MinterEllison LAWYERS

Oil and Gas in Australia and New Zealand

AN INVESTOR'S GUIDE TO THE SECTOR AND ITS REGULATIONS

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Foreword

Global energy demand is projected to rise by 40% through to 2035, driven by rapid urbanisation, population growth and rising incomes.

The greatest demand most likely will come from the energy-hungry, high-growth economies in emerging Asia, and from China and India in particular. Although all sources of energy will be needed, oil and gas are likely to continue as major sources of supply for the foreseeable future.

Australia and New Zealand are ideally positioned to take advantage of the strong demand for energy from Asia. Oil currently accounts for 18% of Australia's exports and gas about 16%. New Zealand does not currently export natural gas, but oil is its fourth-largest export earner.

Demand from Asia has seen Australia's oil and gas production increase in both value and quantity in recent years. The liquefied natural gas (LNG) projects in Western Australia, Queensland and the Northern Territory, for example, represent some of the biggest projects ever undertaken in the country. Over the next decade, as production from these projects commences, the value of Australia's gas exports will increase significantly.

Shale gas looms large on the horizon, especially in Australia, and as technology makes its extraction easier and more economical, it has the potential to transform the country's energy industry just as it has done in the USA.

Yet even as both Australia and New Zealand continue to expand their portfolio of oil and gas reserves, extensive areas of land – onshore and offshore – remain either unexplored or underexplored.

As both countries strive to secure the industry's long term economic platform, policymakers and industry participants face some important challenges – emerging regulatory issues, foreign investment, availability of skilled labour, development costs and community activism. Understanding and resolving these challenges will be crucial as governments and company executives plan their strategies for the years ahead.

Throughout Australia and New Zealand, Minter Ellison acts for oil and gas explorers, producers, pipeline owners and their customers. This Guide provides an overview of the oil and gas sector in each country. It also summarises the policy and regulatory framework – upstream and downstream, onshore and offshore; taxes and royalties that impact the sector; environment and planning laws; native title and aboriginal cultural heritage issues; workforce-related legislation; and the implications of carbon policy and regulation for the industry.

We trust you will find this Guide a useful resource.

01

AUSTRALIA

"The oil and gas sector is a major contributor to Australia's economy, providing employment, investment opportunities and export earnings."

Introduction to Australia's oil and gas sector

1 OVERVIEW

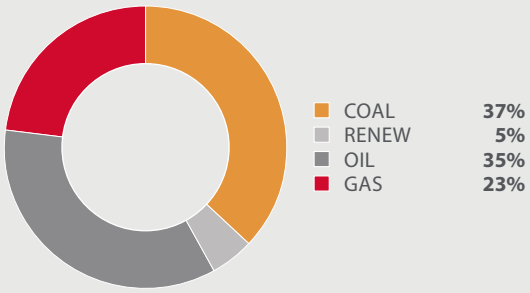
Australia has an abundance of diverse energy resources, with large reserves of coal, uranium, oil and natural gas that supply energy for both domestic consumption and export markets.

The oil and gas sector, which encompasses crude oil, condensate, naturally occurring liquefied petroleum gas (**LPG**) and natural gas, is a major contributor to the nation's economy, providing employment, investment opportunities and export earnings.

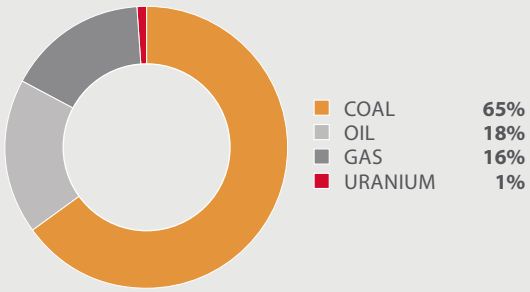
The share of natural gas in Australia's total energy consumption has increased in the past 30 years and that trend is expected to continue in the longer term. Natural gas contributes around 25% of the fuel for Australia's annual primary energy consumption, while oil contributes approximately 36%.[1] By value, coal accounts for 65% of exports, oil 18%, gas 16% and uranium 1%.[2] It is expected that the value of gas exports will significantly increase in the next decade as production commences at liquefied natural gas (**LNG**) terminals under construction across Western Australia, the Northern Territory and Queensland.

Australian domestic consumption and value of exports

ENERGY CONSUMPTION (FUEL TYPE)



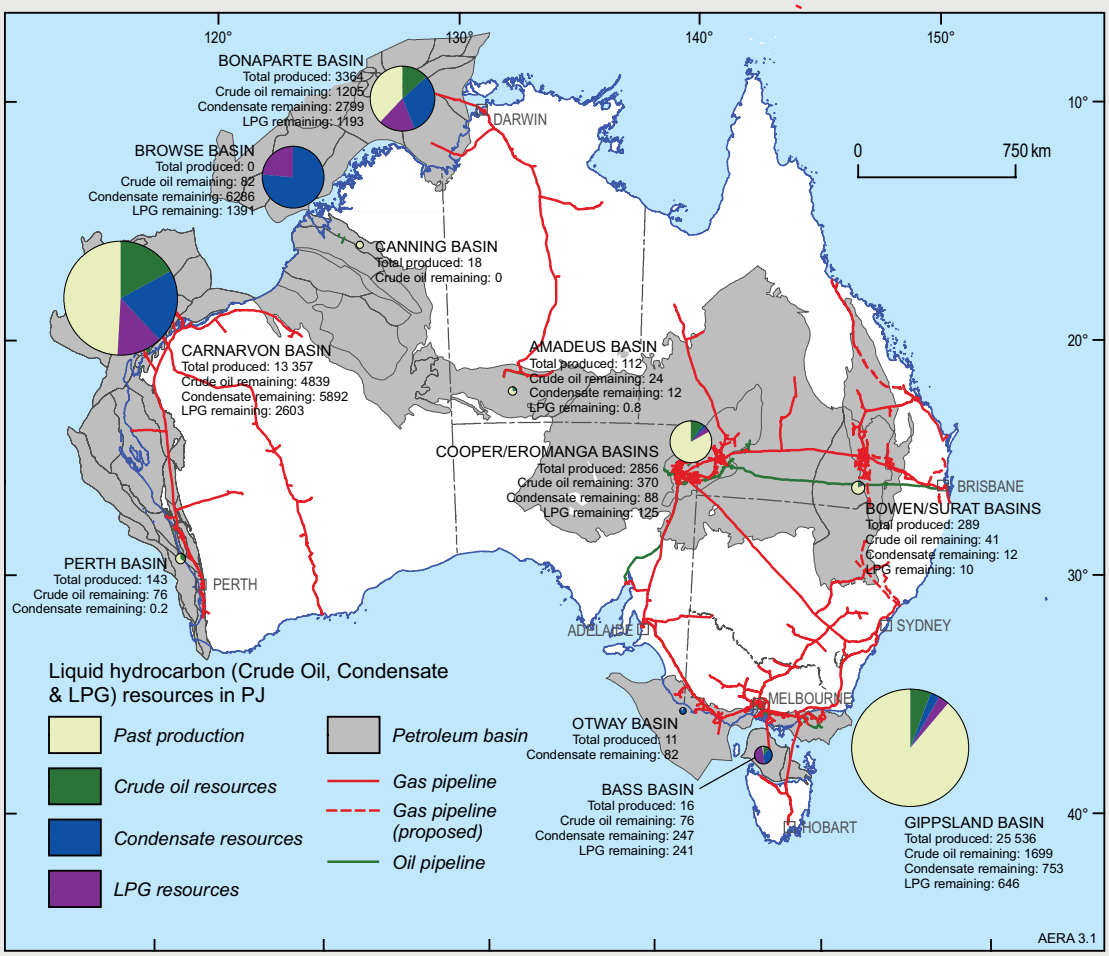
EXPORTS (A$ VALUE)



1 BREE 2012 Australian Energy Update.
2 BREE Resources and Energy Quarterly, December 2012.

2 LIQUIDS: CRUDE OIL AND PETROLEUM

Australian crude oil, condensate and naturally-occurring LPG resources and infrastructure



Source: © Commonwealth of Australia (Geoscience Australia) 2013.

2.1 Production and reserves

The two largest crude oil producing basins in Australia are the Carnarvon Basin (North West Shelf, Western Australia) and the Gippsland Basin (Bass Strait, Victoria). The Carnarvon Basin currently accounts for 73% of Australia's production of crude oil, condensate and LPG. Crude product is mainly exported to Asian refineries. Product from the Gippsland Basin accounts for 17% of Australian production and is predominantly used in domestic refining.

2.2 Exploration

Oil and gas exploration accounts for 82% of total energy exploration expenditure in Australia. In 2011-12, A$3.2 billion was spent on crude oil, LPG and natural gas exploration. Although exploration expenditure in Australia's petroleum industry has declined in recent years – by around 18% between 2008-09 and 2011-12 – the 2011-12 expenditure was still the fourth-highest recorded in Australia's petroleum industry history.[3]

3 BREE Resources and Energy Statistics Annual 2012 Report – December 2012.

2.3 Export and import

Australia is a net importer of crude oil and refined petroleum products but a net exporter of LNG and LPG. Revenue from crude oil and condensate exports increased in 2011-12 – by 8% to A$13.3 billion – as a result of higher export volumes and prices.[4] Revenue from refined petroleum products, of which Australia exports significantly less, also increased in 2011-12 – by 70% compared to 2010-11 earnings – reversing a trend of three straight years of negative growth.[5]

2.4 Refining

Australia's petroleum refining industry produces a range of products, including gasoline, diesel, LPG and aviation turbine fuel. Domestic refinery products account for around 74% of demand. Remaining demand is met by imported product.

