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

PETROLEUM
IN WESTERN AUSTRALIA

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AWE's Irwin 1 spudded 25 March 2015 in the northern Perth Basin

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Cover: Testing the Waitsia field Photo © AWE Limited

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Western Australia's Petroleum and Geothermal Explorer's Guide — 2014 Edition

The 2014 edition of this highly sought after publication has been revised and updated to reflect recent changes to the legislation and regulations governing the petroleum and geothermal industries in Western Australia, in particular the Environment regulations and the Resource Management and Administration regulations.

The Explorer's Guide provides general information to companies interested in exploring and investing in Western Australia's upstream petroleum and geothermal energy industries.

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

All petroleum and geothermal operations must comply with all the relevant legislation.

This guide assists explorers with information on:

- The role of Government
- The geology and prospectivity of Western Australia's sedimentary basins
- Geothermal energy resources
- Carbon capture and storage projects in Western Australia
- How to access data
- Petroleum and geothermal legislation and administration, resource management and environmental assessment and legislation
- Native title and land access
- Occupational safety and health
- Taxation and commercial aspects relating to petroleum and geothermal production

Copies of this publication are available from:
Public Counter, 1st Floor Mineral House, 100 Plain Street, East Perth.

The Public Counter is open from 8.30 am to 4.30 pm Monday to Friday.

A digital copy of the Explorer's Guide can be accessed via the DMP online 'Publications Systems' link at:
www.dmp.wa.gov.au/8481.aspx

or from the petroleum publications page at:
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Minister's message

Hon. Bill Marmion
Minister for Mines and Petroleum

New opportunities emerge beyond the construction phase

Beyond the resource construction boom, decades of project operations will continue to provide high quality jobs and business opportunities to Western Australia.

In 2013–14, Western Australia had a record $121.6 billion in sales from the minerals and petroleum extractive industries. The petroleum sector alone was valued at $26.5 billion, an increase of nine per cent on the previous year. This represents 22 per cent of the total value of resource industry sales for Western Australia, placing petroleum as the second most valuable resource after iron ore.

There are also ongoing capital investment commitments in the State's petroleum sector and as at February 2015, it was estimated that $152 billion worth of resource projects were either under construction or otherwise committed.

A further $75 billion is identified as being allocated to planned or possible projects in the coming years.

The economic benefits to the State do not end there. Strong growth in Western Australia's resources sector is set to continue as more liquefied natural gas (LNG) projects come online.

Among these, the Gorgon LNG project is scheduled to commence production later this year, to be followed by the Wheatstone, Ichthys and Prelude projects in the next couple of years. As these projects move from the construction phase to the operational phase, skilled workers will be required for the new gas plants at Barrow Island and Ashburton North.

This is part of the transition from the construction to the operational phase of the investment cycle with the focus moving to more highly skilled, long-term jobs in operations, maintenance, and logistics support. Additionally, further opportunities will be available in research, training and development.

Operational expenditure is set to increase rapidly as these projects commence production. An added benefit is that operational expenditures generally have a significantly higher local content component in comparison to capital expenditure on these projects.

The industry is supporting and working with educational providers and universities in Western Australia to improve research and education in offshore engineering. For example, the Global FLNG Training Consortium in Western Australia is a partnership between Shell, the Challenger Institute and Curtin University.

One of the State Government's highest priorities remains, however, to encourage exploration and promote opportunities for energy investment in Western Australia, as the State continues to attract the highest levels of exploration expenditure in Australia.

A preference for brownfield projects over greenfield projects is expected in coming years as project proponents look to expanding their LNG production capacity and seek to improve their economic returns by constructing additional LNG trains at existing facilities.

These petroleum projects will continue to make substantial investments in Western Australia for many decades to come.

There is no doubt that underlying long-term market conditions remain robust, and the State is well-positioned to attract a new wave of investment in the resources sector.

While the resources industry has been facing challenging times, the fundamental strengths of the State's resources sector remains the same. Western Australia has world-class petroleum resources and our proximity to the world's fastest-growing markets provides a unique cost advantage.

Executive Director's message

Jeff Haworth
Executive Director
Petroleum Division

Let's not forget onshore conventionals

A lot of attention has been concentrated on Western Australia's potential for sourcing natural gas and oil from shale and tight rocks over the last few years. The potential resources of the Perth and Canning Basins have certainly been the focus of recent exploration programs, with mixed results. However, with the still declining oil price hovering around US$50 (an almost 40% drop in three months), the costs involved in drilling, completing and hydraulically fracturing these wells in Australia are becoming prohibitive and companies are struggling to gain investment dollars to fulfil their exploration programs.

Conversely, Western Australia has had successes over the last five years in discovering conventional reservoirs of both gas and oil onshore. Although these are small when compared to the giant fields of the North West Shelf and Browse Basin, they are closer to infrastructure and cheaper to bring on line.

In the Perth Basin, Empire discovered the Gingin West (2009) and Red Gully (2011) fields which are conventional gas/condensate fields totalling 849 million cubic metres (30 billion cubic feet) of gas. These two fields are located a short distance from the Gingin field discovered in 1972.

Similarly, in 2014, AWE's Senecio 3 extension well (appraising the field's tight gas sands) discovered not only "conventional gas sands" in the Dongara/Wagina Sandstone zones, but also deeper gas sands below the current field. The new accumulation, known as the Waitsia field, has the potential to be the largest onshore conventional gas discovery since the 1960s.

Contrary to popular belief that it takes a long time to progress from exploration to production in Western Australia, Empire moved Red Gully to production in less than three years, with the facility completed and production licences granted in 2014. AWE tested Senecio 3 earlier this year and achieved flow rates of 348 thousand cubic metres per day (12.3 MMscf/d) and after gaining approvals, can immediately supply their Dongara gas facility with Senecio gas.

The Perth Basin has, in my opinion, been overlooked for too long and these two exciting discoveries suggest there are more surprises yet to be found onshore. Companies like AWE, Empire, Norwest and Key Petroleum are actively exploring the northern Perth Basin proving, yet again, the only way you will make a discovery is to get out there and explore and drill.

Similarly, CalEnergy is looking at producing the Whicher Range gasfield in the southern Perth Basin using "conventional" techniques and I look forward to seeing the results of their testing program due to commence in May 2015.

In the Canning Basin, while drilling a tight sand gas play, Buru Energy discovered a conventional oilfield in Ungani in 2011. While a comparatively small field at 5.7 billion litres (35.6 million barrels) of oil in place, the Ungani structure is just one of a chain of similar structures running along the southern margin of the Fitzroy Trough. If more of these structures contain oil, then one can envisage a similar "string of pearls" development much the same as Apache did with the Harriet project.

There has been much said regarding the shale and tight gas potential of the Canning Basin. However, there are greater challenges in the Canning Basin compared with the Perth Basin, especially with regards to infrastructure, the weather window, distance to markets, population and the high costs of drilling and exploration in the region.

With only three hundred odd wells in the large Canning Basin, it can be safely defined as an under explored area with the potential for finding more “Unganis” or even conventional gas plays.

In conclusion, my thoughts are, with finances hard to find and the oil price as it is, perhaps the onshore industry should take heart at the successes that AWE, Empire and Buru have had in the conventional gas and oil world and continue to look for “lumps and bumps” in the basins of Western Australia, as well as exploring for natural gas from shale and tight rocks.

The Red Gully gas and condensate facility in the Northern Perth Basin

Director's message

Denis Wills
Director Petroleum Operations
Petroleum Division

I would like to take this opportunity to introduce myself, having taken up the position of Director Petroleum Operations within the Petroleum Division of the Department of Mines and Petroleum (DMP).

I have worked in the oil and gas industry in Australia and overseas over the last 38 years, having obtained a Chemical Engineering degree from Heriot-Watt University, Edinburgh and am a graduate of the Australian Institute of Company Directors.

This is my fourth month with the DMP in the new role of Director Petroleum Operations. This role ensures that exploration and resource activities, e.g. drilling, building a pipeline or producing gas and oil, are carried out in accordance with the relevant legislation and regulations. It also oversees the granting of Petroleum or Geothermal Titles and determining land access requirements, including Native Title.

Having started my career in process design and operations, I moved into senior functional/project director roles and worked for organisations such as Santos, Woodside, BHP Billiton, OMV (in Vienna), the World Bank and lately with WorleyParsons. This diversity of experience within the oil and gas industry both in Australia and overseas has given me an appreciation of the fact that there are many ways to solve problems and to recognise the community and cultural influences that need to be considered in arriving at acceptable workable solutions.

I have a strong belief that building confidence with stakeholders and the community enables better planned and more informed policies, programs, projects and services by DMP.

Just quickly, I will reflect on the current state of play in the world of oil and gas.

Over my 38 years, I have managed to collect two garages full of professional magazine articles and a whole lot of other "stuff".

During a recent determined effort to get rid of most of this, I came across an article in The Economist.

"The price of oil has fallen by half in the past two years, to just over $10 (US) a barrel. It may fall further – and the effects will not be as good as you might hope" — the date, March 1999.

We are not in a US$10/bbl world today but, the fall in oil price in the last two years has been greater than 50% (the WTI moving from US$97 in March 2013 to approximately US$43 in March 2015). In reality the cost of oil has more than halved in just a year.

The comment "and the effects will not be as good as you might hope" was a view that cheap oil would lead to "gleeful consumption" as it did in the mid 1980s. This did not happen in 1999; some of the reasons put forward were the growing concern for global warming with a move towards gas, and the tax regime on petrol in OECD countries where most of the cost was tax so that a drop in oil price was hardly notice by the consumer.

There is no evidence, to my knowledge, that the current low oil price has spurred consumption to offset the lower price.

The oil price did rise again in the 2000s to the dizzy height of around US$143/bbl in 2008 only to collapse with the Global Financial Crisis.

The main reason given for this dramatic price rise, by most commentators, was a supply and demand scenario. Global supply stagnated while demand was growing strongly, particularly oil consumption in China and the fact that OPEC did not step in to fill the void of under supply.

We now seem to be in a world with over supply, with the US once again a major producer and world economies struggling indicating probably little opportunity for increased consumption at this time. Nobody seems to want to reduce production and in some countries oil production is a must for their economies.

There is probably little chance of oil prices rebounding very quickly (but then again most predictions on oil price have been notoriously wrong). If prices rise again, producers with a low breakeven cost would tend to expand production and those who had suspended production are likely to restart.

What we are seeing now is all companies, big and small, doing a lot of belt tightening.

For DMP we see this as potentially introducing an increased risk around compliance — ensuring that maintenance, well inspections and the drilling of wells continues to be carried out with a high degree of due diligence and rigor.

In this current low oil price climate, DMP Petroleum Division will be giving extra attention to all compliance matters.

Western Australia has the potential for major oil and gas discoveries which should offer a reasonable return to exploration companies. At this time it is a matter of companies getting through this current low oil price period in a safe and sustainable way so that they can prosper in the future.

Photo © DMP

Petroleum Division inspector on a well integrity inspection at the Dongara field

A review of exploration, production and development activities in Western Australia in 2014

Karina Jonasson
Petroleum Resource Geologist
Resources, Petroleum Division

Gorgon Project LNG tanks on Barrow Island

Highlights of 2014

- A new gas discovery, named Waitsia, was made in the northern Perth Basin by AWE Ltd. It is being announced as an exciting new play with significant upside and follow-up potential.

- The discovery of a number of rocky outcrops at North Scott Reef off the Kimberley coast, which are tantamount to islands, has prompted the redrawing of Western Australia's maritime boundaries. This means a potential increase in WA's share of royalties from the future development of the Torosa gasfield in the Browse Basin.

- Western Australia's onshore and State waters fields have produced a cumulative total of 89 875 million litres (ML) of oil, 36 252 ML of condensate and 1465 million cubic metres (Mm^3) of gas, as of 31 December 2014. For annual statistics, see the Production section and the tables at the back of the magazine.

- At the end of 2014, the oil price hit its lowest level since 1979, at $US54/bbl. Implications of the falling commodity price for WA's shut-in oil wells are not hard to guess.

Drilling

Five petroleum wells were drilled onshore in Western Australia in 2014. This total does not include water and CO_2 injection wells drilled for the Gorgon Project on Barrow Island.

The Canning Basin wells were Commodore 1, a new field wildcat, and Ungani 3, an appraisal well on the Ungani oilfield. The Perth Basin wells were Drover 1, Dunnart 2 and Senecio 3 (which discovered the gas at Waitsia).

Buru Energy's Commodore 1 (in EP 390) spudded in November 2014 following release of the rig from workover operations at Ungani North 1. Commodore 1 was drilled in November–December 2014, with funding from a farm-in by Apache Energy into Buru's Canning Basin coastal acreage. Buru Energy and Mitsubishi both have a 25 per cent equity interest in the well and in EP 390, with Apache holding the remaining 50 per cent equity interest. The deal includes a commitment by Apache to fund a $25 million exploration program in EPs 390, 438, 471 and 473.

Commodore 1 is located approximately 140 km to the south of Broome and some 100 km inland from the Great Northern Highway. The well's primary objective was conventional oil reservoirs in the Grant Formation, with secondary objectives in the underlying Nita carbonates. Core was recovered from the full section of the Carribuddy Formation, the Bongabinni Shale and the Nita Formation. Although there were oil shows in some intervals, the results of Commodore 1 for Buru and Apache were disappointing, with no zones having recognised producible hydrocarbons.

Ungani 3 spudded on 14 January 2014 in EP 391 and was completed in March. The well is located about 1000 m east of the central Ungani field. The feature was interpreted from the Ungani 3D seismic data as a separate structure and drilled to target the Ungani Dolomite.

Early reports indicated poor reservoir development in the main reservoir section. However, wireline logs confirmed at least one zone that contained a number of oil saturated fractures with reservoir potential that warrant further testing. The vuggy dolomite present in the central Ungani field was not encountered at the Ungani 3 location. Buru is remapping the Ungani structure using the final processed data from the Ungani 3D seismic survey, which was acquired in 2013.

The Waitsia gasfield, which lies beneath the Senecio gasfield, was discovered in September 2014 with the drilling of the Senecio 3 well in L1/L2 Production Licences. The Joint Venture partners in L1/L2 are AWE Limited (operator) and Origin Energy Resources Limited each holding 50 per cent equity. The two fields

The Senecio 3 well was drilled in September 2014 in the northern Perth Basin

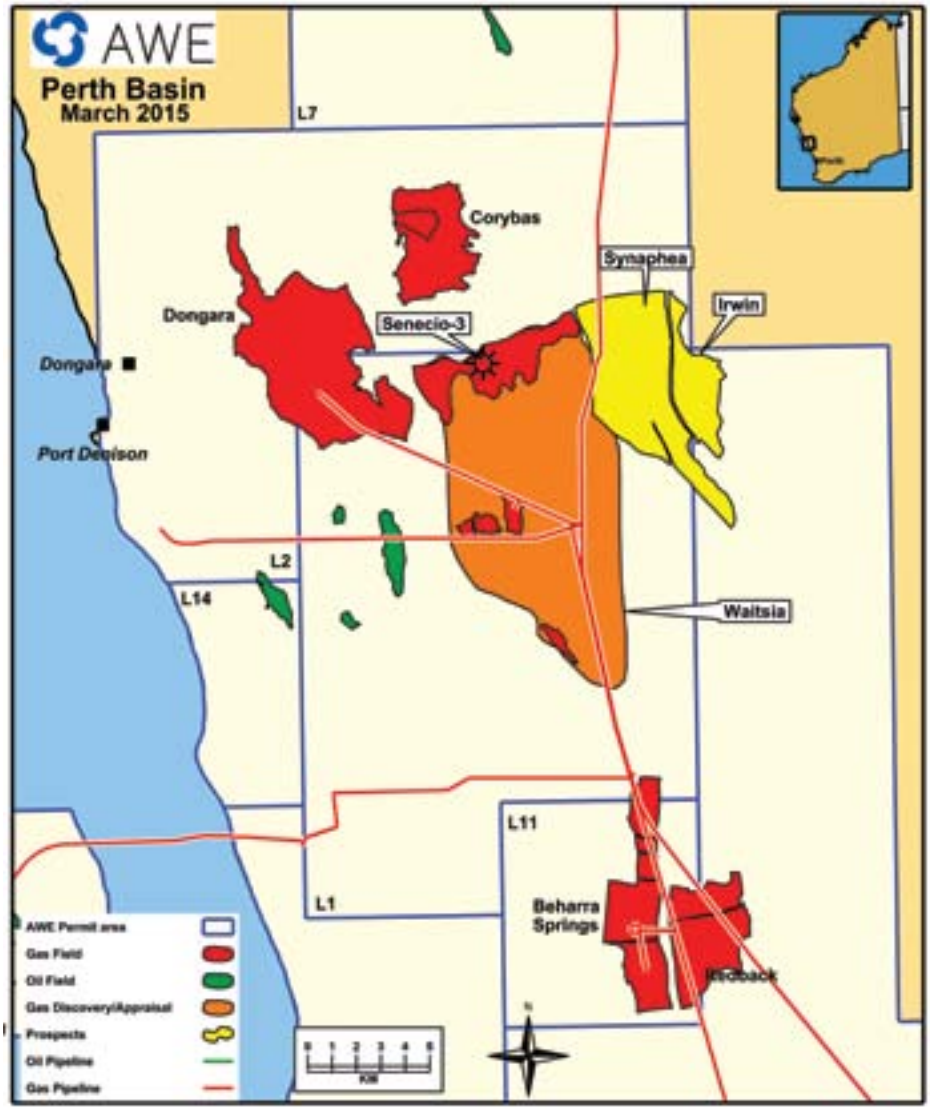
Photo © AWE Limited

are located 7 km west of the Dongara gas plant. Senecio 3 was drilled to a revised total depth of 3370 m, initially targeting the Dongara and Wagina Formations, a tight sandstone reservoir in the Senecio field. The well was deepened into the Kingia/High Cliff Sandstone, following the recording of strong gas shows below the Dongara/Wagina Formations and leading to the discovery of what is now being called the Waitsia field.

AWE has previously flow tested the Senecio 2 well (in September 2012) and a stabilised gas flow rate of 38 228 m^3 per day (1.35 million standard cubic feet per day) was recorded. The combined contingent resource (P50) for Senecio and Waitsia is estimated at 10.2 Gm^3 (360 Bcf). The Irwin River Coal Measures and Carynginia Formation were also gas-bearing and could provide additional resource potential. Testing of the Senecio 3 well occurred in March 2015 and confirms the commercial potential of the Waitsia field. The well flowed at a rate of 348 297 m^3 per day (12.3 MMscf/d) from the Kingia Sandstone, a conventional gas reservoir.

Drover 1, as reported in the previous issue of *Petroleum in Western Australia*, was spudded on 29 June 2014 by AWE Ltd in EP 455. The well is located approximately 18 km southeast of Greenhead and 220 km north of Perth on pastoral land and was drilled with Enerdrill's Rig 3. Drover 1 targeted a shale gas play, with primary and secondary targets in the Kockatea Shale, Carynginia Shale, Irwin River Coal Measures and High Cliff Sandstone. The well reached a total depth of 2356 m in mid-July, and 21.5 m of core was cut in the Kockatea Shale. AWE reported encouraging wet gas shows in the Kockatea Shale and dry gas shows in the Carynginia Shale. The company has received approval for a hydraulic fracturing program on Drover 1, which will proceed depending on the results of the core analysis.

The final well of 2014, Dunnart 2, was drilled by Key Petroleum in EP 437 in the northern Perth Basin from July to September 2014. The well reached a total depth of 670 m using DCA Rig-7. Initial reports said a light (34° API) oil was observed in the Bookara Sandstone and collected while drilling.



Location map of AWE'S Senecio 3 well, the Waitsia discovery and drillable prospects (Courtesy of AWE Ltd)

However, this finding will have to be confirmed with a production test once a suitable workover rig is found to run a production string in the well.

Geophysical surveys

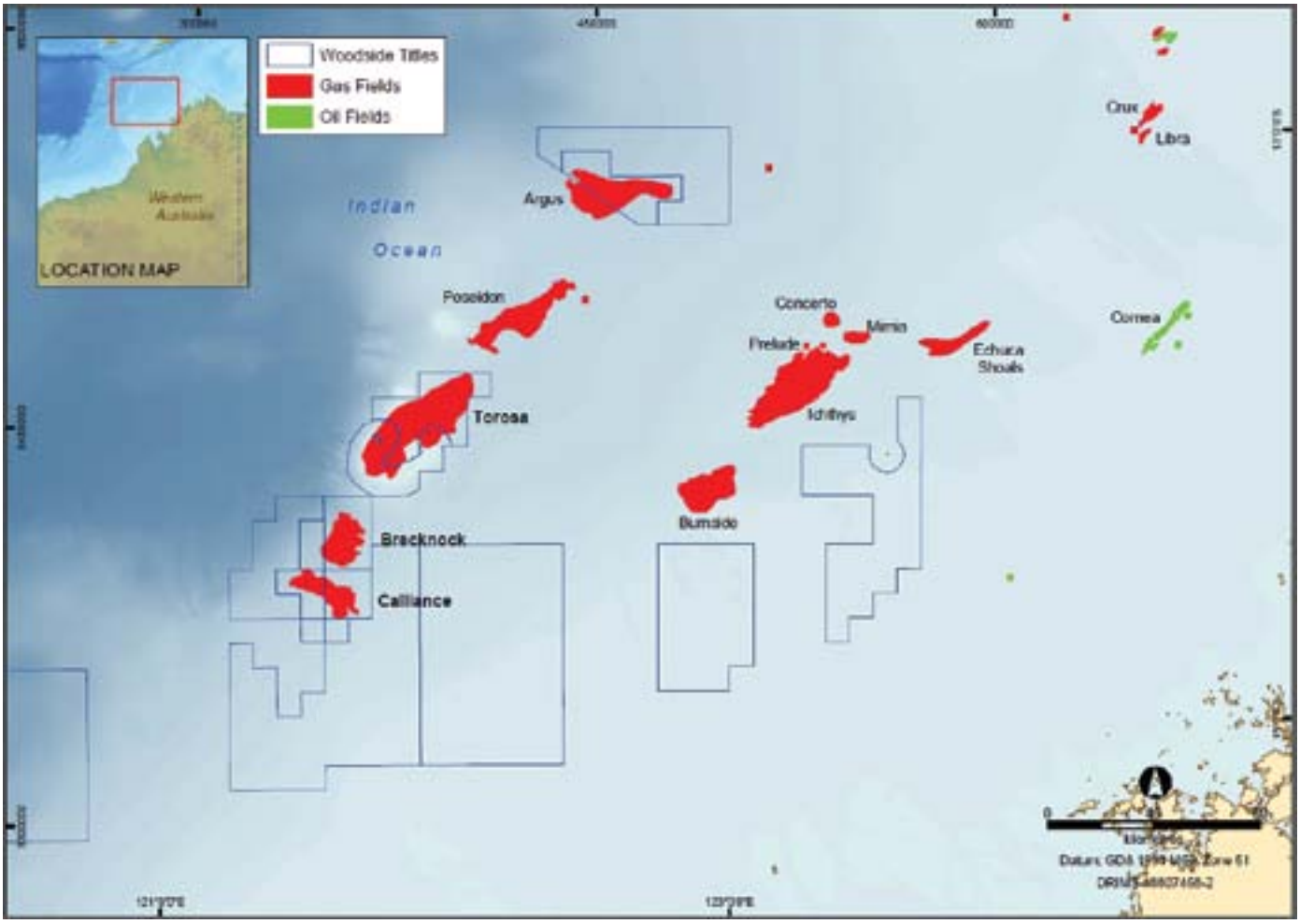
Seven surveys were carried out in onshore Exploration Permits in 2014. This comprised six in the Canning Basin and one in the Perth Basin. Buru Energy was the operator of four 2D seismic surveys: the Barbwire (245 line km), Commodore West (123 line km), Mt Fenton (113 line km) and Mt Rosamund (507 line km) 2D seismic surveys. They also shot the 255 km^2 Jackaroo 3D seismic survey, which covers territory from Yulleroo to Ungani. Admiral Oil conducted the sixth survey in the Canning Basin, a gravity gradiometry/magnetic aerial survey in SPA 17 AO covering 4505 line km. In the Perth Basin, Warrego Energy conducted an 80 km^2 3D seismic survey in EP 469 over West Erregulla.

Production

Fields in Western Australia's onshore and State waters produced a total of 406 187 kL of oil, 455 545 kL of condensate and 19 004 Mm^3 of gas in 2014.

In 2014, there was no production from the following fields: Albert, Double Island, Little Sandy, Mohave, Pedirka, Simpson, South Plato, Victoria, West Cycad and Wonnich, all operated by Apache Energy in State Waters of the Carnarvon Basin; and the Blina, Boundary, Sundown and West Terrace oilfields in the Canning Basin, all operated by Buru Energy. Aside from the Wonnich field, which was undergoing workover operations in 2014, it is anticipated that these fields will be decommissioned in the coming years.

Apache's offshore Rose gasfield recorded an increase in its produced volumes in 2014.



