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

PETROLEUM
IN WESTERN AUSTRALIA

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Contents

Aerial view of the Mondarra gas storage facility in the Perth Basin

ARTICLES

TABLES

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Cover: Enerdrill Rig 3 drilling for APA Group at Mondarra 9 (Photo © APA Group)

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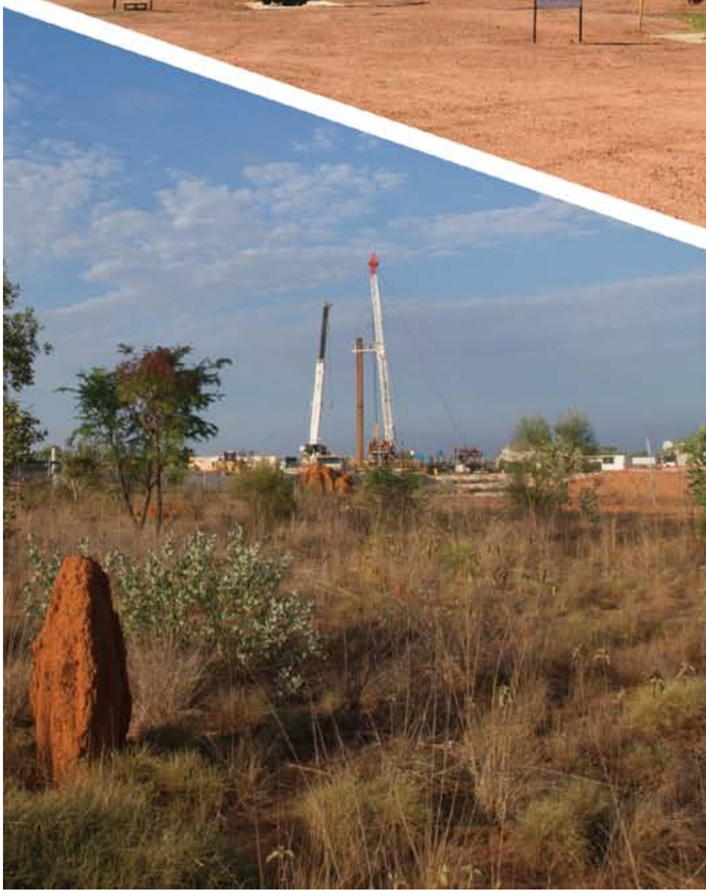
Guide to the Regulatory Framework for

Shale and Tight Gas in Western Australia

A Whole-of-Government Approach

2015 Edition



Minister's message

Sean L'Estrange
Minister for Mines and Petroleum

As the newly appointed Minister for Mines and Petroleum I am aware that Western Australia's petroleum industry is a key contributor to our State and national economy, supporting thousands of jobs and providing broad community benefits. While the industry is confronting depressed commodity prices and tight capital markets, we will continue to support exploration and innovation which can set the sector up for the next upswing in the economic cycle.

We want to make sure we are ready, as a State, to capture future opportunities to grow oil and gas in Western Australia and to reap the benefits that these developments will bring to all Western Australians.

An example is the potential presented by the development of Western Australia's shale and tight gas resources. The State possesses an estimated 2600–5350 Gm^3 (100–190 Tcf) of potentially recoverable shale and tight gas, more than the current known gas resources found off the Western Australia coast.

While this presents a fantastic opportunity for the State, we must continue our excellent efforts to allay any environmental concerns. The State Government, and in particular the Department of Mines and Petroleum, continues to listen to the community and recently released the whole-of-government 'Guide to the Regulatory Framework for Shale and Tight Gas in Western Australia'.

This is a clear and concise road map for the future and provides regulatory certainty and clarity for government, industry and communities to protect public health, water supplies and the environment. This is highlighted in the nine-agency framework to govern shale gas development. From rules for well management and environment plans, to requirements for consultation and landowner compensation, this document details our innovative, cross-agency approach.

We must also continue to work closely and cooperatively with local communities, at all stages of petroleum developments. This means keeping all parties informed – through transparent, timely and accessible information – in a manner that encourages trust and respect.

As the new Mines and Petroleum Minister, and working closely with Director General Richard Sellers, I am committed to looking for opportunities to build on former Minister Marmion's excellent work in reducing approval times and unnecessary red and green tape.

The recent success of the world's biggest LNG conference 'LNG 18,' held in Perth, is testament to how important a role Perth and Western Australia play in the production of these resources. As proud Western Australians we are aspirational people who grasp innovation and push ahead with a view to opening up new and exciting markets. I am confident Western Australians will reap even more benefits from our growing petroleum industry and I thank all members of the petroleum sector for the hard work they do to support ongoing developments.

Executive Director's message

Jeff Haworth
Executive Director
Petroleum Division

As we enter 2016, I would like to take some time to compare the Western Australian petroleum scene over the past two years, 2014 and 2015. These two years reflect the incredible highs and lows in the price of oil and it is interesting to see how this is reflected in the amount of activity that occurred in WA over those two extremes in the oil price.

For me, 2014 was highlighted by the ongoing search for shale and tight rock reservoirs for gas, and the search for oil starting to tail off. The somewhat ambivalent results coming from the tests conducted on prospective shale gas wells over previous years and constraints in the investment market to raise capital for these projects led to a strong focus on exploration for conventional resources in 2015. The discovery of the Waitsia field in the Perth Basin was a significant event in the future development of onshore gas resources.

Last year was also a difficult period for the smaller operators who again found it hard to raise capital to progress their projects. The larger companies went through a major 'belt-tightening' process and rationalisation of their global portfolios. There is no doubt, the ensuing global cutbacks in staff and resources had a dire effect on people with thousands losing their jobs.

The service industry also suffered, with reductions in contract rates dropping by 30 to 40 per cent; this opportunity was utilised by companies who had the money to complete surveys and drilling programs.

In Western Australia, coinciding with the drop in oil prices, was the completion or near completion of some of the largest LNG construction projects in the State. Wheatstone startup is expected in 2016, while Gorgon is nearing completion and Prelude and Ichthys are slotted in for 2017. These four projects draw gas from fields off the northwest coast of Western Australia. The end of the construction phase in LNG projects has led to reductions in staff as companies move towards operations, and this, coupled with the completion of iron ore projects and the reduction in the price of iron ore, has become what some call 'the end of the construction boom' for WA.

So let's look at the actual activity figures for these two years in relation to title activities and well activities. In the Commonwealth area adjacent to Western Australia, the number of wells drilled was 67 in 2014 and 50 in 2015, with many of the wells being production wells for the upcoming LNG projects. Markedly, the number of exploration wells dropped from 26 to nine over the two years.

For the State, however, the number of exploration wells jumped from four in 2014 to nine in 2015. Dominated by smaller exploration companies, exploration activity onshore in Western Australia has not diminished the way it has offshore.

In conclusion, my take on the activity level in Western Australia is that the Commonwealth figures definitely show slowing trends in exploration and new projects in 2015.

However, in the onshore, what is being seen is, that even when oil prices were high, onshore explorers found it difficult to raise capital for their programs and had to rationalise their acreage footprint due to this and other factors. Those with money today have taken the opportunity provided by lower drilling costs (rig rates) to complete their existing well commitments, but whether that is sustainable in 2016 and beyond is yet to be seen.

At the same time, the continuing program of decommissioning wells, which started in 2013, continued in the State as old fields in the Perth Basin and offshore Carnarvon Basin reach the end of their lives.

It is these 'end of life' activities that are driving revision of policies and guidelines on decommissioning, well management plans and field management plans within DMP and decommissioning guidelines in the Commonwealth. It also leads to our continued interest and desire to see more exploration to find replacement resources for the State's petroleum reserves.

DMP inspector at the Praslin 1 exploration well in the Canning Basin

Director's message

Denis Wills
Director Petroleum Operations
Petroleum Division

Recently I started to throw out papers I have had for some time – I think most engineers by temperament must be hoarders – and I came across two articles in two separate editions of the magazine *Chemical Engineering Australia*.

The following are some quotes from the first article (Michelson 1989), with the industry they were referring to left out for the present.

"… there is an increasingly dominant and potentially ominous threat to the xxx industry in Australia. This threat revolves around the volatility of community attitudes towards xxx. The greatest challenge now facing the xxx industry is to be able to play an assertive and positive role in the development of these community attitudes".

"However, greatest priority must be the importance of establishing debate on a scientific level. Too often problems and their resolution are frustrated by a combination of emotionalism and a quick allegiance to anecdotal evidence".

"The xxx recognises that its medium-to-long term future is dependent upon efficiently communicating its position, its relevance to the economy and its concerns for the welfare of its employees and the environment".

"The industry is often the scape-goat to many who are often dogmatic in their views on problems facing modern society. Industry will be persistent in its communication in providing perspective and contributing scientifically to debate. This will occur in the context that the industry respects the importance of the needs and wishes of the community".

From the second article (Cullen 1988):

"– the xxx industry is going through a critical period in its development worldwide – resulting from a loss of public confidence in its worth".

"Those who dismiss the public's criticism as uninformed miss the point, it is perception not facts that are the issue and it is industry's responsibility to provide the public with the information that will modify these perceptions".

"… the xxx industry should face up to the problem of public concern. Firstly, it needs to communicate more freely with the public on crucial issues …. Secondly, it needs to reassure the public that its plants are properly designed, maintained and operated – and that people are adequately trained. Thirdly, it has to communicate to the public and government the vital role it plays in our modern society".

The industry being referred to in these two articles is the Australian chemical industry. The articles date from 1988 and 1989.

This is some 27 years ago. We are in a different industry, but the themes outlined in these quotes have not changed when it comes to the oil and gas industry in Australia, and especially the embryonic shale and tight gas sector. These messages are clear and as relevant today as they were nearly three decades ago, albeit for a different industry:

- the public have a right to be informed and raise legitimate concerns and objections;
- the oil and gas industry must address these concerns in an open, honest and timely manner and this is an ongoing effort;
- the oil and gas industry must respect the importance of the concerns and needs of the community.

All the above quotes, coming as they do from industry, have been on industry's part, but government has a role to play also.

The following quote on government's role comes from the second article:

"Our (this was from a UK regulator's perspective) biggest problem is to establish our role in the minds of the public and this we have attempted to do by raising our public profile …. It is a continuing struggle to keep ahead of public concern" (Cullen 1988).

The Department of Mines and Petroleum's (DMP) regulatory role, accomplished through the regulatory framework, is the assessment and approval of petroleum activities and compliance monitoring against this regulatory framework and DMP approved work plans.

With the above quote in mind, DMP will:

- engage with the community and demonstrate the rigor and caution with which the oil and gas industry is regulated;
- establish in the public mind that they can reasonably look to us for reassurance that their interests are being properly looked after;
- reassure the industry that there will be a balance sought between community needs and concerns and the development of petroleum projects.

Within one of the quotes was the comment that "It (industry) needs to reassure the public that its plants are properly designed, maintained and operated – and that people are adequately trained".

Similarly DMP, as a regulator, needs to ensure compliance with the regulatory framework and approved petroleum activities to assure the public that petroleum activities (for example, drilling a well) are being properly undertaken to ensure safe and environmentally acceptable outcomes. This will be achieved through increased compliance monitoring (for example, site inspections) not only of ongoing petroleum activities, but also of facilities in care and maintenance, and suspended wells.

Given the challenging cost environment we are now in, and most likely to be in for some time, and thus the pressure on operating costs, the industry needs to be vigilant that the maintenance and inspection 'cloth' is not cut too tight. DMP is aware of these cost pressures and will be putting additional effort into working with industry to ensure compliance monitoring.

References

Cullen, Dr John, 1988, Luncheon address – Chemeca 88 *in* Chemical Engineering in Australia, Vol ChE 13, No 3 September 1988, pp 14-15.

Michelson, Rudi, 1989, Community attitudes and the Australian Chemical Industry *in* Chemical Engineering in Australia, Vol ChE 14, No 2 June 1989, pp 8-10.

Dr John Cullen was the President of The Institution of Chemical Engineers (UK) and the Chairman of the UK Health and Safety Commission.

DMP's Executive Director Petroleum engaging with interested community members at the Kimberley Community Information Sessions in March 2015

Annual review of petroleum activities in Western Australia in 2015

Karina Jonasson
Petroleum Resource Geologist
Resources Branch

Altas Rig 2 at Praslin 1

Highlights of 2015

- A significant increase in the number of wells drilled onshore in WA
- Oil recovered at Ungani Far West 1
- Perth Basin search for gas intensifies
- Positive results at Warro gasfield

Drilling

A total of 13 wells were drilled onshore in Western Australia in 2015 in the Canning and Perth Basins, up from five wells in 2014. Nine wells were new field wildcats and four were appraisal wells. This total does not include water and CO_2 injection wells drilled for the Gorgon Project on Barrow Island, which are not reported on in this article.

All seven wells drilled in the Canning Basin were new field wildcats, except Ungani Far West 1, which appraised the Ungani oilfield. Buru Energy drilled six wells: Sunbeam 1, Olympic 1, Praslin 1, Victory 1, Senagi 1, and Ungani Far West 1. Three rigs were kept busy drilling the Canning wells: DDH1 Rig 31, GEFCO185 and Atlas Rig 2.

Sunbeam 1 was spudded on 25 January in EP 129, 85 km southeast of Derby and 18 km south of the Gibb River Road. The well reached a total depth of 1200 m on 10 February, but no significant hydrocarbons were observed. The well was suspended for possible re-entry and deepening targeting a Frasnian aged reefal anomaly which contains the Emanuel prospect.

Olympic 1 was spudded using the DDH1 Rig 31 in EP 473 on 22 May. The well is located approximately 60 km southeast of Broome and 22 km inland from the Great Northern Highway. The well was fully funded by a farm-in agreement with Quadrant Energy Australia Limited (formerly Apache Onshore Holdings Pty Ltd). The well was targeting conventional oil in the Willara Formation with a secondary target in the Nambeet Formation. Total depth was reached at 1447 m and cores were retrieved, however no significant hydrocarbons were observed and the well was decommissioned.

Praslin 1 was spudded on 17 July with the Altas Rig 2 in EP 391, 90 km east of Broome and 15 km west of the Ungani oilfield. The well reached a total depth of 2512 m. Testing was carried out on the well following indications of a possible oil column on wireline logs; however there were no indications of moveable hydrocarbons. The well has been suspended for further evaluation and may be used as a water injection well.

Victory 1 was spudded on 9 September in EP 457, 185 km east of Broome and 85 km southeast of the Ungani oilfield. The well was targeting conventional oil and gas in the Ungani Dolomite and Laurel clastic reservoirs with secondary targets in Devonian carbonates of the Nullara Limestone. While drilling, the well experienced lost circulation between 1945 m and 2600 m, and difficulties with logging. The decision was made to decommission the well bore.

Senagi 1 was spudded on 15 October with DDH1 Rig 31 in EP 458, 240 km southeast of Broome and 144 km southeast of the Ungani oilfield. The Senagi 1 well targetted conventional oil and gas in the Ungani Dolomite and the Nullara Limestone. The well reached a total depth of 1045 m, with 286 m of continuous core retrieved from the well. Residual oil shows were interpreted from core. The well has been decommissioned.

Ungani Far West 1 is the first appraisal well drilled on the Ungani oilfield. The well was spudded on 28 November in Production Licence L 21, 97 km east of Broome and 3.3 km southwest of the Ungani producing wells. Atlas Rig 2 was on location to drill the well. The top of the Ungani Dolomite was intersected at 2328 m and a sample of oil was recovered to surface from a 5 m sandstone interval at the top of the Anderson Formation at a depth of 1560 m. Buru interpreted a potential 14 m gross oil column with 5 m net pay, which is a very encouraging result with the zone representing a new play type for the Ungani area. Coring has commenced on the Ungani Dolomite reservoir section. At the time of writing, the rig has not yet been released from the well.

The seventh well, Theia 1, was drilled by Finder Shale Pty Ltd, a wholly owned affiliate of Finder Exploration, in EP 493 approximately 150 km southeast of Broome, in partnership with the Geological Survey of Western Australia (GSWA). Theia 1 was drilled to test the Middle Ordovician Goldwyer III shale, a liquids-rich play in the Canning Basin. The company recovered 778 m of continuous core from Theia 1 while drilling and the core was examined on site by a team of geologists from Finder and GSWA. The two groups collaborated to describe and analyse the core and interpret the intersected stratigraphy to further understand the basin's stratigraphy and petroleum systems. Finder has reported a 120 m section of the Goldwyer III interval with high wet mud gas readings, and that the well has validated their geological model. The well has been decommissioned.

In the Perth Basin, Enerdrill Rig 3 was contracted to drill six wells, including two new field wildcats and four appraisal wells. All wells drilled have been suspended for further evaluation of gas shows.

AWE's Irwin 1 exploration well, located approximately 23 km east of Dongara, was spudded 25 March in EP 320 near the border with Production Licence L 1 and drilled to a total depth of 4049 m. A 32 m gas column was discovered in the Dongara/Wagina Formation, with gas shows in deeper secondary targets. The gas/water contact was interpreted at 3085 m, which is the same gas/water contact depth at Warradong 1, previously drilled on the adjacent Synaphea structure 4.5 km to the south, back in 1981.

AWE's Waitsia 1 appraisal well is located approximately 17 km east of Dongara and 3 km east of the Senecio 3 well, which discovered the Waitsia field. The well was spudded 14 May in Production Licence L 1. The well confirmed a 95 m gross gas column with 18 m net pay. Waitsia 1 was tested in October and flowed gas at a combined rate of 1.4 Mm^3/d (50 MMscf/d) from the Kingia and High Cliff Sandstone Formations.

The Waitsia 2 appraisal well was spudded 29 June in L 1, 16.5 km east-southeast of Dongara and drilled to 3530 m total depth. The well recorded elevated gas shows in the Kingia and High Cliff Sandstones, Carynginia Shale and Irwin River Coal Measures. Following the drilling of Waitsia 2, AWE increased the gross 2P Reserves plus 2C Contingent Resources for the Waitsia gasfield from 8.2 Gm^3 to 13.7 Gm^3 (290 Bcf to 484 Bcf) of gas, from the Kingia and High Cliff Sandstone Formations. Production from the Waitsia field is anticipated to start around August 2016 with the field connected to the Xyris Production Facility.