Most refinery capacity is located close to the major consumption markets on the east coast. There are two refineries in each of Queensland, New South Wales and Victoria, and one large refinery (Kwinana) in Perth, Western Australia. The managers of these refineries are BP, Caltex (Chevron), Mobil (ExxonMobil) and Shell. Shell's Clyde terminal in Sydney has closed, and Caltex's Kurnell refinery is due to close in 2014. Both these terminals will be converted to receive imported refined petroleum produced at larger and newer Asian terminals at a lower per-unit cost. The remaining five operational major petroleum refineries after Kurnell's closure will have a combined capacity of approximately 31 billion litres per year.[6]

3 GAS

3.1 Australia's gas industry

Natural gas and coal seam gas (**CSG**) are the primary types of gas extracted in Australia. However, technological advances and high global demand for gas have led to exploration for and development of shale gas fields.

Australia's natural gas is used in residential, feedstock, commercial and industrial applications, as well as for co-generation, power generation and for vehicles. Reserves are linked to major domestic markets by more than 25,000 kilometres of high pressure transmission pipelines.

3.2 Conventional natural gas

Companies that explore for and produce conventional natural gas in Australia include BP, BHP Billiton, ExxonMobil, Chevron, Shell, Eni, Apache Energy, Woodside Petroleum, Santos, and a number of junior participants. Natural gas licences and facilities are frequently owned through joint venture arrangements between private companies.

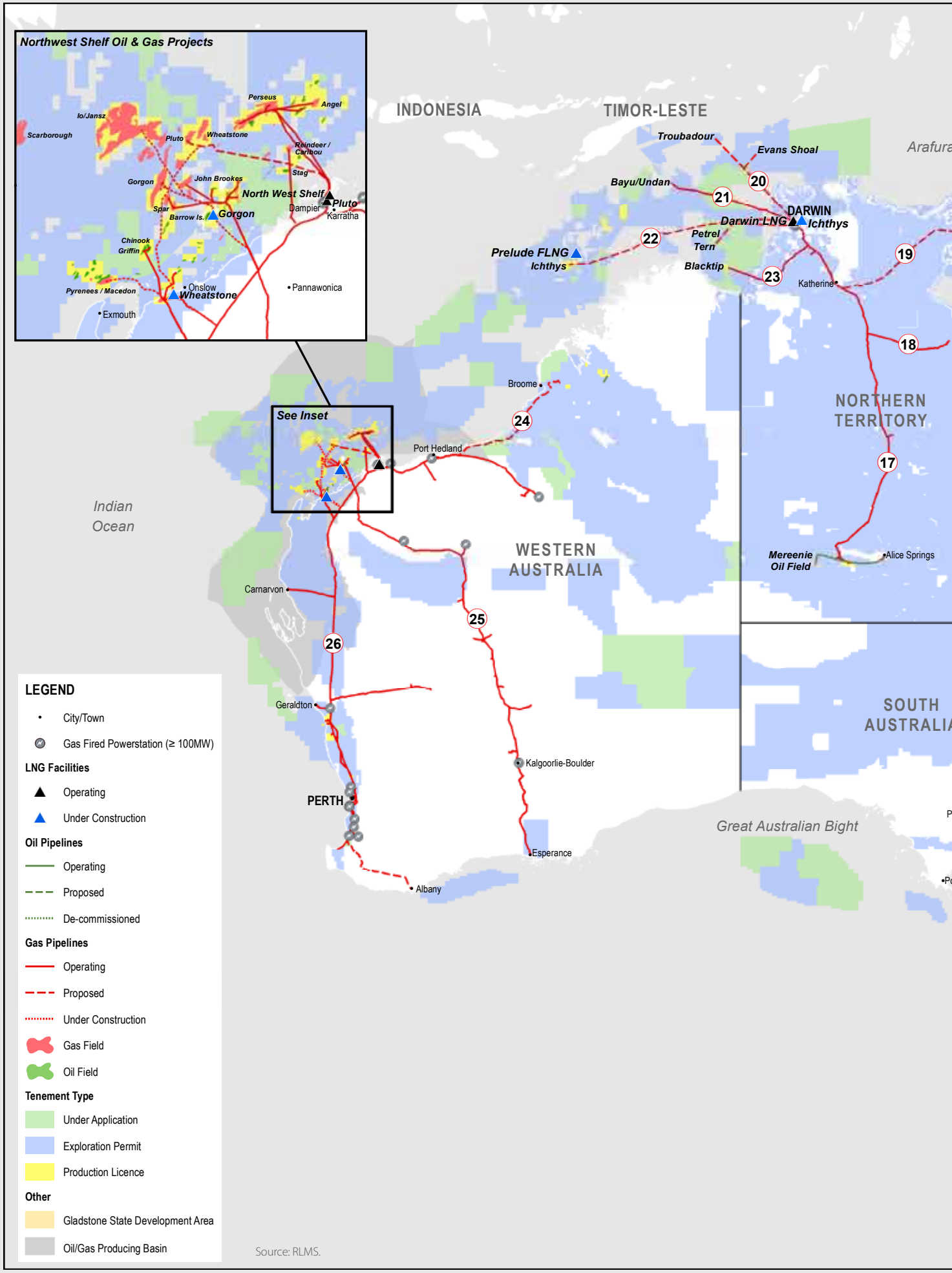
Historically, production of conventional natural gas has come almost exclusively from three major sedimentary basins: Carnarvon (offshore in the North West Shelf, Western Australia), Gippsland (in Bass Strait off Victoria's south-east coast), and Cooper/Eromanga (far inland on the border of South Australia and Queensland). Further basins in the north-west of Australia (Bonaparte and Browse) have been producing, and will continue to produce, substantial quantities of gas. Production and exploration is also conducted in the Otway Basin (onshore and offshore of Victoria and South Australia).

In 2012, total Australian conventional natural gas production exceeded 1800PJ per annum, including more than 800PJ for LNG exports.[7]

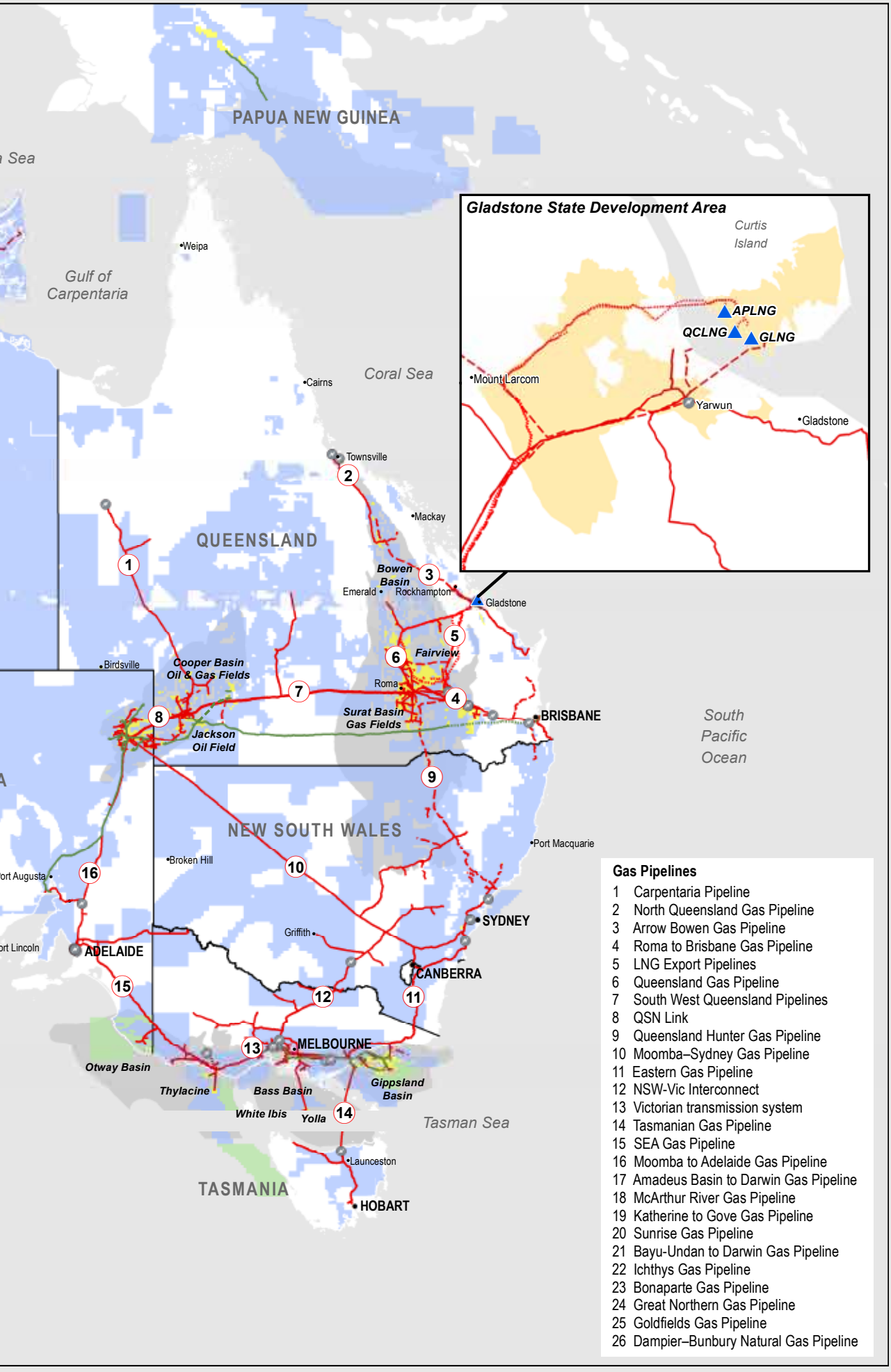
Many gas fields in Australia were discovered as a result of the search for oil. However, with continuing growth in gas use, specific natural gas exploration is now expanding. Australia's most significant non-associated gas reserves (gas reserves exclusive of crude oil production) are offshore of the north-west of Australia in the Carnarvon, Browse and Bonaparte basins.

