WESTERN AUSTRALIA'S DIGEST OF PETROLEUM EXPLORATION, DEVELOPMENT AND PRODUCTION

PETROLEUM

IN WESTERN AUSTRALIA

SEPTEMBER 2015

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Cover: Construction of the gas processing plant for the Wheatstone Project continues. The breakwater is nearing completion and the product loading jetty continues to progress. Photo © Chevron

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

WESTERN AUSTRALIA

Opportunities to Explore – BIDS INVITED FOR ACREAGE

PETROLEUM ACREAGE

Onshore Canning Basin

There is one onshore release area in the Canning Basin of size 2658 km². The release area is situated on the Broome Platform. There may be targets in sub-salt Ordovician and post-salt sequences.

Offshore Northern Carnarvon Basin

There are three release areas in State Waters of the highly petroleum productive offshore Northern Carnarvon Basin. A combined release area is 75 km² in size. The other two areas are 80 km² and 478 km² in size. Targets may include Cretaceous sandstones.

Bids for the release areas close on 28 April 2016.

Acreage release information is available on the Department's website from the gazettal date of 1 September 2015. Information provided includes relevant information about the release areas, acreage access and how to make a valid application for an Exploration Permit.
www.dmp.wa.gov.au/acreage_release

GEOTHERMAL ACREAGE

Acreage is available for the whole of the State not covered by permits or applications. Application is by a Geothermal Special Prospecting Authority (GSPA) with Acreage Option (AO).

Companies are invited to apply for areas each with size up to 160 5'x5' graticular blocks.

Companies interested in geothermal acreage are allowed to bid for multiple areas and are expected to drill at least one well during the first two years of obtaining a geothermal title.

Geothermal acreage information is available from the DMP website:
www.dmp.wa.gov.au/acreage_release

FURTHER INFORMATION:

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Minister's message

Hon. Bill Marmion
Minister for Mines and Petroleum

Community engagement – key to the emerging shale and tight gas industry

Western Australia's shale and tight gas resources represent a potentially significant economic opportunity for the State and also offer benefits to regional communities.

In many ways, gas is fundamental to our modern lives – it helps keep the lights on, powers our desalination plants to give us water, and drives most of the major industries that Western Australian families rely on for jobs.

While the State Government is committed to the responsible development of the gas industry, the protection of public health, water supplies, tourism and agricultural assets is imperative.

So, in line with community expectations, there is a strong focus from the Department of Mines and Petroleum on ensuring potential shale and tight gas projects are assessed with caution, rigor and transparency.

DMP's community engagement and communication activities aim to distribute timely information in a clear and open manner. This is to:

- Increase public and media understanding and demonstrate a robust cross government approach in the regulation of the shale and tight gas industry.
- Build and foster positive relationships by ensuring the community is kept informed of industry activities in Western Australia.
- Enable the community to contribute and participate in the development of a safe and responsible industry.
- Demonstrate that their concerns are being noted, understood, and, if appropriate, acted upon.

The laws and regulations governing petroleum projects also impose a number of consultation requirements on the industry.

These requirements are built on the principle of ensuring the public is informed and can provide feedback about resource projects, their potential impact and how these impacts are managed.

The regulatory criteria for assessment, approval and compliance are readily available, to enable the public to reach an informed point of view.

Concerns about risks are understandable but risk does not equal harm. What really matters is the assessment and management of that risk, and Western Australia has some of the world's toughest regulations in this field.

While the State Government is working to foster community confidence in the gas industry by enacting strong regulation and engaging in extensive consultation, the onus is on the petroleum sector to take a leadership role, too.

The Government will continue to keep stakeholders informed of issues that affect them by providing transparent, timely and accessible information and feedback, and by engaging in a manner that encourages mutual trust and respect.

But the message to industry is clear – engage in a timely, open and ongoing manner with all stakeholders throughout the life of a project or activity.

By doing this, the Western Australian community will be best positioned to benefit from the responsible development of the gas industry.

Executive Director's message

Jeff Haworth
Executive Director
Petroleum Division

For this edition of PWA, I wish to discuss the topic of transparency which is also the theme of this year's Petroleum Open Day. When the Dalai Lama was recently in Perth he said that transparency was all about building trust. This idea struck an accord with me as I also feel that transparency is an essential part of relationship building to gain trust and confidence.

In making sure that the State's petroleum and geothermal energy resources are managed responsibly for the benefit of all Western Australians, I know that it is important that the community, including industry, understands and has confidence in how the department fulfills its duties as the lead regulator. Industry and government need to be open and honest in dealing with local communities, landowners and the public about the oil and gas industry.

Transparency in decision-making begins with the provision of accessible information to help explain how any issues and concerns can be addressed. There are two streams of information dissemination: the first is around how the industry works, a message best delivered by industry itself and secondly, how the industry is regulated, which is best delivered by government. Within each message stream, there is a need to highlight transparency, and for government, this transparency is around regulatory processes and decision-making.

DMP's policy on transparency is clearly stated in its 'Plan for Success to 2017' and Petroleum Division is implementing this policy for onshore oil and gas. Transparency in regulation provides the public and government confidence in the regulatory process. It also provides industry clear direction as to what is required in an application, how the application is assessed and clear timelines on the approval process.

Petroleum Division has already embarked upon this transparency journey by releasing guidelines and assessment criteria on title management for exploration permits and retention leases, as well as assessment criteria for bid assessments for acreage releases. Further guidelines and criteria will be released in the near future on assessment and approvals processes for well management plans and field management plans under the newly introduced Petroleum and Geothermal Energy Resources (Resource Management and Administration) Regulations 2015.

Petroleum Division is further developing online lodgment of applications in the Petroleum and Geothermal Register (PGR). The new features include enhanced authentication algorithms that enable the applicant to validate their information in real time, rather than having to wait for DMP to contact them requesting further information or clarification.

An example of this development is the latest update to the online Pipeline Licence lodgment which was put into production earlier this year. This lodgment procedure was designed with assistance from industry, who contributed to the project scope and design, as well as user acceptance testing during development.

Another part of our transparency strategy is the earlier release of information submitted by industry to DMP and widening the scope of that information. This type of information provision has already occurred with the public release of chemicals used in drilling and hydraulic fracturing and the release of Environment Plan summaries in 2012.

When looking at the legislation, the benchmark DMP uses with regards to the release of information is the *Freedom of Information Act 1992*. DMP is currently reviewing the three petroleum Acts to see if legislative changes are required to enable the wider and earlier release of information. This review will be done in consultation with industry to ensure confidential information is recognised and protected.

DMP is not acting in isolation. We are working with the National Offshore Petroleum Safety and Environmental Management Authority (NOPSEMA) to compare each agency's transparency of processes.

The aim of this project is to seek alignment of our approval processes, to ensure assessment criteria are consistent so that industry is confident that no matter where they explore or produce in Western Australia, the requirements imposed upon it are similar.

DMP will consult with industry regularly, and at milestone points, as we progress down this pathway to ensure agreement is made as to the contents of publicly releasable documents and regarding confidential information required for assessment and how that is to be quarantined.

Transparency is not the only area DMP is developing in its strategies; Petroleum Division is also looking at compliance and consistency strategies to further build confidence in the regulation of the industry in Western Australia. I look forward to reporting on these initiatives in future editions of PWA.

DMP petroleum inspector at Arrowsmith 2 at the choke manifold, northern Perth Basin

Director's message

Denis Wills
Director Petroleum Operations
Petroleum Division

The oil price remains becalmed at around US$40 bbl (WTI) and some analysts expect it to be somewhere between US$30 and US$40 bbl at the end of the year. However, the wild card in the oil price debate is Iran's potential return to the market at some stage in 2016, so who knows where the price may go.

What all this means is further belt tightening. Most operators have been doing this for 18 months or more, so the ability to find more savings from "low hanging fruit" becomes harder. This could inevitably lead to cost savings being sought in core operational activities.

With the introduction of the Resource Management and Administration Regulations 2015, DMP embraced an objective and risked based regulatory framework with the emphases on risk identification, control and compliance.

Compliance is seen as the muscle of the regulatory framework, because when exercised it gives the legislative and regulatory structure strength. Without this activity the processes and procedures operators put in place are only a paper exercise and don't evolve and improve.

As operators are put under pressure to reduce expenditure and maintain or improve profitability there needs to be an awareness and commitment to ensuring compliance is not compromised, for compliance has an ongoing cost which may not be seen as adding to the bottom line.

Compliance means that industry needs to comply with environmental plans, safety cases, well management plans, field management plans, as well as their own compliance/audit program and corrective action process. For DMP it means compliance with legislation and regulations but it also means compliance auditing of petroleum activities, such as drilling.

Given this pressure cooker cost environment, DMP will be increasing its efforts on compliance monitoring.

The move towards a risk based regulatory environment should give operators flexibility to develop a "fit for purpose" approach. This should open up the possibility of reducing the cost of petroleum activities. Further, the risk based methodology should also provide operators with the ability to suggest the application of new technologies, with again the incentive being to reduce cost.

DMP is open to new ideas and ways of achieving the same objectives through the application of a risk based management methodology. However, an overriding assessment consideration will be that risk is reduced to ALARP and that this is within acceptable industry standards.

A brief overview of activities in Western Australia 2015

Lynn Reid
Principal Petroleum Technologist
Petroleum Division

Picking up the slips

This article briefly describes significant petroleum exploration activity onshore during the period January to July 2015. Summary tables for wells, seismic, and the 2014 production and reserves can be found at the back of the magazine.

Drilling

Seven new petroleum exploration wells were drilled in State jurisdiction since January, to add to the five drilled between July and December 2014 as reported in the April 2015 edition of *Petroleum in Western Australia.*

Perth Basin

In the Perth Basin, three wells were drilled in the northern Perth Basin.

Irwin 1 was spudded on 25 March 2015 in Exploration Permit EP 320, east of Production Licences L 1 and L 2 by operator AWE Limited on behalf of title holder Origin Energy Developments Pty Ltd. Total depth was 4049 m, with significant stratigraphic information being provided by the well to the title holders.

AWE also drilled Waitsia 1. The well was spudded on 14 May 2015 in the L 1 production licence area, east of the town of Dongara and about 3 km east of the Senecio 3 well. Senecio 3 had discovered a significant gasfield in 2014, called Waitsia, which spans Production Licences L 1 and L 2. The primary objective of the Waitsia 1 well was to appraise the extent of the new gasfield. The well reached 3507 m depth, intersecting conventional gas in the Kingia and High Cliff Sandstones. Several intervals of core were cut.

The final well drilled in this half year was Waitsia 2, again drilled by AWE. Waitsia 2 is located southeast of Dongara in L 1 and approximately 6 km south-southeast of Senecio 3. The well was spudded on 28 June 2015 and at total depth of 3530 m was reached on 26 July 2015. The objective was to further understand the southern extent of the Waitsia field.

Canning Basin

In the Canning Basin, four wells were drilled between January and June 2015. Three were drilled by Buru Energy Ltd. Sunbeam 1 was spudded on 25 January 2015 in EP 129, east of Derby. The vertical well reached 1200 m into the Betty Member of the Grant Formation. Unfortunately, no significant quantities of hydrocarbons were detected, and the well was plugged and decommissioned.

Olympic 1 in EP 473 was the second Buru Energy well drilled, spudding on 22 May 2015. The well reached 1447 m in the Willara and Nambeet Formations. Again, the well was unsuccessful at finding hydrocarbons; Olympic 1 was plugged and decommissioned.

Praslin 1 was the third well drilled by Buru Energy in the period January to July 2015. Praslin 1 was spudded on 17 July 2015 in EP 391. The objective was the dolomites of the Laurel Formation at approximately 2600 m total depth, following the same trend as the successful Ungani oilfield. At the end of July, drilling was still underway.

Theia 1 was spudded on 14 July 2015 in EP 493 in the Canning Basin southeast of Broome. The operator Finder Shale Pty Ltd is drilling a stratigraphic well to understand the geology and liquid petroleum potential of the Goldwyer III shale. The well had not been completed by end of July 2015.

Carbon sequestration at Barrow Island

Batch drilling of Gorgon CO_2 injection wells has continued for wells on the B, D and E drill centres. Perforation and flowback has started on CO_2 wells in the A and C drill centres.

Other non-drilling well activities

Completion and testing were carried out at Dunnart 2 by Key Petroleum Limited and at Senecio 3 by AWE Limited. Dunnart 2 had negative results and was converted to a water well.

Plugging and decommissioning was carried out at the Eremia 6 well by AWE.

Enerdrill Rig 3 at Waitsia 2, Perth Basin

Surveys

Four surveys were carried out in Exploration Permits from January to July 2015, to add to the five reported in the April 2015 edition of *Petroleum in Western Australia.*

Two of the surveys were three-dimensional seismic surveys. The Numbat 3D multi-client seismic survey was performed by Searcher Seismic in May and June 2015 in the Northern Carnarvon Basin, covering 146 km^2 in SPA 2 T. The Arrowsmith 3D seismic survey was performed for Norwest Energy in EP 413 R3 at the end of April into May 2015. This survey covered 106 km^2 onshore in the Perth Basin.

The remaining surveys were airborne gradiometric gravity surveys (AGG), which utilise sensitive accelerometers carried by a plane to detect small changes in the vertical and horizontal gravitational potential of the rocks below. The Canning Airborne Gravity Gradiometric Survey was performed for Buru Energy in June 2015. The survey flew 5765 km over three permits: EP 391 R3, EP 431, and EP 436. The intention was to determine regional trends of the carbonate formations which host the Ungani oilfield.

Another AGG survey was performed for Empire Oil & Gas NL in the Perth Basin. Called the Black Swan Airborne Geophysical Survey, 12,776 km were flown over all of Empire's Perth Basin permits: EP 368 R4, EP 389 R2, EP 416 R1, EP 426, EP 430, EP 432, EP 440 R1, EP 454, and EP 480. Again, the minimally invasive geophysical technique was used to provide a permit-wide picture of the subsurface prospectivity.

Gorgon Project Update

As at July 2015, Chevron Austraila reports that the Gorgon Project is now more than 90 per cent complete. Commissioning is underway on the subsea gas gathering system at the Jansz-Io field where subsea valves are being tested, paving the way for first gas to the plant site.

All LNG Train 1 and common modules required for first LNG are on their foundations and all the utilities required for the commissioning and operation of Train 1 are now operational. The final LNG Train 2 module has been placed on its foundations while delivery of LNG Train 3 modules continues.

All eight LNG and two condensate loading arms are now installed on the jetty – the final major components before commissioning activities take place.

Wheatstone Project Update

Chevron's Wheatstone Project is more than 65 per cent complete. At the LNG plant site, equipment and modules continue to be delivered and installed, including the LNG Train 1 cold boxes, which will play a central role in the gas liquefaction process, cooling gas to -160 °C.

The slug catcher header and piping systems have been installed, which will separate condensate from gas at the inlet of the plant before further gas processing.

The breakwater for the Materials Offloading Facility is complete, and the loading platform has been installed on the 1.2 km product-loading jetty.

At the offshore gas processing platform, 225 km from Ashburton North, a 440-person accommodation vessel has been connected to the platform to support hookup and commissioning activities now underway.

Installation of subsea manifolds is complete, and subsea equipment and flow lines are now being installed on the Wheatstone and Iago gasfields.

Aerial view of the Gorgan Project on Barrow Island

Resource Management and Administration Regulations 2015

Eric Cormack
Senior Legislation & Policy Officer
Strategic Business Development

DMP petroleum inspector at Warro 4

Two sets of Resource Management and Administration Regulations for petroleum and geothermal activities commenced on 1 July 2015.

The regulations are the Petroleum and Geothermal Energy Resources (Resource Management and Administration) Regulations 2015 (the 'onshore' regulations) and the Petroleum (Submerged Lands) Resource Management and Administration) Regulations 2015. Copies are available at *http://www.slp.wa.gov.au/legislation/statutes.nsf/main_subsif_p.html*

The 'onshore' resource management regulations were released by DMP for stakeholder comment on 5 February 2014 with a closing date for comments of 30 May 2014. During the consultation period, numerous presentations on the draft regulations were given to stakeholders. The second part of this set of regulations, the Petroleum (Submerged Lands) Resource Management and Administration) Regulations 2014, cover submerged lands adjacent to the coast of WA, and were drafted following the review of public and stakeholder consultation comments for onshore regulations. A draft of these regulations was referred to relevant petroleum title holders for information in May 2015.

Background

The starting point for the development for petroleum objective-based regulations was the Piper Alpha disaster in the UK North Sea in 1988. The subsequent inquiry led to recognition that safety in the petroleum industry was best addressed by a risk-based outcomes or objective-based style of regulation. In Australia there was national agreement to move to objective-based safety regulation.

In 1994 the then Australian and New Zealand Minerals and Energy Council (ANZMEC) Sub-Committee on Upstream Petroleum agreed that the 1990 Schedule of Directions be converted into regulations. A similar Schedule applied onshore. During 1996 the first objective-based petroleum legislation commenced with the introduction of the safety case regulations.

The 1998 Minerals and Petroleum Resources Policy Statement stated that the (Federal) Government would continue with the development of objective-based regulations for management of offshore petroleum code.

Given WA's long standing commitment to the common (petroleum) mining code (i.e. similar petroleum legislation across all three jurisdictions), this decision was a policy direction for the State as well as the Commonwealth.

Following on from the introduction of the offshore safety regulations, the timeline for the development of object-based legislation was:

- 1999 Commonwealth Environment regulations (WA Chaired Working Group)
- 2004 Commonwealth Well Operations Management Plan regulations (WA Chaired Working Group)
- 2006 WA Petroleum (Submerged Lands) Act 1982 Well Operations Management Plan regulations
- 2006/2010 WA Safety regulations (see below)
- 2011 Commonwealth Resource Management and Administration regulations (with extensive WA input due to Designated Authority/State role and recognition of importance of model)
- 2012 WA Petroleum and Geothermal Environmental Plan regulations (x 3)
- 2014 WA draft onshore Resource Management & Administration regulations.

Resource Management and Administration Regulations

These two sets of regulations provide a risk-based management scheme for the exploration for, and production of, petroleum and, for the onshore regulations, geothermal energy resources. A range of resource management and administration matters are covered by the regulations, including well management plans (WMP) for the approval of all drilling activities (including shale and tight gas), notification and reporting of discovery of petroleum, field management plans (FMP) and approval of petroleum recovery.

The regulations ensure that adequate information will be provided about all aspects of exploration, discovery, development and production operations in relation to petroleum and geothermal energy resources. They also outline confidentiality periods applicable to information submitted by title holders. This information ensures that petroleum and geothermal energy resources operations are carried out in a proper and transparent manner.

In the case of operations relating to the exploration or recovery of petroleum, they also ensure work is conducted in accordance with good oilfield practice, carried out in a way that reduces the risk of aquifer contamination and compatible with optimum long-term recovery of petroleum and geothermal energy resources. These regulations also support the safe and efficient management of the resources and assist with optimising long-term benefits to Western Australian community.

Transitional provisions in both regulations allow for:

- existing surveys that were approved and undertaken prior to the commencement of the regulations to continue without needing further approval under the regulations
- title holders undertaking well activities approved prior to the commencement of the regulations to have 12 months from 1 July 2015 to submit an application for a WMP
- petroleum licensees undertaking petroleum recovery operations approved prior to the commencement of the regulations to have 12 months from 1 July 2015 to submit an application for approval under regulation 43(1) or an application for an approval to recover petroleum without a FMP under regulation 58(1).

Complementary Legislation

The two sets of Resource Management and Administration Regulations will form the third and final part of the suite of petroleum and geothermal regulations. This phase first commenced in 2007 with four submerged lands area safety regulations commencing:

- Petroleum (Submerged Lands) (Management of Safety on Offshore Facilities) Regulations 2007
- Petroleum (Submerged Lands) (Occupational Safety and Health) Regulations 2007
- Petroleum (Submerged Lands) (Pipelines) Regulations 2007
- Petroleum (Submerged Lands) (Diving Safety) Regulations 2007.

The second phase of safety regulations commenced in 2010 with the following four onshore safety regulations:

- Petroleum and Geothermal Energy Resources (Management of Safety) Regulations 2010
- Petroleum and Geothermal Energy Resources (Occupational Safety and Health) Regulations 2010
- Petroleum Pipelines (Management of Safety of Pipeline Operations) Regulations 2010
- Petroleum Pipelines (Occupational Safety and Health) Regulations 2010.

Lastly, in 2012 the following three environment regulations commenced:

- Petroleum and Geothermal Energy Resources (Environment) Regulations 2012
- Petroleum (Submerged Lands) (Environment) Regulations 2012
- Petroleum Pipelines (Environment) Regulations 2012.

Previous regulatory regime

The commencement of the Petroleum (Submerged Lands) Resource Management and Administration) Regulations 2015 repealed the former Petroleum (Submerged Lands) Management of Well Operations) Regulations 2006.

Further information

Comprehensive guidelines covering both sets of regulations have been developed and are available at http://www.dmp.wa.gov.au/19487.aspx

Further information can be obtained by contacting Colin Harvey, Principal Legislation and Policy Officer, Petroleum Division on 9222 3273.

State areas released for petroleum exploration September 2015

Drilling at Sally May 2, Canning Basin, 2009

Richard Bruce
Exploration Geologist
Petroleum Division

Petroleum Acreage

An acreage release was gazetted on Tuesday 1 September 2015 for onshore Canning Basin and State Waters Northern Carnarvon Basin areas.

Four blocks are available for work program bidding with a closing date for this release of 28 April 2016.

Information on the DMP website will include how to apply for acreage, royalties, online petroleum systems, environment, native title and so forth. Information specific to this release will include various maps of release areas, the gazette notice, release area prospectivity summaries, data listings and land access planning considerations.

Size of Release Areas

Canning Basin

L14-2	2658 km²

Northern Carnarvon Basin

L15-2/T15-2	75 km²
L15-3	80 km²
L15-4	478 km²

Canning Basin

The Canning Basin has been of increased interest to explorers, particularly since the oil discovery at Ungani (originally a gas target) opened up a new play in the basin.

Canning Basin oil has been trucked to the Kwinana oil refinery in the south of the State and to ports in the north of the State for shipment to refineries in southeast Asia.

L14-2 is a re-release area and is located in the central Canning Basin (Figure 1). Based on regional knowledge, the area is considered most prospective for oil sourced mainly (but not exclusively) from the Goldwyer Formation for both conventional type and shale oil and gas resources.

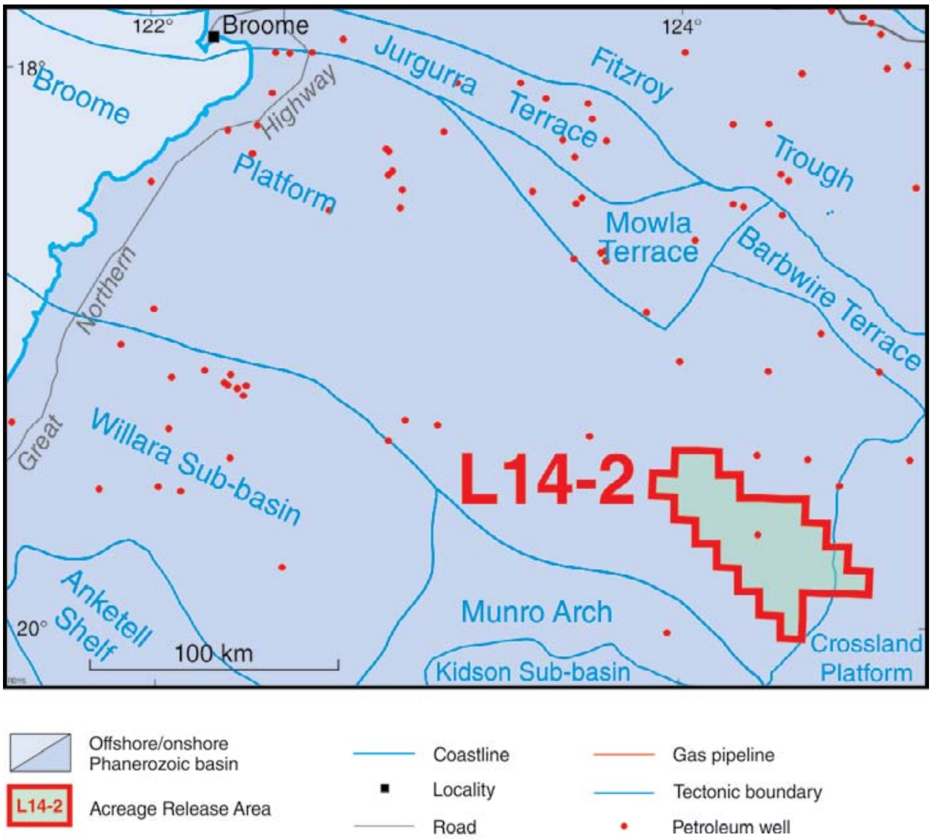

Figure 1. Location of L14-2 release area in the onshore Canning Basin

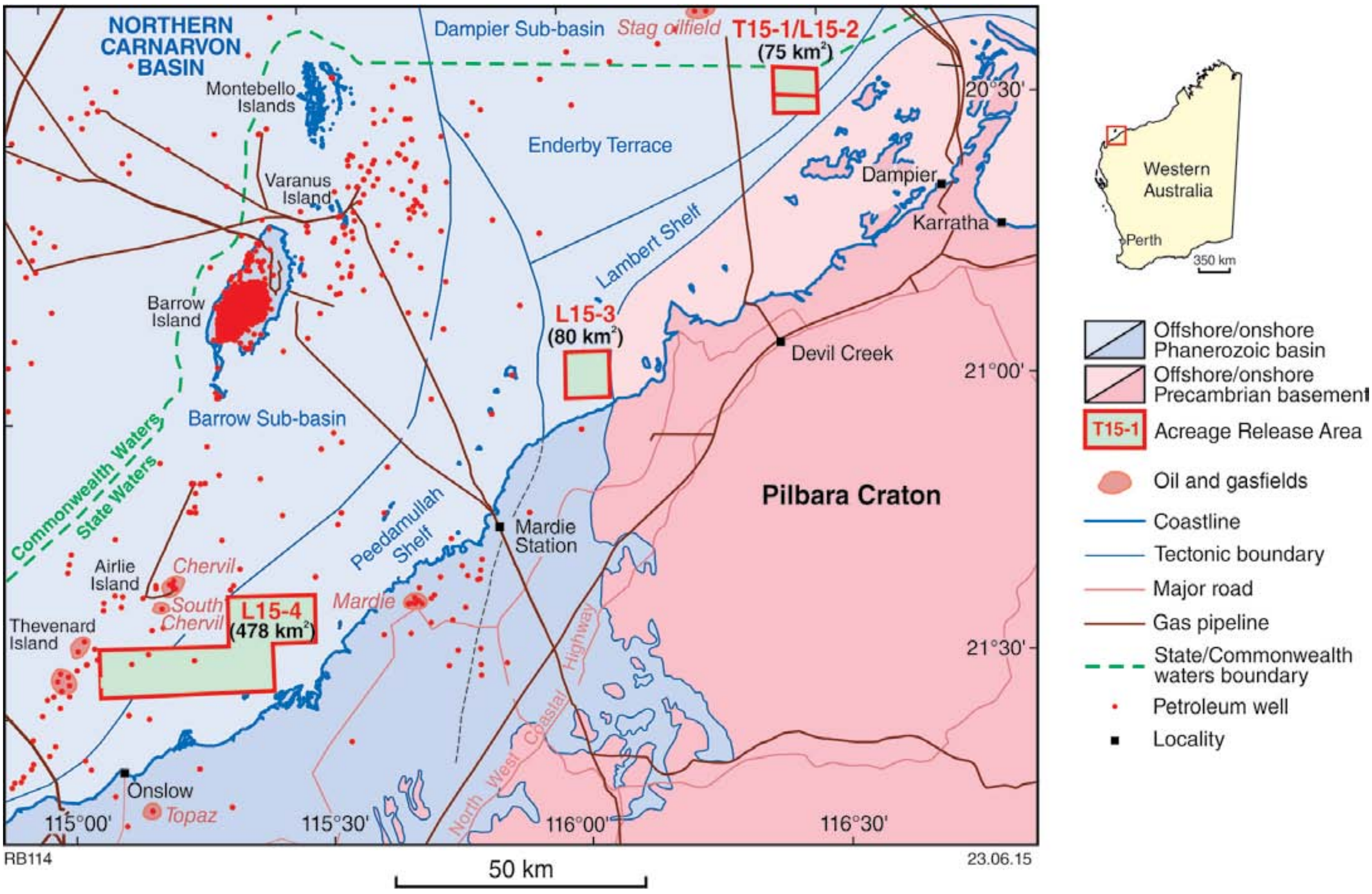

Figure 2. Location of release areas offshore Carnarvon Basin

Northern Carnarvon Basin

There are three release areas in the State Waters, including one (L15-2/T15-1) of which is a combined area (Figure 2).

