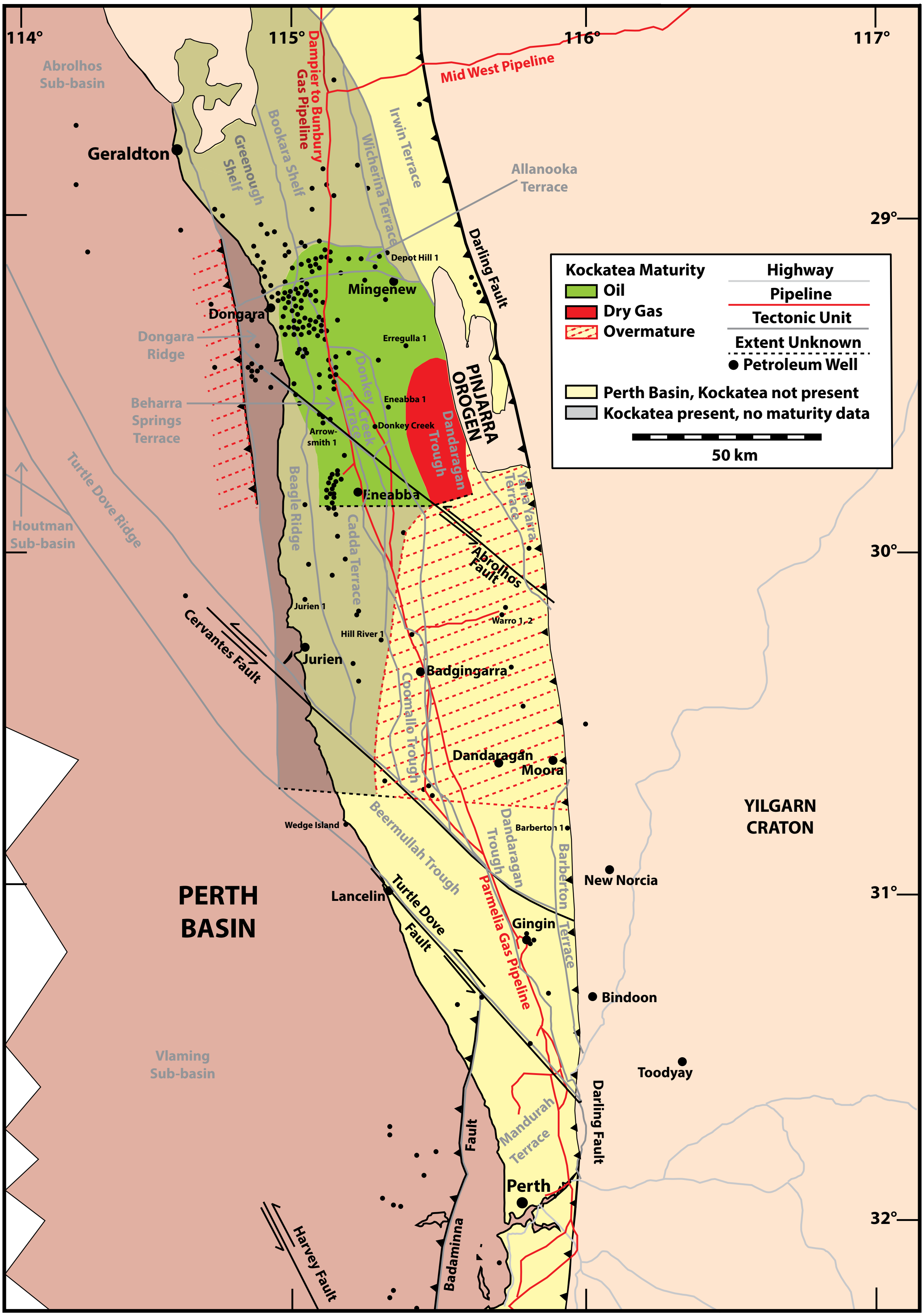

Figure 28. Thermal maturity and prospectivity of the Kockatea shale

Geologist measuring surface values of uranium, thorium and potassium from granite outcrops in the Vasse region with a hand-held scintillometer

Introduction

Geothermal energy is a low emission alternative energy source to traditional fossil fuels. Geothermal energy resources are administered under the *Petroleum and Geothermal Resources Act 1967* (PGER Act) and all current exploration titles are landward of the coastline.

Geothermal energy can be exploited in various Western Australian regions in a number of ways depending on the density of industrial, commercial and domestic markets. Geothermal explorers are directing their interests not only towards electricity generation, but also low temperature heat-energy applications such as air conditioning, pool heating and agriculture. Presently there is no commercial production of geothermal energy in Western Australia.

The Premises for Geothermal Prospectivity in Western Australia

The general prospectivity for geothermal energy is governed by the intended use of the energy and the type of development planned for its exploitation. The premises for geothermal prospectivity are, therefore, both technical and economic. Each of the three main types of geothermal development is linked to a specific temperature–depth range. The three main types of geothermal developments are:

- hot dry rock (HDR),
- hot aquifer (HA) or hydrothermal, and
- shallow heat pumps or heat exchangers.

Geothermal heat sources, in terms of ambient rock temperature that are relevant for energy usage, fall into three classes:

- temperature less than 60 ºC, i.e. low temperature heat sources (typical applications: air conditioning, pool heating and agriculture);
- temperature from 80 ºC to 250 ºC, i.e. hot aquifer (HA) or hydrothermal heat sources (typical applications: low efficiency electricity generation and industrial heating systems); and
- temperature greater than 250 ºC, i.e. hightemperature heat sources such as hot dry rock sources and volcanic sources (usual application: electricity generation).

When the temperature is in the vicinity of 40 ºC to 60 ºC, the geothermal development is from relatively shallow (less than 1000 m) sources, and focuses on heat pumps, air conditioning and agriculture. For a hot aquifer (HA), or hydrothermal development, an aquifer with good porosity and permeability, and a temperature in the range 80 ºC to 250 ºC, is the target. A hot dry rock (HDR) development captures heat from fractured basement rocks, with the fractures preferably in a sub-horizontal orientation, and at a temperature in excess of 250 ºC. Volcanic sources are not relevant to Western Australia. Figure 29 shows a schematic of the three main types of geothermal applications relevant for Australia.

Dry-steam rankine-cycle turbines, such as used in coal-powered electricity generation, optimally operate at temperatures of about 350 ºC, and would require a geothermal well in excess of 6 km depth in most parts of Western Australia. Therefore, in terms of electricity generation, the use of organic rankine cycle (ORC) turbine systems are probably best-suited for geothermal energy sources possessing a temperature range of 80 ºC to 250 ºC. There is a loose correlation between temperature of the source versus the amount of electric power that an ORC turbine can generate, and is summarised in Table 10.

This table suggests that a 90 ºC to 110 ºC geothermal source at 2000 m would have to be gauged as non-prospective, if the geothermal developer had to carry the full investment cost of drilling an extraction and injection well. However, if the principal reason for drilling the wells was other than geothermal, for example petroleum exploration, it may prove economically viable to establish a small geothermal-driven electricity generation plant for a small local community or commercial enterprise.

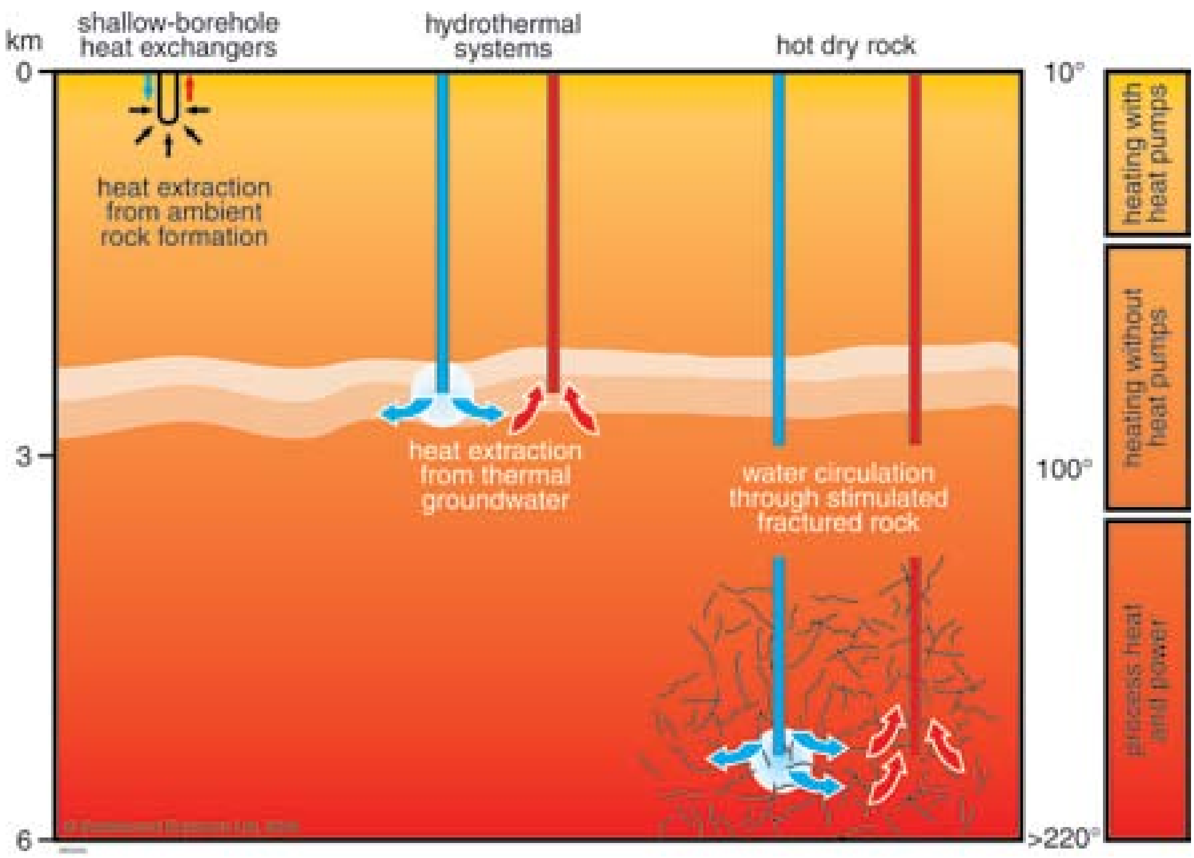

Figure 29. Types of geothermal resources from the Earth's heat. All systems show extraction wells (red) and injection wells (blue) (Courtesy of Geothermal Explorers Ltd)

GEOTHERMAL ENERGY RESOURCES

Economic considerations come into play when one balances the amount of thermal energy that can be extracted from rocks of a particular temperature, the cost to gain access (i.e. drill and perhaps create fracture porosity and permeability), and the mechanism to convert the thermal energy in the subsurface to usable energy at the surface (e.g. electricity, space heating, etc).

The cost to drill a 2000 m well will be at least A$10–15 million, and probably more depending on location. A 10-well development (five extraction and five injection wells to approximately 2000 m each) will probably cost in excess of A$50 million, excluding the electricity generation plant and connection to an electricity-power grid. Hence, in establishing prospectivity, it is important to consider the economic viability of anticipated geothermal projects.

Most of the easily accessible geothermal resources in Western Australia fall in the temperature range of 40 °C to 150 °C (see Tables 11 to 13 in the basin geothermal prospectivity summaries). Furthermore, the tables demonstrate that the temperature range 40 °C to 150 °C corresponds with a depth interval from 200 m to 4500 m.

A recent study by the GSWA shows that the most prospective basin for geothermal energy appears to be the Carnarvon Basin, followed by the Canning and Perth Basins. This is based on the present-day geothermal gradient of wells where the estimated depth to 200 °C is less than 5000 m.

These three specific regions are reviewed below. Detailed information about the geology of the main sedimentary basins of Western Australia is provided in the "Petroleum Prospectivity" chapter and is not repeated here. In the following sections, the main focus lies on providing additional information about the geothermal prospectivity of these three regions.

Table 10. Chart showing notional electrical power generated by a binary ORC turbine for various geothermal source temperatures and thermal power input. The thermal power input is governed by the temperature and flow rate of water/steam from the geothermal source and the type of heat exchanger used to transfer the heat energy from the geothermal fluid to the operating fluid of the ORC.

GEOTHERMAL SOURCE TEMPERATURE (ºC)	TYPICAL THERMAL POWER INPUT (KW)	TYPICAL ELECTRICAL POWER OUTPUT (KW)
90	120	10–12
150	2000	50–200
280	11,000	500–2000

Geothermal Prospectivity

Perth Basin

The major population centres in Western Australia are located in the Perth Basin region, and as such, it encompasses the major energy demand in the State. Exploration for, and implementation of, geothermal energy in the Perth Basin is advantageous for future domestic energy supply.

Table 11 shows selected petroleum exploration wells drilled in the Perth Basin and details of the maximum temperature (referred to as bottomhole temperature or BHT) and depth of measurement for each well. The localities of these wells are shown in Figure 30. The table also presents mean annual surface temperature (from Chopra and Holgate 2007) and geological unit, porosity and permeability information for the deepest potential aquifer intersected in each well. It is important to note that the measured BHT will be less than the true formation temperature in most cases, as invasion of the formation by drilling fluid, during drilling operations, has the effect of initially decreasing the temperature in the borehole by 10 to 20 ºC. Various correction techniques have been proposed, but there is inconsistent data from many wells to make a reliable correction. Therefore, the maximum measured BHT is quoted rather than a true formation temperature with inconsistent accuracy.

A maximum BHT of 60 ºC is commonly encountered between 1000 and 1500 m, and 90 ºC is commonly measured at about 2000 m. The deepest well drilled in this dataset is West Erregulla 1 with a maximum BHT of 144 ºC at a depth of 4064 m. A previous study by Chopra and Holgate (2007) suggests that it is probably necessary to drill more than 5 km to encounter true formation temperatures in excess of 250 ºC over most of the Perth Basin. Overall, the Perth Basin is most prospective for:

- low temperature systems, with heat tapped in the 1000 to 1500 m depth range, and
- HA systems with heat drawn from aquifers in the depth range of 2000 to 3000 m.

Carnarvon Basin

Based on the study of Chopra and Holgate (2007), the onshore Carnarvon Basin appears to be warmer than the Perth Basin. Table 12 presents the BHT maximum temperature and potential aquifer data for selected wells (location in Figure 31) in the Carnarvon Basin. From this table, 80 ºC commonly occurs in the depth range of 1000 to 1500 m. Although, a number of exceptions probably occur in the basin, for example a temperature of 82 ºC has been measured in Tubridgi 4 at 589 m.

It is also common to find a temperature of 60 ºC between 600 and 700 m in many parts of this basin (see Table 12). In this shallow zone, less than about 1500 m, the Carnarvon Basin apparently possesses higher temperatures than the Perth Basin. This could be caused by either higher heat flow or a lower magnitude of the thermal conductivity of the shallow sediments, in the onshore Carnarvon Basin relative to the Perth Basin. Very little good quality heat flow or thermal conductivity data are available for either basin. If the difference is caused by thermal conductivity alone, then the average thermal conductivity of the shallow sediments in the Carnarvon Basin would be expected to be about two-thirds of the average thermal conductivity of the shallow sediments in the Perth Basin.

In terms of potential geothermal usage in the Carnarvon Basin, shallow low temperature (ca. 60 ºC to 80 ºC) geothermal applications may be attractive for specific industrial applications or community heating and cooling. Generation of electricity through combinations of ORC turbines, or combined geothermal and solar energy, may be attractive also for small communities or mining centres.

Canning Basin

The Canning Basin is remote in terms of population and infrastructure. Nevertheless, geothermal energy may be attractive to produce electricity for small communities, cattle stations, agricultural industries and other activities in the region. Solar-supplemented geothermal energy is a viable energy source for small electricity generation plants of 10 to 20 kW, again based on ORC turbines. Table 13 shows selected wells (location in Figure 32) with temperature and potential deep aquifer information.

The Canning Basin commonly has maximum BHTs of about 90 ºC to 100 ºC at approximately 2000 m (Table 13). Where a well has been drilled to greater depths, the observed BHT does not necessarily increase linearly. For example, the maximum BHT at Mimosa 1 is 143 ºC and at St. Georges Range 1 is 113 ºC, being measured at 4115 m and 4431 m, respectively.

It has been estimated that the geothermal energy plant at the remote outback town of Birdsville in Queensland saves A$135,000 annually in costs for diesel to run electricity generators, and reduces 430 tonnes of greenhouse emissions. Such a philosophy may also be applied to remote Western Australian communities or commercial enterprises. Thus, a A$30,000 complete 10 kW ORC package built around a dry exploration petroleum well, which has been completed as a water producer in a deep aquifer, may become an attractive power source for a remote community or industry.

Table 11. List of selected wells for the Perth Basin with maximum bottomhole temperature (BHT), the depth of BHT measurement, mean annual surface temperature and details of the deepest potential aquifer (including porosity and permeability, if available). Refer to Petroleum Prospectivity chapter for stratigraphic information, and Figure 30 for locality.

WELL	DEPTH OF BHT (m)	SURFACE TEMP. (ºC)	MAX BHT (ºC)	DEEPEST AQUIFER (LITHOLOGY)	POROSITY (%)	PERMEABILITY (md)
Allanooka 1	1186	20	60	Nangetty Fm (sst)	~ 2 (fractured)	–
Arramall 1	2246	20	97	Irwin River Coal Measures (IRCM) (sst) over granite	–	–
Beekeeper 1	3013	20	119	IRCM (sst)	low	–
Beharra Springs 3	3503	20	135	Carynginia Fm sst	5–18	–
Bonnifield 1	1011	20	60	Carynginia Fm (sst) over granite	15–23	–
Conder 1	252	20	31	Triassic (sst) over metasediments	~ 12	–
Cypress Hill 1	989	20	57	Parmelia Group (sst) over Otorowiri Fm	25–34	142–930
Denison 1	2302	20	97	Nangetty Fm (sst) over Tumblagooda Sst	8–16 ~ 8	–
Depot Hill 1	2467	20	122	Nangetty Fm (sst)	~ 11.5	–
Dongara 1	2160	20	88	Dongara Sst (1671 m); over Nangetty Fm (sst)	~ 20 ~ 18	~ 190 ~ 5
East Lake Logue 1	2430	20	113	Carynginia Fm (lst) over shale	10–20	–
East Lake Logue 1	2430	20	122	DST: Basal Kockatea Shale & Carynginia Fm (lst)	Flowed 0.295 Mm^3/d (10.4 MMcf/d) gas	
Eleven Mile 1	322	20	36	Basal Triassic sst over metasediments	13–24	–
Gairdner 1	2170	19	99	IRCM (sltst)	low	–
Georgina 1	1825	20	77	IRCM (sltst)	–	–
Horner West 1	1442	20	68	Nangetty Fm (sst)	10–28	
Indoon 1	2255	20	109	Carynginia Fm (lst) over shale	fractures	fractures
Mooratara 1	1500	20	74	High Cliff Sst	~ 21	–
Mount Horner 1	2253	20	79	Nangetty Fm (siltstone)	low	–
Mountain Bridge 1	3415	20	139	High Cliff Sst (3218 m; sst) over granite	~ 10.4 + fractures	~ 0.01 + fractures
North Yardanogo 1	2380	20	91	Lesueur Sst	10–14	–
Peron 1	2601	19	120	Holmwood Shale over acid igneous basement	Poor aquifer	
Point Louise 1	948	19	61	IRCM (sltst)	~ 5	–
Robb 1	1980	20	89	10-m thick sst unit in Holmwood Shale	~ 15	–
South Yardanogo 1	2341	20	93	no data	–	–
Tabletop 1	1785	20	78	IRCM (sst)	2–22; average=15	–
Warradong 1	3715	20	146	Carynginia Fm (3368–3397 m; lst) over IRCM	~ 9 low	–
Warramia 1	1478	19	63	Yarragadee Fm (sst)	~ 19	–
Warro 1	3430 4310	20	106 121	Yarragadee FM (sst) Cadda Fm (sltst, sst)	9–17 3–6	–
Wattle Grove 1	805	20	52	Carynginia Fm (sst) over granite	17–27	–
West Erregulla 1	4064	20	144	Kockatea Shale (basal sst) over Wagina Sst	5–10 ~ 5	–
West White Point 2	2354	20	94	Carynginia Fm	low	low
Woodada 1	2357 2354	20	117 106	Carynginia Fm (lst) (2242 m; lst) over IRCM	1–6 matrix + fractures low	Fractures low
Woodada 2	2453	20	112			
Woodada 3	2477	20	99	Carynginia Fm (2343 m; lst)	1–3 matrix + fractures	0.01–1425
Woodada 3	2518	20	97	as above	as above	as above
Woodada 5	2781	20	131	Carynginia Fm (2343 m; lst) over IRCM	1–6 matrix + fractures low	very low low
Yardarino 2	3075	20	116	Nangetty Fm (sltst)	3–5	–

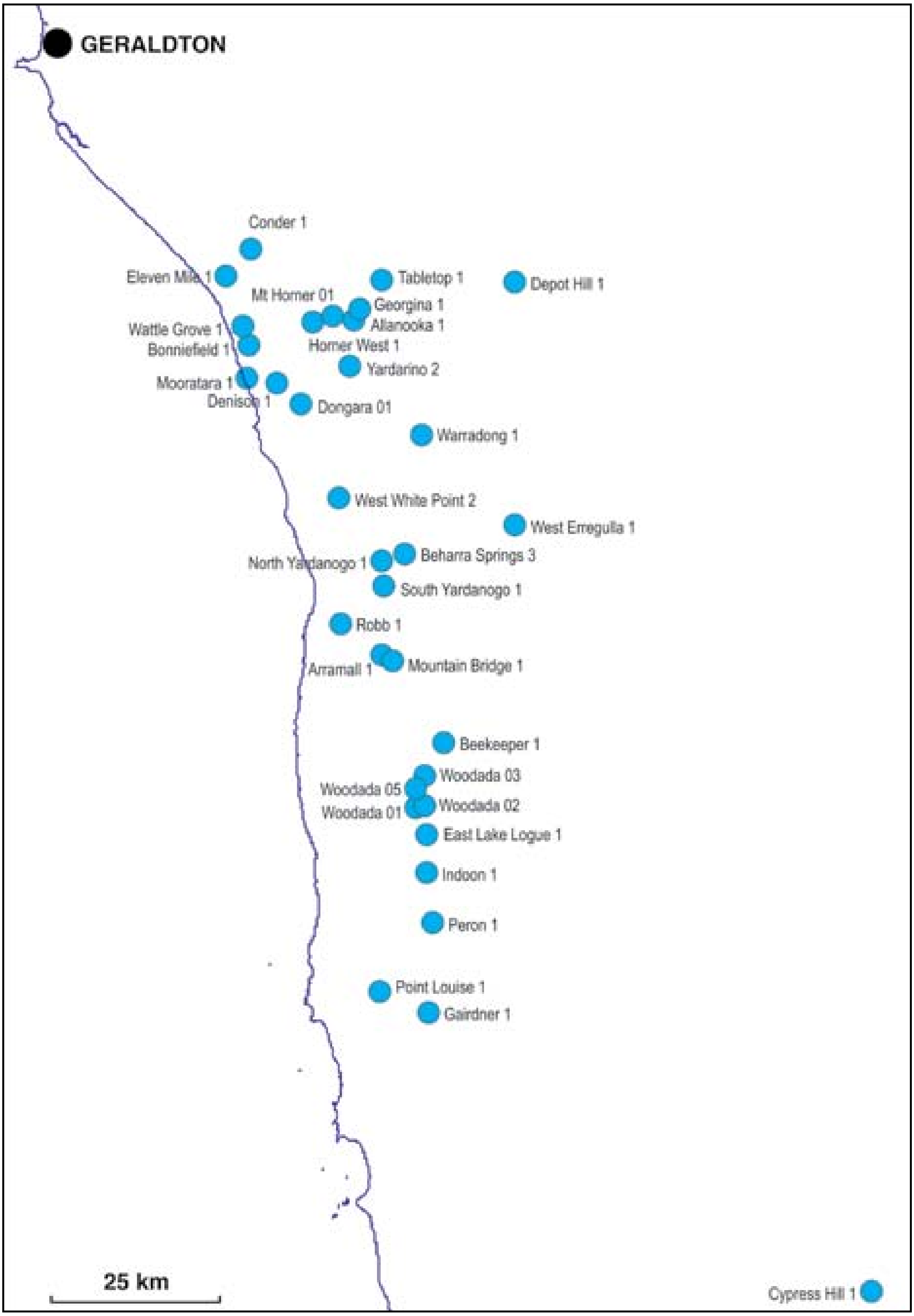

Figure 30. Locality map for selected wells in the Perth Basin listed in Table 11

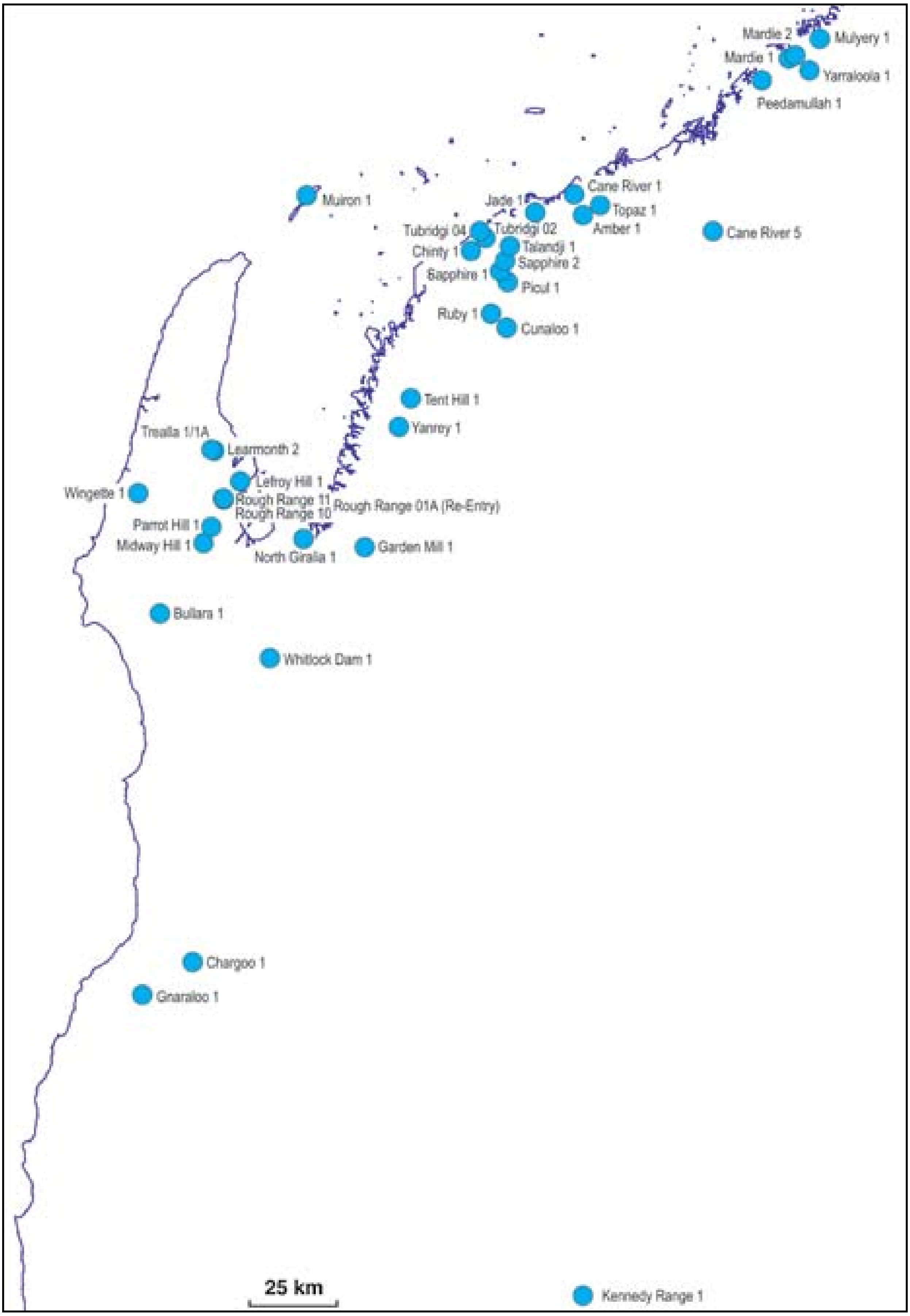

Figure 31. Locality map for selected wells in the Exmouth region of the Carnarvon Basin listed in Table 12

Table 12. List of selected wells for the Carnarvon Basin with maximum bottomhole temperature (BHT), the depth of BHT measurement, mean annual surface temperature and details of the deepest potential aquifer (including porosity and permeability, if available).
Refer to Petroleum Prospectivity chapter for stratigraphic information, and location in Figure 31.

WELL	DEPTH OF BHT (m)	SURFACE TEMP. (ºC)	MAX BHT (ºC)	DEEPEST AQUIFER (LITHOLOGY)	POROSITY (%)	PERMEABILITY (md)
Amber 1	679	26	59	Quail Fm (sst units)	10–25	–
Bullara 1	1298	24	80	no data	–	–
Cane River 1	693	26	57	Lower Carboniferous (570–610 m; sst)	15–20	–
Cane River 5	197	26	37	Yarraloola Conglomerate over metamorphic basement	good	–
Chargoo 1	427	24	46	Lyons Group (sst)	fair	–
Chinty 1	1673	25	89	Chinty Fm (sst)	14–23	–
Cunaloo 1	795	25	58	Kennedy Group (sst)	~ 20	–
Garden Mill 1	544	25	63	Permian (sst) over metamorphic basement	16–24 average=19	– –
Gnaraloo 1	503	24	53	Quail Fm	poor	poor aquifer
Jade 1	601	26	54	Mungaroo Fm (sst)	~ 25	-
Kennedy Range 1	2218	24	100	Moogooloo Sst (2013 m; sst) over Lyons Group	11–18 very low	<0.01 very low
Learmonth 2	1732	25	86	Triassic (sst)	moderate	–
Lefroy Hill 1	1494	25	81	Learmonth Fm (1488 m; sst) over Kennedy Group (shale and sltst)	19–25 poor	– poor
Mardie 1	214	26	36	Yarraloola Conglomerate over Carboniferous claystone	good	–
Mardie 2	165	26	41	Yarraloola Conglomerate	good	–
Midway Hill 1	1308	25	78	Learmonth Fm (sst)	5–15	–
Muiron 1	1780	25	104	Dingo Claystone (occasionally sandy)	15–25	poor
Mulyery 1	139	26	41	Yarraloola Conglomerate	good	artesian aquifer in region
North Giralia 1	913	25	67	Byro Group (shale)	very poor	very poor
Parrot Hill 1	1261	25	90	Jurassic (sst)	11–20.5 average=16	–
Peedamulla 1	327	26	43	Gneuda Fm (sst)	~ 15.5	2
Picul 1	491	25	51	Locker Shale (occasional sst beds)	good (visible)	–
Rough Range 1	1117 2438	25	82 93	Birdrong Sst (1117 m; sst) over Lyons Group (2438 m; sst)	~ 15.5 fair	900–1000 –
Rough Range 10	1139	25	66	Wogatti Sst	good (visible)	–
Rough Range 11	1166	25	79	Wogatti Sst	excellent (visible)	
Ruby 1	415	25	54	Permian Nalbia Sst	23–38	–
Sapphire 1	553	25	54	Locker Shale (393–510 m; sst)	10–23	–
Sapphire 2	575	25	59	Locker Shale (sst above 580 m)	10–23	–
Talandji 1	1487	25	83	Locker Shale (1422–1488 m; sst)	10–20	–
Tent Hill 1	577	25	58	Birdrong Sst over metasediments	~ 30	1250–1620
Topaz 1	400	26	48	Quail Fm (353–378 m; sst & congl.) over Moogooree Lst	~ 20 nil	– nil
Trealla 1/1A	1489	25	81	?Jurassic (no data)	no data	no data
Tubridgi 2	592	25	61	Mungaroo Fm (sst)	–	–
Tubridgi 4	589	25	82	Mungaroo Fm (sst)	19–33	–
Whitlock Dam 1	396	24	47	Birdrong Sst (369–390 m; sst) over Byro Group (sst)	25.5–38 fair matrix +fractures	– –
Wingette 1	1433	25	83	Jurassic (1371 m–TD; sst)	~ 20 (near top) Average=10	–
Yanrey 1	408	25	44	Windalia Radiolarite over metamorphic rocks	~ 34	<0.01
Yarraloola 1	268	26	46	Yarraloola Conglomerate (112–156 m; sst & congl.) over Carboniferous (sst)	20–37 5–12	artesian flows in both units at 500,000–1,000,000 gal/day

Technology Considerations

Organic Rankin Cycle (ORC) Turbines

Geothermal resources in many regions in Western Australia are probably best developed in terms of electrical power generation with the use of ORC turbines. This section briefly reviews the functioning conditions of these turbines with respect to Western Australian subsurface temperatures, and also briefly touches on other technologies relevant for geothermal energy.

Conventional steam turbines operate most efficiently when the source temperature is about 350 ºC, and will not work for the relatively low temperatures encountered in HA geothermal regions. In Western Australia, it is expensive to drill to depths where temperatures of 300 ºC to 350 ºC are encountered, which will support a conventional rankine cycle turbine to convert superheated steam into electricity. Accordingly, to convert thermal energy into electricity, many geothermal energy projects make use of ORC technology, which becomes applicable when the source temperature is over 90 ºC. The trade-off of being able to use ORC technology versus conventional dry-steam technology is a loss in conversion efficiency from thermal energy to electrical energy. A conventional dry-steam turbine has a typical thermal-electric efficiency of about 33 per cent, while an ORC turbine may be in the order of 10 to 15 per cent efficiency.

ORC turbines, which can generate from 10 kW to over 2 MW, are currently available off-the-shelf from a number of international distributors. Figure 33 shows the basic working principal of the binary cycle power plant in conjunction with a HA geothermal source. The beauty of the ORC turbine is that the working fluid needs only to be heated to 90 ºC for many ORC systems to function, although higher temperatures are desirable. A review of the literature of available off-the-shelf ORC turbines indicates that a 90 ºC temperature source will generally only permit generation of 10 kW of electrical power, whereas a 270 ºC source can generate up to 2 MW (see Table 9).

Furthermore, electricity generation through combinations of 10 or 20 kW ORC turbines may be attractive for small communities or mining centres. It is important to recognise that a combination of 10 x 12 kW ORC turbines in series is comparable to the artesian-based (1230 m deep) geothermal plant currently in use at Birdsville in Queensland. Such a power option may be attractive in remote towns and communities in Western Australia, bearing in mind that an off-the-shelf 12 kW ORC turbine costs in the vicinity A$30,000, and that replacement of the Birdsville geothermal power station is estimated to cost in the range of A$8 million.

Heat Pipes

A heat pipe is a heat-transfer mechanism that can transport large quantities of heat with a very small difference in temperature between hotter and colder regions. Inside the heat pipe, a hot region converts a liquid (working fluid, commonly an organic medium) to vapour, and the gas flows naturally towards the cold region, where it condenses. The liquid flows by capillary action back to the hot region, where the process commences again (Figure 34).

It has been suggested that a heat pipe may be applied to geothermal energy extraction. The technological innovation of a heat pipe is that relatively large amounts of heat may be extracted from a single borehole or well, as the heat pipe contains both the upward and downward flow of the working fluid (see Figure 34). This technology possesses two strong advantages; first, the removal of the necessity of having separate extraction and injection wells, and second; the elimination of having to flow a deep aquifer to the surface, as the heat is transferred by a closed circuit working fluid within the heat pipe.

Lockett (2008) has recently summarised the work of Rice (1985), who proposed the use of a heat pipe in a single borehole system in a HA geothermal field with temperatures of about 200 ºC to 300 ºC. A series of calculations were computed for a hypothetical heat pipe in a 1.5-km borehole. The models indicated that between 0.5 to 0.7 MW of electrical output could be possible for a HA capable of maintaining the deep end of the heat pipe at 200 ºC. Similarly, a 300 ºC HA could generate between 0.7 and 1.3 MW (Rice 1985).

An example of small scale use of geothermal energy – the pool at Challenge Stadium in Perth is heated by geothermal energy (photo courtesy of Grant Bolton)

Table 13. List of selected wells for the Canning Basin with maximum bottomhole temperature (BHT), the depth of BHT measurement, mean annual surface temperature and details of the deepest potential aquifer (including porosity and permeability, if available). Refer to Petroleum Prospectivity chapter for stratigraphic information, and location in Figure 32.

WELL	DEPTH OF BHT (m)	SURFACE TEMP. (ºC)	MAX BHT (ºC)	DEEPEST AQUIFER (LITHOLOGY)	POROSITY (%)	PERMEABILITY (md)
Aquila 1	1734	26	104	Nambeet Fm (sst)	3.5–15.5	–
Babrongan 1	1748	27	93	Famennian (sltst & carbonates)	–	–
Canopus 1	1774	27	95	Willara Fm (sltst & carbonates)	–	–
Cow Bore 1	2589	27	103	Famennian (sltst & shale)	poor	poor
Doran 1	760	27	63	Luluigui Fm (sltst)	6–12	~ 5
East Crab Creek 1	2537	27	98	Tandalgoo Sst & Carribuddy Fm (sst & shale)	poor	poor
East Yeeda 1	3553	28	118	Fairfield Group: Yellow Drum Sst	poor (visual)	–
Edgar Range 1	1964	27	93	Ordovician (lst) over metamorphics	poor	poor
Ellendale 1	3192	27	121	Famennian (sst)	poor	poor
Frome Rocks 2	2282	27	83	Clanmeyer Sltst (fractured and faulted, occasional sst beds)	fair	fair
Fruitcake 1	1691	27	87	Willara Fm (sst)	8–12	–
Goldwyer 1	1414	27	77	?Nita Fm carbonates over granite	poor	poor
Hangover 1	1652	27	81	Anderson Fm (various sst beds)	average=14	–
Hawkstone Peak 1	1186	28	71	?Frasnian (sst unit) over metamorphics	11–17	9–116
Hilltop 1	1734	27	92	Nambeet Fm (sst) over granite	<6	–
Kora 1	3101	28	120	Napier Fm/Van Emmerick Congl. (sst & congl.)	average=14	–
Lake Betty	3133	27	122	Poulton Fm (sst)	poor	poor
Mimosa 1	4115	27	143	Frasnian (3565–4117 m; sst)	1–6	<0.01
Mt. Hardman 1	3355	27	116	Luluigui Fm (siltstone and carbonates)	0–5	–
Mt. Wynne artesian spring	0	27	46	Surface hot spring	Artesian spring; GSWA Bulletin 93 (1927): 60,000-80,000 gal/day	
Napier 1	1799	28	83	Devonian (1706–1773 m sst) over gneiss	3–12	0–3
Nita Downs 1	1835	27	99	Goldwyer Fm (sltst & carbonates)	2–12	0.1–11
					one zone: porosity = 12% permeability = 2680 md	
Notabilis 1	2808	27	100	Tandalgoo Sst & Carribuddy Fm (shale & lst)	–	–
Pictor 1	2146	27	98	Nambeet Fm (sst) over		
				metamorphics	poor	
				(visible)	–	
St. George Range 1	4431	27	113	Laurel Fm (sltst & mudstone)	very poor	very poor
Sundown 3	1219	28	72	Grant Group (sst)	15–17	94–515
Thangoo 1	919	26	59	Odrovician (lst with sst beds)	?cave @ 1059 m; fractures and faulting	
Thangoo 2	1471	26	77	Willara Fm (958–970 m; lst) over	cavernous	cavernous
				Nambeet Fm (1367–1438 m; sst) over gneiss	3–12	<0.1
The Sisters 1	2919	27	132	Devonian (2591–2996 m; shale with thin beds of sst & lst)	vuggy in lst; poor elsewhere	
West Kora 1	2605	28	114	Fairfield Fm (sst & carbonates)	poor	poor
				over Nullara Lst	poor	poor

Table 13 List of selected wells for the Canning Basin continued from previous page						
WELL	DEPTH OF BHT (m)	SURFACE TEMP. (ºC)	MAX BHT (ºC)	DEEPEST AQUIFER (lithology)	POROSITY (%)	PERMEABILITY (md)
West Philydrum 1	1111	27	60	Grant Group (sst)	0–19 average=12	
West Terrace 1	1250	28	71	Grant Group (sst)	17–24	–
Whitewell 1	1751	28	84	Anderson Fm (sst)	10.5–16	–
Willara 1	3904	27	143	Nambeet Fm (sst)	poor	poor
Willara Hill 1	858	27	66	Grant Group (poorly consolidated sst)	18–38 average=30	
Yarrada 1	3293	28	123	?Van Emmerick Congl.	1.5–4.8	0.01–12
Yulleroo 1	4573	27	121	Carboniferous (3395–3401m; sst) and Devonian (ca. 4383 m; sltst)	4.6–11.8 5–10 + fractures	0.01–4.5 –

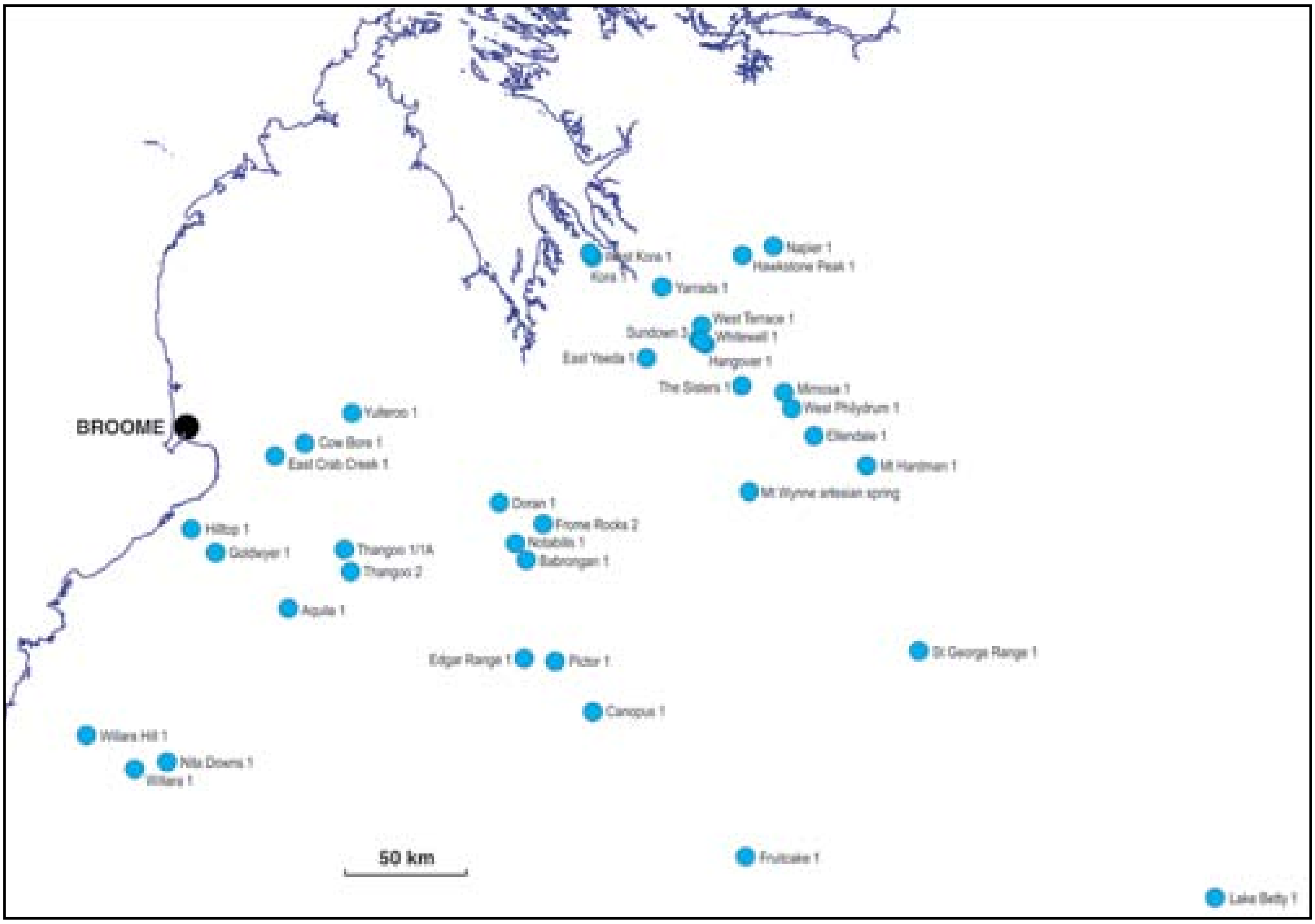

Figure 32. Locality map for selected wells in the Broome region of the Canning Basin listed in Table 13

GEOTHERMAL ENERGY RESOURCES

Kusaba *et al.* (2000) built a small 150 m long geothermal heat pipe at a geothermal site in Kyushu, Japan and demonstrated that 90 kW of thermal energy could be extracted at a working temperature of 80 ºC. In addition, 100 kW of geothermal power, which can be converted to about 7.8 kW electrical power (about 8 per cent thermal-electrical energy conversion efficiency), could be generated by a 300 m heat pipe in a geothermal field of 84 ºC. Reay and Kew (2007) also report on the development of a prototype of the heat pipe turbine with 55 ºC at the evaporator (heat input) and 25 ºC at the condenser. However, the very low temperature system has poor heat-electricity conversion efficiency, requiring 100 kW thermal energy to produce 3 kW of electrical energy, because of the very low temperatures involved.