4 Energy White Paper 2012; BREE Resources and Energy Statistics Annual 2012 Report – December 2012.
5 BREE Resources and Energy Statistics Annual 2012 Report – December 2012.
6 1 barrel = approximately 119 litres.
7 BREE Energy in Australia 2012 Report – February 2012.

Oil and gas infrastructure in Australia



Source: RLMS.



Gas Pipelines

1 Carpentaria Pipeline
2 North Queensland Gas Pipeline
3 Arrow Bowen Gas Pipeline
4 Roma to Brisbane Gas Pipeline
5 LNG Export Pipelines
6 Queensland Gas Pipeline
7 South West Queensland Pipelines
8 QSN Link
9 Queensland Hunter Gas Pipeline
10 Moomba–Sydney Gas Pipeline
11 Eastern Gas Pipeline
12 NSW-Vic Interconnect
13 Victorian transmission system
14 Tasmanian Gas Pipeline
15 SEA Gas Pipeline
16 Moomba to Adelaide Gas Pipeline
17 Amadeus Basin to Darwin Gas Pipeline
18 McArthur River Gas Pipeline
19 Katherine to Gove Gas Pipeline
20 Sunrise Gas Pipeline
21 Bayu-Undan to Darwin Gas Pipeline
22 Ichthys Gas Pipeline
23 Bonaparte Gas Pipeline
24 Great Northern Gas Pipeline
25 Goldfields Gas Pipeline
26 Dampier–Bunbury Natural Gas Pipeline

3.3 Coal seam gas

In addition to the natural gas reserves mentioned earlier, Australia has substantial reserves of CSG in both New South Wales and Queensland. These resources have become an increasingly valuable energy source. To date, almost all of the CSG production and the majority of the exploration has occurred in Queensland.

CSG production began in Queensland in 1996 and has grown rapidly in recent years, with an estimated 90% of Queensland gas consumption now satisfied by CSG and production and reserves trebling in the past three years.

In the 2010-2011 financial year, CSG production in Queensland was estimated to be 234PJ. The number of CSG wells drilled annually increased from a low of 10 in the early 1990s to between 450 and 750 per year since 2007. As at June 2011, proved and probable reserves (2P) reached around 38,000PJ. This quantity of gas would be valued at approximately US$175 billion at a 'netback' price, that is, the price excluding the cost of liquefaction and transport. Production is fairly evenly divided between the Surat Basin (200-300km west of Brisbane) and the Bowen Basin (125km south-west of Gladstone), although the Surat Basin has approximately three-quarters of the 2P reserves.

3.4 Shale gas

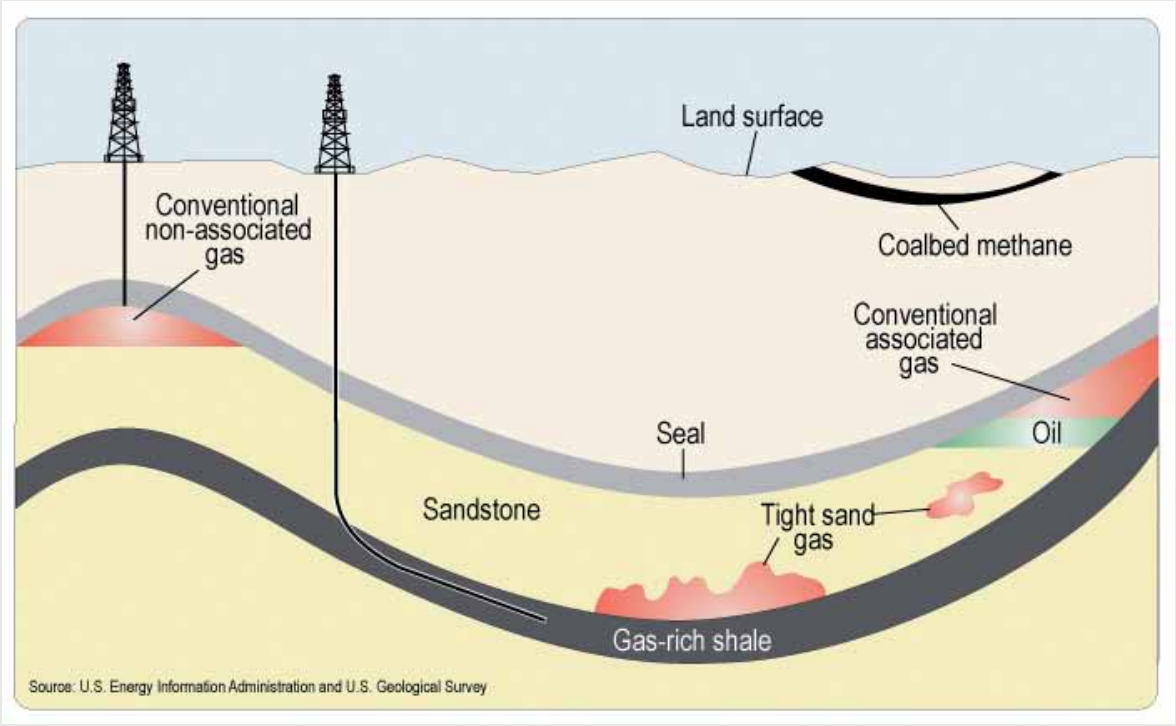
Advances in horizontal drilling and hydraulic fracturing technologies have made the extraction of shale gas easier and more economical. These factors have already altered the energy industry in the USA and have the potential to do the same in Australia.

Exploration for shale gas is still in relative infancy in Australia. The US Energy Information Administration estimates that Australia has 420,000 PJ of 'technically recoverable' shale gas reserves,[8] with potential in Queensland, New South Wales, South Australia, Western Australia and the Northern Territory. Exploration is currently being undertaken in the Cooper, Georgina, Galilee, Bowen, Sydney, Canning, Onshaore Perth, Beetaloo sub-basin and McArthur basins.[9]

There is only limited commercial production of shale gas in Australia at present – Santos commenced commercial production of shale gas in October 2012 from wells in the Cooper Basin. It is likely that shale gas reserves in areas that have existing conventional gas or CSG production (such as the Cooper Basin) will become increasingly attractive for development and production because existing pipelines and infrastructure can be utilised.

8 World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States – April 2011.
9 CSIRO: Australia's shale gas resources.

Typical gas geology



3.5 LNG

Australia is currently the fourth-largest exporter of LNG in the world and the Bureau of Resources and Energy Economics predicts that it will be the second-largest by 2015.[10] There are three operational LNG plants in Australia at the time of publishing (see Table 1 on page 9).

Current capacity is approximately 24 Mt/year. A further 65 Mt of capacity is either under construction or has reached a final investment decision. Three development projects are located in Gladstone, with the rest in the north-west of Australia. A summary of the projects, their size and status is set out in Table 2 on page 9.

Australian's main LNG export customers are Japan and China, taking 70% and 20% of the export volumes respectively. Australia's LNG production is set to triple by 2016, and about 80% of the production from these new facilities has been contracted to Japanese and Chinese buyers, with the balance either uncontracted or contracted to Korean, Malaysian and Indian entities.

3.6 Transmission

Australia's natural gas reserves are linked to major domestic markets by more than 25,000 kilometres of high pressure transmission pipelines. There is now an interconnected pipeline network covering Queensland, New South Wales, Victoria, South Australia, Tasmania and the Australian Capital Territory.

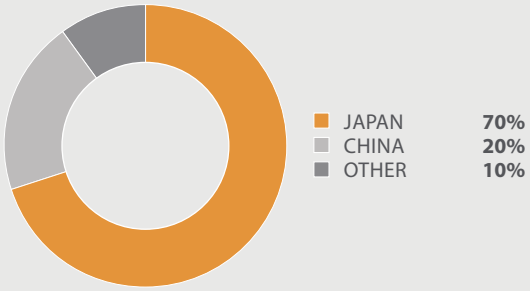
Since 2010, nearly A$3.8 billion has been invested in new gas transmission infrastructure.[11] There has been a significant consolidation of ownership of transmission pipelines in recent years. The major gas transmission pipelines companies operating in Australia currently include:

- the APA Group, which owns more than 50% of Australia's gas transmission network and includes Epic Energy's assets following the 4 January 2013 takeover;
- Jemena (owned by Singapore Power International); and
- DUET Group, an ASX-listed entity with a controlling interest in the Dampier to Bunbury pipeline.

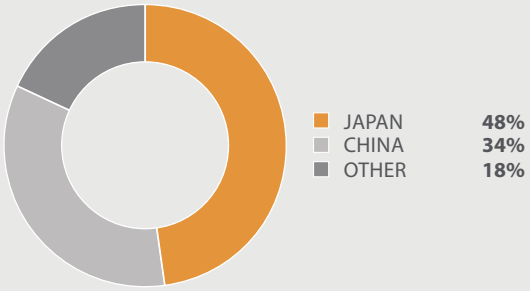
10 BREE Gas Market Report – July 2012.
11 BREE Gas Market Report – July 2012.