Well test at Waitsia 1

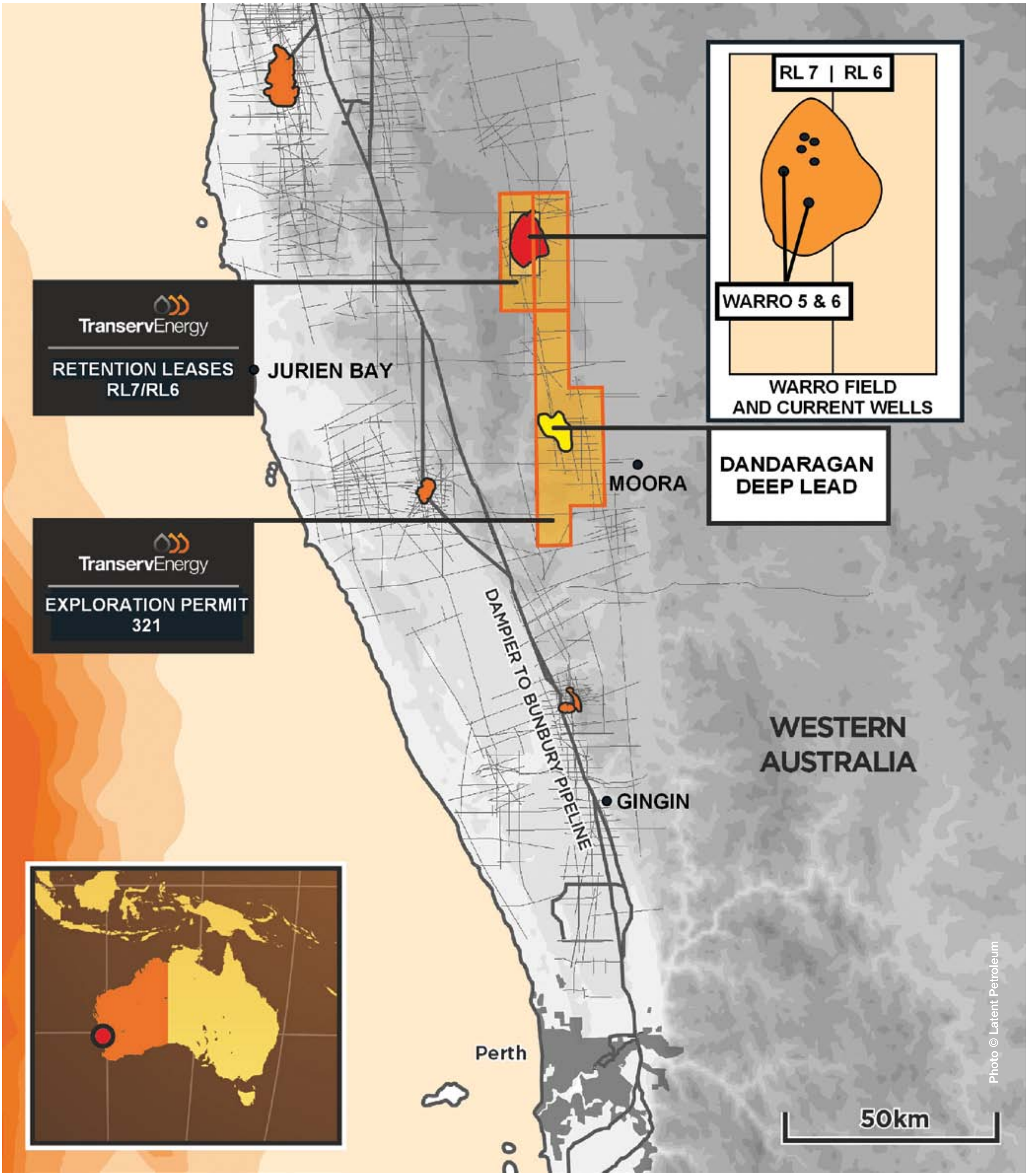


Figure 1. Location map of the Warro 5 and 6 wells in the northern Perth Basin

Latent Petroleum drilled two successful appraisal wells on the Warro gasfield in Retention Lease R 7 (Fig. 1). Warro 5 was spudded 16 August, sidetracked on 6 September and drilled to a total depth of 4327 m. Based on interpreted wireline logs, the well intersected a 161 m gross gas column with 95 m net pay. The Warro 6 appraisal well was spudded 12 October, approximately 3 km to the northwest of Warro 5ST1 and drilled to a total depth of 4520 m. Preliminary interpretation of the wireline logs show Warro 6 intersected 315.5 m of gross pay with 210 m net gas pay.

The Warro 5 and 6 wells were drilled as part of the Alcoa farm-in arrangement with Latent Petroleum, the operator of R 7. Alcoa is earning up to 65 per cent under the farm-in agreement, in which Alcoa is spending up to $100 million on exploration and development at Warro. Alcoa is funding a staged program which includes the drilling of further wells and constructing production infrastructure.

Empire Oil and Gas spudded the Red Gully North 1 exploration well in EP 389, 4 km from the Red Gully Processing Plant near the town of Gingin on 18 November. Red Gully North 1 discovered gas in three intervals of the Cattamarra Coal Measures, the D, B and Coaly Unit. The D Sands flowed on production test at a stabilised rate of 340 km^3/d (12 MMcf/d) gas and 132 277 m^3 (832 bbl) of condensate per day. The other intervals are to be tested at a later date. The well is planned to be tied in to the Red Gully Gas and Condensate Processing Facility following testing and completion.

Surveys in WA

Seven surveys were carried out in Western Australia in 2015. Buru completed the Yakka Munga 3D (190 km^2), Kurrajong 3D (196 km^2) and Raphael 2D (163 line km) seismic surveys with contractor Terrex Seismic, as well as an airborne gravity survey of 5765 line km over EPs 391, 431 and 436.

Another airborne survey, the Black Swan Airborne Geophysical Survey was conducted for Empire Oil and Gas over nine Perth Basin exploration permits, EPs 368, 389, 416, 426, 4430, 432, 440, 454 and 480. Also in the Perth Basin was a 3D seismic survey over the Arrowsmith field, which will help determine the location of the next Arrowsmith appraisal well, and a 146 km^2 offshore marine seismic survey, the Numbat 3D MSS under a Special Prospecting Authority for Searcher Seismic in the Northern Carnarvon Basin.

Hydraulic fracturing

During April, AWE completed a Diagnostic Fracture Injection Test (DFIT) on the Drover 1 exploration well in EP 455. The purpose of the DFIT was to assess reservoir pressure, permeability, natural fracturing and potential for hydraulic stimulation. Following evaluation of the DFIT, the joint venture made the decision to not fracture stimulate the well. The well has been decommissioned and the site rehabilitated.

Buru Energy completed the hydraulic fracture stimulation at two of their Canning Basin wells in the second half of 2015. At Valhalla North 1, four zones were stimulated with sand and ceramic proppants and at Asgard 1, seven zones were stimulated with slickwater and sand proppant. Water quality monitoring was carried out prior to and during the operations and no environmental impact was observed.

Latent Petroleum conducted hydraulic fracture stimulation activities at two of their Warro gasfield wells, Warro 5 and Warro 6. The stimulation of Warro 6 was completed in December 2015; the stimulation of Warro 5 was completed in January 2016. The Warro field is located approximately 200 km north of Perth and 31 km east of the Dampier to Bunbury natural gas pipeline (DBNGP) and is an undeveloped gasfield with six wells drilled. Depth to reservoir is approximately 4100 m in the Yarragadee Sandstone at the Warro field.

Warro 5 Stage 1 stimulation was completed during November but these operations were suspended when proppant from the initial stimulation phase screened out and filled the borehole. The program was recommenced in January 2016.

Enerdrill Rig 3 at Warro 5

Warro 6 is located 3 km northwest of Warro 5ST1. At Warro 6 three stages of reservoir stimulation were completed over the deeper 50 per cent of the gross reservoir section. Initial flow back operations commenced at Warro 6 on 17 December and resulted in the recovery of a substantial portion of the stimulation fluids.

Water and soil sampling was undertaken during operations and as part of the agreement to participate in a water and soil/atmospheric gas project with CSIRO and other Perth Basin operators. Surface seismic monitoring was also undertaken during the stimulation operations.

Recently, resources at the Warro gasfield were upgraded to 38.5 Gm^3 (13.6 Tcf) GIIP by an independent assessment.

Development news

Waitsia Gas Project

The AWE-operated L 1/L 2 joint venture achieved FID for Stage 1A of the Waitsia Gas Project in early January 2016. Stage 1A comprises the installation of new infrastructure and upgrades to existing assets that will connect the recently flow tested Waitsia 1 and Senecio 3 gas wells to the Xyris Production Facility (XPF). Treated gas from XPF will be delivered to the Parmelia pipeline for domestic consumption.

Construction work will include two 101 mm (four-inch) flowlines from the well heads to a northern gathering manifold, a 152 mm (six-inch) pipeline to transport the gas to XPF and minor upgrades to the XPF. FEED studies have been completed, and an EPCM contract has been awarded. In addition, the pipeline licence and the construction environment plan for the in-field gas pipeline have been approved.

The initial capacity of XPF will be approximately 10 TJ per day, with further expansion possible, and first gas is scheduled for August 2016.

Gorgon Project Update

The Project is located on Barrow Island, around 60 km off the northwest coast of Western Australia. It includes a three-train, 15.6 million tonnes per annum (Mt/a) liquefied natural gas (LNG) facility and a domestic gas plant with the capacity to supply 300 terajoules of gas per day to Western Australia. The first LNG cargo is expected in the first quarter

Gorgon Project's commissioning cargo at Barrow Island

of 2016. This will be followed by the commencement of domestic gas supply to the market.

The commissioning cargo has arrived and cooldown of the LNG storage and loading facilities is in progress. The Train 1 startup sequence is progressing with feed gas introduced into the plant. Gas for Train 1 startup will come from the Jansz-Io wells, which have been successfully flow-tested. All 51 modules required for the three LNG trains have been delivered to Barrow Island and construction is progressing on Trains 2 and 3.

Wheatstone Project Update

The Wheatstone Project is located at Ashburton North, 12 km west of Onslow in Western Australia. The project will consist of two LNG trains with a combined capacity of 8.9 Mt/a and a domestic gas plant. First LNG is expected to be midyear 2017.

Hookup and commissioning activities continued on the offshore platform, including the startup of utility systems. The installation of the offshore pipelines connecting the platform to the subsea infrastructure is complete. Six of nine wells are drilled and completed offering sufficient well capacity for the first train.

At the plant site, all Train 1 process modules required for first LNG have been delivered. The first Train 2 module has been received at the LNG plant site. The LNG storage tanks are nearing completion with hydro testing ongoing. The LNG and condensate export loading arms have been installed on the product-loading jetty.

Wheatstone platform hookup and commissioning

Government investigations of shale gas implications

Nina Triche
Petroleum Geologist
Resources Branch

Well cleanup after hydraulic fracture stimulation in the Canning Basin in 2015

Recent publications by governments around the world have addressed the issue of shale gas production and its potential effects on water resources, both in terms of usage and of possible negative impacts on water supply. In only the past two years, these have included inquiries that address potential impacts of hydraulic fracturing on water resources by the US Environmental Protection Agency (EPA) (2015); on the environment by the Northern Territory (NT) Chief Minister (2014), the Council of Canadian Academies (2014) and the Parliaments of South Australia (2015) and of Victoria (2015); on safety concerns associated with hydraulic fracturing by the Australian Chief Scientist (ABC 2015) and the New South Wales (NSW) Chief Scientist (2014); and on the regulation of shale and tight gas in Western Australia by the Western Australian (WA) Parliament (2015) and by the Government of Western Australia (2015).

Responses and publications by these bodies and organisations have generally concluded that hydraulic fracturing, if properly regulated, is a safe and well understood technique that has been in use in the petroleum industry for more than 70 years, with no known significant adverse consequences to the environment or to water resources. They have also produced a number of recommendations relating to how government and industry can address community concerns regarding shale gas production and ensure that shale gas producers continue to minimise any potential impacts to water resources and to the environment in general. These investigations are summarised below.

US EPA Report

The US EPA commenced an assessment of the potential impacts of hydraulic fracturing on drinking water resources in early 2010. They subsequently released their draft assessment for public comment and peer review in June 2015; the draft is not yet finalised, but is available to view online. The study was based on research projects and literature reviews conducted by the EPA Science Advisory Board, as well as workshops and input from state, industry and NGO bodies. In particular, they addressed the impacts of large water withdrawals; surface spills of fracturing fluids or of produced water; injection and hydraulic fracturing; and inadequate treatment of wastewater on drinking water resources in the United States.

The EPA concluded that the amount of water used for hydraulic fracturing in the US constituted about one per cent of the country's total annual consumption and that there are aboveground and subsurface mechanisms that could allow these operations to impact drinking water resources. They also concluded that, during the entire history of fracturing in the US, there was no evidence that these mechanisms led to any "widespread or systemic impacts" on water resources, although they did note that these conclusions could be caused in part by a lack of baseline water quality data or by preexisting water contamination unrelated to fracturing, both of which are valid concerns.

The environmental impacts that were identified were small in number and in magnitude, especially as compared to the number of US fractured wells. They identified 376 surface chemical or produced water spills that occurred from 2006 to 2012, during which time approximately 95 000 fracturing jobs were performed. Of these 376, only nine per cent reached to surface water, and 74 per cent of cases occurred owing to container integrity failure.

Canadian Shale Gas Inquiry

In the past twenty years, shale gas production expanded rapidly in Canada, prompting the Minister of Environment to assemble a panel of experts for the purpose of addressing potential associated risks. Specifically, the Council of Canadian Academies was tasked with determining the state of knowledge of "potential environmental impacts from the exploration, extraction, and development of Canada's shale gas resources" and of "associated mitigation options".

The panel's key findings include the following:

- The potential for environmental impacts has been lessened by the development of new techniques such as recycling flowback water, use of multi-well pads, reduced chemical usage and better surface fluid containment.
- There has, however, been no comprehensive investment in monitoring of environmental or health impacts, leading to a lack of basic data.
- The main environmental risk of shale gas development is gas leakage from improperly completed wells, but this will not necessarily lead to negative impacts on groundwater.
- Contamination from surface spills is a concern and should be mitigated through engineering improvements, regulatory enforcement and performance management.
- Seismic risks from fracturing are low, but injection of waste fluid should be well monitored and involve careful site selection.
- Health risks and quality of life effects from shale gas production are not well studied and remain largely unknown.
- Shale gas production is preferable to the current reliance on coal for electricity generation, but not if it were to displace low-carbon fuels or renewable energies.
- Canadian regulation of shale gas production is evolving and must account for the fact of regional benefits compared with potential local adverse impacts.
- The efficacy of current regulations is not established, owing to a lack of adequate monitoring.
- An adaptive, science and outcomes-based regulatory approach, rather than a prescriptive approach, is recommended, especially in terms of gaining public trust.

The Australian Chief Scientist

Dr. Alan Finkel was recently appointed Chief Scientist of Australia and has commented on the safety and environmental aspects of hydraulic fracturing (ABC, 2015). Specifically, he has said that "Overall … if properly managed, with a good regulatory framework – and Australia is capable of applying good regulatory frameworks – there is a lot of evidence that fracking is safe."

Dr. Finkel also participated in the 2013 Australian Council of Learned Academies' (ACOLA) investigation of unconventional, mainly shale gas production (Cook et al. 2013). ACOLA concluded that "The evidence suggests that, provided appropriate monitoring programs are undertaken and a robust and transparent regulatory regime put in place (and enforced), there will be a low risk that shale gas production will result in contamination of aquifers, surface waters or the air, or that damaging induced seismicity will occur."

The Australian Petroleum Production and Exploration Association (APPEA, 2015) has commended these remarks, calling them "evidence-based conclusions" that should be respected.

Northern Territory Report

The NT Government completed an inquiry into hydraulic fracturing and all its potential impacts on the environment in the NT in November 2014. The main goals of the study were to give an accurate picture of environmental risk from fracturing and to provide recommendations on potential mitigation efforts. As with the EPA study, conclusions were drawn based on community consultation, including meetings with environmental groups, NGO's and industry and other associations.

The NT's main recommendation was that "environmental risks associated with hydraulic fracturing can be managed effectively subject to the creation of a robust regulatory regime," much as other inquiries and reports have concluded (e.g. Cook et al. 2013, Parliamentary Commissioner 2012, Royal Society and Royal Academy of Engineering 2012). Its authors further state that, in conjunction with "the substantive weight of agreed expert opinion, the Inquiry finds that there is no justification whatsoever for the imposition of a moratorium on hydraulic fracturing in the NT."

The authors did note, however, that there is "confusion or poor understanding within the community" about fracturing, particularly surrounding the differences between production of coal seam gas (CSG) and that of shale gas. They also pointed out that industry itself is sometimes the source of this confusion, as it often conflates terms such as 'unconventional' or 'fracking', fuelling the public's emotional response to these techniques.

South Australian Hydraulic Fracturing Inquiry

In late 2014, the Natural Resources Committee of the Parliament of South Australia initiated the 'Inquiry into Unconventional Gas (Fracking)', in order to address the potential risks of fracturing to groundwater and landscape, the effectiveness of current legislation and regulation and the potential economic outcomes of unconventional gas production to the State. A short, interim report was released in November 2015, and the final report should be tabled by mid-2016.

To complete the inquiry, the committee has undertaken two fact-finding visits to the community, received a large number of submissions and held 10 public hearings. They are currently reporting that the committee's "opinions differ on the potential impacts and risks of unconventional gas".

Victorian Fracturing Inquiry

An inquiry into the potential presence and possibility of safe extraction of unconventional gas was completed in December 2015 by the Victorian Parliament. It received more public submissions than possibly any other inquiry held in the State. Proceeding through these submissions, as well as through consultation with scientists, community and environmental groups, local governments and the gas industry, the committee could not reach a majority decision on whether or not to ban the unconventional gas industry in the State or to apply a five year extension to the current fracturing moratorium.

Conclusions from the report were prefaced by two acknowledgements:

1. Avoiding an industry or activity unless or until it is "100 per cent safe" is an unrealistic goal, as all human activities carry risk.
2. A proper regulatory framework can manage risk and mitigate it to acceptable levels, although it is unclear whether Victoria's current framework is suitable or not.

The Committee did, however, propose 10 recommendations, which included:

- Acquire significantly more baseline data and increase groundwater monitoring funding prior to commencing exploration.
- Commission an independent water science committee and a full government review of possible human health impacts of unconventional gas production.
- Investigate improving petroleum regulation in the State, to ensure community consultation and dispute regulation processes and to strengthen landholder rights while maintaining an equitable balance with industry.
- Implement mandatory environmental impact assessments.
- Develop an industry-wide code of best practice addressing such activities as well integrity, fracturing, produced water, well decommissioning and rehabilitation and baseline/ongoing water monitoring.
- Require companies to seek approval for all proposed chemicals and require full disclosure of those approved.
- Consider the Queensland GasFields Commission model and others for use in Victoria.

The NSW Chief Scientist

In September of 2014, the Chief Scientist of the NSW government published a report regarding the independent review of CSG in NSW. Using information from a large group of worldwide experts, as well as extensive consultation with community groups, industry and government agencies, the review concluded that challenges posed by CSG and by hydraulic fracturing can be well managed within an appropriate legislative framework; with associated, transparent reporting and compliance; and with a commitment to rapid emergency response and effective remediation. They concluded that this management should proceed through the use of the following:

- careful designation of areas that are geologically suitable for CSG extraction
- high engineering and professional standards and a well-trained and certified workforce
- a Whole-of-Environment data repository for the State
- comprehensive operations monitoring
- application of new technologies.