Heat pipes exhibit the potential for the generation of low levels of electrical power from single boreholes into hot aquifers. The use of such devices may provide a valuable source of energy in small remote communities and commercial projects in Western Australia. The lack of injection and extraction wells, as well as the removal of the necessity to bring hot groundwater to the surface, present significant advantages for this technology. Nevertheless, further research is required into their application, especially improving thermal-electrical energy conversion efficiency.

Conclusions

Western Australia possesses low- to medium temperature geothermal resources that can be exploited to provide moderate levels of electrical power and low-temperature heat energy applications. The onshore Carnarvon Basin appears to possess greater temperatures in the upper 1500 m of the sedimentary succession than the Perth and Canning Basins. Future technological advances, especially in the improved efficiency of ORC turbines and heat pipes, may render much of the Perth Basin and some areas in the Canning Basin amenable to economic geothermal energy developments. Exploration rights for geothermal energy resources can be obtained via application for a Geothermal Special Prospecting Authority with an Acreage Option to undertake an exploratory survey. Based on the results of the survey, a subsequent application for either a Geothermal Exploration Permit or Geothermal Drilling Reservation may be made. More information on geothermal titles can be found in Part 2 of this guide.

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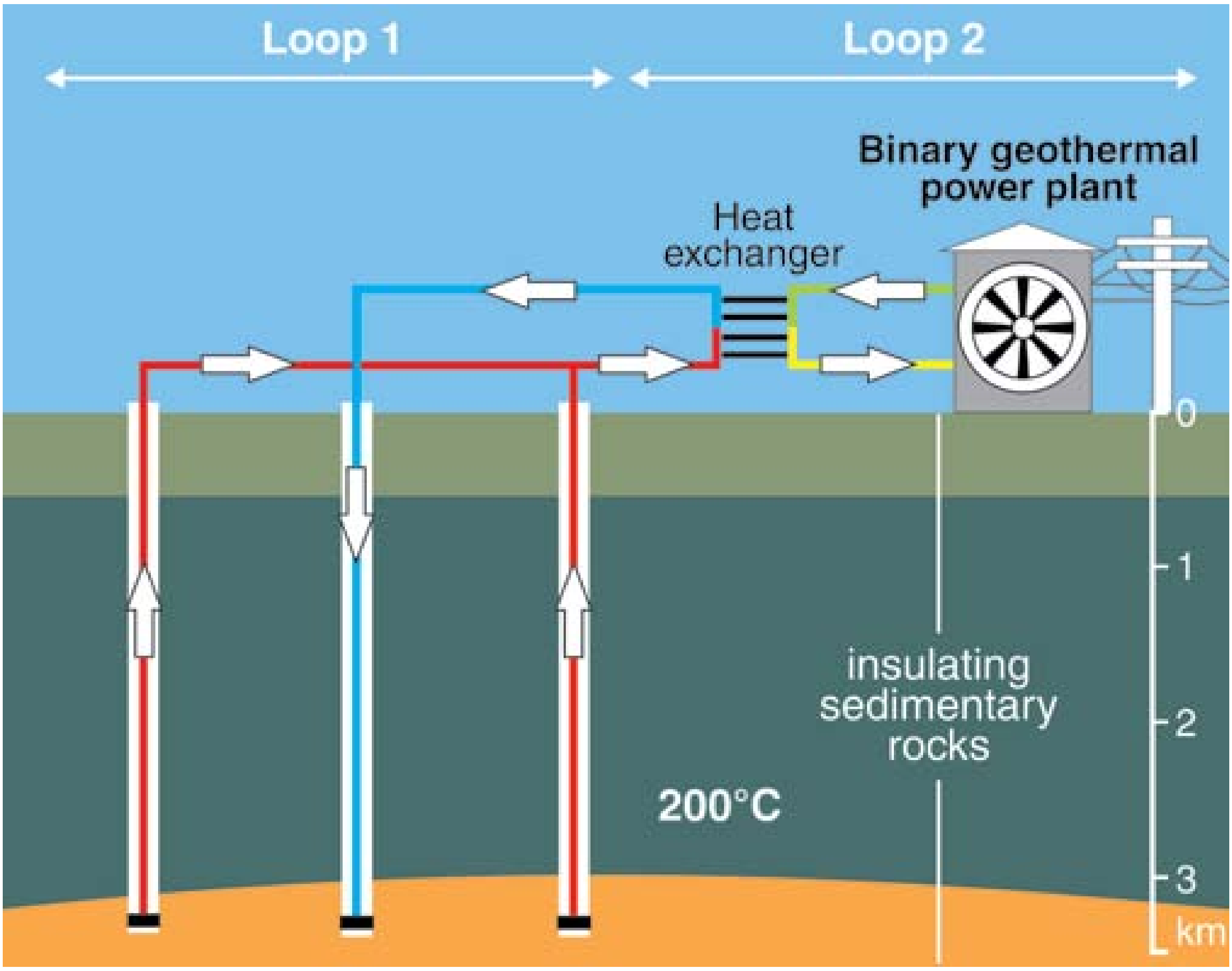

Figure 33. Example of binary cycle power plant, where the hot geothermal fluid is run through a "heat exchanger" and returned directly to the source reservoir. The turbine is run by a closed circuit "working fluid"

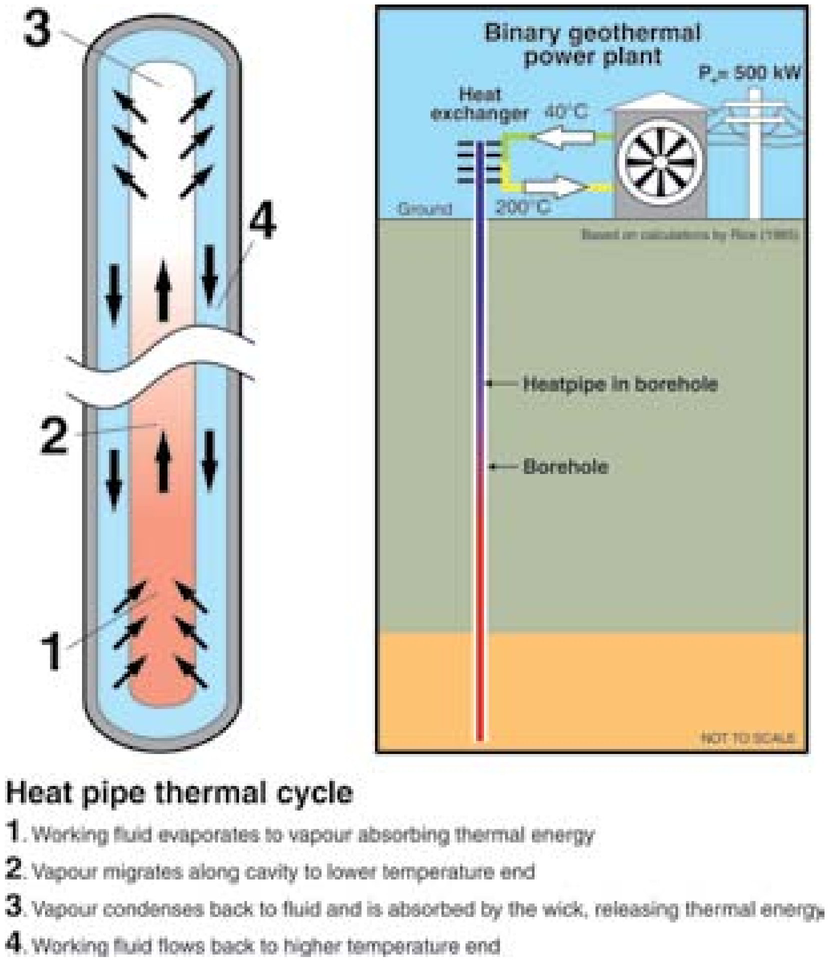

Figure 34. Schematic diagram of a heat pipe, which will work in any orientation

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Century Rig 7 at the Harvey 1 well site in the southern Perth Basin

The South West Hub

The South West CO_2 Geosequestration Hub, known as the South West Hub, is a partnership between the Department of Mines and Petroleum (DMP), electricity generator, Verve, and four major industrial companies based in the South West of Western Australia. These companies have formed the South West Hub Joint Venture.

The South West Hub is three years into a six-year characterisation project of the Lesueur Sandstone Formation in the southern Perth Basin. This will determine the suitability of the reservoir for a major onshore carbon capture and storage (CCS) project (Figure 35).

The South West Hub was chosen to be part of a global initiative to have 20 commercial scale CCS projects active by 2020, after being assessed for its potential contribution to the acceleration of commercial scale CCS.

The South West Hub has the potential to store up to 240 million tonnes of carbon dioxide (CO_2) and is the first project in Australia to be granted flagship status.

The project received a A$52 million grant from the Australian Government's A$2 billion CCS Flagships Program — an initiative developed to help Australia meet its target of an 80 per cent cut in greenhouse gas emissions (on 2000 levels) by 2050.

DMP is playing a significant facilitating role for the early part of the South West Hub project. The project proposes to capture CO_2 from industrial emission streams to a site in the Harvey or Waroona Shires. Injection wells would be used to pump the liquefied CO_2 into the Lesueur Sandstone Formation (Figure 36).

This three-dimensional modelling of the subsurface in the Harvey Shire will help to determine the viability of the South West Hub project.

At this stage of the research and modelling, the Lesueur Sandstone, which lies between 1.4 km and 3 km below the surface, is showing good potential as a storage formation. The lower section of the Lesueur Sandstone, the Wonnerup Member, is the target storage reservoir where the CO_2 is trapped in the sandstone and partly dissolved in saline water, while the Upper Lesueur or Yalgorup Member and the Eneabba Formation lying above show potential as a seal over the reservoir. The various trapping mechanisms would ensure permanent storage of the CO_2.

Two phases of research have been completed as part of what will be a four-year research project to test the viability of CO_2 geosequestration in the Lesueur. The first phase of data acquisition, a 2D survey, was completed in 2011 and gave a clear indication of formation depth and faulting, and was used to locate a stratigraphic well.

Between February and March 2012, the Harvey 1 well was drilled to a depth of 2945 m, collecting core samples and data that are being used to gain a better understanding of the subsurface. Core sample testing and data analysis has assisted the planning for three or four additional stratigraphic wells during 2014/15. The results have so far confirmed expectations about the geology of the area.

Community Consultation

Throughout the planning and research phases of the project, the South West Hub has focussed on developing and maintaining clear and open communications with landowners, local shires and the local community. From the beginning the population in Harvey and Waroona Shires (30,000) and surrounding areas in the South West (about 150,000) have been kept informed of the project's progress.

Communication activity was stepped up in 2011 with a community workshop held in February in the lead up to the 2D seismic survey and sinking the Harvey 1 well. Three community information sessions focussing on the 3D seismic were held in 2013. Letters to landowners, information pamphlets and reports have all been made publicly available.

Avoiding any potential impacts on the freshwater aquifers in the region is extremely important as the maintenance of potable water supplies is a major community and political issue. The Yarragadee Formation, which is an important freshwater aquifer in the region, is present in parts of the southern Perth Basin but is absent in the area under investigation.

Economic and social considerations such as dairy farming routines and farming infrastructure are critical to the smooth operation of the 3D seismic survey. These have been important considerations for Land Access Teams talking to landowners and users.

The Lesueur Community Consultative Committee was established in August 2011 to help keep the public informed, to provide community feedback and to answer questions. A communications strategy was designed to ensure that the community has access to information about all stages of the project in the lead-up to commercial decisions to be made in 2017.

Technology Considerations

In 2006 the State Government and local coal-using companies joined forces to analyse what could best provide a step-change to reduce the amount of CO_2 being emitted into the atmosphere.

CCS was identified as a potential answer, with the capture technology being an issue mainly for the private sector and storage seen as a key government issue.

A Regional Assessment, carried out in 2007 by the CO2CRC, investigated the feasibility of geosequestration and potential areas for underground CO_2 storage. A more detailed static and dynamic modelling of the area was undertaken by Schlumberger Carbon Services in 2010.

The data acquisition has so far included the 100 km of 2D seismic survey in 2011 and the stratigraphic Harvey 1 well drilled in February-March 2012, which were conducted by the Geological Survey of Western Australia (GSWA).

A 3D seismic survey covering approximately 115 km^2 was completed in April 2014. The next phase of data acquisition will include up to four further evaluation wells in 2015.

More detailed information including research reports and other documentation can be found at www.dmp.wa.gov.au/ccs.

Gorgon CCS Project

Located off the northwest coast of Australia in an area known geologically as the Investigator Sub-Basin of the Carnarvon Basin, the Gorgon Project is the largest single resources project in Australian history and one of the world's largest natural gas projects. The project will be significant for Western Australia, both economically and in terms of its application of new technology designed to decrease CO_2 emissions on a scale that is unmatched anywhere else in the world (Figure 35).

The Greater Gorgon Area gasfields represent a world-class gas resource containing approximately 25 per cent of all the natural gas discovered to date in Australia. The project will develop the Gorgon and Jansz-Io gasfields, located about 130 km off the northwest coast of Western Australia. The natural gas in the Gorgon field contains approximately 14 per cent carbon dioxide (CO_2) while the natural gas in the Jansz-Io field contains less than 1 per cent CO_2. This CO_2 will be produced with the hydrocarbon gases as the fields are developed. The Gorgon Joint Venture (GJV) plans to dispose of reservoir CO_2 by injecting it approximately 2 km underground into the Dupuy Formation saline reservoir under Barrow Island.

The Gorgon Project is operated by an Australian subsidery of Chevron, and the GJV consists of the Australian subdidiaries of Chevron (47.3%), ExxonMobil (25%), Shell (25%), Osaka Gas (1.25%), Tokyo Gas (1%), and Chubu Electric Power (0.417%).

CARBON CAPTURE AND STORAGE

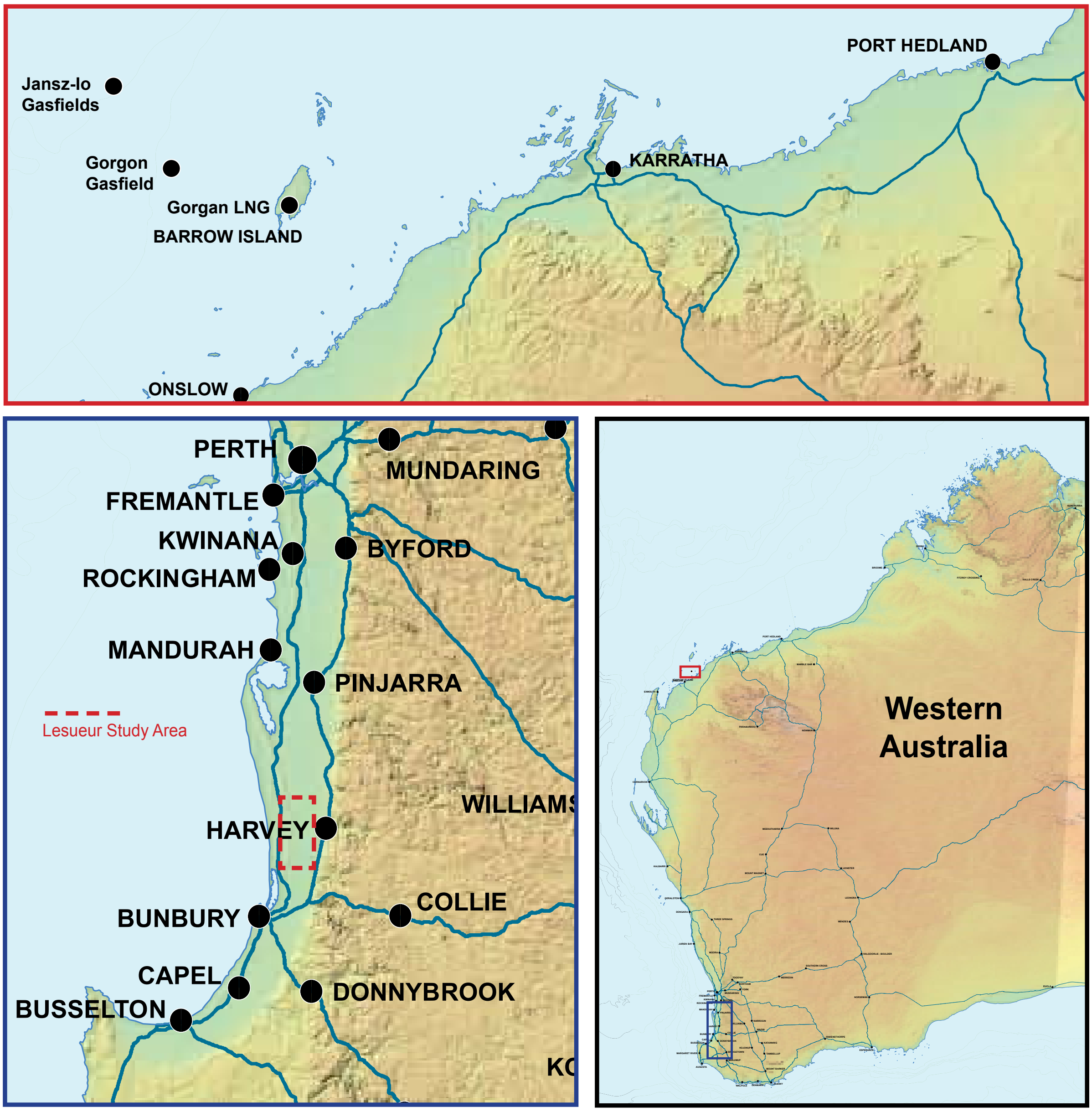

Figure 35. Map showing the locations of Western Australia's two CCS projects: the South West Hub near Harvey and the Gorgon Project on Barrow Island

The Gorgon project includes the construction of a 15 million tonne per annum (Mtpa) liquefied natural gas (LNG) plant on Barrow Island and a domestic gas plant with the capacity to provide 300 TJ of gas per day to supply gas to Western Australia. Along with minor concentrations of other substances, the CO_2 will be separated from the hydrocarbon gases at the LNG processing facility.

The reservoir CO_2 will be separated at the LNG plant site and transported by pipeline to one of three drill centres. To minimise the environmental footprint on the Island, nine injection wells are expected to be directionally drilled from the three drill centres.

Once the CO_2 is injected, it will migrate through the Dupuy Formation until it becomes trapped.

An on-going monitoring program, which includes observation wells and seismic surveys, will assist in managing the performance of the Dupuy Formation.

CO_2 injection project facilities on Barrow Island are expected to include:

- 9 CO_2 injection wells at three drilling centres
- 2 pressure management drill centres that consist of:
  - 4 water production wells
  - 2 water injection wells
- 2 reservoir surveillance wells
- A 7 km underground CO_2 pipeline from the LNG plant site to the drill centres, and
- 3 CO_2 compressor modules.

The project will position Western Australia as a world-leader in commercial scale CO_2 injection technology. A total of 125 million tonnes of CO_2 will be injected during the life of the project. Sequestering CO_2 on such a scale has attracted huge international interest, so in order to fully understand the CO_2 disposal process and the associated risks, DMP and Chevron agreed to regularly review the technical work for 'due diligence' purposes.

The final investment decision was made by the GJV in 2009 and the project is at execution stage. LNG production is expected to commence in 2014 and the CO_2 injection project is expected to occur following the start up of the second LNG train in late 2015. The Gorgon CO_2 injection project is regulated under the *Barrow Island Act 2003*.

Regulatory Regime and Titles

The injection and permanent storage of greenhouse gas (GHG) in underground geological formations has not occurred, therefore, it is not yet regulated in Western Australia. However, this excludes the Gorgon Project for injection and storage of CO_2 (a GHG), which is regulated by a State agreement under the *Barrow Island Act 2003*.

The South West Hub project is likely to be the first project operating under Western Australia's proposed GHG legislation.

In October 2012, the *Petroleum and Geothermal Energy Legislation Amendment Bill* was introduced into Parliament to amend the State's petroleum legislation to provide a legislative framework for the onshore transport and geological storage of greenhouse gases in Western Australia. The legislation is required to enable greenhouse gas projects to progress and to provide certainty and clarity for investment and regulation.

The Western Australian *Onshore Greenhouse Gas Storage Bill* amends the *Petroleum and Geothermal Energy Resources Act 1967* (PGER Act) and the *Petroleum Pipelines Act 1969* (PP Act). At the time of going to press, the bill is still in Parliament awaiting going to debate in the Upper House.

The *Petroleum and Geothermal Energy Legislation Amendment Bill 2012* is designed to amend the petroleum legislation to provide a regulatory regime for the onshore storage of GHG which will predominantly be CO_2.

These amendments will allow for GHG storage formation property rights, acreage release provisions, exploration, retention and injection licences as well as addressing long-term liability issues.

The amendments will result in a title structure for underground acreage with CO_2 storage potential that is similar to the regime for petroleum titles.

GHG titles will be subject to similar fees and charges that currently apply for petroleum titles and there is no intention for royalties to apply to the injection and permanent storage of GHGs.

The PGER Act allows for overlapping petroleum and geothermal titles and these will be able to co-exist with GHG titles under the new amendments.

Under the proposed amendments the Minister for Mines and Petroleum will invite applications for the grant of work-bid GHG Exploration Permits, and may direct that applications are accompanied by information concerning the volume, source and composition of the GHG proposed to be injected.

ONSHORE SOUTHERN PERTH BASIN STRATIGRAPHY
LESUEUR SANDSTONE

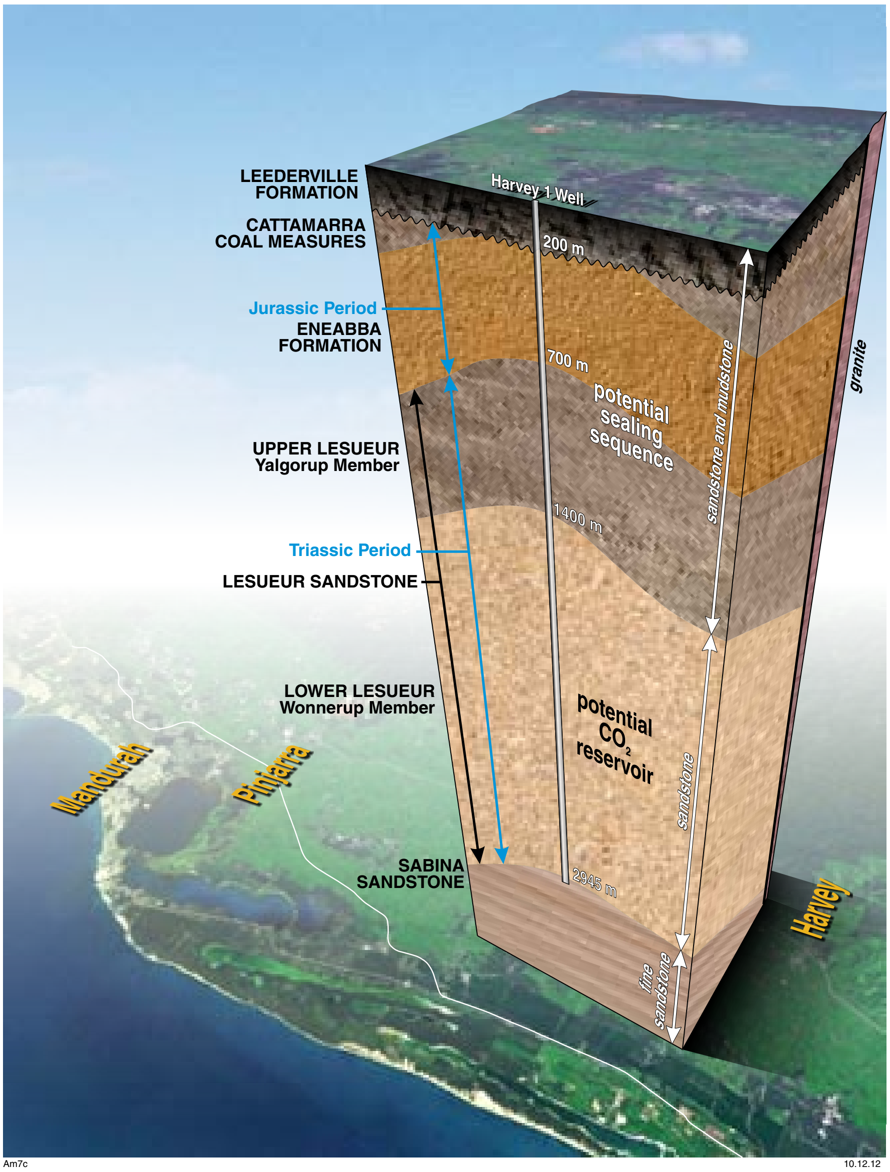

Figure 36. Schematic of the proposed South West Hub CCS storage project in the southern Perth Basin

As a measure designed to prevent the warehousing of areas with GHG storage potential, a work program will need to be provided by applicants and this will form part of the conditions of any Exploration Permit.

There will be three categories of storage formation – potential, eligible and identified. Injection licences will require a site plan for the life of the operations, to be approved by the Minister.

Existing Petroleum Production Licence holders and Retention Lease holders will have the option to apply for a GHG Injection Licence if any GHG acreage release overlaps their licence area or lease and they believe their petroleum title contains a potential storage formation.

The holder of a GHG title will also be required to maintain insurance as directed by the Minister and must apply for a site closure certificate once operations have ceased.

Ownership of GHG storage formations will be vested in the Crown and long-term liability will be assumed by the State at least 15 years after the site closure certificate is issued, or if the licensee ceases to exist.

Handling the bottom hole assembly at the Harvey 1 well in the southern Perth Basin

The Department Website and Online Systems

Most of the publicly available petroleum and geothermal data can be accessed via the online systems on the DMP website. Titles and descriptions of these online systems can be found at www.dmp.wa.gov.au/3959.aspx. These services provide essential reference material for anyone exploring Western Australia for petroleum and geothermal resources.

Clients need to complete the free registration via the Department's Single Sign-On system to gain access to any of the departmental systems.

Forms

Application forms for Titles and work approvals under the three Acts (e.g. Special Prospecting Authority Applications, Exploration Permit Applications, Retention Lease Applications, Pipeline Licence Applications, Drill a Well Application, etc.), can be downloaded in PDF or Word document format via a direct link on the Department's homepage under the heading "Forms and Regulations" (or www.dmp.wa.gov.au/8480.aspx). Petroleum and Geothermal Safety forms can also be accessed via this link.

Western Australian Petroleum and Geothermal Information Management System (WAPIMS)

WAPIMS is an exploration database containing data on titles, wells, geophysical surveys and other non-confidential petroleum exploration data submitted to DMP by the petroleum industry. Data includes well header data, biostratigraphy, reservoir characteristics, velocity surveys, directional surveys and organic geochemistry. WAPIMS also contains lists with physical assets submitted to the department and the facility to order them online (e.g. seismic tapes, core, cuttings, and petrology and palynology slides).

WAPIMS releases all information arising out of petroleum exploration activities within Western Australia's State jurisdiction (onshore and State waters) together with Commonwealth area activities with the release date prior to 1 January 2012.

For information on petroleum exploration activities in Commonwealth waters off Western Australia released after 1 January 2012, please contact Geoscience Australia at the following email address ausgeodata@ga.gov.au.

To access WAPIMS log onto the DMP website or go to: www.dmp.wa.gov.au/4187.aspx

Access to WAPIMS is by Single Sign-On as a registered user and is free of charge. Once registered, you can personalise the settings to suit your own requirements and searching can be done via a data tree, as well as map-based searching. The information currently stored in WAPIMS covers petroleum exploration and development activities in Western Australia since the 1920s.

The data available to download via WAPIMS are:

- well log data in zip files containing LIS, DLIS, LAS or ASCII files
- well reports (including well completion reports and composite well logs) in PDF
- 2D Seismic Survey post-stack SEGY and navigation data in UKOOA (3D SEGY data on request)
- seismic acquisition, processing and interpretation reports and support data.

Excel spreadsheets containing information on all wells and surveys conducted in Western Australia can also be downloaded via WAPIMS.

Contact the Petroleum Digital Data Officer for further information on the availability of digital data.

Statutory Exploration Information Group
Department of Mines and Petroleum
100 Plain Street
EAST PERTH, WA 6004
Fax: +61 8 9222 3893
Email: petdata@dmp.wa.gov.au

Petroleum and Geothermal Register (PGR)

PGR is an online electronic titles register that administers title information and monitors approvals for Petroleum and Geothermal Exploration Permits and renewals; Production Licences and renewals; Retention Leases and renewals; Pipeline Licences and variations; as well as Wells, Surveys, Special Prospecting Authorities and Access Authorities.

PGR provides full access to public information. Users need to complete the free registration via the department's Single Sign-On system to gain access. Once registered, to access PGR, log onto the DMP website and select Online Systems, or go directly to https://pgr.dmp.wa.gov.au/pgr/

For access to online payments, lodgement of applications and non-public information, a secure login is required which is restricted to business users ensuring that confidentiality is maintained.

Future development will included PGR being expanded to deal more with resource management issues as well as automating processes in a paperless environment.

Environmental Assessment and Regulatory System (EARS Online)

EARS Online is a system which allows lodgement and tracking of Mineral and Petroleum Environmental Applications such as Mining Proposals, Programs of Work, Environment Plans, and Oil Spill Contingency Plans. Users must be registered against a company in order to access the system via www.dmp.wa.gov.au/8266.aspx

Public Chemical Disclosure on DMP website

DMP maintains a list of all current environmental proposals, including a link to Environment Plan summary documents. These EP summaries contain information on all chemicals used down-hole in approved petroleum and geothermal activities. View publicly available EP summaries for petroleum and geothermal activities submitted to DMP on the DMP website at https://ace.dmp.wa.gov.au/ACE/Public/PetroleumProposals

Royalties Online

Royalties Online allows mineral and petroleum producers to prepare, lodge and view royalty returns and production reports online. It also provides for online royalty payments. www.dmp.wa.gov.au/3978.aspx

Safety Regulation System (SRS)

This online system allows the electronic lodgement of documents and data, providing industry with the ability to monitor the progress of submissions. The system currently allows:

- Notifications – online submission of injury, incident and monthly status reports
- Approvals – online submission and tracking of project management plans and radiation management plans
- Compliance – online management and response to audits, notices and inspections
- Publications – includes access to all fatality summaries released since 1943, Mines Safety Bulletins, and Significant Incident Reports published since 1 January 2014
- Other – SRS maintains the levy assessment process and is used to manage licensing and certifications.

Geochemistry (Geochem Extract)

Geochemistry Online is a multi-element geochemistry database, which provides base level information for mineral exploration. www.dmp.wa.gov.au/6564.aspx

Interactive Geological Map (GeoVIEW.WA)

GeoVIEW.WA is an online GIS-based mapping tool. Users can construct their own geological map and incorporate other petroleum and mineral exploration datasets including petroleum wells and active leases. www.dmp.wa.gov.au/7113.aspx

GeoViewer.WA is the compact, stand-alone version of GSWA's online GeoVIEW.WA software that you can install on your desktop or laptop computer (Microsoft Windows only). It provides complete flexibility for presenting, labelling, and ordering data in any combination of formats including ESRI shp, MapInfo tab, geoTiFF and ECW.

ACCESS TO DATA

GeoScience Publication Search Tool allows you to find GSWA publications associated with a geographic region in WA via an active link which views the document in DigitalPaper™.

Mines and Mineral Deposits (MINEDEX)
MINEDEX is a continuously updated database containing information on mines, mineral deposits and prospects – with information on projects and project ownership, sites, location data, commodities and commodity groups, mineral resource estimates and production, mining proposals for development and mine operators and contact addresses.
www.dmp.wa.gov.au/3970.aspx

Airborne Geophysics Index (MAGIX)
MAGIX is a GIS-based register and index of airborne geophysical surveys reported to DMP under the provisions of the *Mining Act 1978*.
www.dmp.wa.gov.au/4030.aspx

Western Australian Mineral Exploration Index (WAMEX)
WAMEX is a searchable database of open file (public) reports on exploration for minerals (excluding oil and gas). Where a digital copy is not yet available, a microfiche copy of the report is kept at the Mineral House Library and at the Geological Survey's Kalgoorlie Regional Office.
www.dmp.wa.gov.au/5136.aspx

TENGRAPH
TENGRAPH® Online displays the position of Western Australian mining tenements and petroleum titles in relation to other land information and provides an easy means of determining land available for mineral exploration. It gives a current and accurate picture of land under mining activity.
www.dmp.wa.gov.au/3980.aspx

Publications
Publications from the Petroleum Division, such as the Petroleum in Western Australia magazine and the Petroleum and Geothermal Explorer's Guide, can be found at www.dmp.wa.gov.au/5909.aspx

Digital products can be accessed via the DMP online 'Publication Systems' link, which includes the eBookshop, GSWA publications, posters and flyers, the Library Catalogue and the Data and Software Centre.
www.dmp.wa.gov.au/3959.aspx

eBookshop contains mainly books, maps and datasets published by the GSWA. Geoscience Publications is built on the latest DigitalPaper XE technology. The document delivery service provides fast online access to GSWA's growing store of digital geoscience data including 'Basin Summaries', Atlas of Petroleum Fields' and many more titles.
www.dmp.wa.gov.au/4995.aspx

Library Catalogue (GeoLib)
Use the Library Catalogue to search the DMP Mineral House Library for publications on Western Australian geology, mining, petroleum and environmental subjects. Please note that loans of material are not available to individuals.
www.dmp.wa.gov.au/4999.aspx

The Data and Software Centre enables the download of spatial datasets such as Mining Tenements, Exploration Tenements, Petroleum Titles, and Geothermal Titles. In addition, the Data and Software Centre contains spatial application software, including GeoMap.WA and the Mineral Exploration Reporting Templates Software. Each dataset zip file contains the following:

- Metadata statement (HTML File)
- The Dataset [un-projected, geographical coordinates based on the 1994 Geocentric Datum of Australia (GDA94)]
- Licence statement (text file).

A range of products (including maps and publications) produced by DMP are also available from the Public Counter, 1st Floor Mineral House 100 Plain Street, East Perth. The Public Counter is open from 8.30 am to 4.30 pm Monday to Friday.

Access to other Western Australian Data

Hardcopy Data
Hardcopy data such as well logs, seismic lines, maps and reports, can be viewed at the DMP Library on the 1st Floor, 100 Plain Street by appointment. Clients should email the Petroleum Data Release Officer at petdata@dmp.wa.gov.au to arrange an appointment.

Onshore data that can also be purchased by contacting either:

Exploration Data & Scanning Services
Unit 5, 24 Burton Street
CANNINGTON, WA 6107
Tel: +61 8 9258 4039
Fax: +61 8 9258 4039
Contact: Mr Mike Gray (Director)
Email: infor@explorationservices.com.au

Spectrum Australian Seismic Brokers
Unit 5, 171-175 Abernethy Road
BELMONT, WA 6104
Tel: +61 8 9479 5900
Fax: +61 8 9479 5911
Contact: Ms Diane Jeffrey
Email: asb@asb.com.au
Website: www.asb.com.au

Sampling Cores and Cuttings
To examine and sample cores and cuttings for a well, send an email to: corelibrary.requests@dmp.wa.gov.au attention Petroleum Data Release Officer, specifying the wells and intervals you wish to sample and the purpose of the sampling. There are two modern, purpose-built facilities, one in Perth, the other in Kalgoorlie, for the secure archive and display of drill core and other materials acquired during petroleum and mineral exploration programs in the Western Australia.

The following services are available:

- core viewing facilities in either artificial or natural light
- core sampling (conditions apply)
- non-destructive core testing facilities
- binocular microscopy
- core photography facilities including UV light (Perth only)
- HyLogger System for analysing core.

Paleontological Material
To borrow paleontological slides for wells, email petdata@dmp.wa.gov.au attention Petroleum Data Release Officer, specifying the wells and the intervals you wish to borrow and the purpose of the loan.

Geoscience Australia Data
Geoscience Australia (GA) is the country's national agency for geoscience research and geospatial information and houses one of the world's largest collections of petroleum data. Much of this data is non-confidential and available to the petroleum industry, research organisations and the public. The collection includes seismic survey data and well data submitted by industry under legislative requirements as well as data collected by research projects and marine surveys undertaken by Geoscience Australia or other government agencies or institutions.

The collections comprise three kinds of data:

1. Physical specimens and samples of geoscience material such as samples from petroleum wells and stratigraphic holes, down hole drill cores and cuttings, onshore side wall core samples, thin sections, reservoir plugs, liquid and gas hydrocarbon samples.
2. Digital data such as:
   - 2D and 3D seismic survey field data, navigation data, processed data, velocity data, observer's logs, operational reports, processing reports, bathymetry data, potential field data (gravity and magnetic);
   - well completion reports, well logs, destructive analysis reports, vertical seismic profiles, core photography, special studies;
   - databases compiled from data/reports/ interpretations from government activities or submitted by industry under legislation.
3. Hard-copies submitted during the pre-digital era including seismic sections and other analogue formats.

Search for Petroleum Data

Search Repository – PIMS is a search tool for discovery of survey and well data and physical samples held by the Data Repository. Data can be ordered via an online form. Although this is public data, fees are charged to cover the cost of transcription and delivery.

Search Wells – search for well data and information, download data, produce online graphs and reports. Data includes well header data, biostratigraphy, reservoir characteristics, velocity surveys, directional surveys and organic geochemistry. dbforms.ga.gov.au/pls/www/npm.pims_web.search

Enquiries

To request well and survey data from GA's repository holdings or to view samples please contact: ausgeodata@ga.gov.au

To make other enquires regarding petroleum databases, scientific data or other petroleum information please contact: petroleum@ga.gov.au

Data Reporting Requirements

Whenever any exploration or production activity is conducted in Western Australia under any of the three petroleum Acts, there are reporting requirements that need to be met by the registered holder(s).

The statutory requirements for submission of data to the Department of Mines and Petroleum are outlined in the *Guidelines for data submission required under Western Australian and Commonwealth Petroleum legislation* which is available from the ebookshop on the DMP website.

This guide assists industry in managing data submission requirements. It will be modified with changes to petroleum legislation and supporting regulations. In the event of disagreement between this guide and current legislation or directions the latter will prevail.

The purpose of the guidelines, in accordance with the Schedule of Requirements (State legislation), is to specify the format, contents and standards required in the submission of petroleum exploration and production data.

The two main purposes of reporting are to ensure that any work conducted has been done in compliance with the Acts; and to make this information available to the public to further the search for petroleum in the State in the most economical and efficient manner.

All information and data submitted to DMP in accordance with the various Acts remains confidential until the information is eligible for public release as prescribed in Section 112 of the PGER Act 1967 or Section 118 of the PSL Act 1982.

Acreage Release Packages

For the State's petroleum acreage releases, the gazettal inviting applications identifies precise permit configurations and releases them for competitive bids, generally on a biannual basis. Release notices are published in the Government Gazette to formalise the releases. A release information package, which includes information on applying for acreage, land access, basin geology and available data, can be viewed on the DMP website and is also available on disc from DMP.

Petroleum and Geothermal Exploration
www.dmp.wa.gov.au/850.aspx

Petroleum Acreage Release
(current and previous)
www.dmp.wa.gov.au/18282.aspx and
www.dmp.wa.gov.au/18285.aspx

Geothermal Acreage Release
(past releases)
www.dmp.wa.gov.au/18288.aspx

Enerdrill Rig 3, running in to cut core at Drover 1 in the Perth Basin (photo courtesy of AWE Ltd)

PART 2

PETROLEUM ADMINISTRATION

GEOTHERMAL ENERGY ADMINISTRATION

RESOURCE MANAGEMENT

LAND ACCESS – ABORIGINAL AFFAIRS

LAND ACCESS – PRIVATE LAND

ENVIRONMENTAL ASSESSMENT

SAFETY

FINANCIAL CONSIDERATIONS

ABOUT PERTH AND WESTERN AUSTRALIA

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Regulatory Regime and Petroleum Titles

Basic legal and constitutional framework

Under Australian law, rights to petroleum are owned or held by Government but assigned to private interests under arrangements set out in legislation. While Government does not directly engage in commercial petroleum exploration and production, it does provide an orderly and equitable system by which the private sector can undertake such activities. Government has four main roles in relation to the petroleum sector:

- it establishes the macro-economic environment (broad economic policy);
- it provides a regulatory framework for exploration and development, including safety and environmental assessment, as well as revenue collection;
- it reduces commercial risk in petroleum exploration by collecting, generating and disseminating basic geoscientific information; and
- it looks for ways to remove impediments to industry competitiveness.

In the Australian Federal system, both the national Government (the Commonwealth) and the State and Northern Territory Governments have important roles affecting petroleum exploration and development.

The Commonwealth Government is responsible for broad economic policy and international matters, including personal and company income tax, interest rates, the overall level of government spending, foreign investment guidelines, trade and customs, commercial corporations and international agreements.

The State owns and allocates petroleum rights, administers petroleum operations including occupational safety and health, and collects royalties on petroleum produced in the State areas. The Department of Mines and Petroleum (DMP) is the lead agency for these upstream petroleum matters. Offshore petroleum seaward of the State's coastal waters is controlled by the Commonwealth. Day-to-day administration in the Commonwealth zone is carried out by the National Offshore Petroleum Titles Administrator (NOPTA) with major decisions being made by a Joint Authority comprising the Commonwealth Minister responsible for petroleum and each of the States' Resource Ministers. Because of their shared interest in the contribution of the petroleum sector to national economic well-being, the Commonwealth and State Governments hold regular formal consultations through the Ministerial Liaison Groups, to ensure policies, standards, and regulatory requirements are coordinated.

Uniform Petroleum Legislation

Western Australia is the only Australian State that has a petroleum code common to both its onshore and offshore areas. The code is similar to that in the *Commonwealth Offshore Petroleum and Greenhouse Gas Storage Act 2006* (OPGGS Act), which was established by the Commonwealth Government in conjunction with all Australian State Governments and that of the Northern Territory.