L15-2/T15-1	75 km^2
L15-3	80 km^2
L15-4	478 km^2

Release Areas T15-1/L15-2 (combined), L15-3 and L15-4 lie in State Waters on the southeastern margin of the prolific Northern Carnarvon Basin, in the Barrow and Dampier Sub-basins, and adjacent shelves.

Lower Cretaceous sandstone structural and stratigraphic plays may be a key target in these release areas.

There is abundant infrastructure in the vicinity of these near coastal release areas, including gas pipelines, and onshore support centres for the North West Shelf. The shallow nearshore waters are suitable for jackup drilling.

Geothermal Acreage

Acreage is available for the whole of the State not covered by permits or applications. Application is by a Geothermal Special Prospecting Authority (GSPA) with Acreage Option (AO).

Companies are invited to apply for areas each with size up to 160 five minute by five minute graticular blocks.

Companies interested in geothermal acreage are allowed to bid for multiple areas and are expected to drill at least one well during the first two years of obtaining a geothermal title.

Further information: www.dmp.gov.au/acreage_release

Jackup rig at the Blacktip platform

Grant of titles

Justin Donnelly
Senior Titles Officer
Petroleum Tenure and Land Access Branch

Production Licences L 20 and L 21 have been granted over the Ungani oilfield

State Awards

From March 2015 to mid-July 2015 the following petroleum titles were awarded in State areas.

Petroleum Special Prospecting Authority and Access Authorities

SPA 2 T and Access Authorities AA 2 T and AA 9 were granted to Searcher Seismic Pty Ltd in April 2015 for a period of six months to conduct the Numbat 3D marine seismic survey. The Numbat 3D marine seismic survey will cover an area of 146 km^2 within the Territorial and Internal Waters of the Northern Carnarvon Basin. SPA 2 T does not have an acreage option on expiry.

Petroleum Exploration Permit

After completing the Northern Perth Basin #6 ESR Survey, Southern Sky Energy Pty Ltd exercised its acreage option, associated with Special Prospecting Authority SPA 1 AO, to apply for an exploration permit over part of the special prospecting authority area. In May 2015 Petroleum Exploration Permit EP 494 was granted over an area of 2577 km^2. The work program for the firm two year period includes a new 80 km 2D seismic survey and studies to an estimated expenditure of $1,385,000. The secondary period (years 3, 4, 5 and 6) includes two stratigraphic wells, two exploration wells and studies with an estimated expenditure of $5,870,000.

Petroleum Retention Lease (Renewal) in the Browse Basin

Petroleum Retention Leases R 2 and TR/5 were renewed for a further five years with registered holders BP Developments Australia Pty Ltd, Japan Australia LNG (MIMI Browse) Pty Ltd, Shell Australia Pty Ltd, Woodside Browse Pty Ltd and PetroChina International Investment (Australia) Pty Ltd. These two retention leases cover an area of approximately 5 km^2 over Territorial and Internal Waters of the Browse Basin.

Petroleum Production Licence

In July 2015 Petroleum Production Licences L 20 and L 21 were granted to Buru Energy Limited and Diamond Resources (Fitzroy) Pty Ltd. These production licences contain the Ungani oilfield in the Canning Basin.

Petroleum Pipeline Licence

In June 2015 Buru Energy Limited was granted Licence PL 109 for the Ungani Pipeline in the Canning Basin. When completed, PL 109 will support production of oil from petroleum Production Licences L 20 and L 21, mentioned above.

Commonwealth Joint Authority Awards

Petroleum Special Prospecting Authority

In May 2015 Special Prospecting Authority WA-32-SPA was awarded over an area of 1045 km^2 to Searcher Seismic Pty Ltd to conduct the Dunnart Non-Exclusive 2D Marine Seismic Survey.

In June 2015 Special Prospecting Authority WA-35-SPA was awarded over an area of 723 km^2 to CGG Services (Australia) Pty Ltd to conduct the Davros MC 3D Part 3 survey.

In July 2015 Special Prospecting Authority WA-36-SPA was awarded over an area of 145,417 km^2 to Spectrum Geo Pty Ltd to conduct the Rocket MC2D Marine Seismic Survey.

Petroleum Exploration Permits

Petroleum Exploration Permit WA-515-P (released as W14-7) located within the Dampier Sub-basin of the Northern Carnarvon Basin off the northwest coast of Western Australia was granted to Tap Oil Limited in March 2015.

Petroleum Exploration Permit WA-516-P (released as W14-16) located within the Barrow Sub-basin of the Northern Carnarvon Basin off the northwest coast of Western Australia was granted to Tap Oil Limited in March 2015.

Exercise Westwind

Lisa Dumbrell
Acting Senior Environmental Officer
Petroleum Operations, Environment Division

Strategic response meeting, Exmouth

Exercise Westwind was the first Level 3 exercise in the National Plan history to exercise a theoretical loss of well control from an offshore facility in the North West Shelf and test the industry arrangements to respond to such a scenario. This exercise was planned and led by the Australian Marine Oil Spill Centre (AMOSC) in conjunction with the Australian Maritime Safety Authority (AMSA), Department of Parks and Wildlife, Department of Transport and also combined personnel from the AMOSC core group, National Response Team; a total of 16 oil and gas companies and many other contributors with specialist knowledge or experience in environmental management and oil spill response.

The exercise consisted of two phases including a Perth based strategic response on 27 and 28 May and an operational response co-located in Perth and Exmouth between 8 and 12 June. The operations phase of the exercise involved operational strategy development through the Incident Management Team (IMT) based in Perth, combined with operations controls and tactical operations in Exmouth, including source intervention, aerial surveillance, aerial dispersant application, and offshore, near-shore, shoreline and oiled wildlife response.

The Department of Mines and Petroleum (DMP) participated in both phases of the response, with one officer attending the Perth based strategic response to provide regulatory advice and two officers attending the operational response in Exmouth as trained and experienced members of the National Response Team.

Deployment of shoreline protection boom

The two officers involved in the operational response undertook multiple functions throughout the exercise period including marine deployment, shoreline deployment and operational control tasks. These officers have gained valuable experience in both the hands-on practicalities and constraints of oil spill response, as well as practical experience and insight in incident management. Valuable learnings are also being collated from all aspects of this exercise, which will improve the knowledge and understanding of both petroleum operators and regulators. These learnings combined with the hands-on practical experience gained by DMP officers will aid in the continual improvement of the regulation of petroleum operations and oil spill contingency planning in Western Australia.

Level 3 Incidents are generally characterised by a degree of complexity that requires the Incident Controller to delegate all incident management functions to focus on strategic leadership and response coordination and may be supported by national and international resources.

The National Response Team is a group of trained and experienced personnel from various National Plan stakeholder agencies that is available to provide support across all response disciplines to any National Plan Combat Agency in the event of a major oil pollution incident. This team is managed by AMSA as part of the Inter-Governmental Agreement on the National Plan to Combat Pollution of the Sea by Oil and other Noxious and Hazardous Substances 2002 of which Western Australia is a signing party.

Western Australia also has a trained and experienced State Response Team which includes DMP Environmental Officers and is managed by the Department of Transport to provide support for WA oil pollution incidents as outlined in the Inter-Governmental Agreement to support the Westplan for Marine Oil Pollution.

The AMOSC Core Group is the petroleum industry supplied personnel who are experienced and well trained in marine spill response operations. This team is managed by AMOSC and has around 120 members from 12 companies ready for response.

Left to right:

Exercised cleaning of oiled wildlife

Exercised spraying of dispersant using water

Deployment of offshore boom used to collect and contain oil

Decontamination set-up at the shoreline deployment area

Permian play mapping in the northern Perth Basin

Darren Ferdinando
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Ian Longley
GIS-pax

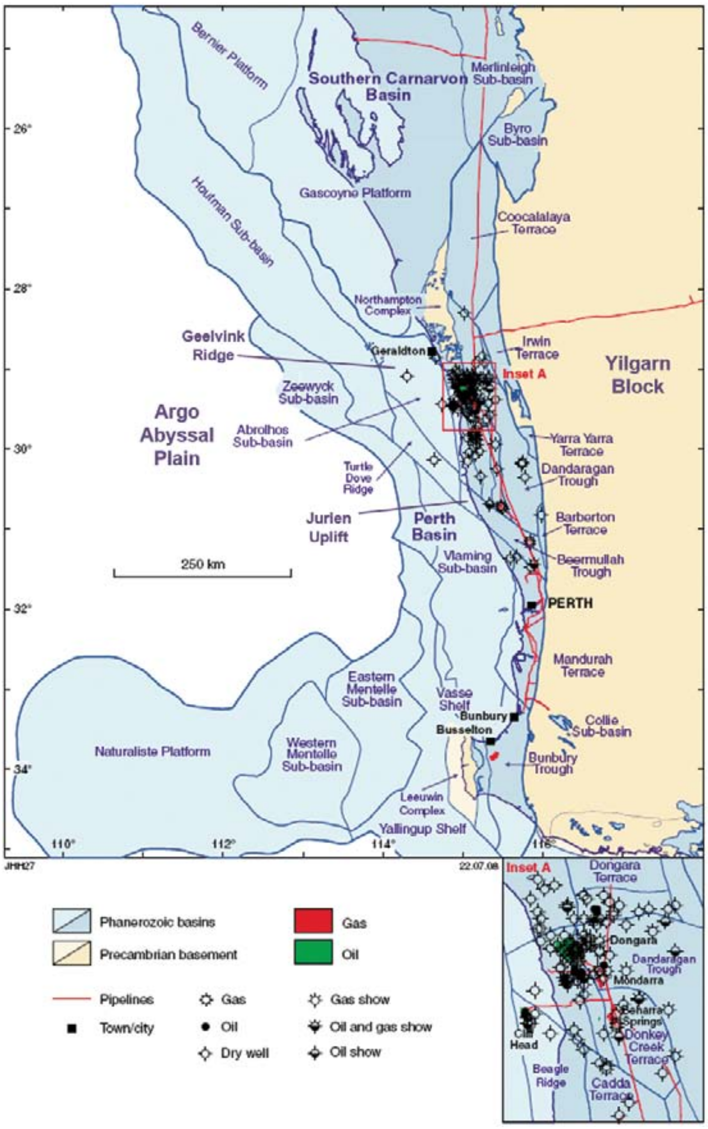

Figure 1. Regional setting of the Perth Basin (from Geological Survey of Western Australia, 2008)

Abstract

As part of a regional geological analysis of the northern Perth Basin during 2012–13, play-based mapping and evaluation was undertaken utilising the Player extension in ArcGIS. The stratigraphy was divided into eight play intervals, representing key depositional sequences in the basin. This included two play intervals covering the key exploration targets of the Late and Early Permian. Using these stratigraphic divisions a thorough assessment of each exploration well within the basin was undertaken, assessing the presence of effective reservoir, top seal, fluid migration into the structure, and whether a valid trap was penetrated in the well at each play level. For each play level these well results were integrated with paleogeographic, depth and isopach maps and ancillary data collected from publically available sources to create a series of regional risk maps for reservoir presence and effectiveness, top seal, and hydrocarbon charge. Once QC'ed and 'reality checked' these individual play risk element maps were "stacked" to create a composite risk map for each of the play intervals.

Introduction

The Perth Basin is an elongate, north–south trending rift underlying approximately 100,000 km^2 of the Western Australian margin located between the population centres of Geraldton and Augusta. The basin is bounded by the Yilgarn Craton to the east, the oceanic crust of the Argo Abyssal Plain to the west, the Northampton Complex to the north, and Leeuwin Block to the south (Figure 1). Slightly more than half the basin lies offshore with water depths extending out to 3000 m.

The northern Perth Basin is located in a zone approximately 150 km wide extending between the towns of Cataby and Geraldton. It hosts most of the hydrocarbon accumulations discovered to date in the basin, including all, bar one, of the currently producing oil and gas fields.

The northern Perth Basin is made up of a series of horsts and grabens formed as part of a long history of rifting episodes. The deepest depocentre of the northern Perth Basin, the Dandaragan Trough, is adjacent to the Darling Fault. Up to 15,000 m of Silurian to Cretaceous sediments were deposited in this trough in response to rifting, which began prior to the Early Permian and culminated in the separation of India and Australia in the Valanginian. To the west, the Dandaragan Trough is flanked by a series of north–south trending horsts and grabens bringing basement relatively shallow (e.g. Beagle Ridge and Turtle Dove Ridge).

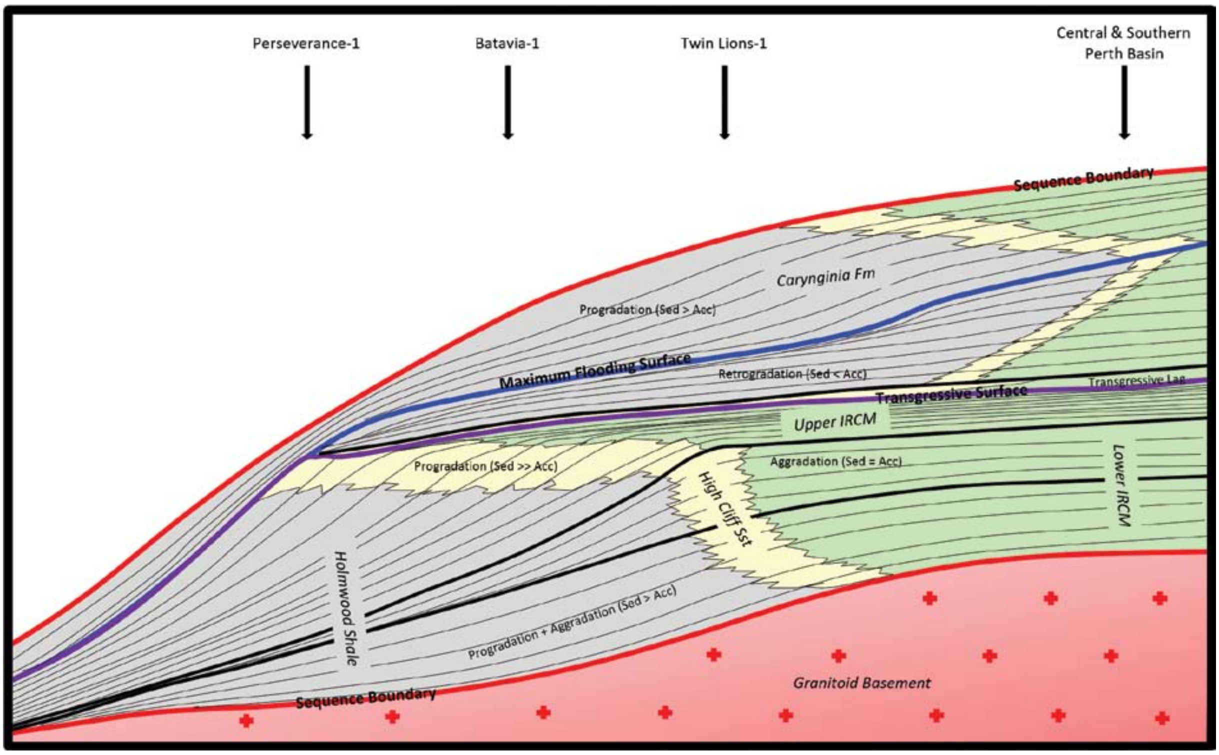

Figure 2. Simplified diagrammatic sequence stratigraphic depositional model for the Early Permian of the northern Perth Basin

Stratigraphy

The deposition in the northern Perth Basin essentially commenced with a rifting phase in the Late Carboniferous/ Early Permian, which formed a series of interconnected NW–SE oriented broad half grabens. The half grabens are filled with a sequence of marine to marginal marine clastic sequences. The oldest of these consists of pre-rift to early synrift glacial to proglacial Nangetty Formation sands and diamictites overlain by shale and siltstone of the Holmwood Shale, which in places includes interbedded shallow marine sands. These were deposited in a proglacial marine shelf setting as a result of incursion of a Tethyan ocean from the north.

Continued rifting, fault growth and fault block rotation in the Early Permian, combined with strong sediment supply from the hinterland, resulted in deposition of marine lowstand sands of the High Cliff Sandstone, then shallow marine to fluvial coarse clastics of the Irwin River Coal Measures (IRCM), and transgressive marine sediments of the Carynginia Formation. The High Cliff Sandstone represents coastal and shallow marine sandstones deposited along the front of a northward prograding IRCM delta. This delta encompasses both aggradational and progradational systems (Figure 2), which included fluvial channels, overbank claystones and coals. The overlying Carynginia Formation comprises a marine shale interval, with minor transgressive sandstone inter-beds, resulting from renewed marine transgression (Figure 2). Reservoir/seal pairs within this Early Permian megasequence are 'lumped' as one interval for the purposes of play evaluation.

The culmination of the initial phase of rifting that commenced at the start of the Late Permian resulted in uplift and erosion of the Carynginia, IRCM, High Cliff and Holmwood Shale on the northern margin of the basin and the development of an erosion surface across the major fault blocks (Figure 3). In the basins to the south and east (such as the Dandaragan Trough, not shown in Figure 3), sedimentation may have been continuous, such that the Carynginia Formation marine claystones are overlain by deep water clastics of the Wagina Formation. In the areas where the Late Permian Wagina Formation has been penetrated however, there is a distinct unconformity between the Early Permian Carynginia Formation and the Late Permian Wagina Formation. Overlying this, possibly unconformably, medium- to coarse-grained sandstones of the Dongara Sandstone were deposited over nearshore to dunal facies along the rims of exposed land and over paleohighs.

The Kockatea Shale provides top seal for underlying Permian reservoirs. The organically rich Sapropelic Interval (top portion of the Hovea Member) is the main source rock in the basin (Thomas and Barber 2004). This unit ranges in thicknesses penetrated by wells from 10 to 30 m. It is inferred from onlapping geometries on seismic data in the study area that the Kockatea Shale thickens towards the basin deeps, and thins on to the regional pervasive outboard highs. Potential exists for Intra Kockatea basin floor sands (such as those observed in Dunsborough 1 from 1263-1279 mTVDSS).

Highstand deposits of the upper Kockatea Shale and the overlying Woodada Formation were deposited over most of the basin's passive margin setting, such that facies distribution was relatively uniform. Increasing sand content is seen in the upper Kockatea Shale and deltaic facies in the overlying Woodada Formation. The upper Kockatea Shale includes a succession of thin-bedded very fine- to fine-grained sandstones deposited in the pro-delta shelf facies, known as the Arranoo Member (Gorter et al. 2009).

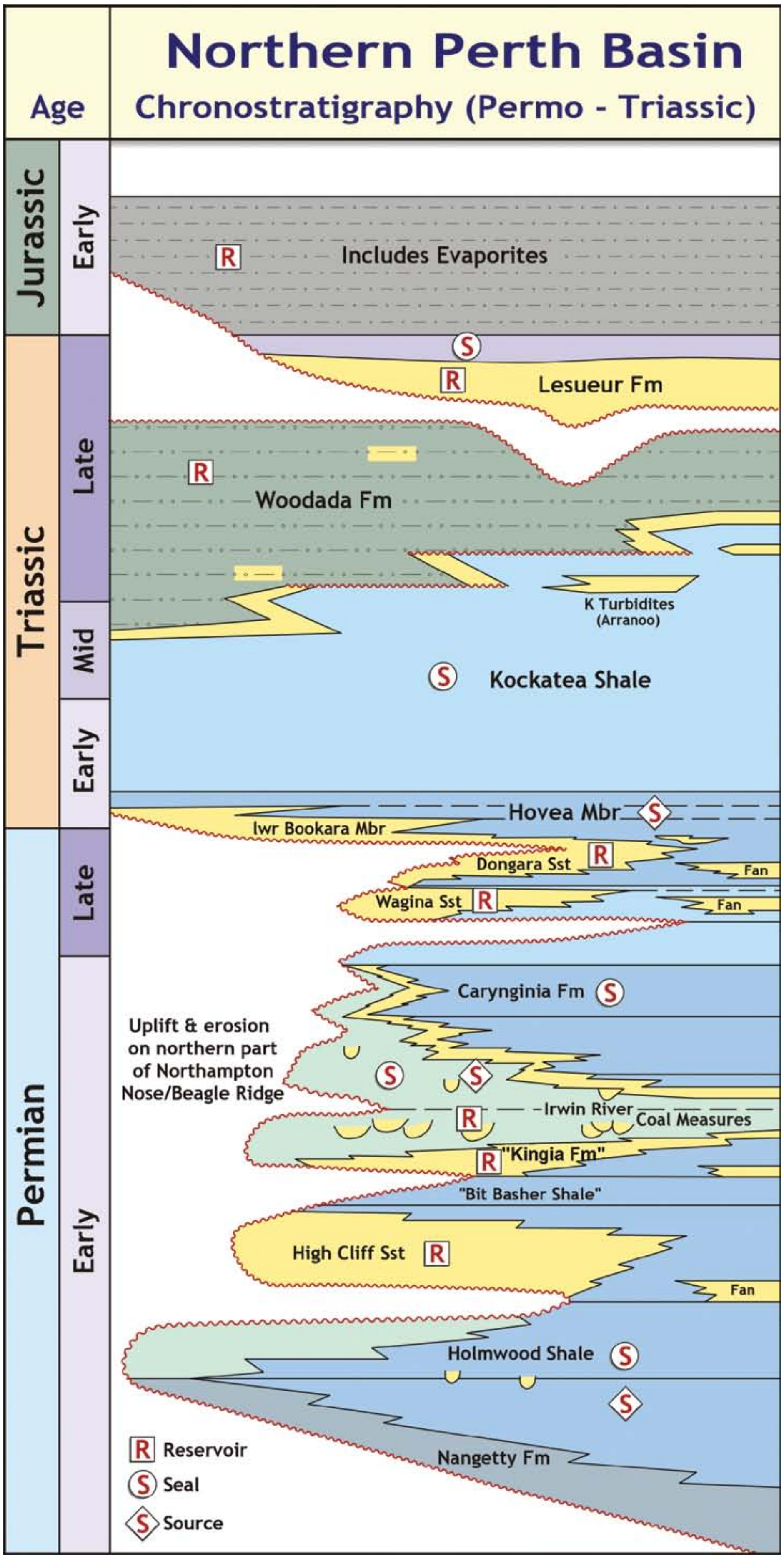

Figure 3. Chronostratigraphy of the Permian to Early Jurassic of the northern Perth Basin, showing significant inversion and erosion between the Early to Late Permian (Modified from Ferdinando et al. 2007)

Why plays were selected

The main hydrocarbon-bearing stratigraphy of the Permian in the northern Perth Basin is divided into two plays — the Late Permian and Early Permian. The Late Permian play consists of the shale marine clastic and carbonate reservoir intervals of the Dongara Sandstone, Wagina Formation and Beekeeper Formation. The Early Permian play intervals covers the clastic reservoirs of the Caryngினia Formation, Irwin River Coal Measures, Kingia Formation (informal name) and the High Cliff Sandstone. The top seal for both of these plays is ultimately the Kockatea Shale, although the Caryngினia Formation and Irwin River Coal Measures can act as top seals locally. Both of these plays are proven to host oil and gas pools, and when combined, form the majority of the hydrocarbon resources discovered in the northern Perth Basin to date.

A spatial database in ArcGIS using the Player extension from GIS-pax was created for the plays using well and field information across the two selected play intervals.

Play analyses: field size distributions, failure and success mechanisms

Failure mechanism analysis of the plays for trap type, field size distributions, and hydrocarbon column heights was completed for each of the plays and also for the overall Permian section. The discovery history plot (Figure 4) for the two plays shows a significant early resource addition in the Late Permian related to the discovery of the Dongara gasfield in 1966. This is followed by a period of smaller volume additions approximately ten years apart, until 2001, when renewed exploration onshore and offshore resulted in the discovery of hydrocarbon fields such as Cliff Head, Hovea, Jingemia, Apium and Xyris. Post 2007, the discovered resources in the Late Permian play have not been significantly added to. This may indicate that the Late Permian is effectively 'creamed', at least in the region focussed over the Dongara Terrace, northwestern shallow portion of the Dandaragan Trough and the inboard portion of the Abrolhos Sub-basin. The most exciting implication of this creaming curve is that the Early Permian play shown in dark blue in Figure 4, is showing recent significant resource additions (such as Senecio 3), illustrating that there are still potentially a number of new discoveries to be made in this deeper stratigraphy.

A log-normal pool size distribution of the combined Permian plays is shown in Figure 5 and displays a linear trend with upside (>P10) field sizes of 40 million barrels of oil equivalent (MMbblOE) and above.

Further analysis of the size of the fields indicates that on average the pool volume for the Late Permian play is 9 MMbblOE and for the Early Permian play it is 33 MMbblOE. It is anticipated that as the Early Permian matures and the prospect inventory starts to target the smaller opportunities that this average pool size will decrease.