Western Australia Shale and Tight Gas Framework

DMP served as lead agency for the compilation and publication of the West Australian Government's multi-agency framework document, which outlines the legislative and regulatory basis for managing shale gas projects in the State. Rather than assessing the potential impacts of fracturing on various environmental resources, which has been the focus of other recent publications, the framework document brings together the State's best practice requirements for shale and tight gas projects and provides an account of the assessment and regulation processes for approving these ventures. It also clarifies that the State government will respect the rights of communities and individuals to form their own opinions regarding shale gas and hydraulic fracturing, and that industry must engage in a "timely, open and ongoing manner with all stakeholders".

Recent publications by governments around the world on shale gas production and hydraulic fracture stimulation

Hydraulic fracture stimulation equipment at Valhalla North 1 in the Canning Basin

Western Australian Parliament

In August 2013, the WA Standing Committee on Environment and Public Affairs proposed to investigate hydraulic fracturing and its implications for the State, particularly in regard to environmental considerations. The Committee reported its findings in November 2015. This report reviewed fractured wells across the State, public submissions and hearings and investigations of issues such as groundwater protection, chemical disclosure and obtaining social licence.

Conclusions and recommendations from the report include, among others:

- Energy security is a vital concern, but a "shale gas revolution" similar to that of the US will not necessarily occur in Australia or in WA.
- Government must acknowledge the inherent risk in energy production and justify any decision to proceed with exploration and/or development.
- Modern technologies such as horizontal drilling, multi-well pads, wastewater recycling and saline fracturing water significantly minimise environmental impacts.
- Regulation –
  - Essential regulatory safeguards and their management by DMP have improved recently, e.g. requiring Field Management Plans, Environmental Plans, monitoring and compliance activities, EPA referrals and baseline monitoring.
  - Sufficient safeguards currently exist to protect public drinking water.
  - DMP's system for monitoring abandoned wells and excluding wastewater reinjection is supported.
- Risks –
  - The likelihood of hydraulic fractures intersecting aquifers or inducing seismicity is negligible.
  - The risk of chemical or fluid spills and of fugitive methane leakage is highly unlikely and/or can be effectively managed currently.
  - Claims that shale gas development will result in thousands of wells in the Kimberley or Midwest are over-stated and not evidence based.
- Community Consultation –
  - 'Well failure' is a misunderstood term; it must be clarified that it does not equate to 'environmental impact'.
  - Early and ongoing consultation, including data transparency and effective communication, is essential for continued social licence.
  - Future fracturing in the State should be based on established facts, including baseline data and monitoring, to strengthen industry's social licence to operate.
- Recommendations –
  - Current penalties for breaching DMP regulations are inadequate for effective deterrence and should be increased.
  - DMP regulations specifying "permanently confidential information" should exclude "trade secrets".
  - Government should establish a statutory body, similar to the Queensland GasFields Commission, to act as an arbiter for land owners and industry, as well as a statutory framework for land access agreements.
  - A petroleum rehabilitation fund, similar to that in use in the mining sector, should be established.

Conclusion

In summary, shale gas exploration is currently progressing in numerous countries. Shale gas production has been ongoing in the US for over 20 years, and hydraulic fracturing has been undertaken worldwide for more than 70. Recent government inquiries in numerous jurisdictions, including the US, Canada, the UK, New Zealand and many Australian states, have concluded that hydraulic fracturing is a low-risk technology that can be safely applied, if proper regulatory regimes are in place or will be implemented. Many investigations have also concluded, by engaging with multiple stakeholders, such as landowners and those with environmental concerns, that a social licence to operate is obtainable, provided early, ongoing and in-depth community consultation is undertaken. This will be imperative if shale gas is to become a significant opportunity in Australia.

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Online transactions the way of the future

DIGITAL DMP 2016
DEPARTMENT OF MINES AND PETROLEUM

Hayden Samuels
Compliance Monitoring Officer
Strategic Business Development

Completing paper forms and lodging them will soon become a thing of the past as the Department of Mines and Petroleum (DMP) progresses to online submissions and other transactions.

DMP is continuing to improve its interactions with customers by rolling out online systems to ensure a faster and more seamless customer experience for conducting business with the department. These systems will provide 24/7 access, improved processing timelines as well as reporting benefits and reducing red tape.

On 1 July 2015, DMP began phasing out some paper-based transactions where a digital system is currently available.

The list of current paper transactions being phased out is available on the DMP website at www.dmp.wa.gov.au.

The move is part of the department's online lodgement initiative. Executive Director, Strategic Projects, Julie de Jong said it will help to deliver a faster and more seamless customer experience.

"The benefits for our customers will include improved processing and reporting timeframes, and around the clock access to payment and application lodgement systems," Mrs de Jong said.

The petroleum industry will be familiar with elements of the Petroleum and Geothermal Register (PGR), which has been progressively implemented since 2007. Functions currently in operation include:

- Online Payments of all fee types including Electronic Funds Transfer (EFT) facilities
- Issuing of Tax Invoices and Receipts
- Approvals Tracking
- Exploration Permit Lodgement
- Pipeline Licence Lodgement
- Well Application Lodgement
- Change of Company Name Lodgement
- Integration with Global Information System (GIS) allowing a Basic Map Viewer to display locations of petroleum titles
- Integration with the Petroleum and Geothermal Information System (WAPIMS)
- Integration with the Environment Assessment and Regulatory System (EARS)
- Bidding System Module
- Audit and Inspections Module

Director General Richard Sellers launching Digital DMP to staff

- Location Management Module (i.e. Declaration of Location, Variation of Location etc.)
- Native Title Module
- Drilling Management Module
- Well Management Plan and Field Management Plan Modules

Further development of the online lodgement module for petroleum pipelines was completed and made available to industry in June 2015.

The department will inform relevant industry sectors when systems that affect them are available online. Helpful tools, training, and dedicated staff will be provided to assist with the introduction of the new systems.

The Petroleum Division is encouraging customers to use the available online systems and invites customers to lodge all of their future transactions online. We are aiming for a 100 per cent take up of our online systems so we can speed up the phasing out of paper transactions. In addition, in the coming year, we will be making more forms available online to our customers.

Petroleum customers needing to transition from paper to online lodgement can register for a free account via the DMP website.

Customers requiring access to PGR for public information about petroleum titles will not need to register.

Support is available for PGR online by calling +61 08 9222 3623 or emailing it.servicedesk@dmp.wa.gov.au.

Your feedback is important to us and is crucial to ensuring that our systems are the best they can be. To provide feedback please visit the DMP website.

Julie de Jong (right) and Strategic Projects team at Digital DMP launch

Hydrodynamic modelling of hydraulic fracturing fluid injection in northern Perth Basin shale gas targets

Loading proppant (sand) into the sand dragon prior to the fracture stimulation at Warro 5

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Resources Branch
Petroleum Division

Introduction

Recent discussions on potential Australian shale gas developments have raised public concerns regarding groundwater protection. This article presents the results of modelling the movement of the hydraulic fracturing (HF) fluid after injection in northern Perth Basin shale targets (Carynginia Formation). The model is also used to predict the migration of HF fluid along an imaginary adjacent fault. Similar studies are rare in terms of the technique applied and the geographical area covered. Although a large number of studies were carried out on solute/contaminant transport modelling, very little has been done specifically to study the effects of HF fluid injection in shale targets. Myers (2012) conducted MODFLOW-based simulations to estimate contaminant travel times through potential pathways such as the sedimentary rock matrix, and fractures and faults in the Marcellus Shale region in the US.

The exploration for oil and gas in the onshore northern Perth Basin began in 1951. Since then a large number of wells have been drilled and subsurface geophysical (seismic, gravity and magnetic) data acquired that provide a good understanding of the geological structure and stratigraphy of the basin (Mory and Iasky 1996a).

Exploration drilling identified a substantial amount of conventional gas-in-place in the northern Perth Basin, leading to commercial production (Owad-Jones and Ellis 2000). The northern Perth Basin has been identified as prospective for shale gas and already has the infrastructure in place for its development.

Australia has an estimated 12.4 Tm^3 (437 trillion cubic feet (Tcf)) of risked recoverable shale gas resource, of which about 5.21 Tm^3 (184 Tcf) of risked recoverable shale gas lies in the Canning and Perth Basins of Western Australia (EIA 2013). Due to low permeability of shales, gas is unable to flow out freely, and hydraulic fracture stimulation (HFS or fraccing) is required to produce the gas. HFS requires injection of fluids (mostly water, which is combined with some chemicals and proppants, i.e. sand) under high pressure. This is to increase the permeability of the shale in the immediate vicinity of the well through the creation of fractures that will allow the gas to flow. The two basins in Western Australia identified for their shale gas plays, the Canning and Perth Basins, also contain substantial quantities of potable water in large regional aquifers. In the US and Australia there have been community concerns regarding the impact of hydraulic fracturing on drinking water sources. It is thus important to understand the potential risks to water resources in these basins before undertaking large-scale shale gas development.

The purpose of this study is to predict the movement of hydraulic fracturing (HF) fluid after injection into a shale target within the geological setting of the northern Perth Basin and to estimate the transport times of this fluid through the formation. We also model the movement of fluid when contacting an adjacent hypothetical fault and its movement along the fault. The modelling was carried out using the multispecies, density and temperature dependent MODFLOW-SEAWAT code (Harbaugh et al. 2000; Langevin et al. 2008). The model was then used to simulate the post injection flowback using the Drain package in MODLOW. The injection rate, fluid concentrations and number of days of flowback considered for modelling were based on actual operational data. In this study, the concentration of HF fluid includes the concentration of additives (excluding proppants) in the HF fluid. In addition, this study does not consider the effects of formation water extraction as part of the well test and production phases (subsequent to HFS and flowback operations).

Northern Perth Basin shale gas and groundwater resources

According to US Energy Information Administration (EIA, 2011; EIA, 2013) studies, the northern Perth Basin contains two main organic-rich shale formations occurring at depths greater than 2000 m. These formations are the Permian Carynginia Formation and the Triassic Kockatea Shale. The most organic-rich portion of the Kockatea Shale is the Hovea Member, a thin (15-38 m thick), basal shale that averages 2.0% Total Organic Carbon (TOC). This percentage is well above the overall formation average of about 0.8% TOC. In the underlying Carynginia Shale, TOC values of up to 11.4% have been recorded. An estimated 5646 km^2 area of the Beagle Ridge and Dandaragan Trough in the northern Perth Basin could be considered prospective for shale gas development. The Permian aged Carynginia Shale has an estimated gas-in-place of 3510 Gm^3 (124 Tcf), and technically recoverable resources of approximately 700 Gm^3 (25 Tcf). For the Triassic Kockatea Shale, the gas-in-place is 1246 Gm^3 (44 Tcf) and technically recoverable resources are approximately 226 Gm^3 (8 Tcf). The underlying Permian Irwin River Coal Measures may also be prospective for shale gas and is undergoing further evaluation (Bahar and Triche 2014).

The fresh groundwater resources of the northern Perth Basin are contained within the Superficial Leederville-Parmelia and Yarragadee aquifers, and to a lesser extent in the Mirrabooka, Cattamarra, Eneabba-Lesueur and Tumblagooda aquifers. The renewable resource is at least several hundred gigalitres per year, but the aquifer system is approaching full allocation. Brackish to saline groundwater resources are contained within portions of all the aquifers, particularly the Superficial aquifer north of Green Head, the Yarragadee aquifer at depth and the Cattamarra aquifer. The Superficial, Permian, Yandanooka fractured rock, Northampton fractured rock and Mullingara fractured rock aquifers are minor and predominantly brackish to saline aquifers with usage limited mainly to stock and domestic purposes (Pennington Scott 2010).

Model setup

The geology of the northern Perth Basin was described in detail by Mory and Iasky (1996a). The Perth Basin is a north–south elongate rift/trough, straddling the west coast of Australia. The tectonic framework of the onshore basin is dominated by the Darling Fault and a series of troughs bounded by transfer faults. The Dandaragan Trough, in the north, is a major depocentre up to 12 000 metres thick.

The 3D model represents the geology of the northern Perth Basin as per the geological section C-C' of Mory and Iasky (1996b), but only as far as the Urella Fault (Fig. 1). The model domain extends 100 km east–west and 10 km north–south. Vertically, the model extends to a depth of 5 km. The model was developed and run using the Schlumberger Visual Modflow pre- and post-processing package.

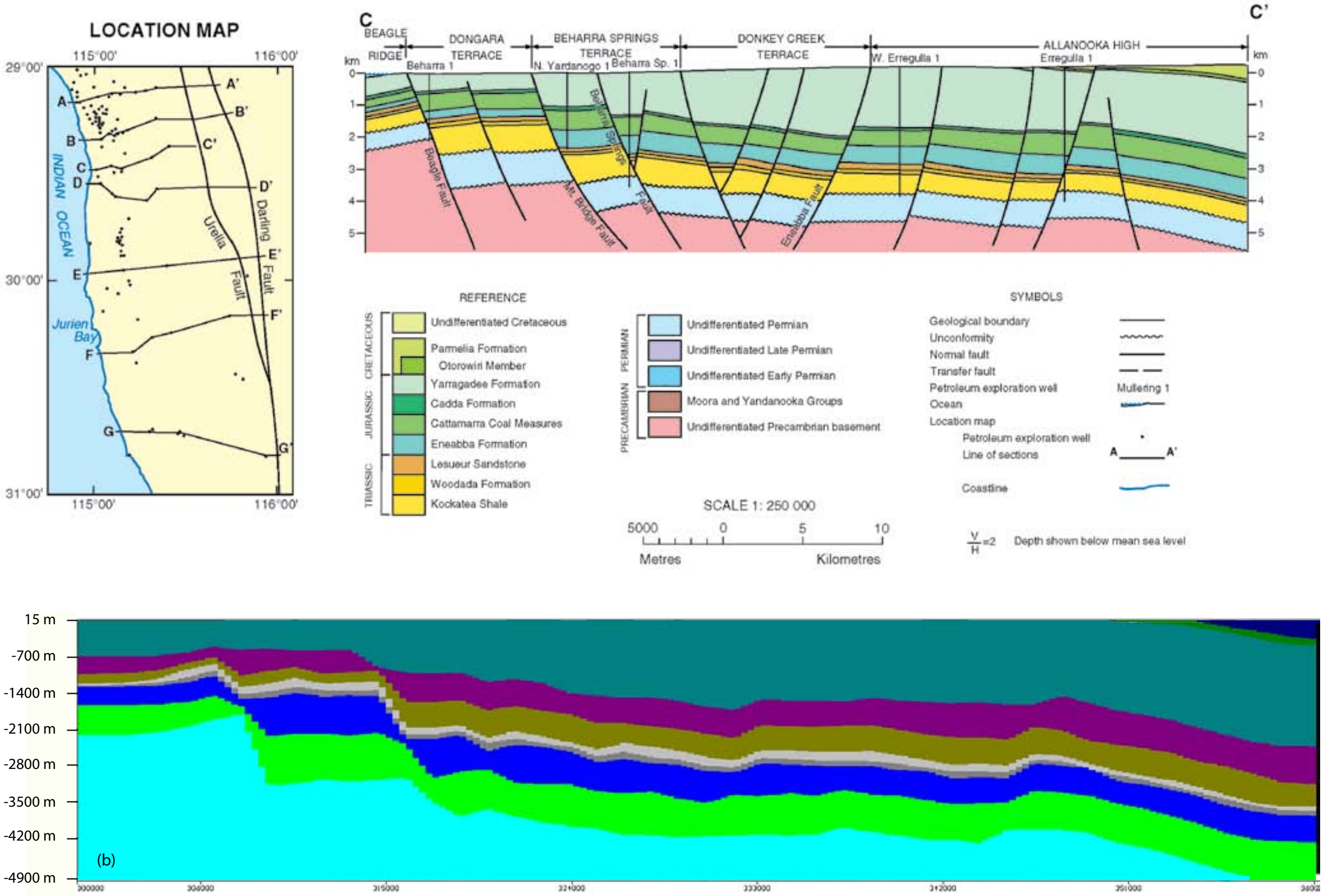


Figure 1. (a) Geological cross section C-C' exrtracted from Mory and Iasky (1996b). Note, other cross sections on the location map can be found in the original plate; and (b) as represented in the model

Table 1. Aquifer Parameters (Source: Sanders 1967, Harley 1974, Moncrief 1989, Groves 1995, Irwin 2007, GHD 2011)

Layer	Aquifer/Aquitard Unit	Horizontal Hydraulic Conductivity, Kh (m/d)	Vertical Hydraulic Conductivity, Kv (m/d)	Specific Yield, Sy	Specific Storage Coefficient, Ss (1/m)
1	Superficial -Leederville -Parmelia	10	10^{-3}	0.1	10^{-6}
2	Otorowiri Siltstone	10^{-4}	10^{-5}	10^{-5}	10^{-7}
3	Yarragadee Formation	5	10^{-3}	0.07	10^{-6}
4	Cadda Formation	2	10^{-3}	0.1	10^{-6}
5	Cattamarra Formation	1	10^{-2}	0.1	10^{-6}
6	Eneabba Formation	0.37	10^{-2}	0.07	10^{-6}
7	Lesueur Formation	0.37	10^{-3}	0.07	10^{-6}
8	Woodada Formation	0.3	10^{-5}	0.05	10^{-6}
9	Kockatea Shale Formation	10^{-5}	10^{-5}	0.05	10^{-6}
10	Caryngina Formation	0.01	10^{-5}	0.001	10^{-6}
11	Basement rock	10^{-5}	10^{-5}	10^{-5}	10^{-7}

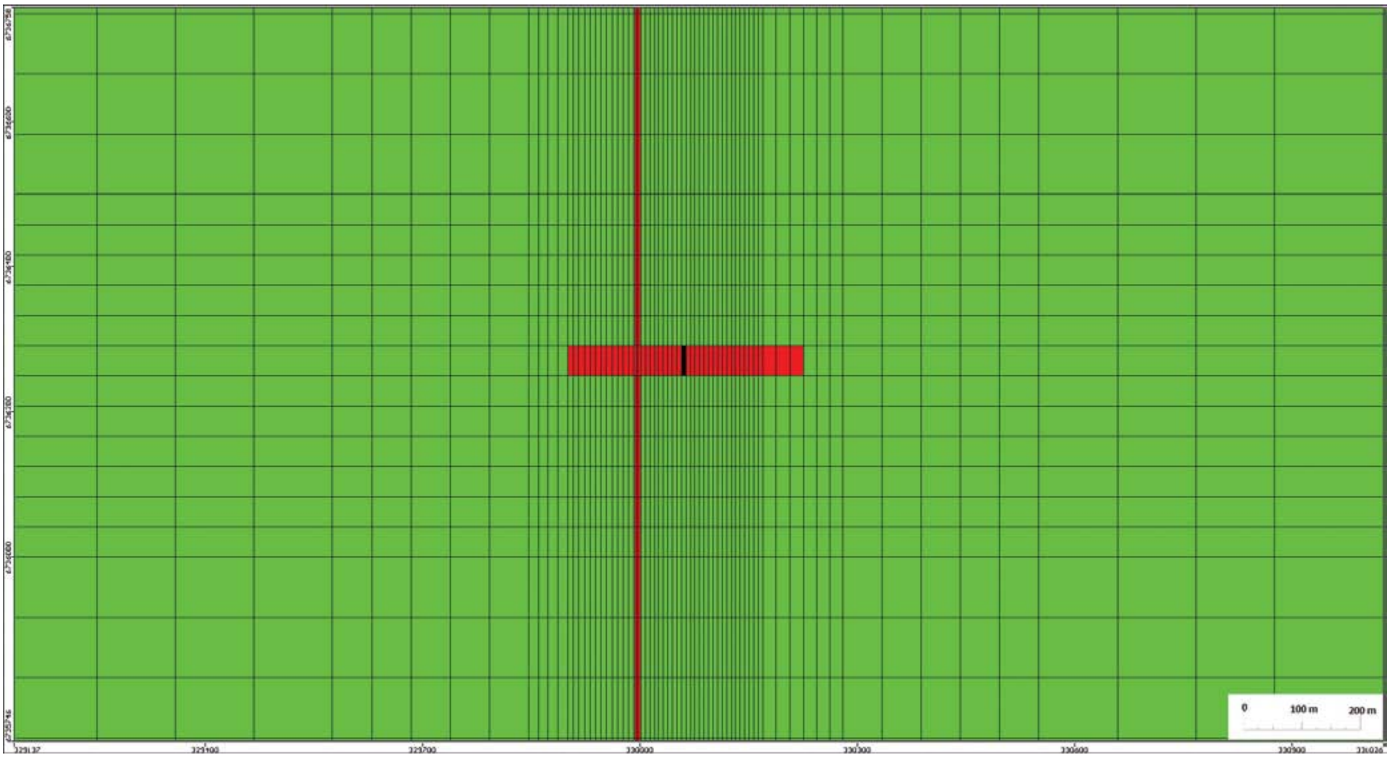


Figure 2. Model grid in XY plane. The red zone is the extent of the modelled fractured area

The northern, southern and eastern boundaries of the model act as no-flow boundaries. The western edge of the model extends 10 km past the coastline. The final calibrated hydrogeological parameters are presented in Table 1 based on GHD (2011).