Location of the Torosa field in the Browse Basin. The field is situated in both State and Commonwealth waters (Courtesy of Woodside)

Onshore, the Redback and Red Gully gasfields in the Perth Basin had increased production in 2014, with Red Gully in its second year of production. The extended production test at Red Gully was completed in November 2014, and Production Licences L18 and L19 were granted over the field.

In the Canning Basin, extended production testing continued at Buru's Ungani oilfield, with oil being produced from the Ungani 2 well at a steady rate with little water cut and pressure depletion.

Flow testing at Whicher Range 4 by Cal Energy was suspended.

Decommissioning

Thevenard Island is the hub where crude oil from six Chevron-operated offshore petroleum fields — Saladin, Roller, Skate, Yammaderry, Cowle, and Crest — was processed and prepared for shipment by ocean tanker to Australian refineries. The first oil from Thevenard Island operations flowed in 1989, and subsequent fields were brought into production in a staged development.

In December 2013, Chevron applied to abandon the Thevenard Island fields, and received approval from DMP. Chevron indicated that all the fields ceased production in April 2014. Decommissioning of these fields will be ongoing for the next few years.

AWE finished the plug and abandon process to decommission the Woodada 5 and Yardarino 6 wells. Applications were also received to decommission the Mt Horner 9, 12 and 14 wells.

Expansion of the Mondarra Gas Storage Facility

APA Group has expanded the Mondarra Gas Storage Facility to accommodate additional gas supply for WA. The commissioning of the new plant was completed and the new facility became commercially active in Q3 of 2013. The facility comprises three wells with the capability to inject gas at 70 TJ per day and withdraw it at 150 TJ per day. The storage capacity is estimated at 15 PJ. This upgrade of the facility is significant to WA's gas market in terms of managing increased gas production and meeting the State's demand for gas.

Torosa boundary changes

Department of Mines and Petroleum Minister Bill Marmion said that marine boundary changes of the Torosa field in the Browse Basin could result in an additional $2.9 billion in state royalties from the Torosa field alone. The Browse Joint Venturers are Woodside (operator), Shell Australia, BP Developments Australia, Japan Australia LNG, and PetroChina International Investment.

The field, along with two others in the area that are not affected by the boundary changes (Brecknock and Calliance), is likely to be produced using floating liquefied natural gas (FLNG) technology, with floating facilities similar to Shell's Prelude FLNG vessel. DMP and the Commonwealth are working closely

to establish the exact size of WA's share in Torosa, with around seven of the 13 blocks in the Torosa field being affected by the boundary changes. Legislation change is required before the changes take effect; legislation change was passed through the WA parliament in record time in December 2014.

The Retention Leases for the Torosa field (TR/5, R2 and WA-30-R) are pending renewal as they all expired in December 2014. The first two leases are in Western Australia's jurisdiction. Woodside has also lodged renewals for the remaining Browse project leases (WA-28-R, WA-29-R, WA-30-R, WA-31-R and WA-32-R covering Calliance and Brecknock). The combined contingent resources of these Browse fields is 422 Gm^3 (14.9 Tcf) of dry gas and 70 GL (441.2 MMbbl) of condensate.

Gorgon Project update

Construction of the Gorgon Project began on Barrow Island, offshore Western Australia, in late 2009. This Chevron-led project is on track to deliver the first shipment of LNG by mid-2015. The Gorgon Project is 90 per cent complete as of 30 January 2015.

All LNG Train 1 modules and 13 of 17 Train 2 modules have been placed on their foundations. Both LNG tanks are now ready for LNG and construction is complete on three of the four condensate tanks. The jetty has been completed, except for the loading arm installation. The domestic gas pipeline is now connected from the mainland through the jetty to the plant site and pre-commissioning activities have been completed. Finally, upstream subsea facilities are also finished. The operations team have started commissioning and monitoring systems in the central control room.

Wheatstone Project update

Construction on the Wheatstone Project began in late 2011. The Chevron-led project includes an 8.9 Mt/a LNG facility with two processing units and a separate domestic gas plant. The project is now 55 per cent complete as of 30 January 2015.

At the DSME shipyard in Okpo, Korea, the 105 m flare boom was installed on the platform topsides as fabrication continued in preparation for sail away in 2015.

At the LNG plant, civil site preparations are now complete. The roof of LNG Tank 1 has been raised. At LNG Tank 2, the roof panels have been installed. The first two LNG Train 1 modules and four utility pipe rack modules have arrived on-site, with one of the Train 1 modules already set in place and the gas processing columns already installed. The Train 2 compressor deck is now complete. At the Materials Offloading Facility, the breakwater has taken shape as shipments continue to arrive at South Quay.

2015 drilling plans

AWE are planning to drill new field wildcat Irwin 1, in EP 320, 8 km east of Senecio field, and two appraisal wells on the Senecio/Waitsia fields in early 2015.

Key Petroleum is planning to run a production completion string in the Dunnart 2 well. Key are also considering up to three more exploration wells in EP 437 in the northern Perth Basin, including Condor South and the Wye Knot prospect located to the north of Dunnart 2. In the Canning Basin, upcoming prospects include Griffiths 1 and Patterson 1.

Finder Exploration, a privately-owned Australian company, is preparing to drill its first shale oil exploration well in the Canning Basin in mid-2015. The well, Theia 1, is targeting a liquids-rich shale play in EP 493 and will likely spud around June.

Empire plans to drill up to three wells in 2015, including one in EP 389, where the Red Gully discovery was made.

Latent Petroleum's appraisal program for the Warro field comprises two wells, Warro 5 and Warro 6, planned to be drilled in the first half of 2015.

The Buru Energy Joint Venture in EP 458 also plans to drill several prospects on the Ungani trend. Senagi 1 is planned for July in EP 458, with Olympic 1 in August and Jackeroo 1 in September 2015.

GSWA is currently planning a stratigraphic well in the Canning Basin with a 2015 to 2016 timeframe.

Wheatstone Materials Offloading Facility's breakwater construction takes shape

New guidelines out: WA Petroleum and Geothermal Guideline for Exploration Permit Management

Jason Medd
Principal Policy Officer
Strategic Business Development,
Petroleum Division

Drover 1 exploration well, northern Perth Basin

The Department of Mines and Petroleum (DMP) has recently released its new WA Petroleum and Geothermal Guideline for Exploration Permit Management, which is now available on the Department's website. The new guideline is the result of an internal review of the Petroleum Division's policies and guidelines, which aim to simplify and better explain DMP's procedures and requirements on petroleum and geothermal title holders.

The WA Petroleum and Geothermal Guideline for Exploration Permit Management deals primarily with the management of conditions relating to work program commitments of petroleum and geothermal exploration permits.

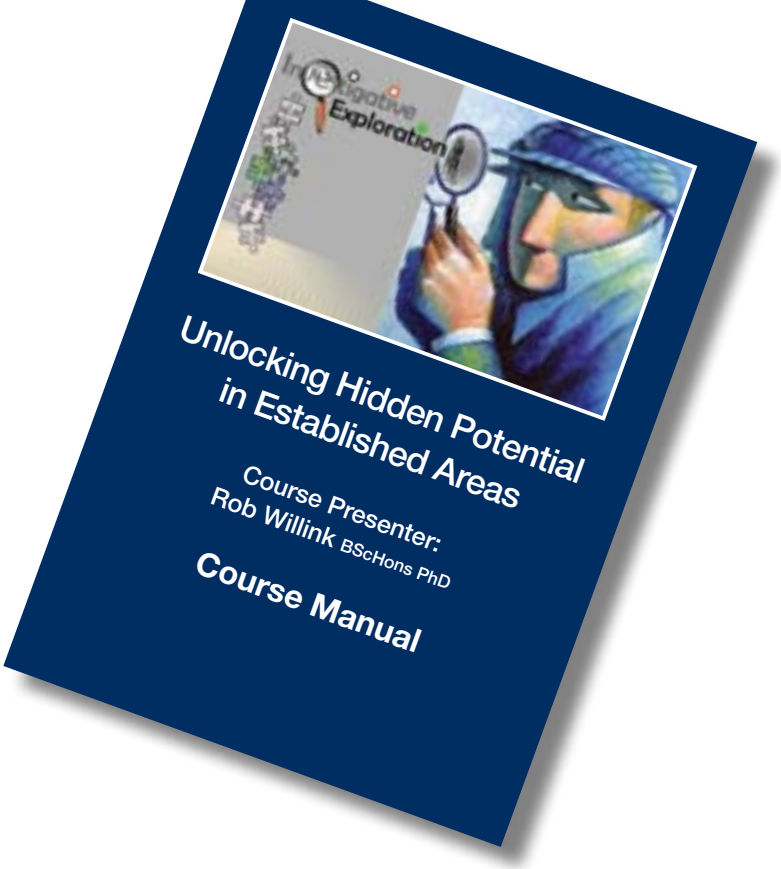
Specifically, the guideline provides advice on fulfilment, variation, suspension and exemption of work program commitments. Force Majeure is clearly defined, using commonly accepted definitions and provisions. Exploration permit renewal requirements are clearly explained as are the surrender and cancellation of permits. The guideline provides a clear explanation and application of the relevant sections of the *Petroleum and Geothermal Energy Resources Act.*

The WA Petroleum and Geothermal Guideline for Exploration Permit Management is now available on the DMP website:

http://www.dmp.wa.gov.au/documents/PD-PTLA-AR-110D.pdf

Vibroseis trucks conducting a 2D seismic survey

Delayed discoveries and Rob Willink's words of wisdom



Richard Bruce
Exploration Geologist
Resources, Petroleum Division

Australia's largest conventional offshore oil discovery in 2014 is believed to be Phoenix South 1 drilled by Apache in the Canning Basin. In addition, Australia's largest conventional onshore gas discovery in the same year was Senecio 3 drilled by AWE in the Perth Basin.

On 18 August 2014, Carnarvon Petroleum Ltd, a joint venture participant in Phoenix South 1 well, announced to the market that this discovery well had encountered four discrete oil columns in Triassic reservoirs. Also in August 2014 Apache estimated that there might be as much as 47.5 billion litres (300 million barrels) of oil in place (P10 estimate). Although too early to assess recoverable reserves, Carnarvon concluded that this discovery was 'the most significant new oil play in the North West Shelf since the Enfield discovery opened up the Exmouth Basin almost 20 years ago'.

On 9 March 2015, AWE Ltd announced that its Senecio 3 well, drilled in 2014, had flowed gas at 348 297 cubic metres per day (12.3 million cubic feet per day) from the Permian Kingia Sandstone, and aptly named this new pool the Waitsia field. Preliminary 2C resource estimates were put at 8.2 Gm^3 (290 Bcf) with an upside in excess of 28 Gm^3 (1 Tcf), a remarkably big discovery in a mature basin.

Interestingly both these significant new discoveries were made in structures that had already been drilled. The Phoenix structure was first drilled with Phoenix 1 in 1980, and the Senecio structure with Senecio 1 drilled in 2005. I was on the BP Phoenix 1 well in 1980 and the mudlog had some oil and gas indications (fluorescence and up to pentane on the chromatograph). However, further testing was required to determine if the well could flow at commercial rates.

As such, these discoveries came as no surprise to Dr Rob Willink, who, as PESA Distinguished Lecturer in 2013, delivered a course to the industry entitled "Investigative Exploration: Unlocking Hidden Potential in Established Areas".

Rob's course highlighted the fact that many oil and gasfields in Australia, and around the world, were just missed by, simply not detected in, or not reached by the initial well(s) drilled on the field. Even if hydrocarbons were encountered in the initial well(s), the potential commercial significance of those hydrocarbons was often not appreciated at the time of drilling. Apparent lack of initial success of a particular well frequently had a negative impact on further exploration of the prospective trend on which the well was drilled.

Rob expressed the view that significant potential remains in Australia's 'mature' basins in prospects or prospective trends already drilled. Only an open minded, critical and multidisciplinary approach to well evaluation can unlock this potential, bearing in mind that what was concluded at the time of drilling of old wells, is not necessarily valid today.

I recently caught up with Rob, now Exploration Advisor with Central Petroleum Ltd in Brisbane, and asked him some salient questions about his training course in the light of the Phoenix South and Waitsia discoveries.

RB: You delivered your course to the industry in 2013, and these discoveries were made in 2014. Do you claim any responsibility for them?

RW: Much as I would like to, the Phoenix South prospect was identified well before I gave my course, although I did have a slide on it in my manual as 'a well to look forward to'. Yes, it was a fantastic result, and much of the credit for that discovery should go to the team at Finder Exploration.

That said, I think everyone thought it was going to be a tight gas, not oil discovery, so serendipity I suspect also played a role. Incidentally on one of my course slides, I highlight that

serendipity continues to play a significant role in our exploration endeavours, and that if you don't drill, you will never benefit from it. Very true!

The discovery of the Waitsia field I do like to think I played a role in, if only a subliminal one, as several AWE geoscientists attended my course in 2013. In my checklist of review questions there is a very important one that states: 'Could closure persist, or independent closures be developed, below the total depth of the well and so provide potential in deeper reservoirs?'

Very relevant to the Waitsia discovery, I believe.

I know from feedback that I received from course attendees, that they valued the comprehensive checklists of well review questions that I left them. Some even said they would pin it up in their workspace in the office!

And of course, from my days at Origin, I have always been a Perth Basin-o-phile. I think there is still lots of potential left in that basin. Waitsia is not the only discovery made on a previously drilled structure. For example, Redback 1 drilled in 2004 missed the Redback gasfield by less than 50 metres due to fault cut out of the Wagina Sandstone reservoir at this well location, and was not discovered until five years later with the drilling of Redback 2. And it took real courage to drill that well!

RB: Why did you actually put your course together in the first place?

RW: There were two main reasons. Firstly, I have been lucky in my career and made quite a few discoveries in structures already drilled. But I also walked away from prospects too early after apparent lack of success was recorded in drilling. I wanted to share my experiences and, more importantly, I don't want others to make the same mistakes that I made.

Secondly, I wanted to put a course together that stressed the truly 'investigative' nature of the exploration business. In my opinion, there are far too many courses out there that simply load attendees up with new information or new technology, but virtually none that really make people think. I wanted to change that.

RB: How long did it actually take you to put the course together?

RW: It took me close on a year on a part-time basis. We are actually very lucky in Australia, in that many pertinent case histories have been published in the APPEA Journal or in PESA Basin Symposia that I was able to glean information from.

RB: Do you still give your course?

RW: Yes, I do, although my advisory role at Central has kept me very busy. I have three-day and four-day versions and my employment contract allows me to present it externally if it does not conflict with other priorities. When I retire I will be able to give it more frequently. But I seem to have trouble retiring!

RB: Other than the Perth Basin, are there any other onshore basins in Western Australia you are particularly attracted to in terms of "hidden potential"?

RW: I think the Canning Basin is the obvious candidate. Many old wells in this basin recorded excellent oil shows at various levels but were not logged extensively, nor tested conclusively. I note that in recent gazettal documentation, you have promoted the big Sally May anticline as worthy of another look despite two wells having already been drilled on this prospective trend. And rightly so! Not all potential reservoirs in the two wells drilled on this very large structure were logged and drill stem tests were inconclusive. And in any event because the structure is so large, reservoir quality may well be better elsewhere on this structure. And then there is unconventional potential unevaluated as well.

Rob has kindly given permission to DMP to publish his checklist of review questions in this magazine. Please see the checklist on the following pages.

Critical Well Review Checklists (Courtesy of Rob Willink)

PETROPHYSICAL

1. Was the log suite run sufficiently comprehensive, were logging tools properly calibrated, and were hole conditions adequate to allow at least a qualitative assessment to be made of the presence, quality and fluid content of potential reservoirs in the well?
2. Were previous petrophysical interpretations rigorous in particular with respect to any reservoirs encountered in the well that were not regarded as objectives predrill, but which were associated with oil or gas shows during drilling?
3. Have all hydrocarbon shows recorded during drilling been correctly reconciled with the petrophysical evaluation of the logs?
4. Could the adoption of incorrect values for any of the petrophysical parameters m, n, Rw, Vsh or Qv in the quantitative calculation of hydrocarbon saturations have led to underestimation of potential net pay in the well, and/or failure to test zones that in hindsight warranted testing?
5. Were the cut-offs for Ø, Sw, Vsh and/or K adopted for effective reservoir and hydrocarbon pay definition too pessimistic, resulting in potential pay zones having been left untested?
6. Could potential hydrocarbon bearing zones in the well not have been detected and/or fully resolved due to the limited bed thickness of reservoirs?
7. Could potential hydrocarbon bearing zones have been missed ("by-passed pay") in the well due to an anomalously low resistivity response over prospective reservoirs, and/or to a low resistivity contrast between hydrocarbon and water bearing zones?
8. Were any HDT's (hydrocarbon-down-to's) in the well misinterpreted as HWC's (hydrocarbon-water-contact's)?

RESERVOIR ENGINEERING

1. Were the results of tests undertaken in the well interpreted correctly, and were recorded fluid flows or fluid recoveries consistent with log, wireline pressure, core poro/perm data and with hydrocarbon indications recorded during drilling?
2. Could any tests undertaken in the well that failed to recover fluid, recovered an unexpectedly small volume of hydrocarbons, or recovered water instead of hydrocarbons, have been invalid or unrepresentative, due to:
    i. Incorrect interval tested?
    ii. If conducted in cased hole, imperfect perforations?
    iii. Significant filtrate invasion?
    iv. Mechanical faults with tools or plugging of flow lines?
    v. Test duration being too short?
    vi. Interval tested being too large or encompassing separately pressured reservoirs?
    vii. Incomplete isolation of reservoirs tested due to poor cement bond or leaking packers?
    viii. Interference effects due to dual porosity/ permeability development?
    ix. Reservoirs having sustained near well bore or deep formation damage?
    x. Excessive water cushions prohibiting or limiting influx from the reservoir?
    xi. "Gas block" or "water block" in low permeability reservoirs causing imbibitions?
3. Could reservoirs that yielded non-commercial hydrocarbon flow rates on test, be drilled underbalanced, drilled with oil-based mud, or otherwise stimulated (e.g. hydraulic fraccing) and flow hydrocarbons at commercial rates?
4. Are reservoir pressure gradients consistent with inferred hydrocarbon column heights?
5. Are there intervals not recognised or considered unworthy of testing at the time of drilling that would have warranted testing if the well was drilled today?

GEOLOGICAL/GEOPHYSICAL

1. If reservoir objectives were encountered significantly off prognosis and/or the well synthetic does not tie with seismic through the well location, could the well have been drilled on the wrong location?
2. Could the well have been an invalid test, or drilled significantly downdip of the crest of closure at reservoir level leaving updip potential unevaluated, due to:
    i. Top reservoir not having being accurately mapped?
    ii. Top reservoir having been poorly imaged (e.g. incorrect statics corrections applied, inappropriate migration algorithm adopted, other processing shortcomings etc)?
    iii. Top reservoir time maps not having been accurately depth converted?
3. Could the reprocessing of existing seismic, or the acquisition of new seismic, in particular 3D, enhance structural and stratigraphic resolution at reservoir level, and identify previously unrecognised potential?
4. If the targeted reservoir in the well was unexpectedly missing or anomalously thin, could this be a function of fault cut-out at the well location subsurface?
5. If reservoirs are poorly developed in the well but hydrocarbons appear to be present, or reservoirs are entirely absent at target level, could reservoir development in fact be better elsewhere within the confines of structural or stratigraphic closure?
6. Could closure persist, or independent closures be developed, below the total depth of the well and so provide potential in deeper reservoirs?
7. If gas was discovered, has the potential for an oil rim in the prospect been evaluated?
8. Could the results of wells drilled nearby, and/or of regional studies completed post-drill, have changed the perception of the attractiveness of the reservoir section targeted in the well, or identified any other plays worthy of pursuing in the prospect drilled by the well?
9. Was the well drilled before the potential of unconventional resources (i.e. coal seam gas, shale gas, shale oil, tight gas etc) was fully appreciated, and if so could such potential exist in the prospect drilled by the well?

COMMERCIAL/TECHNOLOGICAL

1. Were any recognised zones of interest not fully evaluated for operational and/or financial, as opposed to technical, reasons e.g. budgetary constraints, non availability of testing equipment, feared impact of negative outcome etc?
2. If the well made a discovery considered uncommercial at the time of drilling, could this accumulation now be economically developed due to:
    i. An increase in estimated trapped volumes resulting from changes in log or test interpretation, or an increase in predicted reservoir bulk rock volume?
    ii. Advances in technology resulting in improved flow rates and/or recovery efficiencies from tight reservoirs e.g. hydraulic fraccing, acidisation, enhanced oil recovery, horizontal drilling etc?
    iii. Advances in technology now allowing the development of smaller fields, accumulations with thin reservoirs or thin hydrocarbon columns, gas accumulations with high levels of impurities such as carbon dioxide or hydrogen sulphide, oil pools with adverse properties such as high viscosity or wax content etc?
    iv. The field now being located closer to accessible processing facilities?
    v. For gasfields, condensate yields being higher than expected?
    vi. An increase in the price of oil, condensate or gas?
    vii. A favourable change in demand for oil or gas?
    viii. A favourable change in fiscal terms?
    ix. A decrease in drilling, completion and/or development costs?
    x. The application of an innovative development solution?
3. If the well encountered a hydrocarbon accumulation considered uneconomic on a stand-alone basis, could this accumulation now be economic to develop in conjunction with nearby discoveries.

The pursuit of understanding the Canning Basin and its backbone

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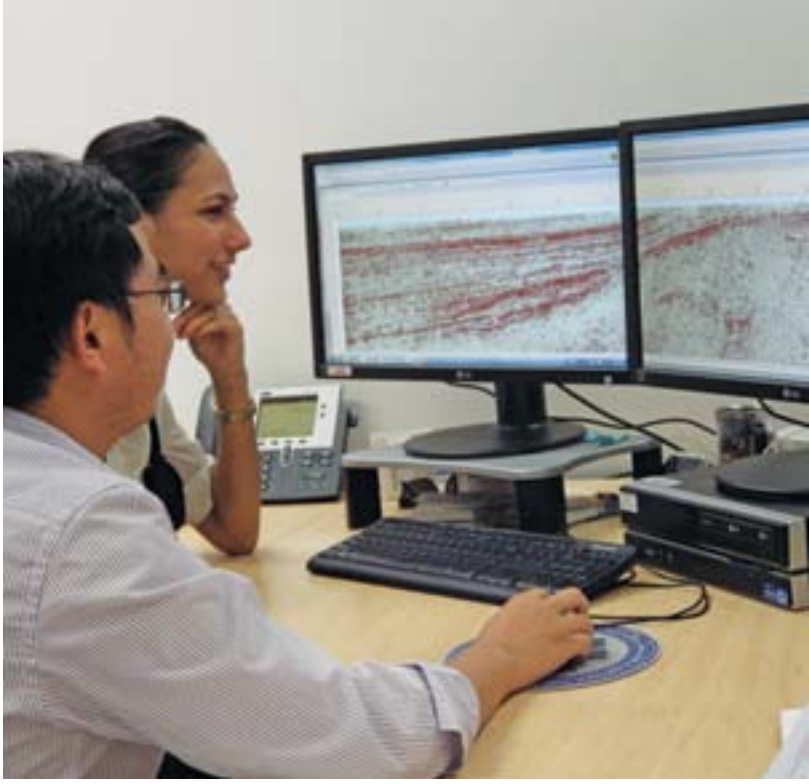

Interpreters viewing seismic data

In May and June 2014 the Geological Survey of Western Australia (GSWA) in collaboration with Geoscience Australia (GA) acquired a deep crustal geophysical survey across the onshore Canning Basin, from Pardoo Roadhouse on the North West Coastal Highway to Stumpy's Jump-up on the Gibb River Road. The 20 second seismic reflection and gravity data were recorded along two contiguous lines for a total length of 700 km (Figure 1). Acquisition was funded by the Western Australian State Government's Royalties for Regions Exploration Incentive Scheme (EIS). Processing was funded by the Australian Federal Government.

Seismic processing was designed to meet two objectives. The first objective was to process the 20 second profile to allow for imaging of the basement blocks beneath the Canning Basin, and investigating the suture between the Western and Northern Australian Cratons. The second was to process the upper 8 seconds to focus on the geology of Canning Basin, which would allow companies exploring for minerals or petroleum to relate the local geology within their tenements or permits to the regional picture of the basin (Figure 2). It would also allow government agencies to better understand groundwater aquifers.