The code varies little between the offshore and onshore areas, and only where it is necessary to recognise the requirement of other land tenures and usage. Amendments to the OPGGS Act providing for greenhouse gas storage have yet to be adopted by Western Australia. Regardless, the basic commonality makes for more consistent and expedient administration and is far less confusing for explorers.

The basic premise for this common petroleum code is that all petroleum resources of Western Australia and its adjacent offshore areas are reserved to the Crown, as is the right of access for the purpose of searching for, and recovering these resources. In this regard, exploration for and production of petroleum is permitted only under the provisions of legislation applying to Western Australia and its adjacent offshore areas.

Petroleum exploration and development activity in Western Australia, its adjacent waters and offshore area is subject to three State, and one Commonwealth act. The Western Australian *Petroleum and Geothermal Energy Resources Act 1967* (PGER Act) covers all onshore areas of the State, including its islands and, in certain circumstances, areas of submerged lands internal to the State (i.e. those waters landward of the baseline), other than 'subsisting' permit areas under the Western Australian *Petroleum (Submerged Lands) Act 1982* (PSL Act).

The Western Australian *Petroleum Pipelines Act 1969* (PP Act) applies to petroleum pipelines in onshore areas.

The State PSL Act applies to Western Australia's territorial sea, designated as the adjacent area, (three nautical miles seaward of the baseline), including the territorial sea around State islands, and under certain circumstances, some pre-existing titles in the State's internal waters.

The Commonwealth *Offshore Petroleum and Greenhouse Gas Storage Act 2006* (OPGGS Act) applies to areas of the continental shelf beyond the three nautical mile territorial sea boundary, which are designated as being the offshore area to Western Australia. Both the PGER Act and the PSL Act are administered solely by Western Australia, while the Commonwealth Act, in respect to the Western Australian offshore area is administered by a Joint Authority, comprising the Commonwealth and State Ministers responsible for petroleum administration. The division of State and Commonwealth waters occurs at the three nautical mile mark of the territorial sea.

Obtaining A Petroleum Title

Release of Acreage for Exploration

For State areas, the system of inviting applications for petroleum exploration acreage is generally that of identifying precise permit configurations and releasing them for competitive bids. This system is known as 'acreage release'.

State releases are formalised by way of publication in the Western Australia *Government Gazette* and details of the releases are shown on the DMP website and in release packages which are available on request from DMP. Releases are generally made twice a year for the areas within Western Australia's jurisdiction.

It is usual for the releases to be announced by State officers at significant industry events, such as the Australian Petroleum Production and Exploration Association (APPEA) Annual Conference (April–May) and DMP's Petroleum and Geothermal Open Day (September).

The release package contains details of the geotechnical data available for the areas and provides details on how and when applications are to be made. Included in this package is an outline of the assessment criteria by which applications are to be considered, as well as other information pertinent to the particular areas.

Areas from the previous release that did not attract successful bids in the first instance are generally re-released in the next release.

Acreage Option for Special Prospecting Authorities

In addition to the Acreage Release process, under the PGER Act or PSL Act, an explorer may at any time apply for a Special Prospecting Authority with Acreage Option (SPA/AO). The Acreage Option must be sought in conjunction with the SPA application and cannot be applied for retrospectively. The purpose of this title is to conduct a geophysical or geochemical survey (or other operational activity other than the making of a well) to identify areas which have the potential for further exploration. An explorer may then exercise the Acreage Option by making an application for an Exploration Permit (EP) or Drilling Reservation (DR) in respect of the block or those blocks identified as prospective.

The Acreage Option must be exercised by applying for an EP or DR within the application period specified in the SPA/AO Instrument following the maximum six-month term of the SPA title.

PETROLEUM ADMINISTRATION

Exercising the Acreage Option does not guarantee that an EP or DR will be granted. Approval of the application will depend upon the appropriateness of the program of exploration work proposed in respect to the area sought, the capacity of the applicant to undertake the program, and the applicant's past performance with respect to native title negotiations and fulfilling work commitment requirements. All applications for SPA/AOs and exploration titles, whether by way of Release or exercising of an Acreage Option, are subject to the Criteria for Assessment of Applications for the Award of Petroleum Exploration Permits guidelines available from the DMP website.

The SPA/AO is intended to encourage exploration in areas where little or no exploration has been undertaken (so called 'greenfields' or 'frontier' areas) and is not appropriate for areas which are being actively explored.

Under circumstances where DMP intend to release acreage for exploration, an explorer may only apply for an SPA without the AO. Where multiple or overlapping applications for SPA/AOs occur for an area, the acreage may be gazetted by DMP and no SPA/AOs granted.

All other applications for SPA/AOs will be considered on merit, including the extent of the geophysical or geochemical work proposed in respect to the area sought, the ability of the explorer to undertake the work proposed and their past performance.

Explorers wanting to make use of this facility should discuss their proposals with the Petroleum Division to ascertain the likelihood of acceptance.

Farm-in to existing titles

Interests in petroleum titles are capable of being bought and sold and farm-in/farm-outs are a regular occurrence.

All dealings and transfers need to be approved and registered by the Government and an *ad valorem* registration fee system applies. In transferring into a title the transferee needs to demonstrate its ability (both financial and technical) to assume the responsibilities of the interest being acquired.

Transfer of a petroleum title must relate to the whole of the interest(s) in the title and not merely the interest being dealt with.

It should be noted that the new registered holder of the title has to fulfil the originally approved work program.

Derivative Titles

Once a discovery of petroleum is made the holder of the exploration title has the right to convert that discovery to a Production Licence. Should the discovery be demonstrated as presently noncommercial but likely to become so within 15 years, an interim title, a Retention Lease, may be granted.

Pipeline Licences

Pipeline Licences can be applied for by any party. However, under WA's PSL Act, the holder of the resource, which the pipeline is intended to service, has a right of first option.

Infrastructure Licences

As with Pipeline Licences, any party can apply for an Infrastructure Licence. The holder of the petroleum resource is not given exclusivity to apply for a Infrastructure Licence as a processing facility (requiring an Infrastructure Licence) may receive petroleum from a variety of sources.

The grant of an Infrastructure Licence is at the discretion of the Government and all relevant circumstances will be considered.

Petroleum Titles System

The State of Western Australia is divided into graticular blocks, each five minutes of latitude by five minutes of longitude. These graticules constitute the building blocks for exploration and production titles (Figure 37).

The State petroleum titles award process is depicted in Figure 38. Specific petroleum titles are described below.

Petroleum Exploration Permit

The prime title for exploration under State Petroleum legislation is the Petroleum Exploration Permit. Permits are made available through a periodic release of vacant acreage in a work program-based competitive bid process. The exception to the periodic release process is applications for Special Prospecting Authorities with an Acreage Option.

Petroleum Exploration Permits are awarded to those applicants who bid a work program that will undertake the fullest assessment of an area's petroleum potential, in accordance with sound resource management principles, having regard to safety and the environment and satisfy the requirements of the Criteria for Assessment Guidelines. Following discovery of a petroleum resource, the successful explorer will apply for rights, such as the right to produce the resource and to construct pipelines or other infrastructure.

Should an explorer require a particular area to be made available, an approach to the Petroleum Division of DMP may be made giving broad details of the general area of interest. It should be appreciated, however, that such an approach does not convey a preferential right to that party if the area is ultimately released.

While the maximum area that can be held under a single permit is 400 graticular blocks, the number of blocks contained in releases will usually be far less than the maximum.

The formal release of areas is by way of a notice in the *Government Gazette*. Each individual area is identified by map sheet block numbers illustrated in an accompanying area release plan. Applications need to be made in respect to an entire area. Details of the areas to be released are widely circulated through other media, including the DMP website, industry conferences and direct mailouts.

The State Minister nominates the date and time by which applications need to be submitted, with a six-month period being usual.

All bids are regarded as strictly confidential. However, following an applicant party's acceptance of the Minister's offer for the award of the exploration permit (PSL Act) or upon entering the native title future act process as the applicant deemed most suitable for the award of the area (PGER Act), certain information (other than details of the financial/technical abilities of the applicant or any interpretive data) may be made publicly available.

An applicant is required to supply details of the proposed work program on a year-by-year basis for the six-year term of the permit. The work proposal should be described in concise terms and an indicative cost of such work, in Australian dollars, should be quoted. Contingent work should not be included in any proposed work program as it will not be taken into consideration during the assessment process.

It is expected that some drilling work will occur early in the program, but this will depend upon the extent of prior exploration work in the area. Justification of the program nominated should be in terms of the geological and geophysical information available. The estimate of the expenditure is required only as an indication of the extent of the work and does not form part of the commitment.

Details of the financial/technical ability of the applicant are to be submitted. It is important that this information is as comprehensive as possible and particularly addresses the capacity/strategy for financing the proposed program.

Equally important is the applicant's past performance in petroleum exploration in Australia or, if relevant, elsewhere. Consideration of past performance includes compliance with permit conditions, participation in native title negotiations, and safety and environmental management history.

Many applications for Petroleum Exploration Permits have been unsuccessful, simply because the applicants have failed to demonstrate their financial and technical ability to undertake the proposed program or have failed to demonstrate to the Minister's satisfaction how a prior detrimental past performance occurrence would be mitigated in a future exploration title.

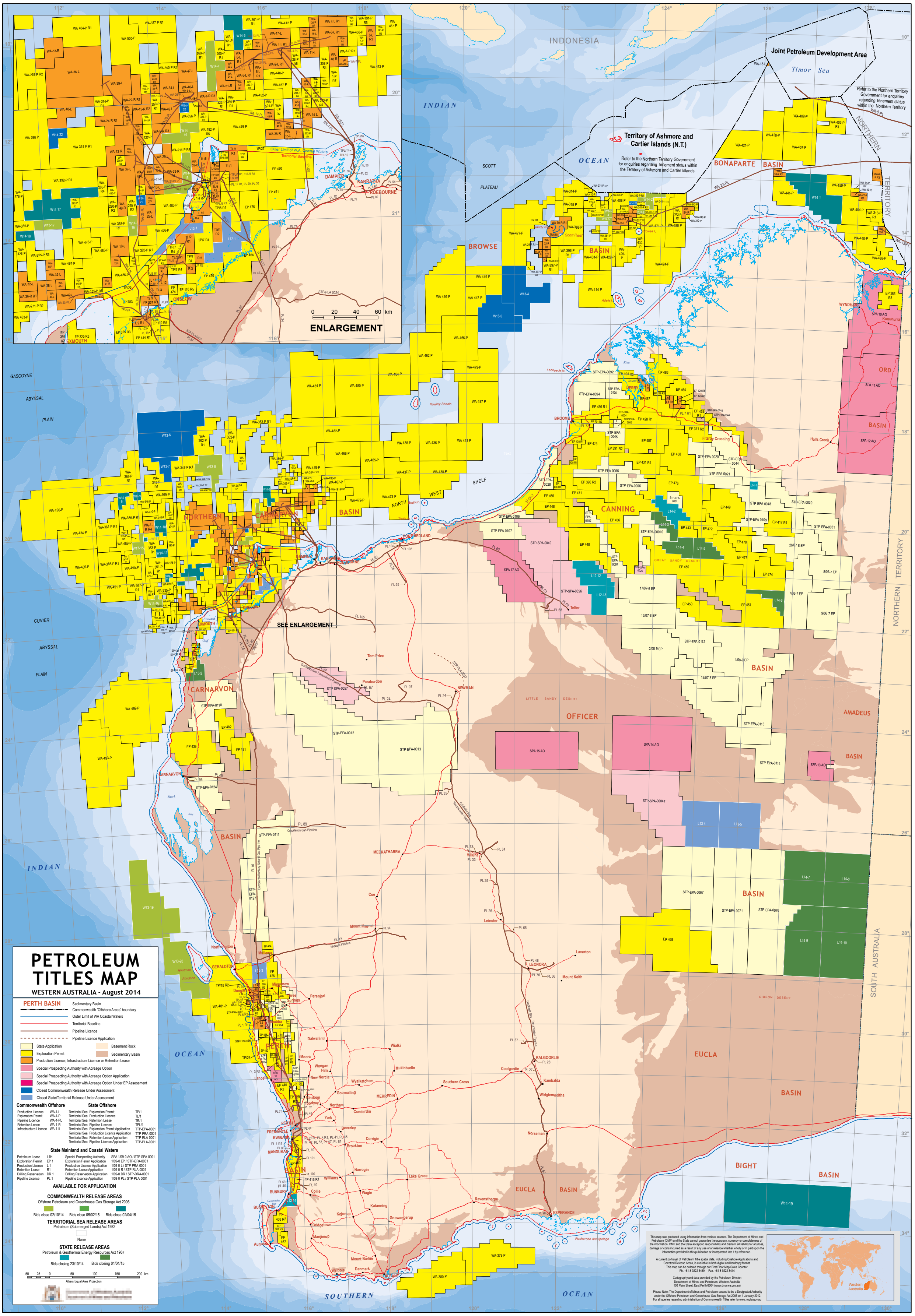

Figure 37. Overview of Western Australia's sedimentary basins showing petroleum titles

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An important point to note is that the petroleum legislation recognises only individuals or corporate bodies. Permits or other titles cannot be granted to a Joint Venture name. Where an application for a Petroleum Exploration Permit is made by a consortium it is usually a requirement to provide a positive indication, such as a heads of agreement, that a joint operating agreement will be forthcoming as soon as possible after grant.

It should be noted that a company must be registered in accordance with the *Corporations Act 2001* before it can operate within Australia. It is DMP policy that foreign companies may bid for acreage but they must be registered before a title can be awarded to them.

Permits in the State are granted on the basis of a guarantee to complete the first two years of work without variation. This is also known as the dry hole system and means that the permit holder is required to fulfil the nominated commitment for those initial years, regardless of the circumstances, excepting *force majeure*. *Force majeure* refers to any uncontrollable event that interrupts the expected course of events. Generally financial and commercial matters do not qualify as *force majeure* grounds. At the end of the firm period a decision may be made to continue or not. If the latter is decided, the permit may be surrendered in good standing providing all the conditions have been met to that date.

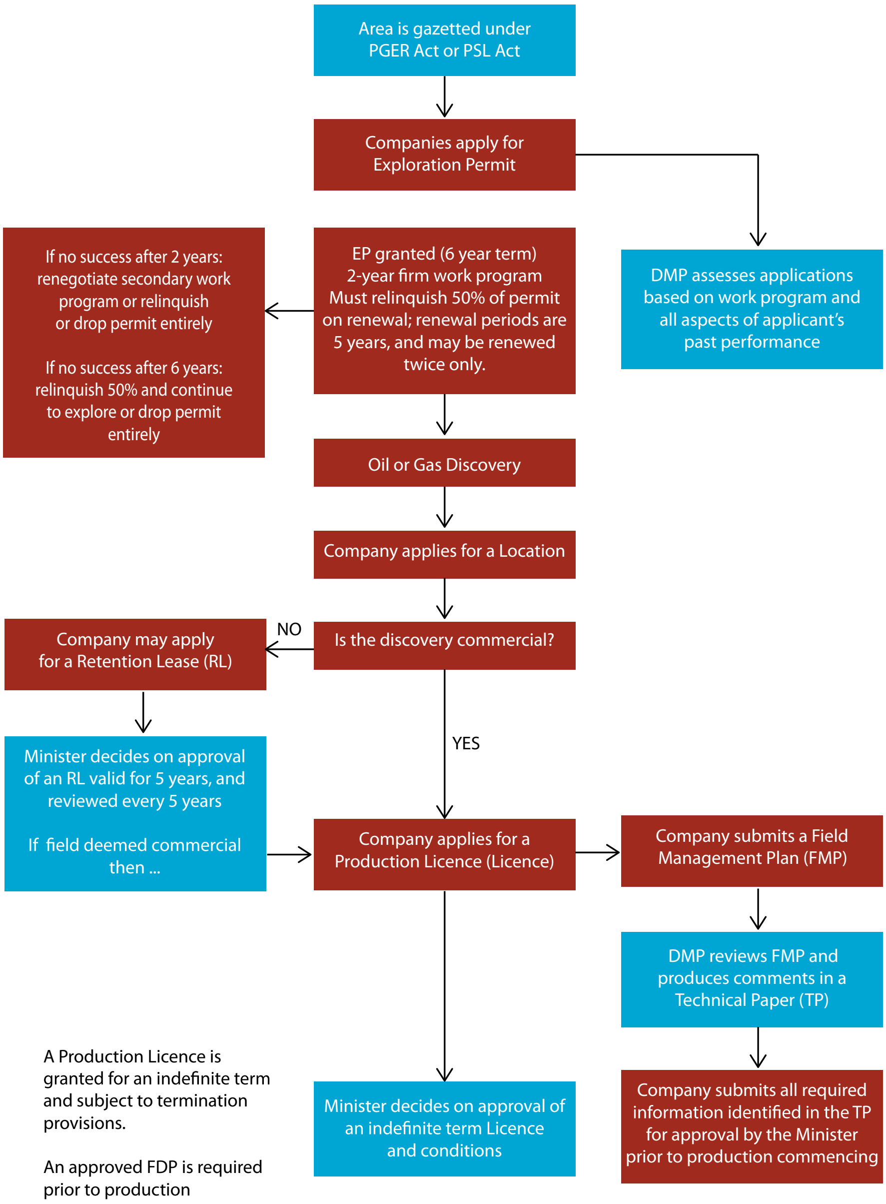


Figure 38. Petroleum title award process for Western Australian legislation

The second phase of the program may be negotiated on a year-by-year basis prior to the commencement of each permit year. However, if agreement with the Minister cannot be reached as to the extent of the program, then the work proposed for those years at the time the application was initially made will prevail. A permit holder may apply at any time to surrender the permit in this second phase provided the permit is in good standing.

While the extent, timing and appropriateness of the work program are the main considerations for the award of a permit, there are other important criteria, particularly the financial and technical ability of the applicant. Any particular terms of assessment would be made known in the release package. The initial term of the permit is six years. An Exploration Permit can only be renewed for two further periods of five years, with 50 per cent relinquishment of the area at the end of each term (for a total of 16 years).

Permits are granted subject to specific minimum work commitments that must be met each year (or earlier). Permits in the State area must complete the first two years firm work program before they can be surrendered.

Declaration of Location

Upon discovery of petroleum, a permittee must notify the authorities, giving details of the discovery. Hydrocarbons have to be recovered to surface before a Location can be declared. Before applying for a Retention Lease or Production Licence, the permittee must identify the block or blocks which cover the area of the discovery.

Where a location is declared over a discovery, the blocks remain under the exploration title and the permittee may undertake further exploration and/or appraisal activities within the Location to determine more accurately the extent of the discovery. Based on further appraisal outcomes, the permittee may apply to the Minister to vary the Location to adjust the number of blocks affected. The permittee has two years after the Declaration of Location in which to apply for either a Retention Lease or Production Licence. This period may be extended for a further two years at the discretion of the Minister. Within this period the permit holder selects from this 'Location' the blocks to be included in a Production Licence or Retention Lease.

Production Licence

Where a commercial discovery is made, the successful explorer has a statutory right to the grant of a Production Licence. A Production Licence is granted for an indefinite term (subject to termination provisions if no operations for the recovery of petroleum under the licence have been undertaken during a continuous period of 5 years).

A Production Licence provides the registered holder(s) with an exclusive right to carry out operations (e.g. drilling of development wells, installation of production platforms) for the recovery of petroleum within the licence area in accordance with an approved Field Management Plan and individual activity work approvals.

Retention Lease

Retention Leases are awarded for non-commercial petroleum discoveries. The applicant must demonstrate that the resource is not currently commercially viable, but is likely to become so within the next 15 years. The initial term of a Retention Lease is five years and it may be renewed provided it still meets the noncommerciality criteria. When the discovery is deemed to be commercial, the Retention Lease must be converted to a Production Licence. At any time during the five-year term of the lease, the Government can request a review of the commercial viability of the field.

Drilling Reservation

Generally, petroleum exploration is carried out by way of a Petroleum Exploration Permit but exploration can also be carried out by way of a Drilling Reservation. A Drilling Reservation is a prospect-size title granted under the PGER Act that allows drilling and other exploratory operations, such as seismic surveying, in support of the drilling operation. Drilling Reservations are granted for a period up to three years (at the discretion of the Minister) and only where a drillable target has already been identified. Drilling Reservations are not available under the PSL Act.

Special Prospecting Authority (with an Acreage Option)

Special Prospecting Authorities with an Acreage Option (SPA/AO) titles are granted for the purpose of enabling geophysical or geochemical surveys (or other operational activities other than the making of a well) to be undertaken in areas not currently under title, the subject of competing applications, or identified by DMP for a future Acreage Release. They are intended as a means of preliminary assessment of the prospectivity of areas where little or no exploration has been undertaken prior to a more permanent exploration title being applied for. These authorities are restricted in time to a maximum six months for the field work and generally a further six months to enable the option to be exercised. Drilling is not to be undertaken under an SPA/AO title.

Application forms for SPA/AO are available from the DMP website and these forms detail the information which must necessarily be provided when an application is made.

Generally, the grant of a SPA/AO will depend upon the rationale for the proposed activity, the applicant's financial and technical ability, and past performance in respect to exploration and native title negotiations.

The approval of an SPA with Acreage Option is at the Minister's discretion as some applications may not be regarded as appropriate for such exclusivity. This may be due to the prospectivity of the area, competing applications over the same blocks or the type and quantity of the proposed activity.

The Acreage Option only extends to the right to apply for an Exploration Permit or Drilling Reservation and does not infer any obligation on the part of the Minister to grant a title. Such a title will only be granted on the merits of the proposed work program and satisfaction of the required assessment criteria as applied under the competitive bidding system.

Once the SPA/AO period has expired, the data generated from the survey is to be made publicly available. SPA/AOs are not available under the PSL Act.

Access Authority

An Access Authority title enables the holder of a permit, drilling reservation, lease, licence or SPA to extend limited exploration activities (usually seismic lines tying into some other known control) in vacant acreage or acreage held under another party's title.

Where access is required in the above circumstance, the permit holder, so affected, needs to be given the opportunity to comment on, but not veto, the proposed access. To hasten the approval process, it is advisable to seek the consent of the other permit holder and include this consent with the application.

Access Authorities are usually limited in time to the period in which the exploration activity can be completed. To avoid delays, applications should be made at the same time as the application for the activity. The type of activity proposed to be undertaken within the Access Authority area will determine the level of referral under the *Native Title Act 1993* (Cwth) (NT Act) that will be required prior to grant.

Application forms that outline the information to be provided in support of an Access Authority application are available from DMP's Petroleum Division.

Pipeline Licence

A petroleum pipeline is defined as a pipe or system of pipes used for the conveyance of petroleum and includes all structures for protecting or supporting a pipeline and is generally, in respect to high pressure trunk lines, associated with petroleum production facilities or high pressure natural gas distribution lines. A pipeline licence may also include storage tanks, pumps, terminal stations, and ancillary facilities. Field gathering lines are not usually licensed as a petroleum pipeline, but are included as part of the Production Licence facilities.

Pipelines under the *Petroleum Pipelines Act 1969* (PP Act) and PSL Act are granted for an indefinite term (subject to termination provisions if a pipeline licensee has not carried out any construction work under the pipeline licence or used the pipeline during a continuous period of 5 years).

A PP Act Pipeline Licence, being restricted to onshore areas, is likely to coexist with other land tenures; accordingly a licence enables the holder to construct a pipeline only over land which it has acquired by easement, purchase or some other authorisation.

The area required for a PP Act Pipeline Licence varies but is usually a narrow corridor of about 30 m for access purposes. Pipeline Licences are subject to stringent safety and environmental conditions and audits.

Infrastructure Licence

Infrastructure Licences (IL) are only available under the PSL Act. An IL enables the handling/processing of petroleum outside a Production Licence area but within the offshore area. An IL could be in a vacant area or an area held under another Petroleum Title. Its area is defined as a place and does not involve the block system of granting titles.

As with Production Licences and Pipeline Licences, Infrastructure Licences are granted for an indefinite term with similar termination provision.

Greenhouse Gas Titles

Greenhouse Gas Titles are titles within Commonwealth offshore waters (i.e. beyond State coastal waters), by which the exploration for potential storage sites and the eventual injection/storage of greenhouse gas into those sites is possible. These titles were incorporated into the offshore petroleum act which is now known as the *Offshore Petroleum and Greenhouse Gas Storage Act 2006*.

The State's PGER Act will be amended to accommodate greenhouse gas storage, with legislation that mirrors the Commonwealth's legislation.

Greenhouse Gas Titles can coexist with Petroleum Titles and enable the exploration for storage sites, (Greenhouse Gas Assessment Permit), the retention of such a site until commercial storage can be effected (Greenhouse Gas Holding Lease) and eventual storage of the greenhouse gas (Greenhouse Gas Injection Licence).

Areas for exploration are made available in the same manner as that for Petroleum Exploration Permits, that is, periodic release of areas on a competitive work program bid basis.

While Greenhouse Gas Titles can coexist with Petroleum Titles, provision is made for protecting the interest and operations of both sets of titles.

PETROLEUM ADMINISTRATION

Registered Holder's Obligations

The legislation provides that all registered holders must carry out operations according to good oilfield practice, including carrying out operations in a manner that is safe and prevents the escape of petroleum into the environment. The operations must also be conducted in a manner that does not unnecessarily interfere with the surface of land or any improvements or other persons' lawful activities. In order to retain title, conditions of work and compliance with directions must be met, data and reports submitted, and annual fees paid.

A summary of the obligations and conditions of each licence type under State legislation is provided in Table 14.

Petroleum Work Approvals

The rights contained in a petroleum title is pertinent to the type of title, e.g. a Petroleum Exploration Permit (EP) provides the exclusive right to explore for or recover petroleum and to undertake works necessary to do so. However, the exercise of that right is subject to the requirements of the Act, its regulations, any directions given under the Act and also to specific conditions endorsed on the title. It is also subject to all other relevant laws of the land. Primarily, the work to be undertaken will need to be carried out with due regard to public and worker safety, protection of the environment and the interest of others who have an interest in the land.

The process developed to ensure that these requirements are addressed is the works approval system. Any proposal by a petroleum registered holder to undertake any fieldwork needs to be submitted to DMP in sufficient time to allow the application to be properly assessed.

While the exercise of petroleum rights applies to all land within a title area, the interests of others needs to be considered, e.g. any work to be carried out onshore will likely require a heritage survey to ensure compliance with the requirements of the *Aboriginal Heritage Act 1972*. Similarly, should the work proposed be on private land then a compensation agreement would need to be negotiated with the private land owner. Further details in this regard are dealt with in the "Land Access" chapter.

All work is subject to WA's *Environmental Protection Act 1986*. Any work within WA's jurisdiction, likely to impact on the conservation estate or have a significant environmental impact may require independent approvals under that Act. More information concerning the protection of the environment appears in the "Environment Assessment" chapter.

Naturally, the sensitivity of the land on which the work is proposed will have a bearing on the time required to properly assess that proposal. In those circumstances sufficient lead times should be provided by the applicant so that deadlines may be met.

Application forms for petroleum work proposals (e.g. drilling a well or conducting surveys) are available from DMP and some can be submitted online. The forms are comprehensive and provide details of the information required and any accompanying documentation. More details of the forms are provided under the "Online Systems" heading in the "Access to Data" chapter.

Monitoring Approvals Processes

DMP is committed to encouraging and facilitating responsible exploration, development and production of petroleum and geothermal resources for the benefit of all Western Australians.

The Petroleum Division assesses applications for new wells, well tests, other well operations and field development plans to ensure that well operations and field developments are carried out with good industry practice and to ensure sound resource management.

DMP has implemented a range of administrative initiatives to improve the approval processes specific to the resources sector. These include:

- establishment of approval timeline targets and performance measures;
- website publication of DMP's quarterly approval performance;
- revision of the memorandum of understanding with the Environmental Protection Authority; and
- establishment of an online application approval tracking system.

DMP's Petroleum and Geothermal Register (PGR) is an online electronic titles register that administers title information and monitors approvals for Petroleum and Geothermal Exploration Permits and renewals; Production Licences and renewals; Retention Leases and renewals; as well as Wells, Surveys, Special Prospecting Authorities and Access Authorities.

Using a 'single sign-on', petroleum proponents can also track their applications for environmental assessment through the online Environmental Assessment and Regulatory System (EARS). The system shows whether an application is under assessment by DMP or another agency, if it is on hold, and whether it has been approved, rejected or withdrawn from the process. Proponents can print the online reports of their application approval status.

DMP is the first government regulatory body in Australia to introduce online payments to the petroleum industry by enabling industry to lodge an application, register and pay title search and annual fees online. Using PGR industry can conduct business from anywhere around the world. For example, a finance team in Houston can monitor and pay accounts, an Application to Drill can be lodged in Sydney and an office in Perth can monitor the company's applications online.

DMP uses an approvals monitoring system to track and monitor the progress of petroleum and geothermal applications and assessments online. An overview of the application processes are shown in the following pages:

- for Acreage Release (Figure 39)
- Petroleum Exploration Permit from the acreage release or SPA/AO process (Figure 40)
- Petroleum/Geothermal Special Prospecting Authority (SPA) approval process (Figure 41)
- Petroleum/Geothermal Special Prospecting Authority (SPA) with Acreage Option (AO) approval process (Figure 42)
- Petroleum Drilling Application approval process (Figure 43)
- Survey approval process (Figure 44)
- Production Licence application (Figure 45)
- Pipeline Licence approval processes (Figures 46, 47 and 48).

These overviews of approvals processes can be found in full on the DMP website, www.dmp.wa.gov.au/18041.aspx

As part of the monitoring process, PGR is able to provide reports that assist with identifying:

- the length of time taken to process an application from the start of the approval process to completion;
- the number and percentage of applications completed within timeline targets;
- the percentage of applications progressing on schedule; and
- the average time taken by assessors (internal or external) over a given period.

The information obtained from these reports assists in identifying where bottlenecks and work volumes occur. Problems are easily identified, analysed and remedial action taken to streamline processes.

The Department publishes quarterly Petroleum and Geothermal performance reports online. These reports are located on the Department's website at www.dmp.wa.gov.au/7436.aspx.

Table 14. Summary of Petroleum and Geothermal Titles

TITLE	TERM	AREA	RIGHTS	OBLIGATIONS
Petroleum Exploration Permit (EP)	Original 6-year term. Renewal 5-year term, twice only.	Number of blocks in release area.	1. To explore for petroleum. 2. To convert any discovery made to a Production Licence or if presently uneconomic a Retention Lease.	1. To fulfil the work commitment on which the grant of title was made and in the time frame prescribed. 2. To conduct operations in accordance with good oilfield practice. 3. To provide for safety of workers. 4. To provide for the protection of the environment. 5. To not unduly interfere with other land uses or activities. 6. Compliance with the Act, Regulations and Directives. 7. To pay annual fee and royalties.
Petroleum Drilling Reservation (DR) (PGER Act only)	Up to a 3-year term (plus extension period of one year).	Corresponds to potential size of prospect, in blocks.	1. As for Exploration Permits.	1. As for Exploration Permits.
Petroleum Retention Lease (RL)	5-year term. Right of renewal for subsequent 5-year periods.	Corresponds to discovery, in blocks.	1. To explore for petroleum to convert to a Production Licence once economic viability confirmed.	1. As for Exploration Permits but also obliged to conduct economic viability studies as requested.
Petroleum Production Licence (L)	Indefinite term commensurate with production plus 5 years.	Corresponds to size of discovery, in blocks.	1. To recover petroleum.	1. To recover petroleum in accordance with direction of Minister. 2. To continue to explore licence area. 3. To conduct operations in accordance with good oilfield practice. 4. To provide for safety of workers. 5. Comply with environmental Management Plan. 6. To pay annual fee and royalties.
Geothermal Exploration Permit (GEP)	These Titles have similar terms, areas, rights and obligations to those of the above Petroleum Titles and can coexist with Petroleum Titles			
Geothermal Drilling Reservation (GDR)				
Geothermal Retention Lease (GRL)				
Geothermal Production Licence (GL)				
Infrastructure Licence (IL) (PSL Act 82 only)	Indefinite term commensurate with remote production operations and/or processing plus 5 years.	Area of facility.	1. Construct and operate a facility for remote production operations and/or processing.	1. To construct and operate a facility for remote production operations and/or processing of petroleum in accordance with the Act, regulations, directions and conditions of licence. To conduct operations in accordance with good oilfield practice. 2. To provide for the safety of workers. 3. To provide for protection of the environment. 4. To pay annual fee.
Pipeline Licence (PL)	Term commensurate with conveyance operations plus 5 years.	Area necessary to accommodate pipeline and associated facilities, e.g. pumping stations, storage tanks.	1. To construct and operate a pipeline for the purpose of conveying naturally occurring hydrocarbons.	1. To construct and operate pipeline in accordance with the requirements of the Act, regulations, directions and conditions of licence. To act as common carrier should Minister so determine. 2. To conduct operations in accordance with good oilfield practice. 3. To provide a safe working environment for employees. 4. To provide for the protection of the environment. 5. To not unduly interfere with other land uses or activities. 6. To pay annual fee.

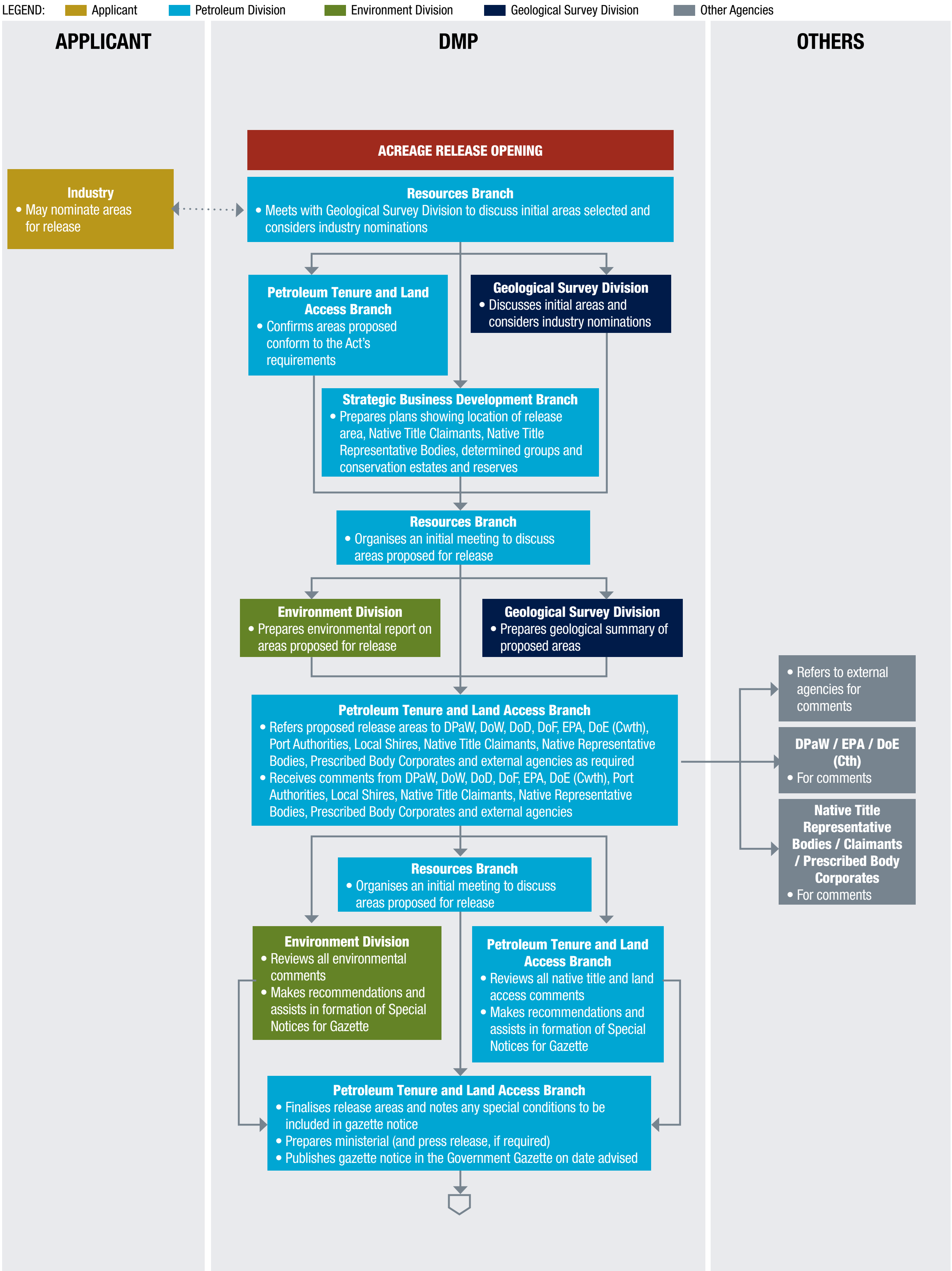
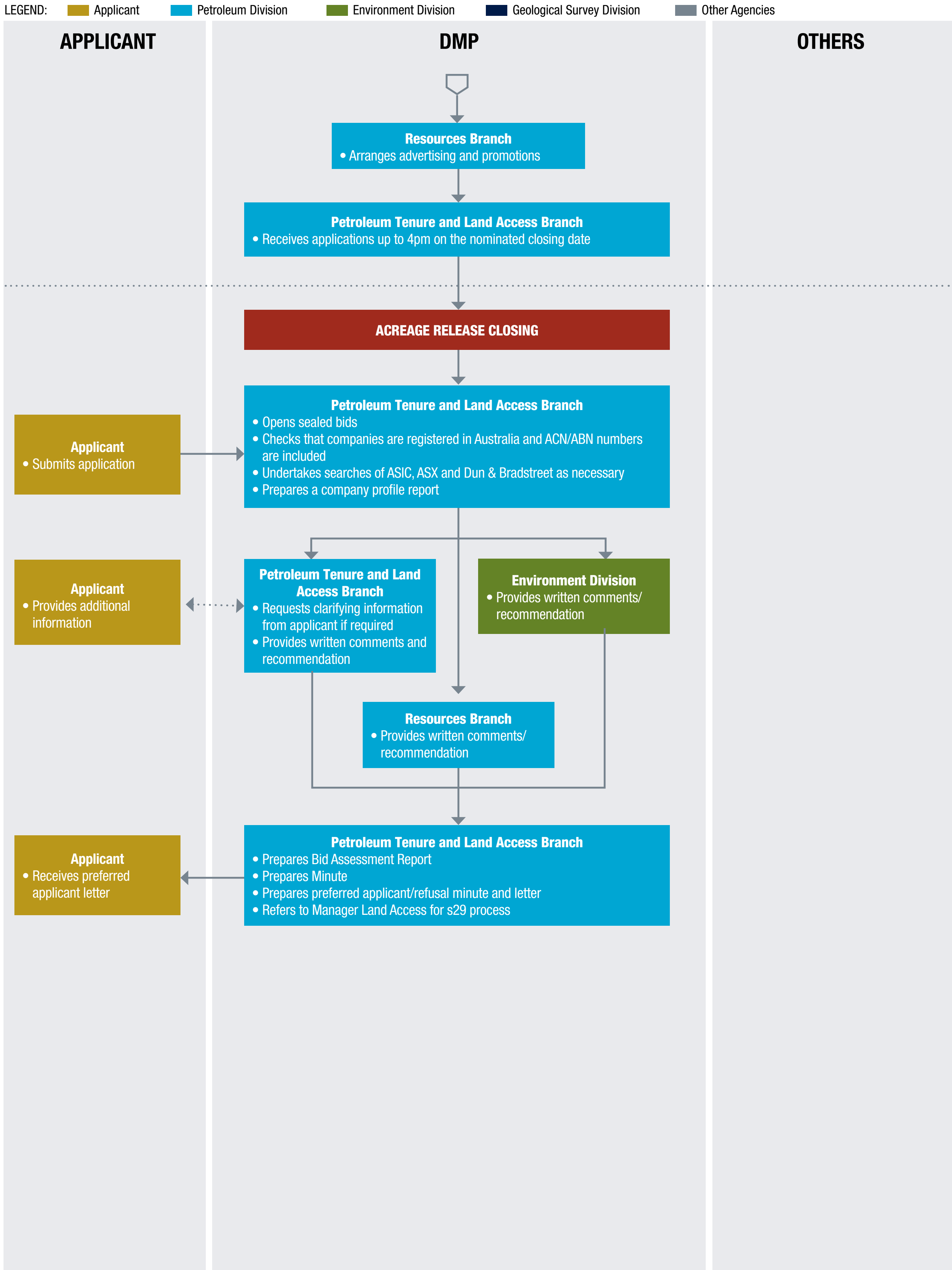


Figure 39. Acreage Release – Petroleum/Geothermal State Onshore (PGER Act)/Petroleum State Offshore (PSL Act) Process
Refer to Appendix 1 for abbreviations and acronyms


LEGEND: Applicant Petroleum Division Environment Division Geological Survey Division Other Agencies
APPLICANT
DMP
OTHERS
Resources Branch
• Arranges advertising and promotions
Petroleum Tenure and Land Access Branch
• Receives applications up to 4pm on the nominated closing date
ACREAGE RELEASE CLOSING
Applicant
• Submits application
Petroleum Tenure and Land Access Branch
• Opens sealed bids
• Checks that companies are registered in Australia and ACN/ABN numbers are included
• Undertakes searches of ASIC, ASX and Dun & Bradstreet as necessary
• Prepares a company profile report
Applicant
• Provides additional information
Petroleum Tenure and Land Access Branch
• Requests clarifying information from applicant if required
• Provides written comments and recommendation
Environment Division
• Provides written comments/ recommendation
Resources Branch
• Provides written comments/ recommendation
Applicant
• Receives preferred applicant letter
Petroleum Tenure and Land Access Branch
• Prepares Bid Assessment Report
• Prepares Minute
• Prepares preferred applicant/refusal minute and letter
• Refers to Manager Land Access for s29 process