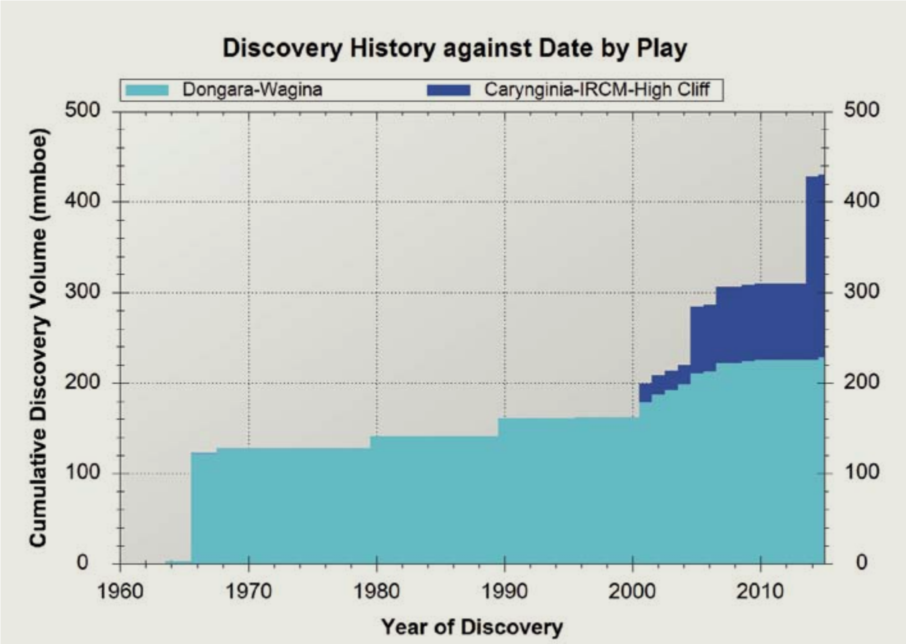

Figure 4. Creaming curve (by date) for the combined Permian plays. The Late Permian play volumes are coloured light blue and the Early Permian are coloured dark blue

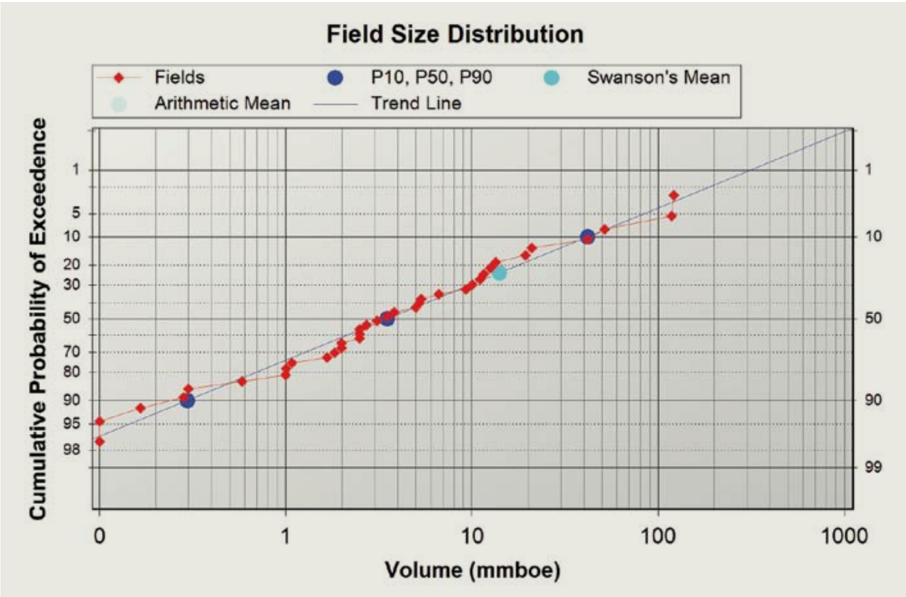

Figure 5. Field size-distribution plot for both the Permian plays (recoverable reserve estimates in barrels of oil equivalent based on Murphy Australia Oil evaluation)

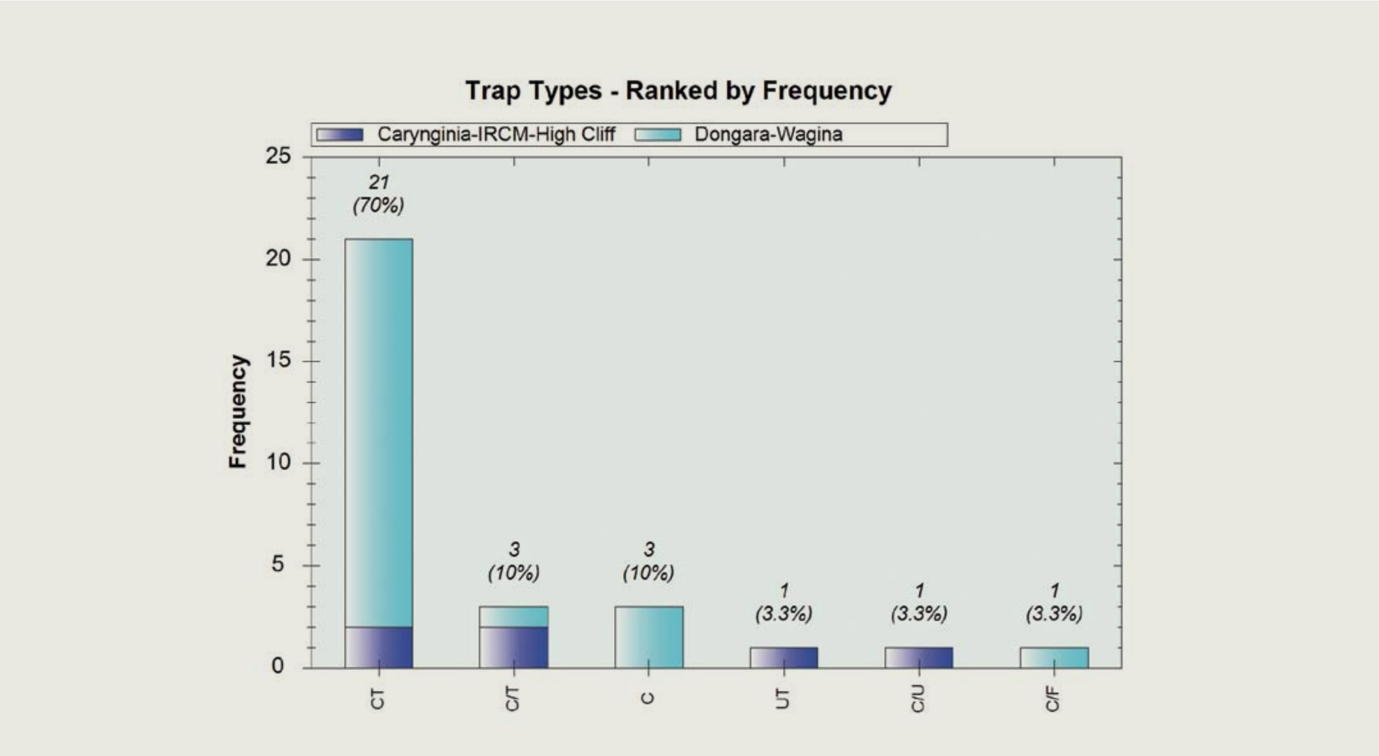

Figure 6. Trapping styles targeted across the Early and Late Permian plays

In terms of targeted traps across the two plays, Figure 6 shows the frequency of trap success against the trapping mechanism as per the trapping style nomenclature of Milton and Bertram (1992). In essence, a CT trap is a high-side fault bound trap, C/T is a low-side fault bound trap, C is an anticlinal trap, UT is a high-side fault trap with unconformable top seal, C/U is an onlap trap and C/F is a trap defined by depositional facies change. This figure shows the majority of discoveries drilled targeting the Permian in the northern Perth Basin to date have overwhelmingly been hosted in simple high-side fault traps. With the recent discovery of the Waitsia field sealed against a lowside fault, the prevailing paradigm of targeting the high-side structures may start to change.

Late Permian

The pie chart in Figure 7 shows that of the wells targeting the Late Permian play, 37 per cent have intersected moveable hydrocarbons and are classed as a technical success (although not necessarily a commercial success). Of the 63 per cent of wells that are dry holes, 28 per cent are classed as off structure tests (generally drilled on sparse, low quality 2D seismic data), 27 per cent are dry failed trap tests, which can be sub-divided into high confidence and low confidence failed trap tests, and 9 per cent have targeted valid structures that are dry (source and/or migration failure).

Within the Late Permian play, trap failure is the most common failure mechanism within exploration wells, being the failure mechanism for nearly half (48 per cent) the dry holes targeting the play (Figure 8). Of the remaining dry holes, nearly a quarter (24 per cent) are interpreted to have failed to due to lack of reservoir (either no sands developed or no effective porosity present). Charge failure (16 per cent) and non-trap related seal failure (12 per cent) are lower frequency causes of exploration target failure. These findings are consistent with established observations and experience in the basin where it is clear trap failure from uplift during the Valanginian and variable reservoir quality within the Dongara Sandstone and Wagina Formation are both recognised as significant risks.

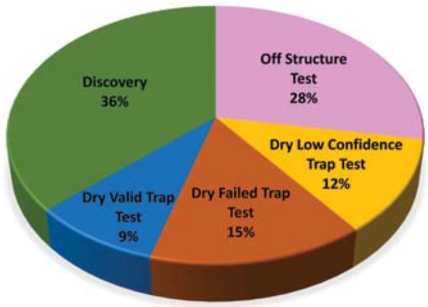

Figure 7. Success/failure analysis of the Late Permian play

Figure 8. Late Permian failure mechanisms

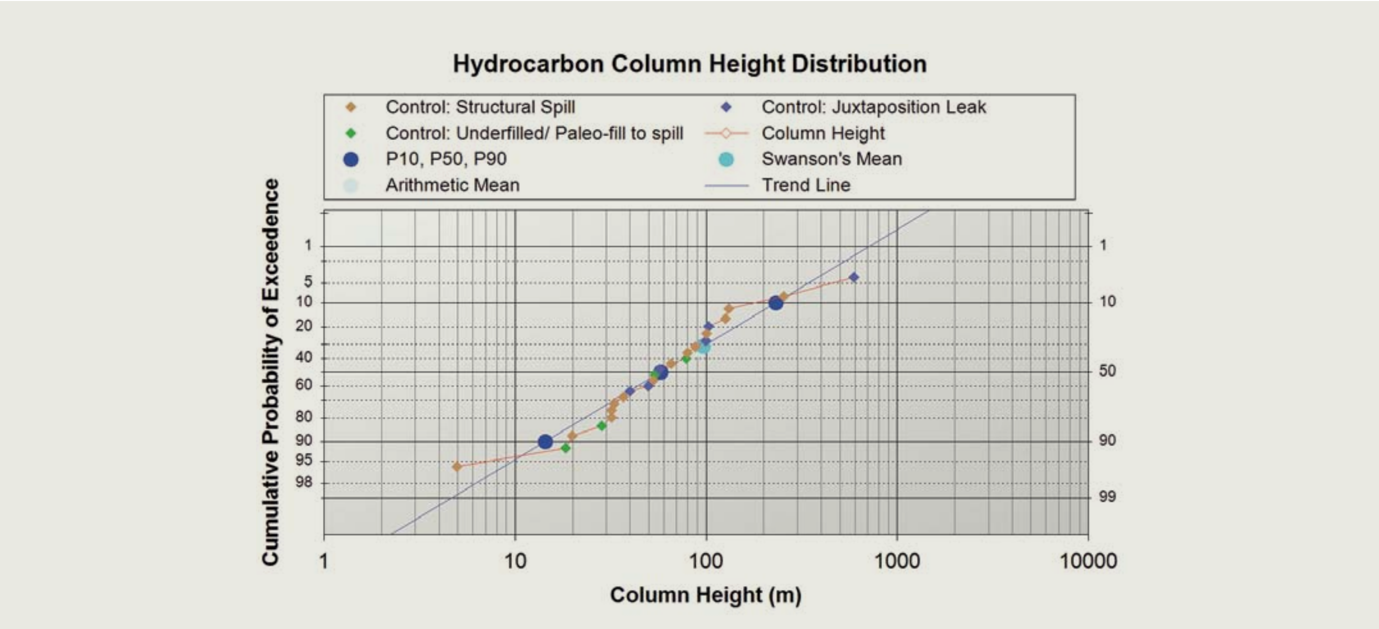

Figure 9. Late Permian column height distribution

Of the successful wells within the Late Permian the average (P50) hydrocarbon column height is around 58 m and column heights within this play are dominantly controlled by the structural spill. Several notable exceptions, such as the Hovea oilfield, appear to be under-filled, probably due to post-charge structural enhancement related to the Valanginian uplift (Figure 9).

Early Permian

Successful tests of Early Permian targets have been more elusive than in the Late Permian play, with only 17 per cent of penetrations into the Early Permian discovering moveable hydrocarbons (Figure 10). Of the dry hole results in Early Permian tests, the majority were off-structure tests, and of the 50 per cent attributed to failed trap tests, nearly half of these had low confidence in the presence of a valid trap. The dataset includes wells that penetrate only a short way into the Early Permian after testing a Late Permian trap, whilst still within what appears to be a seismically valid structure. This does introduce the point that some of the penetrations included in the dataset were not 'true' tests, however because of the subjective nature of deciding which of the penetrations were truly testing the Early Permian, this study has chosen to include all the Early Permian penetrations into the dataset.

Of the wells that penetrated Early Permian targets and were dry, almost half (46 per cent) of these wells lacked either reservoir presence or reservoir effectiveness, with trap failure accounting for another 41 per cent of the well failures (Figure 11). Charge failure accounted for just under 8 per cent of the dry holes and lack of top seal (seal/trap effectiveness failure) was attributed to the remaining 5 per cent of failure cases. As with the success/failure analysis, these results may be skewed from wells reaching total depth (TD) in the Carynginia Formation where reservoir development is problematic. However, the dataset includes a number of penetrations into the upper Irwin River Coal Measures where tight reservoir was noted, so the overall high reservoir risk appears to be valid and consistent with actual experience in the northern Perth Basin.

Of the six successful exploration tests of Early Permian pools at Arrowsmith 1, Cliff Head 1, Drakea 1, Corybas 1, Hovea 2 and Senecio 3, the hydrocarbon column height varies from 40 m to 350 m (Figure 12). With the exception of the Cliff Head oilfield where the column appears to be controlled by fault juxtaposition leak, structural spill appears to be the controlling mechanism, although in some cases poor quality seismic data at depth does leave some ambiguity.

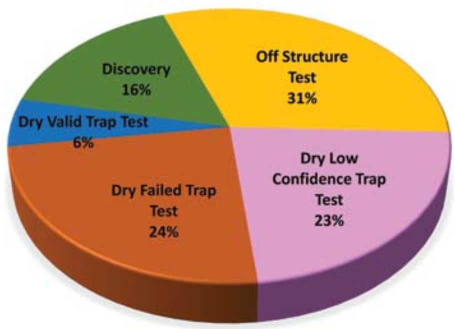

Figure 10. Early Permian success/ failure evaluation

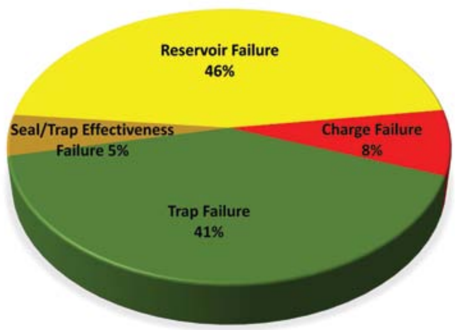

Figure 11. Early Permian failure mechanisms

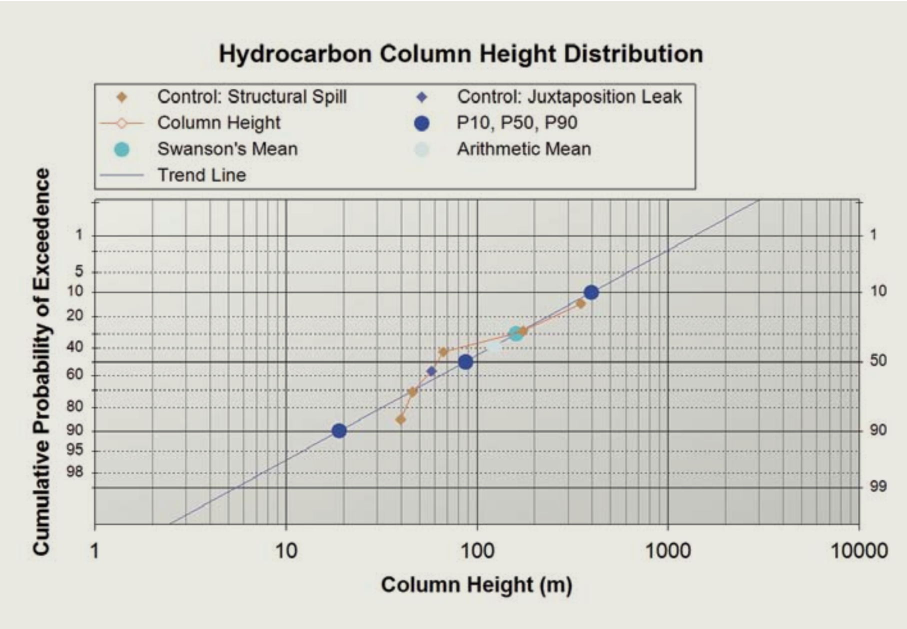

Figure 12. Early Permian column height distribution

CRS Maps

Common risk segment (CRC) maps were generated for the Permian plays across the northern Perth Basin based on the author's perceived chance of play success for the key risk elements across the region. The chance of success was derived from well results, geological mapping, tectonic elements, basin modelling and other publically available information relating to spatial distribution of the petroleum system elements across the northern Perth Basin. The maps represent the chance of each geological element being successful somewhere within the polygon (presence), and not the chance of it always being successful within the mapping polygons (repeatability).

The geological elements used in determining the overall common risk segment maps for each play were the presence of reservoir, the chance of reservoir being effective, and the presence of a top seal. The presence of a trap and lateral seal elements were considered as prospect-specific chance elements and not used as part of the regional play analysis. The discrete regional play elements were finally stacked with a regional model of charge, representing a simplified chance of hydrocarbon charge from either the Early Triassic Hovea Member of the Kockatea Shale, or the Early Permian Irwin River Coal Measures. The stacking process is a simple spatial multiplication of the play element percentage chance of success. The resulting maps are the composite common risk segment map for each of the two plays (Figures 13 and 14).

Across both composite maps a simplified rosette, or 'wagon wheel', at each well penetration of the play is used to denote the presence, or absence, of a play element within each well. The top left quadrant indicates the presence of reservoir when it is filled yellow, the absence of reservoir when it is blank and ambiguous or uncertain reservoir when it is half filled. The reservoir component is a combination of reservoir presence and reservoir effectiveness and shows the minimum assessed state of the two elements within the well. In the top right quadrant the top seal element is shown in brown. The bottom left quadrant shows the interpretation of the presence of a valid trap in green. The bottom right quadrant indicates the presence of hydrocarbons, a full red quadrant indicates moveable hydrocarbons, the half-filled quadrant indicates hydrocarbon shows deemed significant and a blank bottom right quadrant indicates either no observed hydrocarbons or non-significant shows.

Late Permian

The composite CRS map for the Late Permian play fairway (Figure 13) illustrates the lowest risk region of the fairway extends from the edge of the Dandaragan Trough across the Dongara Terrace and Beagle Ridge onshore to the eastern edge of the Abrolhos Sub-basin offshore. Moderate risk zones, mainly related to uncertainty of reservoir presence are present over the Turtle Dove Ridge and the southern part of the Beagle Ridge and Cadda Terrace. The high risk area for the play are coloured red and generally represent either outboard regions to the west where there is little data that supports the presence of the play, regions to the south where the Late Permian is deep with no evidence for porosity preservation at depth, or the region to the north where the play is either eroded or exceptionally shallow.

The fairway map indicates that the central heartland of the low risk region centred over the Dongara Terrace is well explored, but opportunities exist in the northern offshore portion and the eastern part of the play proximal to the Urella Fault.

Early Permian

Play fairway mapping of the Early Permian (Figure 14) shows the prospective zone is spatially similar to the Late Permian, although the region covered by the Abrolhos Sub-basin and Turtle Dove Ridge are considered prospective due to greater chance of reservoir development across here, based on seismic facies mapping, and the possibility of porosity preservation at depth, as shown by the Kingia Fm/ High Cliff Sandstone in the recent Senecio 3 and Waitsia 1 wells. While the central portion of the onshore play appears to be well tested, a number of these wells only tested the upper portion of the play in the Carynginia Fm and IRCM, while recent discoveries in the Early Permian have been made in the stratigraphy of the Kingia Formation and High Cliff Sandstone. There appears to be scope for a number of drilling opportunities into untested structures at this deeper level.

Offshore, a working petroleum system from the Abrolhos Sub-basin has been

Northern Perth Basin
Late Permian
Composite CRS

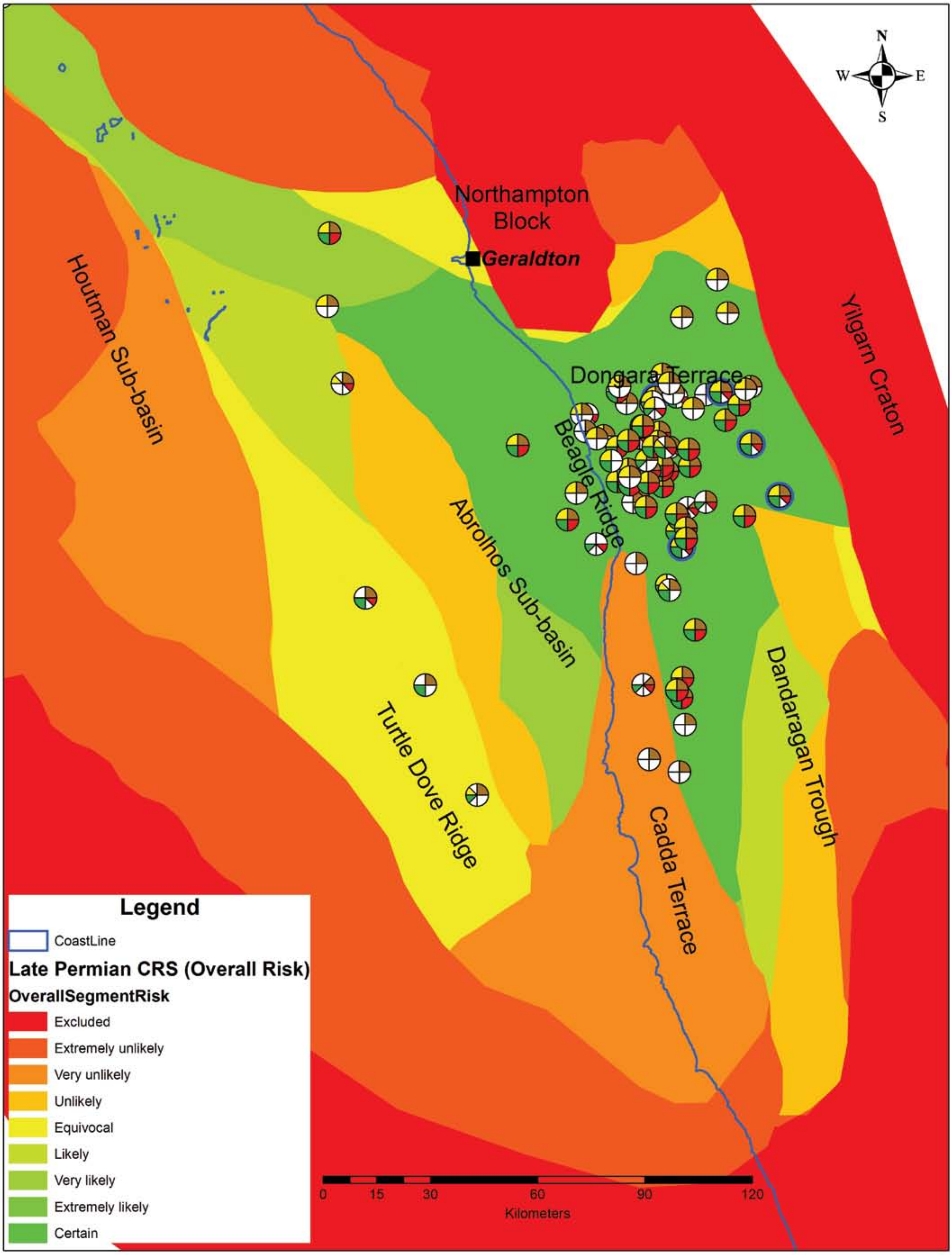

Figure 13. Late Permian composite common risk segment map

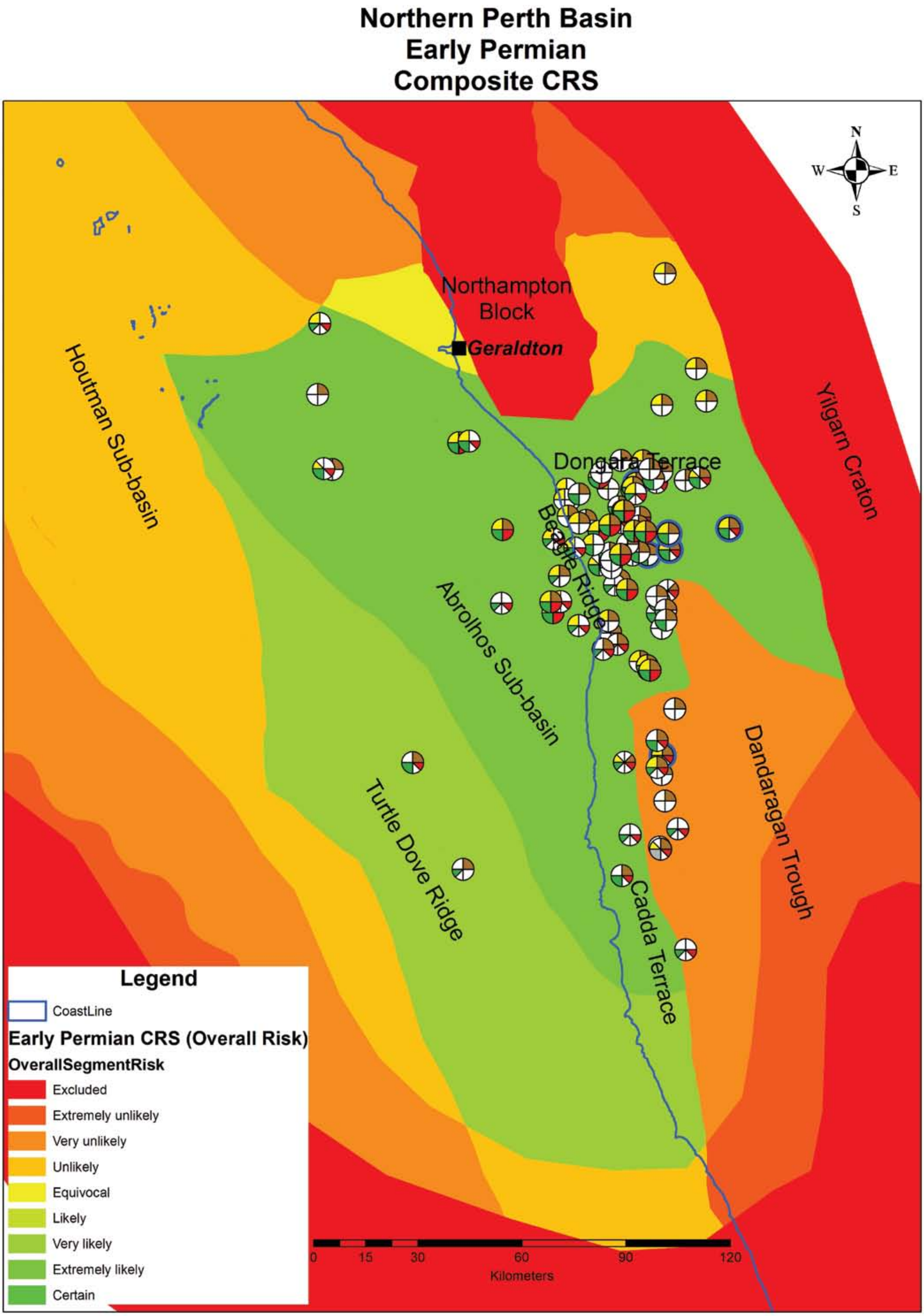

Figure 14. Early Permian composite common risk segment map

proven by discoveries in Cliff Head, Dunsborough and Frankland, and effective reservoir found in a number of wells. The key to the Early Permian play offshore appears to be unlocking the correct trapping mechanism, be that structural or stratigraphic.