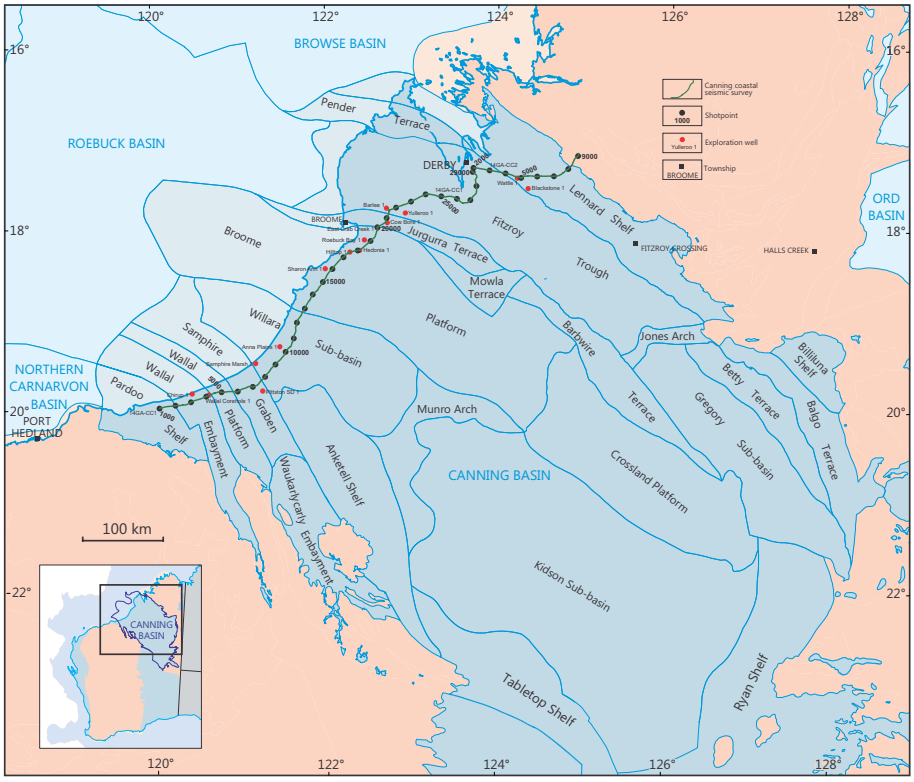

Figure 1. Location of the seismic traverse

Integration of the new seismic profiles with outcrops and drillholes provides a great deal of information about the subsurface geology. For example, the Vines Fault, cropping out in the Gregory Range Inlier and separating the Pilbara Craton from the Paterson Orogen to the north, can now be correlated to a master fault below the Mesozoic cover in the southwestern part of the line.

The reflectors from about 500 msec to 1500 msec under the northern Lennard Shelf are presumably the Neoproterozoic Oscar Range Group, which is exposed to the southeast as the spine of the Oscar Range. These types of correlations will assist in better defining the tectonic elements within the Canning Basin and the spatial extent of stratigraphic units.

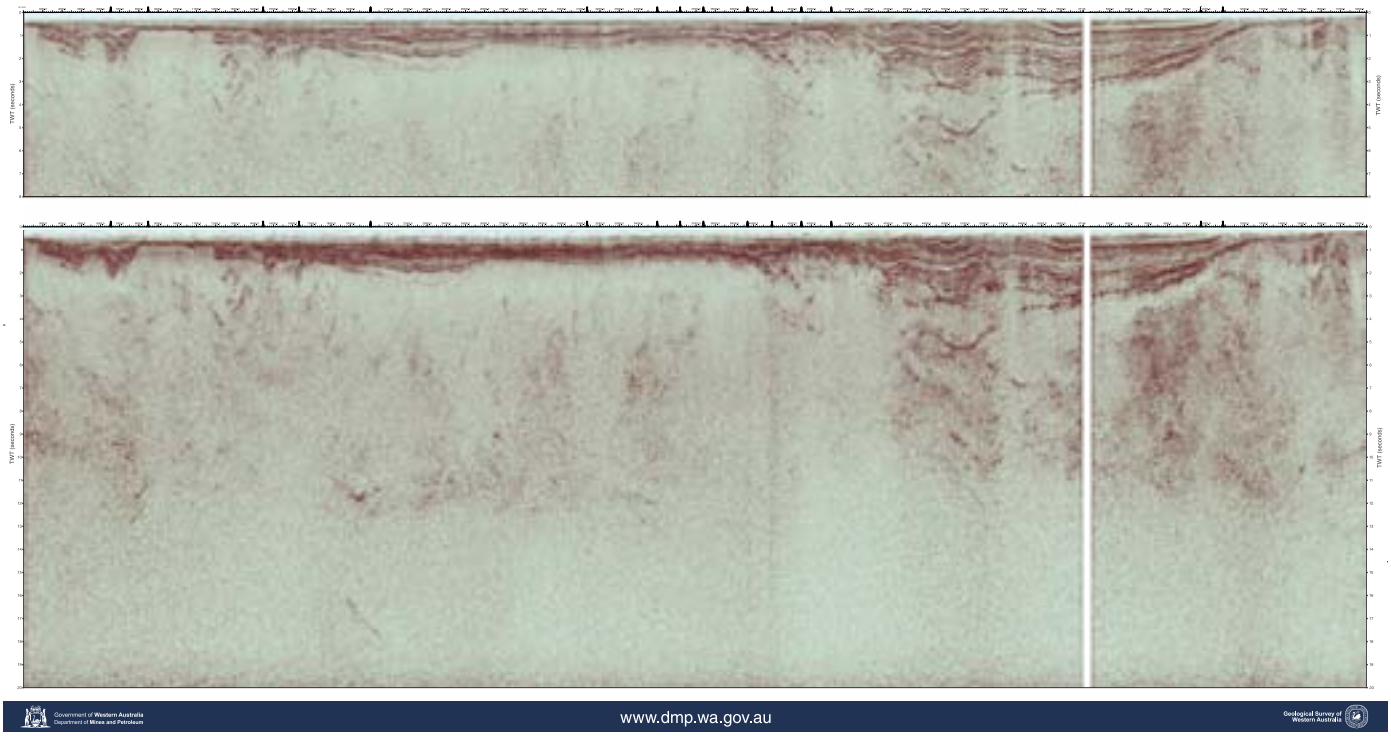

Figure 2. Processed data of the Canning coastal seismic survey.
Above: upper 8s profile with a focus on the basin geology. **Below:** 20s profile for imaging the basement blocks and Moho

The data will not only clarify some key points relating to the subsurface geology, but also allow interpretation of new features not evident in pre-existing seismic data across the basin. The images show variation in the framework of the Fitzroy Trough, from a southward deepening half-graben bounded by the Fenton Fault in the south inland, to a southward shallowing sag-like structure closer to the coast. A first-pass inspection of the processed images for the deep crust suggests that the subtle change in reflectivity seen at about 10 seconds under the Pardoo Shelf in the 20 second profile may represent the Moho, which then plunges to 12 seconds beneath the Willara Sub-basin and central Broome Platform, and then from about 9 seconds under the Fitzroy Trough to 12 seconds under the northern Lennard Shelf. The indistinct zone under the northern Broome Platform, and shift from 12 seconds back to 9 seconds, may mark the suture between the Kimberley and Pilbara Cratons. Such features will provide a new perspective of the basin backbone to better understand the basin's evolution and the continent's assembly.

Interpretation workshop starting soon

Data processing was completed by DownUnder Geosolutions Pty Ltd in February 2015. The processed seismic and gravity data are available for download via the Western Australian Petroleum and Geothermal Information Management System (WAPIMS). Alternatively, a portable hard drive containing processed data and reports can be ordered by sending requests to GSWA or GA (petdata@dmp.wa.gov.au; ausgeodata@ga.gov.au). Interpretation of the data by GSWA, with input from GA, universities and industry, will begin shortly. By-invitation workshops are planned for later in 2015, to be held in-house in DMP.

Geothermal for industrial use

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View of the groundwater cooling pumps and distribution system inside the Pawsey Centre

Pawsey Groundwater Cooling Scheme in Kensington, Western Australia

Geothermal energy is derived from the naturally occurring heat of the earth. When "geothermal power" is mentioned, we tend to think of steaming fumaroles nestled in snowbanks in Iceland, or boiling power plants in New Zealand. The steam drives compressors that generate electricity, in the same manner as a coal-fired power plant. But a different type of geothermal energy is being used in Perth — geothermal cooling.

Heat within the earth increases with depth; in Perth the temperature increases by about 20°C with each kilometre in depth (Reid et al. 2012). However, for geothermal cooling, another aspect of subsurface temperature is the most important. About 10 m below the ground, seasonal temperature fluctuations stabilise. Shallow groundwater temperatures stay roughly constant year round at approximately 19 to 21°C, as opposed to the air temperature which may vary from near 0°C to 45°C in Perth.

This constant temperature water can be used to cool industrial equipment. Such a groundwater cooling (GWC) scheme has been designed and implemented by CSIRO at the Pawsey Supercomputer Centre in Kensington, Western Australia. At the site, cool groundwater is extracted from the Mullaloo Aquifer, passes through a heat exchanger where it is warmed by heat from the supercomputer, before being reinjected into the same aquifer. The general concept is shown in Figure 1, where cool (blue) water is extracted from the aquifer, and warmer (red) water is reinjected.

Advantages of geothermal cooling

The Pawsey Supercomputer Centre is located adjacent to the Australian Resources Research Centre (ARRC) in Kensington, Western Australia. The centre was constructed to host supercomputing facilities and expertise to support Square Kilometre Array pathfinder research, geosciences and other high-end science. Like all supercomputing facilities, the Pawsey Supercomputer Centre requires a cooling solution to dissipate heat generated by the supercomputer.

Conventional cooling technologies involve transferring this heat to a cool water stream, then rejecting the heat to the atmosphere by evaporation in cooling towers. However, cooling towers use large amounts of water and may not be effective during extreme summer conditions found in Perth. The groundwater cooling scheme has the advantage that there is no net loss of water, a crucial design point in groundwater-reliant Perth, and a requirement of the groundwater licence issued by the WA Department of Water. CSIRO estimates the Pawsey scheme will save approximately 14.5 million litres of water in the first two years of operation (CSIRO 2013). Moreover, the performance of the GWC scheme is independent of the weather.

Other advantages of the GWC scheme are the nearly non-existent visual and aural impacts of the underground solution, compared to a noisy cooling tower. Further environmental benefits are provided by solar panels on top of the building powering the groundwater pumps.

Design of groundwater cooling

A GWC scheme can be designed by knowing the amount of thermal load $\boldsymbol{H}$ (or heat, [W]) that needs to be cooled, as well as the allowable temperature change $\boldsymbol{\Delta T}$ [°C] between the ambient extracted water and the warmed reinjected water. The flow rate of water Q [L/s] past the heat exchanger is calculated as

$$Q = \frac{H}{\Delta T * c_v} \qquad (1)$$

Here, c_v is the volumetric heat capacity of water [J/(L*K)]. The Pawsey GWC scheme was designed to handle a thermal load of about 2.4 MWth. For a design temperature difference of 12°C, the required pumping rate calculated from Equation (1) would be 57 L/s. However, advances in supercomputer

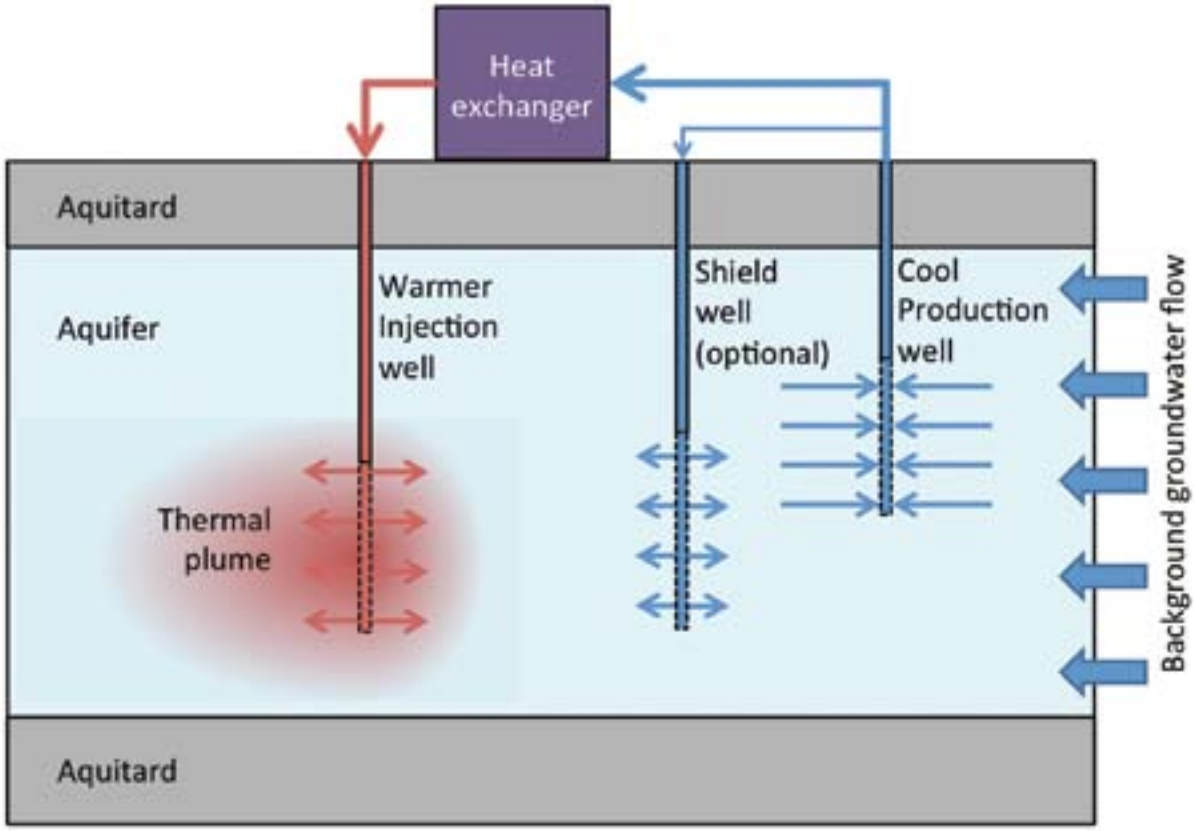

Figure 1. Schematic of a groundwater cooling system (from Sheldon et al. 2014)

design meant that the Pawsey Centre supercomputer that was installed in 2013 generates less heat than previously anticipated; hence, the required operational pumping rate is lower. Heat from the warm injected groundwater is dissipated in the aquifer by conduction, advection and dispersion.

In addition to the flow rate, groundwater cooling schemes need to consider other factors in design:

- Longevity of the system, especially in terms of the time when warm injected water reaches the cool extraction bores (thermal breakthrough);
- The effect of the scheme on temperature and water levels in the surrounding area, including impacts on:
  - existing wells (e.g. wells used for irrigation);
  - groundwater-dependent ecosystems; and
  - groundwater chemistry and microfauna.

The longevity of the geothermal system is increased by having the extraction bores located "upstream" (upgradient) from the injection wells (see Figure 1); the natural groundwater flow of the Mullaloo Aquifer helps move the warmer water away from the production bores. Additional "shield" wells were installed in the Pawsey GWC scheme, which can be used to inject cool water between the production and injection wells (Trefry et al. 2014), to increase the time to thermal breakthrough.

The Pawsey GWC extraction and injection wells are drilled into the Mullaloo Aquifer, approximately 100 m below ground surface. At the site, the Mullaloo Aquifer lies at a depth of 35 to 120 m. The Superficial Aquifer overlies the Mullaloo Aquifer, and is commonly used for domestic irrigation bores. The water for GWC is extracted from the Mullaloo at about 21°C, and the warmed water is heated up to a limit of 30°C. The locations of the injection, production, and shielding wells are shown in Figure 2. Also shown are monitoring bores, which sample the Mullaloo and Superficial Aquifers (Poulet et al. 2015).

The GWC system creates a thermal plume in the aquifer, which migrates to the west and decays with distance from the scheme. Computer simulations of the GWC during the design phase (Sheldon et al. 2014) investigated how the pumped groundwater and the injected heat may affect nearby groundwater users and environments. At the designed pumping loads, simulated drawdown of the water table above the production wells ranges from <0.1 to 0.9 m. Thermal effects on existing licensed wells in the area are predicted to be small (< 1°C temperature increase), except in the three wells closest to the site which are predicted to experience temperature increases of up to 6°C depending on the pumping rate and duration (Figure 3). Twelve licensed wells in the simulation model area experience drawdown ≥0.5 m, with the largest drawdown at a well location being 1.9 m. Most of the drawdown is predicted to occur in the first year of simulated pumping.

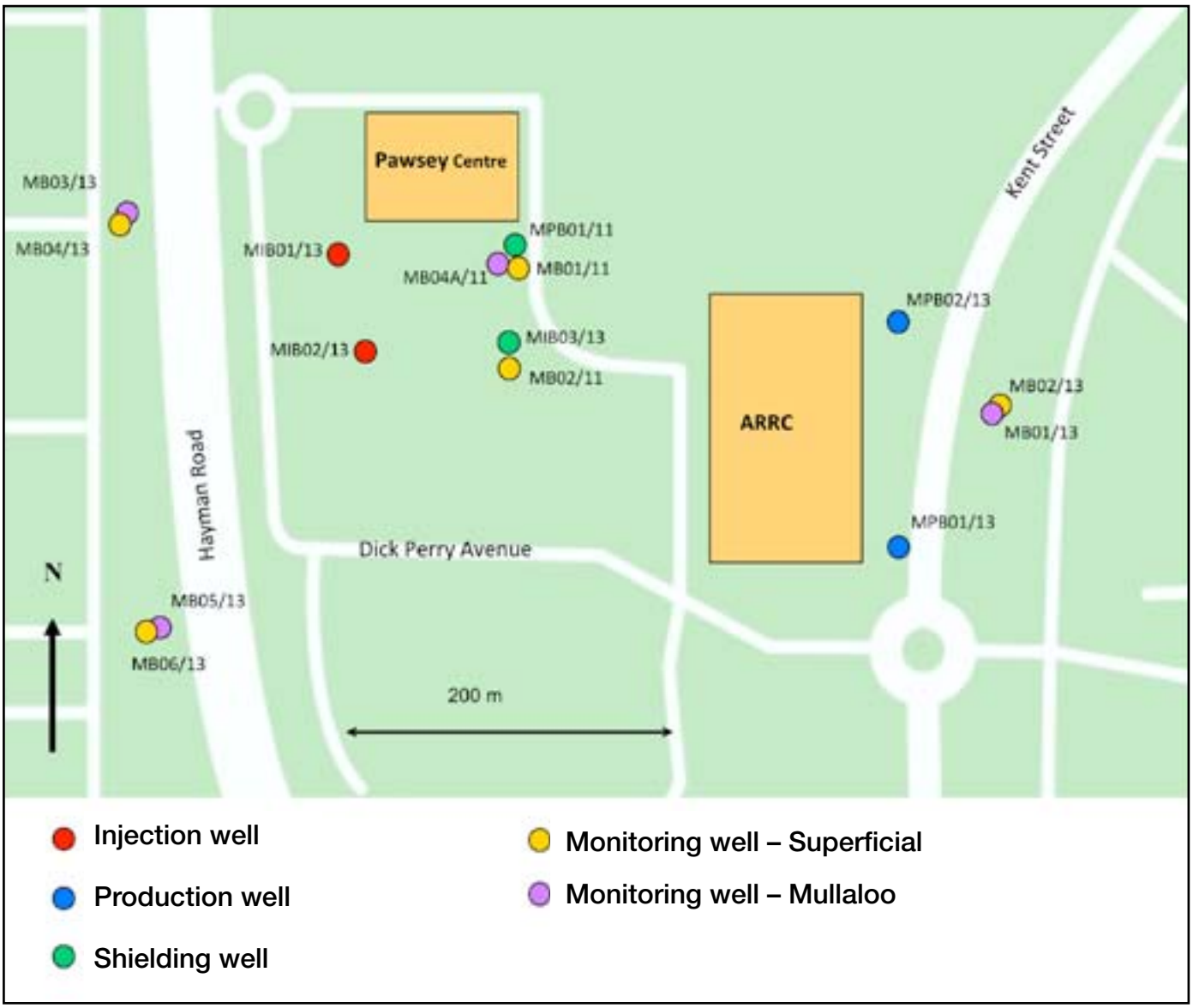

Figure 2. Site map in Kensington, WA showing locations of the GWC and monitoring wells (from Poulet et al. 2015)

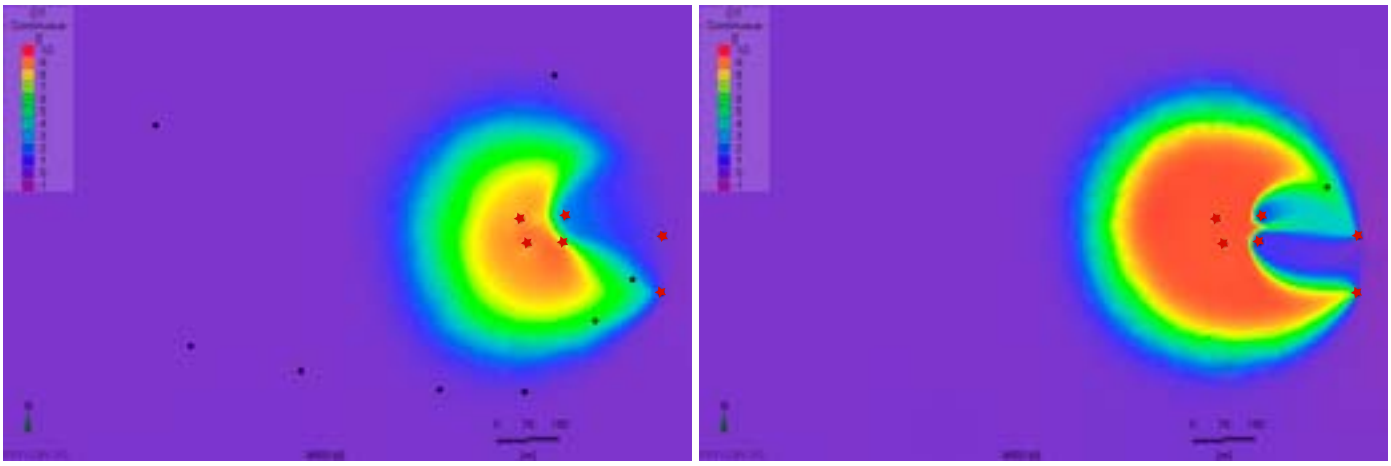

Figure 3. Simulated temperature changes (°C) at licensed groundwater extraction wells after 10 years of injection. Left image shows temperature in the Superficial Aquifer, right image in the Mullaloo Aquifer (from Sheldon et al. 2014). Scheme wells are shown as red stars. Other water bores are shown as black dots

The Pawsey Centre building seen from Burvill Court. The solar panels are visible on the left but the groundwater cooling system is underground

Drawdown of the water table may potentially impact some vegetation in the nearby Kensington Bushland. Maximum simulated drawdown in the bushland is 0.6 to 1.1 m. However, vegetation in the bushland copes with seasonal variation in the water table of at least 1.2 m, and the maximum predicted drawdown occurs in an area of the bushland which is already degraded. Note also that current operational pumping is lower than the predicted values.

In addition to the simulations, water sampling and analysis showed that the reinjected warmed water would not significantly change the aquifer geochemistry (Douglas et al. 2014). The closed-loop design of the above-ground system means that no oxygen enters the circulating piping, which decreases the likelihood of chemical and biological clogging. Ongoing sampling of groundwater at nine monitoring bores (see Figure 2) will provide regular pictures of the health of the system.

Conclusions

The groundwater cooling scheme at the Pawsey Supercomputer Centre is now in operation. A research program based on numerical modelling is investigating the behaviour of the system, refining the underlying hydrogeological simulator based on geophysical results, and tracking parameters from the monitoring system in real time. Preliminary results indicate that the GWC system has had no detrimental effect on the surrounding environment and minimal consequences on groundwater levels as the system functions in a closed loop. The technology concept, if deployed more widely, has the potential to replace cooling towers in commercial and residential buildings in the Perth Basin. So, while steaming geothermal power plants are unlikely to exist in Perth, it is possible to use the earth's energy for other industrial applications in Western Australia.

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Acknowledgements

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Review of well integrity in Western Australia

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Production Christmas tree, northern Perth Basin

Introduction

All petroleum and geothermal wells drilled in Western Australian State jurisdictional areas are subject to State legislation and regulation administered by the Department of Mines and Petroleum (DMP). The three primary areas of regulation are: safety, environment and resource management, which includes well integrity. Primary in DMP's assessments in the subsurface are the protection of aquifers and resources. A properly designed well ensures that these protections and integrity are retained.

Well integrity is defined as the "application of technical, operational and organisational solutions to reduce risk of uncontrolled release of formation fluids throughout the life cycle of a well" (NORSOK Standard D-010 2013).

A well's integrity should be checked by its operator twice a year as per good oilfield practice. The principle of having at least two barriers between the subsurface environment and the interior of the well to maintain well integrity is an established standard to keep wells safe in all phases of their development.

Many different types of barrier failures can lead to loss of well integrity. Some well integrity issues are not critical, whereas some may lead to incidents. Possible consequences of a more critical integrity failure are blowouts or leaks that can cause material damage, personnel injuries, loss of production and environmental damages resulting in costly and risky repairs and remediation. All well integrity failures must be reported to DMP and remediated as soon as practicable.

This article explains the importance of well design in ensuring risks to personnel and the environment are mitigated and describes the most common barrier failures found in petroleum or geothermal wells in WA.