The numerical model grid consists of 140 columns and 42 rows with refinement near the fault and the hydraulic fracturing target zone in shale (Fig. 2) resulting in a total of 276 360 cells in the 3D model. The grid refinement helps in assigning a section of higher hydraulic conductivity and storativity to represent the fractured zone. The hypothetical fault is placed within the fractured zone to simulate a worst case scenario. The fault is also assigned a higher conductivity and storativity similar to that of the fractured zone.

Simulation methodology

The model was run using the multispecies, density and temperature dependent MODFLOW-SEAWAT code. SEAWAT is a coupled version of MODFLOW and MT3DMS and is designed to simulate three dimensional, variable-density, saturated groundwater flow (Langevin et al. 2008). SEAWAT allows for temperature and viscosity variations.

The simulation is run in three steps. In Step 1, the model is run in steady state conditions without any injection to calculate the initial head values for the next step of the modelling.

Step 2 simulates the HF fluid injection/hydraulic fracturing operation in the Caryngina Formation for six hours. The final model head and concentration outputs are used as initial conditions for Step 3 of the modelling, the purpose of which is to include the flowback operation (30 days) and assess the concentrations of the injected HF fluid over the long term (20 years).

Table 2. PKN and GDK model input parameters

Input data	Magnitude
Injection rate (m^3/min)	9.54
Total time of injection (min)	200
Gross fracture height (m)	82.2
Net fracture height (m)	82.2
Fluid loss coefficient (m/√min)	7.62E-04
Fluid loss spurt volume (m^3)	0
Possion's ratio	0.2
Power law exponent	0.5
Power law coefficient	0.06
Young's modulus (MPa)	2.07E+04
Shear modulus (MPa)	8.62E+03
Closure pressure (S_{hmin}) (MPa)	23.15

Model initial and boundary conditions

A constant rainfall recharge of 100 mm per year was applied over the topmost layer. The model assumed an initial concentration of HF fluid to be 0 mg/l. Salinity of groundwater in the various layers was based on observed values as reported in hydrogeological and petroleum well completion reports. The rate of HF fluid injection was taken from the observed field data from a northern Perth Basin stimulation project. Concentration values were assigned from field observed values in northern Perth Basin operations. The temperature input values were taken from logging while drilling (LWD) logs of a northern Perth Basin well that was drilled to intersect the target shale formations. The temperatures from the logs ranged from 75°C at 2450 m to 97°C at 3400 m. The maximum temperature in the model was assumed to be below 99°C.

Hydraulic fracture propagation modelling

The 2D PKN and GDK fracture models were used to estimate the extent of the hydraulically fractured zone in the shale targets in the northern Perth Basin for a given injection rate. The modelling takes into account the geomechanical properties of shale based on data from northern Perth Basin wells, together with the injection rate, leak off coefficient and likely duration of fracturing (Table 2). The propping parameters such as average proppant size and bulk density of the proppant are not considered in this study, assuming that fractures will maintain their width after treatment and attainment of closure pressure (the pressure at which fractures close and their width becomes zero). Rock elastic properties such as Young's modulus, shear modulus and Poisson's ratio were based on field data. The fluid loss coefficient was derived from calibration.

The injection rate, duration of injection and fluid parameters are the treatment parameters which can be controlled to achieve a desired fracture dimension. The assumed fracture height of 82 m (270 ft) was adopted from analogous hydraulic fracturing operations. The magnitude of minimum horizontal stress (or closure pressure) is added to the resultant pressure from the PKN and GDK model to achieve the net treatment pressure (fracturing pressure).

The Power law exponent (n) defines the type of fluid flow in the fracture. For Newtonian fluids n equals one (n = 1). Here we adopt a non-Newtonian flow to calibrate the results with existing well data in the northern Perth Basin. The effect of injected fluid temperature or reservoir temperature on the fracturing is not incorporated in the modelling. The model outputs are presented in Tables 3 and 4. The fracture efficiency is the measure of the volume of fractures created in relation to the volume of fluid injected. The lower the fracturing efficiency, the higher the leak-off into the surrounding formation.

Due to assumptions about the shape of the cross sectional areas of the PKN and GDK models and the resultant average widths, the fracture length in the GDK model is smaller than the length estimated by the PKN model for the same fracture treatment. Other than 2D fracture propagation modelling for which the initial assumption of fracture height is required as an input to the model, more advanced pseudo-3D and 3D hydraulic fracture models are able to predict the fracture height in addition to its width and length. In-situ stresses and rock properties also greatly affect the geometry of the fracture. The fracture containment or vertical growth of the fracture is also affected by in-situ differences between the pay zone and bounding layers (in-situ stress contrasts in layered formations).

Table 3. PKN modelling results

Time (min)	Max width (cm)	Average fracture width (cm)	Fracture half-length (m)	volume (m^3)	Efficiency (%)	Pressure (MPa)
20	1.24	0.76	156.70	98.15	51.45	24.83
40	1.42	0.89	239.36	173.64	45.51	25.09
60	1.55	0.97	306.68	242.44	42.36	25.26
80	1.65	1.02	365.64	307.21	40.26	25.39
100	1.73	1.07	419.06	369.15	38.70	25.49
120	1.80	1.12	468.46	428.92	37.47	25.58

Table 4. GDK modelling results

Time (min)	Max width (mm)	Average fracture width (mm)	Fracture half-length (m)	Volume (m^3)	Efficiency (%)	Pressure (MPa)
20	4.8	3.8	33.64	10.53	55.22	24.11
40	11.9	9.4	129.07	99.04	47.20	24.83
60	15.0	11.9	185.14	180.68	45.10	25.11
80	17.5	13.7	229.95	259.32	43.85	25.30
100	19.3	15.2	268.61	335.98	42.96	25.43
120	21.1	16.5	303.21	411.15	42.26	25.56

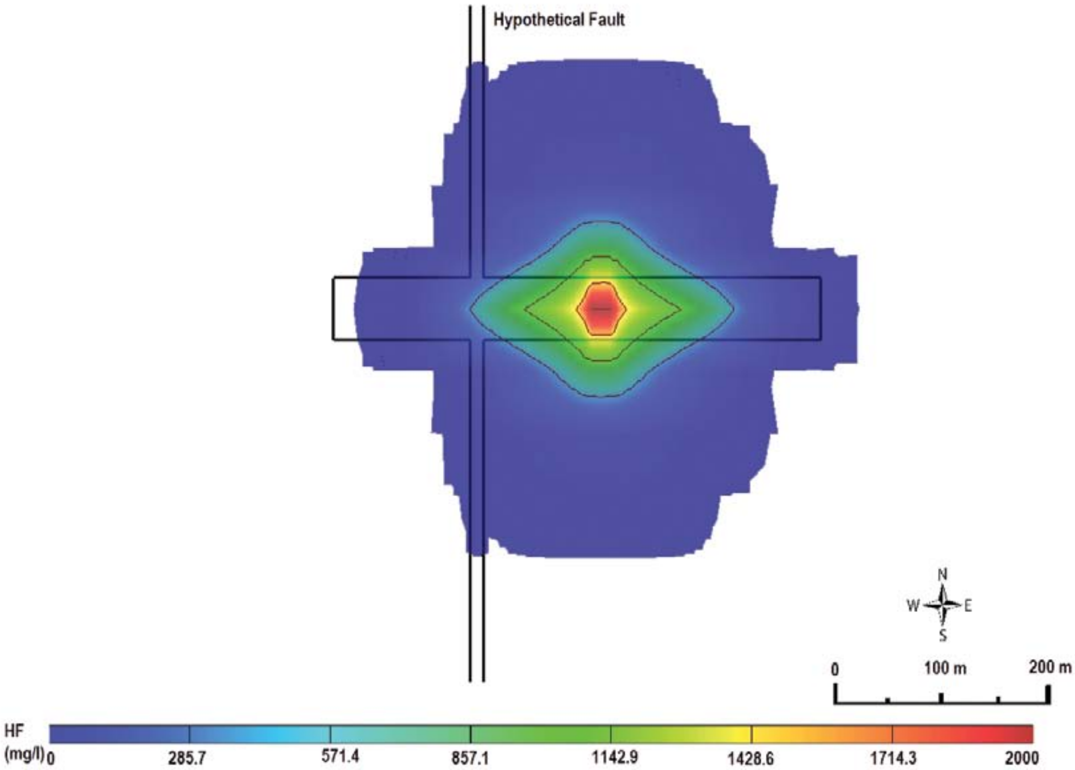


Figure 3. Simulation output at the end of HF stimulation operation (plan view)

The model incorporated the hydraulically fractured zone by increasing the grid resolution around the wellbore and also assigning scaled up properties to this zone; this zone is about 200 m in half-length, 5 m in width and 4 m in thickness. Model properties were scaled down taking into account the larger volume of the simulated fractured zone compared to the actual modelled using the PKN/GDK methods, and the values assigned are given in Table 5.

Simulating flowback

As a part of the fracture stimulation process, injection is followed by flowback of the injected fluid together with some formation water, which starts immediately after the release of the high injection pressure in the well. Theoretically, recovering all the fracturing fluids injected into the target zone is desirable to create better gas production rates. There are several factors affecting recovery of hydraulic fracturing fluids injected into target formations. These factors could include fluid leak-off into the formation, check-valve effect, chemical reactions, adsorption and mixing of fracturing fluids. Operational data from the northern Perth Basin show that the flowback recovery varies from 45% to 85% of the injected volumes with an average of about 60%.

Flowback was simulated in the model using the MODFLOW Drain package. The Drain package removes water from the model based on the drain elevation, d (L) and drain hydraulic conductance, Cd (L2T-1) that are assigned to a drain cell, and the modelled hydraulic head, h (L) in the drain cell. When the hydraulic head (h) in a drain cell is greater than the drain elevation, water flows into the drain and is removed from the groundwater model. The rate of water removed by the drain Qd is calculated by:

Qd = Cd x (h – d).

For the purpose of this modelling, the drain cells were activated after six hours of hydraulic fracturing for around 30 days so that flowback could take place. This drain conductance was iteratively adjusted to calibrate the flowback with the observed field data.

Table 5. Scaled hydraulic properties assigned to fractured zone cells

Property	Value
Hydraulic conductivity	1 (m/d)
Specific storage	0.001 (1/m)
Specific yield	0.05

Modelling results and discussions

The model predicts that at the end of the hydraulic fracturing stimulation period (six hours), the HF fluid would spread through the created fracture network. An output cut-off concentration of 0.01 mg/l was used purely for visual purposes. Laterally, the fraccing fluid reached 115 m in half-width in the east–west direction and extended to a half-length of 150 m in the north–south direction after six hours (Fig. 3). Towards the end of the stimulation operation, the HF fluid reaches a maximum of 45 m in vertical height from the zone of injection.

The model also predicted that though the fluid was injected in the vicinity of a transmissive hypothetical fault, the HF fluid concentration did not increase along the fault. This finding is important since potential for contamination of shallow aquifers by upward migration of fraccing fluid along conductive faults and fractures is a common concern. The concentration of HF fluid reduced rapidly with distance from the wellbore, with high concentrations constrained to the proximity of the wellbore (approximately 40 m from the wellbore, laterally, and 2 m, vertically) (Figs 3 and 4).

The model was used to simulate the post injection behaviour of the fraccing fluid including flowback. The simulation showed that the concentration of the fraccing fluid close to the wellbore declined sharply to 250 mg/l. Towards the end of flowback operations, the lateral extent of the plume was 240 m and 170 m in the east–west and north–south directions, respectively, based on a 0.1 mg/l cut-off concentration. The 30 day image (first image in Figure 5) shows the plume extent at the end of the flowback operation. The cross sectional view of the 30 day image (first image in Figure 6) does not indicate any significant vertical migration along the fault.

The simulation was modelled for a period of 20 years, and the resulting concentrations and plume extents are shown in Figures 5 and 6. The maximum lateral extent of the injected HF fluid was 217 m in the east–west direction, and was attained in five years (Fig. 5). The plume extent in the north–south direction remained at 170 m, similar to its extent at the end of the fraccing. This is likely due to groundwater flow direction being predominantly in the east–west direction. The concentration of the HF fluid, however, reduced sharply in the first month and thereafter gradually to about 200 mg/l at the wellbore.

The cross sectional view of the simulation output is shown is Figure 6, which shows the vertical extent of the model with respect to the top of the targeted Caryngínia Formation. The HF fluid is contained well below the top of the injected formation throughout the simulation period.

The predicted concentrations would have been much lower, had this study taken into account formation water extraction as part of well test and production phases, subsequent to the HFS and flowback operations.

Calibration and sensitivity analysis

As the model used the hydraulic parameters from the shallower strata from an existing model (GARAMS), the calibration effort was minimal. However, for the deeper layers, no transient head data was available. Calibration was attempted by comparing observed and modelled flowback data through manual adjustment of the hydraulic input parameters, which included the manual variation of the drain conductance. The simulated flowback rate of 67% compared well with the observed flowback rate of 51% to 62%.

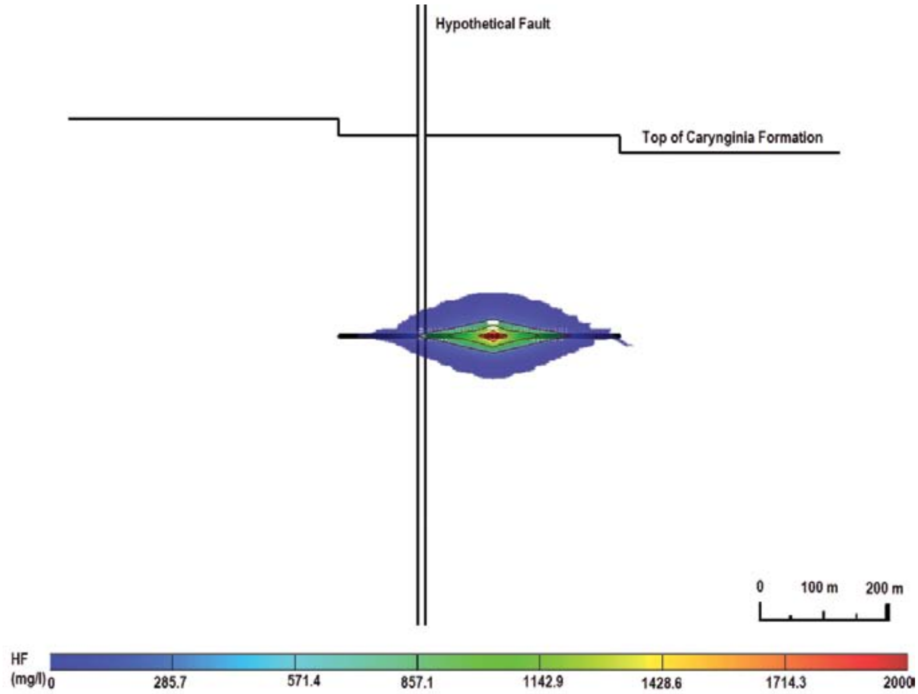


Figure 4. Simulation output at the end of HF stimulation operation (cross sectional view)

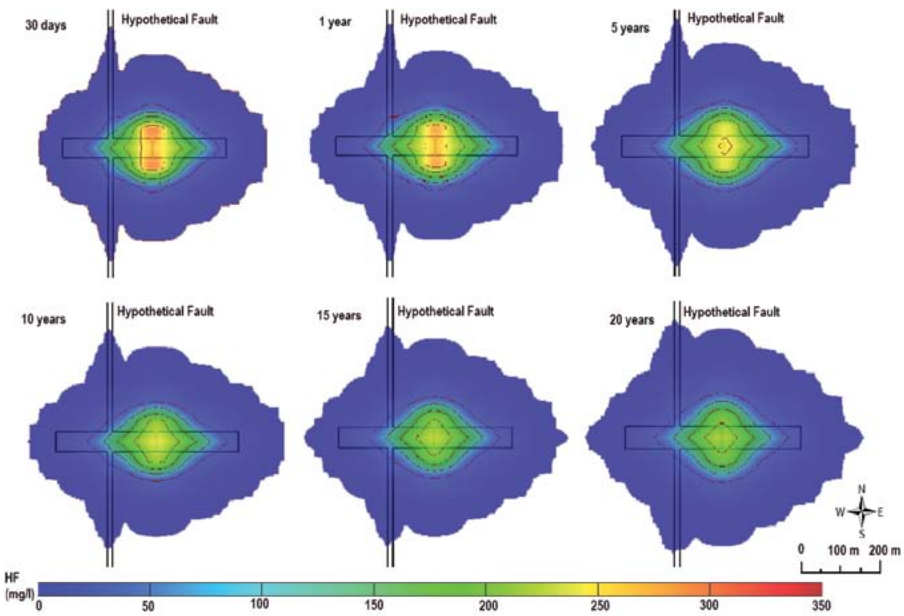


Figure 5. Simulation results (30 days to 20 years) (plan view)