Destination of Australian LNG exports

LNG EXPORT CUSTOMERS (2013)



LNG EXPORT CUSTOMERS (AFTER APPROVED PROJECTS COME ON-LINE)



Gas pipelines can have natural monopoly characteristics, and may be subject to regulatory oversight under a 'coverage' process (discussed in chapter 4).

However, increased competition and a more relaxed approach to regulation has led to the whole or partial lifting of economic regulation from several major pipelines over recent years. There are now 11 gas transmission pipelines regulated under the National Gas Rules.

3.7 Distribution and retail

Australia's gas distribution system comprises more than 80,000 kilometres of local reticulated pipelines, supplying some 3.4 million households (approximately six million persons) and 105,000 commercial and industrial customers (largely in metropolitan areas). The reticulation of gas through distribution systems for domestic use is relatively limited in regional Australia.

All of Australia's major gas distribution networks are now privately owned. Australian competition laws require transmission/distribution to be kept legally separate from gas trading businesses (whether wholesale or retail). Distribution and transmission pipelines are subject to Australia's third-party access regime (discussed in detail in chapter 4).

From 1 July 2008, the Australian Energy Regulator (**AER**) has been responsible for the economic regulation of gas transmission and distribution networks and for enforcing the National Gas Law (**NGL**) and National Gas Rules (**NGR**) in all jurisdictions except Western Australia. The AER has developed a number of guidelines and processes to assist interested parties engaged in relevant processes or meeting obligations under the NGL and NGR.

TABLE 1: EXISTING AUSTRALIAN LNG FACILITIES

Facility	Owner	Location	Commissioned	Capacity (millions tonnes of LNG per annum)
North West Shelf	Woodside, BHP, BP, Chevron, Shell and Japan Australia LNG (Mitsui and Mitsubishi)	Karratha, WA	1989	16.3 MTPA
Pluto LNG	Woodside, Kansai Electric and Tokyo Gas	Karratha, WA	2012	4.3 MTPA
Darwin LNG	ConocoPhillips, Eni, Santos, INPEX, Tokyo Electric and Tokyo Gas	Darwin, NT	2006	3.6 MTPA

TABLE 2: LNG PROJECTS

Project	Owner	Location	Commencement of Construction and Current Status	Projected First Gas Collection	Capacity (millions tonnes of LNG per annum)	Projected CostA$
Queensland Curtis LNG	QGC (British Gas)	Gladstone, QLD	2010 – under construction	2014	12 MTPA	$20.4bn
Gladstone LNG	Santos, Petronas, Total and Kogas	Gladstone, QLD	2012 – under construction	2015	4 MTPA	$16bn
Australia Pacific LNG	Origin, ConocoPhillips and Sinopec	Gladstone, QLD	2010 – under construction	2014 (two trains)	9 MTPA	$20bn
North Rankin and Greater Western Flank Phase I	Woodside, BHP, BP, Chevron, Shell and Japan Australia LNG (Mitsui and Mitsubishi)	North West Shelf, offshore WA	2013 (projected) – Post-FID	TBD	Development and redevelopment to support existing North West Shelf LNG plant	$5bn
Gorgon	Chevron, Shell, Mobil, Osaka Gas, Tokyo Gas and Chubu Electric Power	Greater Gorgon, offshore WA	2010 – under construction	2015	15 MTPA	$52bn
Wheatstone	Chevron, Shell, Apache Energy, KUFPEC, Kyushu Electric Power Co	Ashburton North, offshore WA	2011 – under construction	2016	8.9 MTPA	$29bn
Ichthys Field LNG	INPEX, Total, Tokyo Gas, Osaka Gas, Chubu Electric and Toho Gas	Browse Basin, Timor Sea, offshore NT	2012 – under construction	2016	8.4 MTPA	$20bn
Prelude floating LNG	Shell, Kogas, INPEX and CPC (Taiwan)	Browse Basin, Timor Sea, offshore WA	2012 – under construction	2016	3.6 MTPA	$12bn

02

"Legal and political power is divided between the Federal Government and the state governments as set out in Australia's constitution."

Political and regulatory systems

1 CONSTITUTIONAL STRUCTURE

Australia is a federation of six states. Legal and political power is divided between the Federal Government and the state governments as set out in Australia's Constitution.

The Constitution confers power on the Federal Parliament to legislate for specific matters, including taxation, foreign investment, the banking and monetary system and interstate and overseas trade. The states retain the power to legislate for all other matters.

Six states form the federation – Queensland, New South Wales, Victoria, Tasmania, South Australia and Western Australia.

In addition to the federal and state governments, investors in the oil and gas sector will need to deal with municipal governments on matters affecting land and development.

2 FOREIGN INVESTMENT

The Federal Government regulates foreign investment though the *Foreign Acquisition and Takeovers Act 1975* (Cth). It has established policy guidelines to inform potential foreign investors of the kinds of investments that will be encouraged and the terms on which these are likely to be approved. Foreign investment is generally welcomed in the oil and gas sector and up to 100% of foreign ownership is permitted.

A foreign company that proposes to invest in Australia will usually need to submit an application to the Foreign Investment Review Board (**FIRB**), and most investments in oil and gas assets will require approval. Applications by foreign state-owned enterprises to move from an exploration licence to a production licence will also require approval. The FIRB recommends to the Federal Treasurer whether the proposed investment should be approved and on what terms.

3 REGULATORY ENVIRONMENT

Each state and territory, except for Tasmania and the Australian Capital Territory, has its own legislation covering exploration for, and production of, onshore petroleum.

Offshore petroleum operations, on the other hand – ie, those beyond the states' coastal waters (generally three nautical miles) – fall under the jurisdiction of the Federal Government. These regulatory regimes are discussed in more detail in chapter 3.

4 TAX AND ROYALTIES

4.1 Tax

States have enacted laws that permit them to generate revenue from royalties payable to the Crown for any petroleum that is produced. Licence holders also have to pay an annual fee to the Crown.

At the federal level, the Petroleum Resource Rent Tax (**PRRT**) is applied to taxable profits derived from all petroleum recovered from a project area, including crude oil, condensate, natural gas, LPG, and ethane. It is not payable on refined or processed petroleum. On an LNG project, PRRT will be payable on the value of the gas extracted and not on the processed LNG. A federal excise of up to 30% applies once field production reaches 30 million barrels and is deductible against the PRRT.

PRRT is assessed on either a project basis or a production licence area and is levied on the taxable profits of a project at a rate of 40%. The tax is assessed on the Australian financial and tax year from 1 July to 30 June.

The PRRT was extended to onshore projects (and the previously exempt North West Shelf project) from 1 July 2012. The extension coincided with the introduction of the controversial Minerals Resources Rent Tax (MRRT) for iron ore and coal projects.

The Liberal-National Coalition Government elected on 7 September 2013 plans to abolish the MRRT. It remains to be seen whether this new Federal Government will retain the PRRT or attempt to remove it along with the MRRT.

The taxable profit of a project is the assessable receipts of the project after deduction of:

(a) deductible expenditure of a project in a financial year;

(b) amounts of exploration expenditure transferred to the project from other projects held by the taxpayer; and

(c) (if the taxpayer is a company in a wholly-owned group) amounts of exploration expenditure transferred to the project from projects held by other companies in the group.

Federal, state and territory excise and royalties are credited for PRRT purposes, by 'grossing--up' the amount of excise or royalty by the PRRT rate.

4.2 Royalty rates

Royalties payable in relation to North West Shelf "grandfathered" exploration permits and retention leases, and production licences related to those permits, are determined by the *Offshore Petroleum Royalty Act 2006* (Cth).

In Queensland, South Australia and the Northern Territory, the royalty rate is 10% of the value at the wellhead of petroleum recovered (10-12.5% in Western Australia). The wellhead value is the amount agreed between the title holder and the Designated Authority or Minister. This royalty rate is only economically relevant in any year when a project does not make a sufficient profit so that PRRT would otherwise exceed the royalty payable. If there is any profit, the royalty is offset against the payment of the PRRT.

4.3 Income tax

Oil and gas companies pay Australian income tax on their taxable income in the same way as other businesses. Federal and state excise and royalties, and the PRRT, are deductible for income tax purposes.

The new Federal Government proposes to introduce an 'Exploration Development Incentive' that will grant tax credits to investors investing in greenfield developments for exploration expenditure.

The credits would be available for investments in exploration companies that have no taxable income.

03

"The vast reserves and producing discoveries off the north-west of Australia fall under the jurisdiction of the Federal Government."

Upstream oil and gas regulation

1 OFFSHORE

1.1 Principal legislation and regulator

Any petroleum operations beyond the states' coastal waters (three nautical miles) fall under the jurisdiction of the Federal Government. This includes the vast reserves and producing discoveries off the north-west of Australia. The primary federal legislation is the *Offshore Petro leum and Greenhouse Gas Storage Act 2006* (Cth).

The primary decision maker under this legislation is the 'Joint Authority', which comprises the Federal Minister and the relevant state appointee. However, the day-to-day administration is vested in two newly-established bodies: the National Offshore Petroleum Titles Administrator (**NOPTA**) and the National Offshore Petroleum Safety and Environmental Management Authority (**NOPSEMA**). These names of these entities give some indication of their responsibilities.

1.2 Exploration licences, expenditure obligations and term

NOPTA allocates acreage to be released in offshore areas, currently twice a year (in May and November). These areas may be nominated by industry, each state or territory, and Geoscience Australia before they are released. On release, information held by Geoscience Australia, including geological details, previous activity and potential exploration risks, is made available to industry.