DMP has conducted a review of 1035 of the approximately 1060 wells in Western Australian State waters and onshore that have not yet been decommissioned. The information is sourced from DMP's database, WAPIMS, and from industry reports and is grouped under three main integrity issues: tubing integrity, casing integrity, and wellhead / Christmas tree integrity.

It should be noted that a leak path to the external environment cannot be created when only one barrier has failed. Further barrier failures must also occur in order for a leak path to be created to the external environment. However, well integrity is considered to have failed as soon as a barrier has failed and remedial action to re-establish that barrier is required. For this reason the majority of well integrity issues do not involve leaks to the external environment.

In Western Australia (WA), the vast majority of petroleum and geothermal wells are drilled, completed, produced and decommissioned without any adverse environmental impacts.

Well design — barriers and well integrity

In the first instance, well locations are selected based on geological considerations. If a surface location is unsuitable this will normally be determined before the well is designed. Every well is designed, constructed, operated, maintained and finally decommissioned with specific well integrity considerations in mind for each of its life cycle phases, from the time of a well's conception until it is permanently decommissioned. Not every well will have the same life cycle, but in general, it will include drilling, completion and production. Some wells might be converted from producers into injection wells used to enhance reservoir pressure or dispose of produced water. Finally, every well will be decommissioned.

Well design is a vital stage in the life of a well. Risks should be identified, evaluated and resolved or mitigated during the well design stage. This should be undertaken both in terms of probability and impact, in order to define and implement risk control arrangements. The risks remaining after applying initial control arrangements constitute residual risk, including those which have the potential to generate the greatest impact on the environment. The most important element of risk control is to prevent barrier failure by predicting the performance of barriers under any operating conditions.

Minimum design factors should ensure a well is designed to withstand all planned and/or unexpected loads and stresses including those induced during potential well control situations. The risk treatment options should ensure that potential deviation from what is planned or expected for the operations, are mitigated.

Well barriers are used to prevent leakages and reduce the risks associated with drilling, production and intervention activities. The purpose of a primary well barrier is to prevent, by isolation:

- ingress and egress of fluids, such as drilling fluids or formation fluids, between the wellbore and the external environment, both on surface and subsurface; and
- communication or fluid flow between different formations under differing pressure regimes.

A secondary well barrier is a back-up to the primary well barrier.

A well barrier has one or more barrier elements, which may be active, passive, or in some cases reactive. Active barriers, such as valves, can prevent formation fluid flowing to the surface while passive barriers are fixed structures, such as casing and cement. A reactive barrier may be a human or mechanical response to activating or triggering an event. When barriers are used in series, a multiple-barrier system is created (Hollnagel 1999; Fleming and Silady 2002; Skylet 1999; Sklet 2006a, b). Reactive barriers are activated when a pressure, flow rate or other behaviour limit is exceeded. Tables 1a and 1b show the various elements used as barriers and their function. These are also illustrated in Figure 1.

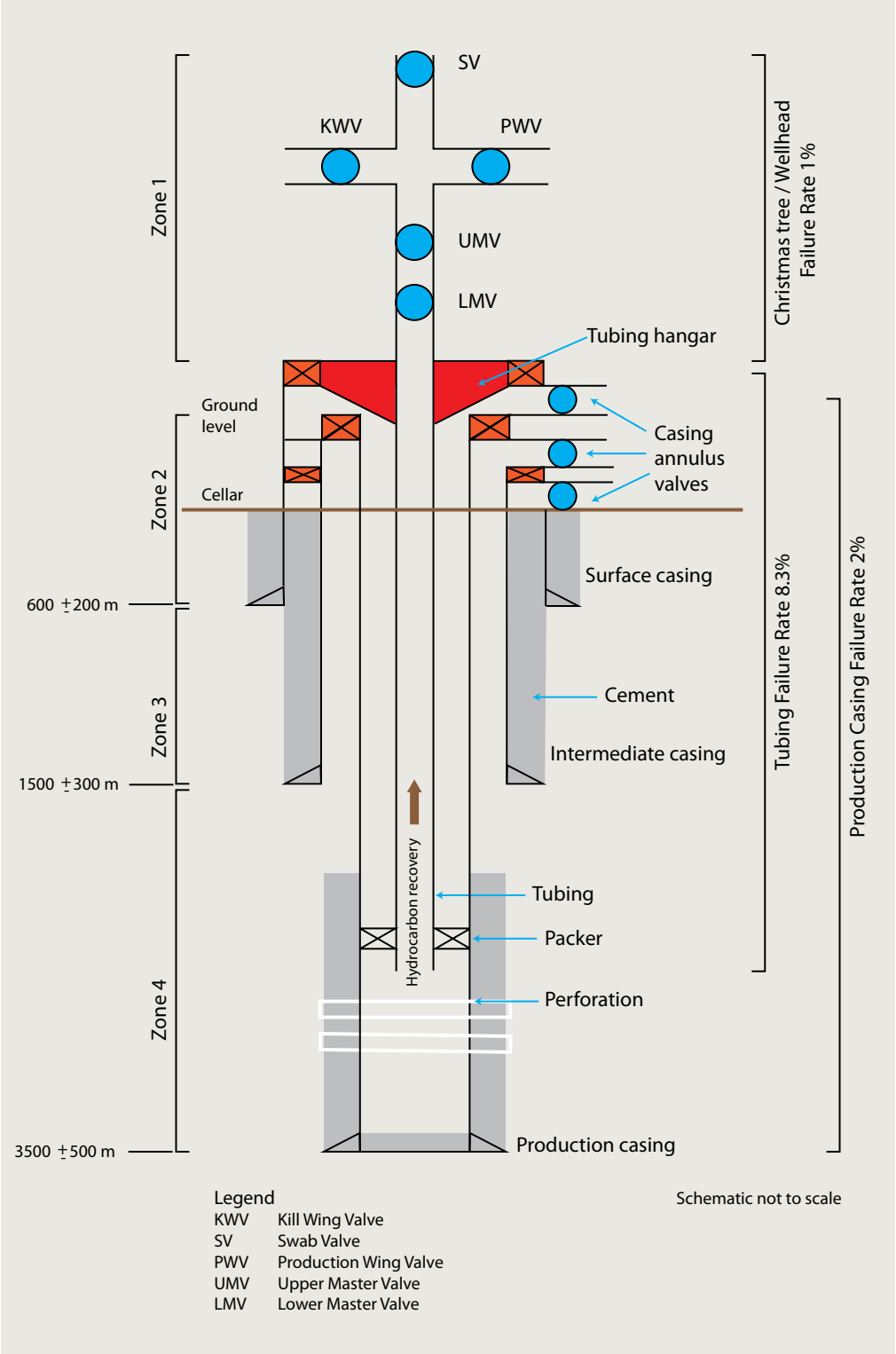

Figure 1. Well barriers schematic

Table 1a. Tubing barrier elements and their function (as per NORSOK D-010 2013)

Elements	Functions
Production Christmas tree	Provides a flow conduit for formation fluids from the tubing into the surface lines with the ability to stop flow by closing the flow and/or master valves; vertical access to wellbore; and an access point where kill fluid can be pumped into the tubing
Production Wing Valve (PWV)	Ability to stop the flow of formation fluids from the tubing to the surface line; used to control the production flow
Lower / Upper Master Valve (LMV / UMV)	Has the ability to stop the flow of formation fluids flowing from the tubing; used to completely shut in the production tubing
Wellhead	Provides mechanical support for the suspending casing and tubing strings and hook-up of risers or BOP or tree and to prevent flow from the bore and annuli to formations or the environment
Tubing	Provides a flow conduit for hydrocarbons to be produced or to inject fluids into the wellbore

Table 1b. Casing barrier elements and their function (as per NORSOK D-010 2013)

Elements	Functions
Annulus valves	Used to access the different annuli in between tubing and casing and between different casings in the well
Casing	Isolates the wellbore from the external rock formations (including aquifers)
Casing cement	Acts as a vertical barrier. Surface casing and cement isolate the well from an aquifer. Provides a continuous, permanent and impermeable hydraulic seal along the well in the casing annulus or between casing strings, to prevent flow of formation fluids, resist pressure from above or below, and support casing or liner strings structurally
Production packer	Provides a seal between the outside of the production tubing and the inside of production casing or liner to prevent communication from the formation into the annulus above the production packer
Tubing	Isolates the flow of hydrocarbons from the production casing above the production packer

When a well is being drilled, the primary well control barrier is the drilling fluid, which exerts a hydrostatic pressure in the wellbore that will prevent well influx/inflow (kick) of formation fluids. The Blow Out Preventer (BOP) and casing are secondary barriers. The BOP prevents flow from the wellbore to the surface environment. Once the drilling phase is completed, the BOP is replaced by the Christmas tree.

Well control failures occur more often in the drilling phase than in the completion phase (post drilling phase) due to unexpected high formation pressure or other drilling related factors encountered while a well is being drilled. Producing wells and completed wells have multiple barriers which are tested and monitored at all times.

Individual barriers are designed and built to withstand a specific load without help from other barriers. If one barrier fails, the next barrier will provide isolation so that a leak path will not form. Table 2 shows the number of barriers present in different zones. The number of barriers is typically proportional to the potential hazard in a specific well.

The failure of a well barrier element will result in a well with compromised integrity. Examples where a loss of well integrity has occurred include any issues subsurface, such as packer failures, tubing failures or casing failures, or on the surface, such as leaking Christmas tree valves or annulus valves, missing lockdown screws, or exposed valve removal (VR) plugs. If a well barrier has failed, the well must be shut in and remedial action taken to restore the failed well barrier.

Well integrity in Western Australia

All non-decommissioned wells should be inspected for well integrity issues twice per year under the Schedule of Onshore Petroleum Exploration and Production Requirements 1991. Inspections involve pressure testing the barrier elements to determine the integrity of each barrier. A well barrier is deemed to have failed when it loses integrity in one barrier element and does not pass a pressure test.

Table 2. Recommended number of barriers (after King 2013)

Zone	Hazard to groundwater	Number of barriers
1 – At Surface*	Very Low	2
2 – Shallow	Low to Moderate	2 to 4
3 – Mid Depth	Very Low	1 to 2
4 – Deep	Negligible	1

*Onshore it is ground surface, offshore it is the seabed

Table 3. Rate of well integrity failure in Western Australia

Type of failure	Number of wells affected	Percentage (%) of total number of wells in WA
Tubing failure	86	8.3
Casing failure	22	2.1
Wellhead / Christmas tree failure	14	1.3
Total	122	11.7

In WA, all wells including the wells drilled onshore, on Barrow and Thevenard Islands and in State waters that have not yet been decommissioned were examined for well integrity issues by the Department of Mines and Petroleum. The survey found 122 (less than 12 per cent of non-decommissioned wells) cases of integrity/barrier failure in approximately 1035 wells (Table 3). Tubing failure dominated these occurrences.

Tubing leaks

Tubing is a small diameter pipe, which is installed inside production casing and normally carries the fluids being produced or injected. When tubing fails, pressure is exerted into the production annulus through the leak in the tubing. In such cases, the well is left with only one barrier and would temporarily be shut-in until the second barrier is re-established. Leaks can occur through holes corroded or eroded by produced or injected fluids inside the tubing, as shown in Figure 2, or from twisting of the tubing, as shown in Figure 3. During the production phase of a well's life cycle, tubing failure occurs more often than any other failure.

If tubing integrity fails, fluids inside the tubing can leak out of the tubing into the production casing / tubing annulus. Conversely, packer fluids in the production casing / tubing annulus can leak into the tubing. Note that groundwater wells normally do not contain tubing (NUDLC, 2012).

Of the 1035 wells in this study, 86 wells had a tubing failure (61 of these wells were on Barrow Island). This equates to about 8.3 per cent of the total number of non-decommissioned wells in the State. Fifty-seven wells with tubing integrity failures were over 40 years old, as shown in Figure 4. No wells in this study were more than 60 years old.

Tubing failure is an internal integrity failure; it does not imply a leak outside of the well. Overall the tubing failure rate in Western Australia is very low compared to other parts of the world (see Table 4).

Figure 2. Hole in tubing (Source: DMP)

Figure 3. Tubing that has twisted due to corrosion (Source: DMP)

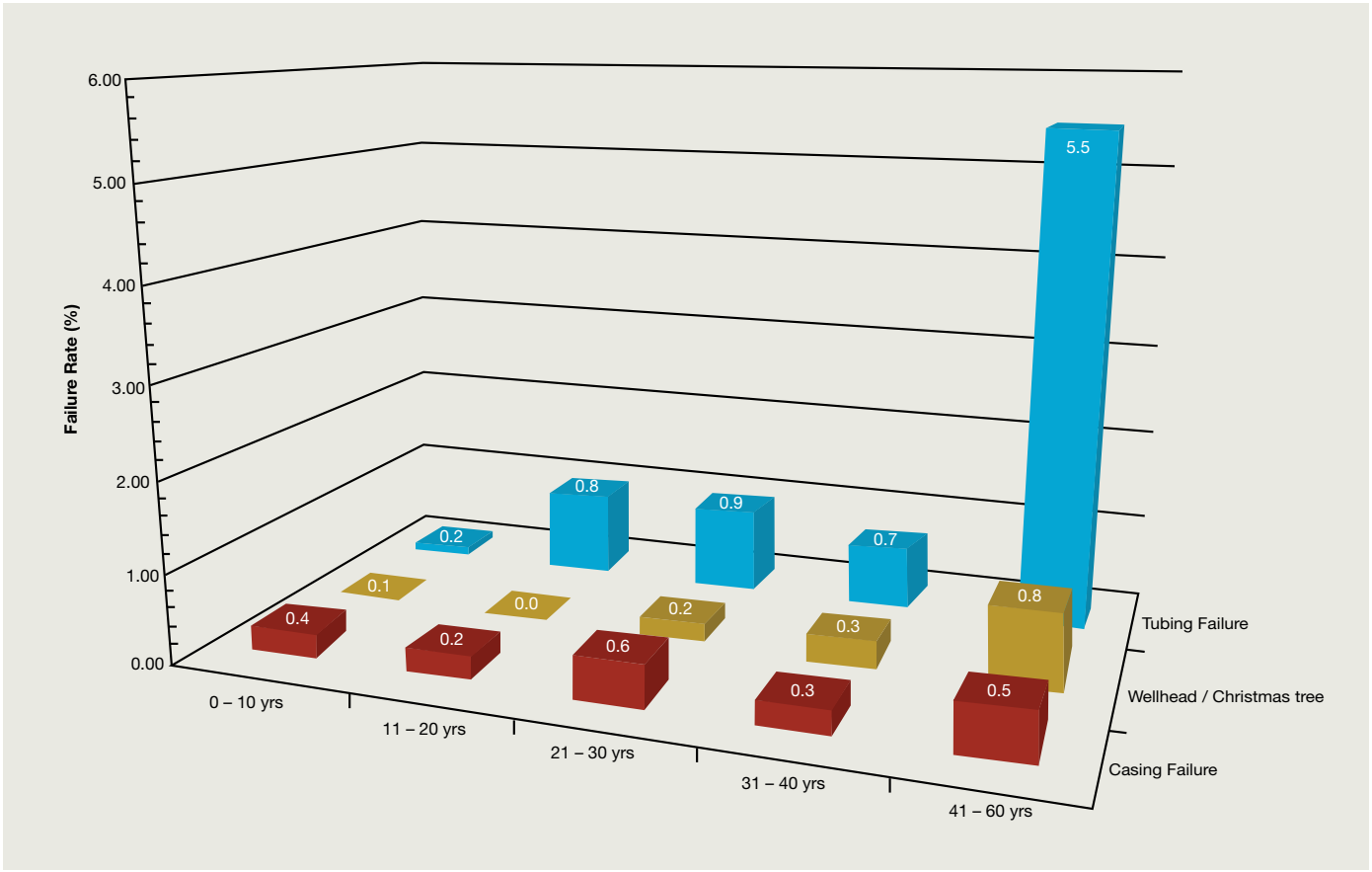

Figure 4. Well integrity data for Western Australia showing a correlation between the age of the well and the type of barrier element failure

Casing leaks

Leaks can occur through the connections between lengths of casing and in the body of the casing. Corrosion is the primary cause of damage. The fluids causing the corrosion can be inside the casing, or sometimes, formation fluids outside the casing. The fluids may include acid gas (CO_2) or sour gas (H_2S). Casing can also be damaged mechanically when workover operations are conducted after the well has been completed.

Casing is cemented in place, with a sheath of cement forming a seal outside the casing. In many cases the casing is cemented from the bottom back to surface, but long production strings of casing may not be cemented along their entire length. In these cases it is possible, where damage occurs above where the casing is cemented, for fluid to leak to or from casing and formation.

Casing failure occurs predominantly in production casing due to corrosion, pressure differential and thermal effects causing the pressure behind the production casing to exceed the collapse resistance of the casing. While the root causes of these failures may be metallurgical or design flaws, casing failure can occur due to improper use of a casing type in a well. If a casing failure occurs, the well will be shut in until remedial action can take place. If remedial action does not re-establish the second barrier, the well must be decommissioned.

Reservoir pressure decreases during the production phase, which leads to a potential pressure difference across the wellbore. Low bottom hole pressure wells do not have the driving force to oppose the constant hydrostatic pressure of fluids outside of the wellbore; hence, if a leak path is formed through the sequence of barriers, the highest potential is for exterior fluids (usually salt water) to leak into the wellbore (King 2013).

Twenty-two of the 1035 wells examined in this study had a production casing failure, equating to about two per cent of the total well number of wells. Figure 4 shows the wells in WA with the least casing failures were aged 11 to 20 years old.

Christmas tree / wellhead integrity leaks

The Christmas tree is an assembly of valves and fittings above the wellhead, often above ground, which connect the well to production facilities. In groundwater wells, the equivalent equipment is commonly called headworks (NUDC, 2012).

A loss of surface / wellhead integrity may involve a leak in surface equipment such as a Christmas tree valve, tubing hanger seal, Christmas tree connections, annulus valve, annular safety valve, or surface safety valve (Figure 1). A leak within a valve will not necessarily mean the creation of a flow path to the external environment.

Instances of surface integrity failure occur far less frequently than subsurface failures primarily because the Christmas trees are readily accessible for maintenance and corrosion is closely monitored and prevented. Again, more than one barrier would have to fail before a leak path to the external environment is created.

Once a well integrity failure has been established, the operator undergoes a process of assessing the risk and planning and obtaining equipment to conduct remedial activities to re-establish integrity (Humphreys and Ross 2007). There can be delays of several months, awaiting equipment before remediation can occur, during which time the well will be plugged and suspended. It is possible for further integrity issues to occur in wells that have previously been remediated.

After loss of integrity the barriers should be re-established before the well goes back on production.

This type of failure experienced the lowest number of occurrences in WA. This study found approximately 14 wells which reported a loss of Christmas tree / wellhead integrity, or about one per cent of the total number of wells in Western Australia. Though this is a less common type of failure, age of equipment is a factor. Figure 4 shows more than half of the wells with Christmas tree / wellhead failures were aged over 40 years old.

Comparative international studies of well failures

Advances in well construction technology have decreased barrier failure rates and along the way, improved zonal-isolation reliability. The Vintage Bahrain oilfield in the Arabian Gulf showed a moderate degree of casing damage from exterior corrosion, however, the threat of leakage was minimised through design modifications and workovers (Shivkumar and Janahi 2004). In a sequence of design changes dating from 1932 to the early 2000s, casing damage and barrier failures were reduced from 60 per cent to only rare occurrences, by inspection, monitoring and proper maintenance (King 2013).

Vignes and Aadnoy (2010) have conducted a pilot well integrity survey in offshore Norway based on input from 21 per cent of the active wells (production and injection wells) on the Norwegian continental shelf. A total of 406 production and injection wells were included in the survey (Table 4).

The 323 production wells included gas and oil producers, while the remaining 83 wells comprised water alternating gas injectors, gas injectors and water injectors. Decommissioned wells were not included in the study. Figure 5 illustrates the number of wells with well integrity problems and the category of barrier elements failure. Most of the integrity problems were found in barrier elements such as tubing, annulus safety valves, casing, cement and the wellhead.

Conclusions

The current situation in Western Australia is that 122 petroleum wells out of 1035 non-decommissioned wells have been shown to have integrity issues; however, none of the wells had leakage to the external environment. Twenty-five wells remain to be inspected to assess their current well integrity status. However, as this is an ongoing process all non-decommissioned wells must be re-inspected on a regular basis.

Table 4. Tubular-connection failures by connection type (King 2013)

Area	No of wells	Wells with barriers issues	Major problem	Percentage of wells with barrier issues	Source
Gulf of Mexico	14 927	6650	Leak in tubular	45%	Howard (2004)
North Sea, UK	4700	1600	Tubing connection, Cement	34%	SPE (2009)
North Sea, Norway	2682	482	Tubing connection, Cement	18%	SINTEF (2010)
North Sea, Norway	406	75	Tubing leak, Casing, Cement and Annulus Safety Valve	18%	Vignes and Aadnoy (2010)
Western Australia, onshore and State waters	1035	122	Tubing leak	12%	This study

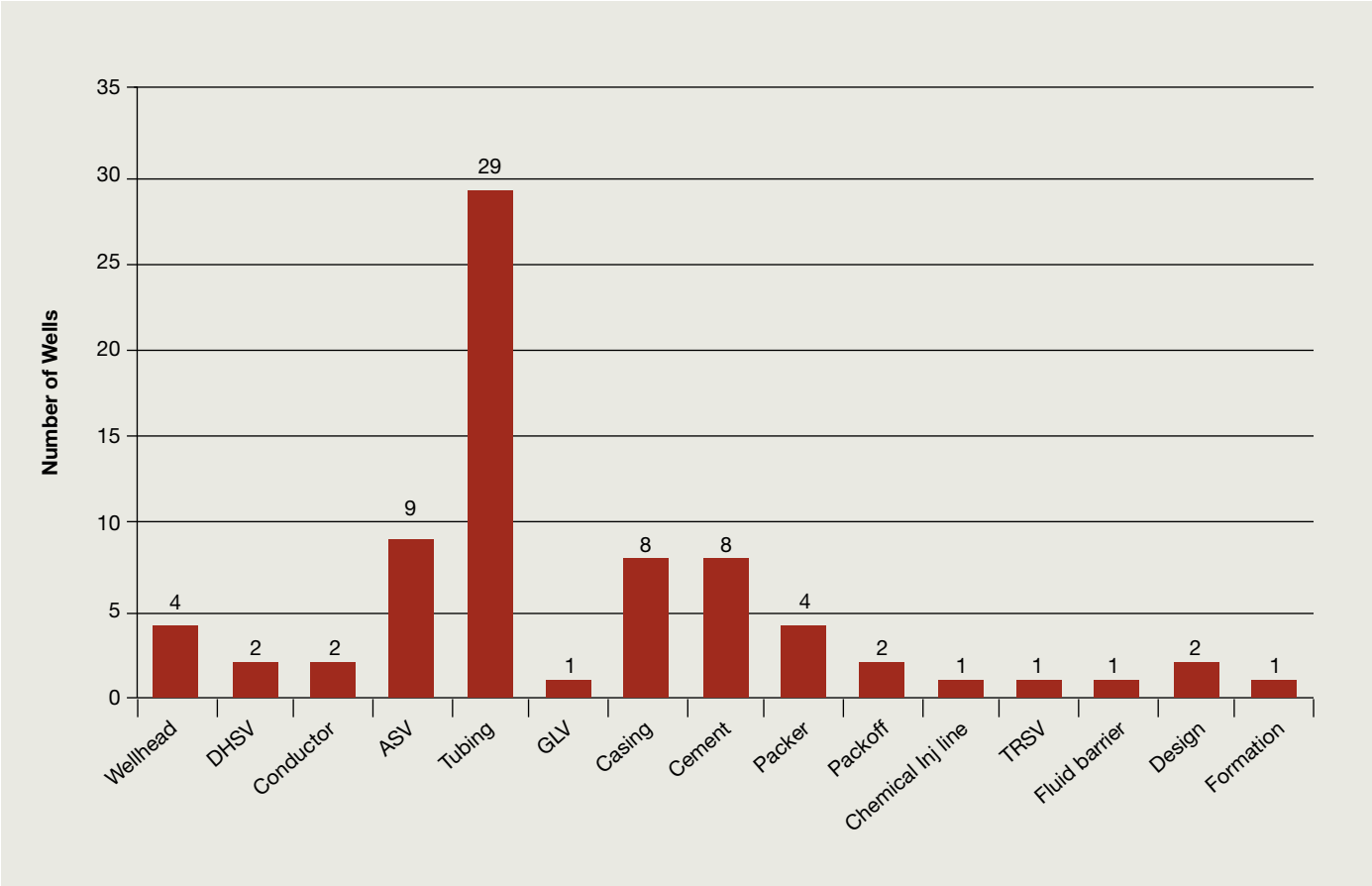

Figure 5. Number of wells with well integrity problems (Vignes and Aadnoy 2010)

Tubing failure was recorded as the most common cause of integrity loss with no compromising barriers. Due to the exposure of tubing to hydrocarbon flow, it can be anticipated that tubing failures will occur more frequently than other types of failures. As such, a normal part of the life cycle of a producing well is to replace worn out tubing strings.