Conclusion

This work illustrates the extent of the play fairways in the Late and Early Permian over the northern Perth Basin and the overall relative maturities of both plays. While the frequency of discoveries in the Late Permian play has decreased in recent years, this is likely a result of exploration focussed in a core region onshore looking at a limited prospect portfolio. The Late Permian play fairway shows there is some scope around the margins of the core drilled region in the Dongara Terrace and inboard portion of the Abrolhos Sub-basin and there is still running room in the offshore region. The key risks facing prospects within this play relate to the reservoir and the integrity of the trap, mainly in situations where a three-way fault bound structure is targeted.

The Early Permian creaming curve indicates that there may still be significant scope for a number of discoveries to be made both onshore and offshore. Specifically, the offshore region and the area to the east, close to the Urella Fault appear to hold potential for further discoveries in this region. To the south of the Waitsia discovery, the region around the Drakea oil discovery also holds promise for future discoveries in the Early Permian play.

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Depositional architecture and exploration implications of fluvial deltaic strata; offshore northern Perth Basin

Semi-submersible drilling rig, offshore Western Australia

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Abstract

An understanding of the base-level controls on facies distribution is important to better comprehend the petroleum potential of the Early to Middle Jurassic interval of the offshore northern Perth Basin. By providing a framework for the prediction of facies distribution throughout the study area, this analysis has implications for petroleum exploration, including applying this work to a depositional model to predict reservoir and seal development.

Channel sandstones of the fluvial-deltaic Cattamarra Coal Measures have the potential to form hydrocarbon reservoirs. The interbedded finer-grained flood plain deposits, however, have poor reservoir potential and affect the vertical migration of hydrocarbons to shallower reservoirs. This lack of vertical permeability is interpreted to be an issue in the Houtman Sub-basin, where thick fine-grained deposits are well preserved. The reservoir potential of sandstones reduces significantly basinward from Houtman 1 to Charon 1. This suggests that the most prospective area from a petroleum point of view would be landward of Charon 1 in the offshore northern Perth Basin study area.

The overlying marine Cadda Formation contains marine shales deposited in a shelfal environment, along with lower shoreface and estuarine sandstones.

Figure 1. Map of Western Australia showing the extent of the Perth Basin and other major sedimentary basins. The Perth Basin is circled in red. Also highlighted is the transect used in this analysis. Modified from Turner et al. (2009)

Figure 2. Location map showing the well transect used in the analysis. The sparse well distribution highlights the paucity of exploration conducted in this area of the basin

Landward thinning of the marine shales causes fault juxtaposition issues in fault-related traps. The sandstones identified within the interval could also affect its sealing capabilities if their permeability is high enough, although, a high enough permeability would give rise to the possibility of these sandstones acting as reservoirs within the interval.

Introduction

The Perth Basin is situated on the western coast of Western Australia covering more than a thousand kilometres of coastline (Kretschmer et al. 2011) (Figure 1). Petroleum exploration of the basin began in the 1930s and has traditionally focused toward the onshore area in the north, targeting the Permo-Triassic petroleum system (Cadman et al. 1994). However, with increasing global energy demands companies are aiming to maximise natural resource production. Focus has shifted towards the discovery of new plays within the basin and exploration of new and innovative offshore petroleum systems in the region.

The Early Jurassic Cattamarra Coal Measures (CCM) and overlying Middle Jurassic Cadda Formation, is an example of a petroleum system that has become an alternative exploration target. The CCM contain interbedded sandstones, siltstone and claystones, with associated coal seams forming potential source rock horizons (Kantsler & Cook 1979). The depositional setting of the CCM has been interpreted as a fluvial channel system within a large delta plain. Coal accumulations occur in interdistributory marshes and flood plains (Mory & Iasky 1996; Gorter et al. 2004). A marine incursion during the Middle Jurassic resulted in the deposition of the Cadda Formation, a succession of shales and bioclastic limestones (Mory & Iasky 1996; Jones et al. 2011). Shales within the Cadda Formation have the potential to act as a regional top seal for the underlying fluvial reservoirs of the CCM (Jones et al. 2011), creating a classic source below seal play.

Onshore, hydrocarbons have been produced from reservoirs in the CCM. Offshore, however, a great deal of uncertainty remains around the extent of this petroleum system, with well penetrations being sparse and to date no Jurassic hydrocarbon pools having been discovered.

Materials and methods

This sequence stratigraphic analysis investigates an area off the coast of Geraldton in the Abrolhos and Houtman Sub-basins (Figure 2). Six exploration wells are located within the study area, all of which penetrate the Jurassic section. Of these, Houtman 1 and Gun Island 1 were cored over the Early to Middle Jurassic interval whilst Charon 1 contained side wall cores.

A sedimentological analysis was undertaken of the available well core and thin sections to identify facies association distributions. Five facies associations were identified in the CCM: two consisted of thick sandstone packages with interbedded mudstones associated with channel-fill deposits; the other three consisted of interbedded fine-grained mudstone and siltstone deposits interpreted as examples of overbank and floodplain deposition. The depositional environment of these facies associations is interpreted as a lower delta plain setting.

Six facies associations were identified in the Cadda Formation: two mudstone deposits, one of which contained abundant shell fragments; three distinct bioturbated fine-grained sandstones; and a heterolithic facies containing interbedded sandstone and mudstone. The depositional environments of these facies associations are interpreted as marine shelf, lower shoreface, and estuarine settings, respectively.

The interpreted facies associations were then correlated with gamma ray logs and used to interpret stacking patterns and identify key surfaces relating to changing depositional environments. A sequence stratigraphic framework of the Cadda Formation and CCM intervals was created by integrating the sedimentological analysis with the analysis of gamma-ray wireline. Biostratigraphic data for the wells was available at sufficient resolution to constrain time frames for several key sequence stratigraphic surfaces. Accuracy in regards to timing of the surfaces is adequate for establishing the hierarchy of cycles as per Vail et al. (1991).

Sequence stratigraphic framework

The resulting sequence stratigraphic framework shows the Early to Middle Jurassic strata being deposited over four base-level cycles (Figure 3). Cycles one and two are classified as second-order cycles, while cycles three and four are examples of third-order base-level cycles.

A key consideration when interpreting the sequence stratigraphy of a fluvio-deltaic environment is the relationship between accommodation and the stacking of channel deposits (Figure 4). In a high accommodation fluvial environment, lowstand channel deposits stack on top of finer grained highstand and transgressive deposits.

In a low accommodation setting, however, there is not enough available space to stack sediments deposited over a base-level cycle. As a result, repeated incision of underlying deposits occurs during a lowstand as sedimentation moves basinward. The constant incision causes a higher channel density in lowstand environments. Analysis of the sequence stratigraphic framework was used to identify how base-level changes control the deposition of facies throughout the study area.

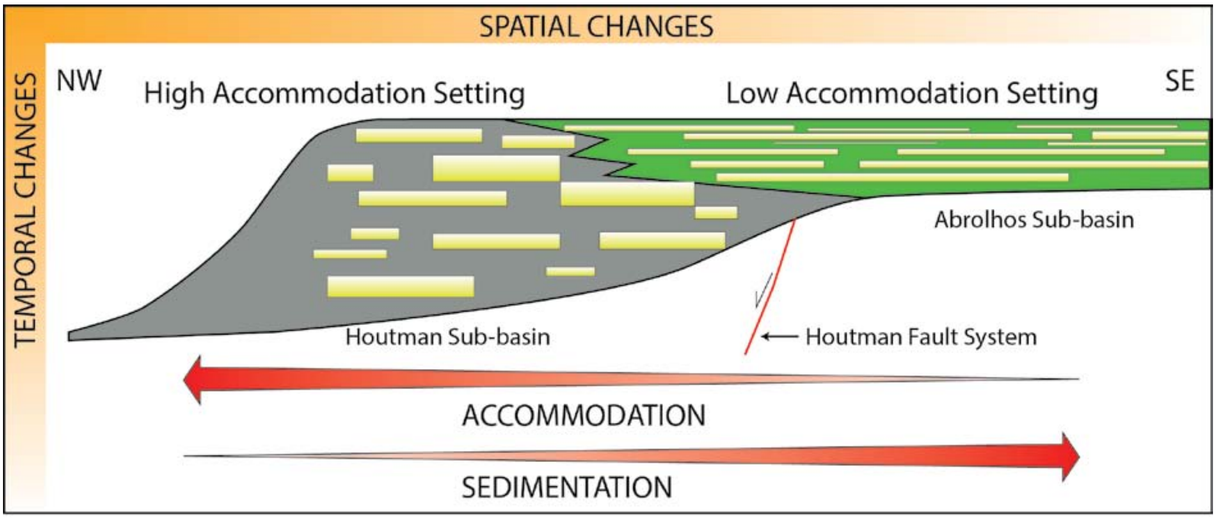

Figure 3. Sequence stratigraphic interpretation of the Early to Middle Jurassic strata in the Houtman and Abrolhos Sub-basins, offshore northern Perth Basin. Several base-level cycles are recorded throughout the deposition of this interval. The marine transgression is observed to thin landward. Biostratigraphic data was used to establish the hierarchy of base-level cycles

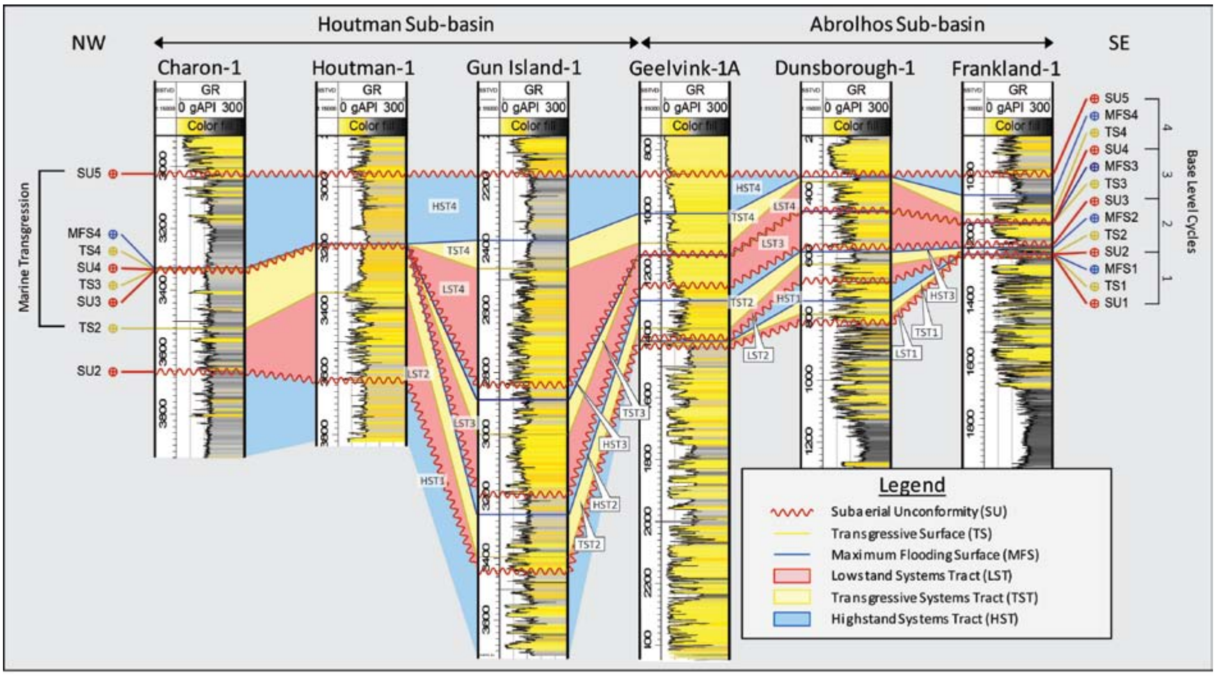

Figure 4. Schematic diagram illustrating changes in channel density with changes in accommodation of a fluvial-deltaic environment. The diagram depicts how these changes may occur between the Abrolhos and Houtman Sub-basins. Modified from Foix et al. (2013)

Fluvial deposition in a high accommodation setting is observed in well cores from Houtman 1 and Gun Island 1 (Figure 3). These cores show thick packages of channel-fill sandstone deposits separated by fine-grained mudstone and siltstone overbank deposits. The deposition of these channel-fill facies associations occurred during the lowstand and early transgressive sequences of LST2, TST2 and LST4 (Figure 3). Fine-grained flood plain facies associations occurred during the HST1 and HST2 highstand periods. The correlation of the observed facies associations with the systems tracts in Houtman 1 and Gun Island 1 allows for the prediction of deposit types throughout the area.

High fluvial channel density is interpreted to be indicative of a low accommodation setting during LST3 and LST4 in Geelvink 1A, Dunsborough 1 and Frankland 1 (Figure 3). Coarse-grained sandstone deposition, similar to that observed in Houtman 1 and Gun Island 1 cores, occurs in Geelvink 1A, Dunsborough 1 and Frankland 1 during these lowstand sequences (BP 1969, Roc Oil 2009 (1) & 2009 (2)). Thin highstand and transgressive flood plain facies associations may be preserved between the lowstand periods in these intervals.

Thicker packages of highstand deposits, similar to that observed in the Houtman 1 and Gun Island 1 cores, is observed in the lower part of Geelvink 1A, Dunsborough 1 and Frankland 1 (Figure 4). Fine-grained mudstones and siltstones deposits are observed in drill cuttings over these intervals (BP 1969, Roc Oil 2009 (1) & 2009 (2)). Accommodation availability was therefore greater during the earlier sequences in the Abrolhos Sub-basin relative to later sequences.

Thicker fine-grained deposits are observed in the gamma-ray log of the distal Charon 1 compared to the other wells. It is apparent that the CCM sandstones are much finer-grained in Charon 1 (Figure 3) and therefore a lateral change to distal facies associations is likely, as the well is located at the basinward extent of the fluvio-deltaic environment.

Depositional Model

Cycle 1 – 2nd Order Base-level Cycle

Figure 5a shows the initial lowstand deposit with a subaerial unconformity (SU1) marking the base of the interval. SU1 also marks the base of a falling stage systems tract that results in sedimentation in distal parts of the basin. These deposits may exist as basin floor fans.

The diagram shows the marked difference in available accommodation between the Houtman and Abrolhos Sub-basins. The accommodation differential is controlled by the Houtman Fault System. A lowstand delta marks the deposition during the lowstand systems tract (Figure 5a). The diagram shows that sandstone deposits in a delta system become muddier throughout a lowstand. This occurs as the aggradation of deposits decreases the fluvial slope near the shoreline, reducing the overall energy of the fluvial system (Catuneanu 2006).

It is at the late stage of a lowstand when thick coals start to accumulate. Coal development requires a delicate balance between the build-up of

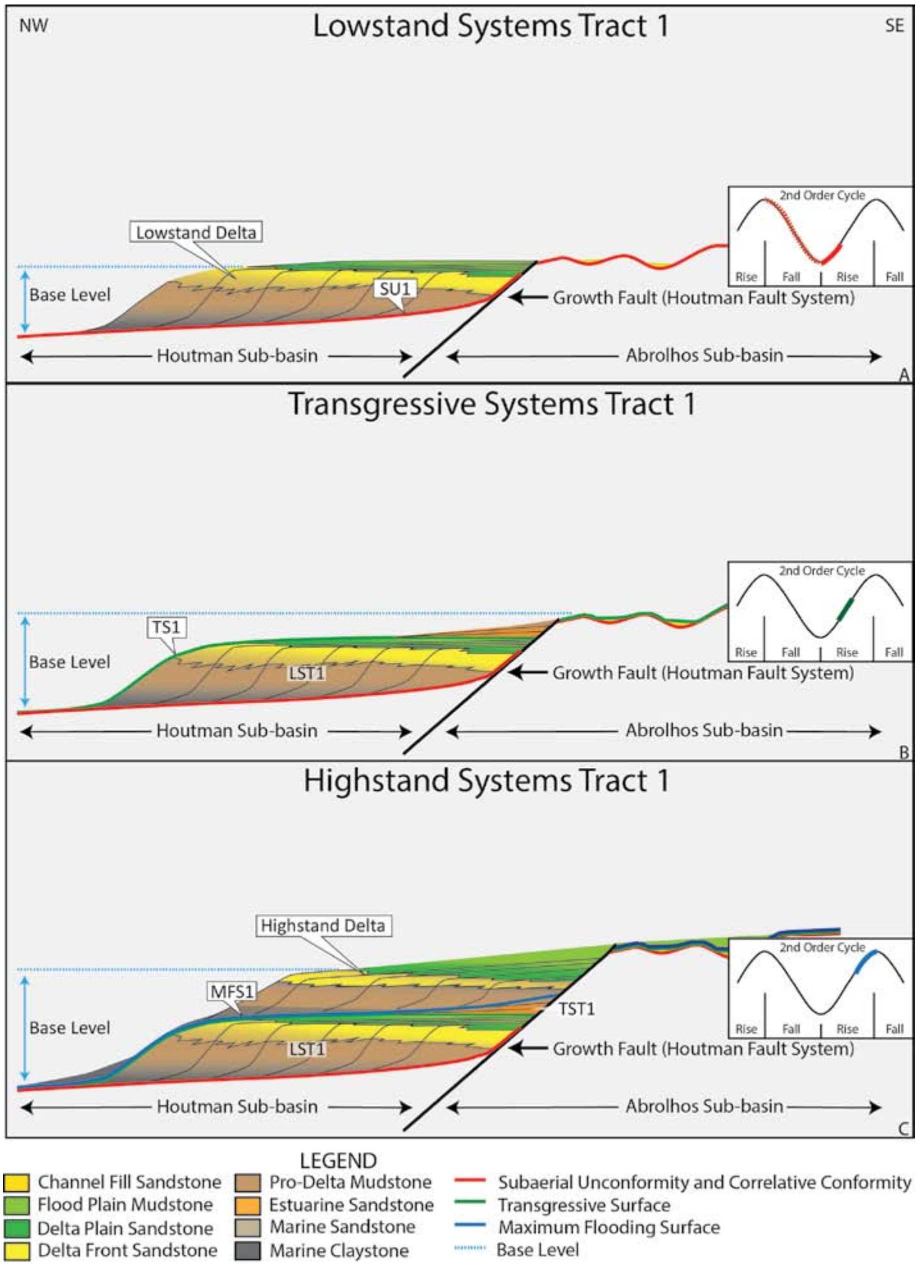

Figure 5. Architecture of the Early to Middle Jurassic depositional system showing system tracts and key surfaces of the first base-level cycle (Cycle 1). This is an example of a second-order base-level cycle. The diagrams show accommodation being created by movement of the Houtman Fault System

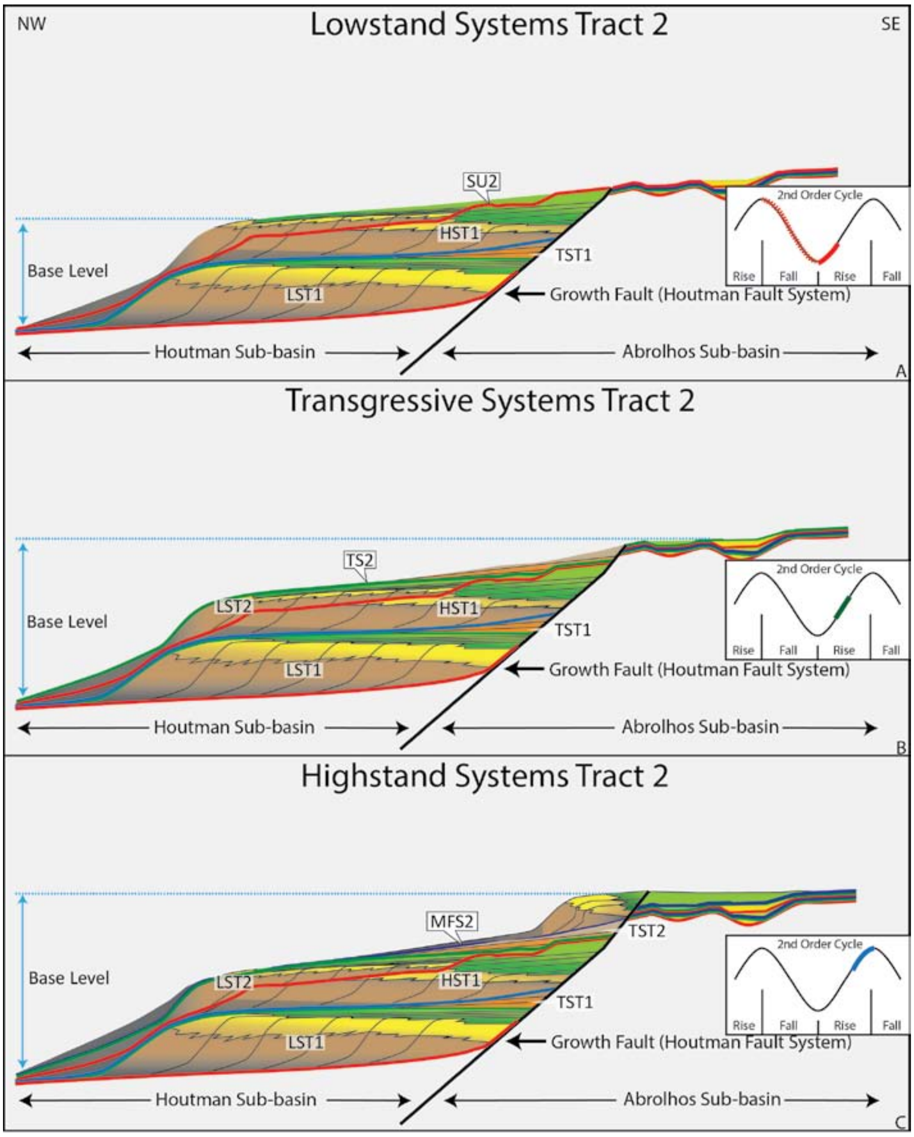

Figure 6. Architecture of the Early to Middle Jurassic depositional system showing system tracts and key surfaces of the second base-level cycle (Cycle 2). The deposition of a condensed section begins to occur in the basinward (NW) area of the models. Cycle 2 is also an example of a second-order base-level cycle with ages constrained by biostratigraphy

organic matter, rising water table and rate of sedimentation (McCabe 1991, Holz et al. 2002). As the existence of coals within the CCM has been well documented, there were periods during the depositional history of this interval where ideal coal forming conditions were met.

Figure 5b shows the onset of shoreline regression is marked by the transgressive surface, TS1. The accommodation is created by movement of the Houtman Fault. As the shoreline retreats, sedimentation is restricted to fining-up healing deposits. Preservation of these deposits tends to be low due to shoreface reworking processes occurring at this time (Catuneanu 2006). The maximum flooding surface, MFS1, marks the extent of the shoreline regression.

Figure 5c shows the highstand delta marking deposition during this time period. Unlike lowstand deltas, the sand/mud ratio increases over time in a highstand delta. This is caused by both the progradation of the delta, as well as the reworking of sediments in the later stages of the highstand (Catuneanu 2006). The commencement of the highstand marks the end of the ideal coal forming timeframe. The coal formation slows as sedimentation begins to increase relative to accommodation, interrupting the build-up of organic matter.

Cycle 2 – 2nd Order Base-level Cycle

The subaerial unconformity and correlative conformity, SU2, marks the beginning of the second base-level cycle. This second cycle is similar to the first, with a lowstand delta prograding out into the Houtman Sub-basin. Again there is a fining-up of deposits in the latter stages of the lowstand as the overall energy of the depositional environment decreases (Figure 6a).

As the cycle continues, the control of the Houtman Fault System on accommodation in this area remains apparent (Figure 6b). The cycle culminates with another highstand delta building out into the Houtman Sub-basin. At this stage there has also been enough accommodation to preserve some of the overbank deposits in the fluvial environment of the Abrolhos Sub-basin (Figure 6c).