Prospective licensees are invited to submit bids with work programs and budgets for the blocks. The Joint Authority for the area then makes a decision to award acreage based on the technical merit of the program and the capacity of the applicant to fulfil the program. The Federal Government has announced that it will introduce cash bidding for areas with known petroleum accumulations from 2014.

As an example of the operation of the bid and award process, in October 2012 the Federal

Government announced the award of seven exploration permits that had been made available for bidding in September 2011. Six of the permits were awarded offshore of Western Australia and one off the Northern Territory. For the licences granted, the initial three-year guaranteed work programs are all for seismic, processing and assessment expenditure. The three-year optional period provides for drilling an exploration well. Budgeted expenditure ranged from A$21 million to A$177 million over the six-year term.

Petroleum exploration permits are awarded for an initial term of six years, with the possibility of two five-year renewals. The initial six-year term has two components: an initial guaranteed three-year program, and a further program that may be pursued by the licensee if it has fulfilled its initial three-year program. The licensee must relinquish 50% of the licence area before a five-year renewal is granted.

Two other types of exploration licences are available:

- **Petroleum special prospecting authority:** this authorises the holder to conduct exploration activities, but not to drill a well. It cannot be granted for any period longer than 180 days, and is generally granted to permit a seismic firm to shoot data.
- **Petroleum access authority:** this authority can be granted to the holder of a permit (including a special prospecting authority or an exploration permit) to access an adjoining area and conduct activities on that area.

1.3 Transition to production licence or retention lease

If a permit holder discovers an accumulation of petroleum, it must notify the Joint Authority, which can then decide to make a 'Declaration of Location'. Once this declaration is made:

- the holder may apply for a petroleum *production licence* if the discovery is commercial; or
- the holder may apply for a petroleum *retention lease* if the discovery is not presently commercial, but the licensee can demonstrate it is likely to be commercial within 15 years.

1.4 Production licence

Apart from some licences granted before 1998, production licences are for the 'life of field' but may be revoked if no production has occurred for a continuous period of five years. An applicant for a production licence must first have a field development plan (**FDP**) approved by NOPTA. After a production licence is granted, the licensee can only carry on activities in accordance with the approved FDP. NOPTA has a range of powers to direct the holder of a non-producing field to take all steps to enable production, and to require adjoining fields with a shared reservoir to agree to a unitisation arrangement.

1.5 Retention lease

A retention lease permits exploration and appraisal activity. Depending on the reason for the discovery not presently being commercial, a retention lease may require additional work to be carried out by the licensee to remove this impediment. If the impediment is outside of the licensee's control (for example, if technical advances are required), the retention lease may have no work obligations.

Federal petroleum legislation makes extensive provision for the grant of greenhouse gas storage (ie, carbon capture and storage) licences, and for dealing with the potential overlap of these licences with petroleum exploration or production licences. No licences for greenhouse gas storage have been granted to date.

1.6 Other authorisations

Other authorisations required for petroleum activities are:

- **Infrastructure licence:** This is required for any infrastructure for processing or storing petroleum connected to the seabed, or for the production of petroleum using any remote control. It is not required for normal production operations, or even for the operation of a floating production, storage and offloading vessel (**FPSO**) within a production licence area, as these activities are authorised by the production licence. The only known infrastructure licences granted to date are to Shell's Prelude floating LNG project and to Woodside's Pluto LNG project.

- **Pipeline licence:** This licence is required to construct any pipeline to convey petroleum products.
- **Well operations management plan:** Before drilling a well, the title holder must obtain the approval of NOPSEMA.
- **Operator approval:** The operator of a field must be approved by NOPSEMA.

1.7 Environment and safety

Offshore petroleum activities require:

(a) an approved Environment Plan before any activity takes place (including seismic activity, drilling and production). In preparing the plan, the operator must consult with each government department (state and federal) and any other person that might be affected by the activities. The consultation obligations could include, for example, those in the fishing industry, coastal residents or those in coastal industries. The plan must include a description of: the proposed activity; the environment; the environmental risks and environmental performance objectives and standards. It must provide an implementation strategy, including an oil spill prevention plan.

(b) any necessary approvals under the *Environment Protection and Biodiversity Conservation Act 1999* (Cth). These approvals could be required where the activities are in a Commonwealth Marine Reserve, where there is an area of National Environmental Significance (eg, world heritage areas or threatened species) or for activities that may interfere with whales.

(c) an approved safety case, which must be renewed every five years.

1.8 Transfers and dealings with licences

A petroleum title, or an application for a licence, can only be transferred with the approval of NOPTA. Criteria for approving a transfer include that the transferee has appropriate financial and technical capabilities. The parties must disclose the consideration for the transfer, and a registration fee of 1.5% of the consideration is payable to NOPTA. Titles cannot be subdivided.

Dealings relating to a petroleum title must be registered on the petroleum register to have legal effect. This includes pre-emption provisions, royalties, carried interests, farmouts and security interests. Registered dealings can be viewed on the petroleum register (presently located at www.neats.nopta.gov.au).

1.9 Operations, emergency and sanctions

Australia had not seen an oil spill in more than 20 years before 21 August 2009, when a fire on the Montara Platform resulted in the release of oil and gas into the Timor Sea for more than 10 weeks. This was the third-largest oil spill, and the worst offshore oil spill, in Australia's history. It is estimated that an area of about 90,000 square kilometres was affected by patches of sheen or weathered oil at various times.[12]

The Montara Commission of Inquiry was established in an effort to prevent another such occurrence. Three months of consultation followed. The Commission's key recommendations were subsequently adopted by the Federal Government.

As part of this process, Federal Parliament passed a package of regulatory reforms that resulted in the following key changes:

(a) NOPSEMA was created. It took over functions relating to occupational health and safety and structural integrity of facilities, wells and well-related equipment and was given additional responsibility for regulating environmental management and day-to-day operations. This included the power to issue directions, gazette safety zones around petroleum facilities, and appoint Petroleum Project Inspectors – these powers were previously exercised by the Designated Authority;

(b) NOPTA was established to advise the Joint Authority on petroleum titles, advise the responsible Federal Minister on greenhouse gas storage titles, administer titles (and keep the register of titles), and data and resource management; and

(c) before any petroleum activity can occur, petroleum titleholders must now have a safety case that contains an oil spill contingency plan and demonstrates emergency preparedness.

If a significant offshore petroleum incident occurs within the title area that has caused or might cause an escape of petroleum, NOPSEMA may issue a direction:

(a) requiring the titleholder to take action to prevent or eliminate the escape of petroleum (or potential escape of petroleum) and/or to mitigate, manage or remediate the effects of an escape of petroleum; and

(b) where necessary, requiring the titleholder to take action either within or outside the title area in which the incident occurred.

2 ONSHORE (AND STATE COASTAL WATERS)

2.1 Regulatory regime

The state governments have sovereignty and jurisdiction over oil and gas reserves located onshore and within their respective coastal waters. Accordingly, each state has its own legislative and administrative framework for oil and gas exploration and production.

In all jurisdictions, ownership of oil and gas located onshore and within the respective coastal waters is reserved in the Crown (ie, the state government), which issues licences to explore for and produce oil and gas. The person holding the relevant licence obtains ownership of the oil or gas once it passes above the surface of the land.

Different authorisations are necessary for the various stages of oil and gas developments. The particulars of the licensing regime vary from jurisdiction to jurisdiction. A summary of the regulations that apply to the onshore areas of the mainland states (and the Northern Territory) are set out in Table 3 on pages 20-21 Each state also has similar legislation applying to the offshore area (three nautical miles offshore).

2.2 CSG developments

CSG reserves make up the major part of onshore production and reserves in Australia. The CSG industry has developed rapidly over the past 5 to 10 years and the fast-changing environment has led to regulatory, cost and resources pressures. Some of the key areas impacting CSG development are overlapping tenure, access to land, disposal of water and environmental issues. These are discussed in more detail below.

12 Montara Commission of Inquiry, *Report of the Montara Commission of Inquiry,* June 2010, pp. 5-6.

Overlapping tenure

A number of Australia's CSG basins lie under urbanised land, high value agricultural land, or land that bears commercial coal deposits. As CSG is extracted from coal seams, the interests of CSG companies can be (and often are) in conflict with those of coal mining companies. The map below shows the often-overlapping locations of coal and CSG reserves.