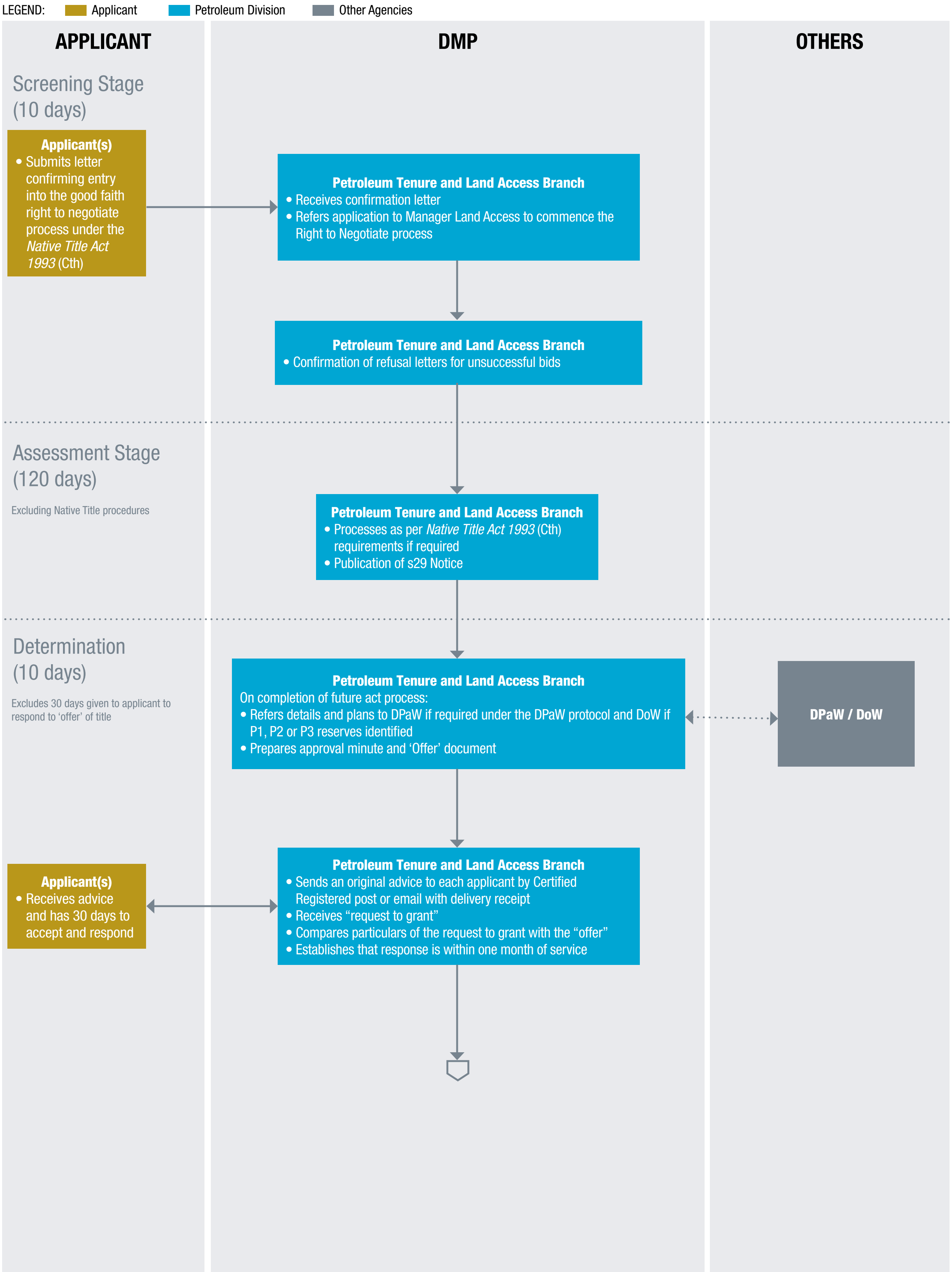
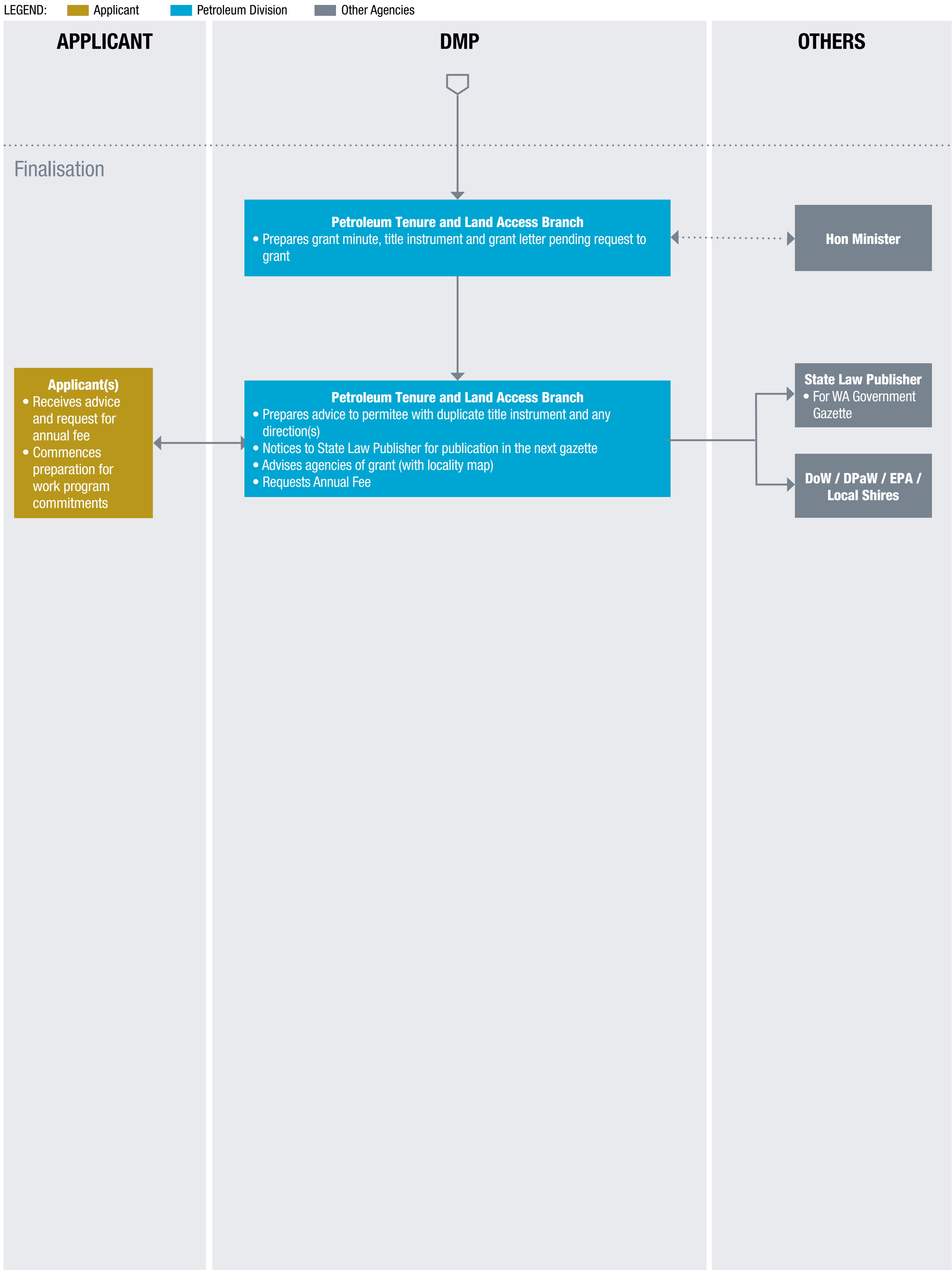


Figure 40. Exploration Permit Application (from Acreage Release) Grant Process (PGER Act and PSL Act)

Refer to Appendix 1 for abbreviations and acronyms


LEGEND: Applicant Petroleum Division Other Agencies
APPLICANT
DMP
OTHERS
Finalisation
Petroleum Tenure and Land Access Branch
• Prepares grant minute, title instrument and grant letter pending request to grant
Hon Minister
Applicant(s)
• Receives advice and request for annual fee
• Commences preparation for work program commitments
Petroleum Tenure and Land Access Branch
• Prepares advice to permitee with duplicate title instrument and any direction(s)
• Notices to State Law Publisher for publication in the next gazette
• Advises agencies of grant (with locality map)
• Requests Annual Fee
State Law Publisher
• For WA Government Gazette
DoW / DPaW / EPA / Local Shires

PETROLEUM ADMINISTRATION

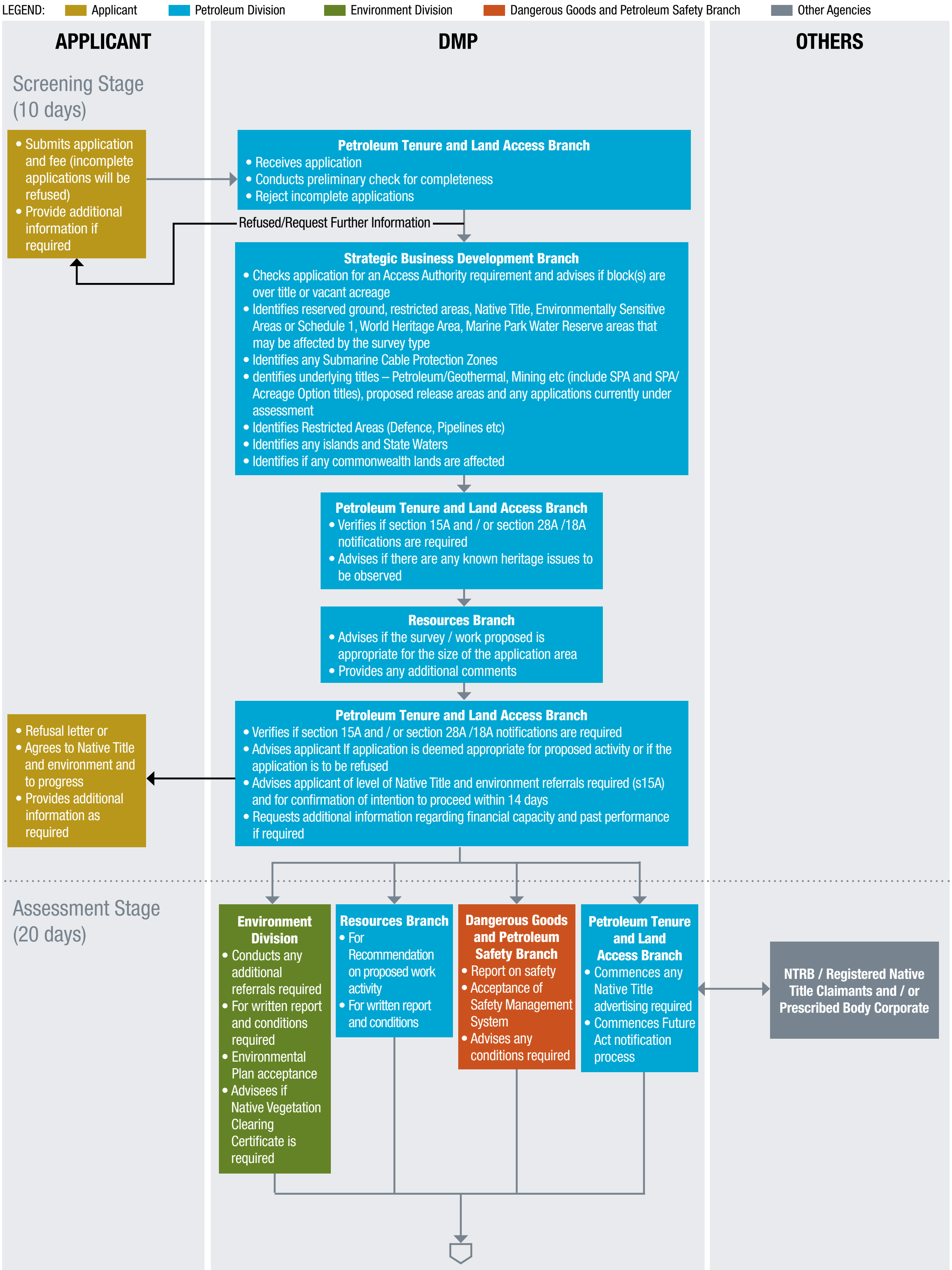
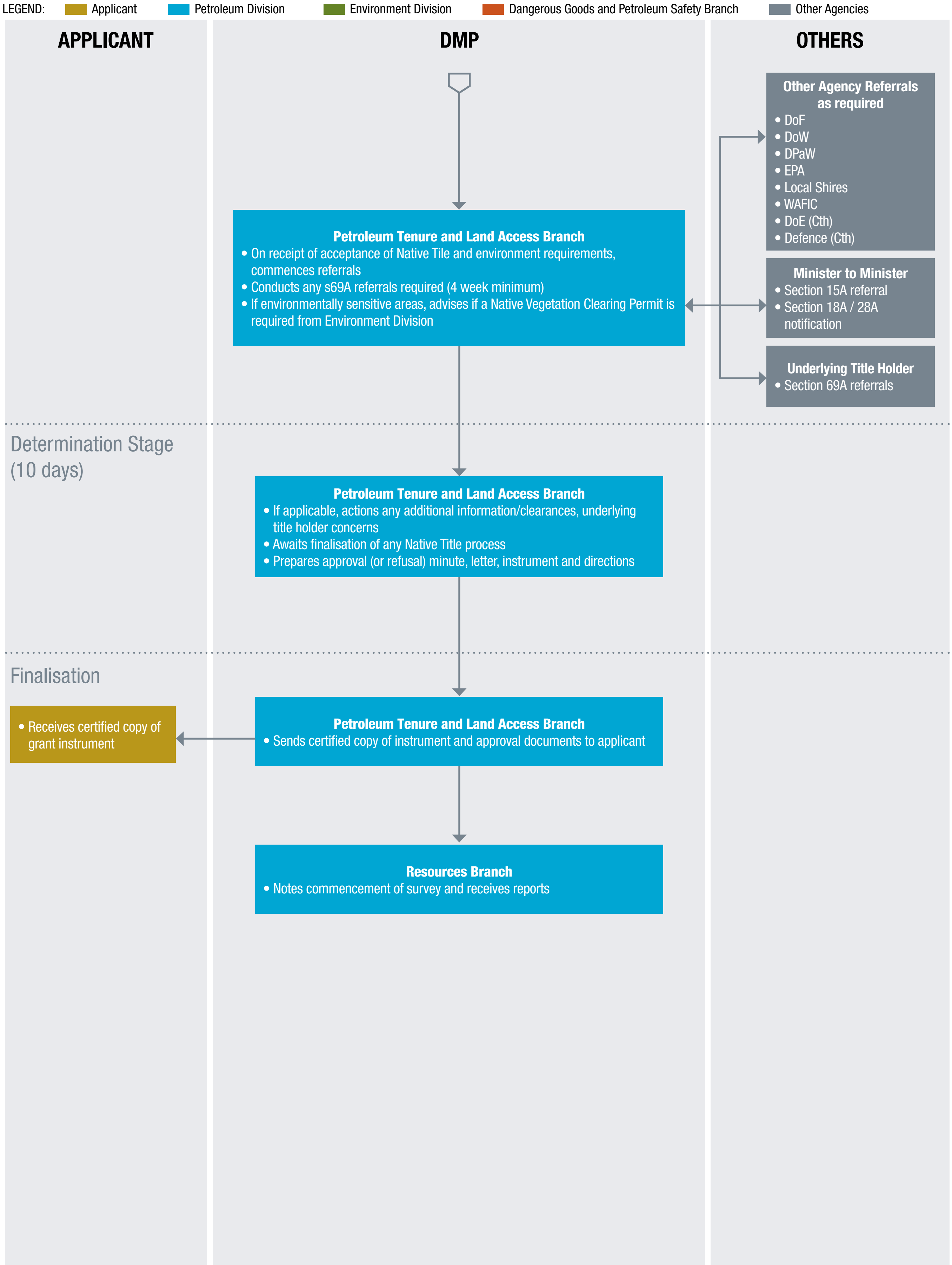


Figure 41. Petroleum/Geothermal Special Prospecting Authority (SPA) (PGER Act and PSL Act) Approval Process

Refer to Appendix 1 for abbreviations and acronyms


LEGEND: Applicant Petroleum Division Environment Division Dangerous Goods and Petroleum Safety Branch Other Agencies
APPLICANT
DMP
OTHERS
Other Agency Referrals as required
• DoF
• DoW
• DPaW
• EPA
• Local Shires
• WAFIC
• DoE (Cth)
• Defence (Cth)
Petroleum Tenure and Land Access Branch
• On receipt of acceptance of Native Tile and environment requirements, commences referrals
• Conducts any s69A referrals required (4 week minimum)
• If environmentally sensitive areas, advises if a Native Vegetation Clearing Permit is required from Environment Division
Minister to Minister
• Section 15A referral
• Section 18A / 28A notification
Underlying Title Holder
• Section 69A referrals
Determination Stage (10 days)
Petroleum Tenure and Land Access Branch
• If applicable, actions any additional information/clearances, underlying title holder concerns
• Awaits finalisation of any Native Title process
• Prepares approval (or refusal) minute, letter, instrument and directions
Finalisation
• Receives certified copy of grant instrument
Petroleum Tenure and Land Access Branch
• Sends certified copy of instrument and approval documents to applicant
Resources Branch
• Notes commencement of survey and receives reports

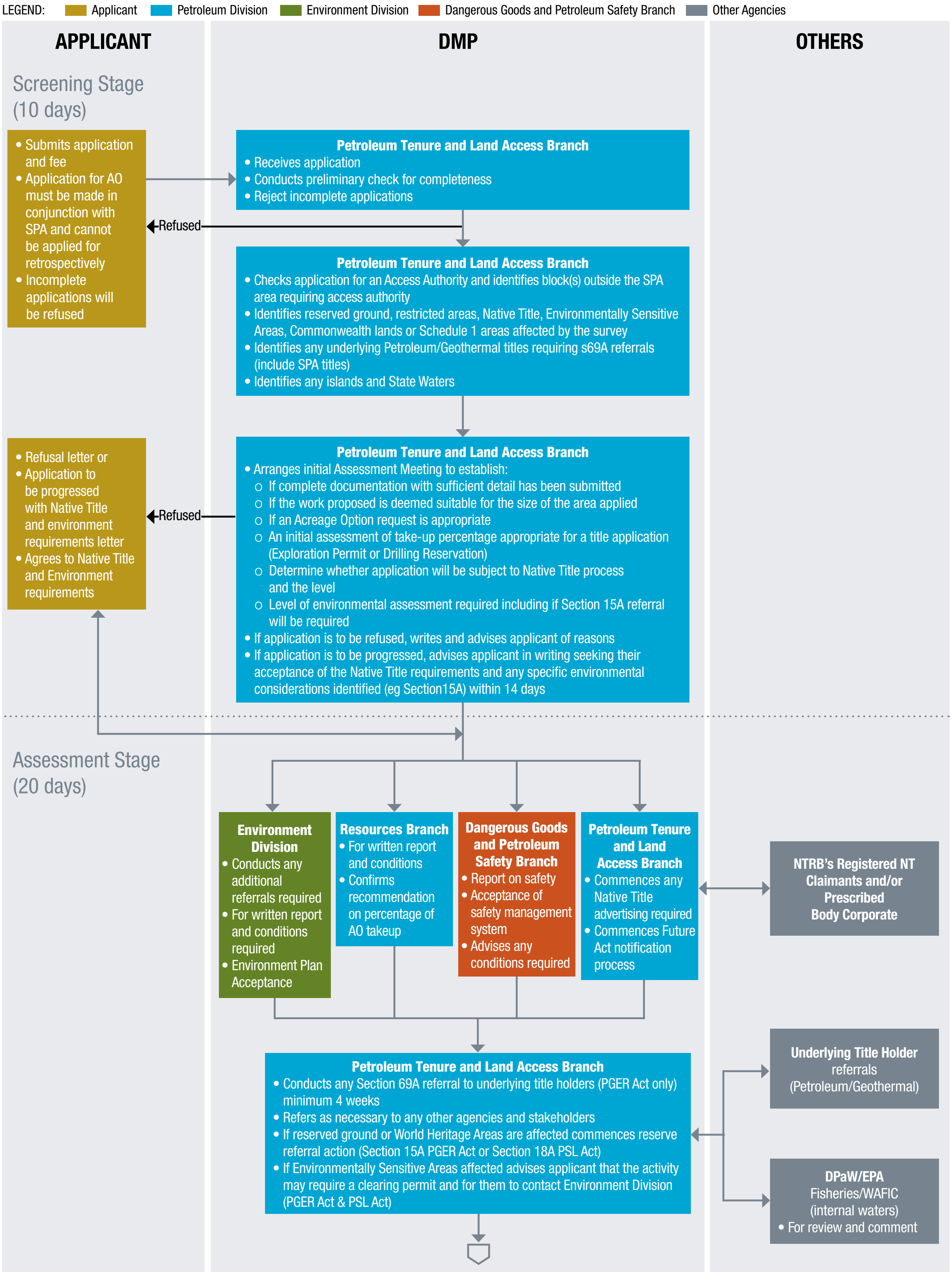
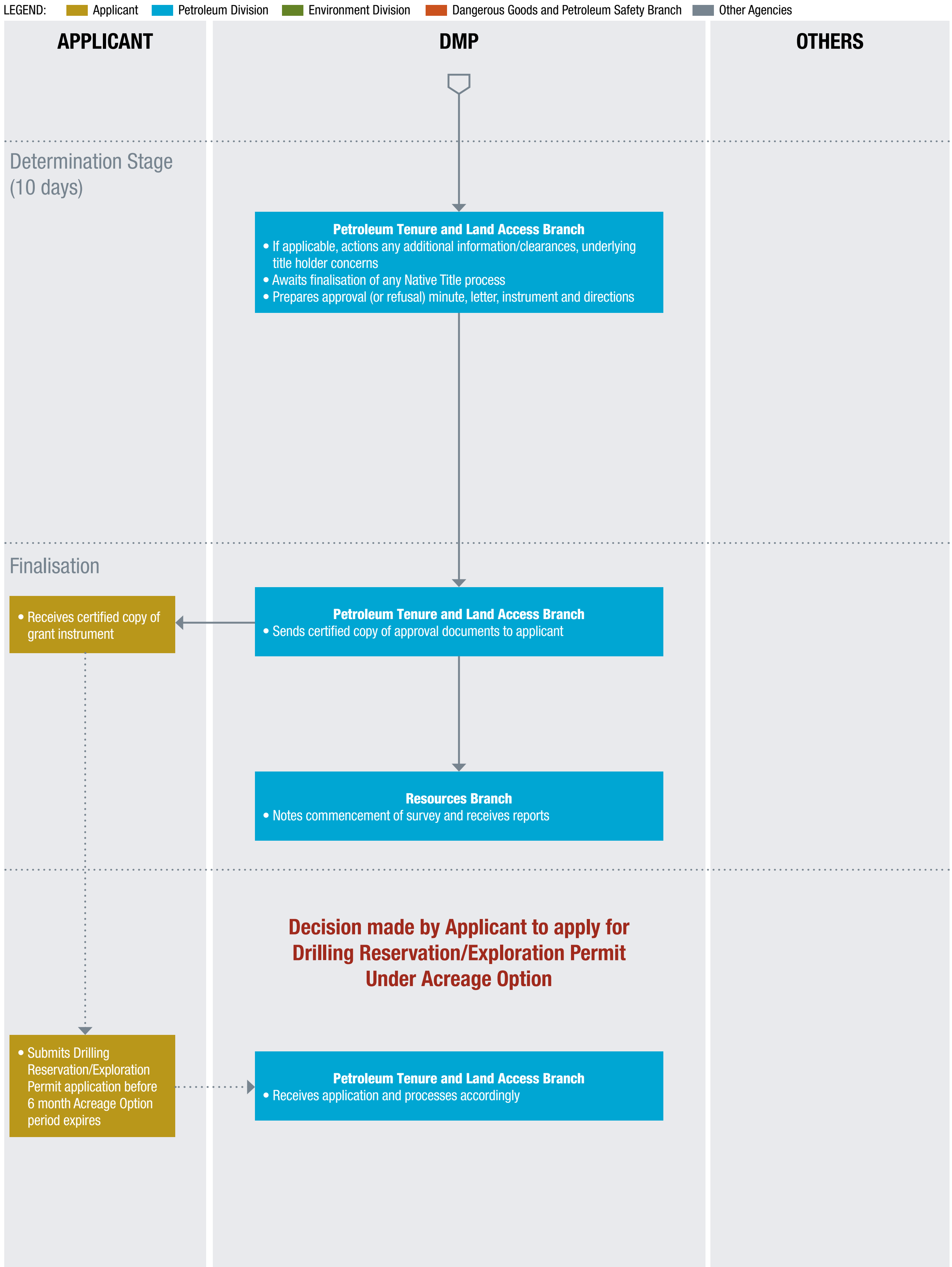


Figure 42. Petroleum/Geothermal Special Prospecting Authority (SPA) with Acreage Option (AO) (PGER Act) Approval Process
Refer to Appendix 1 for abbreviations and acronyms


LEGEND: Applicant Petroleum Division Environment Division Dangerous Goods and Petroleum Safety Branch Other Agencies
APPLICANT
DMP
OTHERS
Determination Stage (10 days)
Petroleum Tenure and Land Access Branch
• If applicable, actions any additional information/clearances, underlying title holder concerns
• Awaits finalisation of any Native Title process
• Prepares approval (or refusal) minute, letter, instrument and directions
Finalisation
• Receives certified copy of grant instrument
Petroleum Tenure and Land Access Branch
• Sends certified copy of approval documents to applicant
Resources Branch
• Notes commencement of survey and receives reports
Decision made by Applicant to apply for Drilling Reservation/Exploration Permit Under Acreage Option
• Submits Drilling Reservation/Exploration Permit application before 6 month Acreage Option period expires
Petroleum Tenure and Land Access Branch
• Receives application and processes accordingly

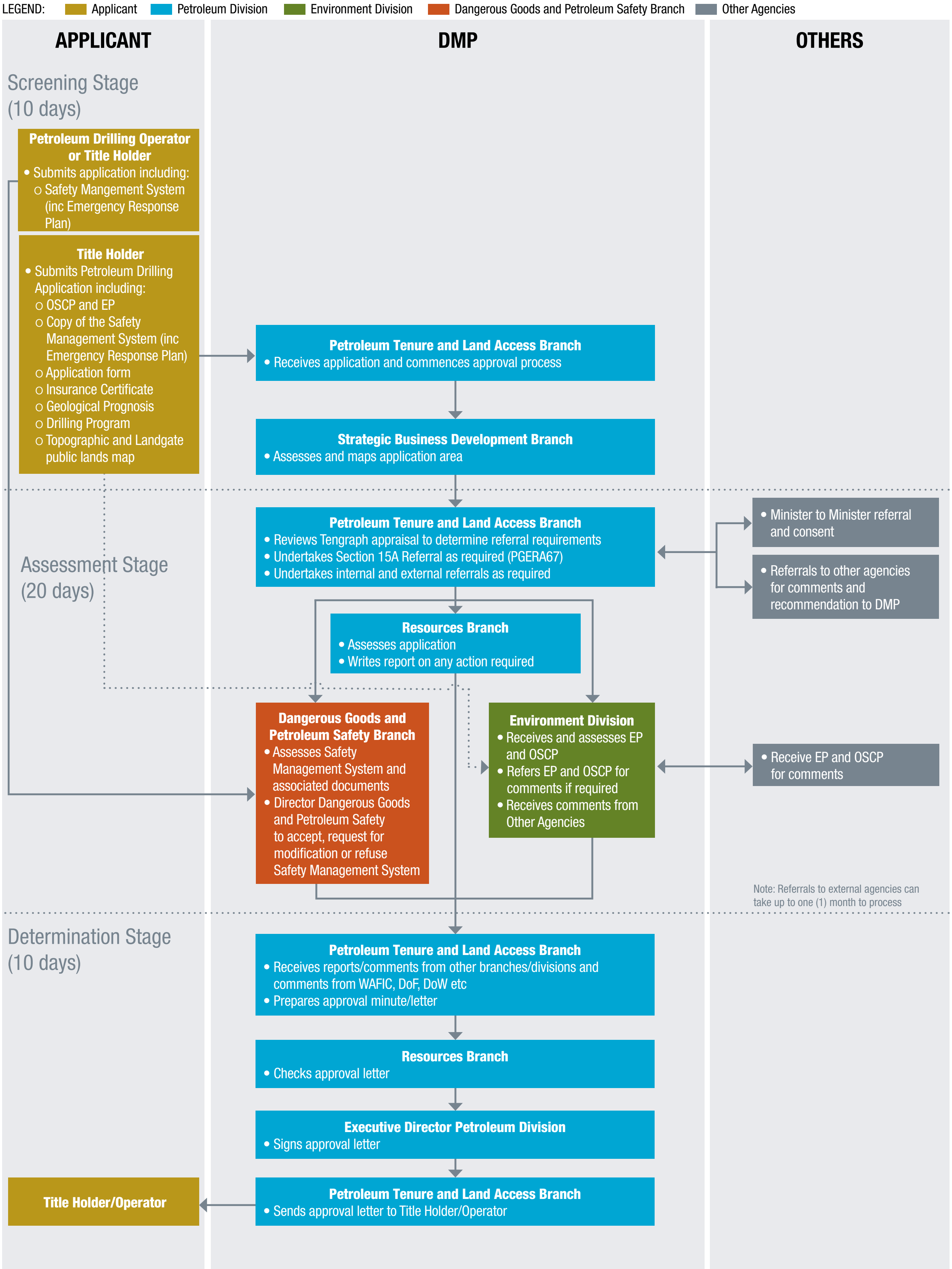


Figure 43. Petroleum Drilling Application Approval Process

Refer to Appendix 1 for abbreviations and acronyms

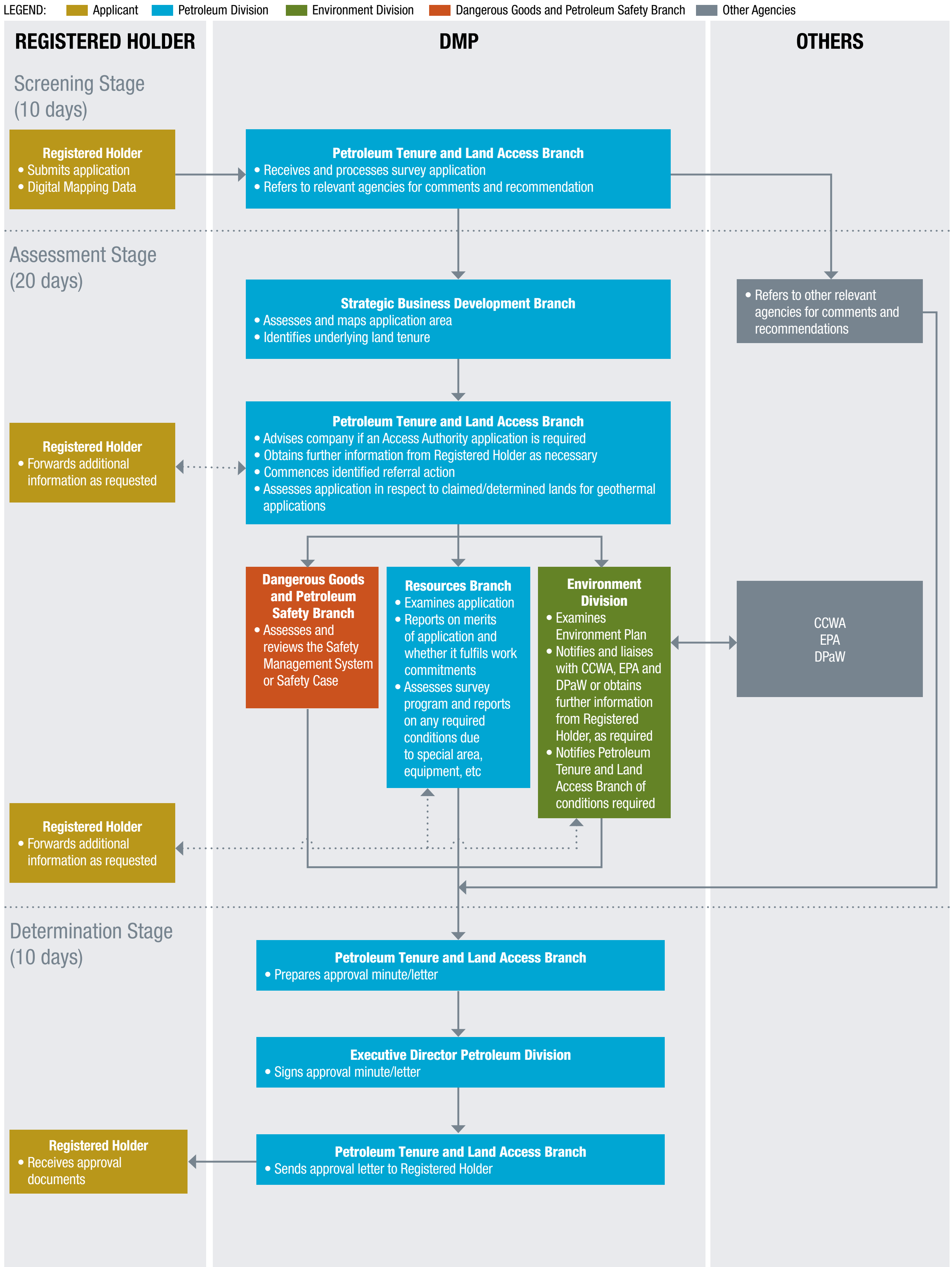


Figure 44. Petroleum/Geothermal Survey Application Approval Process
Refer to Appendix 1 for abbreviations and acronyms

PETROLEUM ADMINISTRATION

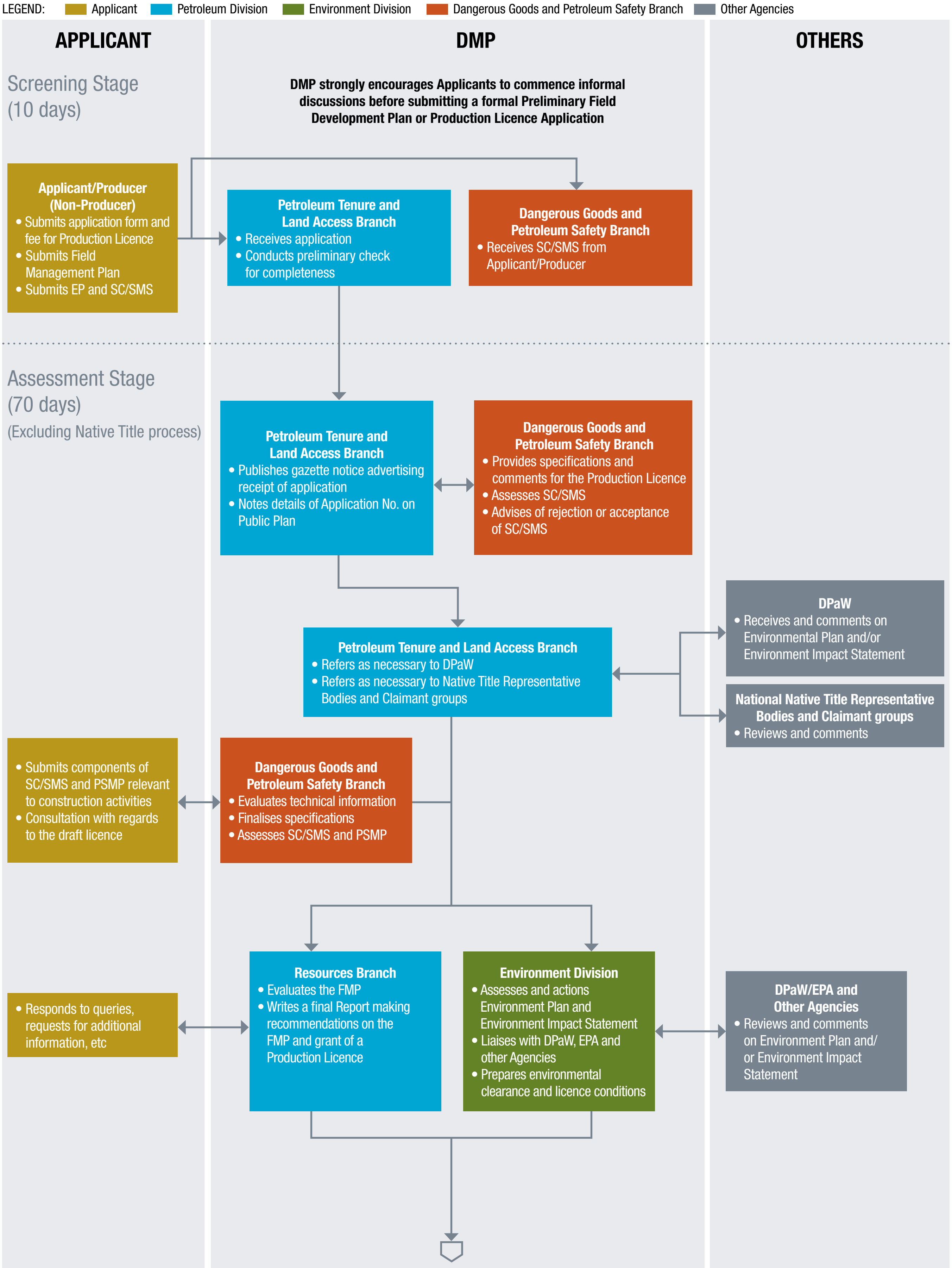
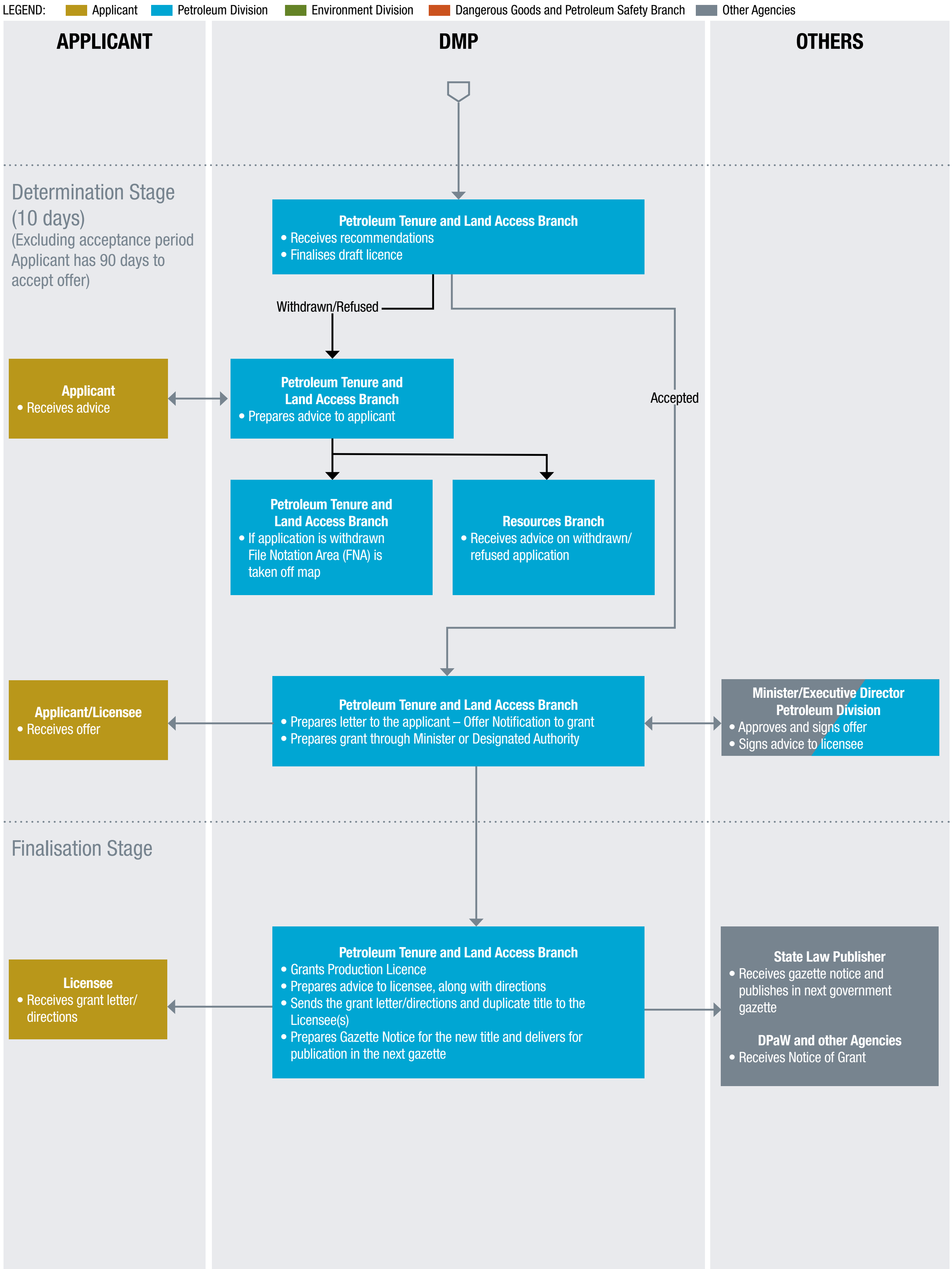


Figure 45. Petroleum Production Licence Approval Process (PGER Act and PSL Act)
Refer to Appendix 1 for abbreviations and acronyms


LEGEND: Applicant Petroleum Division Environment Division Dangerous Goods and Petroleum Safety Branch Other Agencies
APPLICANT
DMP
OTHERS
Determination Stage (10 days)
(Excluding acceptance period Applicant has 90 days to accept offer)
Petroleum Tenure and Land Access Branch
• Receives recommendations
• Finalises draft licence
Withdrawn/Refused
Accepted
Applicant
• Receives advice
Petroleum Tenure and Land Access Branch
• Prepares advice to applicant
Petroleum Tenure and Land Access Branch
• If application is withdrawn File Notation Area (FNA) is taken off map
Resources Branch
• Receives advice on withdrawn/ refused application
Applicant/Licensee
• Receives offer
Petroleum Tenure and Land Access Branch
• Prepares letter to the applicant – Offer Notification to grant
• Prepares grant through Minister or Designated Authority
Minister/Executive Director Petroleum Division
• Approves and signs offer
• Signs advice to licensee
Finalisation Stage
Licensee
• Receives grant letter/ directions
Petroleum Tenure and Land Access Branch
• Grants Production Licence
• Prepares advice to licensee, along with directions
• Sends the grant letter/directions and duplicate title to the Licensee(s)
• Prepares Gazette Notice for the new title and delivers for publication in the next gazette
State Law Publisher
• Receives gazette notice and publishes in next government gazette
DPaW and other Agencies
• Receives Notice of Grant