Casing failures occur almost equally for wells of all ages, while surface failures increase as the wells age and are most common in the oldest wells. In fact, wells aged over 40 years experienced the highest proportion of failures in two of the three integrity categories.

Despite the relatively small number of wells drilled in WA compared to the number of wells in the US, North Sea, Bahrain and Gulf of Mexico, this study indicates the well failure rate is similar to that experienced in other parts of the world.

Recommendations

1. Every well must be inspected to determine the integrity of the well at intervals not exceeding six months. The inspection of production wells includes measuring the tubing and production annulus pressures. A report of the inspections must be submitted to DMP.
2. A well's status may change during its lifetime. At the end of the well's life, it must be decommissioned as per good oilfield practice.

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Inspection of a non-decommissioned well on the Senecio field

The use of cement bond logs in assessing well integrity

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A wireline logging unit

Introduction

The first casing cement job in a petroleum well was conducted in 1903 (Fertl et al. 1974), and since that time operators and regulators have been interested in monitoring whether well integrity (hydraulic isolation) exists both within and behind the casing.

Cement bond logs (CBLs) were invented to indirectly address well integrity but, like all wireline logs, CBLs have strengths and weaknesses. CBLs come in a variety of forms but typically consist of one or more acoustic transmitters and receivers that are run in the centre of casing (centralised) after the cement is set (Figure 1; King 2012).

A typical CBL will consist of a left hand track with a depth control log such as gamma-ray, a casing collar locator (CCL) and sometimes a caliper or other logs. The centre track consists of the acoustic amplitude log in milli volts (mV), which may be displayed at a number of different scales. The amplitude log records how well the outer edge of the casing is bonded to the inner part of the cement sheath, with low values suggesting a good bond and higher values a poor bond or absence of cement behind the casing altogether. The right hand track usually consists of a Variable Density Log (VDL) which displays the full acoustic waveform (Figure 2).

The fundamental principle of a CBL is that acoustic signals are more attenuated in the presence of cement than when casing is uncemented. Modern CBLs can acquire azimuthal, or circumferential, data and utilise ultrasonic frequencies (e.g. the Ultrasonic Imaging Tool or USIT log).

Interpretation of CBLs

The simplest interpretation of a CBL is to observe the acoustic amplitude log and infer that, where it is less than about 10 mV over a significant interval of the well, isolation is likely.

Once the cement has set, it begins to cool and can slightly de-bond with the casing, creating a micro-annulus. The micro-annulus formed by this de-bonding causes an increase in amplitudes received, but experience has shown that isolation can still be present even without an increase in amplitude. The simplest way to check the cement bond if micro-annuli are suspected is to pressurise the well fluid and re-run the CBL. This can often result in a drop in amplitude values because the casing is now acoustically coupled to the cement. Some operators do not re-pressurise the casing and re-run the CBL, resulting in ambiguous interpretations where micro-annuli are suspected.

Where there is no (or limited) cement present, the amplitude log will give high readings and the VDL will exhibit strong vertical bands, as the casing reverberates (Figure 2, top right). “W” shaped reflections or chevrons will be present on the VDL image, centred on casing collars.

The bonding of the cement sheath to the formation is critical for isolation. The VDL image can provide hints about how this interface is bonded if the casing to cement bond is good, and hence the signal can travel further out to the formation. Good bonds of both casing to cement and cement to formation (or cement to a larger casing string) typically reflect a low amplitude value and the first arrival on the VDL (casing to cement) appears fuzzy looking. Also, the later VDL waveforms are stronger and vary as the formation velocities change.

Even if both the amplitude and VDL are interpreted to show good cement bonding, channelling in the cement remains a possibility. Channels may be caused by impurities or intrusions, introducing connected zones without cement. These channels typically form a spiral and can make isolation doubtful. Channelling can be identified by acquiring azimuthal CBLs and is easily identified on azimuthal VDLs.

Interpretation of CBLs and open-hole logs should be performed in conjunction. Open-hole logs should be inspected for permeable zones that indicate possible mud cake build-up.

Significant mud cake build-up on the formation wall could inhibit the cement-to-formation bond. The VDL display could be distorted by fast formation velocities representing mud. Also, formations with significant porosity and permeability have the potential to act as thief zones, where cement might be lost during a casing cement job.

Log header information often includes comments from the logging engineer on tool and hole conditions and in some cases even provides log interpretations. The cement job report should also be critically reviewed.

King (2012) reports that newer tools such as the Segmented Bond Tool (SBT), Cement Volumetric Scan Tool and USIT are definite improvements over the conventional CBL/VDL, but the small channel detection problem remains. Each logging technique currently in use has limitations, and none measures isolation as well as a pressure test.

The casing pressure test (a hydraulic pressure test) is done within the casing to evaluate the mechanical integrity of the casing string and ensure that there are no fluid leaks. This test is performed by increasing the pressure in the casing to one and a half times the average operating pressure. The test is then held for 10 to 15 minutes. The pressure test would fail if the casing doesn't hold pressure (i.e. if there is a leak through the shoe that indicates poor tail cement slurry or if there is a leak through a connection between casing joints). A positive pressure test indicates casing integrity — implying there are no holes or leaks at connections. The casing pressure test does not test the integrity of the formation.

The casing is run to protect and preserve hole sections that have already been drilled through, from pressures and hole problems that might be encountered when the well is drilled deeper. A formation integrity test (FIT) or leak off test (LOT) is conducted after drilling out the casing shoe and before continuing to drill deeper, to check the integrity of the formation. An FIT or LOT also confirms that the casing shoe is sound.

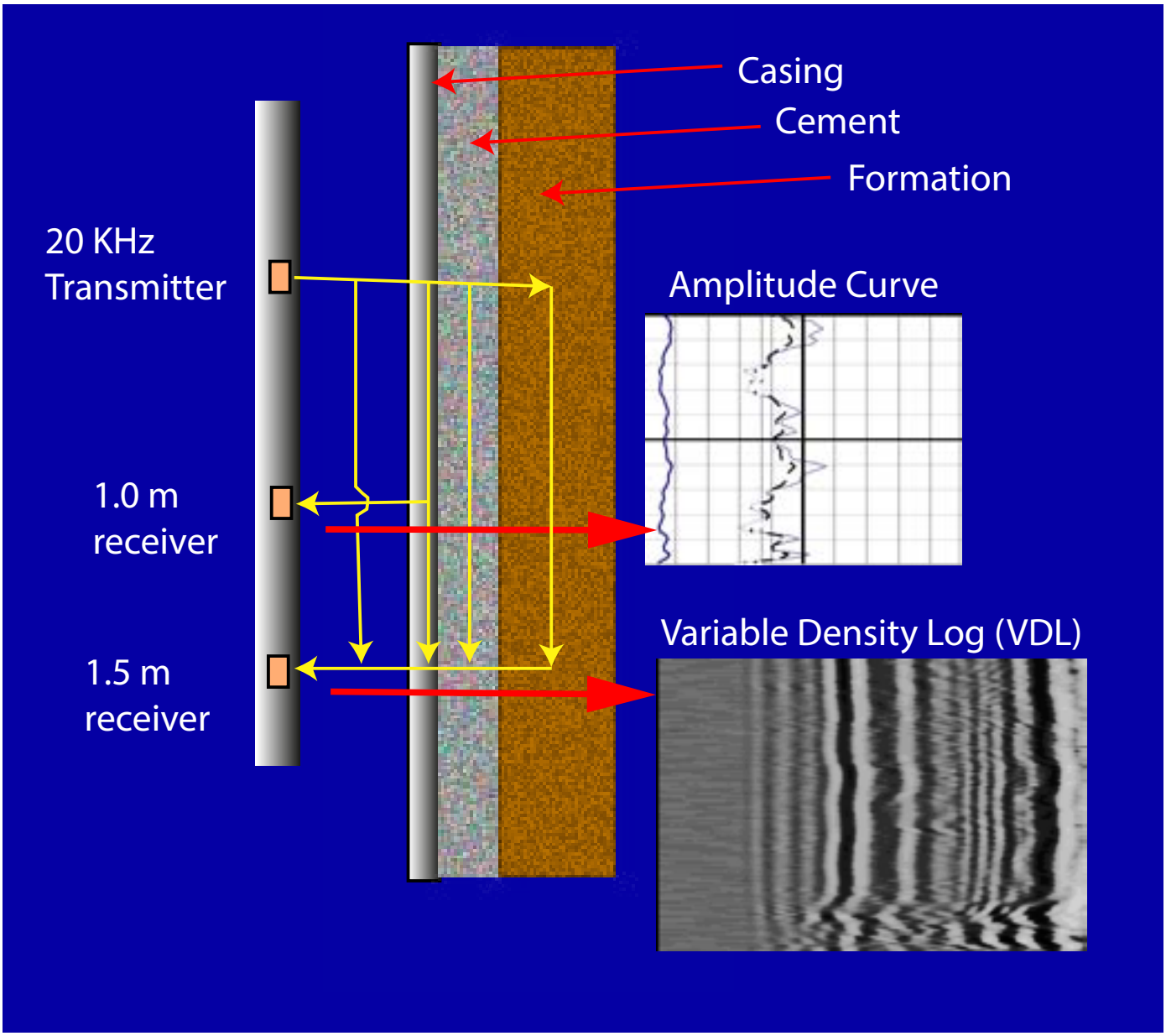

Figure 1. A conventional CBL (Source: King 2012)

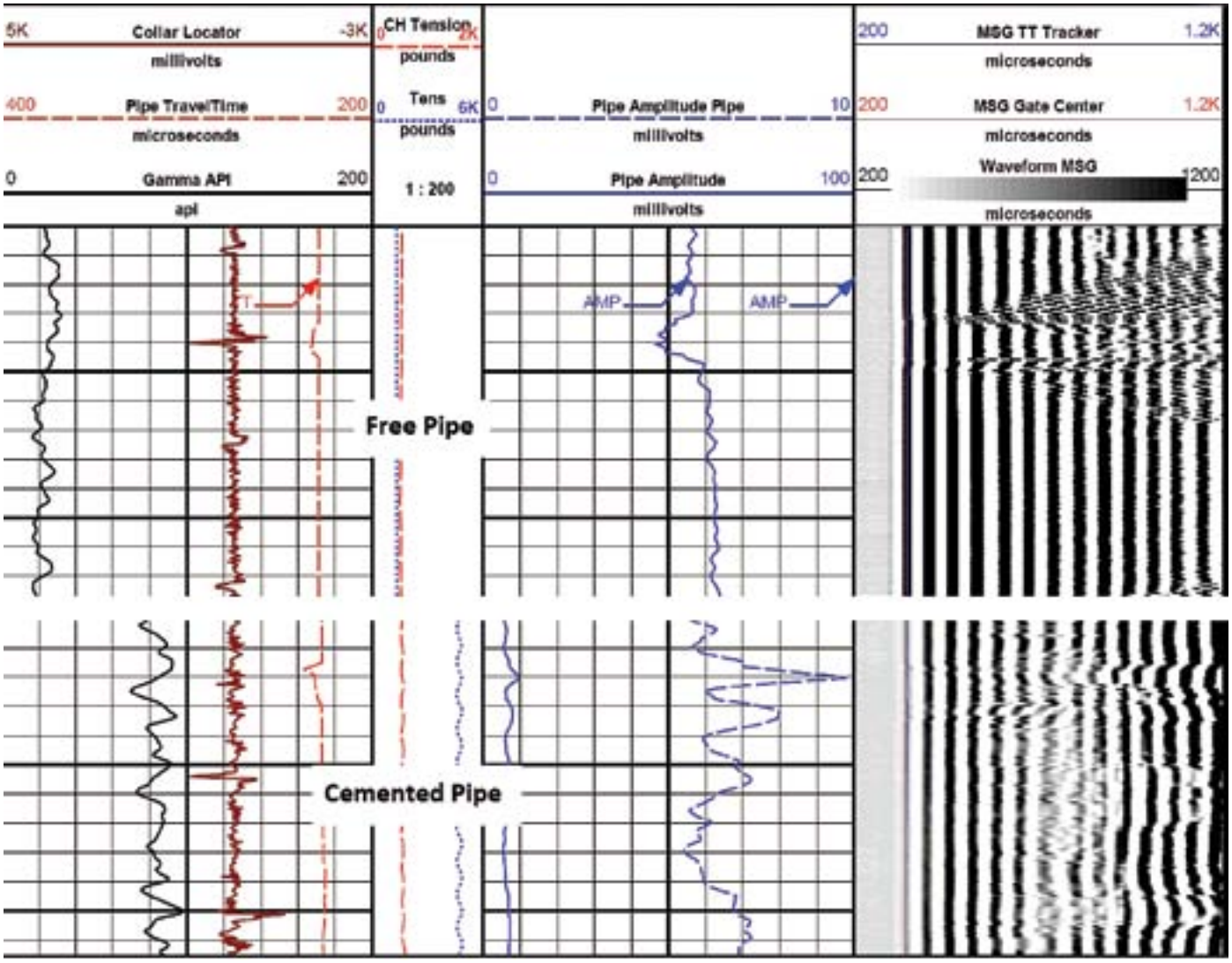

Figure 2. Typical CBL/VDL (Source: Schlumberger)

Further pressure tests are done inside the casing when packers are run and set. This validates isolation between the tubing and annulus, and isolation below the packer from above the packer.

Conclusions

Cement bond logs will not give a definitive answer as to whether well integrity exists over zones of interest; only pressure testing can confirm hydraulic isolation over and between the zones of interest.

Cement bond logs can give false positives in that isolation can be interpreted, but this may not actually be the case; and false negatives in that isolation may be interpreted to be absent or doubtful when later pressure testing or long-term production confirms that isolation actually exists.

One of the roles of a government regulator is to ensure that a well is fit for purpose. When a HFS program or other major work-over involving high pressure is proposed by an operator, it is important that subsurface data be integrated with wellhead and other surface data to confirm that adequate barriers exist during operations to ensure safety and well integrity.

Recommendation 1:

Operators should acquire azimuthal CBLs because this is likely to reveal the presence of channels in the cement sheath, which may compromise isolation.

Recommendation 2:

The interpretation of CBLs for isolation should be done in conjunction with open-hole log interpretation, cement job reports and other relevant data.

Recommendation 3:

Operators should check for the likely presence of micro-annuli as soon as the CBL is acquired. If relevant, operators should pressurise the well fluid and casing, then re-run the CBL.

Recommendation 4:

Operators should acquire relevant data during and after a cement job to enhance well integrity and isolation interpretations. This could include a record of pressure tests conducted and their resulting data.

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Schlumberger 2015, Oilfield Glossary, http://glossary.oilfield.slb.com

Glossary

Casing

Large-diameter pipe lowered into an open-hole and cemented in place. Casing is run to protect fresh water formations, isolate a zone of lost returns or isolate formations with significantly different pressure gradients (Schlumberger 2015).

Casing pressure test

Pressure testing is a common hydraulic testing method to assure integrity of casing. After the cement has set, the pressure integrity test is performed by increasing the internal casing pressure to a prescribed higher pressure. If no leakage is detected, the cement seal is deemed successful.

Casing shoe

A short assembly typically manufactured from a heavy steel collar and profiled cement interior that is screwed to the bottom of a casing string. The rounded profile helps guide the casing string past any ledges or obstructions that would prevent the string from being correctly located in the wellbore (Schlumberger 2015).

CBL: Cement bond log

Cement bond tools measure the bond between casing and the cement placed in the annulus between the casing and the wellbore. The measurement is made by using acoustic sonic and ultrasonic tools.

DFIT: Diagnostic fracture injectivity test

The well is pressurised until formation fracturing is detected. The well is then shut in, and the surface pressure is monitored for closing pressure for 1–2 weeks.

Formation arrivals

The VDL (see below) may be split into casing, then formation and finally mud arrivals, as their individual velocities decrease. Formation arrivals are the chevrons caused by the cement-to-formation bond and by lithology.

FIT: Formation integrity test

Formation integrity test is conducted to test the strength and integrity of a new formation and casing shoe to a designed pressure. FIT is typically conducted to ascertain that formation remains intact while drilling deeper sections with increased bottom hole pressures. FIT also ensures that no communication is established with higher formations. FIT differs from a LOT in that the pressure applied in an FIT is less than that in a LOT and does not fracture the formation.

Isolation

Isolation in this report refers to preventing interaction between producing zones in the borehole and to blocking migration of fluids to the surface.

LOT: Leak off test

A test to determine the strength or fracture pressure of the open formation, usually conducted immediately after drilling below a new casing shoe. During the test, the well is shut in and fluid is pumped into the wellbore to gradually increase the pressure that the formation experiences. At a certain pressure, fluid will enter the formation, or leak off, either moving through permeable paths in the rock or by creating a space by fracturing the rock. The results of the leak off test dictate the maximum pressure or mud weight that may be applied to the well during drilling operations (Schlumberger 2015).

Micro-annulus

Micro-separation between the outside of the casing/pipe and the inside of the cement sheath.

Mud cake

The residue deposited on a permeable medium (i.e. borehole wall) when a slurry, such as a drilling fluid, is forced against the medium under pressure. Filtrate is the liquid that passes through the medium, leaving the cake on the medium (Schlumberger 2015).

USIT: Ultrasonic imaging tool

The USI tool delivers an accurate, high-resolution, comprehensive, real-time confirmation of the pipe-to-cement bond quality and downhole pipe condition.

VDL: Variable density log

VDL is a presentation of the acoustic waveform at a receiver of a sonic or ultrasonic measurement, in which the amplitude is presented in colour or the shades of a gray scale. The variable-density log is commonly used as an adjunct to the cement-bond log and offers better insights into its interpretation; in most cases micro-annulus and fast-formation-arrival effects can be identified using this additional display.

Well integrity

Application of technical, operational and organisational solutions to reduce the risk of uncontrolled release of formation fluids throughout the life cycle of a well.

Domestic gas supply potential in Western Australia

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NWS domestic gas plant at Karratha

Introduction

The gas resources and reserves analysed in this report include conventional gas reserves and resources from both the WA and offshore Commonwealth jurisdictions. Those from WA include reserves and resources from both onshore WA (Perth and Canning Basins) and WA Territorial waters (Carnarvon Basin).

The importance of a secure and reliable gas supply for Western Australia (WA) cannot be overstated because it is the most energy and gas-dependent economy in Australia. Natural gas fuels half of WA's primary energy needs and 70 per cent of its electricity generation. This compares to 22 per cent and 16 per cent for Australia as a whole. A secure and reliable gas supply will underpin jobs, investment and economic growth in the State.

Western Australia's Domestic Gas (Domgas) Reservation Policy aims at securing the State's long-term energy needs by ensuring supply of domestic gas from LNG export projects.

A domestic gas policy position has been maintained by successive WA governments since the 1970s, when the then State Government entered into domestic gas supply arrangements to support the development of the North West Shelf Joint Venture (NWS JV). In 2006, the WA Government formalised the policy with the release of the *WA Government Policy on Securing Gas Supplies*. In 2012, the Government clarified arrangements for the application of the policy in its *Strategic Energy Initiative, Energy 2031* final paper. Gas producers are required to demonstrate their ability to meet the Domestic Gas Policy as a condition of project approval.

In order to understand the supply side of domestic gas, this report analyses gas reserves in Western Australia, by assessing the distribution of remaining gas reserves in producing fields and contingent resources in fields under Western Australian jurisdiction. This report also covers current domestic gas processing plants in Western Australia and the remaining gas reserves from offshore fields in Commonwealth jurisdiction that supply domestic gas to Western Australia.

The gasfields reserves in WA jurisdictions are sourced from the latest (December 2013) reports supplied to the Department of Mines and Petroleum (DMP) by operators. For those fields on the NWS that fall under the State Agreement, data is provided to DMP via the Department of State Development. However, since the establishment of the National Offshore Petroleum Titles Administration (NOPTA), DMP no longer has access to updated reserves and resources data for the remaining offshore Commonwealth waters fields. Consequently, the in-place data and remaining reserves/resources data for Commonwealth waters were sourced from December 2011 reports, the last available to DMP, as well as recent production data. Therefore, the accuracy of the derived reserves data for John Brookes, Macedon, Halyard, and Reindeer may not be guaranteed.

Gas processing plants and associated fields

Currently in Western Australia, the majority of domestic gas is supplied by the Karratha Domestic Gas Plant of the North West Shelf project, Varanus Island domestic gas processing hub, Devil Creek domestic gas plant and Macedon domestic gas plant at Ashburton North. Gas processing facilities in the Perth Basin, including Dongara, Hovea, Xyris, Beharra Springs and Red Gully facilities, also supply a small volume of domestic gas to the WA market. The Mondarra gas plant is not included in this report, because its gas comes from other fields. These plants are summarised in Table 1.

The total processing capacity for all domestic gas plants is 1562 TJ/d, while the actual supply rate fluctuates and is less than this number. The average supply during 2013 was about 960 TJ/d.

Table 1. WA Domestic Gas Processing Plants, Processing Capacity and Supplying Fields

Plant	Operator	Nameplate processing capacity (TJ/d)	Processing capacity as at August 2014 (TJ/d)	Current utilisation percentage (%)	Fields
CARNARVON BASIN					
NWS domestic gas plant	NWS JV	700	460	65	Perseus, Goodwyn, North Rankin, Angel, Searipple, Cossack, Wanaea, Hermes, and Lambert
Varanus Island gas processing hub (Harriet JV and East Spar JV)	Apache	390	260	67	Bambra, Lee, Linda, Rose, Wonnich, John Brookes, Halyard
Macedon domestic gas	BHP Billiton	200	140	70	Macedon
Devil Creek gas plant	Apache	220	90	41	Reindeer
PERTH BASIN					
Dongara	AWE	7	2	29	Dongara, Corybas
Beharra Springs	Origin	20	18	90	Beharra Springs, Beharra Springs North, Redback (including Redback South), Tarantula
Red Gully	Empire Oil & Gas	10	8	80	Red Gully, Gingin West
Xyris	AWE	10	0	0	Apium, Xyris, Hovea 2 well
Woodada	AWE	5	0	0	Woodada
TOTAL CAPACITY		1562	978		

Two new domestic gas processing plants are currently under construction. The Gorgon domestic gas processing facility located on Barrow Island, is around 90 per cent completed. The Wheatstone domestic gas plant, part of the Wheatstone LNG development, is around 55 per cent complete. The Gorgon plant will supply up to 300 TJ/d of domestic gas to the WA market, while Wheatstone will supply 200 TJ/d (valid as of December 2013).

Two domestic gas plants, Tubridgi and Thevenard Island, are decommissioned or being suspended for decommissioning.

Gas reserves and resources

This section covers remaining gas reserves and contingent resources from currently producing fields in WA jurisdiction, basin by basin.

Perth Basin gas reserves

The three domestic gas-processing facilities currently in operation in the Perth Basin are the Dongara, Beharra Springs and Red Gully gas processing facilities. By the end of December 2013, the remaining reserves of these fields totalled 1.32 Gm^3 (0.047 Tcf). Note the Apium field is now depleted.

There are other discovered gasfields in the Perth Basin, such as Warro, Whicher Range, Senecio and Arrowsmith. The companies involved are progressing their understanding of the fields and in some cases preparing for their development. No reserves were booked for these fields

by the end of 2013, and therefore the timeframe of supplying gas to WA domestic market from these fields is uncertain.

Canning Basin gas resources

At the end of 2013, there were no producing gasfields and no reserves have been booked in the onshore Canning Basin. However, there are contingent resources of 5.41 Gm^3 (0.19 Tcf) of gas and 0.45 GL (2.81 MMstb) of condensate, but there is no certainty in the completion timeframe for their potential supply to the domestic gas market.

Meanwhile, gas resources from the offshore Canning Basin are yet to be discovered.

Carnarvon Basin gas reserves/ resources

The offshore Carnarvon Basin is the most prolific hydrocarbon-bearing basin in Australia. Owing to the discoveries of several large oil and gasfields, the basin now provides about 90 per cent of the gas supply for the domestic gas market in WA.

North West Shelf gas reserves/ resources

North West Shelf (NWS) gas reserves are reported separately because these fields supply more than half of the domestic gas to the WA market. The Angel and Searipple fields have seen water breakthrough and are on intermittent production. Associated gas from Cossack, Wanaea, Lambert, and Hermes oilfields, although a small portion of the NWS production, also contributes to the domestic gas supply. The Echo/Yodel gasfield is already depleted and is suspended.

As of 31 December 2013, the remaining reserves from these producing fields are 305.91 Gm^3 (10.8 Tcf) of gas, and 31.4 GL (197.53 MMstb) of condensate.

Except reserves from producing fields, contingent gas resources are booked in the NWS Retention Leases, which include Dixon and Wilcox. For these fields, the State Agreement with the NWS JV applies hence WA will receive royalties and excise compensation for the development of these fields. Their remaining resources are 13.2 Gm^3 (0.47 Tcf) of gas, and 3.91 GL (24.59 MMstb) of condensate.