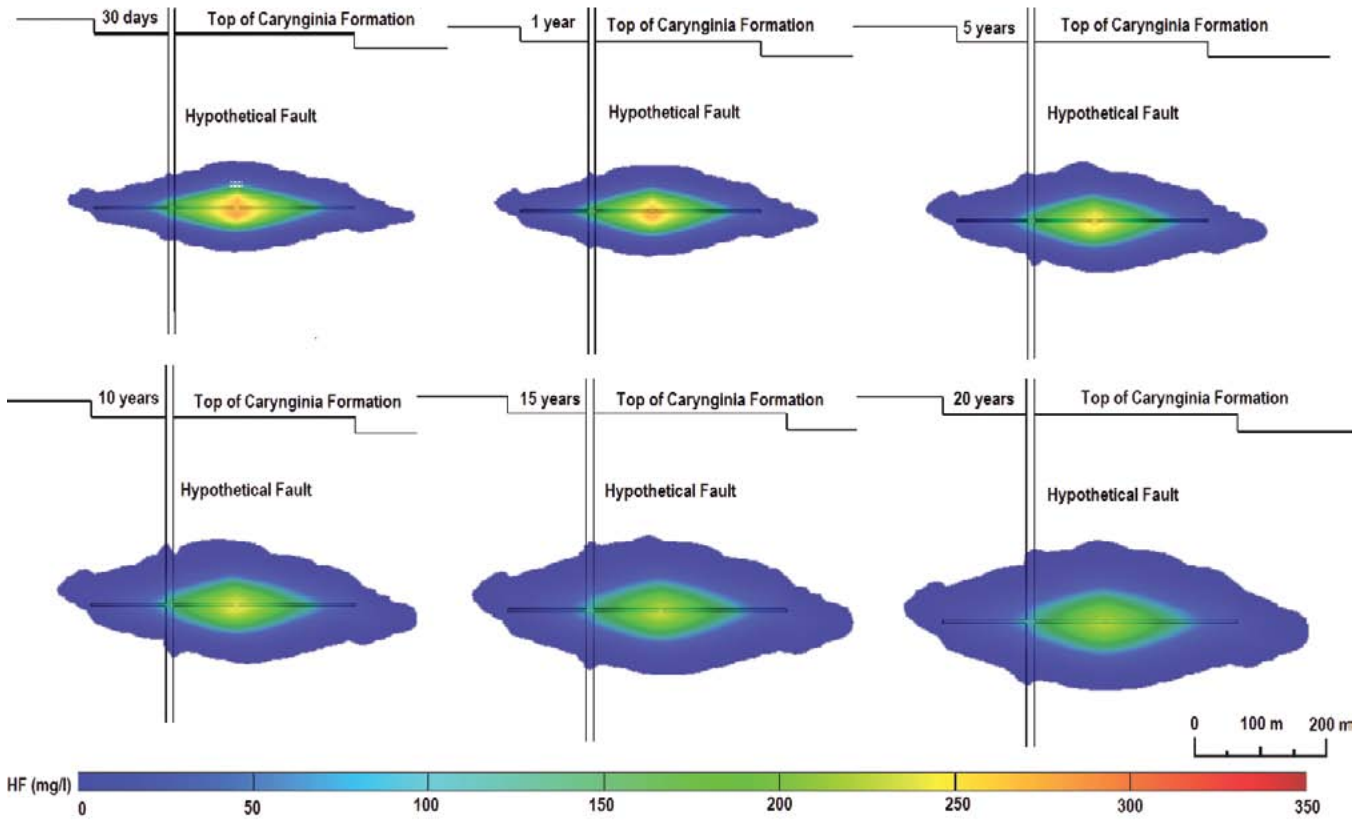


Figure 6. Simulation results (30 days to 20 years) (cross sectional view)

A sensitivity analysis was performed by varying the hydraulic parameters and monitoring the simulated hydraulic heads. The sensitivity analysis indicated that the model is sensitive only to pumping rate, concentration of injected fluid and specific storage of the fractured network and the shale formation.

Increasing the conductivity of the fractured network by an order of magnitude decreased the maximum concentration at the well bore from 200 mg/l to 20 mg/l in 20 years; while the plume extent increased slightly by 60 m half-length (using an adopted 0.01 mg/l concentration cut-off). Increasing the specific storage by two orders of magnitude decreased the maximum concentration at the well bore from 200 mg/l to 70 mg/l, and the plume extent increased by 25 m in half-length over the 20 years simulation time. The rate of flowback was found to be sensitive to the rate of injection. When the rate of injection was increased by 15%, the plume extent remained the same as the base case, and the maximum concentration was found to be 200 mg/l at the well bore. However, the rate of flowback at the end of 30 days increased by 9% to a recovery rate of 71.4%.

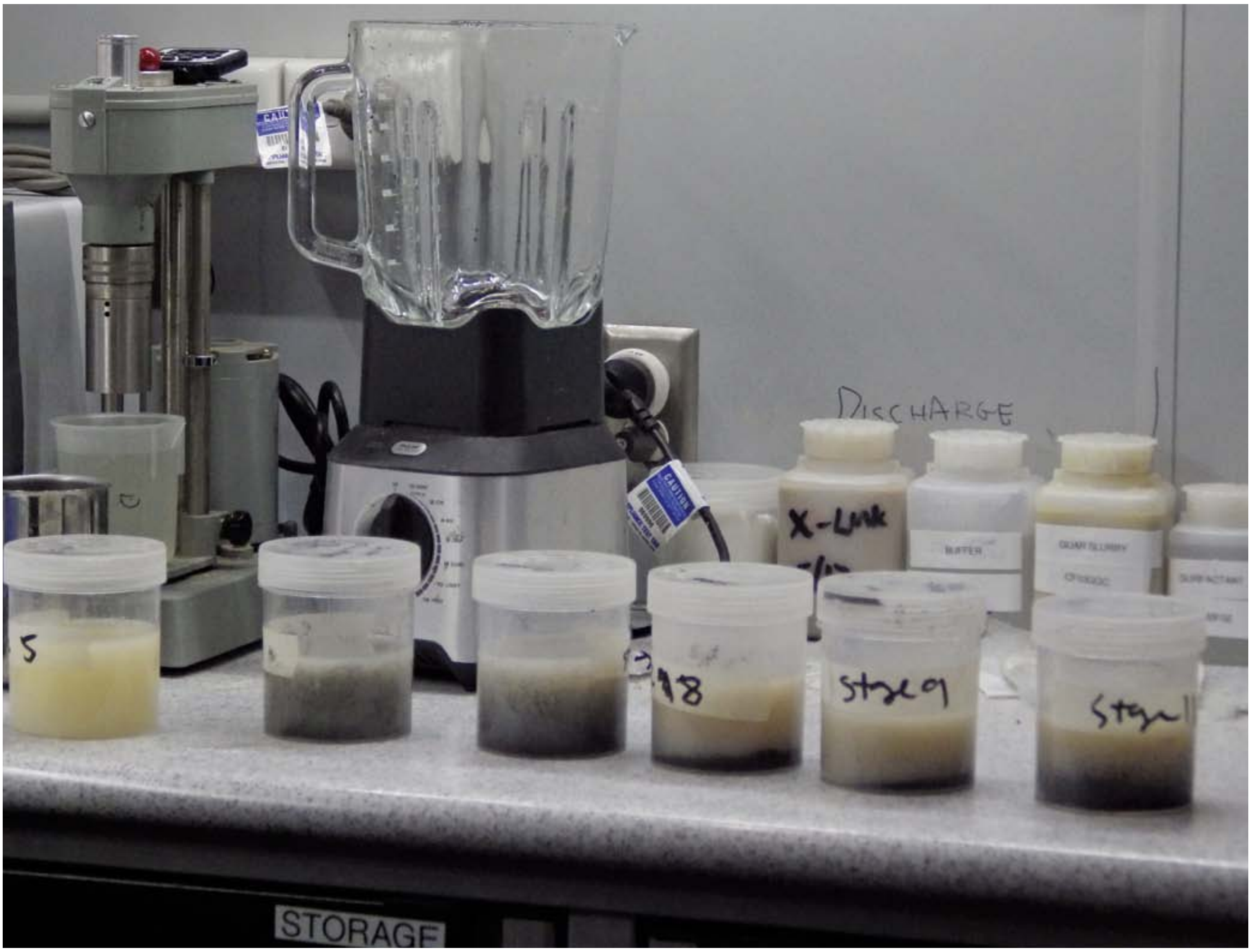
Human risk-based concentrations for additives

A study was undertaken by Gradient Corporation in 2012 for Halliburton Energy services (Gradient Corporation 2012) into human health risk from commonly used additives in HF stimulation operations. The report, which was based on toxicology information, tabulated commonly used additives and respective concentrations above which they may cause health effects in the long term. In the report, these concentrations are termed Risk Based Concentration (RBC).

We have identified additives used for stimulation purposes in the northern Perth Basin and compared the RBC at 200 mg/l (average plume) concentrations. The comparison is provided in Table 6 and shows that all but one of the additives remains below the RBC.

Table 6. Risk-based concentration comparison

Additive	RBC concentration of the additive in 200 mg/l HF fluid (µg/l)	RBC (µg/l)
A	40	1000
B	100	7800
C	1	3500
D	20	499,800
E	90	260
F	60	460
G	120	105
H	20	350,000



HF fluids being tested for flow properties

Conclusions

A 3D numerical solute transport model of an area of the northern Perth Basin has been developed and applied to simulate HF fluid injection and migration and post-injection flowback.

The model predicts that the HF fluid plume will be contained in close proximity to the injection well, and the fluid concentration will decrease sharply at a close distance from the well. The model also predicts that injecting near the fault will not induce a significant upward flow of the HF fluid, with concentrations decreasing rapidly with height. The maximum concentration of the HF fluid declined to well below the human risk-based concentration of the critical constituents within one year. Therefore, hydraulic fracture stimulation impacts during shale and tight gas development on potable groundwater sources in the northern Perth Basin are low.

A model sensitivity analysis showed that the plume extent is mostly sensitive to hydraulic conductivity of the fractured zone, specific storage and the rate of HF fluid injection.

This study does not consider the effects of formation water extraction as part of the well test and production phases, subsequent to HFS and flowback operations. The predicted concentrations would have been much lower, had this study taken into account formation water extraction as part of the well test and production phases, subsequent to the HFS and flowback operations.

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Grant of titles

Justin Donnelly
Senior Titles Officer
Petroleum Tenure and Land Access Branch

Drilling in EP 455 in 2014

State Awards

From mid July 2015 to February 2016 the following titles were awarded in State areas.

Petroleum Exploration Permit (Renewal)

On 18 January 2016 the first renewal of petroleum exploration permit EP 455 was granted to AWE Perth Ltd and Titan Energy Ltd over an area of 296.90 km^2 within the Perth Basin. The estimated expenditure for the first two years of the renewal period is $250,000 with the firm work program including the reprocessing of 150 km of 2D seismic data from historical surveys conducted over the area and geotechnical, geological and geophysical studies to integrate data acquired from the Dover 1 exploration well drilled 2014. The work program for the remaining three years of the renewal period will include geological and geophysical studies to identify a drillable target for the proposed exploration well in the fifth year of the renewal period. The estimated expenditure for these remaining three years is $5,200,000.

Petroleum Retention Lease (Renewal)

On 8 October 2015 the first renewal of petroleum retention lease R 4 was granted to Chevron (TAPL) Pty Ltd, Chevron Australia Pty Ltd, Santos Offshore Pty Ltd and Mobil Australia Resources Company Pty Limited. R 4 contains the Pascoe field and comprises an area of 2.07 km^2 to the south of Barrow Island over the Pascoe and Boodie Islands, and a portion of Middle Island. The first four years of the work program for R 4 includes engineering, marketing and commercial studies progressing to planning in the fifth year for the possible development of the Pascoe field. Total expenditure for the five year work program is $460,000.

Petroleum Pipeline Licences

Petroleum Pipeline Licence PL 110 was granted on 15 October 2015 for the Onslow Lateral Pipeline in the Northern Carnarvon Basin to convey gas from the Ashburton West facilities to the Ashburton Onslow Gas Pipeline Meter Station adjacent to the Onslow Power Station.

Petroleum Pipeline Licence PL 111 was granted on 20 November 2015 for the Waitsia Gas Project Pipeline in the Perth Basin to convey gas from the Senecio 3 and Waitsia 1 wells northern hub to the Xyris Production Facility supporting the L 1 and L 2 petroleum production licences.

Commonwealth Joint Authority Awards

From mid July 2015 to February 2016 the following titles were awarded in Commonwealth Joint Authority areas.

Special Prospecting Authorities and Access Authorities

Access Authority WA-81-AA was issued to Chevron (TAPL) Pty Ltd, Chevron Australia Pty Ltd, Chubu Electric Power Gorgon Pty Ltd, Mobil Australia Resources Company Pty Limited, Osaka Gas Gorgon Pty Ltd, Tokyo Gas Gorgon Pty Ltd and Shell Australia Pty Ltd to 01 October 2015 to conduct the Gorgon Ocean Bottom Node Survey 2015 marine seismic survey.

Access Authority WA-82-AA was issued to Kansai Electric Power Australia Pty Ltd, Tokyo Gas Pluto Pty Ltd and Woodside Burrup Pty Ltd on 10 August 2015 to conduct the Pluto 2015 4D marine seismic survey.

Special Prospecting Authority WA-36-SPA and Access Authority WA-80-AA were issued to Spectrum Geo Pty Ltd on 17 July 2015 to conduct the Rocket MC 2D MSS 2015 Phase 1 and Rocket MC 2D MSS 2015 Phase 2 marine seismic survey.

Special Prospecting Authority WA-37-SPA and Access Authority WA-83-AA were issued to Searcher Seismic Pty Ltd on 22 January 2016 to conduct the Bilby Phase 3 2D marine seismic survey.

Petroleum Exploration Permits

Petroleum Exploration Permit WA-517-P located within the Bight Basin off the south coast of Western Australia was granted to JX Nippon Oil and Gas Exploration (Australia) Pty Ltd and Santos Offshore Pty Ltd on 10 August 2015 over release area W14-9.

Petroleum Exploration Permit WA-518-P located within the Northern Carnarvon Basin off the northwest coast was granted to Hess Australia (Karratha) Pty Limited on 18 September 2015 over release area W14-10.

Petroleum Exploration Permit WA-519-P located within the Northern Carnarvon Basin was granted to Hess Australia (Pilbara) Pty Ltd on 18 September 2015 over release area W14-2.

Petroleum Exploration Permit WA-520-P within the Northern Carnarvon Basin was granted to Finder No 10 Pty Limited on 21 September 2015 over release W14-17.

Petroleum Retention Leases

Petroleum Retention Lease WA-59-R was granted to Finder No 4 Pty Limited and Quadrant Northwest Pty Ltd over the Olympus gasfield on 13 August 2015.

Petroleum Retention Lease WA-60-R was granted to Chevron (TAPL) Pty Ltd, Chevron Australia Pty Ltd, Mobil Australia Resources Company Pty Limited and Shell Australia Pty Ltd over the Yellowglen gasfield on 31 August 2015.

Petroleum Retention Lease WA-61-R was granted to BHP Billiton Petroleum (North West Shelf) Pty Ltd over the Jupiter gasfield on 26 November 2015.

Petroleum Retention Lease WA-62-R was granted to BHP Billiton Petroleum (North West Shelf) Pty Ltd over the North Scarborough gasfield on 26 November 2015.

Petroleum Retention Lease WA-63-R was granted to BHP Billiton Petroleum (North West Shelf) Pty Ltd over the Thebe (WA-346-P) gasfield on 26 November 2015.

Petroleum Retention Lease WA-64-R was granted to Chevron Australia (WA-364-P) Pty Ltd and Shell Australia Pty Ltd over the Bederode gasfield on 16 December 2015.

Petroleum Retention Lease WA-65-R was granted to Chevron Australia (WA-364-P) Pty Ltd and Shell Australia Pty Ltd over the Eendracht gasfield on 16 December 2015.

Petroleum Retention Lease WA-66-R was granted to Chevron Australia (WA-365-P) Pty Ltd and Shell Australia Pty Ltd over the Kentish Knock gasfield on 16 December 2015.

Petroleum Retention Lease WA-67-R was granted to Chevron Australia (WA-365-P) Pty Ltd and Shell Australia Pty Ltd over the Scarborough (WA-365-P) gasfield on 16 December 2015.

Petroleum Retention Lease WA-68-R was granted to Chevron Australia (WA-365-P) Pty Ltd and Shell Australia Pty Ltd over the Thebe gasfield field 16 December 2015.

Petroleum Retention Lease WA-69-R was granted to Eni Australia B.V. over the Penguin gasfield 25/01/2016.

Petroleum Retention Leases (renewal)

The renewal of Petroleum Retention Lease WA-1-R was granted to BHP Billiton Petroleum (North West Shelf) Pty Ltd and Esso Australia Resources Pty Ltd on 2 November 2015.

The renewal of Petroleum Retention Lease WA-33-R was granted to Santos (BOL) Pty Ltd, Tap (Shelfal) Pty Ltd, Hydra Energy (WA) Pty Ltd and Quadrant Oil Australia Pty Limited on 21 September 2015.

The renewal of Petroleum Retention Lease WA-34-R was granted to Encana International (Australia) Pty Ltd, Eni Australia B.V., SK Innovation Co. and Ltd and Tap (Bonaparte) Pty Ltd on 23 December 2015.

Petroleum Production Licences

Petroleum Production Licence WA-57-L was granted to BHP Billiton Petroleum (North West Shelf) Pty Ltd, BP Developments Australia Pty Ltd, Chevron Australia Pty Ltd, CNOOC NWS Private Limited, Japan Australia LNG (MIMI) Pty Ltd, Woodside Energy Ltd. and Shell Australia Pty Ltd over the Pemberton/Lady Nora oil- and gasfield on 3 February 2016.

Petroleum Production Licence WA-58-L was granted to BHP Billiton Petroleum (North West Shelf) Pty Ltd, BP Developments Australia Pty Ltd, Chevron Australia Pty Ltd, CNOOC NWS Private Limited, Japan Australia LNG (MIMI) Pty Ltd, Woodside Energy Ltd and Shell Australia Pty Ltd over the Pemberton/Lady Nora oil- and gasfield on 3 February 2016.