PETROLEUM ADMINISTRATION

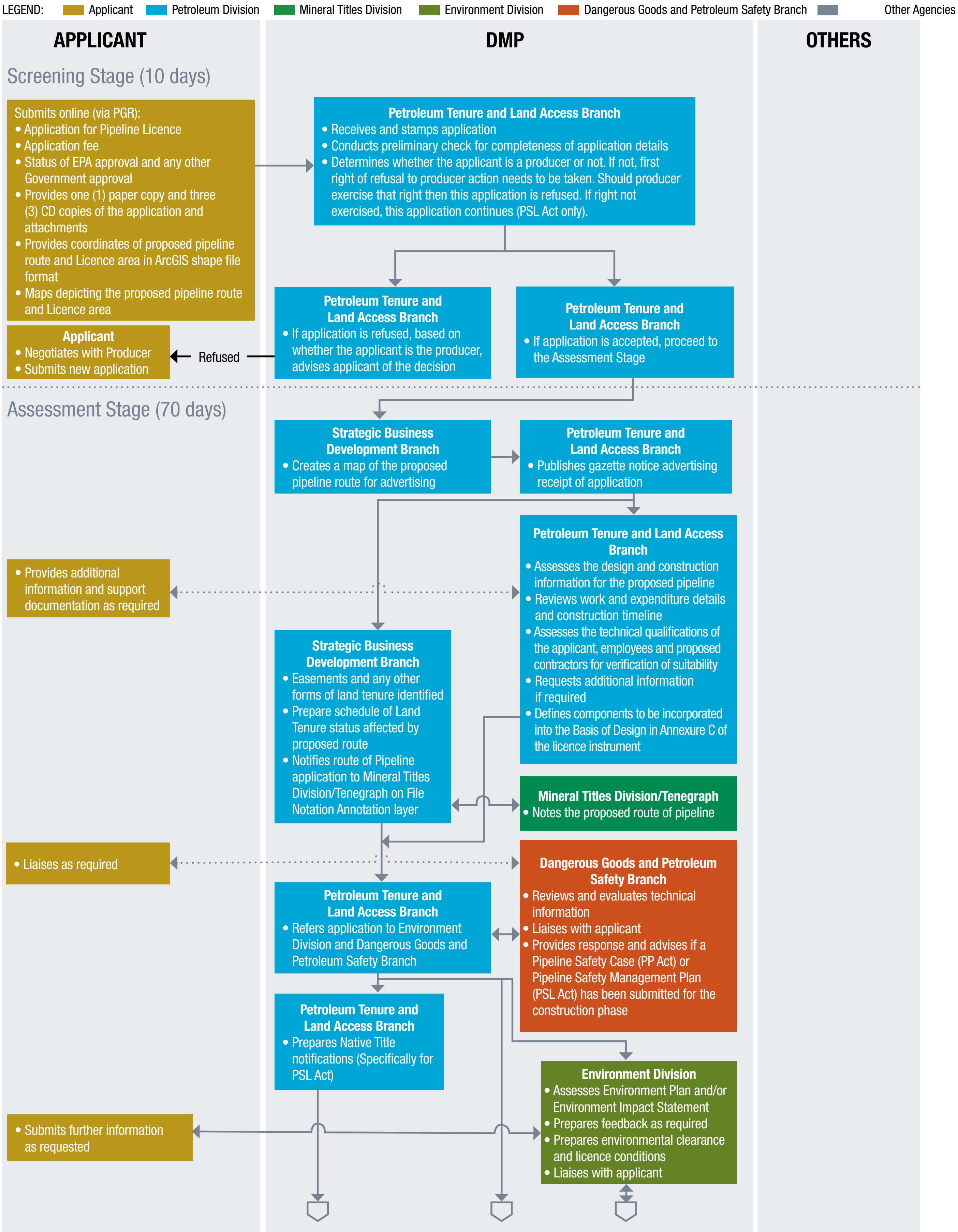
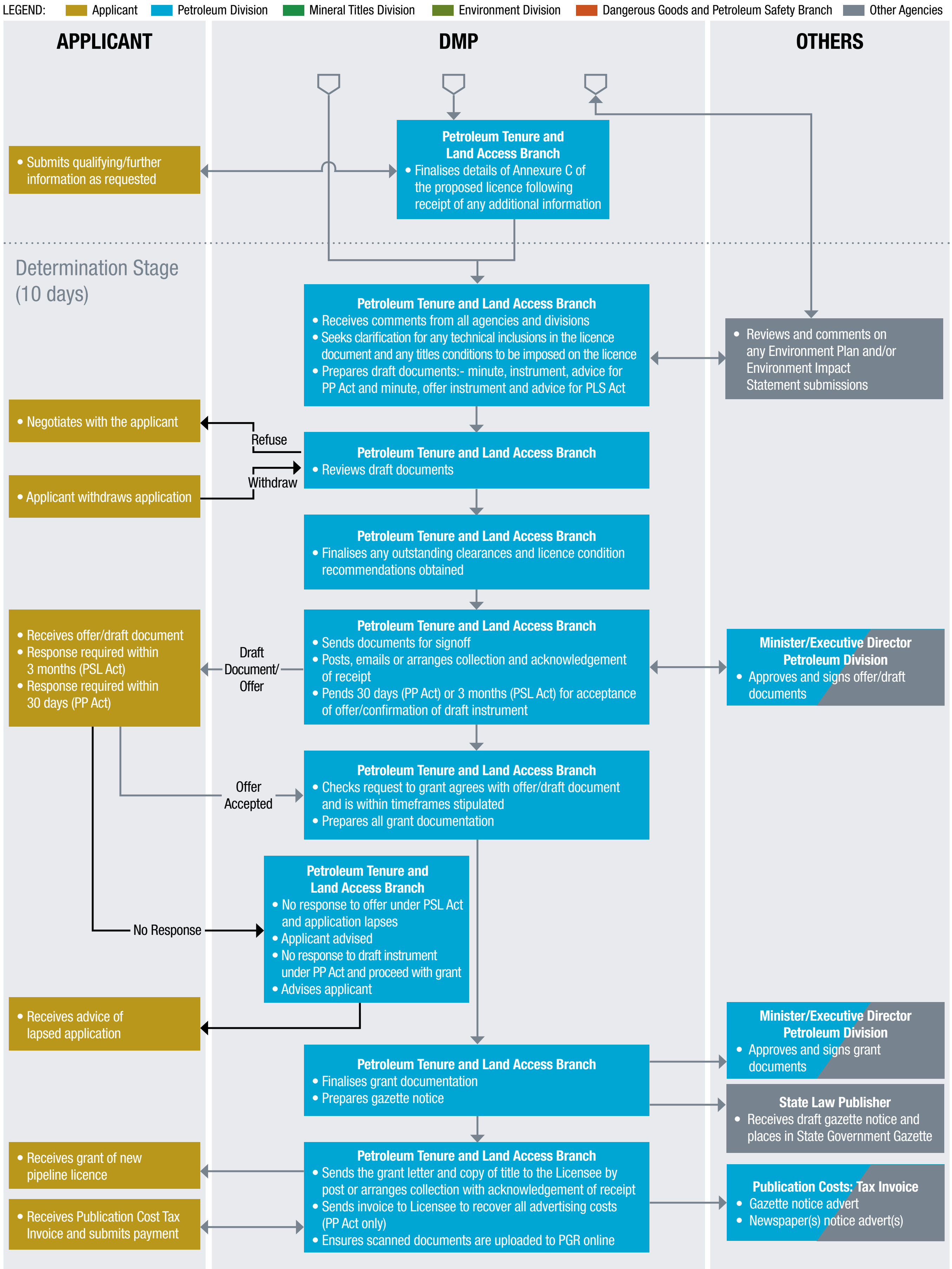


Figure 46. Pipeline Licence Approval Process

Refer to Appendix 1 for abbreviations and acronyms


LEGEND: Applicant Petroleum Division Mineral Titles Division Environment Division Dangerous Goods and Petroleum Safety Branch Other Agencies
APPLICANT
DMP
OTHERS
• Submits qualifying/further information as requested
Petroleum Tenure and Land Access Branch
• Finalises details of Annexure C of the proposed licence following receipt of any additional information
Determination Stage (10 days)
Petroleum Tenure and Land Access Branch
• Receives comments from all agencies and divisions
• Seeks clarification for any technical inclusions in the licence document and any titles conditions to be imposed on the licence
• Prepares draft documents:- minute, instrument, advice for PP Act and minute, offer instrument and advice for PLS Act
• Reviews and comments on any Environment Plan and/or Environment Impact Statement submissions
• Negotiates with the applicant
Refuse
Petroleum Tenure and Land Access Branch
• Reviews draft documents
Withdraw
• Applicant withdraws application
Petroleum Tenure and Land Access Branch
• Finalises any outstanding clearances and licence condition recommendations obtained
• Receives offer/draft document
• Response required within 3 months (PSL Act)
• Response required within 30 days (PP Act)
Draft Document/ Offer
Petroleum Tenure and Land Access Branch
• Sends documents for signoff
• Posts, emails or arranges collection and acknowledgement of receipt
• Pends 30 days (PP Act) or 3 months (PSL Act) for acceptance of offer/confirmation of draft instrument
Minister/Executive Director Petroleum Division
• Approves and signs offer/draft documents
Offer Accepted
Petroleum Tenure and Land Access Branch
• Checks request to grant agrees with offer/draft document and is within timeframes stipulated
• Prepares all grant documentation
Petroleum Tenure and Land Access Branch
• No response to offer under PSL Act and application lapses
• Applicant advised
• No response to draft instrument under PP Act and proceed with grant
• Advises applicant
No Response
• Receives advice of lapsed application
Minister/Executive Director Petroleum Division
• Approves and signs grant documents
Petroleum Tenure and Land Access Branch
• Finalises grant documentation
• Prepares gazette notice
State Law Publisher
• Receives draft gazette notice and places in State Government Gazette
• Receives grant of new pipeline licence
Petroleum Tenure and Land Access Branch
• Sends the grant letter and copy of title to the Licensee by post or arranges collection with acknowledgement of receipt
• Sends invoice to Licensee to recover all advertising costs (PP Act only)
• Ensures scanned documents are uploaded to PGR online
• Receives Publication Cost Tax Invoice and submits payment
Publication Costs: Tax Invoice
• Gazette notice advert
• Newspaper(s) notice advert(s)

PETROLEUM ADMINISTRATION

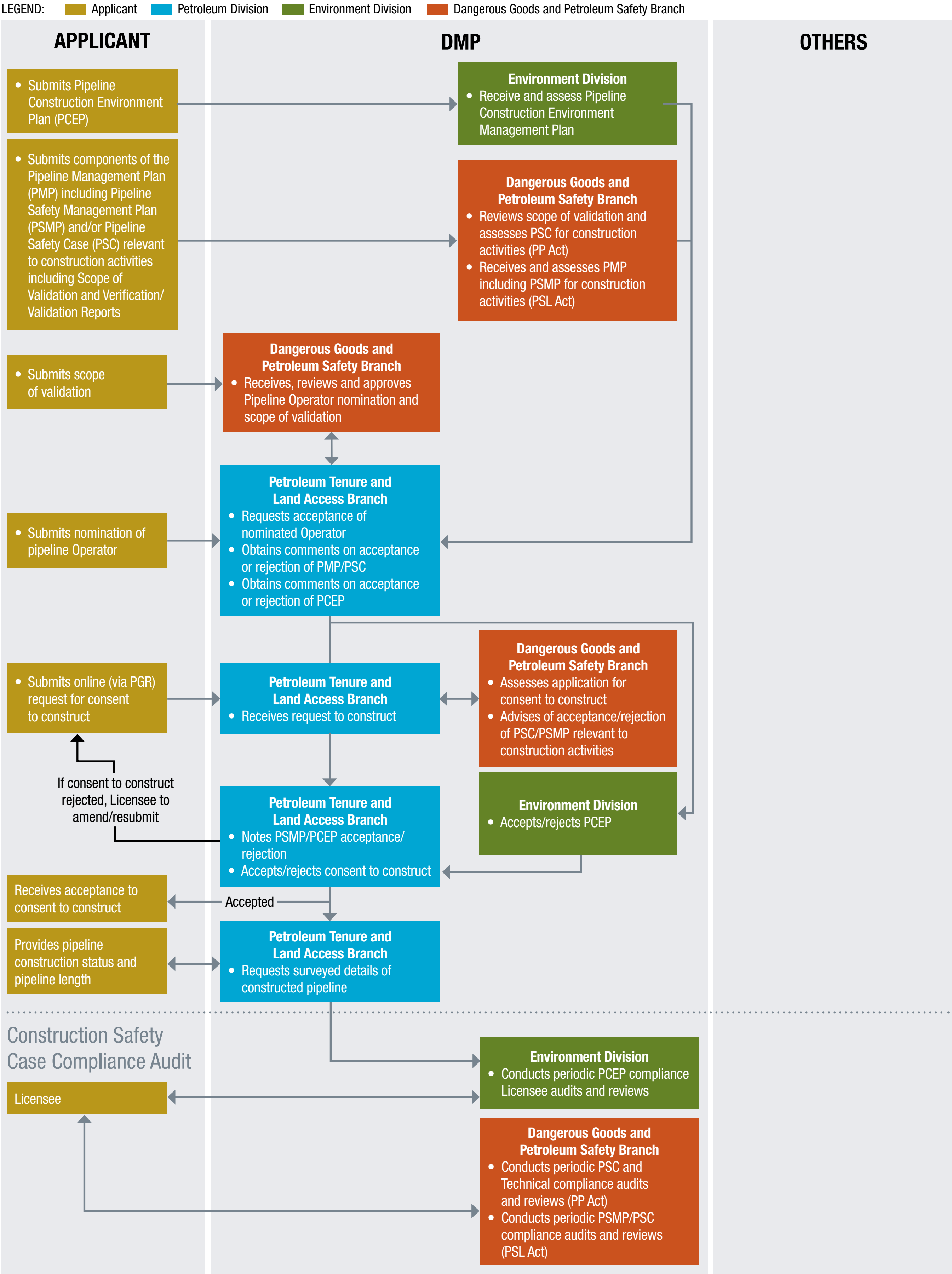


Figure 47. Pipeline Consent to Construct Approval Process

Refer to Appendix 1 for abbreviations and acronyms

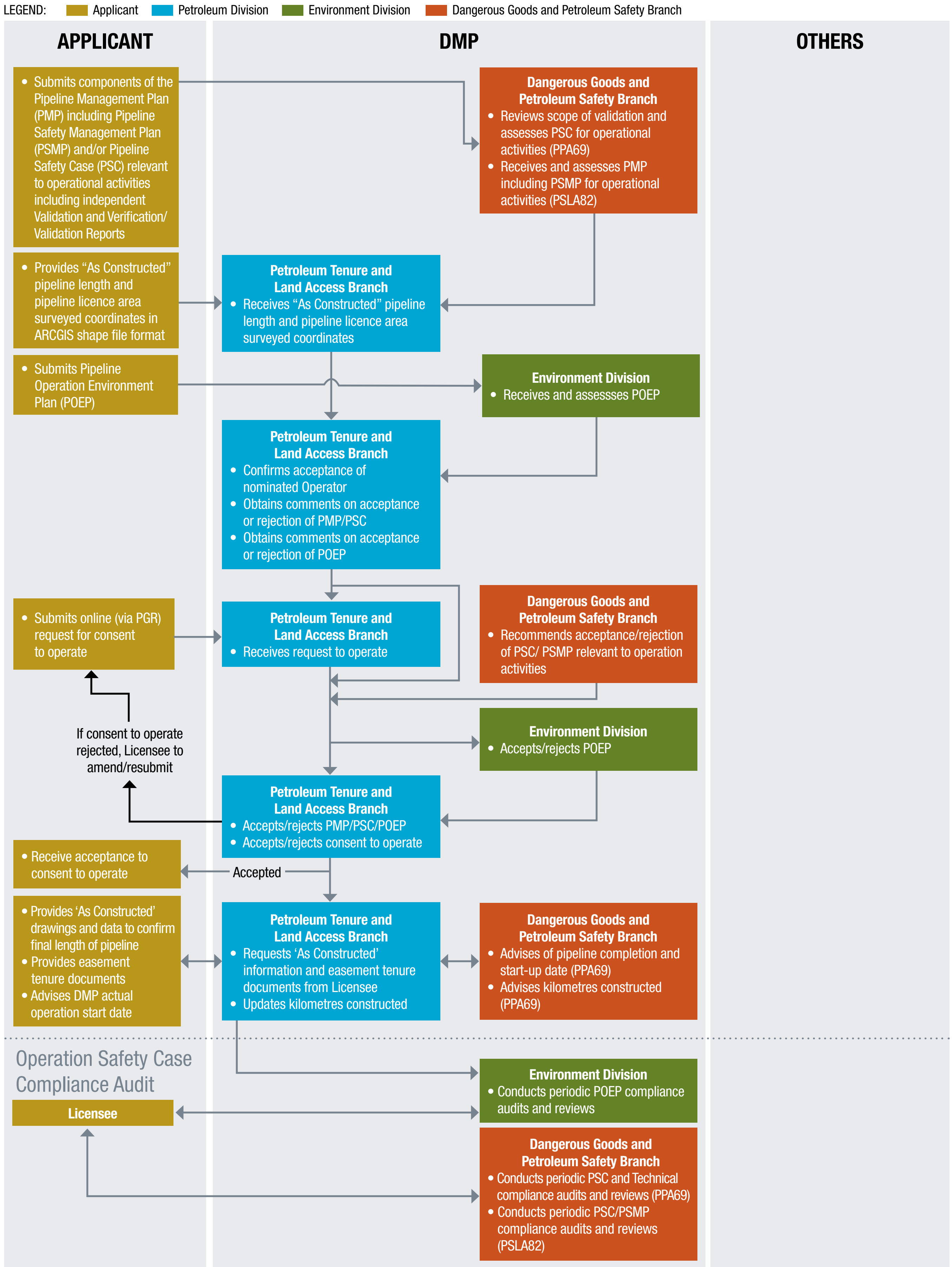


Figure 48. Pipeline Consent to Operate Approval Process
Refer to Appendix 1 for abbreviations and acronyms

GEOTHERMAL ENERGY ADMINISTRATION

Regulatory Regime

Geothermal energy exploration and production is accommodated under Western Australia's *Petroleum and Geothermal Energy Resources Act 1967*. In the same manner as petroleum, Government rather than private individuals own the rights to geothermal energy resources. Government will not necessarily engage in commercial geothermal energy, exploration and development, it does, however, allocate the right to do so to the private sector.

As with petroleum, the Government maintains four main roles in relation to the geothermal energy sector:

- to establish the macro-economic environment (broad economic policy);
- to provide a regulatory framework for exploration and development including safety and environmental assessment as well as revenue collection;
- to provide incentives to exploration by generating and disseminating basic geoscientific information; and
- to look for ways to remove impediments to the industry's competitiveness.

Geothermal Energy Titles

Provision for geothermal energy exploration and production was incorporated into WA's *Petroleum Act 1967* in 2007, which has been renamed the *Petroleum and Geothermal Energy Resources Act 1967* (PGER Act). Accordingly, they share the same system for making areas available, the same competitive bid process and titles system. geothermal titles while separate to petroleum titles can coexist over the same areas. Special provision is made, however, to protect the respective rights of each and to adjudicate any conflict in operations.

While the geothermal energy industry in Western Australia is in its infancy, it is anticipated that its coexistence with the petroleum industry will be successfully managed for the benefit of all Western Australians.

Obtaining a Geothermal Title

Acreage for Exploration

The first Geothermal Exploration Permits (GEP) in Western Australia were granted in July 2009. Periodically, the geothermal acreage may be released for acreage bidding. Due to the current market uncertainties, acreage for geothermal exploration may be obtained through a Geothermal Special Prospecting Authority (GSPA) with Acreage Option (AO) until further notice.

The GSPA is an up to six month, non-renewable title granted for the purpose of conducting a geothermal energy resource exploration survey. A geothermal well is not permitted under a GSPA. On expiry of the GSPA term, proponents have a further six months in which to take up the Acreage Option and apply for either a Geothermal Exploration Permit (GEP) or Geothermal Drilling Reservation (GDR). It is important to note that the Acreage Option (AO) must form part of the GSPA application and cannot be applied for retrospectively. A percentage of the original GSPA is generally relinquished to comply with AO guidelines.

All areas in the State that are not under current geothermal title or assessment are available for GSPA applications.

Applications should be made to the Department of Mines and Petroleum, and should also include the appropriate fee payable to "The Department of Mines and Petroleum". Please consult the Department's website at www.dmp.wa.gov.au/17938.aspx for information about geothermal titles, and www.dmp.wa.gov.au/1911.aspx for application forms.

Farm-in to Existing Titles

Interests in geothermal titles are capable of being bought and sold and farm-in/farm-outs may occur.

In buying into a title the farminee/transferee needs to demonstrate its financial and technical ability to assume the responsibilities of the interest being acquired.

A transfer of a Geothermal Title must relate to the whole of the interest in the title and not merely the interest being dealt with.

Derivative Titles

Once a geothermal energy resource discovery is made, the holder of the Geothermal Exploration Permit has the right to convert that discovery to a Geothermal Production Licence. Should the discovery be demonstrated as presently noncommercial but likely to become so within 15 years, an interim title, a Geothermal Retention Lease may be granted.

Geothermal Titles System

The Geothermal Titles can be divided into exploration and development categories with development titles evolving from the exploration. Applicants propose a program of exploration work for an area and if that applicant is successful (on the basis of the work proposed and the ability to undertake the work) a permit is awarded.

The various titles are as follows:

Geothermal Exploration Permit (GEP) – authorises the holder to explore for geothermal energy and to carry on such operations and execute such works as are necessary. Provided the conditions of the permit are fulfilled the permittee has the right to renew the permit on a reduced area basis.

When a permit is granted the permittee is obliged to fulfil the promised work program in a timely manner in accordance with industry best practice and to secure the health and safety of workers. The permittee must also conduct its activities in a manner which protects the environment.

Geothermal Drilling Reservation (GDR) – authorises the holder to drill for geothermal energy resources and to carry on such operations and execute such works as are necessary for that purpose. While the term of a GDR may be up to three years (at the discretion of the Minister), the holder of a drilling reservation may extend the term by a further year to accommodate further drilling and, as with permits, is obliged to drill the commitment well(s) in accordance with industry best practice.

Declaration of Location – Upon discovery of a geothermal energy resource, the holder of a GEP or GDR must notify DMP, giving details of the discovery. Before applying for a Retention Lease or Production Licence, the GEP/GDR holder must identify the block or blocks which cover the area of the discovery.

Where a Declaration of Location is made over a discovery the permittee may undertake further exploration and/or appraisal activities within the location to determine more accurately the nature of the discovery. The permittee has two years after the Declaration of Location in which to apply for either a Retention Lease or Production Licence. This period may be extended for a further two years at the discretion of the Minister.

Geothermal Retention Lease (GRL) – is a holding title although it authorises the holder to continue to explore for geothermal energy and to carry on such operations and execute such works as are necessary for that purpose. Retention Leases are granted over the blocks comprising a geothermal energy resource, which is currently not economic. Depending on circumstances further exploration work may be undertaken. However, the lessee is obliged to undertake re-evaluation studies on the commercial viability of the geothermal energy resource as required from time to time by the Minister.

Geothermal Production Licence (GL) – authorises the holder to recover geothermal energy from the licence area, explore for geothermal energy and to carry on such operations as are necessary for that purpose. Geothermal Production Licences are granted over the blocks comprising a commercial geothermal energy resource and usually emanate from a Geothermal Exploration Permit, Drilling Reservation or Retention Lease. The Geothermal Production Licence is subject to the conditions imposed on the grant of title and granted for an indefinite term subject to the provisions of the PGER Act.

Geothermal Special Prospecting Authority (GSPA) – allow limited prospecting for geothermal energy but do not authorise the drilling of a well. Geothermal Special Prospecting Authorities are granted subject to conditions, which control the extent of work, and are for a maximum of six months.

Geothermal Access Authority (GAA) – allow the holder of a permit, drilling reservation, lease or licence to conduct exploration activities outside their areas. This includes the drilling of deviated wells. As with Geothermal Special Prospecting Authorities, a Geothermal Access Authority is controlled by conditions and is limited in time to the operation necessitating the access.

It should be noted that the PGER Act does not apply to operations for the recovery of geothermal energy that are:

- carried out for the purposes of a small-scale ground source heat pump used at or near the source of the geothermal energy; or
- involve small scale recovery of a non-commercial kind.

A summary of the obligations and conditions of each licence type is provided in Table 14.

Geothermal Work Approvals

The rights contained in geothermal titles are pertinent to the type of title, e.g. a Geothermal Exploration Permit provides the exclusive right to explore for a geothermal energy resource within the title area. However, the exercise of that right is subject to conditions designed to protect the:

- health and safety of workers and the public;
- environment and to take into account the interests of others who have an interest in the land.

The process developed to ensure that these requirements are addressed is the works approval system. Any proposal to undertake any field work needs to be submitted to DMP, allowing sufficient time for the application to be properly assessed.

While the exercise of geothermal rights applies to all land within the title area, the interests of others need to be considered. Entering lands where native title rights and interests in that land have not been fully extinguished is prohibited without the consent of the native title holders or registerd native title claimants for such land. It is likely a heritage survey would need to be carried out to ensure compliance with the requirements of the *Aboriginal Heritage Act 1972.* Should the work proposed be on private land then a compensation agreement would need to be negotiated with the private land owner.

In most cases the DMP is the focal point for seeking the approval to undertake work but as other agencies may be involved, direct contact with those agencies is possible.

The advantage in using the DMP as the lead agency is that it can initiate contacts on your behalf with other agencies and assist in obtaining their timely input.

Naturally, the sensitivity of the land to be accessed will have a considerable bearing on the length of time required to properly assess the work proposal. In this regard, sufficient notice should be provided by the applicant so that deadlines may be achieved.

Application forms for the various geothermal work proposals, e.g. drilling a well or conducting a geophysical survey are available from DMP and some are capable of being submitted online. The forms are comprehensive and provide details of the information required and accompanying documentation.

Further details of the forms are included under the “Online Systems” heading in the “Access to Data” chapter.

Resources Safety inspectors at the site of a geothermal well being drilled at St Hilda’s school in Perth in 2010


Aerial view of the Red Gully Gas and Condensate Facility in the northern Perth Basin (photo courtesy of Empire Oil & Gas)

New Resource Management Regulations

Exploration and production operations in the State of Western Australia are administered under the Western Australian *Petroleum (Submerged Lands) Act 1982* (PSL Act) and *Petroleum and Geothermal Energy Resources Act 1967* (PGER Act).

DMP, on behalf of the State Government, has responsibility to ensure sound resource management and that State onshore and offshore petroleum operations adequately safeguard occupational health and safety and protect the environment.

DMP has responsibility to ensure its resources are managed in an effective, efficient and sustainable manner by industry to ensure resources are recovered in the public interest, optimising both the short- and long-term benefits to the Western Australian and Australian communities. Community returns on petroleum development projects are provided for by a Petroleum Resource Rent Tax (PRRT) and, where applicable, by excise and royalty arrangements.

Currently under the PGER Act, drilling, production and well operations are controlled by the *Schedule of Onshore Petroleum Exploration and Production Requirements 1991* (Amended 2010). New resource management regulations, the *Petroleum and Geothermal Energy Resources (Resource Management and Administration) Regulations 2014*, modelled on the Commonwealth *OPGGS (Resource Management and Administration) Regulations 2011*, were released for stakeholder consultation on 5 February 2014. The consultation period ended 30 May 2014. When finalised, these regulations will provide a risk-based management scheme for the exploration for, and production of, petroleum and geothermal energy resources. The new regulations are objective-based rather than prescriptive, reflecting the ultimate responsibility of the operator to conduct well operations safely using industry best practice.

These regulations will:
- ensure that petroleum and geothermal operations are carried out in accordance with good industry practice and for the optimum long-term recovery of the resource;
- ensure that the administrators of the *Petroleum and Geothermal Energy Resources Act 1967* are informed, in a timely and consistent manner, of the exploration, discovery and appraisal of petroleum and geothermal resources and the development and production operations in relation to petroleum and the results of operations;
- provide a framework for encouraging the adequate collection, retention and timely dissemination of data.

A range of resource management and administration matters are covered by the regulations, including well management plans for the approval of all drilling activities, notification and reporting of discovery of petroleum, field management plans and approval of petroleum recovery.

The second part of this set of regulations, the *Petroleum (Submerged Lands) Resource Management and Administration) Regulations 2014*, (to replace the existing *Petroleum (Submerged Lands) (Management of Well Operations) Regulations 2006)* will cover submerged lands adjacent to the coast of WA and will be drafted following the review of the public and stakeholder consultation comments for the onshore regulations. It is intended that a draft of these regulations will be released for stakeholder comment.

These two regulations will form the third and final part of the suite of regulations that commenced in 2010 with the introduction of safety regulations followed in 2012 with environment regulations.

Life Cycle

The new regulations will cover the full life cycle of a well (from spud to decommissioning) and of a field (from initial development to field decommissioning). The following sections outline the process.

Planning

Well Management Plans

All petroleum and geothermal drilling operations are regulated. The new Resource Management Regulations, currently in draft, will introduce the requirement of a Well Management Plan (WMP) for wells covered under the PGER Act. For wells existing at the time the Regulations come into force, the WMP will include a program covering the current activity on that well, which will detail the actual operational steps occurring. For a new well, the WMP will include the drilling program, detailing the proposed operational steps. It should be noted that a generic WMP that covers multiple wells in a field and analyses the risks therein may be submitted. Future activity programs for specific wells will need to be submitted for assessment and will be appended to the WMP once approved. (The WMP will be primarily objective-based rather than prescriptive-based and will include risk analysis. Prescriptive regulation has the potential to become obsolete as technology and practice evolve).

The onus of identifying, mitigating and managing risk falls on the registered holder(s). The principle of 'As Low As Reasonably Practicable' (ALARP) applies.

Before a title holder can conduct any work on a well, including drilling, workovers, fraccing (fracturing), production or decommissioning, a WMP must be in place before the activity begins. The WMP will include the activity program, which will detail the actual operational steps proposed. For each activity, an application, with relevant documentation (e.g. drilling program and geological prognosis) must be submitted to the Petroleum Division of DMP for approval. Once the WMP has been approved, future activities on that well will require that activity programs be submitted to the DMP for assessment. The approved activity programs will be appended in turn to the WMP, thus detailing activities during the life of the well. The company must also submit an Environmental Plan (EP) and Safety Management System (SMS) to the Environment Division and Resources Safety Division respectively and obtain approvals. Assessments and approvals from Petroleum Division, Environment Division and Resources Safety Division proceed concurrently.

The objective of a WMP is to ensure the well is designed and managed in accordance with sound engineering principles and industry best practice, including identification of risks. A range of reporting on well operations is required, including daily drilling reports, monthly production reports and well completion reports.

DMP's Petroleum Division assesses a WMP for:
- Well integrity
  - casing and cementing design
  - casing seat locations
  - barriers within the design to prevent any breach of well integrity including isolation of production zones, aquifers and reservoir formations
- Mitigation of subsurface hazards. This applies to items such as:
  - rig inspection reports;
  - blowout preventers;
  - choke manifolds;
  - barrier tabulations/schematics;
  - fluid density;
  - downhole safety valves;
  - well kill methods; and
  - wellhead and Christmas tree configuration.

If any significant variation to a WMP occurs before or during the program, that variation also has to be approved by the Petroleum Division. Circumstances may occur during the drilling of a well where the original plan is no longer viable and Management of Change has to occur. Examples of this might be side-tracking a well or shortening a well above the approved total depth.

Petroleum Division assesses a geological prognosis by well type (exploration, appraisal or production) and objectives, to ensure that work program commitments are adequately met and sufficient information is gathered from a well.

RESOURCE MANAGEMENT

For offshore wells, a Well Operations Management Plan (WOMP) must also be submitted for approval according to *Petroleum (Submerged Lands) (Management of Well Operations) Regulations 2006.* A WOMP does not duplicate the well program. A WOMP explains the basis of design, construction, operational activity and management of a well. Where appropriate, a single WOMP can be submitted for multiple wells in a field or multiple wells drilled in a single drilling campaign. A WOMP is valid for a maximum of five years.


Aerial view of the Yulleroo gasfield in the Canning Basin (photo courtesy of Buru Energy)

Drilling

An Application to Drill must be submitted to the Petroleum Division for approval. DMP puts conditions on application and authorises permission to drill.

During drilling operations, DMP will require the title holder to:

- conduct baseline monitoring of aquifers in new areas
- monitor and verify cementing operations (logging)
- conduct real time monitoring of pressures and drilling fluids during operations, which are reported to DMP daily
- review micro-seismic monitoring of stimulated wells, where applicable
- submit daily drilling reports, and
- submit well completion reports, once the well has been drilled.

Petroleum Division reviews an operator's internal audits of operations and systems to ensure they are properly applied, monitors daily drilling and geological reports and audits field activities, and can provide consultation and approvals at key points during drilling of a well.

Petroleum Division reviews and approves all completion, production, suspension or decommissioning programs upon conclusion of drilling operations.

Production

Discovery

Upon discovery of petroleum, the registered holder(s) must notify DMP's Petroleum Division, giving details of the discovery. An application for a Declaration of Location must identify the block or blocks which cover the area of the discovery, which will be assessed by the Petroleum Division. This application should quote the Exploration Permit/Drilling Reservation number as a reference and be accompanied by:

- an A4 plan showing the outline of the pool or pools nominated in relation to the blocks comprising the permit/drilling reservation.
- a digitally mapped ArcGIS shape file showing the outline of the pool or pools nominated in relation to the proposed blocks.
- a geotechnical report with petrophysical data on the pool(s) to be included in the location;
- structural maps of key horizons and cross sections through the pool(s);
- details concerning recovery of petroleum from the pool(s) nominated.

Petroleum Division assesses the application for a Declaration of Location and approves the blocks. A Declaration of Location is made over the discovery and the registered holder(s) may then undertake further exploration and/ or appraisal activities within the Location to determine more accurately the nature of the discovery. The registered holder(s) has two years after the Declaration of Location in which to apply for either a Retention Lease or Production Licence. This period may be extended for a further two years at the discretion of the Minister. Within this period the registered holder(s) selects from this 'Location' the blocks to be included in a Production Licence or Retention Lease.

Field Management

The current Schedule of onshore petroleum exploration and production requirements stipulates a reservoir management plan must be approved before a completion is brought into production (other than for initial production testing pursuant to Clause 608).

Under the new regulations, prior to developing an oilfield or gasfield, the registered holder(s) will be required to submit a Field Management Plan (FMP) for assessment by the Petroleum Division. The FMP will cover:

- a preface defining the purpose of the FMP, how the proposed plan is compatible with optimum long-term recovery of petroleum, and main issues;
- reservoir description including:
  - o geological setting including structure maps
  - o fault interpretation
  - o reservoir geology and petrophysics
  - o reservoir fluid properties and hydrocarbon contacts
  - o in-place volumetrics
  - o near field exploration, if any;
- reservoir development including dynamic modelling, number, location(s) and type of wells as well as inflow control devices and estimates of well pressures and production;
- monitoring and management of produced fluids and disposal plans for produced water;
- drilling and completions;
- surface facilities;
- operations including pre-commissioning, commissioning, start-up operations, and decommissioning; and
- project plan and management including an overview, resource planning and quality management.

DMP's Petroleum Division

- receives, assesses and approves/rejects an application to drill and complete
- receives and monitors daily drilling reports (DDR) following commencement of drilling
- approves commencement of and monitors production or extended production test (EPT) and establishes the rate of production.

During production, DMP:

- receives and monitors annual title assessment reports and monthly production reports
- assesses and monitors well workovers, interventions, WMPs, the Safety Management System (SMS) (when required) and Environmental Plan (EP)
- audits production metering.

Decommissioning

Well Decommissioning

When a well is to be decommissioned, DMP requires the registered holder(s) to:

- submit an activity program detailing the decommissioning procedure for each well and showing pre- and post-decommissioning schematics
  - justify that the well is no longer economical to produce
  - provide a descriptive procedure on decommissioning of the well(s), including removal of the wellhead(s) and rejuvenation of the site.

Field Decommissioning

If the field is being decommissioned, DMP requires the registered holder(s) to submit a field decommissioning plan as part of the Field Management Plan (FMP) detailing the decommissioning procedure and a description of the decommissioning of the wells, including removal of the wellheads. It should also cover the removal of surface facilities and environmental rehabilitation for the field.

As with all oilfield operations, approval is given if it is demonstrated that the program is in accordance with good oilfield practice, standards and codes.

Rehabilitated Denison 3D Seismic Line; Eastern Yardanogo Nature Reserve (photo courtesy of AWE)

Small drilling rig in the central Canning Basin

Access to the State's land and adjoining coastal waters is administered in accordance with the following Commonwealth and State legislation:

- *Native Title Act 1993* (Commonwealth);
- *Aboriginal Affairs Planning Authority Act 1972* (Western Australia),
- *Aboriginal Heritage Act 1972* (Western Australia); and
- *Aboriginal and Torres Strait Islander Heritage Protection Act 1984* (Commonwealth).

To assist land users in understanding their obligations under the *Aboriginal Heritage Act 1972* (WA) the State government has produced the *Aboriginal Heritage Due Diligence Guidelines*.

In doing so, the exploration, production and development of Western Australia's petroleum and geothermal energy resources is optimised, and the rights and interests of Aboriginal people in lands and waters are observed.

Beyond the three nautical mile limit, Commonwealth petroleum legislation applies. This legislation is administered by the National Offshore Petroleum Titles Administrator. See the chapter on "Government Role".

The information set out below does not constitute legal advice. It is intended as an overview of the relevant legislation and procedures.

Native Title Act

Acknowledgement is given to the Federal Court of Australia, Commonwealth of Australia's Attorney General's Department and the National Native Title Tribunal as the primary reference sources for the following text.

What is Native Title?

Native title rights and interests are rights and interests in relation to land or waters that are possessed under traditional laws and customs acknowledged and observed by Aboriginal people or Torres Strait Islanders and are recognised by the common law of Australia. The laws and customs which give rise to native title rights and interests, which may vary between groups, must have been acknowledged and observed in a 'substantially uninterrupted' way from the time of settlement of the relevant part of Australia to the present day. In 1992, in *Mabo v Queensland No. 2* (1992) 175 CLR 1 ("the Mabo decision"), the High Court of Australia recognised that the Meriam People of the Torres Strait held native title rights and interests over part of their traditional lands. Following the Mabo decision the *Native Title Act 1993* (Cwth) (NT Act) was enacted, to provide for the recognition and protection of native title. Under the NT Act the Federal Court of Australia is responsible for management and determination of all applications made under the NT Act.

For native title to be recognised, Indigenous people must among other things, show that they have maintained their traditional connection to the land and waters. Native title:

- cannot be recognised where government acts have validly extinguished any native title rights;
- is not granted by governments — it is recognised through a determination made by the Federal Court, High Court or possibly some State and Territory courts;
- may vary from group to group and will depend upon evidence of the traditional laws and customs, and the native title rights and interests to which they give rise, of the particular group; and
- may exist but be suppressed to some extent depending on the rights of other people in the same area. For example, where people have leases, licences or a right to public access, native title rights and interests may still exist alongside these other rights, but native title rights and interests will be suppressed to the extent that they are inconsistent with the leases, licences etc. In other words, any activities done pursuant to validly granted leases, licences etc. prevail over the native title rights and interests; and
- can only be claimed on certain areas of land or waters.

What does the Native Title Act do?

The NT Act commenced on 1 January 1994, and the National Native Title Tribunal (NNTT) was established as an independent Commonwealth Government agency to assist people to resolve native title issues over land and waters. Since this date, the NT Act has been amended three times, in 1998, 2007 and again in 2009. Recently, the NNTT functions have been concentrated in the area of future acts, which are described in more detail later in the chapter.

The NT Act sets out amongst other things how native title is to be recognised and protected, including by operation of the future act regime, and provides a process for Indigenous Australians to lodge a claim for the recognition of native title and to negotiate about some proposed developments over land and waters that may affect native title.

How is Native Title Recognised?

A native title determination is a decision by the Federal Court, High Court or recognised State or Territory body that native title does or does not exist over an area of land or water. Where the existence of native title is recognised, the determination will identify who the native title holders are, and set out what their native title rights and interests are. The determination will also set out the non-native title rights and interests in the area, and set out what the relationship between these two sets of rights is — essentially, as noted above, native title rights and interests will be suppressed to the extent of any inconsistency between the two sets of rights.

There are four kinds of applications under the NT Act that could lead to a determination of native title; these are:

- claimant applications, made by Indigenous Australians seeking a determination recognising native title exists in a particular area;
- non-claimant applications by non-Indigenous people seeking a determination that native title does not exist or seeking to do things in relation to an area requiring clearance in relation to native title;
- an application to revise or revoke an existing native title determination; and
- an application by Indigenous Australians seeking compensation for loss or impairment of native title before or after a determination of native title is made by the Federal Court over the same land or water.

Indigenous people can apply to have their native title rights and interests in an area recognised in accordance with the NT Act by filing a native title determination application with the Federal Court. After an application for native title determination is filed with the Court, the Federal Court first refers the application to the Registrar of the NNTT to apply the Registration Test. If the application passes the Registration Test then the native title applicants gain certain rights as Registered Native Title Claimants over the area covered by the application such as:

- the right to object or negotiate over certain proposed developments such as the grant of petroleum exploration, retention or production titles (future acts); and
- other rights such as the right to be notified or to comment on some proposed developments (e.g. future acts in States' internal waters).

There are three processes that can lead to a native title determination:

- if no one contests the application, the Court can make what is called an unopposed determination;
- if all the parties reach agreement about native title through mediation, then a consent determination can be made; or
- a litigated determination is made after a trial where the parties put forward the case for and against recognising native title.

Under the NT Act, native title holders have to establish a body to represent them as a group and to hold in trust or manage their native title rights and interests. This body is called a Registered Native Title Body Corporate (RNTBC) or 'prescribed body corporate' (PBC). A PBC is an Indigenous corporation established under the *Corporations (Aboriginal and Torres Strait Islander) Act 2006* (Cwth) that may hold in trust or manage native title for the whole group. Once the corporation is established by the native title holders, and approved by the Federal Court, it is entered onto the National Native Title Register as a RNTBC.

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Where Does Native Title Exist?

Native title may exist in places where Indigenous people continue to follow their traditional laws and customs and have maintained a link with their country, and where the rights and interests have not been extinguished by acts done, or allowed by government. Some of the areas where native title may exist include:

- vacant or unallocated Crown land;
- some reserve lands (such as national parks, State forests and public reserves);
- some types of pastoral and agricultural leases;
- some land held by or for the benefit of Aboriginal people or Torres Strait Islanders; and
- oceans, seas, reefs, lakes, rivers, creeks, swamps and other waters.

Where is Native Title Extinguished?

Native title rights and interests will have been wholly extinguished by valid government acts that are inconsistent with the continued existence of native title rights and interests, such as the grant or creation of:

- residential freehold;
- farms held in freehold;
- pastoral or agricultural leases that grant exclusive possession;
- residential, commercial or community purpose leases, and
- public works like roads, schools or hospitals.

The Development of Native Title in Australia

There have been a number of landmark decisions on native title in Australia since the Mabo decision and the enactment of the NT Act. These cases have gone to the High Court and have helped clarify native title law:

- *Wik Peoples v Queensland* [1996] – found that the grants of two Queensland pastoral leases did not necessarily extinguish native title, and that native title may coexist with the rights of some pastoral leaseholders;
- *Commonwealth v Yarmirr* [2001] – found that native title could be recognised in the intertidal zone and offshore but that only non-exclusive native title rights could be recognised in these areas;
- *Western Australia v Ward* [2002] – found that native title is made up of a bundle of rights and that native title can be partially extinguished, for example by the grant of a Western Australian pastoral lease;
- *Wilson v Anderson* [2002] – found that perpetual pastoral leases granted under the *New South Wales Western Lands Act 1901* (NSW) completely extinguished native title; and
- *Members of the Yorta Yorta Community v Victoria* [2002] – found that in order to maintain native title, the claimant group must show that they have practised their laws and customs in substantially the same way since European settlement – i.e. that they are "traditional";
- *State of Western Australia v Brown & Ors* [2014] – found that the grant of the mineral leases did not extinguish native title rights and interests and the rights granted under the mineral leases are not inconsistent with the claimed native title rights and interests.

What Rights Arise From Native Title?

Native title rights are a bundle of rights and interests in relation to land and waters which arise from the traditional laws and customs of the native title holders, and which can be recognised by the common law.

The native title rights may include the right to possess, occupy, use and enjoy a particular area to the exclusion of all others (often called the right of exclusive possession). This includes the right to control access to, and use of, the relevant area, which may be unallocated Crown land, a reserve held for the benefit of Aboriginal people and some pastoral leases held by the native title parties.

In other areas, the native title rights can be a set of 'non-exclusive' rights, which means the area will be shared by the native title holders and other people with rights and interests in the same area. This sharing is sometimes called coexistence whereby both sets of rights are recognised over the area, but native title rights cannot interfere with other rights such as pastoral interests, or, as noted above, are suppressed to the extent that they are inconsistent with the rights of the pastoralist.

The petroleum basins of Western Australia are subject to both exclusive and non-exclusive determined native title rights and interests.

There can be no native title rights recognised in a native title determination to petroleum or geothermal resources as set out in the *Petroleum and Geothermal Energy Resources Act 1967* (WA) (PGER Act) or to mineral interests as set out in the *Mining Act 1978* (WA).

Native Title, Petroleum Exploration and Development

Definition of Future Act

A future act is an act done after 1 January 1994, which may affect native title. An act 'affects' native title if it extinguishes or is otherwise wholly or partly inconsistent with the continued existence, enjoyment or exercise of native title rights and interests. An act of government may 'affect' native title if, for example, it allows someone to do an activity on land where native title has been determined to exist, or is claimed to exist, that prevents a native title holder from conducting activities that give effect to their native title rights and interests, such as hunting or conducting ceremonies. In the petroleum context this applies to the grant or renewal of licences and permits.

The NT Act seeks to protect native title rights by prescribing procedures which must be complied with, by Commonwealth, State and Territory Governments, before the future act can be validly done.