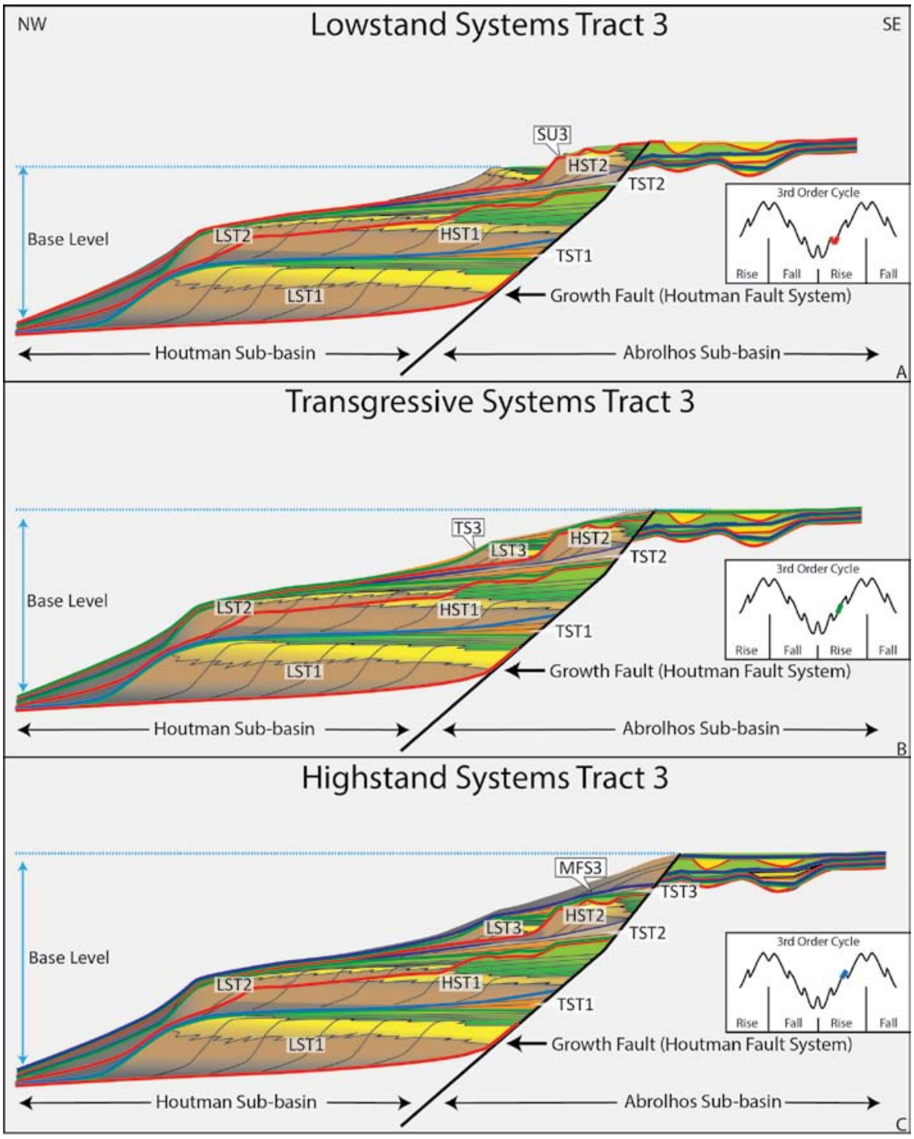

Figure 7. Architecture of the Early to Middle Jurassic depositional system showing system tracts and key surfaces of the third base-level cycle (Cycle 3). This cycle represents the first example of a third-order base-level cycle, preserved in the basin fill due to the increased availability of accommodation

Cycle 3 – 3rd Order Base-level Cycle

SU3 marks the beginning of a third-order base-level cycle (Figure 7a). Previously these higher order cycles had not been recognisable in the basin fill. These deposits are now being preserved due to greater accommodation available within the Houtman Sub-basin.

The build-up of condensed deposits in the distal parts of the basin to the northwest is shown in Figure 7. These deposits represent the marine equivalent of the fluvio-deltaic strata. Due to its diachronous nature, this simultaneous deposition of fluvial deltaic facies (CCM) and marine facies (Cadda Formation) is poorly demonstrated by lithostratigraphic interpretations.

Cycle 4 – 3rd Order Base-level Cycle

SU4 marks the beginning of the final cycle within this interval (Figure 8). This final sequence is another example of a third-order cycle. The lack of accommodation in the Abrolhos Sub-basin area of the study has caused the stacking of channel-fill deposits through continuous incision. This stacking of channel-fill deposits has eroded the underlying finer-grained deposits.

The base-level cycles from MFS2 to MFS4 are not present in the basinward areas to the northwest in this model. The fact these cycles are less regionally extensive than Cycles 1 and 2 suggests that these later cycles are of a higher order, this is also confirmed using the biostratigraphic data. As SU3 and SU4 are not identified in the basinward area, the equivalent correlative conformity condensed sections continue to be deposited at this time.

The final highstand results in marine deposition across the area and, in lithostratigraphic terms, is classified as the Cadda Formation. The delta front during this period moves landward as marine conditions transgress across the area.

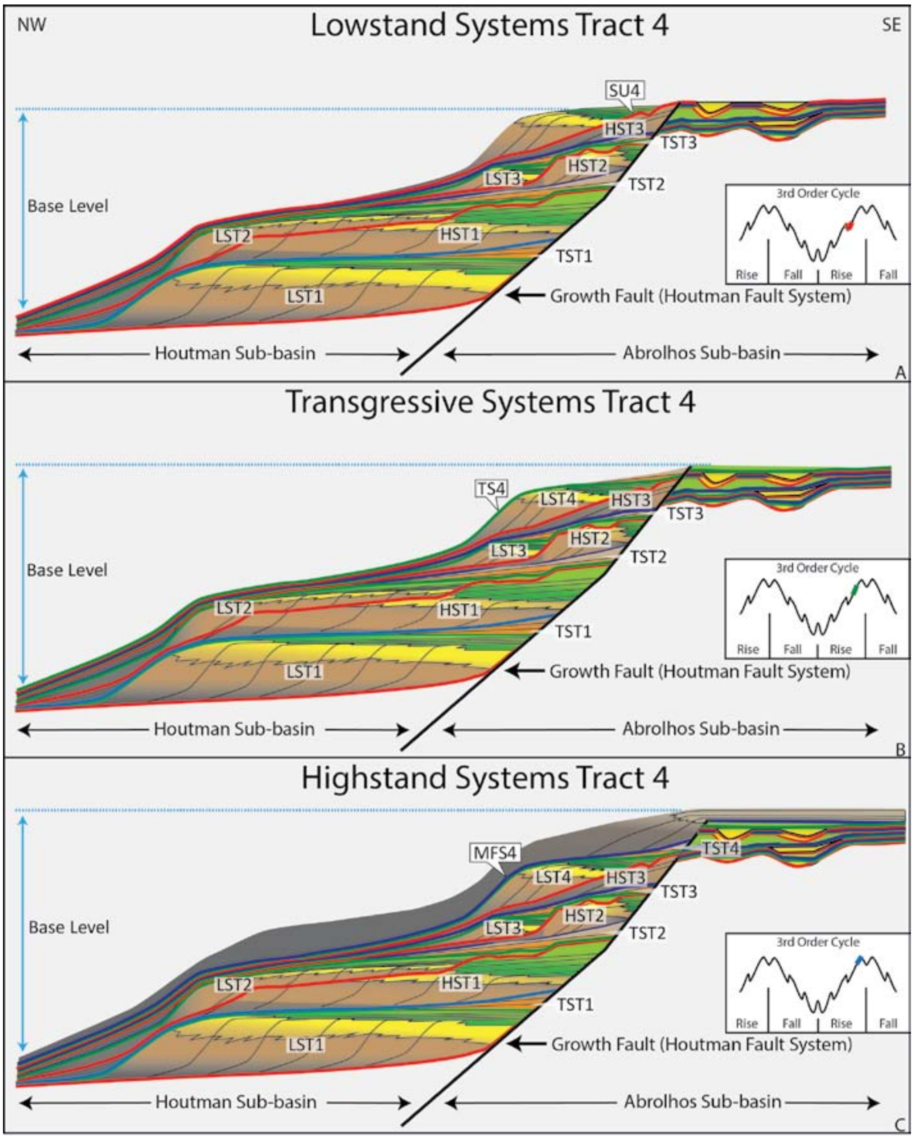

Figure 8. Architecture of the Early to Middle Jurassic depositional system showing system tracts and key surfaces of the fourth base-level cycle (Cycle 4). (A, B) are the last examples of fluvio-deltaic deposition in this area before the marine incursion (C). Cycle 4 also shows examples of continual fluvial channel incision in the Abrolhos Sub-basin due to low available accommodation. Cycle 4 is also an example of a third-order base-level cycle with ages constrained by biostratigraphy

Considerations for exploration

Figure 9 shows how the wells from the study area are positioned across the model. This analysis demonstrates the complexity and heterogeneity of fluvio-deltaic basin fill. To interpret the lowstand deposits of the fluvial deltaic system as containing nice, thick sandstone deposits would be to over-simplify the model. Consideration must be given to factors such as changing sand/mud ratios across highstand and lowstand deltas, peak periods of coal accumulation, extensive delta plain areas and the complex geometries of fluvial channels cutting through them.

This depositional model identifies many issues that need to be considered when exploring for hydrocarbons in this area. Some of the main considerations are:

1. Within the lower accommodation area of the Abrolhos Sub-basin there is not enough space to preserve the highstand and transgressive deposits. Instead a repeated incision of underlying sediments occurs, causing complex channel geometries and heterogeneity in the resulting strata, limiting seal potential and increasing reservoir connectability in the area.
2. The interbedded shale and sandstone sequences observed within the Abrolhos Sub-basin wells affect the trapping potential of the CCM. Here hydrocarbon column heights are restricted to shale thickness if juxtaposed against reservoir in three-way traps.
3. The fine-grained flood plain deposits, observed in both Houtman and Abrolhos Sub-basins, have a very low permeability causing these deposits to affect the vertical migration of hydrocarbons to shallow reservoirs. As a result, these fine-grained deposits act as intraformational seals.
4. There is a reduction in sandstone quality between Houtman 1 and Charon 1. Basin floor fans may exist in the area northwest of Charon 1, containing sediments eroded from the study area during base-level falls.

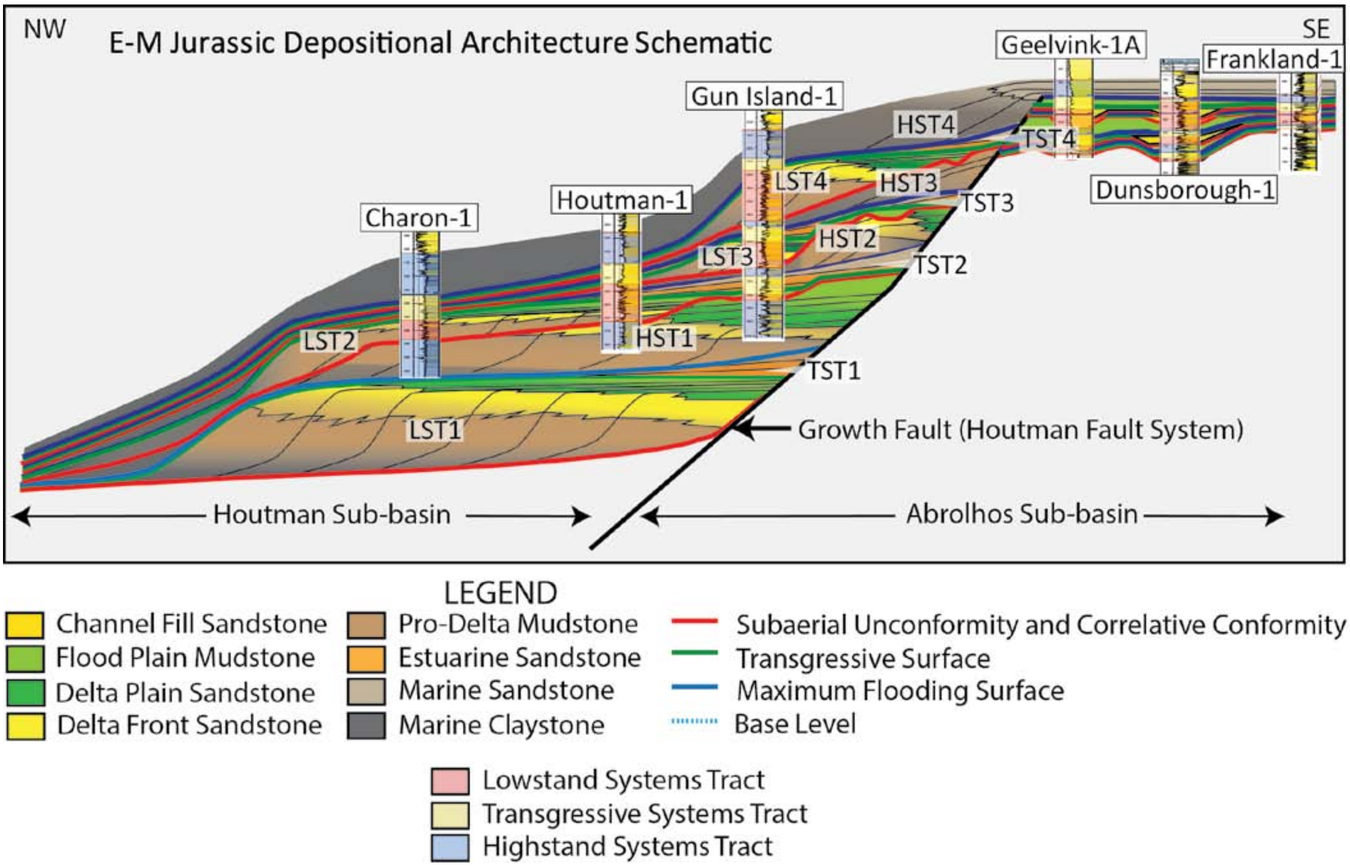

Figure 9. Schematic showing the depositional architecture of the Early to Middle Jurassic basin-fill. Well logs are overlayed on the model to show where these wells are located within the depositional system

Because this model is based on a single transect, there is also the possibility of other sediment input points, yet to be identified, that would aid the prospectivity northwest of Charon 1.

5. The Cadda Formation thins landward, which could be an issue for hydrocarbon column height and spill points if juxtaposition of this formation is required to provide a lateral seal in traps.
6. The sandstones within the Cadda Formation are a problem if they contain enough permeability to reduce the effectiveness of this formation as a top seal. However, these sandstones could also provide alternative reservoir targets, creating a potential new play within the petroleum system.

Conclusion

This sequence stratigraphic study shows how base-level controls are important on the distribution of facies throughout the area, and the heterogeneity of internal strata that arises from such a complex depositional environment. Fine-grained flood plain sediments deposited during the highstands are better preserved in the Houtman Sub-basin, as the higher accommodation setting allows for the aggrading of lowstand deposits on top of highstand deposits. This situation is opposed to the low accommodation setting of the Abrolhos Sub-basin, where highstand deposits are being repeatedly incised during times of lowstand.

Lateral changes in the distribution of facies are also apparent in the sequence stratigraphic framework. A basinward fining of sandstone deposits occurs as marine influences become apparent earlier in the depositional history in the locality of Charon 1. The lateral changes in facies associations are also apparent by the basinward thickening of the marine deposits in this area. This thickening is a function of the greater accommodation available in the Houtman Sub-basin. It is also due to a greater depositional time frame as the regional sea-level transgression is initially observed in the more basinward locations.

The resulting heterogeneity and complexity of the basin-fill needs to be considered for exploration purposes in both areas. Considerations need to be made for presence and quality of reservoir, the effect of intraformational seals, top seal quality and thickness, trapping mechanisms, and location within the depositional environment to name but a few. Overall this depositional model assists exploration through a better understanding of the depositional environment and economic potential of this petroleum system offshore.

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Geothermal production in the Perth metropolitan area: 20 years of success

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Challenge Stadium pool heated by geothermal energy

This article contains highlights of the journal article '20 years of exploitation of the Yarragadee aquifer in the Perth Basin of Western Australia for direct-use of geothermal heat' by Martin Pujol, Ludovic P. Ricard, Grant Bolton, Geothermics (September 2015, Volume 57, Pages 39–55).

Introduction

Geothermal energy has been employed in Australia since the beginning of the 20th century (Burns et al. 2000). Some of the large scale direct use activity included a 10.4 MegaWatt (thermal) (MW_t) district heating system at Portland, Victoria (now decommissioned) and a paper manufacturing unit in Taralgon, Victoria. Electricity generation exists with two geothermal power plants, the first one at Mulka (South Australia) and the second at Birdsville (Queensland) producing 20 kiloWatt (electrical) (kW_e) and 150 kW_e respectively. In Western Australia (mostly in the Perth Basin), geothermal energy was developed mostly for swimming pool heating and coincided with the exploitation of major aquifers for water supply. The first and now obsolete direct-use applications in Perth included: heating of the reptile enclosure at the South Perth Zoological Gardens; water heating at the Claremont laundry; drying of wool in Jandakot; and bathing applications such as the popular Crawley warm baths (often as a by-product of deep groundwater exploration or following uncontrolled artesian flows and pounding at the surface). In 1997, the first modern direct-use geothermal project for bathing and swimming, Bicton pool, emerged. By the end of 2015, there will be a dozen of direct-use geothermal projects in production status for heating leisure centres, building air and outdoor pools in the Perth metropolitan area. These geothermal operations use geothermal water supplies from the Yarragadee aquifer, at depths ranging from 750 to 1150 m, and temperatures between 40 and 52 °C. Heat-depleted groundwater is injected back within the aquifer so as to maintain a neutral water balance. Currently, Perth has the largest concentration of operating geothermal direct-use projects in Australia and the projects have a 100 per cent success track record. These projects exploit more than 2.5 billion litres (GL) of geothermally warmed groundwater each year and distributed heat is estimated to be more than 110 × 10^3 billion Joules (GJ) per year and up to 180 × 10^3 GJ when considering projects currently at construction stage but not yet commissioned.

Resource characterisation

Geology

Three major stratigraphic units exhibit aquifer properties beneath the urbanised Perth metropolitan area (PMA), but only the mid-Jurassic clastic sedimentary rocks of the Yarragadee Formation contain sufficiently warm groundwater (i.e. at temperatures of 40 °C or more) for geothermal direct-use projects. In the Perth region, most of the strata comprising the Yarragadee aquifer lie within the Yarragadee Formation. The aquifer is confined across most of the PMA. North of the PMA, it is directly overlain by shallower aquifers where the confining layers are absent.

The Cockburn 1 well was drilled in 1967 to a depth of 1725 m, about 15 km to the southwest of Perth (Figure 1). The well intersected a complete section of the Yarragadee Formation. There is no other well intersecting the full thickness of the aquifer near Perth. The base of the aquifer was intercepted by wells further north (Gingin 1 and Gingin 2 wells) at 3314 and 3399 m depth, respectively (Figure 1). To the south, the base was intercepted shallower at 1203 m (Pinjarra 1 well) and at 1438 m (MARC-1g geothermal well). Beneath Perth, the upper section of the aquifer has been intersected to 1156 m at BPG 1 geothermal well (Figure 1).

The Yarragadee Formation sediments were deposited in a fluvial environment (Davidson & Yu 2008) where a vegetated floodplain is traversed by meandering rivers. The sediments are composed of coarse-grained sands (around 50%), fine-grained sands (20%) and carbonaceous swampy deposits (30%)

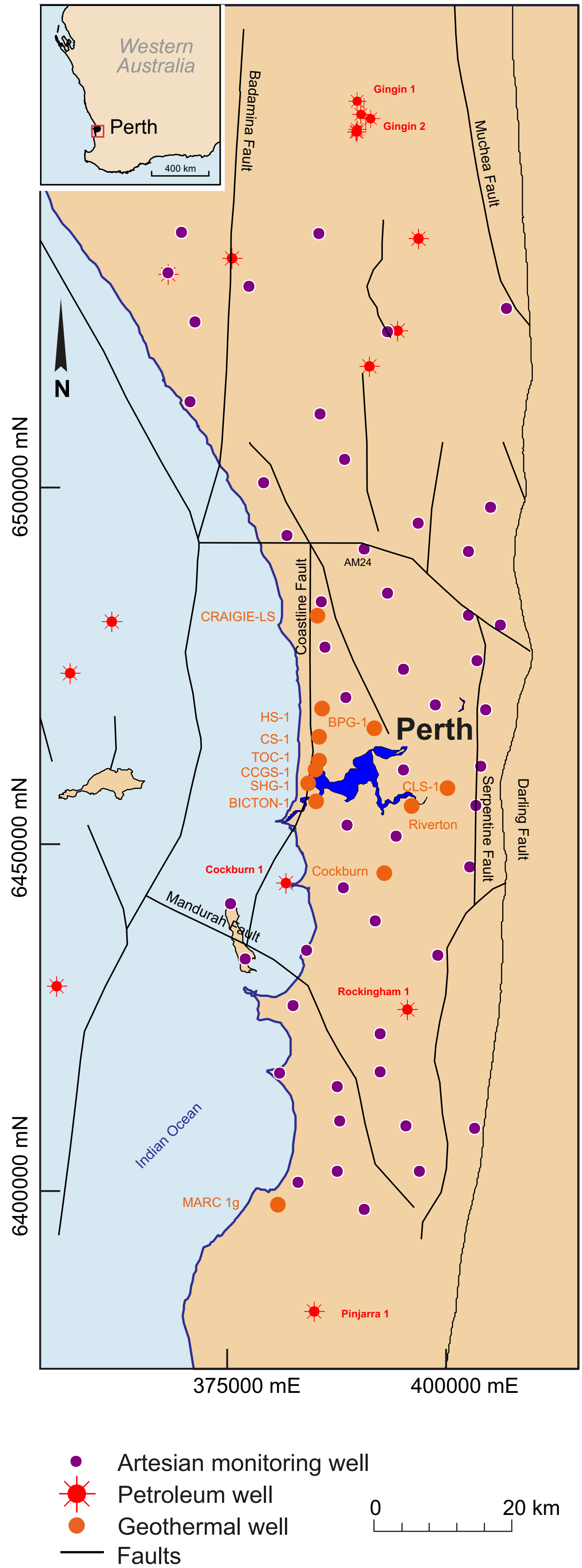

Figure 1. Perth metropolitan area situation map with artesian monitoring (AM), petroleum wells and water production bores. A-A' and B-B' highlight cross-sections presented in Figure 3. See Table 1 for further description of geothermal wells

(Davidson & Yu 2008). The medium- to coarse-grained sandstone beds vary in thickness from 2 to 20 m while inter-bedded finer-grained sandstones and floodplain deposits are generally thinner (2 to 6.5 m). Swampy deposits can reach 12.5 m in thickness and locally restrict vertical groundwater flow within the aquifer.

Aquifer quality

Permeabilities derived from selected short duration well pumping tests range from about 0.4 to 8.8 Darcy (D) and show significant variability resulting from the discontinuous and lensoidal nature of the aquifer. The average permeability (3.4 ±2.5 D) is high and in agreement with permeabilities measured on cores in Cockburn 1 (0.12 to 3.70 D) for medium- to coarse-grained sandstone intervals.

No clear variation trend of permeability versus depth is apparent from the data available for the Upper Yarragadee aquifer. Permeabilities seem to be primarily controlled by facies changes (i.e. interbedded sandstones, siltstones and shales), the discontinuous nature of the intervals conducive to groundwater production and injection and possibly the fault block where the bores are located.

Groundwater in the Yarragadee aquifer is recharged by downwards leakage from overlying shallower aquifers in those areas where the confining units are absent and there are downward hydraulic gradients. The main recharge areas are a 10 km-wide 40 km-long strip to the north of AM24 and possibly an area between the Serpentine and Darling fault southeast of Perth (Figure 1). Recently, increased water extraction for the Perth supply has created a significant area of reduced hydraulic pressure within the Yarragadee aquifer. The current rate of decline of the potentiometric surface is approximately 0.5 m per year near Perth.

Groundwater salinities in the Yarragadee aquifer range from fresh to brackish and generally increase with depth and distance from the recharge zone north of Perth (Davidson 1995). In Cockburn 1, the salinity derived from geophysical logs ranges from about 1 g L^{-1} or less at the top of the aquifer (i.e. down to 1100 m depth) and gradually increases to about 30 g L^{-1} at 1300 m depth (Glasson 2011), the base of the Yarragadee Formation.

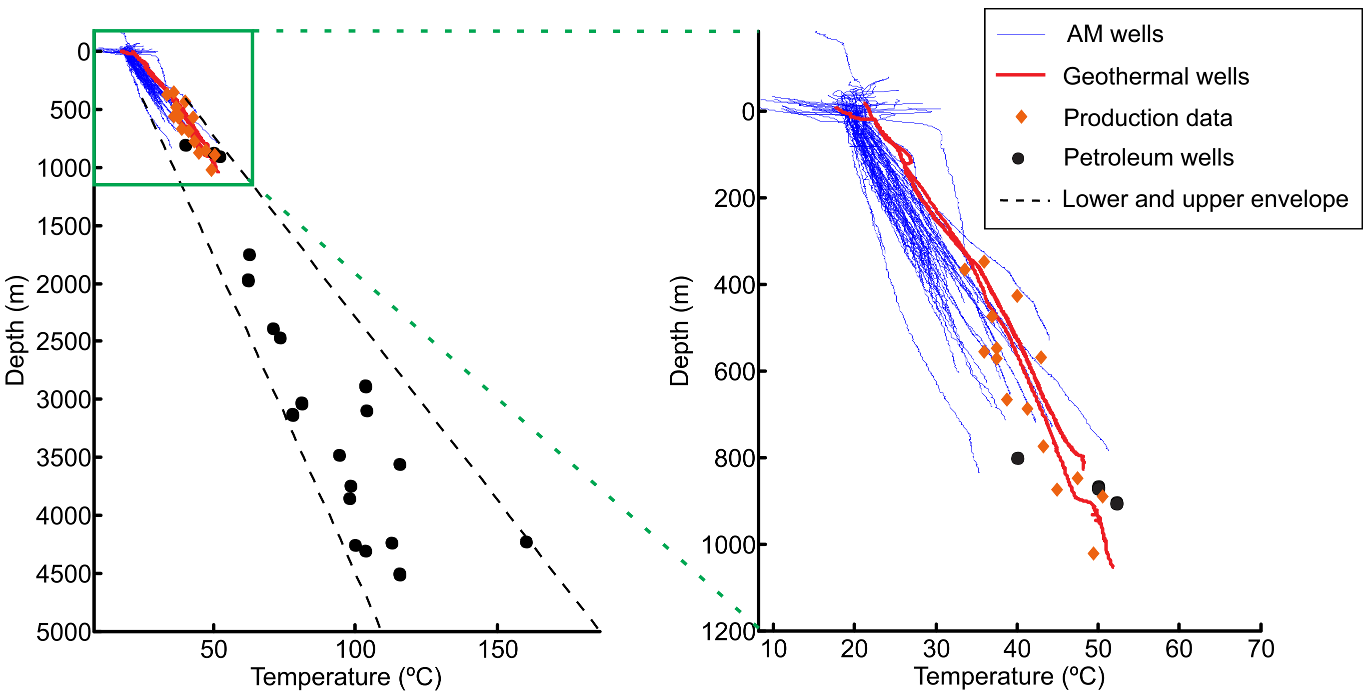

Figure 2. Temperature measurements available for the Perth Metropolitan Area including Department of Water monitoring bores, petroleum wells and including production data from geothermal and deep water supply bores

Geothermics

The first systematic analysis of the temperature distribution in the PMA was performed in 2011 and included the collection of temperature data from 70 Department of Water groundwater monitoring bores at shallow depth within the upper Yarragadee Formation (Reid et al. 2012). Results show that the temperature at 500 m depth is relatively heterogeneously distributed (from 27 to 42 °C). The distribution of temperature within the lower Yarragadee Formation remains largely unknown. Based on a compilation of existing measurements across the wider PMA area, expected temperatures at 1000 m below sea level range from 36 to 58 °C (Figure 2) and at 2000 m below sea level (estimated average depth to the base of the Yarragadee Formation), the temperature can range from 55 to 90 °C. Average temperature gradient with depth for all wells in the Perth Basin from surface to 3000 m varies between 20 and 36.5 °C km^{-1} with temperature ranging from 80 to 130 °C at 3000 m.