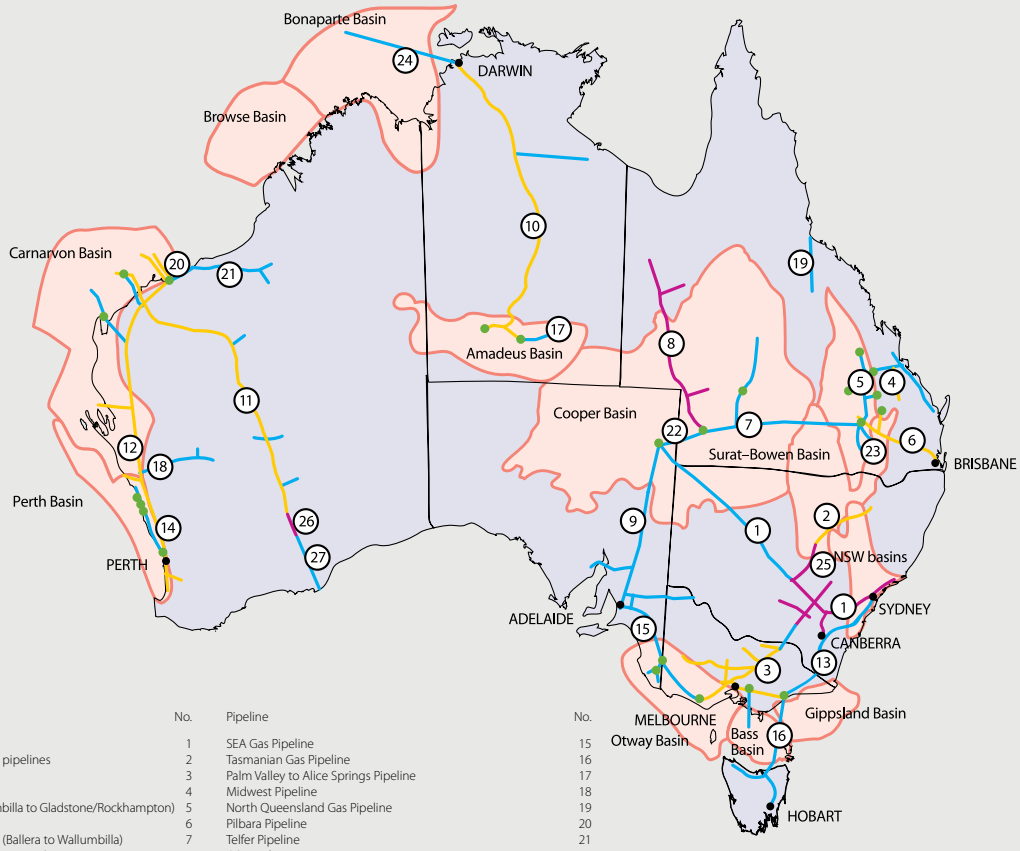
To address these competing interests, legislation has been introduced in Queensland and New South Wales that allows rights in CSG and coal mining to operate contemporaneously if it can be shown that both activities can be conducted together. To resolve any disputes, the common approach taken by state legislative frameworks is to require that:

- parties consult with each other to try and reach a resolution; and
- parties may apply to the relevant Minister to resolve a dispute if private negotiations do not lead to a resolution.

Access to land

A petroleum authority does not give the holder the right to enter land and conduct activities on the land. CSG developments often cover a large area, and this means that the holder needs to negotiate and agree separate access arrangements with each occupier and/or owner of the land. For example, British Gas/QGC's Curtis CSG to LNG project has required more than 1,000 agreements with landholders for access to and use of their land.[13]

Locations of coal and CSG reserves



Pipeline	No.
Moomba to Sydney Pipeline	1
Central West and Central Ranges pipelines	2
Victorian Transmission System	3
Dawson Valley Pipeline	4
Queensland Gas Pipeline (Wallumbilla to Gladstone/Rockhampton)	5
Roma to Brisbane Pipeline	6
South West Queensland Pipeline (Ballera to Wallumbilla)	7
Carpentaria Pipeline (Ballera to Mount Isa)	8
Moomba to Adelaide Pipeline	9
Amadeus Basin to Darwin Pipeline	10
Goldfields Gas Pipeline	11
Dampier to Bunbury Natural Gas Pipeline	12
Eastern Gas Pipeline (Longford to Horsley Park)	13
Parmelia Pipeline	14

Pipeline	No.
SEA Gas Pipeline	15
Tasmanian Gas Pipeline	16
Palm Valley to Alice Springs Pipeline	17
Midwest Pipeline	18
North Queensland Gas Pipeline	19
Pilbara Pipeline	20
Telfer Pipeline	21
QSN Link	22
Berwyndale to Wallumbilla Pipeline	23
Bonaparte Pipeline	24
Central West Pipeline	25
Kalgoorlie to Kambalda Pipeline	26
Kambalda to Esperence Pipeline	27

Source: State of the Energy Market 2009 (AER).

13 QGC website.

TABLE 3: SUMMARY OF ONSHORE OIL AND GAS REGULATION IN AUSTRALIA

	Queensland	NSW	South Australia	
Principal regulator and legislation	Department of Natural Resources and Mines *Petroleum and Gas (Production and Safety) Act 2004* (Qld)	Division of Resources and Energy: Minerals and Petroleum *Petroleum (Onshore) Act 1991* (NSW)	Department of Manufacturing, Innovation, Trade, Resources and Energy *Petroleum and Geothermal Energy Act 2000* (SA)	
Tender process	Since October 2012, cash bidding can be included as part of the tender for areas that are highly prospective. For areas of unknown or limited prospectivity, tenders will be awarded based on the work program, capability and other criteria. The criteria is prescriptive, with points awarded for the depth of wells, area of seismic to be shot and timing of work plan.	The Minister may invite applications for exploration licences (EL). The application must be supported by a work program and evidence of financial standing and technical capabilities.	The Minister calls for tenders for applications over an area of land in a Competitive Tender Region.	
Initial term	An authority to prospect (ATP) is issued for an initial four-year term.	An EL is issued for a term fixed by the Minister and not exceeding six years.	An EL is issued by the Minister for an initial five-year term.	
Work program	The holder of the ATP must have a work program and carry out the activities under the work program. Satisfying the approved work program is not a strict conditionof renewal.	A work program must be submitted in support of EL applications.	A work program must be submitted and approved in support of an EL application as well as details of the applicant's technical and financial resources.	
Relinquishment	One-twelfth of the area must be relinquished each year.	25% of the current licence area must be relinquished on renewal unless the Minister decides otherwise, being satisfied that special circumstances exist.	If the EL is subject to a one term renewal, 50% of the original licence area must be relinquished when the EL is renewed. If the EL is subject to a two-term renewal, one-third of the original EL must be relinquished upon each EL renewal.	
Renewal process	The initial term can be renewed twice for a total of 12 years.	An EL can be renewed by applying to the Minister not less than one month before the EL expires. The Minister has discretion to grant a renewal and determine its term.	An EL may be granted on terms under which the licence is renewable for a further term or further two terms as specified by the Minister at the time of granting the EL.	
Appraisal	There are no appraisal or retention licences in Queensland.	An application for an Assessment Lease (AL) may be made by the holder of an EL to allow the holder to undertake further assessments of any petroleum deposit on the land. The AL is granted for an initial term fixed by the Minister of up to six years The initial term may be renewed at the Minister's discretion.	The holder of an EL can apply for a Retention Licence (RL) where a discovery has been made and the Minister is satisfied that production is not presently commercially feasible but will become so in the next 15 years. An application must be accompanied by a work program. The RL protects the interests of the holder while appraisal is undertaken. An RL can be granted for an initial term for five years and may be renewed once.	
Transition to production	The holder of an ATP (or another person with the holder's consent) may apply for a Petroleum Lease (PL). The government may call tenders for PLs, but this power has not yet been used. The applicant must have its development plan approved by the Minister.	A Petroleum Lease (PL) may be granted to those applicants who hold an EL or AL.	The holder of an EL or RL may apply for a Production Licence (PL). The application must contain all information reasonably required to enable the Minister to make a decision about whether current production is commercially feasible. Where the resource has been discovered and production is commercially feasible, the holder of the EL has a statutory right to the grant of a PL.	
Term – Production	A PL can be granted for a term of up to 30 years.	A PL can be granted for a term of up to 21 years.	The term of a PL is unlimited.	
Royalty	10%	Nil for the first five years, then increases from 6% to 10% from the sixth to tenth years.	10%	

	WA	NT	Victoria
	Department of Mines and Petroleum *Petroleum and Geothermal Energy Resources Act 1967* (WA)	Department of Mines and Energy *Petroleum Act* (NT)	Department of Environment and Primary Industries *Petroleum Act 1998* (Vic)
	Current WA policy is to provide high quality, timely acreage release for companies to bid for. The bidding process is designed to ensure the applicant with the best technical and financial capacity to explore the acreage is selected.	Applications for tenements are not governed by a tender process. Exploration Permit (EP) applications are assessed according to the adequacy of the work program relative to the whole of the area requested in the application.	The Minister may invite tender applications for Exploration Permits (EP). In awarding an EP, the Minister will take into account the merits of the work program, which must be submitted with the application, and the likelihood that it will be carried out as well as the applicant's technical qualifications and financial resources.
	An Exploration Permit (EP) is issued for an initial period of six years.	An EP is issued for an initial five-year term.	An EP is issued for an initial term of five years.
	An applicant must provide a work program and details of financial and technical resources in support of their application.	An application for an EP must include a technical work program that provides evidence of the technical and financial capacity of the applicant to carry out the program.	A work program must be submitted with an application for an EP and in an application for a renewal of an EP.
	50% of an EP must be relinquished on renewal (subject to rounding).	50% of an EP must be relinquished on renewal (subject to rounding).	50% of the permit area will be reduced upon renewal of the EP unless the Minister decides that special circumstances exist.
	An EP may be renewed for up to five years. The application for renewal must be received by the Minister three months before the EP expires. The EP can be renewed twice.	An EP can be renewed up to two times by applying to the Minister. The application must be received between six and three months prior to the expiration of the EP.	An EP can be renewed once only for a further five-year period.
	The holder of an EP may apply for a Retention Lease (RL). The application will be approved if the area contains a discovery and production is not presently commercially feasible but will become so in the next 15 years. The RL remains in force for an initial term of five years and may be renewed on application to the Minister up to six months prior to the expiration of the lease.	The holder of an EP may apply for a Retention Licence (RL) by applying to the Minister. The application must include evidence of the presence of the resource, the need for delay for the production to be commercially viable and the technical and financial capacity of the applicant. A works program must also be submitted.	The holder of an EP may apply to the Minister for a Retention Lease (RL). The application must include details of the commercial viability of extracting the resource and its possible future commercial viability. The RL may be granted for up to 15 years at the Minister's discretion and cannot be renewed.
	The PL application must be accompanied by a work and expenditure proposal. Where a commercial discovery is made, the successful explorer has a statutory right to the grant of a PL.	The holder of an EP or RL may apply for a Production Licence (PL).	The holder of an EP or RL may apply for a production licence (PL). The Minister may also call for tenders for the grant of a PL where the land is not the subject of an EP, RL or PL.
	A PL is granted for a term of 21 years and may be renewed.	A PL can be granted for a term of between 21 and 25 years.	A PL has no term limit and will run until it is surrendered by the holder or cancelled by the Minister.
	Between 5% and 12.5% of the royalty value of the value of the petroleum.	10%	10%

In Queensland, except for any activity that is 'preliminary' (restricted to walking on the land, taking surveys, etc.), a tenement holder must enter into a 'conduct and compensation agreement' with the occupier (and potentially the owner) of each parcel of land on which it wants to undertake activities. The legislation prescribes the terms that must be included in such agreements, including compensation for the actual effect of the proposed activities on the land and for the landholder's costs.