Radiogenic heat generation in Triassic and Permian sediments of the Perth Basin

Mike F Middleton
General Manager Resources Branch
Petroleum Division

Core from Arrowsmith 2

Introduction

Lewan and Buchardt (1989) explored the possibility of petroleum generation from black shales through radiation damage from higher than normal concentrations of naturally occurring radioactive minerals (NORMs) within petroleum source rocks. Spectral gamma-ray logs and gamma-ray spectrometer readings of rocks in the Perth Basin, and surrounds, adds to the potential to explore their proposition. The most recent study relating organic maturity to in-situ radioactivity was by Aliyev et al. (2006), which was only able to recognise broad cyclic correlations, probably owing to low levels of in-situ radioactivity. This article presents data that influences our understanding of both shale oil and gas, hydrocarbon generation potential and geothermal regimes in the Perth Basin.

Spectral gamma-ray logs have been run in a select number of wells in the Perth Basin by the petroleum industry, and gamma-ray spectrometer measurements have been carried out for surrounding granitioid rocks by the Department of Mines and Petroleum (DMP). These granitoid rocks are commonly considered to form the 'basement' of the Perth Basin (Middleton 2013; Middleton et al. 2014). Further, these data suggest that the Perth Basin sediments may contribute significantly to local terrestrial heat flow, and also perhaps indicate a provenance source for the sediments.

From 2011 to 2015, the Petroleum Division of DMP has conducted studies of heat generation in rocks surrounding the Perth Basin as part of its campaign to understand heat flow in the basin to support its regulatory role in administering the *Petroleum and Geothermal Energy Resources Act 1967* (PGERA67) in Western Australia. While interest in geothermal energy peaked in 2012 and 2013 (with 42 geothermal exploration permits existing throughout the State), it declined in 2014. In 2016, the climate for geothermal energy appears to be growing again. This interest in geothermal energy is also supported by the realisation that the same technology to understand heat flow and geothermal energy may be applicable to shale oil and gas reservoirs in the Perth Basin. It is also important to recognise, at this stage, that the observations of this study are intended to be applied only to the Perth Basin.

Association of radiogenic minerals with organic matter

NORMs have been variously reported to occur in conjunction with organic matter in petroleum source rocks, mostly black shales, but this is not always the case. Often reported in the literature is the association of uranium with organic matter in the Alum Shale of Scandinavia (Lewan and Buchardt 1989; Solymar 1997). Figure 1 shows in situ oil dripping from an outcrop of Alum Shale at Kinnekulle in Sweden; at this locality, Lewan and Buchardt (1989) record uranium concentrations ranging from 150 to 440 parts per million (ppm) and thorium from 8 to 12 ppm, with Total Organic Carbon (TOC) in the range of 13 to 23%. Solymar (1997) reported a uranium concentration of 21.7 ppm in an Alum Shale sample with a TOC of 3.2% at a location (Lilljuthatten) in northern Sweden. Lewan and Buchardt (1989) strongly emphasise that a relationship between organic matter and uranium does not universally exist, and point out that this does not happen in the Chattanooga Shale, Woodford Shale or Black Sea sediments.

Figure 1. In situ oil dripping from an outcrop of the Alum Shale in Sweden

Lewan and Buchardt (1989) examined the hypothesis that radiation damage from higher than normal radioactive irradiation in organic-rich sediments may enhance the generation of petroleum. They estimated that a radiation dosage of 1 x 10^{11} μR (1 x 10^{5} Mrads), where R is the unit of a Roentgen, may facilitate radiation damage in organic sediments, but from their analyses concluded that this damage did not break down large carbon chains, instead causing aromatisation and cross-linking of carbon chains. Very little work has been published in this field since their 1989 paper.

This article now reviews radioactivity within Perth Basin organic-rich sediments, and especially the Triassic-aged Kockatea Shale and Permian-aged Carynginia Formation (Fig. 2), and investigates the possible existence of any correlation with radioactivity of the sediments and surrounding basement rocks. These formations are being investigated because they constitute some of the best source rocks in the basin as well as the most prospective for potential shale gas and/or oil plays.

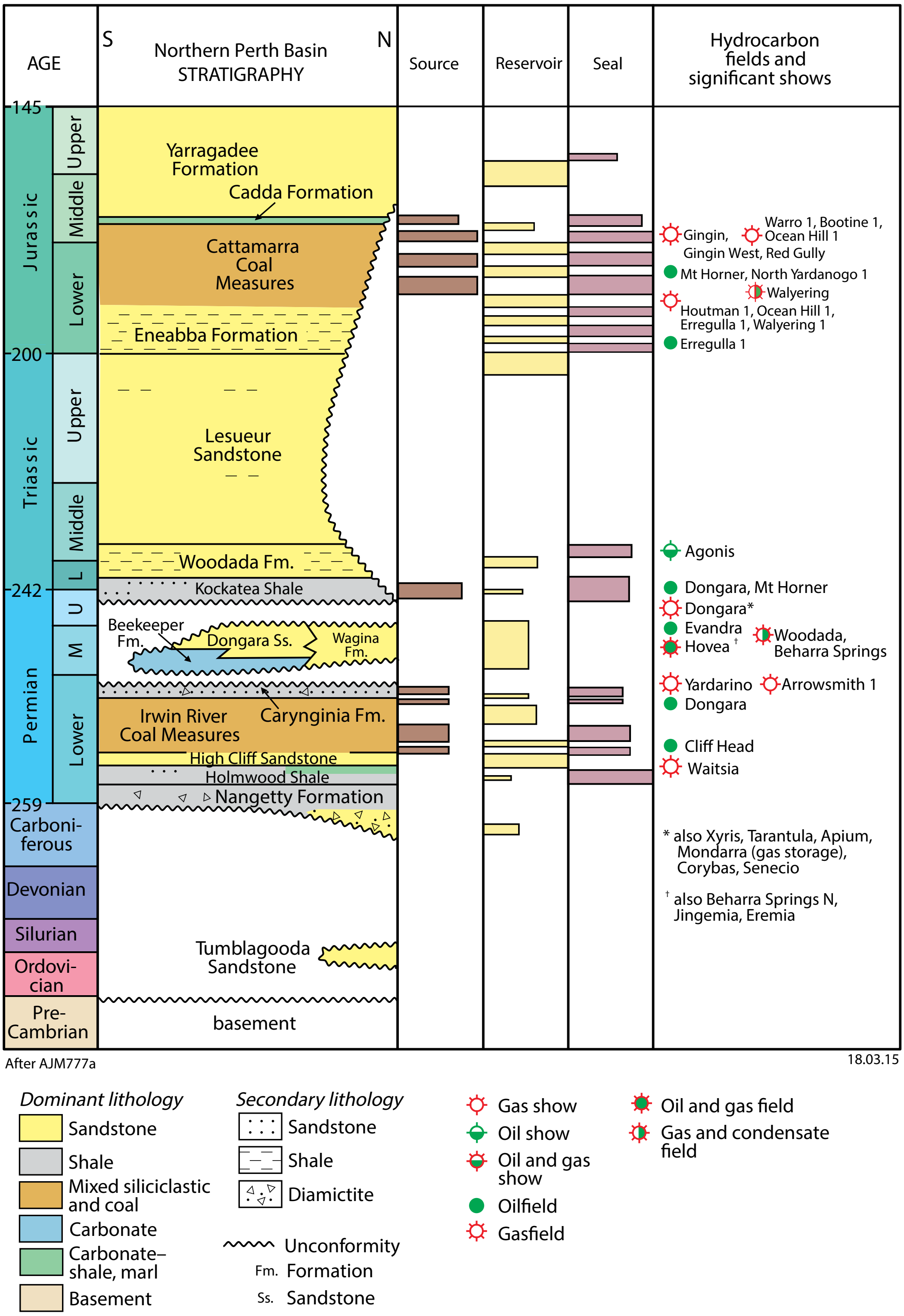

Figure 2. Relevant stratigraphy of the Perth Basin

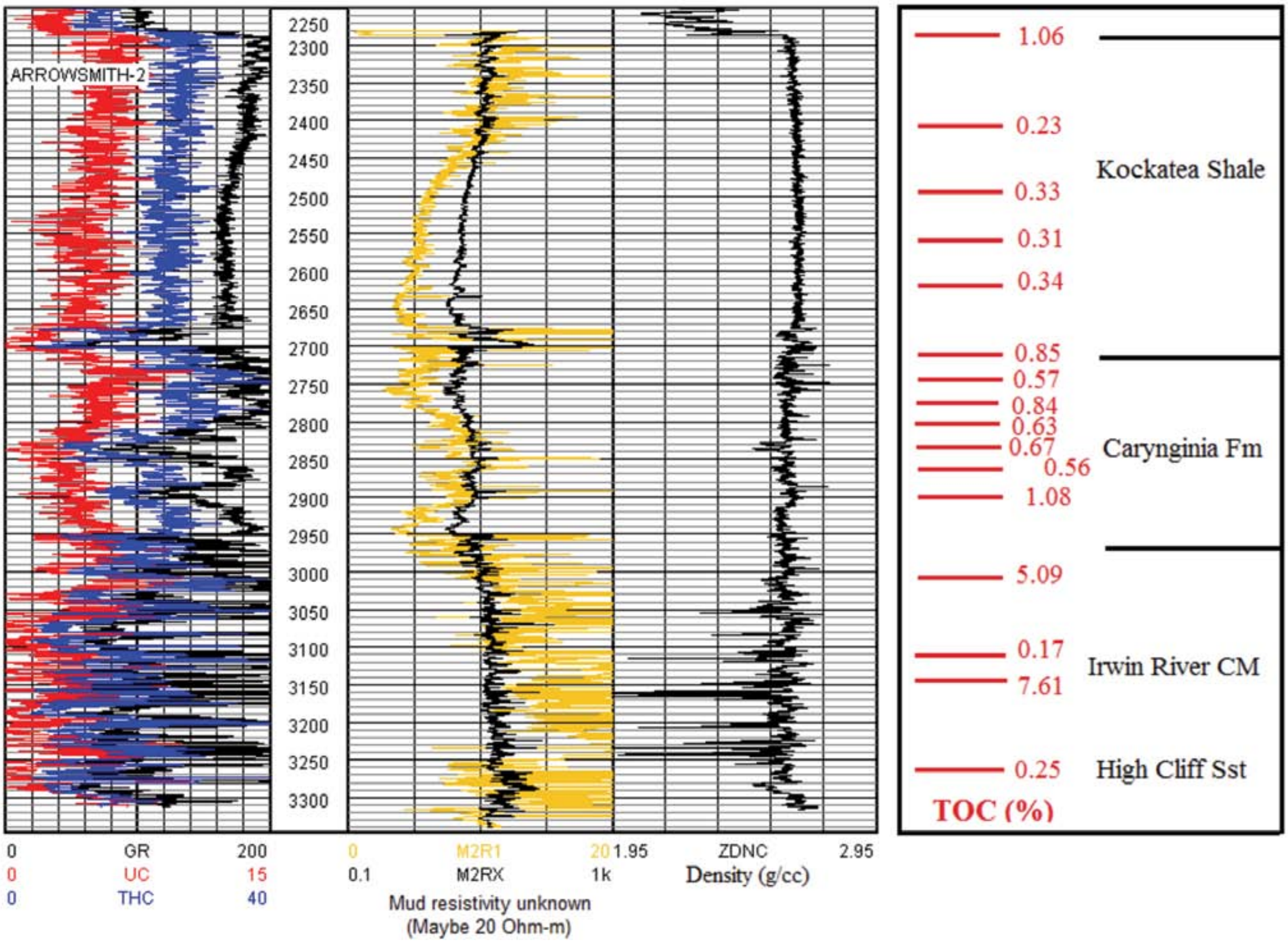

Figure 3. Data from the Arrowsmith 2 well (source: WAPIMS DMP)

Spectral gamma-ray logs in the Perth Basin

Spectral gamma-ray measurements detect gamma rays with specific emission energies, which relate to the elemental sources of the gamma-ray emissions. Such measurements are often carried out in petroleum wells, using wireline logging. These gamma-ray emissions detected in the logging instruments can be related to the concentrations of uranium (U), thorium (Th) and potassium (K) in the rock that has sourced them. It is known that the U, Th and K concentrations in the source rock are related to heat generation (A) by the simple formula:

$$Ao = 0.26 (U) + 0.07 (Th) + 0.1 (K)$$

where U and Th are in parts per million (ppm) and K is in percent (%) (Beardsmore and Cull 2001; Middleton 2013). Figure 3 shows a typical spectral gamma-ray log for the northern Perth Basin.

In Figure 3, wireline log data are plotted for the Arrowsmith 2 well. The plot shows spectral gamma-ray data (panel 1), shallow resistivity data in yellow and deep resistivity data in black (panel 2), density data (panel 3) and TOC % data (panel 4). Some samples measured for organic richness (TOC) are relatively high (> 1 %), especially in the Irwin River Coal Measures, and others quite low (< 0.3 %). However, there appears to be no obvious correlation between organic richness and radiogenic elements in this part of the Perth Basin.

Figure 3 also reflects an overview of the timing of the sedimentary deposition in the northern Perth Basin during the Permian and Triassic periods. The density (panel 3; in tonnes/m^3 = g/cc) of the sediments remains high throughout the Permian, and decreases upon cessation of deposition of the Early Triassic aged Kockatea Shale. This seems to suggest that the gross physical composition of the sediments does not correlate to their radiogenic mineral content. The 7.61% TOC value reflects the presence of coal, which is confirmed by the low spike in the density log.

What is worthy of remark is that the radiogenic content of the Kockatea Shale and Caryngina Formation commonly contains a very high concentration of uranium (> 7 ppm) and thorium (> 35 ppm). However, there is no obvious correlation observed between radiogenic content of the sediments and their TOC.

Correlation between heat generation and provenance for the Perth Basin

It has been proposed that the provenance of Permo-Triassic sediments in the Perth Basin is from the south, along a north-south oriented rift between the Australian Plate and the Greater Indian Plate. Essentially, there appears to have been a sediment source in the southwestern corner of Western Australia and Antarctica, where erosion occurred before and during continental breakup (Mory and Haines 2013).

Figure 4 shows a plot of heat generation (Ao), based on the above equation, and conventional gamma-ray log versus depth for Arrowsmith 1 and 2. The correlation is extraordinary in its consistency. Wellman and Reid (2014) suggested that Permo-Triassic sediments in the Perth Basin may have a heat generation of about 1 μW/m^3, which is reasonable based on global sedimentary averages (mauve zone, Figure 4). However, the spectral gamma-ray logs indicate that the heat generation in the Kockatea Shale and Carynginia Formation is in the range of 3.5 to 5.0 μW/m^3, which is up to five times greater than the global average.

It is not definitely known if the high concentrations of U and Th in the Permo-Triassic sediments are caused by the presence of these elements in transported sediments or by percolation of radioactive-rich fluids after, or during, deposition. A clue is found in the radiogenic content of the basement granitoid rocks of the Leeuwin Complex, which Middleton et al. (2014) showed to possess U and Th concentrations about five times greater than the more northerly basement granitoids surrounding, and assumed to be underlying, the Perth Basin. It would seem reasonable to conclude that the source of the radioactive-rich Permo-Triassic shales in the Perth Basin was derived from the vicinity of the Leeuwin Block granitoids to the south.

Radiation dosage and alteration of organic matter

Lewan and Buchardt (1989) investigated the ability of the presence of radiogenic elements and minerals to irradiate and damage organic molecules with resulting production of moveable petroleum or facilitation of primary migration. They concluded that certain types of radiation damage can occur, and estimated that radiation dosages of approximately 1 x 10^{11} μR (1 x 10^5 Mrads) are necessary to achieve similar radiation damage as observed in the Alum Shale of Sweden and to cause initial aromatisation of organic molecules.

No conclusive evidence has been found, or perhaps sought, to demonstrate significant breaking or cracking of carbon-chain lengths for uranium concentrations less than 55 000 ppm, which was suggested by Sassen (1983). Sassen (1983) did observe that significantly higher radioactive element (uranium) content can alter the maturation index of vitrinite reflectance, which implies increased petroleum generation. It is uncertain from the study what levels of radiation dosage are required to impact hydrocarbon maturity and generation. The radiation exposure-time factor is essentially unknown, whereas conversely it is well known for thermally altered organic matter.

Radiation dosages in the Perth Basin

It is interesting to investigate the dosages received by the Permo-Triassic sediments in the Perth Basin. The studies of radioactive content of Perth Basin sediments and their surrounding (and inferred underlying) granitoid rocks provide a basis to compare the Perth Basin organic-rich sediments with the studies of the Alum Shale of Sweden. Table 1 shows relevant radiometric and heat generation data for granitoid rocks in the Perth Basin and similar data derived from spectral gamma-ray logs from petroleum wells in the basin. The measured dosage rates are based on DMP field measurements. The derived dosage rates are based on petroleum industry spectral gamma-ray wireline well log data.

Further, in the Perth Basin and surrounding rocks, thorium provides an equivalent radiogenic heat output to uranium (Middleton et al. 2014). Thus, the Perth Basin is significantly different to the Alum Shale of Scandinavia, where U concentrations dominate those of Th. The Th/U ratios (6–18) in Western Australian granitoids possess similar ratios to those found in the Permo-Triassic sediments.