Geothermal projects overview

Direct-use geothermal heat-exchange systems used for heating pools in Perth work by extracting the geothermally warmed groundwater, circulating the water through heat exchangers to maintain the pool water temperature at the desired temperature, and then re-injecting the heat-depleted groundwater (usually at 30 to 40 °C) back into the source aquifer. Table 1 lists the characteristics of nine geothermally heated swimming pool projects in the PMA. The geothermal water is generally not used as swimming pool water but re-injected into the aquifer. Heated pools are generally kept at 26 to 28 °C but some leisure centres also operate leisure pools at up to 32 °C and spas at 36 °C. The temperature of the produced water is typically 10 to 12 °C warmer than the desired pool temperature. An injection temperature 1 to 2 °C higher than the pool average temperatures can generally be achieved without compromising the economic selection of heat exchangers.

Space heating of buildings in Perth is only required for a few months of the year and is often undertaken opportunistically when spare heating capacity is available from the geothermal bore.

Perth Basin geothermal design

Two generations of well design concepts were implemented over the years. The second generation began in 2001 with the Christ Church Grammar School geothermal project and has prevailed until today.

In this design, the production bore includes a pump chamber casing (1 in Figure 3), to accommodate a submersible pump, and a production casing (2 in Figure 3) and inline wire wrapped screens at the target production depth (3 in Figure 3). The injection replicates the production bore design with a single injection casing and inline wire wrapped screens (at the target injection depth). Data interpretation suggests that the vertical separation, and the occurrence of beds of shale and siltstone (4 in Figure 3) between the production and injection intervals in the aquifer prevents the direct recycling of the injected groundwater and ensures a sustainable supply of groundwater with a constant temperature. Both wells are then drilled vertically with the injection bore typically completed at 500 to 800 m depth while the production bore can be completed to up to 1500 m depth. Typically, 100

Table 1. Geothermally heated swimming pool projects in the Perth metropolitan area, showing total drilled depth, the temperature difference between extracted and injected groundwater, and the maximum thermal load.

Geothermal operation (Well name)	Year of commissioning	Depth (m)	BHTA,B,C (°C)	ΔT (°C)	Heat-exchanger Max capacity (MW_t)
Bicton P.C. (BICTON-1)	1997	750 (p)	41.0[A]	12*	0.4
Christchurch G.S. (CCGS-1)	2001	628 (i) 757 (p)	41.2[A]	12	0.6
Challenge S. (CS-1)	2004	650 (i) 750 (p)	N/R	8	2.0
Claremont A.C. (TOC-1)	2004	608 (i) 864 (p)	44.5[A]	12	0.6
Craigie L. C. (CRAIGIE-LS)	2006	452 (i) 802 (p)	39.6[A]	8	0.7
Saint Hilda's S. (SHG-1)	2011	681 (i) 1007 (p)	51.8[C]	10	1.0
Canning L.C. (CLS-1)	2012	588 (i) 1165 (p)	45.9[A]	9	1.0
Beatty P.L.C. (BPG-1)	2013	799 (i) 1156 (p)	52.5[C]	10	1.5
Hale S. (HSG-1)	2014	496 (i) 1006 (p)	45.8[B]	15	2.1
TOTAL OPERATING PROJECTS	–	–	–	–	10.0

[A] Uncorrected BHT of unknown lag time
[B] Corrected BHT from 2 or 3 points
[C] Quasi-equilibrium BHT (recorded > 7 days post drilling)
* No injection, water is used for irrigation of parks and gardens in Mosman Park

to 400 m of aquifer is screened in Yarragadee production bores. Since the proportion of medium- to coarse-grained sandstone is around 50% of the total aquifer thickness, the net pay or effective aquifer thickness range from 50 to 200 m in most cases. This design results in permeability-thickness values generally exceeding 100 D m and often in the order of 300 D m.

To date, severe corrosion and scaling issues have not been experienced in the Perth Basin because groundwater salinities are relatively low and the groundwater recirculation system is not exposed to the atmosphere.

Heat-depleted water injection management

To prevent air entrainment and associated geochemical reactions, the system is designed to be over-pressurised (typically 100 to 400 kPa). In recent years downhole injection packers have been used to provide maximum control over the operating

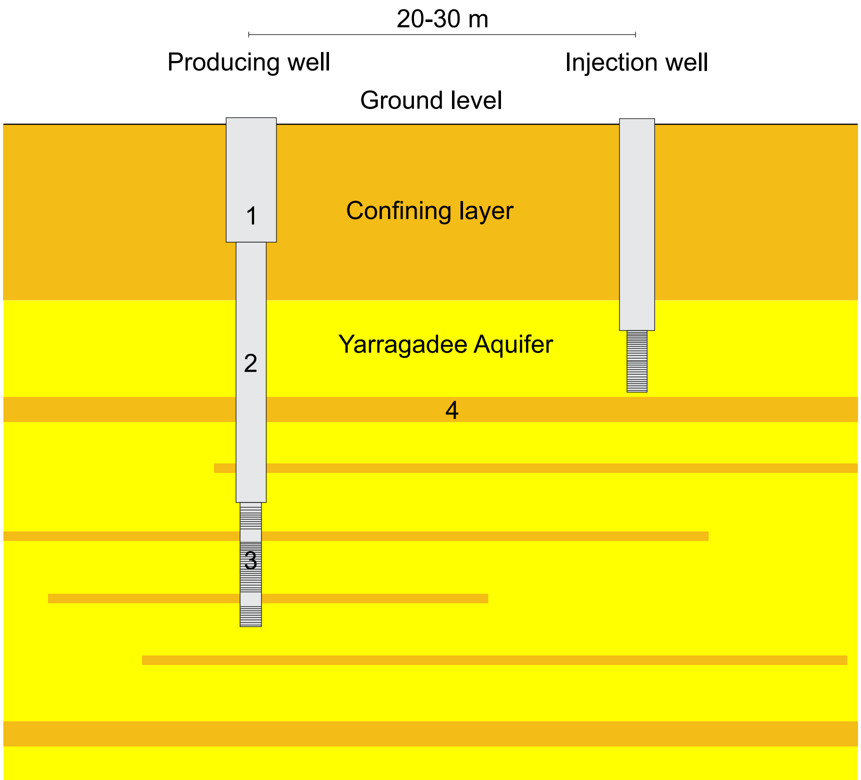

Figure 3. Second generation Perth geothermal bore design (1 is pump chamber casing, 2 is production casing, 3 is inline wire screen and 4 is interbedded sealing unit)

injection pressure. Furthermore to mitigate the potential for scaling and encrustation at the aquifer/screen interface, the injection zone is set at a depth with similar groundwater quality to the production interval. In most projects, suspended solids in the pumped groundwater have also contributed to the gradual clogging. Remediation of the injection bores is typically carried out every 5 to 10 years.

A key aspect when heat-depleted water injection occurs is the planning and mitigation of thermal breakthrough. Thermal breakthrough happens when fluid cooler than the aquifer is re-injected and travels towards the production bore, reducing the produced energy. The impact of the thermal breakthrough on the produced energy is variable depending on site conditions. Its impact is site specific and can be acceptable. It can last in some cases for several years before the project becomes uneconomical. To date, no thermal breakthrough has been identified at any of the Perth projects despite about 15 years of production.

Direct-use geothermal heat-exchange plant design

Perth's geothermal projects provide energy to compensate for swimming pool heat losses that occur through the pool walls and the pool surface. The required peak geothermal heating output for pools in Perth is 150 to 500 kW_t for indoor pools and 500 to 1500 kW_t for outdoor pools. Power requirements for projects in Perth range from 0.5 to 2.5 MW_t depending on the number of pools as well as space heating requirements.

Production of geothermal fluids creates pressure losses. As the Yarragadee aquifer is no longer artesian, all geothermal projects in Perth use an electro-submersible pump (ESP) sitting in the production bore to pump the groundwater to the surface. The required pumping power is a direct ongoing cost associated with the heat production and optimisation of pressure losses can therefore greatly improve the economics of direct-use geothermal systems. The effective pumping power (at the actual Variable Speed Drive frequency) for operating geothermal systems in Perth range from 17 to 61 kW_e at duty despite some of the pumps being equipped with Hi-Temp Franklin motor rated to up to 93 kW_e. For projects currently at the planning stage, ESPs with motors rated to 125 kW_e have been selected.

System performances

Geothermal system performances can be assessed using a coefficient of performance (COP) and capacity factor. COP is a measure of energy produced per energy required to produce it, the bigger the COP, the more productive is the system. For Perth projects, electricity is required to pump water to the surface. Capacity factor qualifies how much the facility is used (1 is maximum and 0 is minimum). Overall, the PMA project performances are mixed. Despite the projects being more efficient than overseas equivalent (24 to 35 versus 15), the utilisation of the systems is low compared to the world average (0.29 to 0.46 versus 0.52). This is due to the Perth climate where heating is required less in summer.

Geothermal heating greatly exceeds the performances of both air-to-water heat pumps and gas-fired heater systems, which have a COP and capacity factor of between 3 and 8 and less than 1, respectively.

Discussion

Perth geothermal projects are well established, economically viable and environmentally sustainable and they present an overall low risk profile as evidenced by their 100 per cent success rate. The development of the direct-use projects in the PMA have benefited from the extensive knowledge and experience of the local groundwater community for water supply as well as from a very favourable geothermal resource. The geothermal resource, the Upper Yarragadee aquifer, is moderately to highly permeable with excellent water quality. This level of maturity has been recognised by ARENA (2014) which evaluated that Perth direct-use projects have mature component technologies, although acknowledging that "the pathway to market for more widespread deployment has been identified as the key barrier for the technology".

Opportunities for future geothermal project development in Perth can be investigated in three key directions:

- Diversity of direct-use and energy optimisation of surface facilities
- Improved understanding of the geothermal resource and scaling-up to larger energy delivery
- Exploration and development of hotter and deeper aquifers.

Diversity of direct-use and energy optimisation of surface facilities

The current focus for geothermal development in the PMA is on heat supply for leisure centres, whereas past, interstate and overseas applications are much more diverse (e.g. pre-heating of industrial processes, aquaculture and district heating). More importantly for Perth, the need for a cooling supply in summer months is large. Existing direct-use projects have great COP but limited capacity factor due to seasonal variations, and little improvement and heat cascading is possible during the summer months; the winter months can provide more potential for energy and energy optimisation but may require re-injection of lower temperature heat-depleted water. Direct-use of 'industrial' applications also have higher capacity factors (e.g. aquaculture (56%), industrial use (70%) and others applications (72%), which will likely have better economics.

With most of the existing projects addressing a specific direct-use, there is a lack of studies investigating the coupling of multiple applications but also energy extraction optimisation aspects of geothermal direct-use systems for the PMA.

Improved understanding of the geothermal resource and scaling-up to larger energy delivery

Despite the success of all geothermal projects, key uncertainties on the characterisation of the geothermal resource exist:

- Hydrogeological and thermal recharge and discharge, including interaction with water supply production
- Compartmentalisation and fault sealing hydrogeological character

- Possible thermal breakthrough. It is not clear if the atypical field design, the nature of the geothermal resource, the production operations schedule (daily and seasonal variations) or a combination of these factors has prevented cold water breakthrough so far.

The re-interpretation of existing data with a geothermal perspective, the acquisition of targeted new data will help to build a more accurate conceptual model, which could then be tested by pragmatic and realistic numerical simulation for predicting areas of high geothermal potential without increasing the exploration risk.

The known range of pumping rates achievable from bores produced from the Yarragadee aquifer for water supply in Perth is up to 850 m^3 $hour^{-1}$ indicating that 5 to 10 MW_t heat exchange capacity from a single production bore should be achievable and likely up to 15 or 20 MW_t should a larger temperature differential across the heat exchange units be adopted. If confirmed, this could open a new range of direct-use projects or supply a group of users. Another opportunity for scaling-up the energy delivery can be to associate several wells to the same heat-exchanger facility.

Finally, with the increase of projects and their increasing scales, there is a need to address the possible issue of thermal recycling but also of interactions between the geothermal projects themselves and with other aquifer users (groundwater extraction and replenishment).

Exploration for hotter and deeper aquifers

The search for deeper aquifers brings risk and cost challenges. A hotter and deeper geothermal aquifer will enable greater differential temperatures at the surface and greater working fluid temperatures, which will in turn increase the range of possible direct-use applications (bringing more flexibility for scaling-up). It will enable a similar energy rate extraction for a less producible aquifer and possibly allow for electricity generation. However, the hydrogeology of the Lower Yarragadee aquifer is largely unknown. It introduces greater risks associated with aquifer suitability and water quality.

An additional issue associated with targeting deeper aquifers is the change of technology and regulatory framework. All current projects in Perth have used water bore rigs and standard groundwater ESP. For the current projects, drilling rigs and auxiliary equipment can generally drill up to 1500 m depth. For deeper aquifers, a larger rig similar to those used for oil and gas exploration (O&G) is likely to be necessary. In addition O&G ESPs are likely to be required for temperatures greater than 55 °C, and pump total dynamic pressure change exceeding 2000 kPa at 200 m^3 $hour^{-1}$. Since the existing geothermal projects are targeting a water resource (Yarragadee aquifer), they are regulated by the Western Australian Department of Water. If a deeper or different geothermal resource is to be targeted, the project might need to be regulated by the WA Department of Mines and Petroleum.

With exploration necessary, and with higher drilling and capital costs, the economics of a deep geothermal project is significantly different from the existing projects. Electricity generation from hotter and deeper aquifers remains a long-term target.

Acknowledgements

The development of geothermal energy in the Perth metropolitan area has received great support from the Western Australian Sate Government via the Department of Commerce, Department of Mines and Petroleum, Department of Water and the groundwater and geothermal industry as a whole. The authors wish to acknowledge their support. Part of the work was conducted within the Western Australian Geothermal Centre of Excellence (WAGCOE), a joint initiative between the Commonwealth Industrial and Scientific Research Organisation, the University of Western Australia, and Curtin University. WAGCOE was funded by the government of Western Australia.

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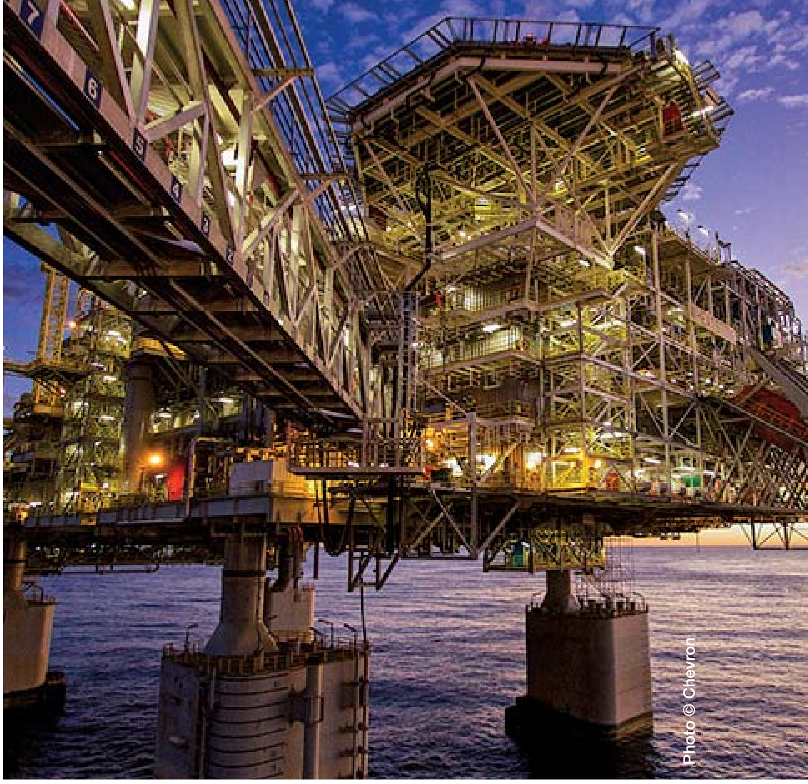
Western Australian gas reserves and resources

Nina E. Triche and Mike Middleton



Hook up and commissioning underway at the Wheatstone Platform

DMP has recently produced a series of maps demonstrating the distribution of natural gas in the Western Australian (WA) onshore and offshore jurisdictions. These include gas reserves and resource estimates for the Perth, Carnarvon, Canning, Browse and Bonaparte Basins, showing locations and volumes of conventional (Figure 1) and shale and tight gas (Figure 2).

Conventional accumulations are reported as reserves and contingent resources, following the Petroleum Resource Management System (PRMS) established by the Society of Petroleum Engineers[1] which is the industry standard for reporting petroleum volumes. PRMS definitions of reserves and contingent resources are discussed by Liu in this issue of PWA.

In DMP's conventional gas map, we report 2P reserves and 2C resources, which correspond to the amount of conventional gas discovered to date in the State, at a 50% probability that the quantities actually produced will equal or exceed the best estimate of their volumes. Reserves exist in the Perth, Carnarvon and Bonaparte Basins, mainly in offshore WA, while contingent gas resources that may become commercially viable in the near future are known from the Perth, Carnarvon, Browse and Canning Basins. Although there are known onshore petroleum shows and discoveries in other basins, the Canning and Perth Basins are currently the only onshore areas with discovered (reserves and contingent) hydrocarbon accumulations. The largest gas reserves in the State lie in the offshore Bonaparte Basin, but no contingent reserves are known from this area. The offshore and State Waters of the Northern Carnarvon Basin also hold reasonably large gas reserves, but additionally contain extremely large continent gas resources, as does the offshore Browse Basin.

Shale and tight gas resources were mapped similarly, but these resources remain in the exploration phase and therefore are reported as total gas initially-in-place (GIIP). The PRMS defines GIIP as undiscovered natural gas plus discovered (sub-commercial and commercial) natural gas, i.e. all the natural gas proposed to exist in an area. GIIP can also be risked by a factor that accounts for the geologic and technical likelihood of achieving successful production. Further, Risked Recoverable Resources can be estimated by applying a recovery factor, or the percentage of the resource that is currently, technically recoverable, to the risked GIIP.

Tight gas quantities were estimated for the Perth and Canning Basins as GIIP; these estimates have not been risked and have not had recovery factors applied. These estimates remain preliminary, as tight gas in the Perth Basin was estimated only for known discoveries and tight gas in the Canning Basin was estimated only for the proposed Laurel Formation basin centred gas accumulation.

Shale gas was estimated for the Perth, Canning and Carnarvon Basins, both as GIIP and as a range of Risked Recoverable Resource. DMP reports risked recoverable figures for these volumes using a risk factor of 50% and a range of 15-30% recovery factors. Vast quantities of shale gas exist in the Canning Basin, but may take some time to become economically viable, while shale gas in the Perth Basin, although smaller in quantity, is currently undergoing active exploration.

[1]http://www.spe.org/industry/docs/Petroleum_Resources_Management_System_2007.pdf

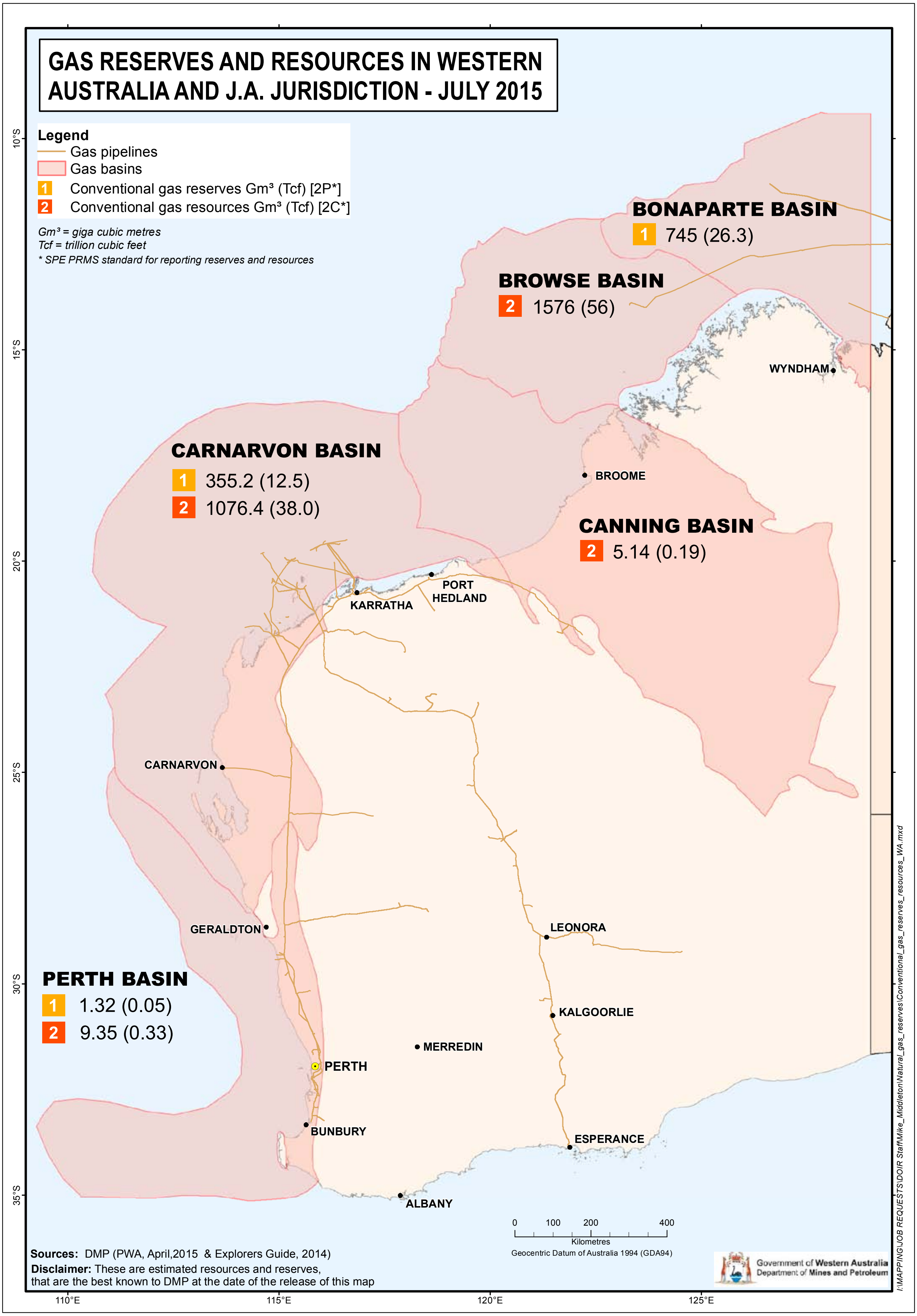


Figure 1. Conventional gas reserves and resources estimates for Western Australia

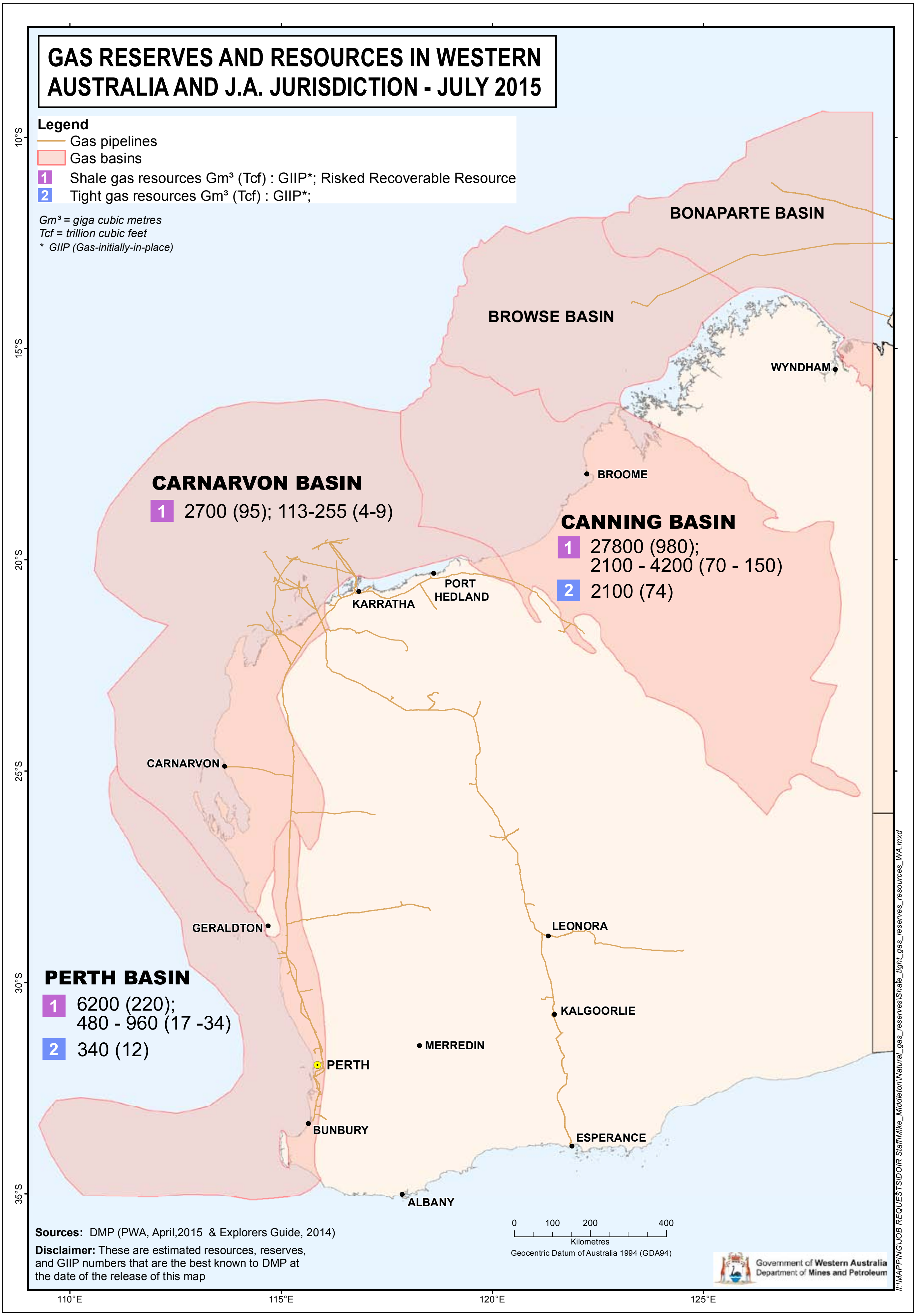


Figure 2. Shale and tight gas resources estimates for Western Australia

A note about hydrocarbon reserves and resources in Western Australia

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Exploration on the Waitsia gasfield

Western Australia (WA) adopts the Society of Petroleum Engineers (SPE) Petroleum Resources Management System (SPE – PRMS) when reviewing and reporting resources and reserves estimates in Western Australian jurisdictions. Here is a short note about SPE – PRMS and the status of WA hydrocarbon resources at the end of 2014.