Different subdivisions within the NT Act relate to different types of activity:

- acts with non-claimant protection (Subdivision F)
- primary production (Subdivision G)
- managing aquatic resources, water and airspace (Subdivision H)
- renewal and extension of permits, etc. (Subdivision I)
- acts with respect to reserves (Subdivision J)
- public works (Subdivision K)
- low impact acts (Subdivision L)
- legislative and non-legislative acts that could be done on freehold land (including compulsory acquisition) (Subdivision M)
- offshore acts (Subdivision N)
- right to negotiate (Subdivision P)

Most subdivisions set out:

- the procedures to be followed to ensure the act is valid;
- the effect of the act on native title; and
- whether compensation is payable to native title holders for the act.

If the relevant procedures are not followed, the future act will be invalid to the extent that if affects native title (Subdivision O and section 25(4)).

Grants and Renewals of Petroleum Titles and Authorities in Onshore and Offshore Areas

This section outlines the future act procedures that have been adopted to satisfy the requirements of the NT Act. It is intended as a general guide only and should not be regarded as an authoritative interpretation of the statutory requirements.

The Right to Negotiate and the Expedited Procedure

Registered native title claimants and registered native title body corporates (native title parties) are entitled to procedural rights to negotiate in relation to acts to which Subdivision P applies – namely the grant of certain petroleum and mining titles, and compulsory acquisition of native title rights and interests. One of the fundamental principles of the future act regime is that any relevant act will be invalid to the extent that it affects native title unless it is done in accordance with the procedures set out in the NT Act. The right to negotiate process is overseen by the NNTT.

Generally, to validly do an act that attracts the right to negotiate a government has two options. It must either comply with the 'right to negotiate' procedures set out in Subdivision P of the NT Act or it can negotiate an Indigenous Land Use Agreement (ILUA).

The exception is geothermal energy under the PGER Act. The Commonwealth Attorney-General has advised that geothermal operations cannot be the subject of "the creation of a right to mine" within the meaning of the NT Act and accordingly the right to negotiate does not apply prior to the grant of an exploration permit for geothermal energy exploration.

Right to Negotiate

The NT Act requires that before doing a future act under Subdivision P, the relevant government must give notice to native title parties and the public in accordance with section 29 of the NTA Act (Figure 49).

Under Section 31 of the NT Act, unless the 'expedited procedure' applies to the act in question, the government is required to give native title parties the opportunity to make submissions about the proposed act and all of the negotiation parties (the government, the applicant for the petroleum title and the native title parties) are required to negotiate in good faith with a view to obtaining agreement that the act be done and, if so, on what conditions (Table 15).

Where a notice of a proposed future act is given under Section 29, the parties have a period of not less than six months to negotiate in good faith an agreement about the proposed act. At any stage the parties can ask the NNTT to mediate during negotiations.

If agreement is reached, the parties enter into a tripartite agreement (Deed for the Grant of Petroleum Title), also referred to as a State Deed. There may also be a confidential ancillary agreement between the grantee and native title party. This agreement may include for example; terms for employment, education and training, Aboriginal heritage protection, compensation payments, dispute resolution clauses and cross cultural awareness training.

If no agreement is reached then, under Section 35, any party can apply to the arbitral body the NNTT for a determination under Section 38 in relation to the proposed act. The arbitral body may make a determination that the act must not be done, the act may be done, or that the act may be done subject to conditions to be complied with, by any of the parties. A threshold issue that may be considered is whether there has been negotiation in good faith; if the NNTT finds that there has not, then a determination as to the doing of the act or otherwise cannot be made – NT Act section 36(2).

Expedited Procedure

Acts attracting the expedited procedure are defined in Section 237 of the NT Act. These are acts that are unlikely to interfere directly with the carrying on of community or social activities of the relevant native title parties, to interfere with areas or sites of particular traditional significance to the relevant native title parties or to involve major disturbance to land or waters.

Under Section 32 of the NT Act, if the government considers that an act attracts the expedited procedure, the government may include a statement to that effect in the Section 29 notice.

A native title party may, within four months after the notice is issued, lodge an objection with the NNTT against the inclusion of the expedited statement in the notice.

If a native title party lodges an objection, the arbitral body must determine whether the proposal attracts the expedited procedure. If the arbitral body determines it does, then the government may do the act. If the arbitral body determines it does not, then the parties must enter into the right to negotiate process.

Indigenous Land Use Agreements

An Indigenous Land Use Agreement (ILUA) is a voluntary, legally binding agreement about the use and management of land and waters made between people who hold, or may hold, native title in the area, and other people, organisations or governments. To be an ILUA an agreement must meet the requirements under the NT Act. Under the NT Act, there are three different types of ILUAs: body corporate agreements, area agreements and alternative procedure agreements. The NNTT can provide assistance (if requested) prior to or during the negotiations of an ILUA.

If the native title holders give their consent to the doing of the relevant act or class of acts (e.g. the grant of an exploration licence or licences) in an ILUA that is entered on the Register of Indigenous Land Use Agreements maintained by the NNTT, the act can validly be done and the other provisions of the NT Act (such as the right to negotiate provisions) do not apply to that act.

Onshore Waters

An 'onshore place' is defined in the NT Act as land or waters within the limits of a State[1]. Unless one of the earlier future act provisions applies to the relevant act, prior to doing an act that takes place between the mean high water mark of the sea and the limits of the State, the government party must observe the requirements of section 24MD of the NT Act. This requires that any registered native title claimant or registered native title body corporate have the same procedural rights as they would have if they held ordinary title (freehold) to the land surrounding or adjacent to the waters.

Offshore Areas

'Offshore place' is defined in the NT Act as "any land or waters … other than land or waters in an onshore place"; in other words, land or waters beyond the limits of the State.

The NT Act provides that before doing a future act offshore, such as the grant of a petroleum title, the requirements of Subdivision 24NA must first be observed. This involves a requirement for any registered native title claimant, registered native title body corporate or any representative Aboriginal/Torres Strait Islander body to "have the same procedural rights as they would have on the assumption that they instead held any corresponding rights and interests in relation to the offshore place that are not native title rights and interests". In practice this means that they are notified and have the opportunity to comment about the proposal to grant the title.

Non-Extinguishment Principle (Section 238)

In most cases, the non-extinguishment principle applies to acts that are validly done under the future act regime or a registered ILUA. Where this principle applies, native title will not be extinguished by a future act, but rather supressed for the period of the time that the future act (for example the grant of a petroleum permit) is in operation. Where the period of operation has ended, native title will no longer be supressed.

Further Information

For further information about native title and future acts applications, procedures, guidelines visit the websites of:

The Federal Court of Australia – www.federalcourt.gov.au

National Native Title Tribunal – www.nntt.gov.au

Department of the Premier and Cabinet – www.dpc.wa.gov.au

1 The limits of the State are not defined in the NT Act. They are therefore to be determined in accordance with common law principles. In New South Wales v Commonwealth (Seas and Submerged Lands Act Case) (1975) 135 CLR 337, the High Court held that the mean low-water mark had always constituted the territorial limit of the States. However, the limits of the State may also include waters that are largely encompassed by land (sometimes referred to as "within the jaws of the land"): A Raptis & Son v South Australia (1977) 138 CLR 346 at 377 per Stephen J; Commonwealth v Yarmirr (2000) 101 FCR 171 at [175] per Beaumont and von Doussa JJ.

LAND ACCESS – INDIGENOUS AFFAIRS

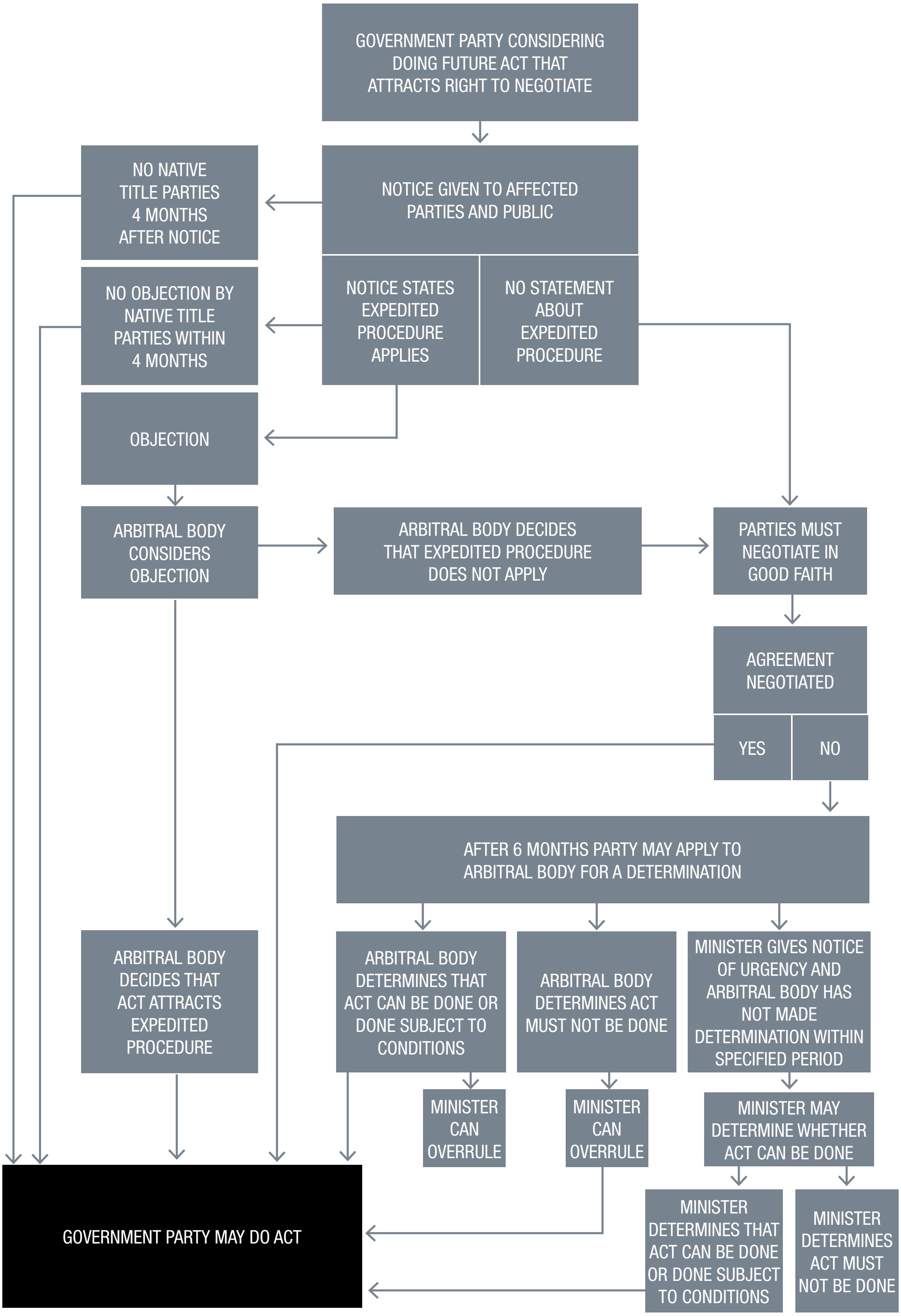


Figure 49. Overview of the Right to Negotiate Process (*Native Title Act 1993 and regulations 2nd edition*, Australian Government Solicitor, Commonwealth of Australia 1998, Canberra p38)

Table 15. Commonwealth *Native Title Act 1993* ~ Future Act Processes ~ Initial Grant Petroleum Titles and Authorities in Onshore and Offshore Areas

LEGISLATION	PETROLEUM TITLE TYPE	REGISTERED NATIVE TITLE BODY CORPORATE	REGISTERED NATIVE TITLE CLAIMANT	NOTES
Petroleum and Geothermal Energy Resources Act 1967 (WA) (Onshore/Land)	Exploration Permit, Drilling Reservation, Retention Lease & Production Licence	Negotiation Procedure (Section 31 of NT Act) or Expedited Objection Procedure (Section 32 of NT Act)	Negotiation Procedure (Section 31 of NT Act)	Managed in accordance with the State's Negotiation Protocol or Optional Conjunctive Agreement i.e. exploration to retention or exploration, retention to production (Section 26D(2) of the NT Act)
Petroleum and Geothermal Energy Resources Act 1967 (WA) (Onshore/Land)	Special Prospecting Authority with Acreage Option & Access Authority	Expedited Objection Procedure (Section 32 of NT Act) or Negotiation Procedure (Section 31 of NT Act)	Low Impact Procedure (Section 24LA of NT Act) or Expedited Objection Procedure (Section 32 of NT Act) or Negotiation Procedure (Section 31 of NT Act)	An assessment of the proposed work program determines which NT Act future act provision applies. Option for Conjunctive Agreement i.e. SPA AO to exploration (Section 26D(2))
Petroleum and Geothermal Energy Resources Act 1967 (WA) (State Waters)	Exploration Permit, Drilling Reservation, Retention Lease, Production Licence, Special Prospecting Authority with Acreage Option & Access Authority	Consultation Procedure (Section 24MD(6A of NT Act)	Consultation Procedure (if applicable) (Section 24MD(6A) of NT Act)	Comments are managed on a case by case basis prior to the grant of title
Petroleum (Submerged Lands) Act 1982 (WA) (Offshore Area)	Exploration Permit, Drilling Reservation, Retention Lease, Production Licence, Special Prospecting Authority with Acreage Option & Access Authority	Consultation Procedure (Section 24NA(8) of NT Act)	Consultation Procedure (Section 24NA(8) of NT Act)	Comments are managed on a case by case basis prior to the grant of title

LAND ACCESS – INDIGENOUS AFFAIRS

Indigenous Reserve Land

Acknowledgement is given to the Office of the Register of Indigenous Corporations and the Department of Aboriginal Affairs as the primary reference sources for the following text.

The Commonwealth *Corporations (Aboriginal and Torres Strait Islander) Act 2006* (the CATSI Act) began on 1 July 2007, replacing the *Aboriginal Councils and Association Act 1976.* Under the CATSI Act, laws governing Indigenous corporations have been modernised while still retaining the special measures to meet the specific need of Indigenous people.

Registration under the CATSI Act is mostly voluntary. However, some corporations, for example prescribed bodies corporate set up under the NT Act, are required to register under the CATSI Act.

The CATSI Act is administered by the Office of the Registrar of Indigenous Corporations and sets out a process for Indigenous people to incorporate organisations that represent their diverse interests. As a result a large number of Indigenous organisations exist throughout Western Australia, covering a range of functions including education, language and culture, small business and enterprise, tourist information and many other areas. Some Indigenous organisations may have a large membership and a regional coverage, while others represent smaller interest groups and have much narrower functions.

In addition, Aboriginal corporations in Western Australia have powers under the *Aboriginal Communities Act 1979* (WA) to make community by-laws, which are enforced by the Police. For instance the Corporation may have the power to make by-laws that prohibit alcohol within the community boundaries, which will also apply to visitors.

A visitor should always seek and gain permission to enter an Aboriginal community, and in the case of Aboriginal reserve land, must do so by obtaining an entry permit.

The Aboriginal Lands Trust (ALT) is a statutory body established under the *Aboriginal Affairs Planning Authority Act 1972* (WA) (AAPA Act). Under the Act, the ALT has responsibility for the overall management of Aboriginal reserves, many of which are leased by the Trust to Aboriginal community organisations.

The ALT administers the issue of permits for entry onto reserves that are subject to Part III of the AAPA Act. There are two types of permits:

1. Transit permits are required for any person visiting or passing through a reserve the subject of Part III of the AAPA Act, unless he/she is:
    - a person of Indigenous descent;
    - a member of either House of Parliament of the State or of the Commonwealth;
    - a person exercising a function under the AAPA Act or otherwise acting in pursuance of a duty imposed by law; or
    - a person authorised under the regulations of the AAPA Act.
2. Mining Access Permits are required whenever you enter a Part III Aboriginal reserve under the AAPA Act to conduct any petroleum operation and on every occasion that you travel through such reserves to access petroleum titles outside the reserve for the purpose of petroleum operations. The Minister for Aboriginal Affairs issues Mining Access Permits, but is first required to seek the views of the ALT, which in turn must consult with the resident Aboriginal Community and relevant native title interests before a Mining Access Permit is issued.

Further Information

For further information about Aboriginal reserve lands, Register of Aboriginal Corporations procedure and guidelines please visit the websites of:
www.daa.wa.gov.au
www. oric.gov.au

Indigenous Heritage

Acknowledgement is given to the Department of Premier and Cabinet and the Department of Aboriginal Affairs as the primary reference sources for the following text.

The management of Aboriginal heritage in Western Australia is governed by the *Aboriginal Heritage Act 1972* (AH Act). The AH Act recognises that there is community interest in preserving and protecting places and objects of Aboriginal heritage as part of the heritage of the State.

The Minister for Aboriginal Affairs is responsible for the AH Act and the day-to-day administration is the responsibility of the DAA.

The definition of an Aboriginal site is set out under section 5 of the AH Act as follows:

- (a) any place of importance and significance where persons of Aboriginal descent have, or appear to have, left any object, natural or artificial, used for, or made or adapted for use for, any purpose connected with the traditional cultural life of Aboriginal people, past or present;
- (b) any sacred, ritual or ceremonial site, which is of importance and special significance to persons of Aboriginal descent;
- (c) any place which, in the opinion of the [Aboriginal Cultural Material] Committee is or was associated with Aboriginal people and which is of historical, anthropological, archaeological or ethnographical interest and should be preserved because of its importance and significance to the cultural heritage of the State; and
- (d) any place where objects to which this Act applies are traditionally stored, or to which, under the provisions of this Act, such objects have been taken or removed.

The definition of an Aboriginal object is set out under section 6 as follows:

- all objects, whether natural or artificial and irrespective of where found or situated in the State which are or have been of sacred, ritual or ceremonial significance to persons of Aboriginal descent, or which are or were used for, or made or adapted for use for, any purpose connected with the traditional cultural life of Aboriginal people past and present; and
- objects so nearly resembling an object of sacred significance to persons of Aboriginal descent as to be likely to deceive or be capable or being mistaken for such and object.

Some objects are exempt from the AH Act, namely the collection held by the Museum as defined in the AH Act and some objects that are made for sale: see section 6(2a) and 3 of the AH Act.

Aboriginal sites and objects as defined in the AH Act are located throughout Western Australia and on every different type of land tenure, e.g. crown land, reserves, pastoral leases, agricultural leases, and freehold land.

All Aboriginal sites and objects are protected by the AH Act, whether or not they have previously been identified or registered, provided that the site or object can be determined to meet the section 5 or 6 definitions.

A land user is obliged to comply with the provisions of the AH Act and failure to do so may result in prosecution. Section 17 of the AH Act makes it an offence to excavate, destroy, damage conceal or otherwise alter in any way an Aboriginal site or assumes the possession, custody or control of, any object on or under an Aboriginal site unless authorised to do so by the Registrar of Sites under Section 16, or with the consent of the Minister for Aboriginal Affairs under Section 18. Therefore land users should carefully evaluate how a proposed activity may affect Aboriginal heritage.

Where a land-user proposes a development that may adversely impact on an Aboriginal site or object they must seek the consent of the Minister for Aboriginal Affairs under Section 18. Under Section 18, the application is lodged with the DAA and then submitted for consideration by the Aboriginal Cultural Materials Committee (ACMC). The ACMC is an appointed body that provides a recommendation to the Minister as to whether or not the Minister should consent to the use of the land for that purpose, and where applicable the extent to which and the conditions upon which the consent should be given.

In considering a Section 18 application, the ACMC enquires into the extent and adequacy of consultation with affected Aboriginal people.

Upon receipt of the recommendation from the ACMC, the Minister may grant or decline consent, or may grant consent subject to conditions. In considering whether to give consent, the Minister is required to take into account the interests of the general community.

Section 38 of the AH Act provides that there is to be a Register of places and objects (Register) kept recording all protected areas, Aboriginal cultural material and all other places (sites) and objects to which the AH Act applies. The Register of reported places and objects is maintained by the DAA. Information that is not culturally sensitive is available to the public. The AH Act protects Aboriginal sites or objects whether or not they have been previously reported or recorded. Although the Register contains information related to reported sites, there are many sites that have not yet been reported to the Registrar.

Anyone planning to develop or use land in a way that might disturb an Aboriginal site or object should be aware of their legal obligations. They must make a reasonable effort to find out if any sites exist in the relevant area. Such an investigation during early project planning will help to avoid possible time consuming and costly delays later.

To assist land users comply with their obligations under the AH Act, the DAA and Department of the Premier and Cabinet have jointly developed the *Aboriginal Heritage Due Diligence Guidelines*. These Guidelines provide guidance to assist in meeting the statutory obligations under the AH Act and are intended to help identify activities which may impact adversely on Aboriginal heritage.

Compliance with the Guidelines will not of itself guarantee compliance with the AH Act, but it will provide a useful starting place for consultation and engagement on the issues. Should you require assistance in determining what your responsibilities are under the AH Act or the Guidelines, you should contact the DAA.

Commonwealth *Aboriginal and Torres Strait Islander Heritage Protection Act 1984*

Acknowledgement is given to the Commonwealth Department of Environment as the primary reference sources for the following text.

The purpose of the *Aboriginal and Torres Strait Islander Heritage Protection Act 1984 (ATSIHP Act)* is to preserve and protect places, areas and objects of particular significance to Aboriginal and Torres Strait Islander peoples in all States and Territories. The ATSIHP Act enables the Commonwealth Minister for the Environment to make an emergency declaration to protect significant Aboriginal areas, objects or classes of objects from threats of injury or desecration for defined periods of time when State and Territory law does not provide effective protection or where that protection is withdrawn by the State or Territory Minister. The Department of the Environment assists the Minister with the responsibilities set out in the ATSIHP Act.

Indigenous people can ask the Commonwealth Minister to make an emergency declaration to protect an area or object which is under a serious and immediate threat of injury or desecration for up to 30 days with an extension of up to an additional 30 days (short term) or any period of time specified in the declaration on a long-term basis. An authorised officer can also make an emergency declaration to protect an area, object or class of objects from a threat of injury or desecration for up to 48 hours.

Declarations can stop activities and override other approvals, but cannot order people to carry out activities such as conservation or repairs to damaged areas. The Minister can vary or revoke a declaration where they are satisfied that the law of a State or Territory effectively protects an area or an object.

The ATSIHP Act functions as a national-wide 'backstop' for the protection of Aboriginal heritage, to be called upon as a last resort when significant places or objects are not adequately protected by State or Territory laws.

References

For further information about State and Commonwealth Aboriginal heritage and the *Aboriginal Heritage Due Diligence Guidelines* please visit the websites of:
www.daa.wa.gov.au
www.dpc.wa.gov.au
www.environment.gov.au


Weathered rock formations at Roebuck Bay on the Kimberley coast

Drover 1 in amongst farmland in the northern Perth Basin (photo courtesy of AWE Ltd)

Private Land under the *Petroleum and Geothermal Energy Resources Act 1967*

Background

The *Petroleum and Geothermal Energy Resources Act 1967* (PGER Act) has the purpose of enabling the exploration for and exploitation of Western Australia's petroleum and geothermal energy resources.

Both petroleum and geothermal energy are regarded as strategic resources and in this regard PGER titles have a certain amount of priority over other land tenures.

The Act has jurisdiction over all land areas of Western Australia and over certain of its coastal waters. However, it is primarily an "onshore" Act and particularly addresses the interaction between PGER titles and other land tenures such as private land.

What is Private Land?

The *Petroleum and Geothermal Energy Resources Act 1967* defines private land as being:

- any land alienated from the Crown for any estate of freehold;
- land held by any person on conditional purpose under the *Land Administration Act 1997*; or
- any lease or concession with or without acquiring the fee simple.

Excluded from the last point of this definition are pastoral or grazing purpose leases, timber leases or a lease for the use and benefit of Aboriginals. The words "any lease or concession" in the private land definition covers a wide variety of land usage (other than the exceptions mentioned) and care should be taken in assessing the status of any land proposed to be entered. It should be noted that the definition does not include reserve land, even if a lease or concession has been granted over it; for example, a Tourist Lease granted over a Nature Reserve.

Are Mining Titles Regarded as Private Land?

Titles under the *Mining Act 1978* are not regarded as private land under the PGER Act. However, special provision is made in the *Mining Act 1978* for conflict in operations between mining and petroleum/geothermal titles. In the advent of such a dispute the matter is reviewed by the Mining Warden and reported to the Minister for Mines and Petroleum. In determining the matter the Minister must give due regard to the public interest, justice and equity.

Gaining Access to Private Land

While access to private land by a holder of a petroleum title cannot be denied, (unless it is land referred to in Section 16 of the PGER Act), the title holder must first obtain consent in writing and negotiate a compensation package, if any, with the private land owner.

Accordingly Section 20 of the PGER Act provides that a petroleum or geothermal energy title holder shall not commence operations on private land until compensation, if any, is paid to the owner and occupier of the land or agreement has been reached as to payment of compensation. It is a condition of the PGER Act title that all on-ground activities require separate approval from the Executive Director Petroleum Division in the Department of Mines and Petroleum (the Executive Director is the delegate of the Minister for Mines and Petroleum in this matter). An application for approval of the operation, e.g. drilling a well, would require the land affected to be identified. Should that land be private land, then the PGER Act title holder would need to identify the land owner and occupier so as to satisfy the compensation requirement.

Can Access to Land be Denied to PGER Title Holders?

Access to a PGER title holder can be denied where the land is: private land less than 2000 m^2 (one fifth of a hectare) in extent; land used as a cemetery or burial place; or land within 150 m laterally from such cemetery, burial place, reservoir or any substantial improvement. The owner or trustee of the land described above can agree to entry onto that land for the purposes of the PGER operations or not.

These provisions are contained in Section 16 of the PGER Act, which also defines a reservoir as including any natural storage or accumulation of water, spring, dam, bore or artesian well.

Insofar as a "substantial improvement" is concerned, the Minister is the sole judge as to whether any improvement is substantial or not. While there has been no instance in which a Minister referred to in the PGER Act, has had to make a judgment as to what is substantial or not, much would depend upon the circumstances and the reasonableness of the arguments advanced. As always, it would be far better for the PGER title holder and land owner to reach a mutually beneficial solution.

It may also occur that a condition has been placed on a PGER title which prohibits the holder from entering specified land within the title area (Section 91B PGER Act). The prohibition isn't necessarily applied to private land as such but could be used to protect, say, a particular environmental feature within that land.

Compensation to be Negotiated with Private Land Owner/Occupier

Operations cannot be commenced on private land unless agreement as to compensation (if any) has been reached with the private property owner and occupier.

The PGER Act title holder and owner and occupier of the private land which needs to be entered, can agree as to amount of compensation (if any) for the right to occupy the land.

Compensation is for the land owner and occupier being deprived of possession of the land and for damage to the land. Further compensation for damage also extends to any improvements on the property and for severance of the land to be occupied from other land of the owner or occupier. It also extends to rights of way and all consequential damage.

What compensation cannot include, is the value of petroleum, geothermal energy resources, gold or minerals supposed to be on or under the land (Section 17 PGER Act).

Section 18 PGER Act also entitles private land holders in the vicinity of the operations to be compensated for all loss and damage suffered as a consequence of the activity, with the amount of compensation being agreed to in the same manner as above.

Compensation Cannot be Agreed

If compensation cannot be agreed between the PGER Act title holder and the owner and occupier of the private land, then either party may apply to the Magistrates Court* to fix the amount of compensation (Section 17 (4) PGER Act).

The time for taking any dispute to the Magistrates Court is prescribed in Regulation 2 of the *Petroleum and Geothermal Energy Resources Regulations 1987* and is three months after the day on which notice was given to the land owner/occupier, of the intention to commence operations on the private land. It is important therefore to provide formal notice to the private property owner/occupier of the intention to explore/produce and to be able to demonstrate that such a notice has been served.

**The application is to be made to the Magistrates Court at the place nearest to where the land in question is situated.*

What Happens if Operations are Undertaken on Private Land Without an Agreement?

A breach of Section 20 (agreement with private property owner/occupier) does not specify a particular penalty. However, exploration for or recovery of petroleum or a geothermal energy resource cannot be undertaken except under and in accordance with a PGER title. As a PGER title requires observance of all the provisions of the PGER Act, conducting activities on private land without having reached agreement with the land owner or occupier, could render the PGER title holder exposed to the illegal 'mining' provisions (Section 29 and Section 49). The penalty for conducting operations without a title or not in accordance with a title is a A$50,000 fine or five years gaol or both. Similarly, observing the requirements of the PGER Act is a condition of all titles and any breach of conditions is grounds for cancellation. It is evident that conducting operations on private land without having reached agreement with the land owner/occupier, is as a serious breach and one which could put the title holder at personal risk as well as jeopardise the title.

Accordingly, before conducting any operations on private land, compensation would need to have been paid or an agreement entered into as to the amount, timing and method of payment (if any). Such agreements would of course be best formalised and recorded. There have been circumstances where such agreements have been lost over a period of time, especially where title ownership has been transferred.

Any agreement entered into for conducting PGER title operations on private land does not need to be provided to the Department of Mines and Petroleum (unless of course in defence of a claim of illegal operations) and it is not the sort of agreement which is contemplated by Section 75 of the PGER Act as requiring approval and registration. In this regard it is very much up to the PGER title holder to protect its interest by ensuring that agreement for compensation has been settled and that it can evidence such settlement.

While it may be possible to have the agreement endorsed against the land title in some manner, this is entirely a matter for the parties to decide.

Who is Entitled to Compensation?

The PGER Act provides for compensation to the owners of private land and also any separate occupier of such land. For example if private land is being leased, compensation (if any) or an agreement is required to be also negotiated with the lessee.

Also entitled to compensation are the owners and or occupiers of any private land, adjoining the land on which PGER title operations are being conducted and who are adversely affected by those operations. Compensation in this instance is for damage or depreciated value of the land or any improvements. The procedure for adjudicating any disputed compensation claim is through the Magistrates Court, in the same manner as that for determining compensation for land directly affected by operations, i.e. as described in Section 17 of the PGER Act (Section 18 PGER Act).

Compensation can also be sought for further damage to private land (damage not previously contemplated or addressed in the agreement for or determination of compensation) in the same manner as described in Section 17 of the PGER Act. Regulation 2 of the Petroleum and Geothermal Energy Resources Regulations 1987 also prescribes the timeframes for taking disputes to the Magistrates Court in respect to Sections 18 and 19.

Compensation for Holders of Pastoral and Other Specified Leases

Pastoral leases and grazing leases, timber leases and leases for the use and benefit of Aboriginal inhabitants are not private land (the PGER Act excludes such leases from its definition of private land). However, there is still an entitlement to compensation for damage to any improvements on the lease lands, occasioned by the PGER title operations. The PGER registered holder(s) should notify the lessee of its proposed operations and determine the likelihood and extent of any damage to improvements, so that some mutually satisfactory arrangement can be reached.

The PGER Act provides capacity for the lessee to take any claim for damage to the Magistrates Court. Similarly, the person liable to pay the compensation, the PGER title holder, could seek a declaration as to the amount of compensation payable (Section 21 PGER Act).

Unlike that for private land, compensation is not payable to the pastoral, etc. lessee for being deprived of the land, any damage to the land, severance of the land or rights-of-way easements. Also, no compensation is payable for the value of the petroleum, geothermal energy resource, minerals, or gold (Section 20 PGER Act).

The Court may consider that it is unable to assess the amount of compensation in full satisfaction of the damage and opt for a judgment which restricts it to a specified period and in respect to the whole or part of the total claim (Section 22 PGER Act).

Private Land under the *Petroleum Pipelines Act 1969*

Background

The *Petroleum Pipelines Act 1969* (PP Act) regulates the construction and operation of petroleum pipelines in onshore Western Australia. The pipelines licensed under this Act are generally the trunk or main lines for the conveyance of naturally occurring petroleum (predominantly natural gas). Pipelines which reticulate gas to domestic users are dealt with under other legislation.

Licences to construct and operate petroleum pipelines are issued upon a valid application being made and where the Minister is satisfied that (amongst other things) it is in the public interest to do so. Most of Western Australia's petroleum pipelines carry natural gas and are generally buried below the ground. It is a requirement that the location of a below ground pipeline is clearly marked with above ground signposts.

Pipelines can be licensed to cross any type of land, including private land. The licence provides the licensee with the right to construct and operate a pipeline but pursuant to Section 12(3) it is a mandatory condition of the licence that before construction of the pipeline commences over a parcel of land, the licensee first acquire all the lands in that part of the licence area, or a lease, licence or other authority over the lands and acquired and registered all easements over those lands as are necessary for him to lawfully construct and have the right of access to the pipeline once constructed.

Can Private Land be Taken to Enable a Pipeline Over That Land?

Pursuant to Section 19 of the PP Act any land can be taken on behalf of the licensee in the same manner as land can be taken for a public work.

Land or an easement over land can only be taken at the request of a pipeline licensee. Accordingly, the Minister in granting the licence needs to be satisfied that the pipeline to be constructed is in the public interest and that land along the route of the pipeline should be taken if the circumstances require.

Upon application by licensee, the Minister may at the licensee's expense, take the land or easement over the land under Part 9 of the *Land Administration Act 1997* (LA Act). However, the Minister needs to be satisfied that, having made reasonable attempts to do so, the licensee has been unable to acquire the land or an easement over the land by agreement with the land owner.

While private land is not mentioned as such in the PP Act (any land can be taken and accordingly, it is not necessary to specifically refer to private land) reference is made to "the owner" of land. The definition of owner is the person who owns the land or is contracted to purchase the land or entitled to receive the rents and profits from the land.

Unlike the PGER Act it does not appear that the occupier of the land, as distinct from the owner, has any ability to be involved in negotiating an easement.

Is Compensation Payable to the Landowner for Land Taken?

In that land is capable of being taken as if for a public work, the provisions of Part 9 of the LA Act apply. In brief, those provisions involve a notice of intention to take the land which can be objected to by the owner of the land. Any objection however, cannot relate to the amount of compensation. Once a decision to take has been registered, every person having an interest in the land which has been taken is entitled to compensation pursuant to Part 10 of the LA Act. The costs involved in the taking of the land and also the compensation awarded becomes the responsibility of the licensee (Section 19(3)(b) PP Act).

The Minister may also require a security from the applicant or licensee to cover the payment of the costs incurred in taking any land, or easement and for the compensation likely to be payable to the owner of the land so taken (Section 10 PP Act). The type of security required is described in Section 13 of the PP Act and is likely to be in the form of a bank guarantee.

Land Owner to be Notified of the Proposed Pipeline

Where a pipeline route is being considered, entry onto the land will most likely be necessary. The PP Act provides the Minister with the power to authorise entry onto any land, for the purpose of making surveys and preliminary investigations. A condition of the Authority to Enter is that reasonable notice to the owner and occupier of the land will be given and that entry from time to time will be during day time and confined to the area specified in the authority (Section 7 PP Act).

It is not a requirement of the PP Act that an Authority to Enter be obtained. In circumstances, where the land owner or occupier has no objections to the land being entered, then the formality of an Authority to Enter from the Minister is not necessary.

An application for an Authority to Enter would need to identify all or any of the land to be entered, reasons why it is required, the general scope of the survey work proposed and the time required to complete the work. When making an application for a pipeline licence (Section 8 PP Act), the applicant is required (amongst other things) to notify each owner and occupier of any land over which the pipeline is proposed to be constructed, that an application has been made.

The government is also required to place a notice in the *Government Gazette*, a State-wide newspaper and the relevant regional newspaper, advising of the receipt of the pipeline application and where a map showing the proposed route of the pipeline may be examined. Any response to that notice within the comment period specified therein by persons affected by the pipeline would be taken into consideration when the pipeline licence application is being considered.


Spring wildflowers in the Gunbarrel Basin

Colours of the Pilbara

Overview

The Department of Mines and Petroleum (DMP) Environment Division conducts environmental assessments and compliance audits of petroleum and geothermal activities in Western Australia (WA). Environmental planning and management are essential to carrying out petroleum and geothermal activities in WA. Guidance and advice can be sought from the Environment Division on environmental assessments, legislation and agency referrals, which may need to be considered when an operator seeks to gain environmental approval for a petroleum or geothermal activity.

DMP regulates petroleum and geothermal activities under the following legislation:

- *Petroleum and Geothermal Energy Resources Act 1967* (PGER Act)
- *Petroleum (Submerged Lands) Act 1982* (PSL Act)
- *Petroleum Pipelines Act 1969* (PP Act)

The PGER Act covers all onshore areas in WA, including its islands and, in certain circumstances, areas of submerged lands internal to the State (i.e. those waters landward of the baseline).

The PSL Act provides the regulatory framework for the exploration and production of offshore petroleum resources located within WA's territorial sea (including the territorial sea around State islands) and includes related pipelines.

The PP Act applies to the construction, operation and maintenance of pipelines for the conveyance of petroleum on land within the State.

Offshore petroleum activities in Commonwealth waters are regulated by the National Offshore Petroleum Safety and Environmental Management Authority (NOPSEMA). For further information on the role of NOPSEMA please visit the NOPSEMA website www.nopsema.gov.au

Environmental approvals may also be required from agencies other than DMP under State or Federal environmental legislation, namely:

- the *Environmental Protection Act 1986* (WA), through a State Environmental Impact Assessment (State EIA) conducted by the Environmental Protection Authority (EPA); or
- the *Environment Protection and Biodiversity Conservation Act 1999* (Commonwealth), through an assessment and approval process conducted by the Department of the Environment (DoE).

Approvals granted by DMP do not remove the need for necessary approvals under the *Environmental Protection Act 1986* (EP Act) or the *Environment Protection and Biodiversity Conservation Act 1999* (EPBC Act). The requirements of the EP Act and the EPBC Act are described in greater detail later in this chapter.

Environmental Assessment under Petroleum and Geothermal Energy Legislation

Environment regulations under the PGER Act, PSL Act and PP Act have been in force in WA since 29 August 2012. The three sets of regulations (collectively referred to as the Petroleum Environment Regulations) are the:

- *Petroleum and Geothermal Energy Resources (Environment) Regulations 2012*
- *Petroleum (Submerged Lands) (Environment) Regulations 2012*
- *Petroleum Pipelines (Environment) Regulations 2012*

Under regulation 4 of the Petroleum Environment Regulations, petroleum and geothermal activities that require approval from DMP include:

- seismic or other surveys;
- drilling;
- hydraulic fracturing;
- construction and installation of a pipeline or facility;
- operation of a pipeline or facility;
- modification, decommissioning, dismantling or removing a pipeline or facility; and
- storage, processing or transport of petroleum.

The Petroleum Environment Regulations require an operator to have an approved Environment Plan (EP) in place prior to the commencement of any petroleum or geothermal activity. The EP regime aims to reduce environmental risks and impacts of petroleum and geothermal activities to a level that is 'as low as reasonably practicable' (ALARP). At a minimum, an EP must include the following information:

- Corporate Environmental Policy;
- environmental legislation and other requirements;
- referrals to other agencies;
- description of the activity;
- description of the environment;
- environmental impact and risk assessment;
- risk management practices;
- environmental performance objectives, standards and measurement criteria;
- implementation strategy;
- recording and reporting arrangements; and
- consultation.

The *Guidelines for the Preparation and Submission of an Environment Plan – 2012* (the Guidelines) were developed to assist operators in meeting the requirements of the Petroleum Environment Regulations and are available from the DMP website (www.dmp.wa.gov.au/documents/ENV-PEB-177.pdf). DMP recommends that all operators review the Guidelines prior to the submission of an EP. The content and level of detail of an EP will depend on the scale of the activity and environmental impacts associated with the proposal.

In accordance with the Guidelines, operators are required to submit an EP to the DMP Environment Division at least three months prior to the planned commencement date of an activity and at least six months prior to the planned commencement date of an activity within proximity to environmental sensitivities.

An Oil Spill Contingency Plan (OSCP) is also required under the Petroleum Environment Regulations. An OSCP may be incorporated into an operator's EP or be a standalone document.

In developing an OSCP it is important to note:

- an OSCP is an operational plan for use in emergency situations. Responsibilities of key personnel, response actions and reporting requirements are to be made clear;
- the plan should be subject to regular training simulation and real-time exercises, review and updates;
- environmental, meteorological, oceanographic and oil characteristic information will be used for on-site decision making and should be accessible (where relevant); and
- where relevant information or procedures exist in other company documents such as emergency response plans, these documents should be clearly referenced.

The Environment Division seeks comment on offshore OSCPs from personnel within the Department of Transport (DoT), on behalf of the State Committee for Combating Marine Oil Pollution. Further information on the content requirements of OSCPs can be found in the Guidelines.

The Assessment Process

The assessment of an EP by the Environment Division is outlined under Process 1 in Figure 50. Processes 2 and 3 are separate assessment processes conducted by DoE and EPA, respectively, and may not be necessary depending on the nature of the specific proposal. It is the responsibility of the operators to refer their proposals for assessment under the EPBC Act if required. If necessary, the Environment Division will refer proposals for assessment under the EP Act. The Environment Division recommends that operators review the need for referral of their proposed activities as early as possible, as referrals can significantly prolong approval timeframes.

Steps 1 to 3 in Figure 50 are the responsibility of the operator. Once the operator has obtained the necessary petroleum or geothermal energy title under the relevant legislation, they may wish to consult the Environment Division to clarify the specific environmental requirements of the project and obtain guidance on which other agencies they may need to contact.

ENVIRONMENTAL ASSESSMENT

Operators are also reminded that they may need to obtain a Native Vegetation Clearing Permit under the *Environmental Protection (Clearing of Native Vegetation) Regulations 2004*. The Environment Division can be contacted for further information on clearing permit requirements and whether any exemptions apply to the activity.

Once the operator has prepared and submitted an EP to the Environment Division, the adequacy of the EP will be considered and an Environmental Officer will contact the operator within 30 days (Steps 4 and 5). If it is determined that the EP does not meet the requirements of the Petroleum Environment Regulations, the Environment Division will request a revision of the EP or additional information. Once the operator submits the revised and/or additional documentation, the Environment Division has another 30 days in which to assess the new information (Steps 5A and 5B). If the EP is deemed to be acceptable, the Environment Division, Director Operations will issue an environmental approval letter (Step 6). Once EP approval and all other necessary approvals from DMP and other agencies (where required) have been obtained, the operator may commence the activity.

Under regulation 11(7) of the Petroleum Environment Regulations, within 10 days of receiving EP approval, operators must submit to DMP a summary of their approved EP for public disclosure (Step 7). At a minimum, the EP summary must include the following information:

- The contact details of the operator's nominated liaison personnel for the activity;
- Description of the location of the activity, coordinates and locality maps;
- A summary of the operational details of the petroleum activity and proposed timetables;
- A general description of the existing environment that may be affected by the activity;
- A summary of the environmental risks and controls and the overall implementation strategy;
- Disclosure of any chemical substances used in accordance with regulation 15(9) of the Petroleum Environment Regulations; and
- Advice on consultation undertaken and provisions for ongoing consultation.

DMP assesses the EP summary and once determined to meet the requirements of the Petroleum Environment Regulations, the summary is published on the DMP website (Steps 8 and 9).

During the initial assessment of the EP, the Environment Division may find that the proposal must be forwarded to the EPA for assessment under the EP Act. Assessment under the EP Act is known as a State Environmental Impact Assessment (EIA) which is described in the following section and represented as Process 3 in Figure 50. Once the proposal has been referred to the EPA, the DMP Environment Division cannot finalise their assessment until the EPA concludes the State EIA process.

State Environmental Impact Assessment under the EP Act

The EP Act provides for an EPA, an independent five-member authority charged with advising the Minister for the Environment on environmental protection.

Petroleum or geothermal energy proposals within State jurisdiction that are likely to have significant environmental impacts must undergo EIA under the EP Act (represented as Process 3 in Figure 50). If an operator is confident that their proposal will require EIA under the EP Act, they should refer it to the EPA for assessment.