The following NWS fields share production licences with other currently producing fields, but are yet to start producing: Dockrell, Egret, Gaea, Goodwyn GHA/B, Keast, Lady Nora, Lambert Deep, Pemberton, Persephone and Tidepole. The NWS State Agreement also applies to these fields, which have total reserves/ resources of 106.4 Gm^3 (3.76 Tcf) of gas, and 15.10 GL (94.98 MMstb) of condensate. Development plans are in place for some of the fields, such as the Phase 1 Greater Western Flank Project, with development of Goodwyn GH and Tidepole fields by tie-in to the Goodwyn Platform.

In addition to the above reserves and resources, the following fields contain contingent resources that are not commercial: Angel, Cossack, Dockrell, Echo/Yodel, Egret Deep, Goodwyn GHA/B, Goodwyn GHC, Goodwyn South, Hermes, Ishmael, Keast, Lady Nora, Lambert, Lambert Deep, Pemberton (East), Perseus, Pueblo, Sculptor-Rankin, Searipple, TIdepole, Wanaea and West Dixon. Their total gas resource is 21.15 Gm^3 (0.75 Tcf), and the condensate resources total is 3.13 GL (19.69 MMstb).

Domestic gas reserves from producing fields offshore under Commonwealth jurisdiction

A few other fields in offshore Commonwealth waters supply a large portion of domestic gas to the WA market as well. These fields are John Brookes, Halyard, Reindeer and Macedon. Their total remaining reserves are 47.26 Gm^3 (1.7 Tcf) of gas and 1.68 GL (10.6 MMstb) of condensate. This amounts to 15 per cent of the remaining reserves of producing fields on the NWS.

WA Territorial waters gas reserves/ resources

In WA's Territorial waters, the Lee, Linda, Rose, Bambra and Wonnich fields also supply gas to Varanus Island for domestic usage. The remaining reserves from these producing fields are 0.50 Gm^3 (17.7 Bcf) of gas, and 0.12 GL (0.78 MMstb) of condensate.

The contingent resources in WA Territorial waters held in production licences are 2.67 Gm^3 (90 Bcf), excluding contingent resources from Barrow Island fields.

In addition to the above fields, a small amount of gas resources totalling 9.98 Gm^3 (0.35 Tcf) were also booked as contingent or non-commercial in WA Territorial waters to the end of 2013 in the following fields: Blencathra, Flinders Shoal, Taunton, South Chervil, Nasutus, Gaius, Ginger, Cryano, and Barrow Island. The Barrow Island oilfield is estimated to contain 7.2 Gm^3 (0.3 Tcf) of gas alone.

Gorgon and Wheatstone reserves

Two LNG and domestic gas projects are being executed in the offshore Carnarvon Basin: the Gorgon and Wheatstone Projects. The Foundation Gorgon Project that will develop the Gorgon and Jansz-Io fields is scheduled to be operational in mid-2015, exporting LNG and supplying domestic gas. For the following six years, Gorgon will provide 150 TJ/d gas to the domestic market, and 300 TJ/d thereafter. The Wheatstone Project will develop the Wheatstone, Iago, Julimar, and Brunello fields, and it is expected that the project will be operational from 2016, supplying 200 TJ/d gas to the domestic market. The reserves from these two projects total 935 Gm^3 (33 Tcf) of gas and 51.1 GL (321 MMstb) of condensate.

Browse Basin gas reserves/ resources

There is no producing gasfield in the Browse Basin at present. The first fields that are most likely to be developed and to commence production of natural gas are the Brecknock, Calliance and Torosa fields. These fields are currently held under Retention Leases by the operator, Woodside, who is assessing FLNG for its front-end engineering design. Meanwhile, the WA government is in discussions with Woodside regarding providing gas to the WA domestic market. The contingent resources at the end of 2013 from these fields are approximately 540 Gm^3 (19 Tcf) of gas and 70 GL (440 MMstb) of condensate.

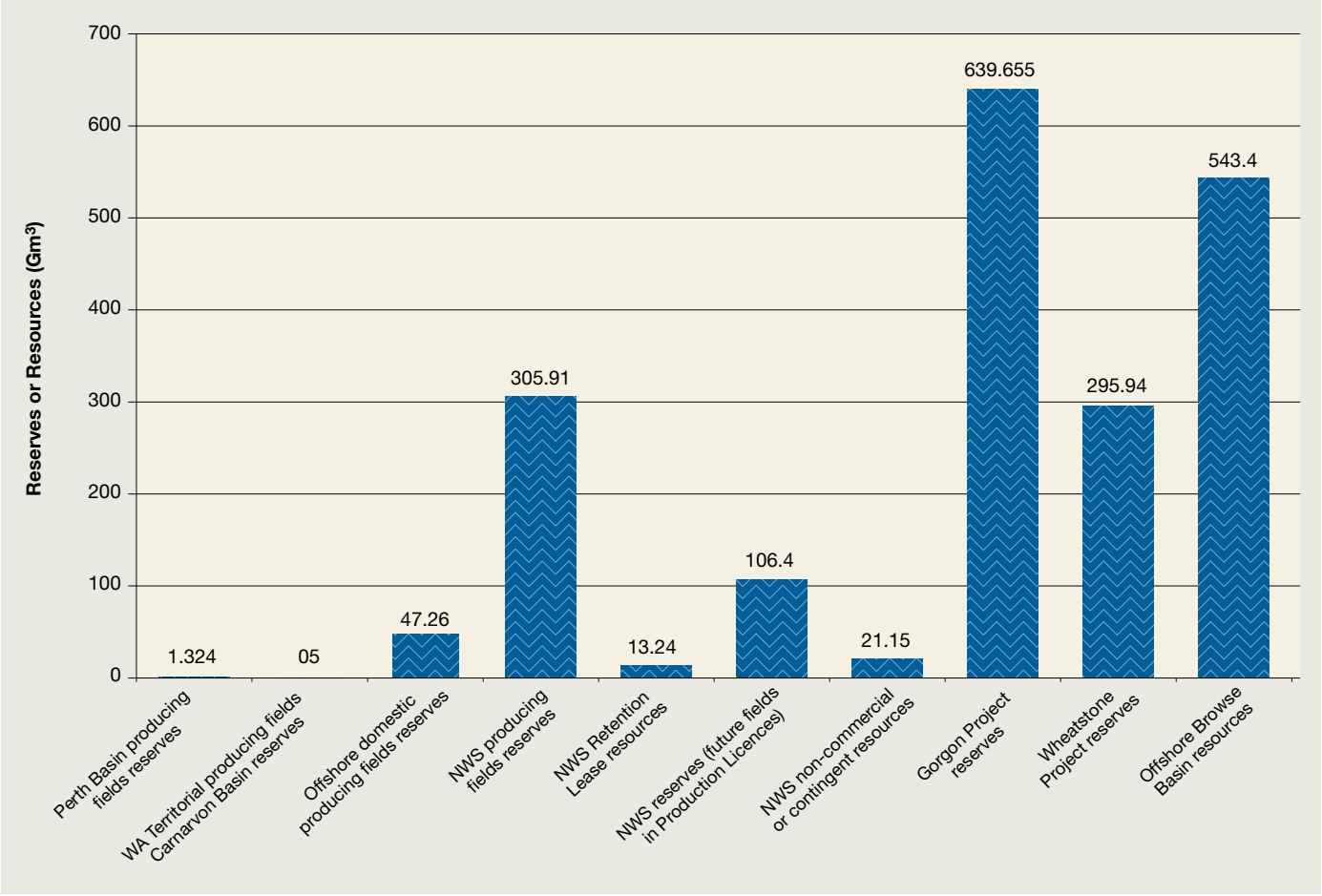
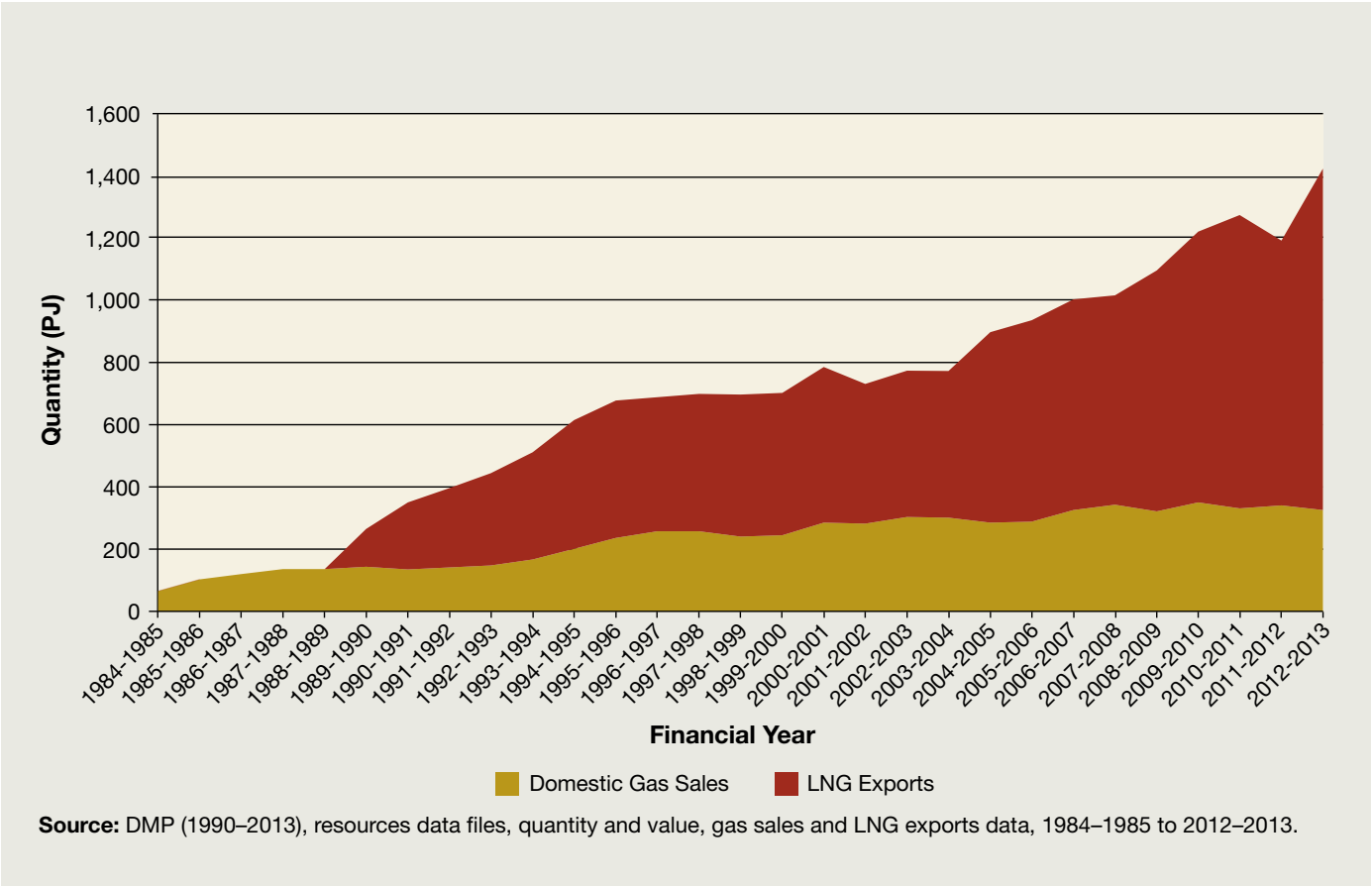


Figure 1. Potential gas supply for the WA domestic gas market



Source: DMP (1990–2013), resources data files, quantity and value, gas sales and LNG exports data, 1984–1985 to 2012–2013.

Figure 2. Domestic gas vs LNG production (1984-1985 to 2012-2013 financial years)
(Gas Statement of Opportunities, January 2014, page 32)

Potential gas supply

Supplies of gas to the domestic market are dependent on sufficient gas reserves, adequate gas plant processing capacity, and the willingness of field operators to supply gas to the domestic market; this section will look at the first two factors.

Potential gas supply for domestic market

Resources that could potentially be developed and supply domestic gas to the WA market from both offshore and onshore fields are shown in Figure 1.

At first glance, it appears that an abundant supply of gas exists in the State. However, these huge reserves/resources are not exclusively supplied to the domestic market as the majority supply the LNG market. This can be seen in Figure 2.

Reserves and resources in Figure 1 do not include all contingent resources, such as shale and tight gas from the onshore Perth and Canning Basins, or contingent resources from WA Territorial waters. They do include, however, reserves and resources from offshore Commonwealth waters and LNG projects that supply the WA domestic gas market.

Pluto gasfield reserves are not included because it is not clear if the field will be commercial for domestic gas supply within five years of its first production of LNG. Even though an arrangement between the WA government and Woodside commits this project to domestic gas, it remains highly contingent on the commercial viability of a domestic gas plant.

Final investment decisions for potential domestic gas production facilities onshore in the Perth and Canning Basins, including at Warro, Pluto, and Yulleroo/Valhalla are still not known.

Potential gas supply from North West Shelf fields

Fields under the NWS State Agreement are of particular interest to WA, as they are not only the source for the domestic gas market, but also provide revenue to the State through royalties and condensate excise compensation.

It is very obvious that producing fields in the NWS region have both the highest percentage of gas initially in place and the highest percentage of remaining gas reserves in the State (Figures 3 and 4). The second highest percentage is from gasfields in a production licence that are yet to commence development and production. The non-commercial or contingent resources only account for a small portion of all the reserves.

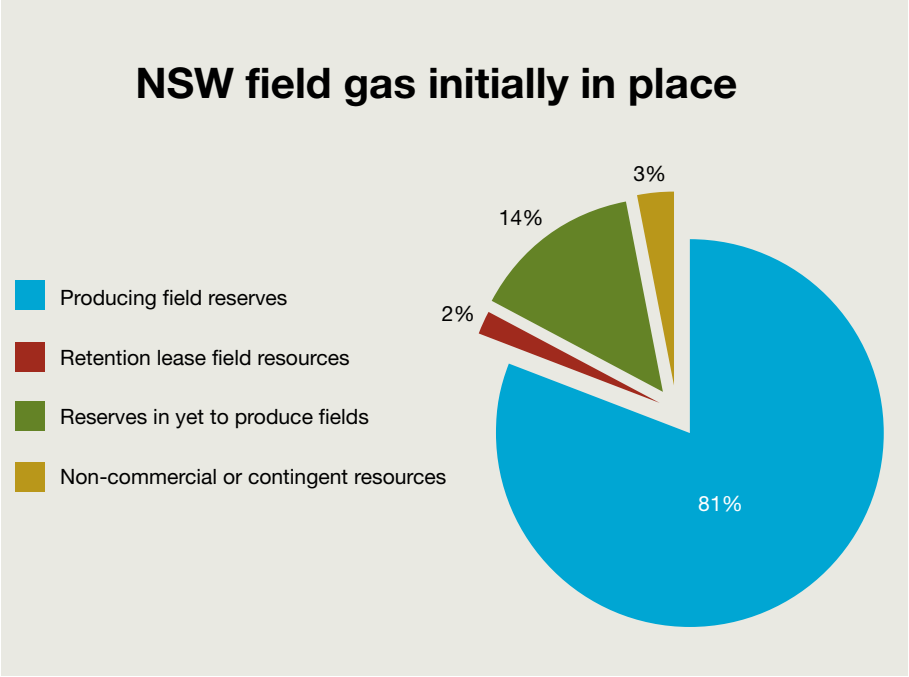


Figure 3. NWS fields gas initially in place

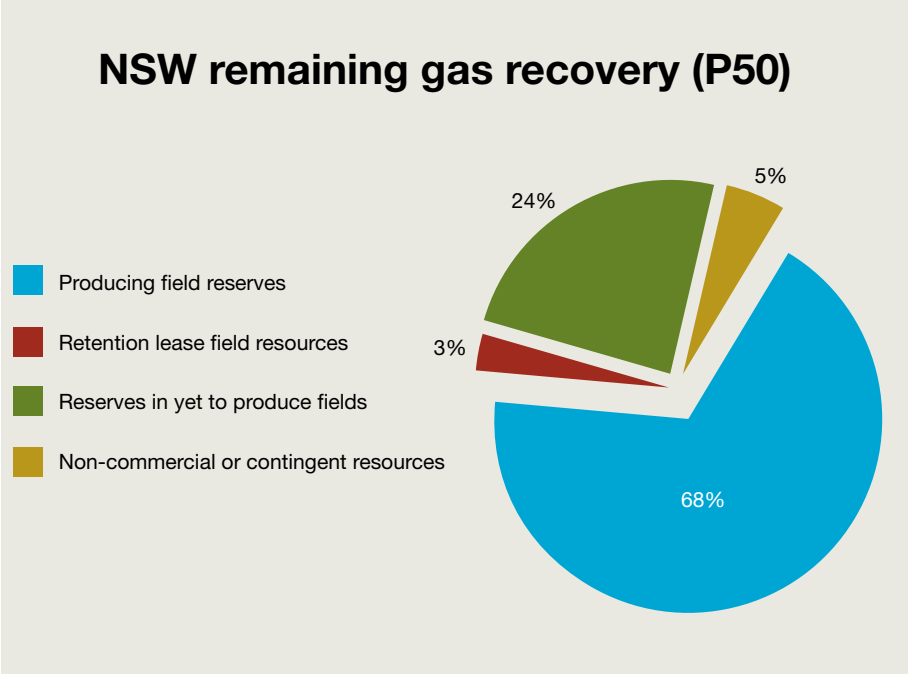


Figure 4. NWS fields remaining gas recovery (P50)

Current domestic gas supply in WA and spare supply capacity

Total production capacity may be used to measure of gas supply in tight gas markets, but this measure is less suitable for current market conditions.

It would significantly overstate the availability of gas because future gas production will serve both the domestic market and the production and export of LNG. Instead, commitments to supply the WA domestic market and the future demands of this market are important considerations for predicting the future domestic gas supply in WA.

The actual domestic gas supply from January 2013 to April 2014 is shown in Figure 5. The average domestic supply in the 2013 calendar year was about 945 TJ/d (source: DMP statistics 2013).

Comparison of the current maximum domestic gas processing capacity of 1562 TJ/d (Table 1) with the actual utilisation of the gas processing capacity of less than 1000 TJ/d indicates a spare capacity of about 33 per cent.

Both the NWS domestic gas plant in Karratha and the Varanus Island gas hub use about 66 per cent of their processing capacity. They, and the Devil Creek gas plant, have spare capacities of 240 TJ/d, 130 TJ/d and 130 TJ/d, respectively.

Another area of prospective capacity is the Perth Basin. Excepting the Beharra Springs gas processing facility and the newly commissioned Red Gully gas processing facility, which are utilised to a reasonable extent, AWE-operated facilities such as Dongara, Xyris, and Woodada all have potential as tie-ins for new gas finds in the Perth Basin.

Challenges and opportunities

Potential gas supply to WA is complex, as future economic growth, commercial considerations, producer strategy, timing of production capacity, the international LNG market, and other factors will all play a role.

Up until quite recently, WA was only going to have two new domestic gas supply projects, i.e., Gorgon and Wheatstone. Now that the WA Government and the NWS JV have come to an agreement over domestic gas supply after 2021, announced in December 2014, the uncertainty regarding the availability of gas resources from the NWS has reduced considerably. If the NWS JV continues to supply domestic gas to the WA market, WA will have an abundant supply of domestic gas well into the future. However, uncertainty remains over the NWS JV's decision regarding the future of the aging domestic gas processing facilities at Karratha.

Currently more than 90 per cent of WA's domestic gas supply comes from one basin, the Carnarvon Basin. This suggests that WA may be too reliant on a single basin for its domestic gas needs and that WA should encourage gas exploration and production in other WA basins, such as the Canning and Perth Basins to secure a continued supply of gas to WA.

In the Canning Basin, there is currently no permanent gas-related infrastructure. Hence, any gas development projects in the basin will rely on the construction of new infrastructure.

While there are large gas resources in the Browse Basin, most significant gas discoveries are intended for potential LNG export projects, and it is very unlikely that any gas from this basin would be available to the domestic gas market in the near future. However, increasing WA's shares of the Poseidon and Torosa resources following the update of WA and Commonwealth borders, it would favour WA in negotiating for a domestic gas supply.

Blacktip is the only gas-producing field in the Bonaparte Basin, but it supplies gas to the Northern Territory. The lack

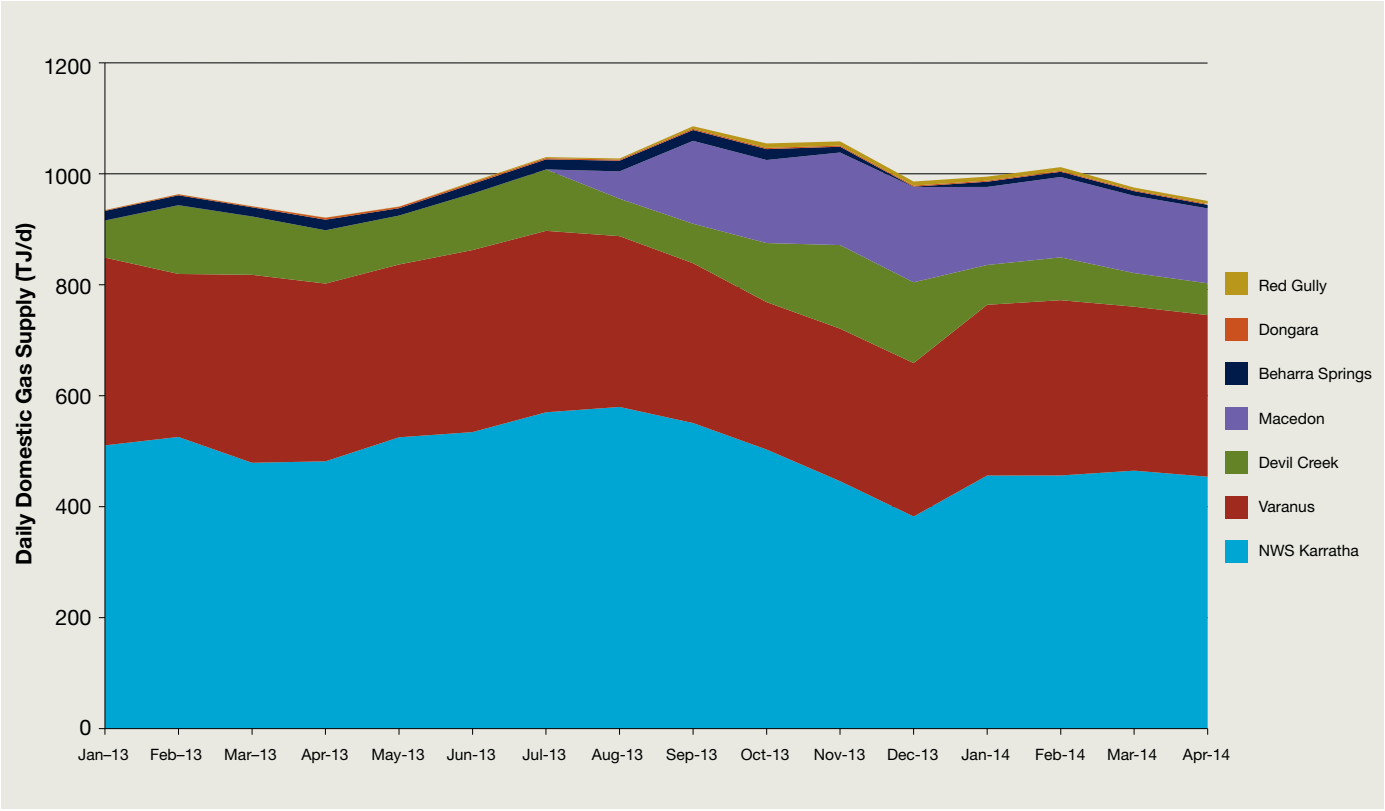


Figure 5. Domestic gas supply to the WA market by facility, from January 2013 to April 2014

of infrastructure and facilities suggests that it is highly unlikely that any gas reserves from the Bonaparte Basin will be extracted and processed for the WA domestic gas market.

Another significant challenge is the long distance from most gas resources to the majority of gas consumers. This challenge also includes the fact that most of the reserves lie under Commonwealth jurisdiction, and WA does not solely control the fate of these fields.

Challenges and opportunities always coexist. The spare processing capacity from our domestic gas plants provides us with real opportunities for tie-ins. For example, in the vicinity of the NWS fields that are being produced, a few fields are already located in production licences.

Opportunities are also present in the Varanus Island gas processing centre and Devil Creek gas plant. It is possible that a higher processing rate will be achieved if there is higher market demand. This is also true for BHP Billiton's Macedon domestic gas plant.

Conclusions and recommendations

Based on the above analysis, we conclude that there is an abundance of gas in WA, especially in the Carnarvon Basin's offshore Commonwealth waters, including the NWS area, which could augment the domestic gas supply. However, current reserves from onshore areas are very small.

We also conclude that there are sufficient gas processing facilities to supply gas to the WA market. There is about 500 TJ/d spare gas processing capacity from all plants in WA, and this could be utilised when gas from a nearby field or a third party is available.