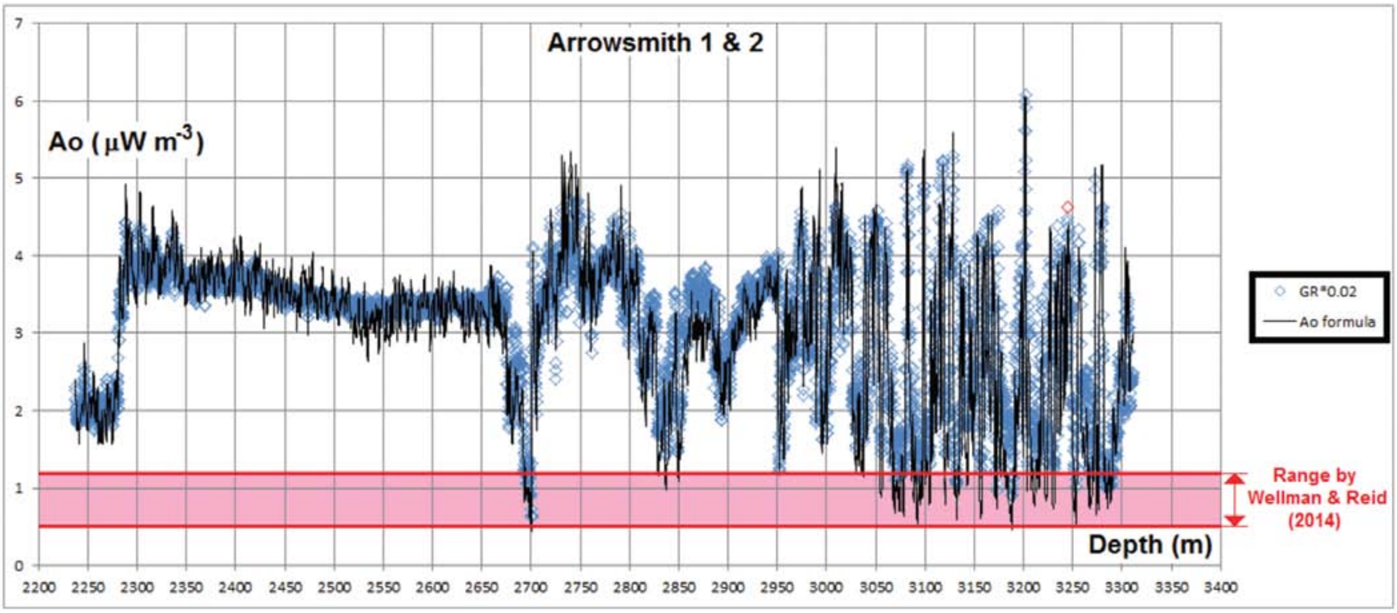

Figure 4. Heat generation versus depth for Arrowsmith 1 and 2. Also shown is the previously assumed heat generation for sediments in the Perth Basin

Table 1. Comparison of estimated radioactive dosage received by Perth Basin sediments versus those of the Alum Shale in Scandinavia. The Perth Basin sediments are estimated to have received a radiation dose of over 100 times greater than that estimated for the Alum Shale by Lewan and Buchardt (1989)

Rock Unit	Measured Dose Rate (μR/hr)	Derived Dose Rates (μR/hr)	Total dose at 240 Ma (μR)	Max Alum Shale Dose (μR) {L & B, 1989}
Dunsborough Granitoid	600	–	1.2×10^{15}	1×10^{11}
Lesmurdie Falls Granitoid	26	–	5.4×10^{13}	1×10^{11}
Parkerville Granitoid	225	–	4.7×10^{14}	1×10^{11}
Kockatea Shale*	–	170	3.5×10^{14}	1×10^{11}
Caryngina Fm*	–	215	4.5×10^{14}	1×10^{11}

* Based on Arrowsmith 2 wireline log data

Lewan and Buchardt (1989) concluded that radioactive-rich fluids circulated through the Alum Shale and were concentrated by certain components within the organic matter; here, the Th/U ratio is approximately 0.03–0.20. The two regimes appear to be quite different, although general conclusions about the radioactive dosages required to alter organic sediments may be still be applicable.

It appears more compelling to hypothesise for the Perth Basin that radiogenic minerals were transported within the sediments in a northerly direction from their provenance to the south of the Perth Basin.

The important question

A number of questions are suggested by these results. However, the overarching unknown and primary question is: has the extra radiation dosage received by the Perth Basin sediments significantly influenced the level of organic maturity of these sediments? Further, can any radiogenic effect influence the development of 'sweet spots' for the entrapment of petroleum in either conventional or unconventional reservoirs? The study of Lewan and Buchardt (1989) suggest that some induced radioactive alteration can occur. However, until the time and radiation-dose behavior of vitrinite reflectance is better known, one can only make conjectures.

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Acreage opens up in the Canning Basin

Richard Bruce
Petroleum Exploration Geologist
Resources Branch

Sundown at the Sundown oilfield, Canning Basin

There is room for more discoveries and new plays in the large intracratonic Canning Basin with its proven Paleozoic petroleum systems. The potential of Western Australia's onshore Canning Basin may be of especial interest to companies active in similar North American Paleozoic basins where there is greater exploration maturity and fewer opportunities for discovering significant new conventional oil provinces.

The Canning Basin remains a frontier and much more exploration is needed to realise its potential. The basin may be the least explored of world-wide Paleozoic basins with proven petroleum systems.

With lower oil prices, exploration and production worldwide has become less economic. Thus in a number of cases conventional onshore activity may have advantages over more expensive offshore and onshore unconventional exploration and production.

Methods of acquiring acreage

Even when the oil price was high, onshore explorers found it hard to raise capital for their work programs and had to rationalise their acreage footprint due to this and other factors. The low world oil price regime led to numerous titles and applications being surrendered. It is hoped that acreage opportunities will be taken up by new players that are willing to engage in a counter-cyclical approach, and that by the time native title negotiations are concluded (prior to award of onshore permits), the oil price may have improved.

There are multiple opportunities for new players to take up acreage (Fig. 1).

- WA DMP has an "over the counter" method of acquiring acreage – the Special Prospecting Authority with an Acreage Option (SPA/AO). www.dmp.wa.gov.au/Petroleum/Understanding-Petroleum-Titles-4224.aspx
- Exploration acreage is available through work program bidding for areas released by the Department of Mines and Petroleum's Petroleum Division. Canning Basin acreage is proposed to be released in mid-September 2016 and will be posted on DMP's website at www.dmp.wa.gov.au/acreage_release
- Many operators would welcome acceleration of their exploration efforts by way of farmin funding. With lower oil prices there are junior exploration companies that lack funds for drilling. The key benefit of a granted title is that there is commercial certainty pertaining to indigenous land access and land usage expectations and requirements. Now is an opportune time for new players with a long-term view to take up an acreage position.
- Some of the participants in the basin are junior companies and there may be scope for acquiring acreage by means of company takeover, subject to Foreign Investment Review Board guidelines.

Some history

After the discovery of the Blina oilfield in an Upper Devonian reef on the Lennard Shelf in 1981, the Canning Basin attracted a number of players including Canadian and US companies, and exploration accelerated.

In the 1980s a number of small fields discovered in Permo-Carboniferous clastics also came into production along the northern margin of the Canning Basin. Exploration decreased after the oil price crashed in February 1986 and a stockmarket correction in October 1987. The exploration spotlight shifted from the onshore Canning Basin to the offshore North West Shelf, where new commercial production started coming onstream from the Northern Carnarvon Basin.

CANNING BASIN

PETROLEUM TENURE March 2016

Government of Western Australia Department of Mines and Petroleum

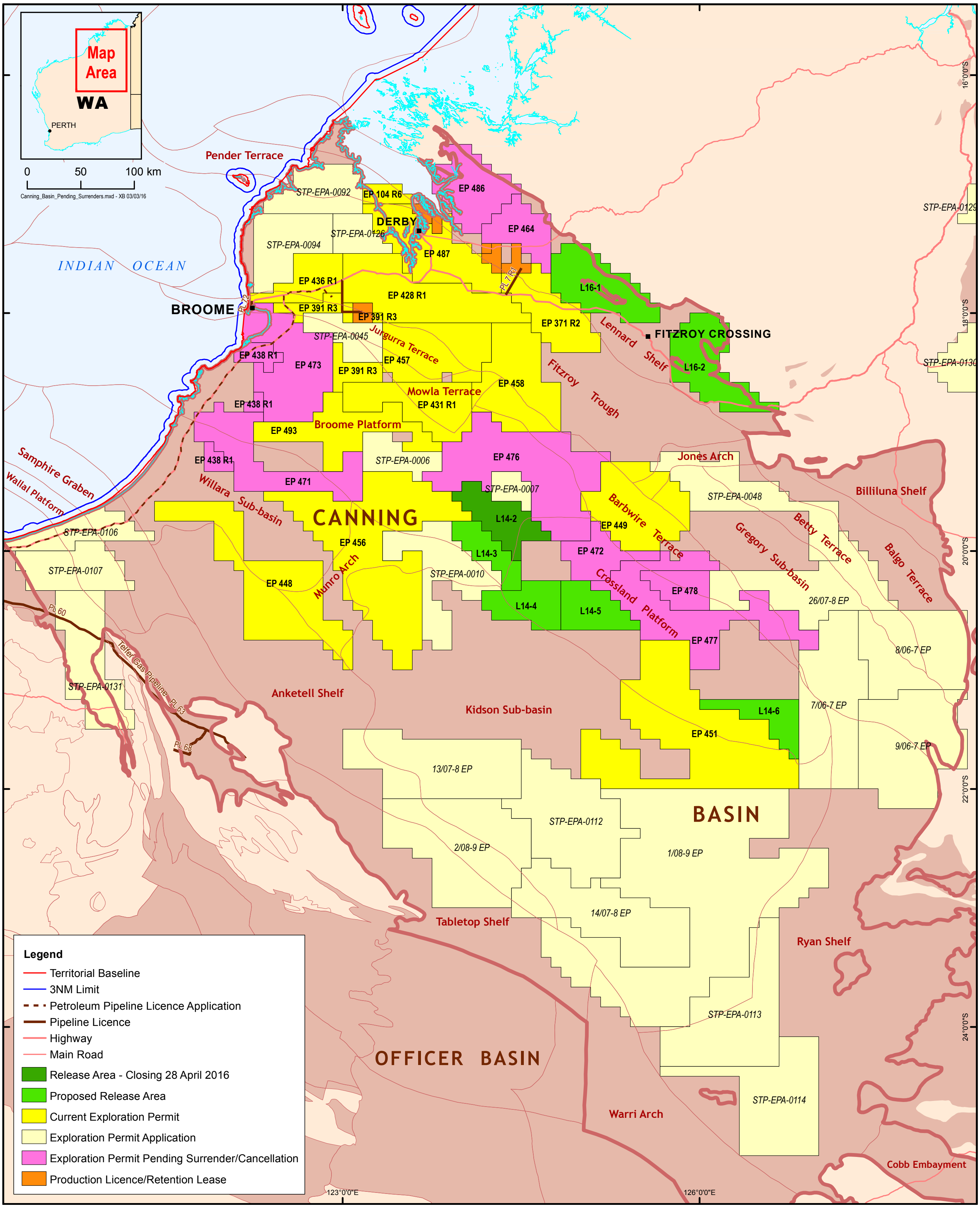

Figure 1. Canning Basin map showing petroleum tenure as at March 2016 and tectonic elements

Interest has returned to the Canning Basin in recent years. In October 2011 oil was discovered in dolomitised limestones of the Lower Carboniferous Laurel Formation with the Ungani 1 well. The well, drilled by Buru Energy, flowed oil at 262 kL (1647 barrels) per day on a 1.27 cm (1/2 inch) choke. The original target for Ungani 1 was gas.

Ungani Far West 1 well was spudded in November 2015. The well encountered a 5 m sandstone interval at the top of the Anderson Formation at a depth of some 1560 m with good permeability (~450 md), from which a 41.5 degree API oil sample was recovered. Well testing has confirmed the permeability.

This discovery represents a new play type for the area. Cores have been recovered from the top of the Ungani Dolomite which have displayed well developed vugular porosity with strong mud gas shows and oil bleeding from cores; this porosity was not evident on wireline logs. In early March, testing of the well was underway.

Theia 1 was drilled in July/August 2015 as a test of the Middle Ordovician Goldwyer III liquids-rich resource play. The well had significant oil and gas shows. The operator, Finder, has indicated that early assessment of the well results appear to validate the geological model and de-risk the play.

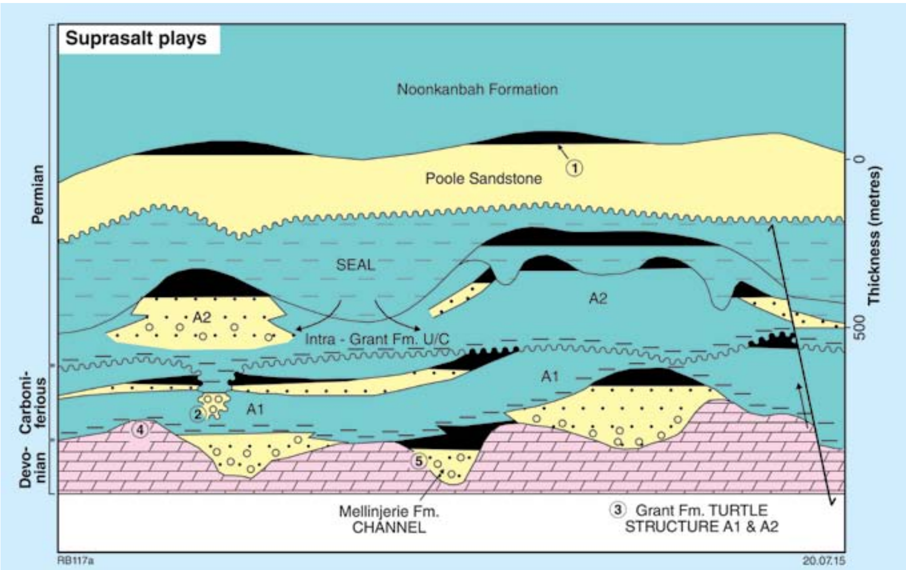

Figure 2. Canning Basin suprasalt plays schematic

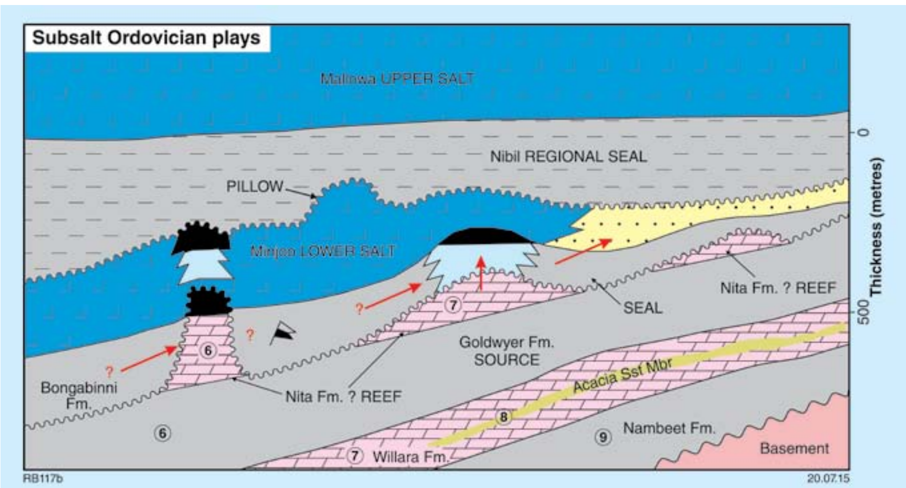

Figure 3. Canning Basin subsalt Ordovician plays schematic

Unlocking the potential

Companies with foresight and determination have traditionally unlocked potential productive fairways in greenfield areas like the Canning Basin.

A giant field is yet to be found in the Canning but some factors in its favour include excellent oil-prone source rocks (such as the Ordovician Goldwyer Formation), excellent salt seals, widespread shows at many stratigraphic levels and in different geological settings, at least three active petroleum systems, and the expanse of unexplored areas.

New exploration approaches are needed. Only a small number of valid structural verifications exist in the basin; seismic misties may have been one factor due to navigation difficulties in days before GPS. In addition, early exploration for faulted anticlines in the basin was unsuccessful as it is thought that structuring may have post-dated migration.

Examples of alternative concepts which may lead to discoveries include:

- mapping the hydrocarbon fluid systems of the subsalt succession before identifying large traps
- trapping of early generated hydrocarbons in a variety of stratigraphic traps, and not just Devonian reefs
- preservation of porosity and permeability, e.g. dolomitised limestones; fracture permeability
- association with topographic features such as basement arches and noses.

Conclusion

In recent years, play opening discoveries such as the Ungani field demonstrate that there is room for further hydrocarbon discoveries in the Canning Basin. In addition to proven suprasalt plays (Devonian reefs, Permo-Carboniferous clastics and Carboniferous carbonates) there are subsalt Ordovician carbonate and sandstone plays which have yet to be proven commercially (Figs 2 and 3).


Ferricrete capping over Liveringa Group, eastern edge of Canning Basin near Balgo

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

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

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

Basin	Reserves						Contingent Resources*					
	Oil, GL		Gas, Gm^3		Condensate, GL		Oil, GL		Gas, Gm^3		Condensate, GL	
	1P	2P	1P	2P	1P	2P	1C	2C	1C	2C	1C	2C
Browse	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.40	24.20	1.30	2.50
Canning	0.00	0.00	0.00	0.00	0.00	0.00	0.56	0.90	1.76	5.41	0.16	0.48
Carnarvon	1.08	8.17	0.37	0.97	0.06	0.08	1.85	3.14	1.15	1.52	0.00	0.00
Perth	0.00	0.00	0.76	1.41	0.06	0.09	0.00	0.00	12.15	52.13	0.12	0.22
WA Total	**1.08**	**8.17**	**1.13**	**2.38**	**0.12**	**0.17**	**2.41**	**4.04**	**27.46**	**83.26**	**1.58**	**3.20**

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

Basin	Reserves						Contingent Resources*					
	Oil, MMstb		Gas, Bscf		Condensate, MMstb		Oil, MMstb		Gas, Bscf		Condensate, MMstb	
	1P	2P	1P	2P	1P	2P	1C	2C	1C	2C	1C	2C
Browse	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	439.00	855.00	8.10	15.80
Canning	0.02	0.02	0.00	0.00	0.00	0.00	3.50	5.66	62.01	191.02	1.01	3.00
Carnarvon	6.80	51.37	12.99	34.28	0.40	0.50	11.59	19.74	40.52	54.01	0.00	0.00
Perth	0.00	0.00	26.67	49.92	0.35	0.59	0.00	0.00	429.14	1,840.99	0.73	1.40
WA Total	**6.82**	**51.39**	**39.66**	**84.19**	**0.75**	**1.09**	**15.09**	**25.40**	**970.67**	**2,941.02**	**9.84**	**20.20**

TABLE 3. PETROLEUM WELLS IN WESTERN AUSTRALIA – ONSHORE AND STATE WATERS 2015

Well Name	Class	On Off	Title	Operator	Latitude	Longitude	Spud Date	TD Date	Rig Release Date
CANNING BASIN									
Olympic 1	NFW	On	EP 473	Buru Energy Limited	-18.299	122.640	5/22/2015	6/19/2015	6/25/2015
Praslin 1	NFW	On	EP 391	Buru Energy Limited	-17.985	123.020	7/16/2015	8/26/2015	9/2/2015
Senagi 1	NFW	On	EP 458	Buru Energy Limited	-18.590	124.373	10/15/2015	11/2/2015	11/9/2015
Sunbeam 1	NFW	On	EP 129	Buru Energy Limited	-17.541	124.368	1/25/2015	2/7/2015	2/10/2015
Theia 1	NFW	On	EP 493	Finder Exploration Pty Ltd	-18.901	123.294	7/15/2015	8/24/2015	8/29/2015
Ungani Far West 1	NFW	On	L 21	Buru Energy Limited	-18.000	123.134	12/28/2015		
Victory 1	NFW	On	EP 457	Buru Energy Limited	-18.253	123.927	9/8/2015	10/2/2015	11/20/2015
PERTH BASIN									
Irwin 1	NFW	On	L 1	AWE Petroleum	-29.259	115.169	3/25/2015	4/24/2015	5/5/2015
Waitsia 1	NFW	On	L 1	AWE Petroleum	-29.253	115.111	5/14/2015	6/9/2015	6/20/2015
Waitsia 2	EXT	On	L 1	AWE Limited	-29.302	115.094	6/29/2015	7/26/2015	8/4/2015
Warro 5 ST1	EXT	On	R 7	Latent Petroleum	-30.207	115.729	8/16/2015	9/24/2015	9/29/2015
Warro 6	EXT	On	R 7	Latent Petroleum	-30.182	115.717	10/12/2015	11/3/2015	11/9/2015
Red Gully North 1	NFW	On	EP 389	Empire Oil & Gas NL	-31.145	115.826	11/18/2015	12/14/2015	12/29/2015