Once a proposal is submitted to DMP, the Environment Division may find that the proposal must be forwarded to the EPA for assessment under the EP Act. The decision criteria which the Environment Division uses to determine whether referral is required are outlined in a Memorandum of Understanding (MoU) between DMP and the EPA*.

** Memorandum of Understanding between the Department of Mines and Petroleum and the Environmental Protection Authority in relation to the referral of Mineral and Petroleum (Onshore and Offshore) and Geothermal Proposals.*

To obtain the most current version of the MoU refer to the DMP website. Operators should examine the referral criteria in the MoU and consider them in relation to their proposal. If it is likely that the proposal will be referred to the EPA for assessment, they are urged to leave plenty of time for this process to occur, as this can often take six months or more. Modification of the proposal could also be considered in order to reduce the environmental impact and reduce the likelihood of referral to the EPA.

For further information please refer to the EPA website www.epa.wa.gov.au

Activities in Reserved / Declared / Managed Land and Referrals under the PGER Act

Under the PGER Act, the Minister for Mines and Petroleum is required to grant written consent of entry for all exploration and operational activities intended to be carried out on land which is within a permit, drilling reservation, access authority, special prospecting authority, lease or licence, and/or within any lands reserved, declared or otherwise indicated under the *Conservation and Land Management Act 1984*, the *Land Administration Act 1997*, or any other written law. This may include:

- State Forest and Timber Reserves
- Conservation Parks
- National Parks
- Nature Reserves
- any other land reserved or declared under any other written law.

Before granting consent, the Minister for Mines and Petroleum must consult with the responsible Minister for those lands. For lands reserved, declared or dedicated under the *Land Administration Act 1997* or *Conservation and Land Management Act 1984*, advice must be sought from the Department of Lands and/or the Department of Parks and Wildlife (DPaW), to determine who the land is vested with and identify conditions applicable to the management of the proposed activity to occur on those lands.

Similar to the assessment processes for EPs and OSCPs, the government agency receiving a referral has up to 30 days to acknowledge receipt of the referral and may request further information from an operator. The referral process has potential to add three months or more to approval timelines, and therefore should be carefully considered if proposed activities are to be carried out in reserved, declared, or managed lands.

Recommendations arising from this referral process are made to the Minister in writing and are specific to the document revision assessed. Changes to a proposal which may influence the scope or impacts of activities must be submitted to DMP in an approved form, and will require liaison between DMP and any agencies which were previously referred to or which have assessed, an earlier proposal. Operators should consult with DMP to determine the most appropriate format, where changes to approval documents are required. DMP advises operators to identify and consult with all stakeholders, as appropriate, as early as possible in the planning process. Approvals are specific to the document assessed and conditions are legally binding, enforceable, and penalties may apply for breach thereof.

Assessment under the EPBC Act

The EPBC Act is Australia's 'national environmental law' and applies to activities under both Commonwealth and State jurisdiction. Under the EPBC Act, actions that have, or are likely to have, a significant impact on a matter of National Environmental Significance (NES), require approval from the Australian Government Minister for the Environment. The Department of the Environment (DoE) administers and conducts assessments under the EPBC Act.

There are nine matters of NES protected under the EPBC Act, namely:

- World Heritage properties;
- National Heritage places;
- wetlands of international importance / RAMSAR wetlands;
- listed threatened species and ecological communities;
- migratory species protected under international agreements;
- Commonwealth marine areas;
- the Great Barrier Reef Marine Park;
- nuclear actions (including uranium mines); and
- a water resource, in relation to coal seam gas development and large coal mining development.

It is the responsibility of the operator to refer their proposal for assessment under the EPBC Act. If the operator is not certain about whether their proposal requires approval under the EPBC Act, it can be referred for a decision by the Australian Government Minister for the Environment; the purpose of referring a proposal is to determine whether or not a proposed action will need formal assessment and approval under the EPBC Act. Severe penalties apply for failure to refer a proposal which impacts a matter of NES; DMP strongly advises operators to investigate the need for EPBC referral before commencing any activities.

Within 20 business days of referral, a determination will be made as to whether the proposal is a Controlled Action. If the proposal is determined to constitute a Controlled Action it will be assessed by DoE under the EPBC Act. This assessment and approval process is represented as Process 2 in Figure 50, and is shown in detail in Figures 51 and 52.

Further information on the EPBC Act and information to assist in determining whether to refer a proposal is available from DoE via their website www.environment.gov.au

Hydraulic fracturing in the northern Perth Basin

State Response Team Ro-Boom deployment exercise

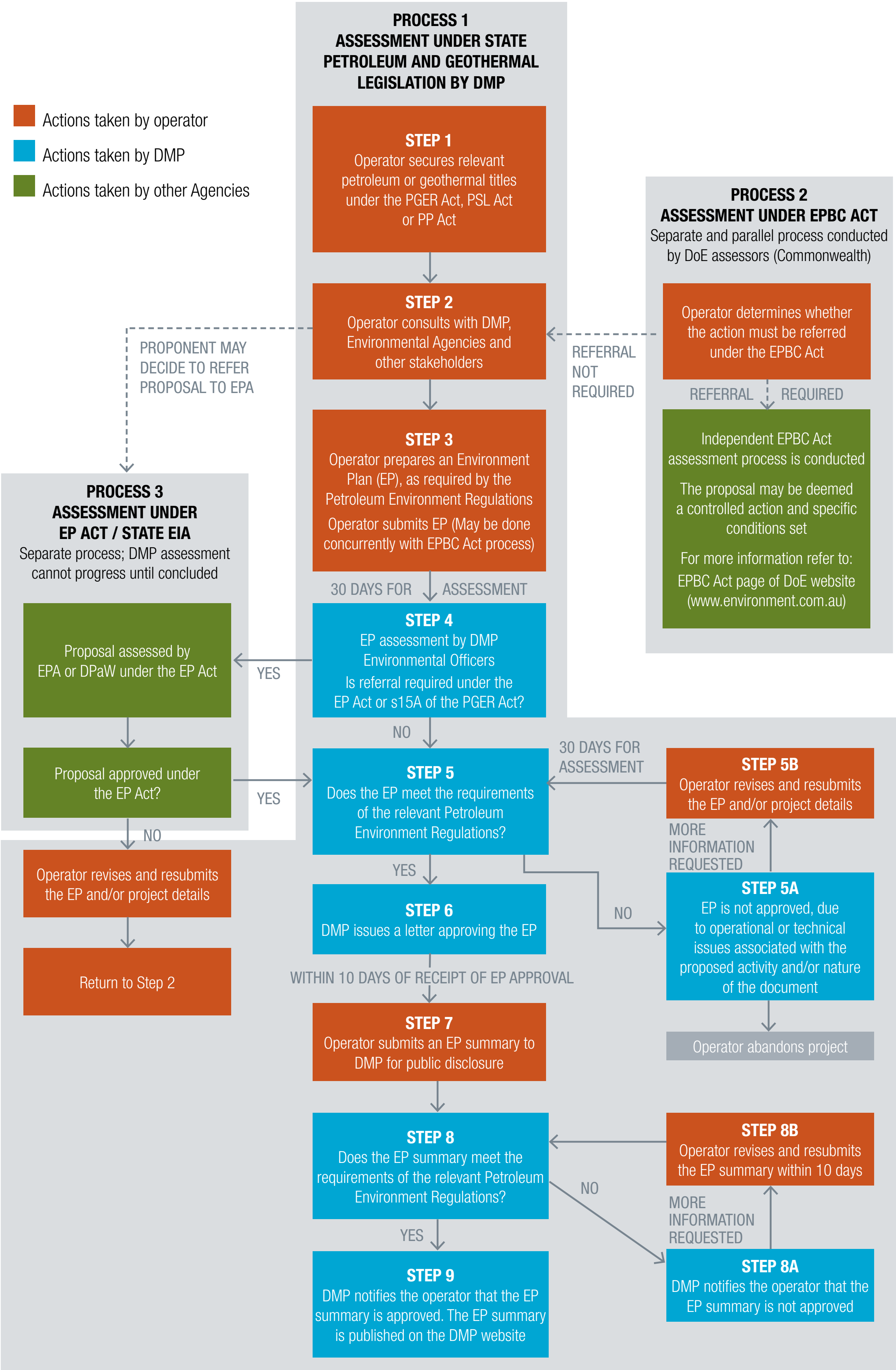
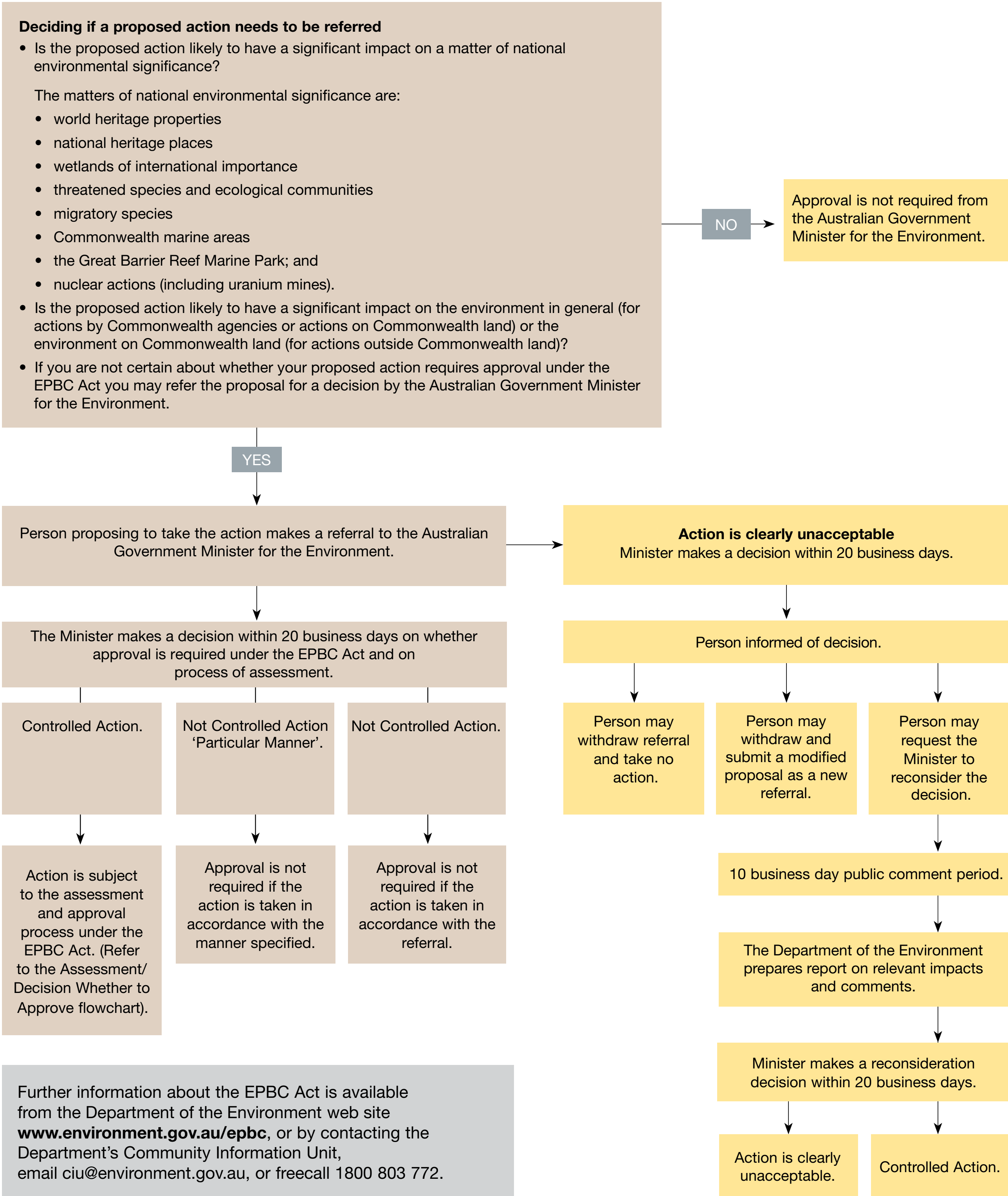


Figure 50. Schematic representation of the EP assessment process conducted at Department of Mines and Petroleum for activities in Western Australia



Further information about the EPBC Act is available from the Department of the Environment web site **www.environment.gov.au/epbc**, or by contacting the Department's Community Information Unit, email ciu@environment.gov.au, or freecall 1800 803 772.

Figure 51. EPBC Act environment assessment process – referral

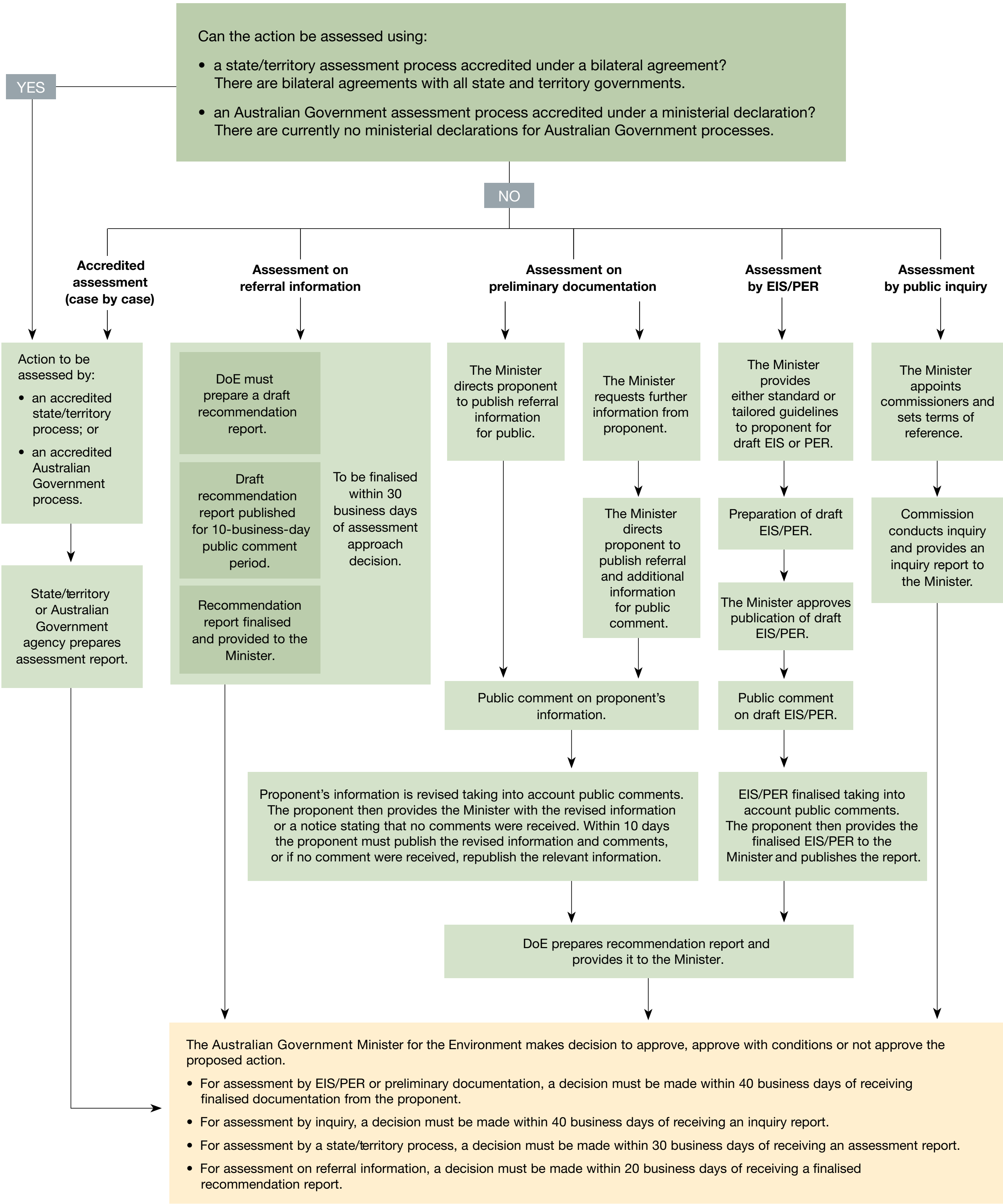


Figure 52. EPBC Act environment assessment process – assessment/decision whether to approve

Derrickman climbing the Rig 826 mast (photo courtesy of Norwest Energy)

Onshore Safety Management

Onshore safety regulation is achieved through the following legislation, which is administered by Department of Mines and Petroleum — Resources Safety Division:

- *Petroleum Pipelines Act 1969*
- *Petroleum Pipelines (Occupational Safety and Health) Regulations 2010*
- *Petroleum Pipelines (Management of Safety of Pipeline Operations) Regulations 2010*
- *Petroleum and Geothermal Energy Resources Act 1967*
- *Petroleum and Geothermal Energy Resources (Occupational Safety and Health) Regulations 2010*
- *Petroleum and Geothermal Energy Resources (Management of Safety) Regulations 2010*

The Resources Safety Division (RSD) promotes safety in the mining, dangerous goods and onshore petroleum and geothermal energy industries through education, enforcement and specialist advice. In this context RSD provides safety and health regulatory services to the industry through its Dangerous Goods and Petroleum Safety Branch and technical advice to the Executive Director Petroleum Division in relation to onshore petroleum, pipeline and geothermal operations. RSD staff are appointed as inspectors under the petroleum legislation.

A safety case / safety management system approach is applied in relation to all aspects of onshore petroleum, geothermal and pipeline operations; this approach is initiated through the regulations and broadly aligns with the methodologies applied for offshore facilities in both Commonwealth and State waters. Safety case submissions are processed and assessed in a similar manner and early dialogue is considered essential to ensure timeliness of approvals.

The regulations also apply a safety management system (SMS) approach that aligns with current Australian Standards to geothermal activities. This SMS approach applies to all exploration and drilling activities, whether petroleum or geothermal.

Offshore Safety Management

Safety regulation for offshore facilities and operations are covered under Commonwealth or State legislation dependent on location.

DMP administers the *Petroleum (Submerged Lands) Act 1982* (PSL Act) and attendant safety regulations 2007 listed below that apply over coastal waters out to the three nautical mile limit. DMP assumed this responsibility from the National Offshore Petroleum Safety and Environmental Management Authority (NOPSEMA) on 1 January 2012.

NOPSEMA regulates petroleum operations in accordance with the *Offshore Petroleum and Greenhouse Gas Storage Act 2006* (OPGGS Act) and the attendant *Offshore Petroleum and Greenhouse Gas Storage (Safety) Regulations 2009* in Commonwealth waters only.

Schedule 5 of the PSL Act establishes a modern occupational safety and health (OSH) regime for petroleum activities at facilities (including pipelines) located in coastal waters. The main features of the regime are:

- Duties of Care
  Specific categories of persons (operators, employers, etc) who are involved in offshore petroleum activities at facilities are required to “take all reasonably practicable steps” to protect the health and safety of the facility workforce and of any other persons who may be affected.
- Consultation Provisions
  Mechanisms are set out that will enable effective consultation between each facility operator, relevant employers and the workforce regarding occupational health and safety.
- Powers of inspectors
  DMP’s Resource Safety inspectors are granted powers to enter offshore facilities or other relevant premises, make inspections, interview persons, take evidence and otherwise take action to ensure compliance by duty holders.

Current compilations of the PSL Act and subsidiary legislation are available from the State Law Publisher website, www.slp.wa.gov.au.

Section 4 of the PSL Act defines the listed OSH laws that DMP and its inspectors administer and enforce in coastal waters. These laws are essentially Schedule 5 of the PSL Act, and the following regulations:

Petroleum (Submerged Lands) (Occupational Safety and Health) Regulations 2007

These regulations establish certain legislative processes that are required by Schedule 5, and also establish some prescriptive OSH standards, such as bans on certain hazardous substances, consistent with national agreements.

Petroleum (Submerged Lands) (Management of Safety on Offshore Facilities) Regulations 2007 (MoSOF)

These regulations require there to be a registered ‘operator’ for each offshore petroleum facility, and require each facility to be managed in accordance with a detailed safety case that has been prepared by the operator and accepted by DMP.

Petroleum (Submerged Lands) (Pipeline) Regulations 2007

These regulations require there to be a registered operator for each licensed pipeline, and require the pipeline to be managed in accordance with a pipeline management plan that has been prepared by the pipeline licensee and accepted by DMP. These regulations address a range of matters, not just OSH, but also management of safety and structural integrity.

Petroleum (Submerged Lands) (Diving Safety) Regulations 2007

These regulations require each diving contractor to act in accordance with a diving safety management system that has been accepted by DMP and in accordance with a diving project plan that has been accepted by the relevant facility operator.

Information for Operators

Introduction to the OSH regime

The OSH regime for Commonwealth waters petroleum operations is set out by Schedule 3 to the OPGGS Act and its associated regulations. Similar provisions apply in State coastal waters where the legislative requirements under Schedule 5 essentially replicate Commonwealth legislation.

The general OSH duty in the regime is that the operator of a facility must take all reasonably practicable steps to ensure that a facility and its activities are safe and without risk to health. This key duty is imposed on the operator of the facility, and also includes duties on employers, suppliers, manufacturers, constructors and members of the workforce.

While there are many other duties imposed on operators of facilities and others, new entrants to the regime need to be aware of the following key process steps.

Operator Nomination and Registration

For coastal waters, under the *Petroleum (Submerged Lands) (Management of Safety on Offshore Facilities) Regulations 2007* (MoSOF), a facility must have a registered operator. Under the *Petroleum (Submerged Lands) (Pipelines) Regulations 2007*, a pipeline must have a registered operator.

The registered operator is the person who has day-to-day management and control of the facility. For facilities other than pipelines, the facility owner or title holder may nominate a party to be the operator of the facility. For facilities that are pipelines, the pipeline licensee may nominate a party to be the operator of the pipeline.

Activities and Facilities

DMP’s functions include promotion of occupational safety and health of persons engaged in offshore petroleum operations. These operations are:

diving operations or operations at, or near a facility. Certain vessels or structures are defined as facilities. Licensed pipelines are also facilities. The categories of activities that cause relevant vessels or structures to be defined as facilities are:

- recovery, processing, storage and offloading of petroleum, or any combination of these activities;
- provision of accommodation for persons at another facility, whether or not connected by walkway;
- drilling or servicing a petroleum well, or doing any work associated with drilling or servicing;
- laying of pipes for petroleum, including any manufacturing of such pipes, or doing work on existing pipes;
- diving support;
- erection, dismantling or decommissioning of a vessel or structure of any of the above types; and
- any other activity related to offshore petroleum that is prescribed.

The facility definition includes a facility being constructed or installed and an associated offshore place (that being an offshore place near the facility where activities relating to the facility occur).

Safety Case Submission

A facility cannot be constructed, installed, operated, modified or decommissioned without a safety case in force for that stage in the life of the facility. The operator of a facility must submit the safety case to DMP with a covering letter stating that it is being submitted for assessment.

Since it is the operator that must submit the safety case, registration of the operator must be completed prior to safety case submission. The MoSOF regulations set out the requirements for the contents of safety cases and a safety case for a facility must comply with MoSOF.

For a proposed facility or an existing facility with a proposed change that is significant, DMP may require the operator to provide a validation. In these cases, the operator must not submit the safety case before the operator and DMP have agreed on the scope of validation for the facility. Therefore the operator should contact DMP early on to discuss the scope of validation.

In general, the regulations impose safety case assessment time frames on DMP. DMP has 90 days in which to complete the assessment of a new safety case, and 30 days for a revised safety case. In all cases DMP may extend the assessment period by setting out an alternate timetable for assessment.

If the initially submitted safety case is not acceptable, DMP will notify the operator and seek clarification. DMP must accept or reject the safety case as set out in legislation. The arrangement for pipelines is similar whereby the pipeline licensee must submit the Pipeline Management Plan (PMP) to DMP for assessment.

Further details can be found on the DMP website, www.dmp.gov.au. If in doubt, it is important to consult DMP early in the process.

Petroleum and Geothermal Energy Safety Levies

To enhance the role of Resources Safety as a leading practice safety regulator, the State Government determined that the necessary resources will be funded through cost recovery from the relevant industry sectors.

The objectives in cost recovery for petroleum and geothermal energy safety are to ensure, to the greatest possible extent, a fair and equitable distribution of the cost of administering onshore petroleum and geothermal energy safety regulation, with minimal administrative burdens for industry and the regulator.

The Levies and Classification

The Safety Management System Levy applies to a Safety Management System in force (SMS), and is charged for regulatory services rendered in relation to listed occupational safety and health laws under the *Petroleum and Geothermal Energy Resources Act 1967* and *Petroleum (Submerged Lands) Act 1982*.

The Safety Case Levy applies to a Safety Case in force (SC), and is charged for regulatory services rendered in relation to listed occupational safety and health laws under the *Petroleum Pipelines Act 1969*.

The CEO classifies each operation taking into account a number of factors; the classifications in turn give rise to a rating that is used to calculate the levy according to the formula in the regulations. The details of the classification process have been published in guidelines rather than being included in the regulations.

Information contained in the SC or SMS on the complexity and risk of an operation are considered, as this indicates the resources required to regulate the operation. The levies will be assessed at the end of each quarter, from the date the SC or SMS is in force.

The levies will continue to apply while the SC or SMS is in force and the date from which the SC or SMS ceases to be in force will be agreed between the CEO and the licensee/operator and used as the end date for the levies.

Formal objections to classifications can only be made to the CEO upon receipt of a levy assessment/reassessment notice, through the objections process specified in the levy legislation. If a significant change to the operation occurs the operator or licencee is required under current safety legislation to notify DMP. Following this, the CEO may review a levy classification decision.

An Agency Special Purpose Account, named the Petroleum and Geothermal Energy Safety Levies Account, will house the levy funds accrued as well as any penalty amounts. Legislation restricts use of moneys in the account to the costs and expenses accrued for the administration of listed OSH laws in the State petroleum legislation and the administration of the Levies Act.

Liability for Payment of the Levies

The person liable for payment is the operator/licensee occupying the position at the end of the quarterly period and defined as the registered holder. The operator/licensee is responsible for any other commercial arrangements with other title holders, contractors, suppliers and customers. DMP will initially assign a person liable for each operation, however this can be adjusted later as required.

Regulatory Reform Progress

Based on model laws developed under the harmonisation process driven by Safe Work Australia and the National Mine Safety Framework, new workplace health and safety legislation for Western Australia is expected to be introduced in late 2014. It is hoped that this will be a single piece of legislation that will provide for the whole resources sector, including major hazard facilities, petroleum and mining industries.

The expectation is that, under the proposed single piece of legislation, the regulator's resources will then be applied where they can have a more efficient and effective influence in driving cultural change across the sector.

Within this new regime, the regulator would provide a two pronged approach to its engagement on resource sites:

- a "critical control" audit, similar to a safety case audit process
- an occupational health and safety audit program.

These would operate in tandem, with resources being applied accordingly.

This approach should also drive consistency and ensure that appropriate skill sets are brought to issues at the critical time. This proposed regulatory reform is another step towards fulfilling the vision for a leading practice regulator that supports industry as it strives to improve safety outcomes, and achieve the safe work places that we all desire.

Update on Petroleum Safety Legislation Amendments

The State and Commonwealth's petroleum safety regimes exist side by side. The State has jurisdiction over coastal waters up to the three nautical mile limit from the baseline along its coastal boundaries. After this point, the Commonwealth safety regime applies.

It is important for the efficient regulation of the petroleum industry that these two regulatory schemes are as harmonised as possible. This is to ensure there is no confusion within industry regarding similar provisions under each legislation.

A gap analysis carried out recently to determine the extent of deviation between the offshore safety regulations and those covering coastal waters identified a number of inconsistencies. Documentation is now being prepared to seek Ministerial approval to effect the appropriate regulatory amendment.

Previously identified areas of duplication and inconsistency between the various State Acts that regulate safety in the petroleum industry, the *Dangerous Goods Safety Act 2004* and the *Occupational Safety and Health Act 1984* also need to be rectified.

The amendments to address these anomalies are currently being drafted by Parliamentary Counsel.

Evaluation of Asset Integrity Management System (Guide)

The management of safety regulations under the petroleum legislation requires, among other things, an operator to have documented arrangements within their safety management system to ensure the facility, plant, machinery and equipment are always maintained in good condition and are fit for purpose.

The regulations are not prescriptive and allow operators to determine how best this can be achieved, taking into account factors such as the operation's activity, circumstance and location.

One methodology is to consider an asset integrity management system (AIMS) as an integrated approach. An AIMS allows operators, particularly those with large-scale petroleum facilities, to demonstrate that, as far as is reasonably practicable, they have ensured the integrity of their assets.

The benefits of this are obvious from a safety perspective — machinery, plant and equipment failures can have serious consequences to the safety and health of the workforce and to the environment. Failures of high pressure gas transmission pipelines that are located in, or near, populated areas could also have catastrophic consequences in relation to the general public.

From a commercial point of view, poor maintenance, inspection and monitoring regimes can result in unexpected downtime, costly repairs and the consequential loss of production. If supply is interrupted, particularly in relation to gas transmission, the economy and community may be affected. Penalties may also apply as there is a legislative requirement to ensure continuity of supply.

To assist industry, Resources Safety has a guide to evaluating an AIMS. Although published specifically for the energy resources sector, the minerals sector and other industries may find it to be a useful document. It contains an evaluation checklist that can be used to quickly assess whether the systems, processes and procedures adopted for any operation are sufficient to demonstrate that appropriate levels of asset integrity can be assured.

Visit the petroleum safety publications section at www.dmp.wa.gov.au/ResourcesSafety to download the guide.

Other sources of safety guidance include:

- NOPSEMA www.nopsema.gov.au/safety/safety-alerts
- Australian Maritime Safety Authority (AMSA) www.amsa.gov.au
- Australian Petroleum Production and Exploration Association (APPEA) www.appea.com.au/safety-environment
- Australian Transport Safety Bureau (ATSB) www.atsb.gov.au/publications/recommendations
- Civil Aviation Safety Authority (CASA) www.casa.gov.au

Recording flow data from the wellhead (photo courtesy of Buru Energy)

Royalties

In Western Australia, all minerals including petroleum and geothermal energy existing in their natural form are owned by the State, being held in trust by the Government on behalf of the community. The exception is where minerals are found on land which was allocated a freehold title before January 1899. When title to these non-renewable resources is transferred to developers, the State expects a return to the community. Compensation in the form of a royalty is paid to the State for the use and loss of an asset. This principle is the basis of the State's royalty system.

Petroleum royalties are levied by the State Governmnet on petroleum production that occurs onshore or within coastal waters, and by the Commonwealth on the North West Shelf Project. Total petroleum royalties, including North West Shelf Grants, collected in 2013 amounted to A$1.05 billion. This is approximately 17.7 per cent of all royalties collected in Western Australia (Figure 53). The rate of royalty is normally set at between 10 and 12.5 per cent of the wellhead value of petroleum produced.

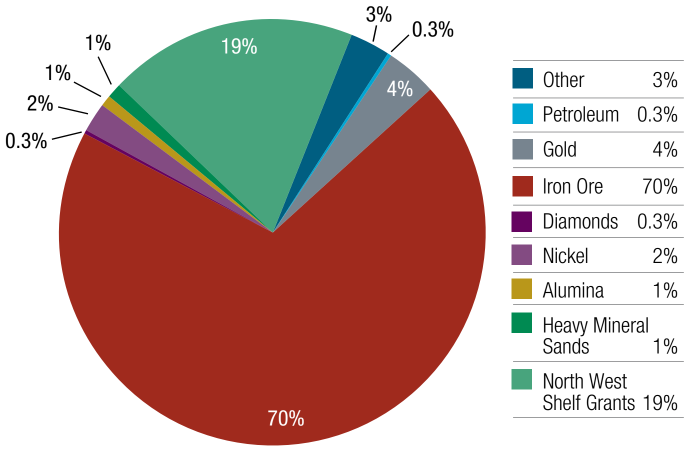


Figure 53. Royalty receipts collected in 2013

In addition to State royalties, Commonwealth legislation provides for an excise on all oil produced from fields of greater than 4,769,618 kL (30 MMbbl). The first 4,769,618 kL (30 MMbbl) is excise exempt. Currently there are no onshore fields that are large enough to pay this tax.

Petroleum royalties are administered and collected under State and Commonwealth legislation (Figure 54). Generally, there are three systems used for the collection of petroleum royalties:

- wellhead value royalty
- resource rent royalty
- petroleum resource rent tax

Royalties collected for onshore projects are retained by the State Government, while offshore projects are shared between the State and Commonwealth governments in accordance with the relevant legislation. Barrow Island onshore royalties are also shared between the Commonwealth and the State governments. There are five Acts that apply in Western Australia:

- The *Offshore Petroleum (Royalty) Act 2006*, which covers production from fields originating from the North West Shelf Project Area covered by permits originating from WA-1-P and WA-28-P. This is an area of Commonwealth jurisdiction in which a wellhead value royalty system is used.
- The *Petroleum (Submerged Lands) Act 1982* (PSL Act), which covers fields within a defined coastal waters area, generally being three nautical miles seaward from the baseline, as well as certain 'subsisting' permit areas located within State inland waters. The State administers a wellhead value royalty system.
- The *Petroleum Resources Rent Tax Assessment Act 1987* applies to all onshore and offshore projects following the amendmentof the Act via a bill in parliament in 2011. The Commonwealth Government administers a resource rent tax, which is effectively aprofit-based tax levied on a project. It replaced a wellhead royalty and excise system.
- The *Petroleum and Geothermal Energy Resources Act 1967* (PGER Act) applies to onshore areas and waters landward of the baseline of the coastal waters, other than 'subsisting' permit areas under the *Petroleum (Submerged Lands) Act 1982* (PSL Act). The State administers a wellhead value royalty system.
- The *Barrow Island Royalty Variation Agreement Act 1982* applies only to Barrow Island. The royalty regime was developed in negotiations between the WAPET consortium, the State and the Commonwealth. It replaced the wellhead royalty and excise system that had previously applied.

Wellhead Royalty

The wellhead value is derived by taking the gross value of petroleum recovered and deducting all costs incurred between a defined valve on the christmas tree and the point of sale. Deductible costs are normally confined to the processing, storage and transport of the petroleum recovered by the producer to the point of sale. All other costs, including costs associated with exploration, drilling, recovery and abandonment are not deductible.

The defined location of the wellhead and the methodology for calculation of wellhead value are usually included in a royalty schedule specific to each producer.

New petroleum projects landward of the outer limit of the coastal waters are subject to either the PSL Act or PGER Act, and in either case, the wellhead royalty regime includes the following elements:

- royalty return;
- royalty rate;
- gross value;
- allowable deductions; and
- deduction limit.

Royalty returns are generally required to be submitted on a monthly basis.

Petroleum Royalty Rates

Royalty rates between 10 and 12.5 per cent of the wellhead value generally apply. The rate applied is dependent upon the type of licence from which the petroleum is produced. A rate of 10 per cent is applied to production from primary production licences, while production from secondary licences attracts a rate of up to 12.5 per cent.

Gross Value

Gross value is the value of petroleum recovered. It includes the value of arms-length sales and the change in stocks of petroleum products. Opening and closing stocks are valued according to the weighted average unit price of the past month's sales.

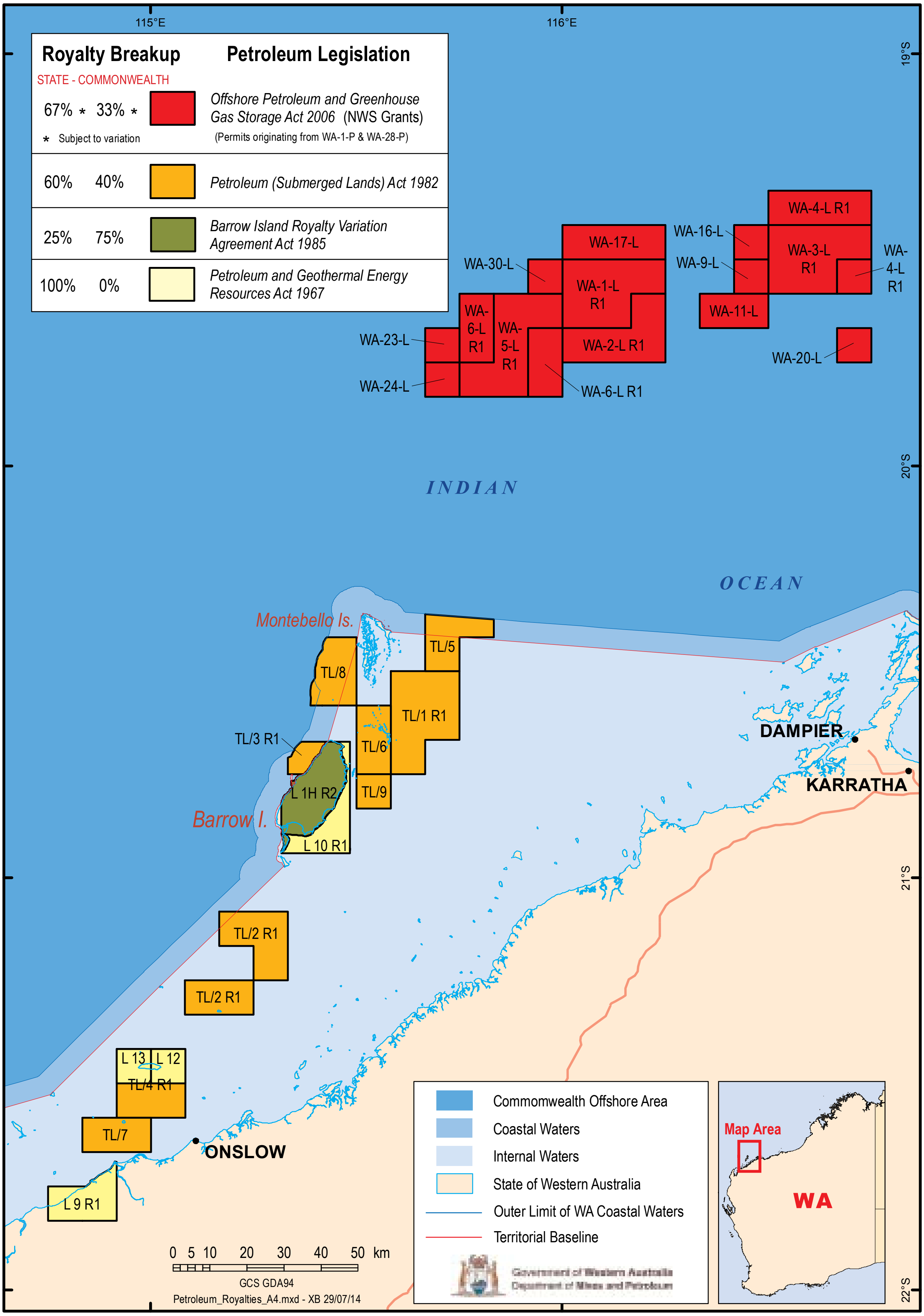


Figure 54. Petroleum royalty collection by legislation

Transactions denominated in foreign currency are converted to Australian dollars based on Reserve Bank of Australia (RBA) mid-rates as published weekly by the RBA and daily in the *Australian Financial Review* newspaper.

Allowable Deductions

Three types of costs are allowed to be deducted against the gross value to determine wellhead value:

- post-wellhead operating costs
- depreciation on commissioned post-wellhead assets
- cost of borrowing on commissioned post-wellhead assets

Post-wellhead Operating and Capital Costs

Usually at the beginning of a petroleum projectexpected operating and capital costs are itemised by a prospective producer. Post-wellhead percentages are then agreed between the State and the producer for each cost item.

Depreciation on Commissioned Post-wellhead Assets

Usually at the beginning of a petroleum project a depreciation calculation is negotiated between the State and the producer and set out in an agreed schedule. A straight-line depreciation calculation normally applies.

Cost of Borrowing on Commissioned Post-wellhead Assets

The wellhead value system allows a producer to deduct from the gross value an amount in recognition of the cost of raising funds related to post-wellhead assets of the project. This amount is calculated from the time each post-wellhead asset is commissioned.

Not all costs of raising funds are allowed. A gearing allowance is determined at the beginning of the project, usually set at a maximum of 50 per cent of the total cost of post-wellhead assets.

The term or write-down period of the deduction is also determined at the beginning of a project and proxies the length of time it will take for the project owners to repay their borrowed funds. A standard interest rate is used instead of the actual interest rates paid for funds by individual project owners. The standard rate is usually the preceding month's five-year term bond rate as published each month by the RBA.

Deduction Limits

Deductible costs can vary up to a limit of 50 per cent of the gross value of production for oil projects or 90 per cent of the gross value of production for gas projects for each royalty period. The choice of the deduction limit is determined by the 'predominant' nature of the project, and may change as a project shifts from a predominantly oil to a predominantly gas project. Any undeducted expenditure is carried forward to the next month.

Resource Rent Royalty

The *Barrow Island Royalty Variation Agreement Act 1982* was agreed between the producer, the State and the Commonwealth governments as an incentive for the continued maintenance of the wells on Barrow Island to ensure optimal oil recovery. The Resource Rent Royalty (RRR) replaced the wellhead royalty and excise system that had previously applied. RRR is a royalty based on a percentage of net cash flow.

The key aspects are as follows:

- all allowable expenditure, both current and capital, is written off when incurred. However, exploration costs incurred more than a year prior to the application of the RRR are not allowable;
- any excess of costs over revenues are carried forward and compounded at a 'threshold' rate;
- any excess income over the threshold rate is charged to RRR at the rate of 40 per cent;
- RRR is a primary tax before income tax, and is deductible against that tax; and
- the revenue is shared 75 per cent to the Commonwealth, 25 per cent to the State. The higher Commonwealth share reflects the far larger proportion of Commonwealth entitlements under the prior royalty and excise regime.

By agreement between the Commonwealth and the State, the State maintains full responsibility for the administration of the RRR regime.

Petroleum Resource Rent Tax

The Petroleum Resource Rent Tax (PRRT) is a secondary tax based on a project's profitability,and applies to all petroleum products froma project (i.e. crude oil, natural gas, LPG condensate but not value added products, such as LNG).

On 2 November 2011, the Commonwealth government introduced the extension to the Petroleum Resource Rent Tax (PRRT) via a bill into parliament with the objective of delivering a fairer return to the Australian community from the extraction of its non-renewable resources. The PRRT regime was extended to all onshore petroleum operations from 1 July 2012. The expanded PRRT regime applies to taxable profits derived from a petroleum project in a financial year and is deductible against income tax. Taxable profit is calculated by deducting eligible project expenditures from the assessable revenue derived from the project. It will cover all Australian onshore and offshore oil and gas projects, including the North West Shelf.

DMP will issue a 'Production Licence Notice' for the purposes of the *Petroleum Resource Rent Tax Assessment Act 1987* on receipt of sufficient information to progress the grant of a Petroleum Production Licence application.

Information about the extension to the petroleum resource rent tax can be found in the *Petroleum Resource Rent Tax Assessment Amendment Bill 2011* and explanatory memoranda on the ATO website. It should be read in conjunction with the *Petroleum Resource Rent Tax Assessment Act 1987* to appreciate the effects of its amendments.

PRRT is a profit based project tax. It is applied at a rate of 40 per cent to a project's taxable profit (project income less project expenditure, project exploration expenditure and exploration expenditure transferred in from other related PRRT projects).

Petroleum projects are generally entitled to deduct exploration expenditure transferred from related projects.

Exploration expenditures that are not deducted in the tax year in which they are incurred can be uplifted and carried forward to be used as deductions in subsequent years.

All project expenditures and payments of PRRT are tax deductible. All State and Commonwealth resource taxes will be creditable against current and future PRRT liabilities from a project.