The parties must first seek to negotiate an agreement, and failing agreement pursue alternative dispute resolution. If no agreement has been reached, either party may seek a determination by the Land Court. The holder of an authority may undertake petroleum activities while a matter is before the Land Court. In practice, applications to the Land Court are rare.

The rules and procedures in New South Wales (the other substantial CSG jurisdiction) are similar to those found in Queensland. However, any eventual determination is made through arbitration rather than a court.

CSG water

CSG extraction requires the 'de-watering' of coal seams before gas can be extracted. This can result in the production of vast quantities of water, which must be processed and then either used or re-injected into deep seams. The processing of the water produces large quantities of brine and other minerals.

In Queensland, CSG producers have a right to use underground water for activities that are authorised under their mining tenements and to supply water to owners or occupiers of land within the tenement area for stock and domestic purposes.

CSG water is classed as 'waste' under Queensland's regulatory regime. Therefore, it must be disposed of in accordance with prescriptive waste management regulations. If a CSG producer wants to use waste water in a beneficial manner, a beneficial use approval is required.

Provision of CSG water to third parties requires a water licence and registration as a water service provider under Queensland law.

The *Environment Protection and Biodiversity Conservation Act 1999* (Cth) (**EPBC Act**) makes water resources (including underground waters) a matter of national environmental significance in relation to coal seam gas and large coal mining development. As a result, all proponents of such developments will need to consider the impacts and likely impacts on a water resource and will probably require Federal Government approval.

Environmental issues – fraccing

Hydraulic fracturing (commonly called 'fraccing') has recently come to the forefront of regulatory debate in Australia following the emergence of the unconventional gas industry in Queensland and New South Wales.

Both government and community concern has been raised about the use and release of fracturing chemicals and the treatment and disposal of water produced as a by-product of fracturing operations.

To address community concerns, the Queensland and New South Wales state governments have started to regulate hydraulic fracturing. They require unconventional gas companies to invest in research to determine the extent of the environmental impact on ground water, connectivity between aquifers and managed aquifer recharge.

The hydraulic fracturing process is regulated directly at a state and federal level – by conditions imposed on environmental permits, authorities and licences. At the state level, however, the regulatory framework with respect to hydraulic fracturing needs to be constantly monitored because of its evolving nature. For example, Queensland's *Environmental Protection Act 1994* now prohibits the use of benzene, toluene, ethylbenzene and xylenes in hydraulic fracturing operations, and the *Petroleum and Gas (Safety and Production) Act 2004* has recently imposed reporting obligations around fracturing operations.

04

"Australia's natural gas reserves are linked to major domestic markets by more than 25,000 kilometres of high pressure transmission pipelines."

Downstream regulation

1 PIPELINES

1.1 Separating gas production and delivery

Australia's natural gas reserves are linked to major domestic markets by more than 25,000 kilometres of high pressure transmission pipelines. Traditionally, gas was transported from a production facility to a commercial market by a single pipeline. The Australian gas market is now moving towards a national pipeline network, however, with an interconnected pipeline network covering New South Wales, Queensland, Victoria, South Australia, Tasmania and the Australian Capital Territory.

Australian competition laws require gas transmission and distribution to be kept legally separate from gas trading businesses (whether wholesale or retail). Transmission and distribution pipelines are subject to Australia's third-party access regime.

1.2 National Gas Law and Rules

The National Gas Laws (**NGL**) and National Gas Rules (**NGR**), have been in place in all Australian states and territories since 2009.

The objective of the NGL is:

> "to promote efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas."

The 'coverage' process under the NGL and NGR determines whether a pipeline should be subject to an access arrangement and, if so, in what form. There are four ways in which a pipeline can become covered under the NGL:

(a) gas transmission and distribution systems covered under the old Gas Pipelines Access Law on the day the NGL commenced are deemed to be covered under the NGL;

(b) any person may apply to the National Competition Council (**NCC**) for a pipeline to be covered;

(c) a pipeline service provider may seek coverage by submitting a voluntary access arrangement for approval by the AER;

(d) if a competitive tender approved by the relevant regulator is used to select the service provider for a new pipeline, that new pipeline will be covered from the time the relevant regulator approves the outcome of the competitive tender.

1.3 Criteria for coverage

The NCC must recommend that the pipeline be covered if it is satisfied that all of the following 'coverage criteria' are met:

(a) access (or increased access) to pipeline services provided by means of the pipeline would promote a material increase in competition in at least one market (whether or not in Australia), other than the market for the pipeline services provided by means of the pipeline;

(b) it would be uneconomic for anyone to develop another pipeline to provide the pipeline services provided by means of the pipeline;

(c) access (or increased access) to the pipeline services provided by means of the pipeline can be provided without undue risk to human health or safety; and

(d) access (or increased access) to the pipeline services provided by means of the pipeline would not be contrary to the public interest.

The NCC's coverage recommendation is then provided to the relevant Minister, who

must decide whether to make a coverage determination in respect of the pipeline.

1.4 Forms of regulation

A 'full regulation' pipeline is one that has been subject to a full coverage determination. Full regulation pipelines are required to have a full access arrangement in place that contains price and revenue terms and other (non-price) terms and conditions of access for reference services provided on the pipeline. Prices that are charged are subject to the regulatory oversight of the AER.

The service provider of a 'full regulation' covered pipeline is required to submit a full access proposal to the AER within three months of becoming a covered pipeline. Once approved by the AER, the access arrangement is enforceable, and an access seeker may request the regulator to arbitrate a dispute.

Access arrangements typically include reference tariffs for the pipeline (usually for firm haulage service). While the NGR contains a number of different options for determining the allowable revenue, the broad pricing principle is that a service provider should be provided with the opportunity to recover efficient costs and have effective incentives to promote efficiency.

1.5 Light handed regulation

In addition to full regulation, the NGL now offers a 'light-handed' regulatory regime for covered pipelines. Under this regime, a person who seeks to provide 'light' regulation services must apply to the NCC for a determination that pipeline services be provided by way of light regulation services.

In making a light regulation determination, the Australian Energy Market Commission must consider various factors, including:

(a) the extent of any market entry barriers for the pipeline services offered;

(b) the market power of the service provider and whether it will be mitigated by any countervailing market power possessed by potential customers;

(c) the availability of substitutes and the elasticity of demand in the market for the pipeline services offered; and

(d) the extent of information available to potential customers enabling them to negotiate on an informed basis with the service provider.

Light regulation is considered particularly relevant for point-to-point transmission pipelines with a small number of users who have countervailing market power.

If the determination is granted, the service provider is not required to obtain approval of an access arrangement or pricing principles. Under the 'light regulation' system, the service provider is only required to publish terms and conditions of access, although it is prohibited from engaging in price discrimination unless it 'is conducive to efficient service provision' or 'can be justified on some other rational economic basis'. Provision exists for arbitration of access disputes by the AER.

1.6 Binding no-coverage determinations/pricing exemptions

Before a greenfields (ie, new) domestic or international pipeline is commissioned, a service provider may apply to the NCC for a '15-year no-coverage determination'. This determination by the Minister means that the pipeline remains uncovered for 15 years from the commissioning of the pipeline. During that period, the AER will not approve access arrangements or make an access determination (in relation to disputes) about the terms and conditions of access for the pipeline.

In making the assessment, the NCC must assess a proposed greenfields pipeline against the 'coverage criteria' and have regard to the objective of the NGL. If the NCC is not satisfied that all of the coverage criteria are satisfied, the NCC must recommend a binding no-coverage determination.

The proponents of an international greenfields pipeline project may also apply for a price regulation exemption for the pipeline before the pipeline is commissioned. The NCC must weigh the benefits to the public of granting the exemption against the detriment to the public.

If a price regulation exemption is granted, the services provided by the pipeline are not subject to price regulation under the gas access regime for a period of 15 years from the commissioning of the

pipeline. However, a price regulation exemption is only effective if a Limited Access Arrangement (**LAA**), approved by the Australian Competition and Consumer Commission (ACCC), is in force in relation to that pipeline. Obtaining a LAA is a separate process from the NGL provisions relating to access arrangements for existing pipelines.

1.7 Gas Market Bulletin Board and Short-Term Trading Markets

A Gas Market Bulletin Board, commenced on 1 July 2008 and has been phased in to various jurisdictions as improved connection has made spot trading possible. The bulletin board is a website covering major gas production fields, storage facilities, demand centres and transmission pipelines in southern and eastern Australia. It is designed to:

(a) facilitate trade in natural gas and markets for natural gas services by providing system and market information that is readily available to all interested parties, including the general public; and

(b) assist in emergency management by providing system and market information.