In addition, there is spare processing capacity in facilities in the Perth Basin, and these facilities are relatively close to the consumer market.

It is recommended that the government facilitate supply to the domestic gas market by continuing talks with producers and companies with interests in gas in WA in order to avoid a shortage of supply to the market.

It is also recommended that the spare capacity from existing facilities be utilised when gas from fields discovered nearby, or from a third party, is available.

The government should also encourage the exploration and development of conventional gas resources, as well as shale and tight gas in the Perth Basin, to take advantage of the spare capacity and its closeness to the consumer market.

Finally, the government would like to diversify the gas supply into other basins and to facilitate the unitisation of existing domestic gas processing plants. This could be accomplished by introducing new gas finds or processing production of third party gas to promote development potential and to contribute to the energy security of the State.

Reference

Independent Market Operation, 2014, Gas Statement of Opportunities, January 2014. http://www.imowa.com.au/docs/default-source/publications-and-reporting/GSOO/gsoo_january-2014.pdf?sfvrsn=0

Note: Reserve estimates in this article are derived from confidential hydrocarbon resources statement reports for individual fields from December 2013, submitted by oil and gasfield operators to the Department of Mines and Petroleum.

Grant of petroleum titles

Richard Bruce
Exploration Geologist
Resources, Petroleum Division

Heliseismic surveying in the Perth Basin

State awards

From 1 July 2014 to the start of March 2015, the following petroleum titles were awarded in State areas:

Production Licences

In October 2014, L18 and L19 in the onshore Perth Basin were awarded to Empire Oil Company (WA) Limited and ERM Gas Proprietary Limited. These licences contain the Red Gully and Gingin West gas-condensate fields.

Petroleum Exploration Permits

In October 2014, EP 492 in the onshore Perth Basin was awarded to Westranch Holdings Proprietary Limited. The firm two year period includes a new 150 km 2D seismic survey and studies to an estimated value of $670,000. The secondary period includes an exploration well, a new 70 km 2D seismic survey and studies to an estimated value of $4,640,000.

In March 2015, EP 493 in the onshore Canning Basin was awarded to Finder Shale Proprietary Limited. The firm two year period includes a new 220 km 2D seismic survey, three exploration wells and studies to an estimated value of $20,550,000. The secondary period includes an exploration well and studies to an estimated value of $10,450,000.

Special Prospecting Authorities with Acreage Option

In November 2014, SPA 18 AO in the Canning Basin was awarded to UIL Energy Limited for the acquisition of an airborne gravity survey. The SPA/AO expires on 30 April 2015. From this date the registered holder has six months to apply for an Exploration Permit.

In November 2014, SPA 19 AO in the Canning Basin was awarded to UIL Energy Limited for the acquisition of an airborne gravity survey. The SPA/AO expires on 30 April 2015. From this date the registered holder has six months to apply for an Exploration Permit.

Commonwealth awards

WA-504-P (released as W13-3) located offshore Western Australia in the Caswell Sub-basin of the Browse Basin, has been awarded to Santos Offshore Proprietary Limited and Inpex Browse E&P Proprietary Limited.

WA-505-P (released as W12-7) located approximately 400 km north of Port Hedland in the Roebuck Basin offshore Western Australia, has been awarded to Apache Northwest Proprietary Limited.

WA-506-P (released as W13-6) located approximately 160 km north of Karratha in the Northern Carnarvon Basin offshore Western Australia, has been awarded to Statoil Australia Theta B.V.

WA-507-P (released as W13-7) located approximately 160 km north of Karratha in the Northern Carnarvon Basin offshore Western Australia, has been awarded to Odyssey O&G Proprietary Limited and Black Swan Resources Proprietary Limited.

WA-508-P (released as W13-4) located approximately 245 km northwest of Broome in the Browse Basin offshore Western Australia, has been awarded to Pathfinder Energy Proprietary Limited.

WA-509-P (released as W13-5) located approximately 230 km northwest of Broome in the Browse Basin offshore Western Australia, has been awarded to Pathfinder Energy Proprietary Limited.

Oil and gas generation in the Dandaragan Trough, northern Perth Basin

Mike F. Middleton
General Manager
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Arrowsmith 2 oil

Introduction

It has been known for fifty years that oil and gas occurs in commercial quantities within the northern Perth Basin. Both oil and gas have been recovered in the Dongara field and a number of other small gas and oil fields in the region (Figure 1). A simplified stratigraphy of the northern Perth Basin is shown in Figure 2, together with horizons of known oil and gas production, hydrocarbon shows and recognised source rocks. Recently, a relatively large gas accumulation was identified in the Waitsia field, which is currently undergoing testing involving interpretation of data from the Senecio 3 well (AWE, Australian Stock Exchange announcement, 18 September 2014). Over 8.9 billion cubic metres (290 billion cubic feet) of gas has been preliminarily reported as a 2C (Contingent Reserves Level 2 — equivalent to approximately 50% probability) best estimate by the company, AWE. Previously, Norwest Energy announced in March 2013 that, from the drilling and subsequent work-over of Arrowsmith 2, it recognised that "the Kockatea Shale represents the first successful test of the shale oil concept in Australia".

The source of the hydrocarbons in the northern Perth Basin has been studied for a long time. Kantsler and Cook (1979) published a study of organic maturity in the Perth Basin. Thomas (1979 and 1984), and Thomas and Brown (1983) published further studies on the hydrocarbon source rocks and maturity trends in the northern Perth Basin. Subsequent geoscientific studies covering the northern Perth Basin were carried out by Crostella (1995), and Mory and Iasky (1996). These studies reviewed vitrinite reflectance data, as a measure of thermal maturity of organic sediments (which include wood, leaves, algae, spores and other organic matter preserved within the sediments). Strictly speaking, vitrinite refers to the humic matter in the sediments. More recently, Triche and Bahar (2013) have reviewed the potential for shale oil and gas within this region with a strong reliance on these earlier studies.

This article reviews the thermal and organic maturity of the northern Perth Basin, and specifically the Dandaragen Trough (see Figure 1). This study takes into the account data presented in the studies by Kantsler and Cook (1979) and Mory and Iasky (1996). The interpretation of these data is reviewed in the light of the work by Price and Barker (1985), and subsequent studies by Buchardt and Lewan (1990), and Middleton (1997), all of whom investigated the impact of "suppressed vitrinite reflectance" on the interpretation of thermal maturity of organic sediments, especially in the presence of thermally altered spores and pollen together with bitumen particles. Suppressed vitrinite reflectance is known to occur where the organic sediments are deposited in a dominantly marine, versus terrestrial, environment. This article specifically targets the Lower Triassic Kockatea Shale.

Organic maturity

Vitrinite is a term for woody or humic material in sediments (an organic mineral is termed a *maceral*). The reflectance of light from vitrinite, as measured under oil by laboratory techniques, has been correlated to the organic maturity of the sedimentary rock encasing it (Stach et al. 1975).

Organic maturity is often expressed as the reflectance of a vitrinite particle in any particular sample (Stach et al. 1975; Hunt 1996), with the zones of organic maturity recognised as:

(1) *immature* (only organic gas, but no thermogenic hydrocarbons),
(2) *oil window* (oil or gas can be produced depending on the organic matter),
(3) *wet gas window* (condensate or gas can be abundantly produced; any oil has been "cracked" to condensate or gas), and
(4) *dry gas window* where dry gas or methane remains).

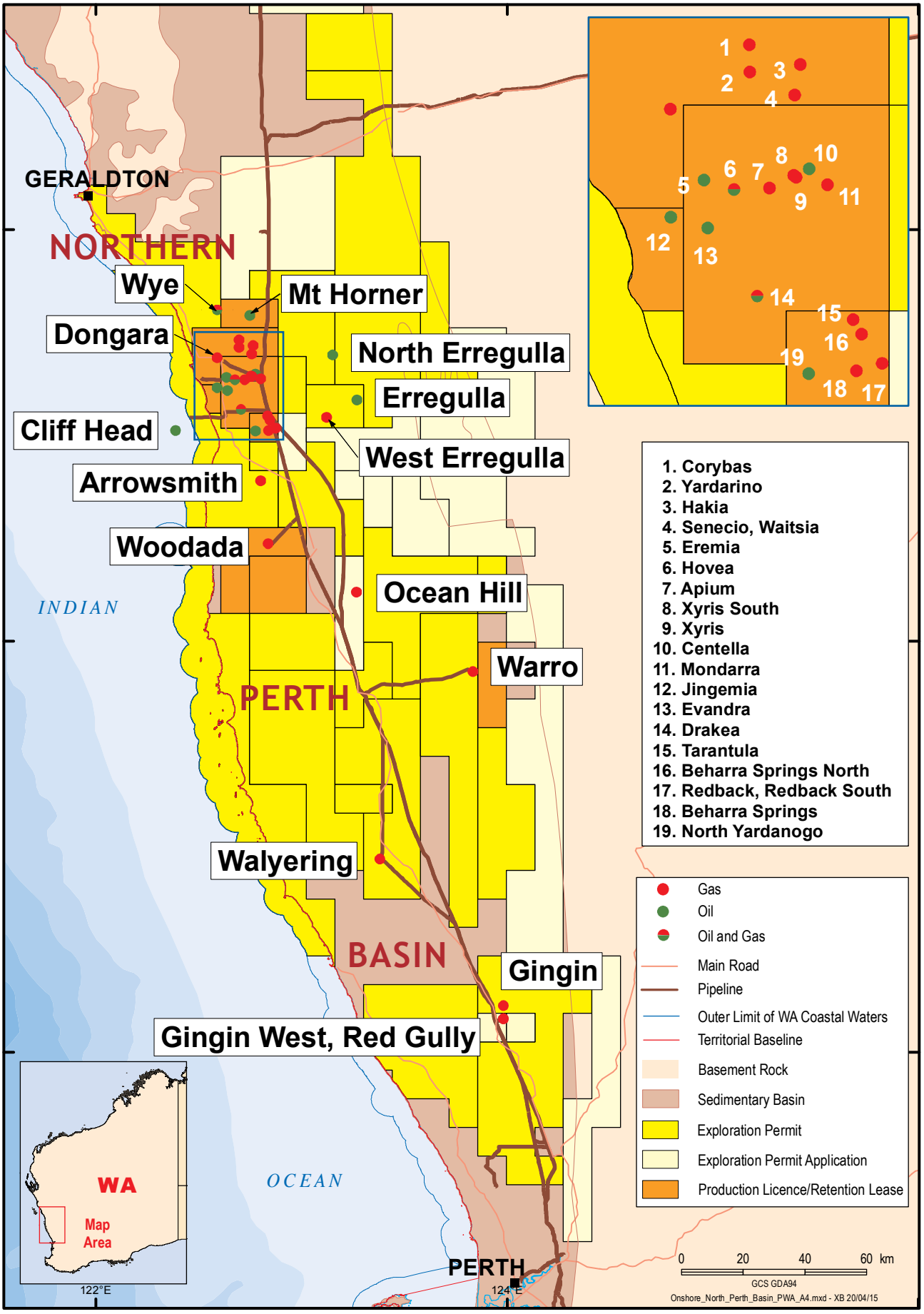

Figure 1. Map of the region showing oil and gas occurrences

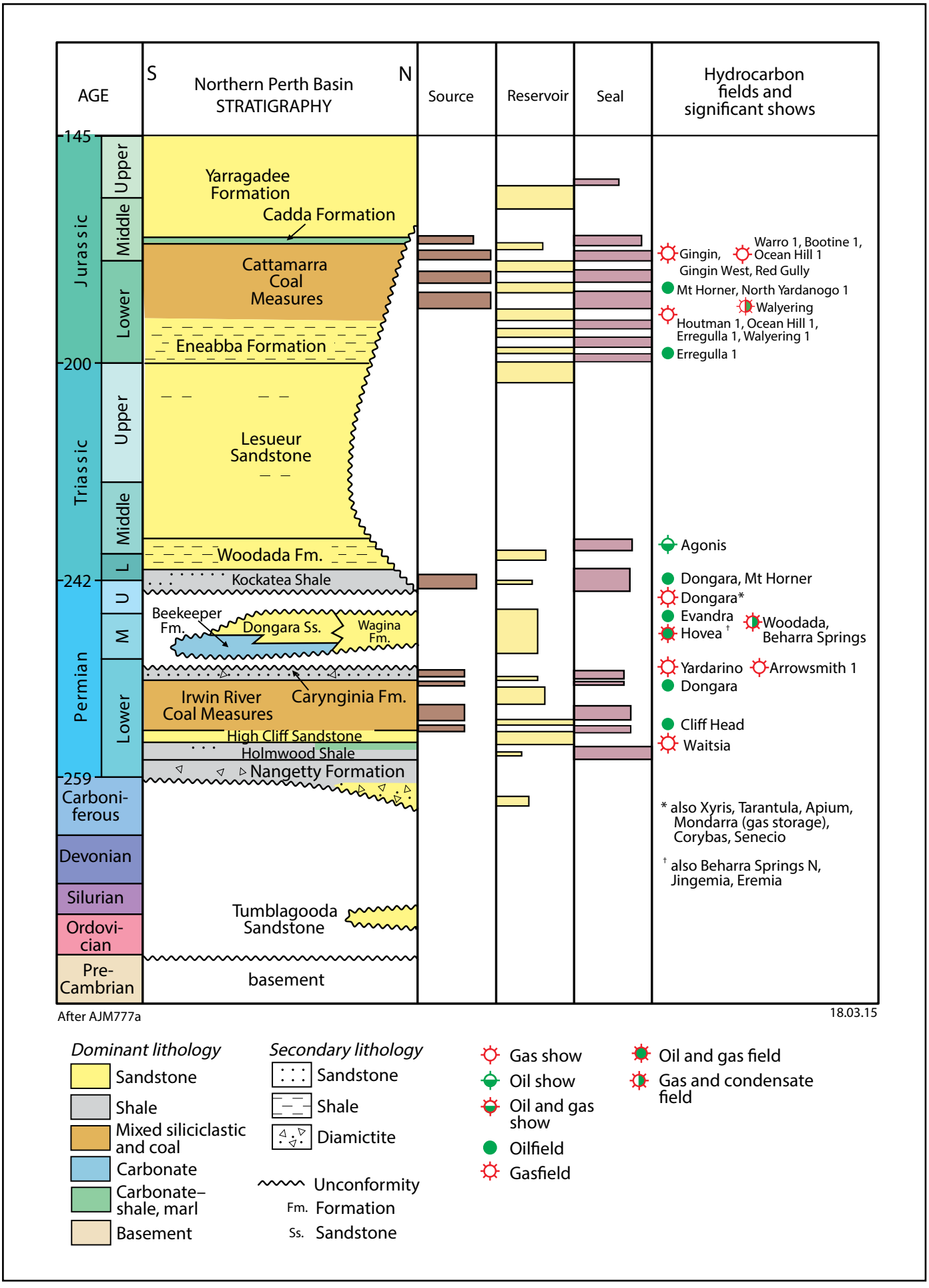

Figure 2. Simplified stratigraphy of northern Perth Basin.
Modified from Petroleum Division and Geological Survey of Western Australia (2014)

Another approach to defining organic sediments is in terms of kerogen types, which can also be related to organic mineral (maceral) types. There are four commonly recognised kerogen Types: (I), (II), (III) and (IV), and these generally indicate whether oil or gas will be produced from organic sediments.

Kerogen Types I and II are considered to produce most of the world's oil, and consist of organic material derived from algae and other fresh water or marine organisms. This commonly equates broadly to the occurrence of maceral type **Exinite**. Kerogen Type III is formed from woody material (coal) and generally produces gas and condensate, with some waxy oil; this often equates broadly to the occurrence of the maceral type **Vitrinite**. Type IV only produces small amounts methane and CO_2; this often equates broadly to the occurrence of the maceral type **Inertinite**. This last kerogen type (inertinite) has undergone appreciable amounts of oxidation, as one might observe in the case of burnt wood (Hunt 1996).

The link between organic maturity (or maturity window) and kerogen type is that kerogen type fundamentally tends to dictate whether oil or gas is generated. However, organic maturity tends to represent the thermal regime within which the petroleum products (either oil or gas) are generated. Thus, Types I and II kerogen tend to generate (in sequence) oil, wet gas and dry gas, as maturity changes from the oil window through to the dry gas window; whereas Type III kerogen tends to generate largely wet to dry gas (little oil), as maturity changes from the oil window through to the dry gas window.

Northern Perth Basin organic maturity

Various maps have been published since the 1980s showing estimated organic maturity of various stratigraphic horizons in the northern Perth Basin (Thomas and Brown 1983; Mory and Iasky 1996; Triche and Bahar 2013). These maps generally show:

(1) the Kockatea Shale to be in the oil window to the north and west of the Dandaragan Trough in the region to the north of Eneabba, and largely *post-mature* (over-mature) south of Eneabba (Triche and Bahar 2013).

(2) The deeper Permian Irwin River Coal Measures are often interpreted to be in the *wet and dry gas window*. This geological unit has been suggested as the source of much of the gas in the northern Perth Basin (Crostella 1995; Mory and Iasky 1996), especially around Dongara.

Figure 3 shows the vitrinite reflectance versus depth for a number of wells in the northern Perth Basin, based

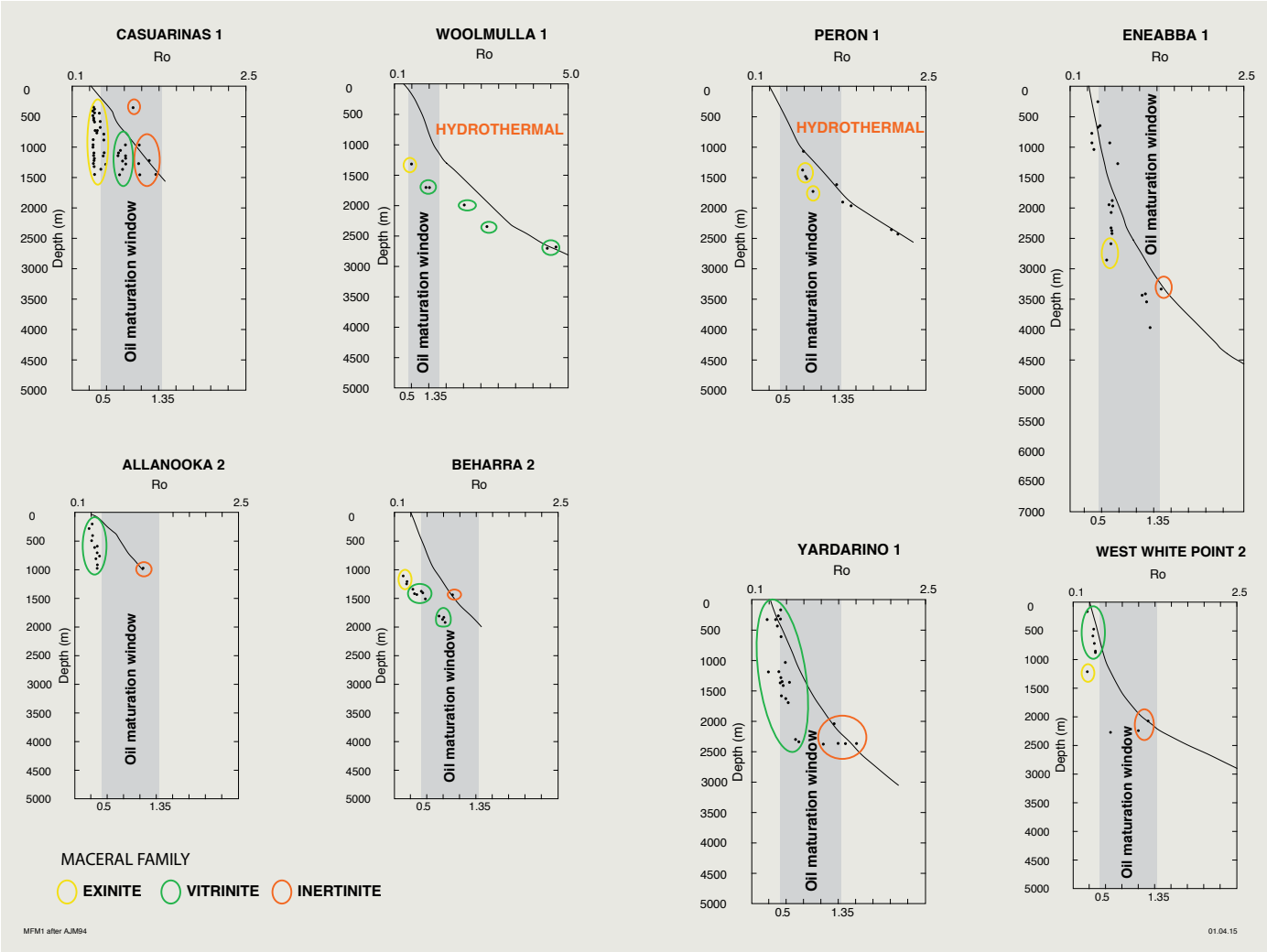

Figure 3. The vitrinite reflectance versus depth for various wells in the north Perth Basin. The graphs are based on Mory and Iasky (1996). Various maceral zones may be interpreted to be exinite (yellow), vitrinite (green) and inertinite (orange)

on data published by Mory and lasky (1996). Matched to these data, are modeled curves of vitrinite reflectance versus depth. The modelled vitrinite reflectance versus depth curves in Figure 3 seem to be matched to the maximum values of the observed reflectance data. The observed data in this figure show a broad scatter, and this broad scatter was also noted by Kantsler and Cook (1979). The matched data may not actually be from kerogen Type III, or the *vitrinite family,* which is the accepted way to assess the sediment maturity by conventional methods (Stach et al. 1975; Hunt 1996). Perhaps, one may wish to look at the data and its source differently.

It is interesting to focus on the Dandaragan Trough, where little work has been recently carried out on hydrocarbon maturity. A new look at the Dandaragan Trough is particularly important in the light of the development of the Warro gasfield and continuing work on understanding the source of its gas in relation to the source of the gas in Waitsia, further to the north (see Figure 1).

The focus herein is to look at the maturity of the Kockatea Shale in the Dandaragan Trough, where both oil and gas can be potentially generated. In the case of an oil-prone source within the Kockatea Shale, the generated gas will emanate from a thermally-cracked oil source within the shale.

Figures 4 and 5 show an interpretation of the organic maturity zones, or windows, in the Dandaragan Trough region of the northern Perth Basin for the top and base of the Kockatea Shale, respectively. It is acknowledged that these zones are approximate at this stage, and are based on a series of assumptions (Table 1). Nevertheless, the zones are considered indicative of this deep sedimentary trough, which is a largely unknown in terms of thermal maturity.

The maps are derived from the contour map of the top of the Permian, equivalent to the base of the Kockatea Shale, published by Mory and lasky (1996). Numerical modelling to derive these zones is based on algorithms published by Middleton (1982 and 1991), which are linked to chemical kinetic studies by Sweeney and Burnham (1990) and in turn used in the industry-standard BasinMod© software. This work will be described in a following publication. Table 1 sets out the assumptions in this modelling, and Table 2 summarises the numerical results.