TABLE 4. SURVEYS IN WESTERN AUSTRALIA – ONSHORE AND STATE WATERS 2015

Survey name	Class	On Off	Title	Operator	Commenced	Completed	2D/Line km @ 31/12/2015	3D km^2 @ 31/12/2015
CANNING BASIN								
Canning Airborne Gravity Gradiometry Survey	GRAVITY	On	EP 391 R3, EP 431, EP 436	Buru Energy Limited	2/06/2015	10/06/2015	5,765	
Kurrajong 3D Reflection Seismic Survey	3D	On	EP 436, EP 391 R3	Buru Energy Limited	20/11/2015	11/12/2015		196
Rafael 2D S.S.	2D	On	EP 428, EP 457	Buru Energy Limited	31/10/2015	13/11/2015	163	
Yakka Munga 3D S.S.	3D	On	EP 428, EP 391 R1	Buru Energy Limited	10/10/2015	29/10/2015		190
PERTH BASIN								
Black Swan Airborne Geophysical Survey	AEROMAG	On	EP 368 R4, EP 389 R2, EP 416 R1, EP 426, EP 430, EP 432, EP 440 R1, EP 454, EP 480	Empire Oil & Gas NL	1/05/2015	30/05/2015	12,776	
EP413 Arrowsmith 3D S.S	3D	On	EP 413 R3	Norwest Energy NL	23/04/2015	2/05/2015		106
NORTHERN CARNARVON BASIN								
Numbat 3D M.S.S.	3D	On	SPA 2 T	Searcher Seismic Pty Ltd	19/05/2015	3/06/2015		146

Classification
2D – 2D Reflection Seismic Survey
3D – 3D Reflection Seismic Survey
Gravity – Airborne Gravity Gradiometry Survey
Aeromag – Airborne Aeromagnetic Survey

TABLE 5. LIST OF PETROLEUM TITLES AND HOLDERS IN WESTERN AUSTRALIAN JURISDICTIONS AS AT 17 FEBRUARY 2016

PETROLEUM (SUBMERGED LANDS) ACT 1982
Exploration Permit

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

PETROLEUM (SUBMERGED LANDS) ACT 1982
Pipeline Licence

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

TABLE 5. LIST OF PETROLEUM TITLES AND HOLDERS IN WESTERN AUSTRALIAN JURISDICTIONS AS AT 17 FEBRUARY 2016

PETROLEUM (SUBMERGED LANDS) ACT 1982
Production Licence

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

PETROLEUM (SUBMERGED LANDS) ACT 1982
Retention Lease

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

PETROLEUM 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	GULLIVER PRODUCTIONS PTY LTD* INDIGO OIL PTY LTD
EP 307 R5	HARRIET (ONYX) PTY LTD KUFPEC AUSTRALIA PTY LTD QUADRANT NORTHWEST PTY LTD*
EP 320 R4	AWE (BEHARRA SPRINGS) PTY LTD ORIGIN ENERGY DEVELOPMENTS PTY LIMITED*
EP 321 R4	ALCOA OF AUSTRALIA LIMITED LATENT PETROLEUM PTY LTD*
EP 358 R3	HARRIET (ONYX) PTY LTD KUFPEC AUSTRALIA PTY LTD QUADRANT NORTHWEST PTY LTD*
EP 359 R3	BOUNTY OIL & GAS NL LANSVALE OIL & GAS PTY LTD PACE PETROLEUM PTY LTD PHOENIX RESOURCES PLC ROUGH RANGE OIL PTY LTD
EP 368 R4	EMPIRE OIL COMPANY (WA) LIMITED* WESTRANCH HOLDINGS PTY LTD
EP 371 R2	BURU ENERGY LIMITED DIAMOND RESOURCES (CANNING) PTY LTD
EP 381 R3	WHICHER RANGE ENERGY PTY LTD
EP 386 R3	ONSHORE ENERGY PTY LTD
EP 389 R2	EMPIRE OIL COMPANY (WA) LIMITED
EP 391 R3	BURU ENERGY LIMITED* DIAMOND RESOURCES (FITZROY) PTY LTD
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	EMPIRE OIL COMPANY (WA) LIMITED* PILOT ENERGY LIMITED
EP 426	EMPIRE OIL COMPANY (WA) LIMITED* WESTRANCH HOLDINGS PTY LTD
EP 428 R1	BURU ENERGY LIMITED DIAMOND RESOURCES (CANNING) PTY LTD

TABLE 5. LIST OF PETROLEUM TITLES AND HOLDERS IN WESTERN AUSTRALIAN JURISDICTIONS AS AT 17 FEBRUARY 2016

EP 430 R1	EMPIRE OIL COMPANY (WA) LIMITED
EP 431 R1	BURU ENERGY LIMITED* DIAMOND RESOURCES (FITZROY) PTY LTD
EP 432	EMPIRE OIL COMPANY (WA) LIMITED*
EP 435 R1	AUSTRALIAN OIL COMPANY NO 3 PTY LIMITED BLACK FIRE MINERALS LIMITED BOUNTY OIL & GAS NL PHOENIX RESOURCES PLC ROUGH RANGE OIL PTY LTD
EP 436 R1	BURU ENERGY LIMITED* DIAMOND RESOURCES (FITZROY) PTY LTD
EP 437 R1	CARACAL EXPLORATION PTY LTD KEY PETROLEUM (AUSTRALIA) PTY LTD REY OIL AND GAS PERTH PTY LTD
EP 438 R1	BURU ENERGY LIMITED* DIAMOND RESOURCES (CANNING) PTY LTD QUADRANT ONSHORE HOLDINGS PTY LTD
EP 440 R1	EMPIRE OIL COMPANY (WA) LIMITED
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 451	NEW STANDARD ONSHORE PTY LTD*
EP 454	EMPIRE OIL COMPANY (WA) LIMITED*
EP 455 R1	AWE PERTH PTY LTD* TITAN ENERGY LTD
EP 456	NEW STANDARD ONSHORE PTY LTD*
EP 457	BURU FITZROY PTY LTD* DIAMOND RESOURCES (FITZROY) PTY LTD REY OIL AND GAS PTY. LTD.
EP 458	BURU FITZROY PTY LTD* DIAMOND RESOURCES (FITZROY) PTY LTD REY OIL AND GAS PTY. LTD.
EP 464	EXCEED ENERGY (AUSTRALIA) PTY LTD
EP 468	OFFICER PETROLEUM PTY LTD
EP 469	WARREGO ENERGY PTY LTD*
EP 471	BURU ENERGY LIMITED* DIAMOND RESOURCES (CANNING) PTY LTD QUADRANT ONSHORE HOLDINGS PTY LTD
EP 472	BURU ENERGY LIMITED* DIAMOND RESOURCES (CANNING) PTY LTD
EP 473	BURU ENERGY LIMITED* DIAMOND RESOURCES (CANNING) PTY LTD QUADRANT ONSHORE HOLDINGS PTY LTD
EP 475	CARNARVON PETROLEUM LIMITED
EP 476	BURU ENERGY LIMITED* DIAMOND RESOURCES (CANNING) PTY LTD
EP 477	BURU ENERGY (ACACIA) PTY LTD DIAMOND RESOURCES (CANNING) PTY LTD
EP 478	BURU ENERGY (ACACIA) PTY LTD BURU ENERGY LIMITED*
EP 480	EMPIRE OIL COMPANY (WA) LIMITED PILOT ENERGY LIMITED
EP 481	NEW STANDARD ONSHORE PTY LTD
EP 482	NEW STANDARD ONSHORE PTY LTD
EP 483	FINDER NO 3 PTY LIMITED
EP 486	EXCEED ENERGY (AUSTRALIA) PTY LTD
EP 487	OIL BASINS LIMITED REY LENNARD SHELF PTY LTD*
EP 488	UIL ENERGY LTD
EP 489	UIL ENERGY LTD
EP 490	CARNARVON PETROLEUM LIMITED
EP 491	CARNARVON PETROLEUM LIMITED
EP 492	WESTRANCH HOLDINGS PTY LTD
EP 493	FINDER SHALE PTY LIMITED
EP 494	MACALLUM GROUP LTD* SOUTHERN SKY ENERGY PTY LTD

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	GULLIVER PRODUCTIONS PTY LTD* INDIGO OIL PTY LTD
L 16	AUSTRALIAN OIL COMPANY NO 3 PTY LIMITED BOUNTY OIL & GAS NL ROUGH RANGE OIL PTY LTD

TABLE 5. LIST OF PETROLEUM TITLES AND HOLDERS IN WESTERN AUSTRALIAN JURISDICTIONS AS AT 17 FEBRUARY 2016

L 17	BURU ENERGY LIMITED
L 18	EMPIRE OIL COMPANY (WA) LIMITED*
L 19	EMPIRE OIL COMPANY (WA) LIMITED*
L 20	BURU ENERGY LIMITED* DIAMOND RESOURCES (FITZROY) PTY LTD
L 21	BURU ENERGY LIMITED* DIAMOND RESOURCES (FITZROY) PTY LTD

PETROLEUM AND GEOTHERMAL ENERGY RESOURCES ACT 1967
Retention Lease

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

PETROLEUM PIPELINE ACT 1969
Pipeline Licence

Title	Registered Holder(s)
PL 1 R1	APT PARMELIA PTY LTD
PL 2 R1	APT PARMELIA PTY LTD
PL 3 R1	APT PARMELIA PTY LTD
PL 5 R1	APT PARMELIA PTY LTD
PL 6 R3	AWE PERTH PTY LTD
PL 7 R1	BURU ENERGY LIMITED
PL 8 R1	MITSUI IRON ORE DEVELOPMENT PTY LTD NIPPON STEEL & SUMIKIN RESOURCES AUSTRALIA PTY. LTD. NIPPON STEEL & SUMITOMO METAL AUSTRALIA PTY LTD NORTH MINING LIMITED ROBE RIVER MINING CO. PTY. LTD.*
PL 12 R1	HARRIET (ONYX) PTY LTD KUFPEC AUSTRALIA PTY LTD QUADRANT NORTHWEST PTY LTD*
PL 14 R1	HYDRA ENERGY (WA) PTY LTD QUADRANT OIL AUSTRALIA PTY LIMITED* SANTOS (BOL) PTY LTD TAP (SHELFAL) PTY LTD
PL 15 R1	CHEVRON (TAPL) PTY LTD CHEVRON AUSTRALIA PTY LTD* MOBIL AUSTRALIA RESOURCES COMPANY PTY LIMITED SANTOS OFFSHORE PTY LTD
PL 16	DBP DEVELOPMENT GROUP NOMINEES PTY LIMITED
PL 17	HARRIET (ONYX) PTY LTD KUFPEC AUSTRALIA PTY LTD QUADRANT NORTHWEST PTY LTD*
PL 18	AWE (BEHARRA SPRINGS) PTY LTD ORIGIN ENERGY DEVELOPMENTS PTY LIMITED*
PL 19	DBP DEVELOPMENT GROUP NOMINEES PTY LIMITED
PL 20	DBP DEVELOPMENT GROUP NOMINEES PTY LIMITED
PL 21	CHEVRON (TAPL) PTY LTD CHEVRON AUSTRALIA PTY LTD* MOBIL AUSTRALIA RESOURCES COMPANY PTY LIMITED SANTOS OFFSHORE PTY LTD
PL 22	APA (PILBARA PIPELINE) PTY LTD
PL 24	ALINTA ENERGY GGT PTY LIMITED SOUTHERN CROSS PIPELINES (NPL) AUSTRALIA PTY LTD SOUTHERN CROSS PIPELINES AUSTRALIA PTY LIMITED*
PL 25	SOUTHERN CROSS PIPELINES AUSTRALIA PTY LIMITED
PL 26	SOUTHERN CROSS PIPELINES AUSTRALIA PTY LIMITED
PL 27	SOUTHERN CROSS PIPELINES AUSTRALIA PTY LIMITED
PL 28	SOUTHERN CROSS PIPELINES (NPL) AUSTRALIA PTY LTD
PL 29	QUADRANT EAST SPAR PTY LIMITED QUADRANT KERSAIL PTY LTD QUADRANT OIL AUSTRALIA PTY LIMITED* SANTOS (BOL) PTY LTD
PL 30	QUADRANT EAST SPAR PTY LIMITED QUADRANT KERSAIL PTY LTD QUADRANT OIL AUSTRALIA PTY LIMITED* SANTOS (BOL) PTY LTD
PL 31	APA (PILBARA PIPELINE) PTY LTD
PL 32	APT PIPELINES (WA) PTY LIMITED
PL 33	APT PIPELINES (WA) PTY LIMITED
PL 34	NORTHERN STAR RESOURCES LTD
PL 35	NORTHERN STAR RESOURCES LTD
PL 36	AUSTRALIAN PIPELINE LIMITED
PL 37	NORILSK NICKEL CAWSE PTY LTD
PL 38	APA (PILBARA PIPELINE) PTY LTD
PL 39	ORIGIN ENERGY PIPELINES PTY LIMITED
PL 40	DBNGP (WA) NOMINEES PTY LIMITED
PL 41	DBNGP (WA) TRANSMISSION PTY LIMITED
PL 42	HARRIET (ONYX) PTY LTD KUFPEC AUSTRALIA PTY LTD QUADRANT EAST SPAR PTY LIMITED QUADRANT KERSAIL PTY LTD QUADRANT NORTHWEST PTY LTD* QUADRANT OIL AUSTRALIA PTY LIMITED SANTOS (BOL) PTY LTD
PL 43	APT PIPELINES (WA) PTY LIMITED* REGIONAL POWER CORPORATION
PL 44	APT PARMELIA PTY LTD
PL 46	APT PARMELIA PTY LTD
PL 47	DBNGP (WA) TRANSMISSION PTY LIMITED
PL 48	ENERGY GENERATION PTY LTD
PL 52	APT PARMELIA PTY LTD
PL 53	APT PARMELIA PTY LTD
PL 54	APT PIPELINES (WA) PTY LIMITED* REGIONAL POWER CORPORATION
PL 55	GLOBAL ADVANCED METALS WODGINA PTY LTD
PL 56	GLOBAL ADVANCED METALS WODGINA PTY LTD
PL 57	AUSTRALIAN GOLD REAGENTS PTY LTD

TABLE 5. LIST OF PETROLEUM TITLES AND HOLDERS IN WESTERN AUSTRALIAN JURISDICTIONS AS AT 17 FEBRUARY 2016

PL 58	BHP BILLITON PETROLEUM (NORTH WEST SHELF) PTY LTD BP DEVELOPMENTS AUSTRALIA PTY LTD CHEVRON AUSTRALIA PTY LTD JAPAN AUSTRALIA LNG (MIMI) PTY LTD SHELL AUSTRALIA PTY LTD WOODSIDE ENERGY LTD*
PL 59	ESPERANCE PIPELINE CO. PTY LIMITED
PL 60	EII GAS TRANSMISSION SERVICES WA (OPERATIONS) PTY LIMITED
PL 61	APT PARMELIA PTY LTD
PL 62	HARRIET (ONYX) PTY LTD KUFPEC AUSTRALIA PTY LTD QUADRANT NORTHWEST PTY LTD*
PL 63	EII GAS TRANSMISSION SERVICES WA (OPERATIONS) PTY LIMITED
PL 64	AWE PERTH PTY LTD* ORIGIN ENERGY DEVELOPMENTS PTY LIMITED
PL 65	SARACEN METALS PTY LIMITED
PL 67	HAMERSLEY IRON PTY LIMITED
PL 68	EII GAS TRANSMISSION SERVICES WA (OPERATIONS) PTY LIMITED
PL 69	DBNGP (WA) NOMINEES PTY LIMITED
PL 70	AWE (OFFSHORE PB) PTY LTD AWE OIL (WESTERN AUSTRALIA) PTY LTD ROC OIL (WA) PTY LIMITED*
PL 72	EDL NGD (WA) PTY LTD
PL 73	REDBACK PIPELINES PTY LTD
PL 74	EDL LNG (WA) PTY LTD
PL 75	EIT NEERABUP POWER PTY LTD ERM NEERABUP PTY LTD*
PL 76	SOUTHERN CROSS PIPELINES AUSTRALIA PTY LIMITED
PL 77	SINO IRON PTY LTD
PL 78	HAMERSLEY IRON PTY LIMITED
PL 80	ALCOA OF AUSTRALIA LIMITED LATENT PETROLEUM PTY LTD*
PL 81	QUADRANT NORTHWEST PTY LTD SANTOS OFFSHORE PTY LTD
PL 82	APA (PILBARA PIPELINE) PTY LTD
PL 83	ATCO GAS AUSTRALIA PTY LTD
PL 84	CHEVRON (TAPL) PTY LTD* CHUBU ELECTRIC POWER GORGON PTY LTD MOBIL AUSTRALIA RESOURCES COMPANY PTY LIMITED OSAKA GAS GORGON PTY LTD SHELL AUSTRALIA PTY LTD TOKYO GAS GORGON PTY LTD
PL 85	CHEVRON (TAPL) PTY LTD* CHUBU ELECTRIC POWER GORGON PTY LTD MOBIL AUSTRALIA RESOURCES COMPANY PTY LIMITED OSAKA GAS GORGON PTY LTD SHELL AUSTRALIA PTY LTD TOKYO GAS GORGON PTY LTD
PL 86	QUADRANT NORTHWEST PTY LTD* SANTOS OFFSHORE PTY LTD
PL 87	BHP BILLITON PETROLEUM (AUSTRALIA) PTY LTD QUADRANT PVG PTY LTD
PL 88	BHP BILLITON PETROLEUM (AUSTRALIA) PTY LTD QUADRANT PVG PTY LTD
PL 89	CROSSLANDS RESOURCES PTY LTD
PL 90	BHP BILLITON PETROLEUM (AUSTRALIA) PTY LTD QUADRANT PVG PTY LTD
PL 91	DBNGP (WA) NOMINEES PTY LIMITED
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
PL 97	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 98	ESPERANCE PIPELINE CO. PTY LIMITED
PL 99	CHEVRON (TAPL) PTY LTD* KUFPEC AUSTRALIA (JULIMAR) PTY LTD KYUSHU ELECTRIC WHEATSTONE PTY LTD SHELL AUSTRALIA PTY LTD WOODSIDE ENERGY JULIMAR 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 108	APA OPERATIONS PTY LIMITED
PL 109	BURU ENERGY LIMITED
PL 110	DDG ASHBURTON PTY LTD*
PL 111	AWE PERTH PTY LTD ORIGIN ENERGY DEVELOPMENTS PTY LIMITED

* denotes Nominee

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

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