SPE Petroleum Resources Management System (SPE-PRMS)

SPE, along with a few partner organisations, has been working on the classifications and definitions for estimation of reserves and resources to provide a measure of comparability and reduce the subjective nature of resources estimation. The supporting organisations worldwide for SPE-PRMS are Society of Petroleum Engineers (SPE), American Association of Petroleum Geologists (AAPG), Society of Petroleum Evaluation Engineers (SPEE), and Society of Exploration Geophysicists (SEG). The SPE-PRMS was published in 2007, and guidelines to SPE-PRMS were published in 2011.

Figure 1 shows a graphical presentation of the latest SPE/WPC/AAPG/SPEE resources classification.

It defines the major recoverable resources classes as production, reserves, contingent resources, prospective resources, as well as unrecoverable petroleum.

The SPE-PRMS is a project-based system. Project maturity (vertical axis in Figure 1) and recovery uncertainty (horizontal axis in Figure 1) are evaluated separately. Projects are classified based on their chance of commerciality (the vertical axis), while estimates of the recoverable and marketable quantities associated with each project are categorised to reflect uncertainty (the horizontal axis), as shown in Figure 1.

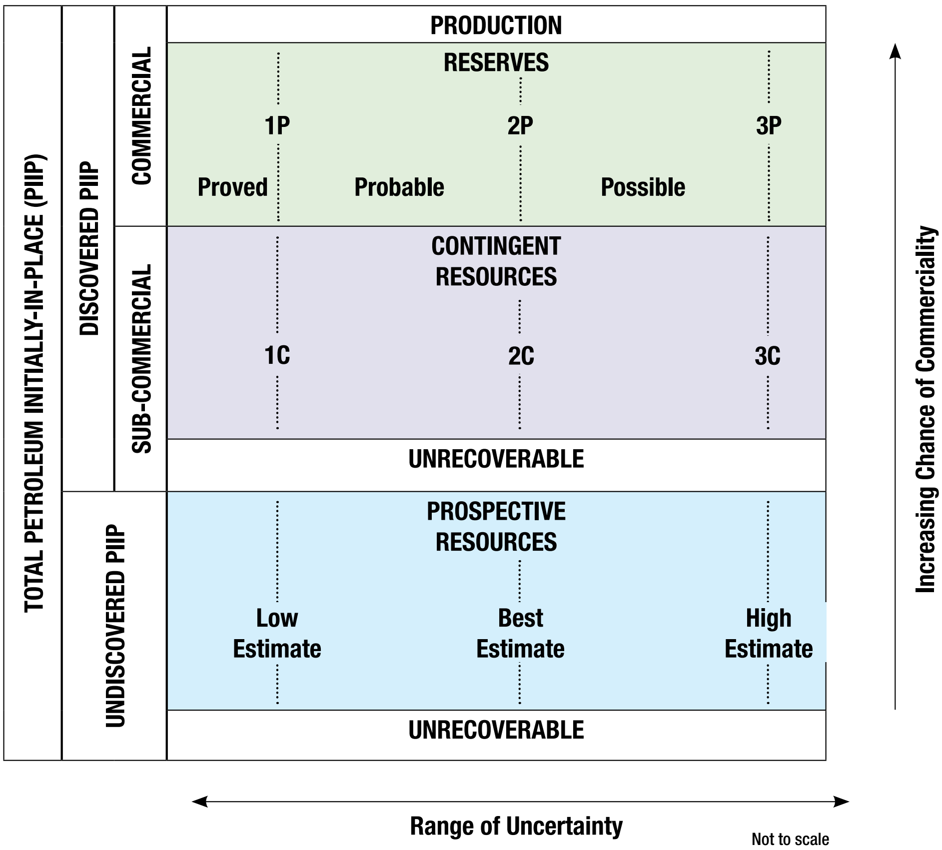

Figure 1. SPE-PRMS classification framework (source: SPE-PRMS)

Reserves must further satisfy four criteria — they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development stage of project(s).

1P is equivalent to the Proved Reserves, it denotes a low estimate scenario of Reserves; 2P is equivalent to the sum of Proved plus Probable Reserves, it denotes a best estimate scenario of Reserves; 3P is the sum of Proved plus Probable plus Possible Reserves, and denotes a high estimate scenario of Reserves.

Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies (or reasons). Contingent resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation (or geological and engineering understanding) of the accumulation is insufficient to clearly assess commerciality.

1C denotes a low estimate scenario of Contingent Resources; 2C denotes a best estimate scenario of Contingent Resources; 3C denotes a high estimate scenario of Contingent Resources.

Both the probabilistic method and the deterministic method can be used to estimate resources and reserves. SPE-PRMS further shows the subclasses of reserves and resources based on project maturity in Figure 2.

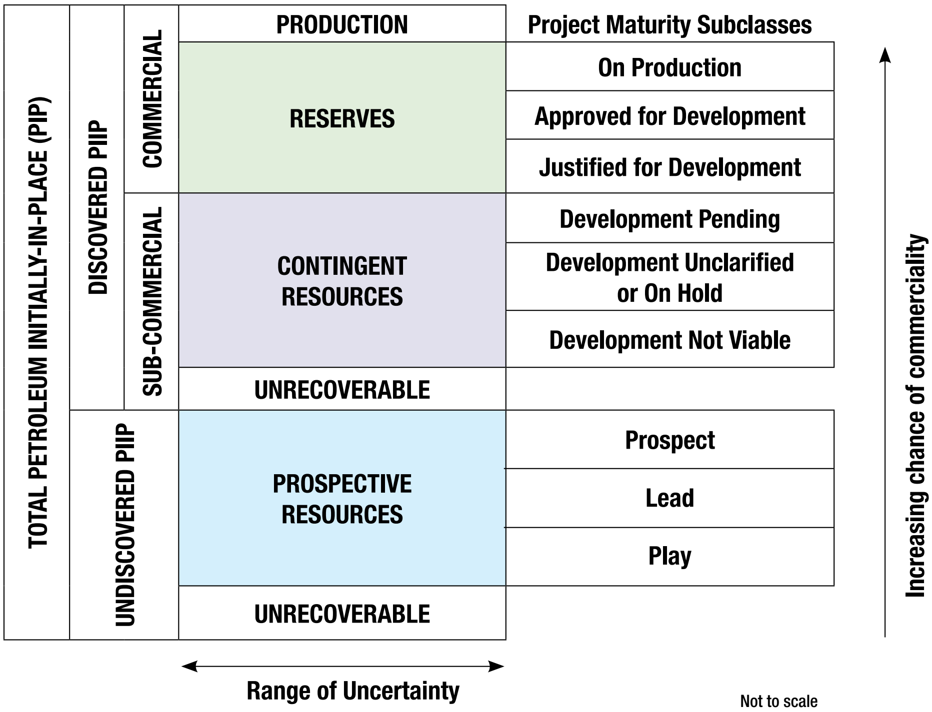

Figure 2. Subclasses based on project maturity

Reserves and resources estimates in WA

Reserves and contingent resources from titles under WA jurisdiction are published each year in the September issue of Petroleum in Western Australia. The 2014 reserves and resources data can be found in Tables 2A (SI units) and 2B (field units) on page 48 of this publication. It is obvious that the Carnarvon Basin holds the largest reserves of oil, gas and condensate. For contingent gas resources, the Perth Basin has become a shining star thanks to the recent discoveries of the Waitsia and Warro gasfields.

Note that aggregation of basin level reserves and resources in Tables 2A and 2B has been made by arithmetic addition based on field level data, thus both 1P and 1C estimates may be very conservative, and both 3P and 3C estimates may be very optimistic. There are slight discrepancies to the reserves and resources reported in SI units and imperial units, as minor rounding discrepancies occur while aggregating to basin level.

Both probabilistic and deterministic methods have been utilised for evaluating WA reserves and resources.

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TABLE 1. 2014 PRODUCTION BY FIELD AND CUMULATIVE PRODUCTION WA ONSHORE AND STATE WATERS AS AT 31 DECEMBER 2014

Field	Operator	2014 Production by Field			Cumulative Production			Permit
		Oil	Condensate	Gas	Oil	Condensate	Gas	
		kL	kL	10^3 m^3	kL	kL	10^3 m^3	
Agincourt	Apache	2,831.7	13.0	446.8	562,435.10	4,282.60	42,320.00	TL/1
Albert	Apache	0.0	0.0	0.0	77,419.80	379.80	16,674.10	TL/6
Bambra	Apache	35,741.0	155.1	20,943.9	438,764.10	158,456.30	1,383,553.20	TL/1
Barrow Island	Chevron	280,430.0	0.0	28,969.1	51,485,088.90	0.00	5,436,337.80	L 1H
Beharra Springs	Origin	0.0	90.9	9,364.5	0.00	24,448.40	2,303,273.80	L 11
Beharra Springs N	Origin	0.0	99.4	10,948.6	0.00	2,155.70	221,346.90	L 11
Blina	Buru Energy	0.0	0.0	0.0	298,725.15	0.00	0.00	L 6
Boundary	Buru Energy	0.0	0.0	0.0	21,212.14	0.00	0.00	L 6
Corybas	AWE	0.0	69.7	3,752.9	0.00	412.10	22,299.30	L 2
Crest	Chevron	27.0	0.0	125.0	275,835.00	108.00	65,898.00	L 12, L 13
Dongara	AWE	183.7	0.0	12,783.2	195,796.40	49,681.21	12,956,244.80	L 1, L 2
Double Island	Apache	0.0	0.0	0.0	708,512.10	2,943.10	59,150.70	TL/9
Gingin West	Empire	0.0	1,020.2	4,329.4	0.00	2,031.00	*8,164.00	L 18, L 19
Harriet	Apache	0.0	0.0	0.0	8,232,695.10	61,226.35	1,510,761.58	TL/1
Hovea	AWE	0.0	0.0	62.7	1,170,005.35	251.09	104,918.20	L 1
Lee	Apache	707.9	166.7	4,790.2	1,021.40	119,379.00	793,150.40	TL/1
Linda	Apache	348.8	26.7	2,947.8	348.80	301,480.50	1,208,043.80	TL/1
Little Sandy	Apache	0.0	0.0	0.0	95,352.90	491.64	15,989.80	TL/6
Mohave	Apache	0.0	0.0	0.0	174,510.90	648.50	40,788.10	TL/6
Pedirka	Apache	0.0	0.0	0.0	341,249.50	1,373.10	45,924.50	TL/6
Red Gully	Empire	0.0	15,174.9	53,898.6	0.00	21,751.70	75,046.50	L 18, L 19
Redback	Origin	0.0	201.0	121,559.7	0.00	915.40	582,553.20	L 11
Roller	Chevron	1,367.0	0.0	647.0	7,212,757.00	0.00	793,862.00	TL/7
Rose	Apache	24,152.6	1,865.9	159,591.8	30,536.10	212,012.30	1,211,679.70	TL/1
Saladin	Chevron	8,647.0	0.0	5,281.0	15,653,984.00	0.00	1,816,934.00	TL/4
Simpson	Apache	0.0	0.0	0.0	857,914.57	14,570.99	90,524.45	TL/1
South Plato	Apache	0.0	0.0	0.0	717,546.10	908.60	52,287.00	TL/6
Sundown	Buru Energy	0.0	0.0	0.0	74,207.18	0.00	0.00	L 8
Tarantula	Origin	0.0	120.4	11,310.3	0.00	4,223.20	342,610.70	L 11
Ungani	Buru Energy	51,751.0	0.0	40.1	70,288.00	0.00	55.90	EP 391
Victoria	Apache	0.0	0.0	0.0	62,587.50	481.20	11,790.70	TL/6
West Cycad	Apache	0.0	0.0	0.0	218,676.00	546.80	36,990.60	TL/9
West Terrace	Buru Energy	0.0	0.0	0.0	39,602.35	0.00	0.00	L 8
Wonnich	Apache	0.0	0.0	0.0	0.00	479,450.13	4,856,471.08	TL/8
Yammaderry	Chevron	0.0	0.0	3,753.0	858,332.00	0.00	146,149.00	TL/4
Total		**406,187.7**	**19,003.9**	**455,545.6**	**89,875,403.44**	**1,464,608.72**	**36,243,629.80**	

* Correct value for cumulative gas at Gingin West. An incorrect value was previously published in this table and on the DMP website in 2014, which inadvertently included Gingin gas in the total.

TABLE 2A. PETROLEUM RESERVES AND RESOURCES ESTIMATES IN WA JURISDICTIONS (SI UNITS, VALID AS OF 31 DECEMBER 2014)

Basin	Reserves						Contingent Resources					
	Oil, GL		Gas, Gm³		Condensate, GL		Oil, GL		Gas, Gm³		Condensate, GL	
	1P	2P	1P	2P	1P	2P	1C	2C	1C	2C	1C	2C
Browse	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.40	24.20	1.30	2.50
Canning	0.00	0.00	0.00	0.00	0.00	0.00	0.56	0.90	1.76	5.41	0.16	0.48
Carnavon	1.08	8.17	0.37	0.97	0.06	0.08	1.85	3.14	1.15	1.52	0.00	0.00
Perth	0.00	0.00	0.76	1.41	0.06	0.09	0.00	0.00	12.15	52.13	32.36	61.05
WA TOTAL	1.08	8.17	1.13	2.38	0.12	0.17	2.41	4.04	27.46	83.26	33.82	64.03

TABLE 2B. PETROLEUM RESERVES AND RESOURCES ESTIMATES IN WA JURISDICTIONS (IMPERIAL UNITS, VALID AS OF 31 DECEMBER 2014)

Basin	Reserves						Contingent Resources					
	Oil, MMstb		Gas, Bscf		Condensate, MMstb		Oil, MMstb		Gas, Bscf		Condensate, MMstb	
	1P	2P	1P	2P	1P	2P	1C	2C	1C	2C	1C	2C
Browse	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	439.00	855.00	8.10	15.80
Canning	0.02	0.02	0.00	0.00	0.00	0.00	3.50	5.66	62.01	191.02	1.01	3.00
Carnavon	6.80	51.37	12.99	34.28	0.40	0.50	11.59	19.74	40.52	54.01	0.00	0.00
Perth	0.00	0.00	26.67	49.92	0.35	0.59	0.00	0.00	429.14	1840.99	203.63	384.22
WA Total	6.82	51.39	39.66	84.19	0.75	1.09	15.09	25.40	70.67	941.02	212.74	403.02

TABLE 3. PETROLEUM WELLS IN WESTERN AUSTRALIA — ONSHORE AND STATE WATERS 2014/2015

Well Name	Class	On Off	Title	Operator	Latitude	Longitude	Gnd Elev (m)	RT/ KB (m)	Spud Date	TD Date	Rig Release Date
CANNING BASIN											
Commodore 1	NFW	On	EP 390 R2	Buru Energy Ltd	122.441	-19.188	113.1	14.0	21/11/2014	22/12/2014	24/12/2014
Olympic 1	NFW	On	EP 473	Buru Energy Ltd	122.640	-18.299	94.1	1.4	22/05/2015	19/06/2015	21/06/2015
Praslin 1	NFW	On	EP 391	Buru Energy Ltd	123.020	-17.985	58.0	3.0	16/07/2015		
Sunbeam 1	NFW	On	EP 129 R5	Buru Energy Ltd	124.368	-17.541	64.0	1.4	25/01/2015	7/02/2015	10/02/2015
PERTH BASIN											
Drover 1	NFW	On	EP 455	AWE Ltd	115.147	-30.077	182.6	6.6	29/06/2014	16/7/2014	25/7/2014
Dunnart 2	NFW	On	EP 437	Key Petroleum	114.938	-29.156	49.5	46.0	13/07/2014	24/8/2014	30/8/2014
Senecio 3	EXT	On	L 2 R1	AWE Ltd	115.080	-29.253	69.0	6.6	05/08/2014	23/8/2014	7/9/2014
Irwin 1	NFW	On	L 1 R1	AWE Ltd	115.169	-29.259	90.0	6.6	28/03/2015	24/04/2015	4/05/2015
Waitsia 1	NFW	On	L 1 R1	AWE Ltd	115.111	-29.253	78.0	6.6	14/05/2015	9/06/2015	21/06/2015
Waitsia 2	EXT	On	L 1 R1	AWE Ltd	115.094	-29.302	39.9	6.6	29/06/2015		

Several wells were drilled on Barrow Island as part of the Gorgon project but are not shown.
These wells were not drilled under the Petroleum Acts.

TABLE 4. SURVEYS IN WESTERN AUSTRALIA — ONSHORE AND STATE WATERS 2014/2015

Survey Name	Class	On Off	Title	Operator	Commenced	Completed	2D/Line km @ 31/12/2014	3D km² @ 31/12/2014
CANNING BASIN								
Barbwire 2D S.S.	2D	On	EP 458, EP 476	Buru Energy Ltd	14/08/2014	1/09/2014	245	
Canning Airborne Gravity Gradiometry Survey	Gravity	On	EP 391 R3, EP 431, EP 436	Buru Energy Ltd	2/6/2015	10/6/2015	5,765	
Commodore West 2D S.S.	2D	On	EP 471	Buru Energy Ltd	25/07/2014	3/08/2014	123	
Mt Fenton 2D S.S.	2D	On	EP 458	Buru Energy Ltd	6/08/2014	14/08/2014	113	
Mt Rosamund 2D S.S.	2D	On	EP 472, 476,477	Buru Energy Ltd	6/09/2014	12/10/2014	507	
Jackaroo 2D/3D S.S.	3DREFL	On	EP 391 R2, EP 428 R1, EP 436 R1	Buru Energy Ltd	17/10/2014	27/11/2014	9	255
NORTHERN CARNARVON BASIN								
Numbat 3D M.S.S.	3D	Off	SPA 2 T	Searcher Seismic	19/5/2015	3/6/2015		146
PERTH BASIN								
Black Swan Airborne Geophysical Survey	Geophysical	On	EP 368 R4, EP 389 R2, EP 416 R1, EP 426, EP 430, EP 432, EP 440 R1, EP 454, EP 480	Empire Oil & Gas NL	1/5/2015	30/5/2015	12,776	
EP413 Arrowsmith 3D S.S	3D	On	EP 413 R3	Norwest Energy NL	23/4/2015	2/5/2015		106
West Erregulla 3D S.S.	3DREFL	On	EP 469	Warrego Energy	29/11/2014	10/12/2014		80

Classification

2D	*2D Seismic Survey*
3D/3DREFL	*3D Seismic Reflection Survey*
Gravity	*Gravity Gradiometry Survey*
Geophysical	*Airborne Geophysical Survey*

TABLE 5. LIST OF TITLES AND HOLDERS IN WESTERN AUSTRALIAN JURISDICTIONS AS AT 27 JULY 2015

PETROLEUM (SUBMERGED LANDS) ACT 1982
Exploration Permit

Title	Registered Holder(s)
TP/7 R4	HYDRA ENERGY (WA) PTY LTD QUADRANT OIL AUSTRALIA PTY LIMITED* SANTOS (BOL) PTY LTD TAP (SHELFAL) PTY LTD
TP/8 R4	HARRIET (ONYX) PTY LTD KUFPEC AUSTRALIA PTY LTD QUADRANT NORTHWEST PTY LTD*
TP/15 R2	WESTRANCH HOLDINGS PTY LTD
TP/23 R1	QUADRANT NORTHWEST PTY LTD
TP/25	FINDER NO 3 PTY LIMITED
TP/26	PERSEVERANCE ENERGY PTY LTD
TP/27	CARNARVON PETROLEUM LIMITED

PETROLEUM (SUBMERGED LANDS) ACT 1982
Pipeline Licence

Title	Registered Holder(s)
TPL/1 R1	HARRIET (ONYX) PTY LTD KUFPEC AUSTRALIA PTY LTD QUADRANT NORTHWEST PTY LTD*
TPL/2 R1	HARRIET (ONYX) PTY LTD KUFPEC AUSTRALIA PTY LTD QUADRANT NORTHWEST PTY LTD*
TPL/3 R1	HYDRA ENERGY (WA) PTY LTD QUADRANT OIL AUSTRALIA PTY LIMITED* SANTOS (BOL) PTY LTD TAP (SHELFAL) PTY LTD
TPL/4 R1	HYDRA ENERGY (WA) PTY LTD QUADRANT OIL AUSTRALIA PTY LIMITED SANTOS (BOL) PTY LTD TAP (SHELFAL) PTY LTD
TPL/5 R1	HARRIET (ONYX) PTY LTD KUFPEC AUSTRALIA PTY LTD QUADRANT NORTHWEST PTY LTD*
TPL/6 R1	CHEVRON (TAPL) PTY LTD CHEVRON AUSTRALIA PTY LTD* MOBIL AUSTRALIA RESOURCES COMPANY PTY LIMITED SANTOS OFFSHORE PTY LTD
TPL/7 R2	HYDRA ENERGY (WA) PTY LTD QUADRANT OIL AUSTRALIA PTY LIMITED* SANTOS (BOL) PTY LTD TAP (SHELFAL) PTY LTD
TPL/8	HARRIET (ONYX) PTY LTD KUFPEC AUSTRALIA PTY LTD QUADRANT NORTHWEST PTY LTD*
TPL/9 R1	CHEVRON (TAPL) PTY LTD CHEVRON AUSTRALIA PTY LTD* MOBIL AUSTRALIA RESOURCES COMPANY PTY LIMITED SANTOS OFFSHORE PTY LTD
TPL/10	BHP BILLITON PETROLEUM (AUSTRALIA) PTY LTD* INPEX ALPHA LTD MOBIL EXPLORATION & PRODUCING AUSTRALIA PTY LTD
TPL/11	CHEVRON (TAPL) PTY LTD CHEVRON AUSTRALIA PTY LTD* MOBIL AUSTRALIA RESOURCES COMPANY PTY LIMITED SANTOS OFFSHORE PTY LTD
TPL/12	QUADRANT EAST SPAR PTY LIMITED QUADRANT KERSAIL PTY LTD QUADRANT OIL AUSTRALIA PTY LIMITED* SANTOS (BOL) PTY LTD
TPL/13	HARRIET (ONYX) PTY LTD KUFPEC AUSTRALIA PTY LTD QUADRANT EAST SPAR PTY LIMITED QUADRANT KERSAIL PTY LTD QUADRANT NORTHWEST PTY LTD* QUADRANT OIL AUSTRALIA PTY LIMITED SANTOS (BOL) PTY LTD
TPL/14	HARRIET (ONYX) PTY LTD KUFPEC AUSTRALIA PTY LTD QUADRANT NORTHWEST PTY LTD*
TPL/15	BHP BILLITON PETROLEUM (NORTH WEST SHELF) PTY LTD BP DEVELOPMENTS AUSTRALIA PTY LTD CHEVRON AUSTRALIA PTY LTD JAPAN AUSTRALIA LNG (MIMI) PTY LTD SHELL AUSTRALIA PTY LTD WOODSIDE ENERGY LTD*
TPL/16	BHP BILLITON PETROLEUM (NORTH WEST SHELF) PTY LTD BP DEVELOPMENTS AUSTRALIA PTY LTD CHEVRON AUSTRALIA PTY LTD JAPAN AUSTRALIA LNG (MIMI) PTY LTD SHELL AUSTRALIA PTY LTD WOODSIDE ENERGY LTD*
TPL/17	QUADRANT NORTHWEST PTY LTD SANTOS (BOL) PTY LTD
TPL/18	AWE (OFFSHORE PB) PTY LTD AWE OIL (WESTERN AUSTRALIA) PTY LTD ROC OIL (WA) PTY LIMITED
TPL/19	KANSAI ELECTRIC POWER AUSTRALIA PTY LTD TOKYO GAS PLUTO PTY LTD WOODSIDE BURRUP PTY LTD*
TPL/20	QUADRANT NORTHWEST PTY LTD SANTOS OFFSHORE PTY LTD
TPL/21	CHEVRON (TAPL) PTY LTD* CHUBU ELECTRIC POWER GORGON PTY LTD MOBIL AUSTRALIA RESOURCES COMPANY PTY LIMITED OSAKA GAS GORGON PTY LTD SHELL AUSTRALIA PTY LTD TOKYO GAS GORGON PTY LTD
TPL/22	CHEVRON (TAPL) PTY LTD* CHUBU ELECTRIC POWER GORGON PTY LTD MOBIL AUSTRALIA RESOURCES COMPANY PTY LIMITED OSAKA GAS GORGON PTY LTD SHELL AUSTRALIA PTY LTD TOKYO GAS GORGON PTY LTD
TPL/23	BHP BILLITON PETROLEUM (AUSTRALIA) PTY LTD QUADRANT PVG PTY LTD
TPL/24	CHEVRON (TAPL) PTY LTD* CHUBU ELECTRIC POWER GORGON PTY LTD MOBIL AUSTRALIA RESOURCES COMPANY PTY LIMITED OSAKA GAS GORGON PTY LTD SHELL AUSTRALIA PTY LTD TOKYO GAS GORGON PTY LTD
TPL/25	APACHE JULIMAR PTY LTD CHEVRON (TAPL) PTY LTD* KUFPEC AUSTRALIA (JULIMAR) PTY LTD KYUSHU ELECTRIC WHEATSTONE PTY LTD PE WHEATSTONE PTY LTD SHELL AUSTRALIA PTY LTD