In the 2007 Budget, the government announced several changes to the petroleum resource rent tax (PRRT) regime. These changes were:

- the introduction of a functional currency rule similar to the rule for income tax. The functional currency rule will allow oil and gas producers to elect to work out their PRRT position in a foreign currency and this will reduce the costs of compliance;
- the introduction of a 'look-back' rule for exploration expenditure. This change will ensure that all exploration expenditure is deductible for PRRT purposes; and
- the removal of an inconsistency in the 'external petroleum' provisions to address the circumstances where two or more petroleum projects are not independent of each other.

This will ensure that a tolling fee received is treated as a PRRT receipt and the expense incurred to process the product is treated as a PRRT deduction.

Through its key features it provides a fiscal regime that encourages the exploration and production of petroleum, while ensuring an appropriate return to the community for the exploitation of these non-renewable resources.

In 2011-12, PRRT collections were over A$1.46 billion, of which 51 per cent relates to collections from Western Australian projects.

FINANCIAL CONSIDERATIONS

Commonwealth Crude Oil and Condensate Excise

The Commonwealth Government applies the crude oil and condensate excise to eligible crude oil and condensate production from the North West Shelf Project Area (originating from Exploration Permits WA-1-P and WA-28-P) in Commonwealth waters, coastal waters andonshore areas. The Government has removed the exemption of condensate from the Crude Oil Excise.

Under the arrangements, all condensate production from petroleum fields located in the North West Shelf Project Area and onshore Australia will be subject to the Crude Oil Excise. This excise is levied as a percentage of the value of crude oil produced from a petroleum field. Condensate will be subject to the same excise rates as crude oil from petroleum fields discovered after 18 September 1975. Under these arrangements, the top Crude Oil Excise rate (which applies once annual production reaches just over 795 ML (5 MMbbl) in a year) is 30 per cent.

Excise liability is worked out by applying the relevant crude oil and condensate excise rate to the volume-weighted average of realised free onboard price (VOLWARE price). The first 4,769,618 kL (or 30 MMbbl) of crude oil/ condensate produced from a field is excise exempt. Past production of condensate from a petroleum field will contribute towards meeting this threshold before the Crude Oil Excise becomes payable.

As part of this measure, the Commonwealth Government will provide the Western Australian Government with ongoing compensation for the loss of shared Offshore Petroleum Royalty revenue resulting from imposing the Crude Oil Excise on condensate. This arises because Crude Oil Excise payments are a deductible expense for calculating the Offshore Petroleum Royalty.

This measure has an ongoing net revenue gain of an estimated A$2.5 billion over the forward estimates period, partly offset by an increase in net outlays of A$69.6 million over the same period. It took effect from 13 May 2008.

The crude oil classifications and top marginal excise rates, following amendments to the *Excise Tariff Act 1921* passed in September 2001 are:

- 'Old' oil is crude oil discovered before 18 September 1975.
- 'Old' oil is excised on a progressive scale with a top marginal rate of 55 per cent of the VOLWARE price.
- 'New' oil is crude oil discovered after 18 September 1975.
- 'New' oil is excised on a progressive scale with a top marginal excise rate of 30 per cent.
- 'Intermediate scale' oil is crude oil from fields discovered before 18 September 1975 but not developed before 23 October 1984.
- 'Intermediate scale' oil is excised on a progressive scale with a top marginal rate of 55 per cent.

Royalty Formula

With minor exceptions, the system of land allocation in Western Australia retains Crown ownership of the minerals and petroleum contained in the ground. When title to these resources is transferred to developers, the State expects a return to the community for the loss of the resource. This return to the community for the transfer or sale of the resource is referred to as a royalty.

State royalties are calculated using a gross value *(ad valorem)* system where royalty is paid as a proportion of the value of the petroleum recovered. The point of valuation for the petroleum (the wellhead) reflects the underlying philosophy of mineral royalties, which were based on ex-mine value. Given that petroleum is not generally sold at the wellhead, a method of deduction has been developed which subtracts the costs incurred between the wellhead and the actual point of sale.

These costs are in respect of the processing, transport and storage of the petroleum and are known as post-wellhead costs. Post-wellhead costs can include:

- freight from the point of valuation to the point of sale;
- operating costs between the wellhead and the point of valuation;
- the value of approved fuel used;
- allowance for overheads and depreciation of post-wellhead capital assets situated within the production unit; and
- allowance for interest on approved post-wellhead capital assets.

Pre-wellhead costs are those incurred as a result of exploration, drilling or recovery activities and these are not deductible for royalty purposes. *Ad valorem* royalties do not meet all objectives of an ideal royalty system since, being based on net revenue post-wellhead, they fail to account for variations between projects in the cost of petroleum recovery prior to the wellhead.

They also involve some degree of arbitrary decision-making in the assignment of costs into pre and post-wellhead components. However, the present wellhead system is widely accepted, reasonably easy to administer for both companies and the Government, and provides a reasonably stable revenue flow.

Summary of Royalty Provisions

Royalty is payable at a rate of 10 to 12.5 per cent of the post-wellhead value of petroleum recovered at the wellhead(s).

The wellhead, in respect of each well, is the exit port of the downstream flange of the first wing valve immediately downstream of the christmas tree.

The wellhead value of petroleum recovered is calculated by deducting, from the arm's-length gross value of the petroleum, post-wellhead costs as agreed or determined.

"Gross value" means the aggregate of the value of all sales products sold, transferred or otherwise disposed of during the period; and the value of the closing inventory of petroleum for that period less the value of the closing inventory for the preceding period.

"Post-wellhead costs" include such operating and capital costs that are incurred during the royalty period and are directly associated with the processing, transportation and storage of the petroleum product(s).

Capital expenditure relating to post-wellhead activities is depreciated on a straight line basis over the life of the field. The straight line method is applied for ease of calculation but may be revised should the field production curve warrant an accelerated rate of depreciation. This would apply where proven reserves were depleted at a greater rate than initially anticipated, hence reducing the overall field life.

Sales revenue in foreign currency is generally translated to Australian dollars using the mid-rate published by the RBA on the date of receipt. Where sales are made during a royalty period but no revenue is received, the mid-rate applicable on the 20th day of the month following shipment is provisionally applied and an adjustment is made upon receipt of the funds.

The maximum deduction that can be claimed against the gross revenue in any royalty period is limited to 50 per cent of that gross revenue for an oil project, and 90 per cent for a gas project. Deduction in excess of these ceilings may be carried forward indefinitely without any adjustment for inflation.

Royalty Reporting Requirements

The holder of a Petroleum Production Licence is required to submit, on a monthly basis, a combined production report and royalty return.

Monthly Production Report

Within 15 days of the expiry of each month, the licence holder is required to submit a production report that shows for the preceding calendar month, the total of:

- liquid and gaseous petroleum, and water produced;

- liquid and gaseous petroleum used;
- gaseous petroleum flared or vented;
- liquid and gaseous petroleum, and water injected;
- liquid petroleum stored;
- liquid and gaseous petroleum delivered from the area; and
- the cumulative quantities of liquid and gaseous petroleum, and water, produced or injected, as at the end of the month.

Royalty Return

Wellhead royalty returns and payments are due on the last working day of each calendar month, following the month of production, and penalties apply for late payment. The returns include details of sale revenue, stock movements and allowable deductions related to the relevant month.

Records

Records need to be maintained to give a true and complete indication of:

- the quantity of the petroleum product
- any sale of the petroleum product
- all costs associated with the sale of the petroleum product

All records must be kept for a period of seven years.

Access to Records

All source documents must be made available for inspection to substantiate royalty returns.

Royalty Rate for Geothermal Energy

A royalty calculated at 2.5 per cent of the royalty value of the geothermal energy will be payable under the legislation. This reflects the renewable energy status of geothermal resources and will be competitive with that of South Australia's royalty rate, also 2.5 per cent. It is likely that geothermal energy will be sold based on the value per energy unit (Gigajoule – GJ). This is similar to gas production, which is also based on energy (GJ) sold.

The royalty value is generally the wellhead value, which is defined as the value of the geothermal energy at the valve station, as agreed or, in default of agreement within such period as the Minister allows, the valve station as determined by the Minister as being the wellhead.

The value of the geothermal energy at the wellhead is not defined under the legislation and is established through a separate arrangement based on established principles, as is currently the case for petroleum projects. The wellhead value is calculated by subtracting post-wellhead costs from the gross value of all geothermal energy produced during the royalty period.

The post-wellhead costs are costs of processing, storage and transporting the geothermal energy. Costs that are not deductible are those of exploration, drilling and recovering the geothermal energy. The Government plans to place all geothermal royalties in a low emissions fund that will be used for specific low emission projects.

Other Financial Considerations

Taxation Regime

The Australian taxation regime is among the most competitive in the world for the petroleum industry. Australian income tax law provides specific concessions for petroleum production. Exploration expenditures are deductible immediately. Special provisions also allow certain capital expenditures to be written off progressively. Exploration expenditures and the special deductions for certain capital expenditures are deductible from income derived from any source and can be transferred to another company, with 100 per cent common ownership, via group loss transfer provisions. Under Australian corporate and taxation laws, there are no property taxes, nor production, severance, export or windfall profit taxes.

Allowable capital expenditure for which the special deductions are given is capital expenditure incurred in carrying on mining operations for the purpose of obtaining petroleum, which includes gas. It also includes spending on buildings and improvements necessary for the petroleum operations.

For example, tax deductions could apply to:

- exploration and operating costs, such as acquiring petroleum prospecting rights or information from another person, cash bids paid for the granting of Exploration Permits and Production Licences;
- provision of housing, welfare and services facilities for employees and their families at, or adjacent to, the production site;
- the provision of services on, or access to, or communications with, the site;
- royalty payments;
- depreciation of plant and equipment;
- depreciation of transport equipment; and
- liquefaction plant for natural gas obtained from the taxpayer's petroleum operations.

Depreciation is generally on a straight line basis over the lesser of 10 years or field life. Investors in petroleum exploration and development in Australia are advised to seek professional advice on how the Australian taxation system will affect their particular projects.

The Australian Taxation Office (ATO) provides detailed taxation information for companies and individuals on their website (www.ato.gov. au), covering such topics as income tax, double taxation agreements, foreign tax credits, dividend withholding tax exemption for foreign source dividend income, fringe benefits tax, capital gains tax, carbon tax and more.

Information on payroll tax can be obtained from the Western Australian Department of Treasury www.treasury.wa.gov.au.

Companies seeking information on the Commonwealth Government's foreign investment policy should consult the Foreign Investment Review Board's website www.firb.gov.au.

Loading Ungani oil onto tankers, Canning Basin (Photo courtesy of Buru Energy)

Road train trucking oil to the Port of Wyndham from the Ungani oilfield (Photo courtesy of Buru Energy)

ABOUT PERTH AND WESTERN AUSTRALIA

General Information

Western Australia covers an area of over 2.5 million km^2. Perth is the capital city of Western Australia, the nation's fastest growing State. It is the largest city in Western Australia with an estimated population of 1.97 million, in a State of 2.5 million people (source ABS, June 2013). Perth's growth and relative prosperity has resulted from its role as the main service centre for the State's resource industries, which produce gold, iron ore, nickel, alumina, diamonds, mineral sands, coal, oil, and natural gas. Whilst most mineral and petroleum production takes place elsewhere in the State, the non-base services provide most of the employment and income to the people of Perth.

The city is modern and its lifestyle has a great reputation; its many advantages include a beautiful riverside setting and sandy beaches along the coast; a Mediterranean-style climate with clear blue skies most of the year; abundant parklands, recreational and sporting facilities; quality housing in attractive low-rise suburbs; and numerous restaurants and a wide range of cultural facilities.

Western Australia is an important service centre for the oil and gas sector in both Australia and South East Asia. Major international companies have relocated their regional operations and administrative bases to Perth, and have joined with innovative local firms in providing a comprehensive supply and service capacity. Engineering and fabrication facilities support the regional mining and petroleum industries, both offshore and onshore.

In 2013, the total number of employees in Western Australia's petroleum industry for areas under State legislation (onshore and coastal waters) was 2066 persons. This figure includes employees as well as contractors for petroleum facilities and pipelines but does not cover LNG and land base service facilities (DMP, 2013). Perth hosts the largest concentration of oil and gas professionals in the region, including geoscientists, engineers, occupational health and safety and environmental specialists, investment bankers, and legal advisers. Educational and training facilities, coupled with government and private research organisations, make Western Australia a recognised leader in supplying oil and gas specialists. Many of these disciplines also benefit the geothermal energy industry and will greatly assist the exploration for geothermal resources in Western Australia.

The development of Western Australia's multibillion LNG industry has seen local companies meet exacting engineering standards required for:

- offshore construction;
- repairs and maintenance;
- replacement parts; and
- sophisticated componentry.

Exploration and information analysis services and advanced software development are also available.

Perth is the leading centre for the Australian upstream petroleum industry, as Western Australia continues to be the prime focus for oil and gas exploration. The shift in the national oil industry focus to Australia's northwest has ensured a continuing presence of oil and gas infrastructure and services including engineering, transport and communications. BP runs Western Australia's only oil refinery, in Kwinana, 38 km south of Perth's central business district (CBD).

An excellent network exists to provide information and support to explorers and producers in the petroleum industry. A number of professional societies have regular meetings in Perth; these include the Petroleum Exploration Society of Australia (PESA), which held its fifth Western Australian Basins Symposium (WABS) in Perth in August 2013. Other societies regularly meeting in Perth include the Formation Evaluation Society of Australia (FESAus), the Society of Petroleum Engineers (SPE), the Australian Society of Exploration Geophysicists (ASEG) and the Petroleum Club of Western Australia. The Australian Petroleum Consultants Association has an office in Perth and the Australian Petroleum Production & Exploration Association Ltd (APPEA), the national body representing Australia's oil and gas exploration and production industry, is also represented in Perth.

APPEA's membership includes most of the key players involved in oil and gas exploration and production in Australia. APPEA produces a variety of publications dealing with all aspects of the petroleum industry. The APPEA Conference and Exhibition is the largest annual petroleum industry gathering in Australia, bringing together explorers, producers, service providers, decision-makers and the latest technology. It is usually held in the second half of the financial year between March and May, in different capital and major cities throughout Australia.

The geothermal industry is represented by the Australian Geothermal Energy Group (AGEG). At the University of Western Australia, the Western Australian Geothermal Centre of Excellence brings together researchers, industry, investors and government agencies. The Western Australian Energy Research Alliance (WA:ERA) is also based in Perth.

Transport

Western Australia has a modern transportation network in which road, rail, sea and airfreight are coordinated to ensure fast and easy access to national and international markets. However much of this infrastructure is concentrated along the western coastline of the State. There are approximately 164,696 km of roads, of which declared highways and main roads comprise 18,594 km (source MainRoads WA). Western Australian Ports Authority ports are found at Broome, Port Hedland, Dampier, Geraldton, Fremantle, Bunbury, Albany and Esperance.

The Port of Fremantle, a 30 minute drive from Perth's CBD, is a modern deepwater port. The State's network of seaports also includes ports in Wyndham, Derby, Port Walcott, Cape Preston, Ashburton North, Cape Cuvier, Useless Loop, Onslow, Kwinana and on Varanus, Thevenard, Barrow and Airlie Islands. Perth's international and domestic airports are 20 minutes from the CBD. International airports are also located at Port Hedland and Broome. There are another 28 regional airports and many other smaller airports spread throughout the State.

Economy

The resources industry is the largest contributor to the Western Australian economy, representing around 37 per cent of the Gross State Product for 2011–12 (DMP). There is currently A$190 billion worth of petroleum resource and infrastructure projects under construction or being considered.

Western Australia's internationally recognised oil and gas industry is the leading petroleum producer in Australia. Western Australia accounts for approximately 57 per cent of Australia's total value of mineral and petroleum sales. The State also has 48 per cent of Australia's total merchandise exports. Petroleum exploration expenditures reached a record A$2.98 billion in 2013 or 66 per cent of Australian petroleum exploration funding.

Business

A growing number of international businesses are selecting Perth, Western Australia as the location for their Southeast Asian regional operations. Foremost among these are companies servicing the minerals and energy industries. This is not surprising, considering Western Australia boasts petroleum and gas production worth A$24.7 billion as part of a A$113.8 billion resources sector in 2013.

Business advantages of Perth include:

- proximity to growing Southeast Asian economies;
- easy, reliable and cost-effective telecommunications links;
- lower business costs compared with neighbouring countries;
- highly skilled, well-educated workforce — almost half have post-secondary or tertiary qualifications. Local universities provide a full spectrum of courses including petroleum geology, geophysics and engineering;
- all the equipment, materials and services required to run an internationally competitive business — from manufacturing to value-adding service centres to knowledge-based industries.

The innovative and efficient manufacturing and service firms that support these sectors can also make ideal partners in regional expansion strategies. Western Australia offers industry access to modern telecommunications, efficient transportation and ports, reliable energy and water supplies and high living standards.

ABOUT PERTH AND WESTERN AUSTRALIA

Australia is known for its political and economic stability, but Western Australia is also located in the world's fastest growing and developing economic region, the Asia Pacific and Indian Ocean rim.

Western Australia continues to rank highly in international surveys as a destination for exploration ventures. Low sovereign risk and the fiscal and legislative regime, combined with the success of offshore exploration have made Western Australia an attractive place to explore for petroleum.

Establishment and Operating Costs

Overseas investors seeking to explore for petroleum in Australia do not need to seek Australian participation, although a local company may provide valuable local experience for foreign investors.

Exploration costs can be relatively high because of the lack of established supply and service companies in remote or rural areas, although the level of supply is increasing. To aid in the cost of exploring in remote areas, the State Government introduced the Exploration Incentive Scheme in 2009, funded by Royalties for Regions over five years to encourage onshore exploration in Western Australia for the long-term sustainability of the State's resources sector. The program is focussed in underexplored minerals, greenfields regions and frontier petroleum basins. Initially the government committed A$80 million towards the program. Phase two has now been boosted by an additional A$37.5 million over two years from 2014–15. The program covers the following activities: exploration and environmental coordination, innovative drilling, geophysical and geochemical surveys, 3D geological mapping, promoting strategic research within industry and encouraging sustainable working relations with Indigenous communities. Phase 1 co-funded the seismic survey near Harvey that located the first drill hole to test the CO_2 storage potential of the Perth Basin and partially funded the Harvey 1 well in early 2012.

The high costs and risk associated with venturing into exploration in Western Australia are more than compensated for by the potential returns.

The Western Australian Government is keen to facilitate projects undertaken by those interested in pursuing petroleum and geothermal energy exploration opportunities in Western Australia.

Markets

Western Australia is strategically positioned in a region that currently accounts for more than 40 per cent of the growth in total world demand for oil and gas. Companies will find the State an ideal location for an Australasian regional headquarters, as Western Australia shares a similar time zone with most countries in the Asian region and Perth is geographically closer to Asia than to Australia's other major cities.

Oil and Gas

A free market was introduced in 1988 for all oil and condensate produced in Australia. There is no restriction on imports or exports of crude oil or refined petroleum products. A similar regime has applied since 1991 for LPG. Western Australia exports most of the crude oil and condensate that is produced from offshore production facilities, with Asia the primary customer. Oil for domestic consumption is refined at Kwinana, south of Perth. Gas is piped into the growing domestic market or shipped overseas as LNG or LPG. Gas is used for power generation and industry throughout the Pilbara and Goldfields mining projects. Power generation spans a range of applications, from single purpose mine sites to supplying grid power to major population centres.

Supply and Demand

In 2013, the State's petroleum industry made up 22 per cent of Western Australia's total value of mineral and petroleum sales. Crude and condensate made up 38 per cent of the total petroleum sales, whilst LNG accounted for 54 per cent. LNG also made up 83 per cent of Australian exports. LNG produced in Western Australia actually comprises 9 per cent of worldwide LNG production, and is forecast to grow in the near future. Growth will come from increased demand from Asia and supply from new projects including Woodside Energy's Pluto LNG project, which commenced production in March 2012.

Approximately 95 per cent (by value) of the State's petroleum products were exported in 2013. The major destinations for crude oil and condensate export were Japan (12 per cent), China (21 per cent), South Korea (20 per cent), Singapore (15 per cent), and Thailand (10 per cent) (Figure 55). LNG was exported mainly to Japan, China and the Republic of Korea. Petroleum sales were valued at a record A$24.7 billion in 2013, with crude oil sales worth A$5.2 billion, and LNG and condensate sales during this period worth A$19.2 billion and A$4.1 billion respectively (Figure 56). The majority of this production was derived from the Northern Carnarvon Basin, on the North West Shelf. Production is forecast to grow in the period ahead due to increased demand from Asia and supply from new projects including Wheatstone and Gorgon, while crude oil output is continuing its downward trend due to maturing fields.

Western Australia currently consumes around 1000 terajoules per day (TJ/d) of domestic gas (Domgas Alliance, 2013). Of this, around 54 per cent is supplied by the North West Shelf Project with the remaining domestic supply coming from the Apache-led joint ventures and the Perth Basin (DMP, 2013). Projections for domestic gas demand in Western Australia indicate between a 30 per cent to 70 per cent increase in demand during the next ten years. The majority of this increase in demand is expected to come from commercial and industrial clients.

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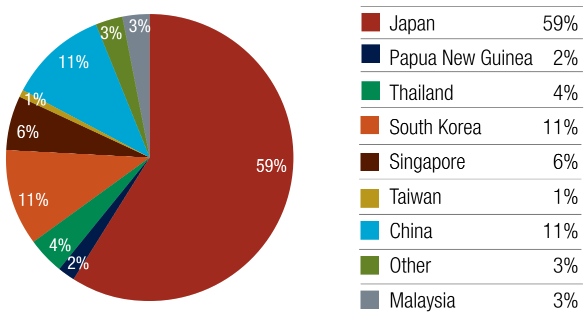

Figure 55. Top export destinations for Western Australian petroleum 2013

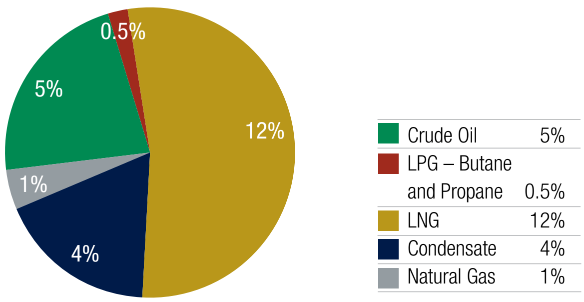

Figure 56. Petroleum sales by product Western Australia 2013

APPENDIX 1
LIST OF ABBREVIATIONS

2D	two dimensional (i.e. seismic)
3D	three dimensional (i.e. seismic)
AA	Access Authority
A$	Australian Dollar
AAPA Act	*Aboriginal Affairs Planning Authority Act 1972* (Western Australia)
ABS	Australian Bureau of Statistics
ACMC	Aboriginal Cultural Material Committee
AH Act	*Aboriginal Heritage Act 1972* (Western Australia)
AIMS	asset integrity management system
ALARP	as low as reasonably practical
ALT	Aboriginal Lands Trust
AMPOL	Australian Motorists Petrol Company
APPEA	Australian Petroleum Production and Exploration Association Ltd
AGEG	Australian Geothermal Energy Group
ASEG	Australian Society of Exploration Geophysicists
ATO	Australian Taxation Office
ATSHIP Act	*Aboriginal and Torres Strait Islander Heritage Protection Act 1984* (Commonwealth)
AWE	Australian Worldwide Energy
bbl	barrels of oil or condensate
BCGA	basin centred gas accumulation
BHT	bottomhole temperature
BMR	Bureau of Mineral Resources, now Geoscience Australia
CALM Act	*Conservation and Land Management Act 1984* (Western Australia)
CATSI Act	*Corporations (Aboriginal and Torres Strait Islander) Act 2006* (Commonwealth)
CBD	Central Business District
CCS	carbon capture and storage
CCWA	Conservation Commission of Western Australia
CEO	Chief Executive Officer
cf	cubic feet
CO_2	carbon dioxide (often written CO2)
congl.	conglomerate
CSG	coal seam gas
CSIRO	Commonwealth Scientific and Industrial Research Organisation
Cwth	Commonwealth
DAA	Department of Aboriginal Affairs (Western Australia)
DBNGP	Dongara to Bunbury Natural Gas Pipeline
DDR	daily drilling report
DER	Department of Environment Regulation (Western Australia)
DMP	Department of Mines and Petroleum (Western Australia)
DoD	Department of Defence (Western Australia)
DoE	Department of the Environment (Commonwealth)
DoF	Department of Fisheries (Western Australia)
DoI	Department of Industry (Commonwealth)
DoT	Department of Transport (Western Australia)
DoW	Department of Water (Western Australia)
DPaW	Department of Parks and Wildlife (Western Australia)
DST	drillstem test
DR	Drilling Reservation
EARS	Environmental Assessment and Regulatory System
EIA	Environmental Impact Assessment
EIA	Energy Information Administration (United States)
EP Act	*Environmental Protection Act 1986* (Western Australia)
EP	Environmental Plan (in Environment chapter)
EP	Petroleum Exploration Permit (in title context)
EPA	Environmental Protection Authority (Western Australia)
EPBC Act	*Environmental Protection and Biodiversity Conservation Act 1999* (Commonwealth)
EPT	extended production test
Esso	Eastern States Standard Oil
FESAus	Formation Evaluation Society of Australia
FID	Final Investment Decision
FMP	Field Management Plan
FPSO	Floating Production, Storage and Offloading Facility
GA	Geoscience Australia
GAA	Geothermal Access Authority
GDR	Geothermal Drilling Reservation
GEP	Geothermal Exploration Permit
GGT	Goldfields Gas Transmission
GHG	greenhouse gas
GJV	Gorgon Joint Venture
GL	Geothermal Production Licence
GRL	Geothermal Retention Lease
GSPA / AO	Geothermal Special Prospecting Authority with Acreage Option
GSWA	Geological Survey of Western Australia
HA	hot aquifer
HDR	hot dry rock
IL	Infrastructure Licence
ILUA	Indigenous Land Use Agreement
IRCM	Irwin River Coal Measures
J	joule (eg PJ – petajoule; TJ – terajoule)
JA	Joint Authority
JNOC	Japanese National Oil Company
km	kilometres
km^2	square kilometres
L	Petroleum Production Licence
LA Act	*Land Administration Act 1997* (Western Australia)
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
lst	limestone
m	metres
Mbr	Member
MoSOF	*Management of Safety on Offshore Facilities* (Regulations)
MoU	Memorandum of Understanding
Mtpa	million tonnes per annum
NES	National Environmental Significance
Nm	nautical mile
NNTT	National Native Title Tribunal
NOPSEMA	National Offshore Petroleum Safety and Environmental Management Authority
NOPTA	National Offshore Petroleum Titles Administrator
NT	Northern Territory
NT Act	Native Title Act 1993 (Commonwealth)
NTRB	Native Title Representative Bodies
NWSJV	North West Shelf Joint Venture
OSCP	Oil Spill Contingency Plan
OSH	Occupational Safety and Health
OPGGS Act	*Offshore Petroleum and Greenhouse Gas Storage Act 2006* (Commonwealth)
ORB	Offshore Resources Branch (Commonwealth)
ORC	Organic Rankine Cycle
PBC	prescribed body corporate
PEPL	Pilbara Energy Pipeline
PER	Public Environmental Review
PESA	Petroleum Exploration Society of Australia
PGER Act	*Petroleum and Geothermal Energy Resources Act 1967* (Western Australia)
PGP	Parmelia Gas Pipeline
PGR	Petroleum and Geothermal Register
PL	Petroleum Pipeline Licence
PMP	Pipeline Management Plan
PP Act	*Petroleum Pipelines Act 1969* (Western Australia)
PRRT	Petroleum Resource Rent Tax
PSL Act	*Petroleum (Submerged Lands) Act 1982* (Western Australia)
PSMP	Pipeline Safety Management Plan
PTLAB	Petroleum Tenure and Land Access Branch
RBA	Reserve Bank of Australia
RNTBC	Registered Native Title Body Corporate
RL	Retention Lease
RRR	Resource Rent Royalty
RSD	Resources Safety Division
SC	Safety Case
SMS	Safety Management System
SPA/AO	Special Prospecting Authority with Acreage Option
SPE	Society of Petroleum Engineers
sltst	siltstone
sst	sandstone
t	tonne
TOC	total organic carbon
TP	technical paper
TSB	territorial sea baseline
US	United States
VOLWARE	volume-weighted average of realised free onboard price
W	watt (i.e. kW, MW)
WA	Western Australia
WABS	Western Australian Basins Symposium
WA:ERA	Western Australian Energy Research Alliance
WAFIC	Western Australian Fishing Industry Council
WANG	West Australian Natural Gas (pipeline)
WAPET	West Australian Petroleum Pty Ltd
WAPIMS	Western Australian Petroleum and Geothermal Information Management System
WMP	Well Management Plan
WOMP	Well Operations Management Plan

APPENDIX 2
UNITS AND CONVERSIONS

SI units are the sole legal units of measurement in Australia.

1 kilolitre (kL) = 6.289811 barrels (bbl)

1 barrel (bbl) = 0.158987 kilolitres (kL), 42 US gallons, or 35 Imperial gallons

1 standard cubic metre (m3) = 35.3147 cubic feet (cf) [1 kilolitre (kL) = 1 cubic metre (m^3)]

1 billion cubic feet (Bcf) of natural gas = 750,000 tonnes (t) of LNG

1 terrajoule (TJ) per day = 26,300 cubic metres (m^3) per day = 0.929 million cubic feet (Mcf) per day

1 metric tonne (t) of LNG = 1333 cubic metres (m^3) of natural gas at 0˚C

1 million tonnes (Mt) of LNG per year = 1.333 billion cubic metres (Gm^3) per year = 3.65 million cubic metres (Mm^3) of natural gas per day

Prefixes – metric	**Prefixes – imperial**	
kilo (k) 10^3	thousand (M)	/d = per day
mega (M) 10^6	million (MM)	/h = per hour
giga (G) 10^9	billion (B)	/a = per year
tera (T) 10^{12}	trillion (T)	
peta (P) 10^{15}		

APPENDIX 3
GLOSSARY OF SELECTED TERMS

Coastal waters: The area between the territorial sea baseline (generally situated at the lowest astronomical tide line along the coast) and the line that is three nautical miles seaward of the territorial sea baseline as well as any waters landward of the baseline that are outside the limits of the States and the Northern Territory.

Commonwealth waters: The area between the outer limit of the coastal waters (three nautical miles from the territorial sea baseline) and the outer limit of the continental shelf.

Continental Shelf: The area extending from the outer limit of the territorial sea (12 nautical miles from the territorial sea baseline) for up to 200 nautical miles from the territorial sea baseline (subject to boundary delimitations with other countries). It can extend further if the physical continental shelf continues beyond 200 nautical miles in accordance with the United Nations Convention on the Law of the Sea.

Exclusive Economic Zone (EEZ): The area extending from the outer limit of the territorial sea (12 nautical miles from the territorial sea baseline) for up to 200 nautical miles from the territorial sea baseline (subject to boundary delimitations with other countries).

Hydraulic Fracture Stimulation: Also known as 'fraccing', it is a process that pumps fluids and other materials — 'proppants', typically sand or ceramic beads — under high pressure into wells to create fractures in the rock formations, increasing the flow of and extraction of gas reserves. When the pressure is reduced, the fraccing fluid flows back to the surface, but the proppants remain in place to hold the fractures open. This allows gas trapped in rock formations to be accessed and extracted faster. After flow back to the surface, carrying fluids are treated or disposed of in accordance with approved environmental procedures.

Joint Authority (JA): The Joint Authority of an offshore area of a State is constituted by the responsible State or Territory Minister and the responsible Commonwealth Minister. The term JA may also be used singularly to describe the Commonwealth or State member where those members are undertaking their role in that capacity.

Offshore area: The area extending seaward from the low tide mark on the coastline to the outer limit of the continental shelf. That is, it includes Commonwealth waters, coastal waters and some internal waters. (For the purposes of the *Offshore Petroleum and Greenhouse Gas Storage Act 2006* (Cwth), the offshore area is defined as Commonwealth waters only.)

Onshore area: The area within the limits of a State or Territory including internal waters that is landward of the low tide mark, such as rivers and creeks.

Territorial sea: The area between the territorial sea baseline and the line that is 12 nautical miles seaward of the territorial sea baseline.

Territorial sea baseline: Generally is the line of lowest astronomical tide along the coast, but it also encompasses straight lines across bays (bay closing lines), rivers (river closing lines) and between islands, as well as along heavily indented areas of coastline (straight baselines) under certain circumstances.

APPENDIX 4
FURTHER INFORMATION

Websites

Western Australian Government Websites

Department of Mines and Petroleum
www.dmp.wa.gov.au

Department of Commerce
www.commerce.wa.gov.au

Department of State Development
www.dsd.wa.gov.au

Environmental Protection Authority
www.epa.wa.gov.au

Australian Government Websites

Australian Commonwealth Law
www.comlaw.gov.au

Australian Taxation Office
www.ato.gov.au

Department of Industry
www.industry.gov.au

Department of the Environment
www.environment.gov.au

Geoscience Australia
www.ga.gov.au

National Offshore Petroleum Safety and Environmental Management Authority (NOPSEMA)
www.nopsema.gov.au

National Offshore Petroleum Titles Administrator
www.nopta.gov.au

Industry Associations Represented in Western Australia include:

Australian Geothermal Energy Group (AGEG)

Australian Petroleum Production & Exploration Association (APPEA)

Australian Society of Exploration Geophysicists (ASEG)

Formation Evaluation Society of Australia (FESAus)

Petroleum Club of WA (PCWA)

Petroleum Exploration Society of Australia (PESA)

Society of Petroleum Engineers (SPE)

Western Australian Energy Research Alliance (WA:ERA)

Companies with Interests in Western Australia's Onshore and State Waters Petroleum Permits and Pipelines as at August 2014 include:

- Admiral Oil NL
- Advent Energy Ltd
- Alcoa of Australia Limited
- Alinta DEWAP Pty Ltd
- Allied Oil & Gas Plc
- APA (Pilbara Pipeline) Pty Ltd
- APA (WA) ONE Pty Limited
- Apache East Spar Pty Ltd
- Apache Julimar Pty Ltd
- Apache Kersail Pty Ltd
- Apache Northwest Pty Ltd
- Apache Oil Australia Pty Ltd
- Apache PVG Pty Ltd
- APT Parmelia Pty Ltd
- APT Pipelines (WA) Pty Limited
- ARC Energy Limited
- ARC Energy Pty Limited
- ATCO Gas Australia Pty Ltd
- Australia Zhongfu Oil Gas Resources Pty Ltd
- Australian Gold Reagents Pty Ltd
- Australian Oil Company No 3 Pty Limited
- Australian Pipeline Limited
- AWE (Beharra Springs) Pty Ltd
- AWE (Offshore PB) Limited
- AWE Oil (Western Australia) Pty Ltd
- AWE Oil Perth Pty Ltd
- Backreef Oil Pty Limited
- BHP Billiton Petroleum (Australia) Pty Ltd
- BHP Billiton Petroleum (North West Shelf) Pty Ltd
- Bharat PetroResources Limited
- Bounty Oil & Gas NL
- Bow Energy Pty Ltd
- BP Developments Australia Pty Ltd
- Buru Energy (Acacia) Pty Ltd
- Buru Energy Limited
- Buru Fitzroy Limited
- CalEnergy Resources (Australia) Pty Limited
- Caracal Exploration Pty Ltd
- Carnarvon Petroleum
- Chevron (TAPL) Pty Ltd
- Chevron Australia Pty Ltd
- Chubu Electric Power Gorgon Pty Ltd
- ConocoPhillips Australia Pty Ltd
- ConocoPhillips (Canning Basin) Pty Ltd
- Crosslands Resources Ltd
- Dalrymple Resources Pty Ltd
- DBNGP (WA) Nominees Pty Limited
- DBNGP (WA) Transmission Pty Limited
- DBP Development Group Nominees Pty Limited
- DDG Fortescue River Pty Ltd
- Diamond Resources (Canning) Pty Ltd
- Diamond Resources (Fitzroy) Pty Ltd
- Dynasty Metals Australia Ltd
- EDL LNG (WA) Pty Ltd
- EDL NGD (WA) Pty Ltd
- EII Gas Transmission Services WA (Operations) Pty Ltd
- EIT Neerabup Power Pty Ltd
- Empire Oil Company (WA) Limited
- Energetica Resources Pty Ltd
- Energy Generation Pty Ltd
- ERM Gas Pty Ltd
- ERM Neerabup Pty Ltd
- Esperance Pipeline Co. Pty Limited
- Exceed Energy (Australia) Pty Ltd
- Falcore Pty Ltd
- FAR Ltd
- Finder No 3 Pty Limited
- GCC Methane Pty Ltd
- Geary, John Kevin
- Global Advanced Metals Wodgina Pty Ltd
- Goshawk Energy (Lennard Shelf) Pty Ltd
- Gulliver Productions Pty Ltd
- Hamersly Iron Pty Ltd
- Harriet (Onyx) Pty Ltd
- Hess Australia (Canning) Pty Limited
- Hydra Energy (WA) Pty Ltd
- Inpex Alpha, Ltd
- Indigo Oil Pty Ltd
- Japan Australia LNG (MIMI) Pty Ltd
- Japan Australia LNG (MIMI Browse) Pty Ltd
- Jurassica Oil & Gas Plc
- Kansai Electric Power Australia Pty Ltd
- Key Petroleum (Australia) Pty Ltd
- Kufpec Australia Pty Ltd
- Kufpec Australia (Julimar) Pty Ltd
- Kyushu Electric Wheatstone Pty Ltd
- Latent Petroleum Pty Ltd
- Lansvale Oil & Gas Pty Ltd
- Longreach Oil Limited
- Mitsui Iron Ore Development Pty Ltd
- Mobil Australia Resources Company Pty Limited
- Mobil Exploration & Producing Australia Pty Ltd

APPENDIX 4
FURTHER INFORMATION

- New Standard Onshore Pty Ltd
- Newmont Yandal Operations Pty Ltd
- Nippon Steel & Sumikin Resources Australia Pty Ltd
- Nippon Steel & Sumitomo Metal Australia Pty Ltd
- Norilsk Nickel Cawse Pty Ltd
- Norilsk Nickel Wildara Pty Ltd
- North Mining Limited
- Northern Star Resources Ltd
- Norwest Energy NL
- Officer Petroleum Pty Ltd
- Oil Basins Limited
- OMV Australia Pty Ltd
- Onshore Energy Pty Ltd
- Origin Energy Developments Pty Limited
- Origin Energy Pipelines Pty Limited
- Osaka Gas Australia Pty Ltd
- Osaka Gas Gorgon Pty Ltd
- Palatine Energy Pty Ltd
- Pace Petroleum Pty Ltd
- Pancontinental Oil & Gas NL
- PE Wheatstone Pty Ltd
- Perseverance Energy Pty Ltd
- PetroChina International Investment (Australia) Pty Ltd
- Phoenix Resources PLC
- Plutonic Operations Limited
- Redback Pipelines Pty Ltd
- Regional Power Corporation
- Rey Resources Ltd
- Rio Tinto Limited
- Robe River Mining Co Pty Ltd
- Roc Oil (WA) Pty Limited
- Rough Range Oil Pty Ltd
- Santos (BOL) Pty Ltd
- Santos Offshore Pty Ltd
- Shell Development (Australia) Propriety Limited
- Sino Iron Pty Ltd
- Southern Cross Pipelines Australia Pty Limited
- Southern Cross Pipelines (NPL) Australia Pty Ltd
- Strike Energy Western Australia Pty Limited
- Sub161 Pty Ltd
- Tap (Shelfal) Pty Ltd
- TEC Pilbara Pty Ltd
- Titan Energy Ltd
- Tokyo Gas Gorgon Pty Ltd
- Tokyo Gas Pluto Pty Ltd
- UIL Energy Ltd
- Vigilant Oil Pty Ltd
- Warrego Energy Pty Ltd
- Westranch Holdings Pty Ltd
- Whicher Range Energy Pty Ltd
- Woodside Browse Pty Ltd
- Woodside Burrup Pty Ltd
- Woodside Energy Ltd

Drilling and Service Companies Operating in Western Australia include:

- Advanced Well Technologies Pty Ltd
- AGR Asia Pacific Pty Ltd
- Aker Process Systems Pty Ltd
- Amdel Limited
- Atwood Oceanics Australia Pty Limited
- Australian FPSO Management Pty Ltd
- Australian Seismic Brokers Pty Ltd
- Baker Hughes Australia Pty Limited
- Boskalis Offshore Subsea Services
- BPM Offshore Pty Ltd
- Cal Dive International (Australia) Pty Ltd
- Century Drilling
- Clough Projects
- Core Laboratories Petroleum Services
- Crocker Data Processing Pty Ltd
- Diamond Offshore Netherlands BV
- DOF Subsea Australia Pty Ltd
- Downunder Geosolutions Pty Ltd
- Enerdrill Pty Ltd
- Ensco Offshore
- Ensign Drilling Services
- Exploration Data Services Pty Ltd
- Fluor Australia Pty Ltd
- FMC Technologies Australia Limited
- Fugro Multi Client Services Pty Ltd
- GHD PCT Engineers
- Halliburton Australia Pty Ltd
- Hallin Marine Australia Pty Ltd
- Helix RDS
- IFAP
- Indianic Services Pty Ltd
- Kvaerner Australia
- Maersk Contractors Australia Pty Ltd
- McDermott Industries (Australia) Pty Ltd
- Mermaid Marine Australia Limited
- Monadelphous Group Limited
- Nabors Drilling Australia
- Neptune Diving Services Pty Ltd
- Oceanic Offshore Pty Ltd
- pbEncom
- PEX Publications Pty Ltd
- PGS Australia Pty Ltd
- Resolutions Resource & Energy Services Pty Ltd
- Resource Information Unit (RIU)
- Saitta Petroleum Consultants Pty Ltd
- Schlumberger Oil Field Australia Pty Ltd
- Songa Offshore Drilling Limited
- Stena Drilling (Australia) Pty Ltd
- Tasman Oil Tools Pty Ltd
- Technip Oceania Pty Ltd
- Terrex Seismic
- TGS-Nopec Geophysical Company Pty Ltd
- Transfield Worley
- Transocean International
- Weatherford Australia Pty Limited
- Wellserv Australia Pty Ltd
- Wood Mackenzie
- Worley Parsons Pty Ltd

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Western Australia's Petroleum and Geothermal Explorer's Guide – 2014 Edition

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Reference
The recommended reference for this publication is:
PETROLEUM DIVISION and GEOLOGICAL SURVEY OF WESTERN AUSTRALIA, 2014, Western Australia's Petroleum and Geothermal Explorer's Guide – 2014 Edition: Western Australia Department of Mines and Petroleum, 148 p.

ISBN 978-1-877065-11-8 (Paperback)
ISBN 978-1-877065-12-5 (Online)

Managing Editor: Karina Jonasson

Cover: Workover activity at the Ungani oilfield, Canning Basin (Photo courtesy of Buru Energy)

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This publication is also available in digital format (PDF) at
http://www.dmp.wa.gov.au/

ACKNOWLEDGMENTS
This guide is updated from a former version of "Western Australia's Petroleum and Geothermal Explorer's Guide – 2012 Edition". The majority of the information in this guide has been compiled from documents published by the Western Australian Department of Mines and Petroleum, and sourced from within different divisions. Some information, however, has been sourced externally and we would like to acknowledge these sources:

- Australian Government Solicitor
- Australian Taxation Office
- Commonwealth Department of Industry
- National Native Title Tribunal

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For further information on the petroleum resources of
Western Australia to complement this publication please refer to:
1. Petroleum in Western Australia
2. Prospect

Published September 2014
DMPJUL14_3215