Table 1. Assumptions for the maturity modelling of the Dandaragan Trough

PARAMETER		
Geothermal Gradient	22°C	0 < time (Ma) < 245
Uplift/erosion	500 m	time (Ma) = 150
Thickness Kockatea Shale	1000 m	Over whole area
Oil Window	0.4 – 1.3	Vitrinite Reflectance (%)
Wet Gas Window	1.1 – 1.4	Vitrinite Reflectance (%)
Dry Gas Window	1.4 – 2.5	Vitrinite Reflectance (%)

Table 2. Table of results of vitrinite reflectance modelling. The table shows base Kockatea Shale depth (depth contour) with the corresponding modelled vitrinite reflectance (R) for the top and base of the Kockatea Shale. The base Kockatea Shale depth (depth contour) based on Plate 7 of Mory and lasky (1996)

Depth contour (km)	R, top Kockatea Shale	R, base Kockatea Shale	Hydrocarbon generation zone for base Kockatea Shale
2.0	0.37	0.48	Oil Window
3.0	0.49	0.63	Oil Window
4.0	0.64	0.82	Oil Window
5.0	0.85	1.08	Oil Window
5.3	–	1.31	Wet Gas Window
6.0	1.11	1.42	Wet Gas Window
6.7	1.31	–	
7.0	1.46	1.87	Dry Gas Window
8.0	1.93	2.47	Dry Gas Window
9.0	2.54	>2.60	Dry Gas Window

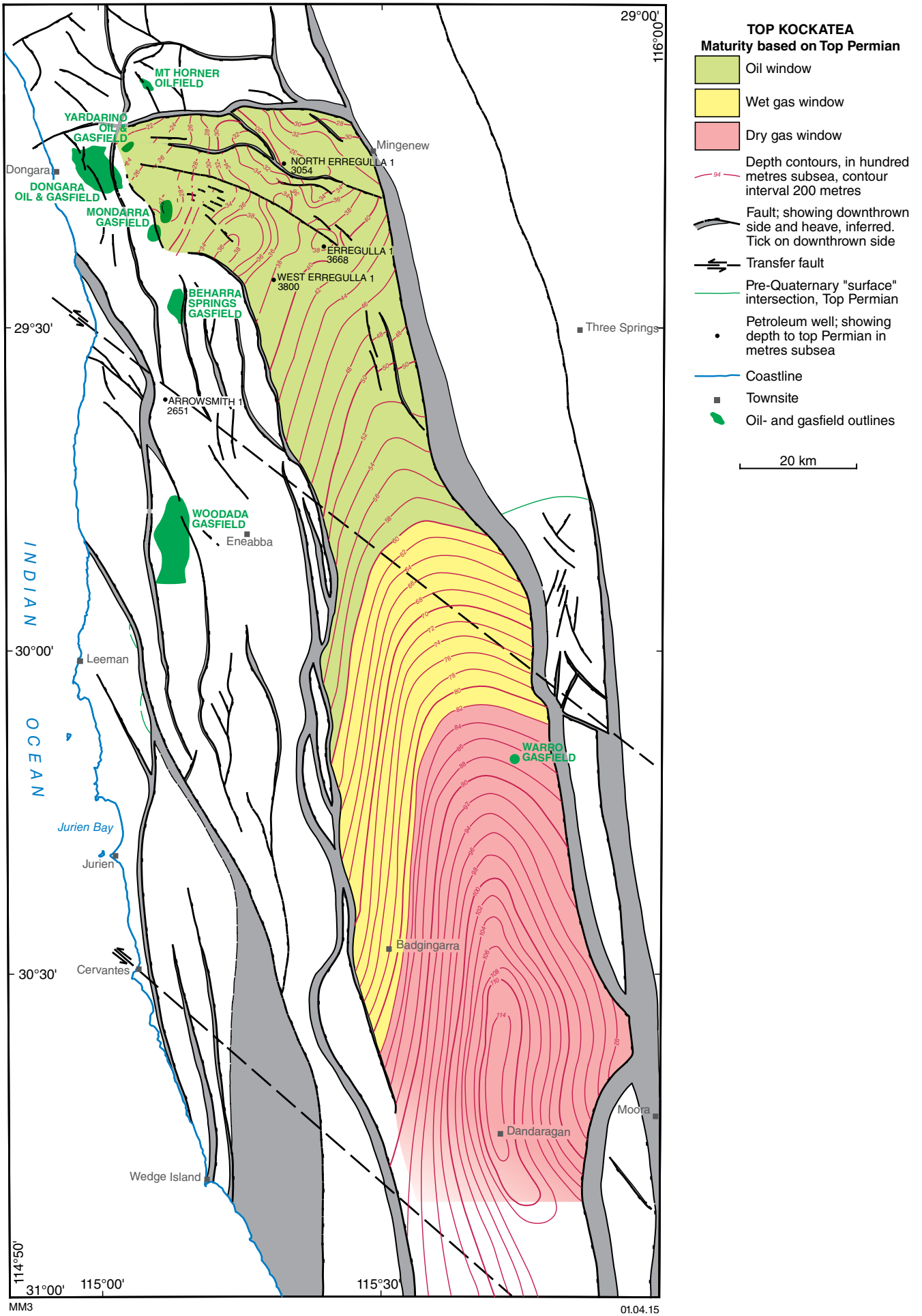

Figure 4. Map of maturity of Top Kockatea Shale in the Dandaragan Trough from modelling shown in Tables 1 and 2. The zones are superimposed on the base Kockatea Shale map of Mory and Iasky (1996)

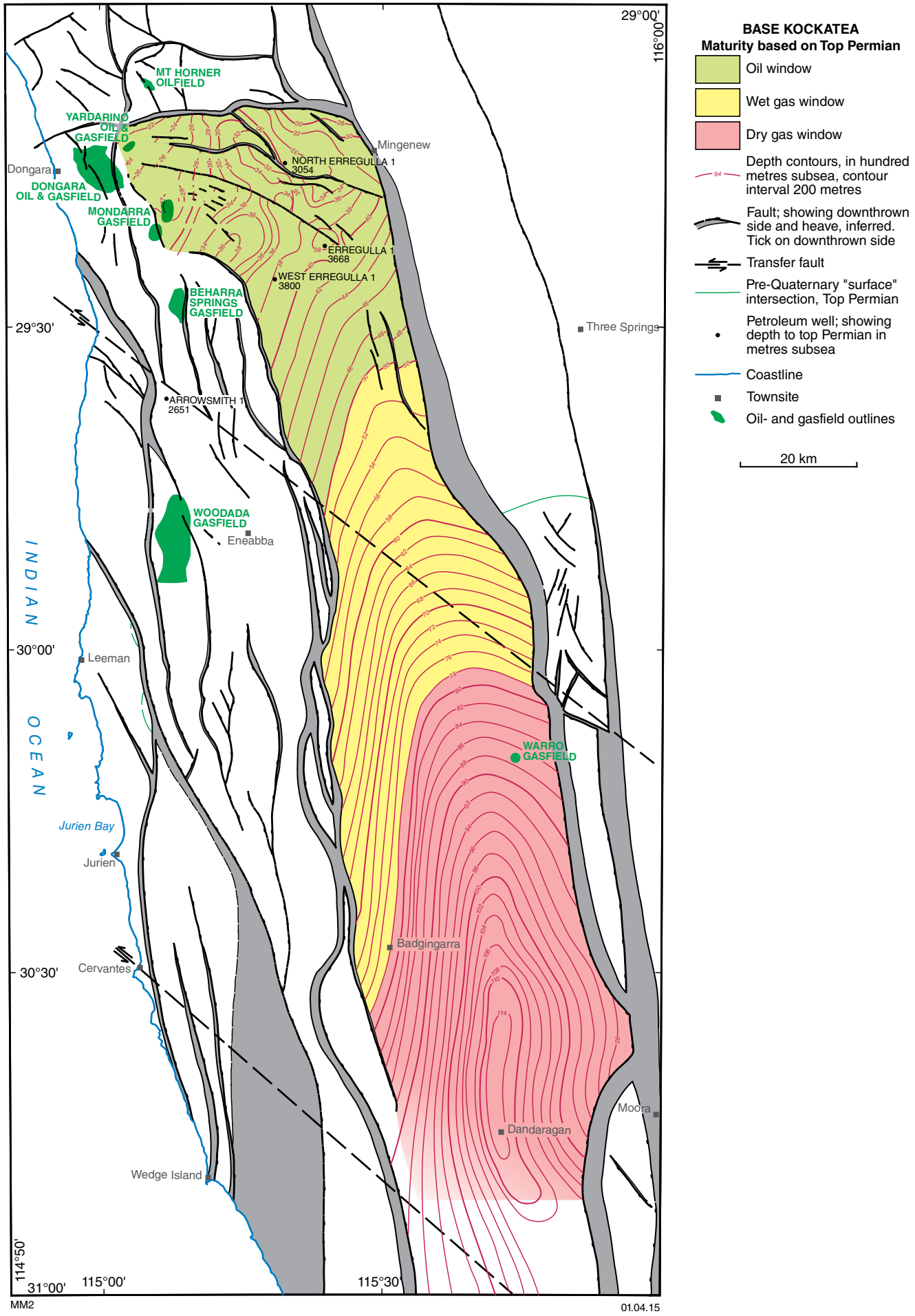

Figure 5. Map of maturity of Base Kockatea Shale in the Dandaragan Trough from modelling shown in Tables 1 and 2. The zones are superimposed on the base Kockatea Shale map of Mory and Iasky (1996)

Conclusion

This article attempts to draw together, in a fairly simplistic way, the sciences of organic chemistry, organic petrology and the thermotectonic history of organic sediments. Nevertheless, a clear message appears to be emerging, which is that there may be a larger zone of the Kockatea Shale in the oil window, than previously recognised, in the Dandaragan Trough of the northern Perth Basin.

Further modelling studies are recommended and will be carried out to refine the various "windows" of hydrocarbon maturity in the Dandaragan Trough of the northern Perth Basin. These studies will be carried out in cooperation by both the Petroleum and the Geological Survey Divisions of the Department of Mines and Petroleum (DMP). Detailed papers and reports from DMP will follow.

Acknowledgements

A review by Ameed Ghori was particularly valuable. Nina Triche and Mohammad Bahar also reviewed the article, and thanks are also attributed to these colleagues. Comments by Lynn Reid are well appreciated. Permission to publish was given by the Director of Operations and the Executive Director of the Petroleum Division.

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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	L1H
Beharra Springs	Origin	0.0	90.9	9,364.5	0.00	24,448.40	2,303,273.80	L11
Beharra Springs N	Origin	0.0	99.4	10,948.6	0.00	2,155.70	221,346.90	L11
Blina	Buru Energy	0.0	0.0	0.0	298,725.15	0.00	0.00	L6
Boundary	Buru Energy	0.0	0.0	0.0	21,212.14	0.00	0.00	L6
Corybas	AWE	0.0	69.7	3,752.9	0.00	412.10	22,299.30	L2
Crest	Chevron	27.0	0.0	125.0	275,835.00	108.00	65,898.00	L12, L13
Dongara	AWE	183.7	0.0	12,783.2	195,796.40	49,681.21	12,956,244.80	L1, L2
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	L18, L19
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	L1
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	L18, L19
Redback	Origin	0.0	201.0	121,559.7	0.00	915.40	582,553.20	L11
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	L8
Tarantula	Origin	0.0	120.4	11,310.3	0.00	4,223.20	342,610.70	L11
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	L8
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 ESTIMATES BY BASIN FOR WA ONSHORE, STATE WATERS AND TERRITORIAL WATERS, AS AT 31 DECEMBER 2013 (METRIC UNITS)

Basin	Oil GL		Sales Gas Gm^3		Condensate GL	
CATEGORY 1	**P90**	**P50**	**P90**	**P50**	**P90**	**P50**
Canning	–	–	–	–	–	-
Carnarvon	0.99	6.00	18.63	19.35	0.08	0.12
Perth	0.00	0.01	18.59	19.47	0.07	0.10
Total	**0.99**	**6.01**	**37.22**	**38.82**	**0.15**	**0.22**
CATEGORY 2	**P90**	**P50**	**P90**	**P50**	**P90**	**P50**
Carnarvon	0.52	0.93	0.38	0.50	–	–
Total	**0.52**	**0.93**	**0.38**	**0.50**	**–**	**–**
CATEGORY 4	**P90**	**P50**	**P90**	**P50**	**P90**	**P50**
Canning	0.02	0.05	1.76	5.41	0.16	0.45
Carnarvon	1.27	6.07	4.39	9.49	–	–
Total	**1.29**	**6.12**	**6.15**	**14.90**	**0.16**	**0.45**
GRAND TOTAL	**2.80**	**13.06**	**43.75**	**54.22**	**0.31**	**0.67**

TABLE 2B. PETROLEUM RESERVES ESTIMATES BY BASIN FOR WA ONSHORE, STATE WATERS AND TERRITORIAL WATERS, AS AT 31 DECEMBER 2013 (FIELD UNITS)

Basin	Oil MMbbl		Sales Gas Bcf		Condensate MMbbl	
CATEGORY 1	**P90**	**P50**	**P90**	**P50**	**P90**	**P50**
Canning	–	–	–	–	–	–
Carnarvon	6.22	37.75	20.26	43.14	0.47	0.78
Perth	0.02	0.08	16.44	46.75	0.45	0.66
Total	**6.24**	**37.83**	**36.70**	**89.59**	**0.92**	**1.44**
CATEGORY 2	**P90**	**P50**	**P90**	**P50**	**P90**	**P50**
Carnarvon	3.25	5.85	13.57	17.57	–	–
Total	**3.25**	**5.85**	**13.57**	**17.57**	**–**	**–**
CATEGORY 4	**P90**	**P50**	**P90**	**P50**	**P90**	**P50**
Canning	0.11	0.29	62.01	191.02	1.01	2.81
Carnarvon	7.99	38.17	154.85	335.03	–	–
Total	**8.10**	**38.46**	**216.86**	**526.05**	**1.01**	**2.80**
GRAND TOTAL	**17.59**	**82.14**	**267.14**	**633.51**	**1.94**	**4.26**

NOTES

Canning Basin reserves are too small to measure.

There are no fields currently under category 3.

Category 1 comprises current reserves of those fields which are producing hydrocarbons or have been declared commercial (with FID)

Category 2 comprises estimates of recoverable reserves which are held under Retention Lease and have not yet been declared commercially viable.

Category 3 comprises estimates of contingent resources which are held in other licences and have been declared commercially viable but may or may not have a FMP and have not yet reached FID.

Category 4 comprises estimates of contingent resources which are held in other licences and have not yet been declared commercially viable and are not held under a Retention Lease.

Reserves estimates for 2014 have not yet been submitted to DMP.

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

Well Name	Class	On Off	Title	Operator	Latitude	Longitude	Gnd Elev/Water Depth (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
Ungani 3	EXT	On	EP 391 R2	Buru Energy Ltd	123.174	-17.989	85.0	8.0	14/01/2014	22/02/2014	11/03/2014
PERTH BASIN											
Drover 1	NFW	On	EP 455	AWE Ltd	115.147	-30.077	182.6	6.6	29/06/2014	16/07/2014	25/07/2014
Dunnart 2	NFW	On	EP 437	Key Petroleum	114.938	-29.156	49.5	46.0	13/07/2014	24/08/2014	30/08/2014
Senecio 3	EXT	On	L 2 R1	AWE Ltd	115.080	-29.253	69.0	6.6	5/08/2014	23/08/2014	7/09/2014

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

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 Limited	14/08/2014	1/09/2014	245	
Commodore West 2D S.S.	2D	On	EP 471	Buru Energy Limited	25/07/2014	3/08/2014	123	
Mt Fenton 2D S.S.	2D	On	EP 458	Buru Energy Limited	6/08/2014	14/08/2014	113	
Mt Rosamund 2D S.S.	2D	On	EP 472, EP 476, EP 477	Buru Energy Limited	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 Limited	17/10/2014	27/11/2014	9	255
SPA 17 AO Aerial Survey	AEROMAG	On	SPA 17 AO	Admiral Oil NL	29/03/2014	1/04/2014	4,505	
PERTH BASIN								
West Erregulla 3D S.S.	3DREFL	On	EP 469	Warrego Energy	29/11/2014	10/12/2014		80

Classification

2D *2D Seismic Survey*
3DREFL *3D Seismic Reflection Survey*
AEROMAG *Aeromagnetic Survey*

TABLE 5. LIST OF PETROLEUM AND GEOTHERMAL TITLES AND HOLDERS IN WESTERN AUSTRALIA AS AT 11 FEBRUARY 2015

*Denotes nominee

PETROLEUM (SUBMERGED LANDS) ACT 1982
Access Authority

Title	Registered Holder(s)
TP/7 R4	APACHE OIL AUSTRALIA PTY LTD* HYDRA ENERGY (WA) PTY LTD SANTOS (BOL) PTY LTD TAP (SHELFAL) PTY LTD
TP/8 R4	APACHE NORTHWEST PTY LTD* HARRIET (ONYX) PTY LTD KUFPEC AUSTRALIA PTY LTD
TP/15 R2	WESTRANCH HOLDINGS PTY LTD
TP/23 R1	APACHE 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	APACHE NORTHWEST PTY LTD* HARRIET (ONYX) PTY LTD KUFPEC AUSTRALIA PTY LTD
TPL/2 R1	APACHE NORTHWEST PTY LTD* HARRIET (ONYX) PTY LTD KUFPEC AUSTRALIA PTY LTD
TPL/3 R1	APACHE OIL AUSTRALIA PTY LTD* HYDRA ENERGY (WA) PTY LTD SANTOS (BOL) PTY LTD TAP (SHELFAL) PTY LTD
TPL/4 R1	APACHE OIL AUSTRALIA PTY LTD HYDRA ENERGY (WA) PTY LTD SANTOS (BOL) PTY LTD TAP (SHELFAL) PTY LTD
TPL/5 R1	APACHE NORTHWEST PTY LTD* HARRIET (ONYX) PTY LTD KUFPEC AUSTRALIA 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	APACHE OIL AUSTRALIA PTY LTD* HYDRA ENERGY (WA) PTY LTD SANTOS (BOL) PTY LTD TAP (SHELFAL) PTY LTD
TPL/8	APACHE NORTHWEST PTY LTD* HARRIET (ONYX) PTY LTD KUFPEC AUSTRALIA 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	APACHE EAST SPAR PTY LTD APACHE KERSAIL PTY LTD APACHE OIL AUSTRALIA PTY LTD* SANTOS (BOL) PTY LTD
TPL/13	APACHE EAST SPAR PTY LTD APACHE KERSAIL PTY LTD APACHE NORTHWEST PTY LTD APACHE OIL AUSTRALIA PTY LTD HARRIET (ONYX) PTY LTD KUFPEC AUSTRALIA PTY LTD SANTOS (BOL) PTY LTD
TPL/14	APACHE NORTHWEST PTY LTD* HARRIET (ONYX) PTY LTD KUFPEC AUSTRALIA 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	APACHE 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	APACHE 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	APACHE PVG PTY LTD BHP BILLITON PETROLEUM (AUSTRALIA) 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 PETROLEUM AND GEOTHERMAL TITLES AND HOLDERS IN WESTERN AUSTRALIA AS AT 11 FEBRUARY 2015

PETROLEUM (SUBMERGED LANDS) ACT 1982
Production Licence

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

PETROLEUM (SUBMERGED LANDS) ACT 1982
Retention Lease

Title	Registered Holder(s)
TR/1 R2	APACHE NORTHWEST PTY LTD* HARRIET (ONYX) PTY LTD KUFPEC AUSTRALIA PTY LTD
TR/3 R2	APACHE 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 R1	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 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 110 R5	PANCONTINENTAL OIL & GAS NL STRIKE ENERGY WESTERN AUSTRALIA PTY LIMITED
EP 129 R5	BURU ENERGY LIMITED
EP 307 R5	APACHE NORTHWEST PTY LTD* HARRIET (ONYX) PTY LTD KUFPEC AUSTRALIA 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 325 R3	ADVENT ENERGY LTD BOW ENERGY PTY LTD ROUGH RANGE OIL PTY LTD STRIKE ENERGY WESTERN AUSTRALIA PTY LIMITED
EP 357 R3	CHEVRON (TAPL) PTY LTD CHEVRON AUSTRALIA PTY LTD* MOBIL AUSTRALIA RESOURCES COMPANY PTY LIMITED SANTOS OFFSHORE PTY LTD
EP 358 R3	APACHE NORTHWEST PTY LTD* HARRIET (ONYX) PTY LTD KUFPEC AUSTRALIA 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 R3	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
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
EP 391 R3	BURU ENERGY LIMITED DIAMOND RESOURCES (FITZROY) PTY LTD

TABLE 5. LIST OF PETROLEUM AND GEOTHERMAL TITLES AND HOLDERS IN WESTERN AUSTRALIA AS AT 11 FEBRUARY 2015

EP 408 R2	CALENERGY RESOURCES (AUSTRALIA) LIMITED* WHICHER RANGE ENERGY PTY LTD
EP 412 R2	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 424	PANCONTINENTAL OIL & GAS NL STRIKE ENERGY WESTERN AUSTRALIA PTY LIMITED
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 433 R1	LANSVALE OIL & GAS PTY LTD PACE PETROLEUM PTY LTD
EP 434 R1	LANSVALE OIL & GAS PTY LTD* PACE PETROLEUM PTY LTD ROUGH RANGE OIL 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 GULLIVER PRODUCTIONS PTY LTD INDIGO OIL 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	APACHE NORTHWEST PTY LTD
EP 443	CONOCOPHILLIPS (CANNING BASIN) PTY LTD NEW STANDARD ONSHORE PTY LTD* PETROCHINA INTERNATIONAL INVESTMENT (AUSTRALIA) 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	CONOCOPHILLIPS (CANNING BASIN) PTY LTD NEW STANDARD ONSHORE PTY LTD* PETROCHINA INTERNATIONAL INVESTMENT (AUSTRALIA) PTY LTD
EP 451	CONOCOPHILLIPS (CANNING BASIN) PTY LTD NEW STANDARD ONSHORE PTY LTD* PETROCHINA INTERNATIONAL INVESTMENT (AUSTRALIA) 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	CONOCOPHILLIPS (CANNING BASIN) PTY LTD NEW STANDARD ONSHORE PTY LTD* PETROCHINA INTERNATIONAL INVESTMENT (AUSTRALIA) 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
EP 472	BURU ENERGY LIMITED* DIAMOND RESOURCES (CANNING) PTY LTD
EP 473	BURU ENERGY LIMITED* DIAMOND RESOURCES (CANNING) PTY LTD
EP 475	ENERGETICA RESOURCES PTY LTD
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 479	EMPIRE OIL COMPANY (WA) 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*

TABLE 5. LIST OF PETROLEUM AND GEOTHERMAL TITLES AND HOLDERS IN WESTERN AUSTRALIA AS AT 11 FEBRUARY 2015

EP 490	CARNARVON PETROLEUM LIMITED
EP 491	CARNARVON PETROLEUM LIMITED
EP 492	WESTRANCH HOLDINGS PTY LTD*
EP 493	FINDER SHALE PTY LIMITED*

PETROLEUM AND GEOTHERMAL ENERGY RESOURCES ACT 1967
Geothermal Exploration Permit

Title	Registered Holder(s)
GEP 37	GREENPOWER ENERGY LIMITED
GEP 38	GREENPOWER ENERGY LIMITED

PETROLEUM AND GEOTHERMAL ENERGY RESOURCES ACT 1967
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 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

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 R1	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 5	APACHE OIL AUSTRALIA PTY LTD OMV AUSTRALIA PTY LTD
R 6	ALCOA OF AUSTRALIA LIMITED LATENT PETROLEUM PTY LTD
R 7	ALCOA OF AUSTRALIA LIMITED LATENT PETROLEUM PTY LTD

PETROLEUM AND GEOTHERMAL ENERGY RESOURCES ACT 1967
Special Prospecting Authority

Title	Registered Holder(s)
SPA 18 AO	UIL ENERGY LTD
SPA 19 AO	UIL ENERGY 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	APACHE NORTHWEST PTY LTD* HARRIET (ONYX) PTY LTD KUFPEC AUSTRALIA PTY LTD

TABLE 5. LIST OF PETROLEUM AND GEOTHERMAL TITLES AND HOLDERS IN WESTERN AUSTRALIA AS AT 11 FEBRUARY 2015

PL 14 R1	APACHE OIL AUSTRALIA PTY LTD* HYDRA ENERGY (WA) PTY LTD 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
PL 17	APACHE NORTHWEST PTY LTD* HARRIET (ONYX) PTY LTD KUFPEC AUSTRALIA 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	APACHE EAST SPAR PTY LTD APACHE KERSAIL PTY LTD APACHE OIL AUSTRALIA PTY LTD* SANTOS (BOL) PTY LTD
PL 30	APACHE EAST SPAR PTY LTD APACHE KERSAIL PTY LTD APACHE OIL AUSTRALIA PTY LTD* 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	APACHE EAST SPAR PTY LTD APACHE KERSAIL PTY LTD APACHE NORTHWEST PTY LTD APACHE OIL AUSTRALIA PTY LTD HARRIET (ONYX) PTY LTD KUFPEC AUSTRALIA PTY LTD SANTOS (BOL) PTY LTD
PL 43	APT PIPELINES (WA) PTY LIMITED* REGIONAL POWER CORPORATION
PL 44	APT PARMELIA PTY LTD
PL 45	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	APACHE NORTHWEST PTY LTD* HARRIET (ONYX) PTY LTD KUFPEC AUSTRALIA 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	DALRYMPLE RESOURCES PTY LTD NORILSK NICKEL WILDARA PTY LTD
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

TABLE 5. LIST OF PETROLEUM AND GEOTHERMAL TITLES AND HOLDERS IN WESTERN AUSTRALIA AS AT 11 FEBRUARY 2015

PL 78	HAMERSLEY IRON PTY LIMITED
PL 80	ALCOA OF AUSTRALIA LIMITED LATENT PETROLEUM PTY LTD
PL 81	APACHE 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	APACHE NORTHWEST PTY LTD SANTOS OFFSHORE PTY LTD
PL 87	APACHE PVG PTY LTD BHP BILLITON PETROLEUM (AUSTRALIA) PTY LTD
PL 88	APACHE PVG PTY LTD BHP BILLITON PETROLEUM (AUSTRALIA) PTY LTD
PL 89	CROSSLANDS RESOURCES PTY LTD
PL 90	APACHE PVG PTY LTD BHP BILLITON PETROLEUM (AUSTRALIA) PTY LTD
PL 91	DBNGP (WA) NOMINEES PTY LIMITED
PL 92	CHEVRON (TAPL) PTY LTD* CHUBU ELECTRIC POWER GORGON PTY LTD MOBIL AUSTRALIA RESOURCES COMPANY PTY LIMITED OSAKA GAS AUSTRALIA PTY LTD SHELL AUSTRALIA PTY LTD TOKYO GAS GORGON PTY LTD
PL 93	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 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*

Please consult DMP's online Petroleum and Geothermal Register for the most current information on Titles and Holdings.

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Department of **Mines and Petroleum**