TABLE 5. LIST OF TITLES AND HOLDERS IN WESTERN AUSTRALIAN JURISDICTIONS AS AT 27 JULY 2015

PETROLEUM (SUBMERGED LANDS) ACT 1982
Production Licence

Title	Registered Holder(s)
TL/1 R1	HARRIET (ONYX) PTY LTD KUFPEC AUSTRALIA PTY LTD QUADRANT NORTHWEST PTY LTD*
TL/2 R1	HYDRA ENERGY (WA) PTY LTD QUADRANT OIL AUSTRALIA PTY LIMITED* SANTOS (BOL) PTY LTD TAP (SHELFAL) PTY LTD
TL/3 R1	CHEVRON (TAPL) PTY LTD CHEVRON AUSTRALIA PTY LTD* MOBIL AUSTRALIA RESOURCES COMPANY PTY LIMITED SANTOS OFFSHORE PTY LTD
TL/4 R1	CHEVRON (TAPL) PTY LTD CHEVRON AUSTRALIA PTY LTD* MOBIL AUSTRALIA RESOURCES COMPANY PTY LIMITED SANTOS OFFSHORE PTY LTD
TL/5 R1	HARRIET (ONYX) PTY LTD KUFPEC AUSTRALIA PTY LTD QUADRANT NORTHWEST PTY LTD*
TL/6 R1	HARRIET (ONYX) PTY LTD KUFPEC AUSTRALIA PTY LTD QUADRANT NORTHWEST PTY LTD*
TL/7	CHEVRON (TAPL) PTY LTD CHEVRON AUSTRALIA PTY LTD* MOBIL AUSTRALIA RESOURCES COMPANY PTY LIMITED SANTOS OFFSHORE PTY LTD
TL/8	HARRIET (ONYX) PTY LTD KUFPEC AUSTRALIA PTY LTD QUADRANT NORTHWEST PTY LTD*
TL/9	HARRIET (ONYX) PTY LTD KUFPEC AUSTRALIA PTY LTD QUADRANT NORTHWEST PTY LTD*
TL/10	HARRIET (ONYX) PTY LTD KUFPEC AUSTRALIA PTY LTD QUADRANT NORTHWEST PTY LTD*

PETROLEUM (SUBMERGED LANDS) ACT 1982
Retention Lease

Title	Registered Holder(s)
TR/1 R2	HARRIET (ONYX) PTY LTD KUFPEC AUSTRALIA PTY LTD QUADRANT NORTHWEST PTY LTD*
TR/3 R2	QUADRANT NORTHWEST PTY LTD
TR/4 R1	CHEVRON (TAPL) PTY LTD CHEVRON AUSTRALIA PTY LTD* MOBIL AUSTRALIA RESOURCES COMPANY PTY LIMITED SANTOS OFFSHORE PTY LTD
TR/5 R2	BP DEVELOPMENTS AUSTRALIA PTY LTD JAPAN AUSTRALIA LNG (MIMI BROWSE) PTY LTD PETROCHINA INTERNATIONAL INVESTMENT (AUSTRALIA) PTY LTD SHELL AUSTRALIA PTY LTD WOODSIDE BROWSE PTY LTD*
TR/6 R1	CHEVRON (TAPL) PTY LTD CHEVRON AUSTRALIA PTY LTD* MOBIL AUSTRALIA RESOURCES COMPANY PTY LIMITED SANTOS OFFSHORE PTY LTD

PETROLEUM (SUBMERGED LANDS) ACT 1982
Special Prospecting Authority

Title	Registered Holder(s)
SPA 2 T	SEARCHER SEISMIC PTY LTD

PETROLEUM (SUBMERGED LANDS) ACT 1982
Access Authority

Title	Registered Holder(s)
AA 2 T	SEARCHER SEISMIC PTY LTD
AA 9	SEARCHER SEISMIC PTY LTD

PETROLEUM AND GEOTHERMAL ENERGY RESOURCES ACT 1967
Access Authority

Title	Registered Holder(s)
AA 5	FINDER NO 5 PTY LIMITED

PETROLEUM AND GEOTHERMAL ENERGY RESOURCES ACT 1967
Exploration Permit

Title	Registered Holder(s)
EP 61 R7	CHEVRON (TAPL) PTY LTD CHEVRON AUSTRALIA PTY LTD* MOBIL AUSTRALIA RESOURCES COMPANY PTY LIMITED SANTOS OFFSHORE PTY LTD
EP 62 R7	CHEVRON (TAPL) PTY LTD CHEVRON AUSTRALIA PTY LTD* MOBIL AUSTRALIA RESOURCES COMPANY PTY LIMITED SANTOS OFFSHORE PTY LTD
EP 104 R6	FAR LTD GULLIVER PRODUCTIONS PTY LTD* INDIGO OIL PTY LTD PANCONTINENTAL OIL & GAS NL
EP 129 R5	BURU ENERGY LIMITED
EP 307 R5	HARRIET (ONYX) PTY LTD KUFPEC AUSTRALIA PTY LTD QUADRANT NORTHWEST PTY LTD*
EP 320 R4	AWE (BEHARRA SPRINGS) PTY LTD ORIGIN ENERGY DEVELOPMENTS PTY LIMITED*
EP 321 R4	ALCOA OF AUSTRALIA LIMITED LATENT PETROLEUM PTY LTD*
EP 357 R3	CHEVRON (TAPL) PTY LTD CHEVRON AUSTRALIA PTY LTD* MOBIL AUSTRALIA RESOURCES COMPANY PTY LIMITED SANTOS OFFSHORE PTY LTD
EP 358 R3	HARRIET (ONYX) PTY LTD KUFPEC AUSTRALIA PTY LTD QUADRANT NORTHWEST PTY LTD*
EP 359 R3	BOUNTY OIL & GAS NL LANSVALE OIL & GAS PTY LTD PACE PETROLEUM PTY LTD PHOENIX RESOURCES PLC ROUGH RANGE OIL PTY LTD
EP 368 R4	EMPIRE OIL COMPANY (WA) LIMITED* WESTRANCH HOLDINGS PTY LTD
EP 371 R2	BURU ENERGY LIMITED DIAMOND RESOURCES (CANNING) PTY LTD
EP 381 R3	WHICHER RANGE ENERGY PTY LTD

TABLE 5. LIST OF TITLES AND HOLDERS IN WESTERN AUSTRALIAN JURISDICTIONS AS AT 27 JULY 2015

EP 386 R3	ONSHORE ENERGY PTY LTD
EP 389 R2	EMPIRE OIL COMPANY (WA) LIMITED ERM GAS PTY LTD
EP 390 R2	BURU ENERGY LIMITED* DIAMOND RESOURCES (CANNING) PTY LTD QUADRANT ONSHORE HOLDINGS PTY LTD
EP 391 R3	BURU ENERGY LIMITED DIAMOND RESOURCES (FITZROY) PTY LTD
EP 408 R2	CALENERGY RESOURCES (AUSTRALIA) LIMITED*
EP 412 R2	WHICHER RANGE ENERGY PTY LTD BOUNTY OIL & GAS NL ROUGH RANGE OIL PTY LTD*
EP 413 R3	AWE PERTH PTY LTD BHARAT PETRORESOURCES LIMITED NORWEST ENERGY NL*
EP 416 R1	ALLIED OIL & GAS PLC EMPIRE OIL COMPANY (WA) LIMITED* ERM GAS PTY LTD
EP 417 R1	NEW STANDARD ONSHORE PTY LTD
EP 426	ALLIED OIL & GAS PLC EMPIRE OIL COMPANY (WA) LIMITED ERM GAS PTY LTD WESTRANCH HOLDINGS PTY LTD
EP 428 R1	BURU ENERGY LIMITED DIAMOND RESOURCES (CANNING) PTY LTD
EP 430 R1	EMPIRE OIL COMPANY (WA) LIMITED
EP 431 R1	BURU ENERGY LIMITED DIAMOND RESOURCES (FITZROY) PTY LTD
EP 432	ALLIED OIL & GAS PLC EMPIRE OIL COMPANY (WA) LIMITED* ERM GAS PTY LTD
EP 435 R1	AUSTRALIAN OIL COMPANY NO 3 PTY LIMITED BLACK FIRE MINERALS LIMITED BOUNTY OIL & GAS NL PHOENIX RESOURCES PLC ROUGH RANGE OIL PTY LTD
EP 436 R1	BURU ENERGY LIMITED DIAMOND RESOURCES (FITZROY) PTY LTD
EP 437 R1	CARACAL EXPLORATION PTY LTD KEY PETROLEUM (AUSTRALIA) PTY LTD REY OIL AND GAS PERTH PTY LTD
EP 438 R1	BURU ENERGY LIMITED* DIAMOND RESOURCES (CANNING) PTY LTD QUADRANT ONSHORE HOLDINGS PTY LTD
EP 439	FALCORE PTY LTD INDIGO OIL PTY LTD JURASSICA OIL & GAS PLC LONGREACH OIL LIMITED ROUGH RANGE OIL PTY LTD* VIGILANT OIL PTY LTD
EP 440 R1	EMPIRE OIL COMPANY (WA) LIMITED
EP 441 R1	QUADRANT NORTHWEST PTY LTD
EP 443	NEW STANDARD ONSHORE PTY LTD*
EP 447 R1	GCC METHANE PTY LTD UIL ENERGY LTD*
EP 448	GULLIVER PRODUCTIONS PTY LTD* INDIGO OIL PTY LTD
EP 449	HESS AUSTRALIA (CANNING) PTY LIMITED
EP 450	NEW STANDARD ONSHORE PTY LTD*
EP 451	NEW STANDARD ONSHORE PTY LTD*
EP 453 R1	GOSHAWK ENERGY (LENNARD SHELF) PTY LTD
EP 454	EMPIRE OIL COMPANY (WA) LIMITED* ERM GAS PTY LTD
EP 455	AWE PERTH PTY LTD* TITAN ENERGY LTD
EP 456	NEW STANDARD ONSHORE PTY LTD*
EP 457	BURU FITZROY PTY LTD* DIAMOND RESOURCES (FITZROY) PTY LTD REY OIL AND GAS PTY LTD
EP 458	BURU FITZROY PTY LTD* DIAMOND RESOURCES (FITZROY) PTY LTD REY OIL AND GAS PTY LTD
EP 464	EXCEED ENERGY (AUSTRALIA) PTY LTD
EP 465	AUSTRALIA ZHONGFU OIL GAS RESOURCES PTY LTD
EP 467	ERM GAS PTY LTD
EP 468	OFFICER PETROLEUM PTY LTD
EP 469	DYAS AUSTRALIA PTY LTD MAZARINE ENERGY AUSTRALIA PTY LTD WARREGO ENERGY PTY LTD*
EP 471	BURU ENERGY LIMITED* DIAMOND RESOURCES (CANNING) PTY LTD QUADRANT ONSHORE HOLDINGS PTY LTD
EP 472	BURU ENERGY LIMITED* DIAMOND RESOURCES (CANNING) PTY LTD
EP 473	BURU ENERGY LIMITED* DIAMOND RESOURCES (CANNING) PTY LTD QUADRANT ONSHORE HOLDINGS PTY LTD
EP 475	CARNARVON PETROLEUM LIMITED
EP 476	BURU ENERGY LIMITED* DIAMOND RESOURCES (CANNING) PTY LTD
EP 477	BURU ENERGY (ACACIA) PTY LTD* DIAMOND RESOURCES (CANNING) PTY LTD
EP 478	BURU ENERGY (ACACIA) PTY LTD BURU ENERGY LIMITED*
EP 480	EMPIRE OIL COMPANY (WA) LIMITED ERM GAS PTY LTD
EP 481	NEW STANDARD ONSHORE PTY LTD
EP 482	NEW STANDARD ONSHORE PTY LTD
EP 483	FINDER NO 3 PTY LIMITED
EP 484	DYNASTY METALS AUSTRALIA LTD
EP 485	DYNASTY METALS AUSTRALIA LTD
EP 486	EXCEED ENERGY (AUSTRALIA) PTY LTD
EP 487	BACKREEF OIL PTY LIMITED OIL BASINS LIMITED
EP 488	UIL ENERGY LTD
EP 489	UIL ENERGY LTD
EP 490	CARNARVON PETROLEUM LIMITED
EP 491	CARNARVON PETROLEUM LIMITED
EP 492	WESTRANCH HOLDINGS PTY LTD
EP 493	FINDER SHALE PTY LIMITED
EP 494	SOUTHERN SKY ENERGY PTY LTD*

TABLE 5. LIST OF TITLES AND HOLDERS IN WESTERN AUSTRALIAN JURISDICTIONS AS AT 27 JULY 2015

PETROLEUM AND GEOTHERMAL ENERGY RESOURCES ACT 1967
Production Licence

Title	Registered Holder(s)
L 1 R1	APT PARMELIA PTY LTD AWE PERTH PTY LTD ORIGIN ENERGY DEVELOPMENTS PTY LIMITED
L 2 R1	AWE PERTH PTY LTD* ORIGIN ENERGY DEVELOPMENTS PTY LIMITED
L 4 R1	AWE PERTH PTY LTD
L 5 R1	AWE PERTH PTY LTD
L 6 R1	BURU ENERGY LIMITED
L 7 R1	AWE PERTH PTY LTD
L 8 R1	BURU ENERGY LIMITED
L 9 R1	DBP DEVELOPMENT GROUP NOMINEES PTY LIMITED
L 10 R1	CHEVRON (TAPL) PTY LTD CHEVRON AUSTRALIA PTY LTD* MOBIL AUSTRALIA RESOURCES COMPANY PTY LIMITED SANTOS OFFSHORE PTY LTD
L 11	AWE (BEHARRA SPRINGS) PTY LTD ORIGIN ENERGY DEVELOPMENTS PTY LIMITED*
L 12	CHEVRON (TAPL) PTY LTD CHEVRON AUSTRALIA PTY LTD* MOBIL AUSTRALIA RESOURCES COMPANY PTY LIMITED SANTOS OFFSHORE PTY LTD
L 13	CHEVRON (TAPL) PTY LTD CHEVRON AUSTRALIA PTY LTD* MOBIL AUSTRALIA RESOURCES COMPANY PTY LIMITED SANTOS OFFSHORE PTY LTD
L 14	AWE PERTH PTY LTD GEARY, JOHN KEVIN NORWEST ENERGY NL ORIGIN ENERGY DEVELOPMENTS PTY LIMITED* ROC OIL (WA) PTY LIMITED
L 15	BURU ENERGY LIMITED FAR LTD GULLIVER PRODUCTIONS PTY LTD INDIGO OIL PTY LTD PANCONTINENTAL OIL & GAS NL
L 16	AUSTRALIAN OIL COMPANY NO 3 PTY LIMITED BOUNTY OIL & GAS NL ROUGH RANGE OIL PTY LTD
L 17	BURU ENERGY LIMITED
L 18	EMPIRE OIL COMPANY (WA) LIMITED* ERM GAS PTY LTD
L 19	EMPIRE OIL COMPANY (WA) LIMITED* ERM GAS PTY LTD
L 20	BURU ENERGY LIMITED* DIAMOND RESOURCES (FITZROY) PTY LTD
L 21	BURU ENERGY LIMITED DIAMOND RESOURCES (FITZROY) PTY LTD

PETROLEUM AND GEOTHERMAL ENERGY RESOURCES ACT 1967
Retention Lease

Title	Registered Holder(s)
R 1 R1	BURU ENERGY LIMITED FAR LTD GULLIVER PRODUCTIONS PTY LTD INDIGO OIL PTY LTD PANCONTINENTAL OIL & GAS NL
R 2 R2	BP DEVELOPMENTS AUSTRALIA PTY LTD JAPAN AUSTRALIA LNG (MIMI BROWSE) PTY LTD PETROCHINA INTERNATIONAL INVESTMENT (AUSTRALIA) PTY LTD SHELL AUSTRALIA PTY LTD WOODSIDE BROWSE PTY LTD
R 3 R1	OIL BASINS LIMITED
R 4	CHEVRON (TAPL) PTY LTD CHEVRON AUSTRALIA PTY LTD* MOBIL AUSTRALIA RESOURCES COMPANY PTY LIMITED SANTOS OFFSHORE PTY LTD
R 6	ALCOA OF AUSTRALIA LIMITED LATENT PETROLEUM PTY LTD*
R 7	ALCOA OF AUSTRALIA LIMITED LATENT PETROLEUM PTY LTD*

PETROLEUM ACT 1936
Petroleum Lease

Title	Registered Holder(s)
L 1H R2	CHEVRON (TAPL) PTY LTD CHEVRON AUSTRALIA PTY LTD* MOBIL AUSTRALIA RESOURCES COMPANY PTY LIMITED SANTOS OFFSHORE PTY LTD

PETROLEUM PIPELINE ACT 1969
Pipeline Licence

Title	Registered Holder(s)
PL 1 R1	APT PARMELIA PTY LTD
PL 2 R1	APT PARMELIA PTY LTD
PL 3 R1	APT PARMELIA PTY LTD
PL 5 R1	APT PARMELIA PTY LTD
PL 6 R3	AWE PERTH PTY LTD
PL 7 R1	BURU ENERGY LIMITED
PL 8 R1	MITSUI IRON ORE DEVELOPMENT PTY LTD NIPPON STEEL & SUMIKIN RESOURCES AUSTRALIA PTY LTD NIPPON STEEL & SUMITOMO METAL AUSTRALIA PTY LTD NORTH MINING LIMITED ROBE RIVER MINING CO PTY LTD*
PL 12 R1	HARRIET (ONYX) PTY LTD KUFPEC AUSTRALIA PTY LTD QUADRANT NORTHWEST PTY LTD*
PL 14 R1	HYDRA ENERGY (WA) PTY LTD QUADRANT OIL AUSTRALIA PTY LIMITED* SANTOS (BOL) PTY LTD TAP (SHELFAL) PTY LTD
PL 15 R1	CHEVRON (TAPL) PTY LTD CHEVRON AUSTRALIA PTY LTD* MOBIL AUSTRALIA RESOURCES COMPANY PTY LIMITED SANTOS OFFSHORE PTY LTD
PL 16	DBP DEVELOPMENT GROUP NOMINEES PTY LIMITED

TABLE 5. LIST OF TITLES AND HOLDERS IN WESTERN AUSTRALIAN JURISDICTIONS AS AT 27 JULY 2015

PL 17	HARRIET (ONYX) PTY LTD KUFPEC AUSTRALIA PTY LTD QUADRANT NORTHWEST PTY LTD*
PL 18	AWE (BEHARRA SPRINGS) PTY LTD ORIGIN ENERGY DEVELOPMENTS PTY LIMITED*
PL 19	DBP DEVELOPMENT GROUP NOMINEES PTY LIMITED
PL 20	DBP DEVELOPMENT GROUP NOMINEES PTY LIMITED
PL 21	CHEVRON (TAPL) PTY LTD CHEVRON AUSTRALIA PTY LTD* MOBIL AUSTRALIA RESOURCES COMPANY PTY LIMITED SANTOS OFFSHORE PTY LTD
PL 22	APA (PILBARA PIPELINE) PTY LTD
PL 23	APT PARMELIA PTY LTD
PL 24	ALINTA ENERGY GGT PTY LIMITED SOUTHERN CROSS PIPELINES (NPL) AUSTRALIA PTY LTD SOUTHERN CROSS PIPELINES AUSTRALIA PTY LIMITED*
PL 25	SOUTHERN CROSS PIPELINES AUSTRALIA PTY LIMITED
PL 26	SOUTHERN CROSS PIPELINES AUSTRALIA PTY LIMITED
PL 27	SOUTHERN CROSS PIPELINES AUSTRALIA PTY LIMITED
PL 28	SOUTHERN CROSS PIPELINES (NPL) AUSTRALIA PTY LTD
PL 29	QUADRANT EAST SPAR PTY LIMITED QUADRANT KERSAIL PTY LTD QUADRANT OIL AUSTRALIA PTY LIMITED* SANTOS (BOL) PTY LTD
PL 30	QUADRANT EAST SPAR PTY LIMITED QUADRANT KERSAIL PTY LTD QUADRANT OIL AUSTRALIA PTY LIMITED* SANTOS (BOL) PTY LTD
PL 31	APA (PILBARA PIPELINE) PTY LTD
PL 32	APT PIPELINES (WA) PTY LIMITED
PL 33	APT PIPELINES (WA) PTY LIMITED
PL 34	NORTHERN STAR RESOURCES LTD
PL 35	NORTHERN STAR RESOURCES LTD
PL 36	AUSTRALIAN PIPELINE LIMITED
PL 37	NORILSK NICKEL CAWSE PTY LTD
PL 38	APA (PILBARA PIPELINE) PTY LTD
PL 39	ORIGIN ENERGY PIPELINES PTY LIMITED
PL 40	DBNGP (WA) NOMINEES PTY LIMITED
PL 41	DBNGP (WA) TRANSMISSION PTY LIMITED
PL 42	HARRIET (ONYX) PTY LTD KUFPEC AUSTRALIA PTY LTD QUADRANT EAST SPAR PTY LIMITED QUADRANT KERSAIL PTY LTD QUADRANT NORTHWEST PTY LTD* QUADRANT OIL AUSTRALIA PTY LIMITED SANTOS (BOL) PTY LTD
PL 43	APT PIPELINES (WA) PTY LIMITED* REGIONAL POWER CORPORATION
PL 44	APT PARMELIA PTY LTD
PL 46	APT PARMELIA PTY LTD
PL 47	DBNGP (WA) TRANSMISSION PTY LIMITED
PL 48	ENERGY GENERATION PTY LTD
PL 52	APT PARMELIA PTY LTD
PL 53	APT PARMELIA PTY LTD
PL 54	APT PIPELINES (WA) PTY LIMITED* REGIONAL POWER CORPORATION
PL 55	GLOBAL ADVANCED METALS WODGINA PTY LTD
PL 56	GLOBAL ADVANCED METALS WODGINA PTY LTD
PL 57	AUSTRALIAN GOLD REAGENTS PTY LTD
PL 58	BHP BILLITON PETROLEUM (NORTH WEST SHELF) PTY LTD BP DEVELOPMENTS AUSTRALIA PTY LTD CHEVRON AUSTRALIA PTY LTD JAPAN AUSTRALIA LNG (MIMI) PTY LTD SHELL AUSTRALIA PTY LTD WOODSIDE ENERGY LTD*
PL 59	ESPERANCE PIPELINE CO. PTY LIMITED
PL 60	EII GAS TRANSMISSION SERVICES WA (OPERATIONS) PTY LIMITED
PL 61	APT PARMELIA PTY LTD
PL 62	HARRIET (ONYX) PTY LTD KUFPEC AUSTRALIA PTY LTD QUADRANT NORTHWEST PTY LTD*
PL 63	EII GAS TRANSMISSION SERVICES WA (OPERATIONS) PTY LIMITED
PL 64	AWE PERTH PTY LTD* ORIGIN ENERGY DEVELOPMENTS PTY LIMITED
PL 65	SARACEN METALS PTY LIMITED
PL 67	HAMERSLEY IRON PTY LIMITED
PL 68	EII GAS TRANSMISSION SERVICES WA (OPERATIONS) PTY LIMITED
PL 69	DBNGP (WA) NOMINEES PTY LIMITED
PL 70	AWE (OFFSHORE PB) PTY LTD AWE OIL (WESTERN AUSTRALIA) PTY LTD ROC OIL (WA) PTY LIMITED
PL 72	EDL NGD (WA) PTY LTD
PL 73	REDBACK PIPELINES PTY LTD
PL 74	EDL LNG (WA) PTY LTD
PL 75	EIT NEERABUP POWER PTY LTD ERM NEERABUP PTY LTD*
PL 76	SOUTHERN CROSS PIPELINES AUSTRALIA PTY LIMITED
PL 77	SINO IRON PTY LTD
PL 78	HAMERSLEY IRON PTY LIMITED
PL 80	ALCOA OF AUSTRALIA LIMITED LATENT PETROLEUM PTY LTD*
PL 81	QUADRANT NORTHWEST PTY LTD
PL 82	APA (PILBARA PIPELINE) PTY LTD
PL 83	ATCO GAS AUSTRALIA PTY LTD
PL 84	CHEVRON (TAPL) PTY LTD* CHUBU ELECTRIC POWER GORGON PTY LTD MOBIL AUSTRALIA RESOURCES COMPANY PTY LIMITED OSAKA GAS GORGON PTY LTD SHELL AUSTRALIA PTY LTD TOKYO GAS GORGON PTY LTD
PL 85	CHEVRON (TAPL) PTY LTD* CHUBU ELECTRIC POWER GORGON PTY LTD MOBIL AUSTRALIA RESOURCES COMPANY PTY LIMITED OSAKA GAS GORGON PTY LTD SHELL AUSTRALIA PTY LTD TOKYO GAS GORGON PTY LTD
PL 86	QUADRANT NORTHWEST PTY LTD SANTOS OFFSHORE PTY LTD
PL 87	BHP BILLITON PETROLEUM (AUSTRALIA) PTY LTD QUADRANT PVG PTY LTD
PL 88	BHP BILLITON PETROLEUM (AUSTRALIA) PTY LTD QUADRANT PVG PTY LTD

TABLE 5. LIST OF TITLES AND HOLDERS IN WESTERN AUSTRALIAN JURISDICTIONS AS AT 27 JULY 2015

PL 89	CROSSLANDS RESOURCES PTY LTD
PL 90	BHP BILLITON PETROLEUM (AUSTRALIA) PTY LTD QUADRANT PVG PTY LTD
PL 91	DBNGP (WA) NOMINEES PTY LIMITED
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PL 94	DBNGP (WA) NOMINEES PTY LIMITED
PL 95	DBNGP (WA) NOMINEES PTY LIMITED
PL 96	EMPIRE OIL COMPANY (WA) LIMITED ERM GAS PTY LTD
PL 97	MITSUI IRON ORE DEVELOPMENT PTY LTD NIPPON STEEL & SUMIKIN RESOURCES AUSTRALIA PTY LTD NIPPON STEEL & SUMITOMO METAL AUSTRALIA PTY LTD RIO TINTO LIMITED
PL 98	ESPERANCE PIPELINE CO. PTY LIMITED
PL 99	APACHE JULIMAR PTY LTD CHEVRON (TAPL) PTY LTD* KUFPEC AUSTRALIA (JULIMAR) PTY LTD KYUSHU ELECTRIC WHEATSTONE PTY LTD SHELL AUSTRALIA PTY LTD
PL 100	DBNGP (WA) NOMINEES PTY LIMITED
PL 101	DBNGP (WA) NOMINEES PTY LIMITED
PL 102	SUB161 PTY LTD
PL 103	DBP DEVELOPMENT GROUP NOMINEES PTY LIMITED
PL 104	APA (PILBARA PIPELINE) PTY LTD
PL 105	DDG FORTESCUE RIVER PTY LTD* TEC PILBARA PTY LTD
PL 106	MITSUI IRON ORE DEVELOPMENT PTY LTD NIPPON STEEL & SUMIKIN RESOURCES AUSTRALIA PTY LTD NIPPON STEEL & SUMITOMO METAL AUSTRALIA PTY LTD NORTH MINING LIMITED ROBE RIVER MINING CO PTY LTD*
PL 107	DDG ASHBURTON PTY LTD
PL 108	APA OPERATIONS PTY LIMITED
PL 109	BURU ENERGY LIMITED

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