The bulletin board is operated by the Australian Energy Market Operator (**AEMO**). The AER monitors and enforces the compliance of market participants with the bulletin board rules. In May 2011, Western Australia's Energy Minister announced that a gas market bulletin board would be set up in that state and operated by Western Australia's Independent Market Operator. Currently, the Northern Territory does not participate in the bulletin board.

In 2010, the Short-Term Trading Market (**STTM**) for natural gas commenced operation in New South Wales and South Australia after a six-month market trial period. The STTM operates at hubs between gas transmission pipelines and distribution networks in Sydney and Adelaide. A further hub was established at Brisbane in 2011.

The STTM operates so that all gas supplied through the hub is transacted in the STTM, including gas supplied under existing long-term contracts. Each hub is scheduled and settled separately under the same STTM rules.

The STTM has been described as a 'hybrid mixture of market and physical operations' because it is not a traditional commodity market, separate from physical operations nor is it a modern network market that determines operations. The STTM is underpinned by pipeliners setting daily capacity for delivery of gas to the hub, and bids and offers being accepted only from shippers and users that have appropriate registered trading rights.

Ensuring compliance with, and enforcement of, the STTM rules is the responsibility of the AER. In addition, AEMO has developed formal market procedures that cover technical and procedural matters for the operation of the market.

The STTM does not operate in Victoria as the existing Victorian Wholesale Gas Market (**VWGM**) continues to operate in that state. The VWGM sets the price for trading imbalances between market participants – the price is set at the marginal bid price for the volume that day ('stacked' from lowest to highest price). To participate in the VWGM, a person must register with AEMO, sign relevant contracts, meet prudential requirements (including providing a bank guarantee) and connect to the IT trading system.

2 LNG AND EXPORT

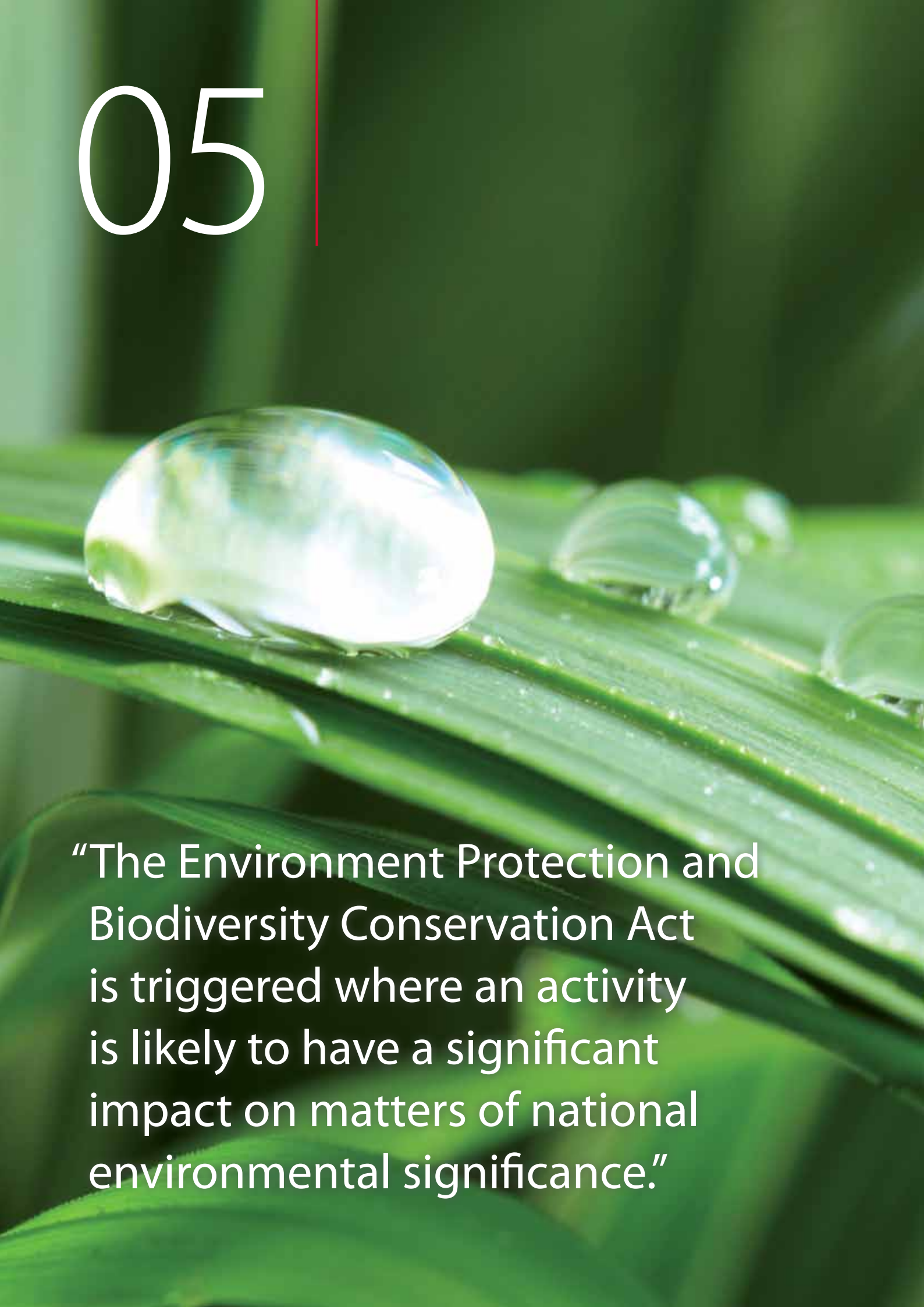
Exporters of LNG in Australia do not need an export licence and are free to liquefy and export any gas produced.

The introduction of a domestic gas reservation policy has been considered by various Australian states. Western Australia is the only one to have introduced such a policy (in 2006).

In Western Australia, proponents of export gas projects must set aside the equivalent of 15% of LNG production from each export gas project for domestic gas supply as a condition of locating processing facilities in that state. Accordingly, the policy (and the reach of the Western Australian Government) does not extend to any floating LNG projects.

For now, other states continue to operate with no requirement for gas to be reserved for domestic use. Queensland has rejected the need for such a policy. Discussions continue in the Northern Territory.

05



"The Environment Protection and Biodiversity Conservation Act is triggered where an activity is likely to have a significant impact on matters of national environmental significance."

Environment and planning

1 ENVIRONMENTAL ASSESSMENT PROCESS

In general terms, any person proposing to undertake oil and gas activities must undergo state or territory, and in some cases federal, environmental impact assessment and approval processes. The level of assessment will depend upon the nature of the activities and their likely adverse impact on the environment.

Where the project activities require a thorough environmental assessment, an environmental impact statement (**EIS**) is usually prepared and there is the opportunity for public comment on the project. The key elements of this type of environmental assessment/approval process are:

(a) identifying the scope of environmental matters to be investigated for the project (this may be publicly notified);

(b) preparing a report on the potential impacts the project will have on the environment and how those impacts will be avoided, minimised and managed (usually by way of an EIS);

(c) consulting with the public on the potential impacts of the project on the environment (usually the EIS will be notified);

(d) assessing the project, which will then be approved, or approved subject to conditions, or refused; and

(e) undertaking monitoring and reporting for the project to ensure that its environmental footprint is properly managed.

The environmental assessment process will require preparing a multidisciplinary report, which canvases areas including flora, fauna, water, noise and dust. This report will rely on baseline studies (where appropriate) and predict the likely impact of the project's activities on the environment.

2 KEY FEDERAL LEGISLATION

At a Federal Government level, the key legislation is the EPBC Act, which is triggered where an activity is likely to have a significant impact on matters of national environmental significance. Matters of national environmental significance include the Great Barrier Reef Marine Park and listed threatened species and ecological communities (and, potentially, water resources in respect of CSG and coal mine developments – see chapter 3, section 2.2). Where the EPBC Act is triggered, approval by the Federal Environment Minister is required.

While there may be some duplication between state/territory and federal environmental assessment and approval processes in some cases, a bilateral agreement between state/territory governments and the Federal Government seeks to minimise duplication by streamlining applicable environmental assessment processes.

Additional federal legislation that may be relevant includes:

(a) Offshore Petroleum and Greenhouse Gas Storage (Environment) Regulations 2009 (Cth), which regulates the conduct of offshore petroleum activities that may impact the environment;

(b) *Protection of the Sea (Prevention of Pollution from Ships) Act 1983* (Cth), which applies to all ships (Australian and foreign), including floating platforms, that may discharge oil and other pollutants into Australia's exclusive economic zone (up to 200 nautical miles); and

(c) *Environmental Protection (Sea Dumping) Act 1981* (Cth), which requires ships and floating platforms to prevent/reduce/eliminate pollution caused by dumping at sea.

3 KEY STATE AND TERRITORY LEGISLATION

Each of Australia's states and the Northern Territory require activities that are likely to affect the environment to be assessed and then approved (with or without conditions). This includes most oil and gas activities. The process must be followed before the grant of any petroleum exploration or production licence and before any environmentally significant change in a project.

The key legislation in each state and territory is:

New South Wales

Environmental Planning and Assessment Act 1979 (NSW)

Protection of the Environment Operations Act 1997 (NSW)

Water Management Act 2000 (NSW)

Victoria

Environment Protection Act 1970 (Vic)

Environmental Effects Act 1978 (Vic)

Offshore Petroleum and Greenhouse Gas Storage Act 2010 (Vic)

Queensland

Environmental Protection Act 1994 (Qld)

Water Act 2000 (Qld)

Western Australia

Environmental Protection Act 1986 (WA)

Conservation and Land Management Act 1984 (WA)

South Australia

Development Act 1993 (SA)

Northern Territory

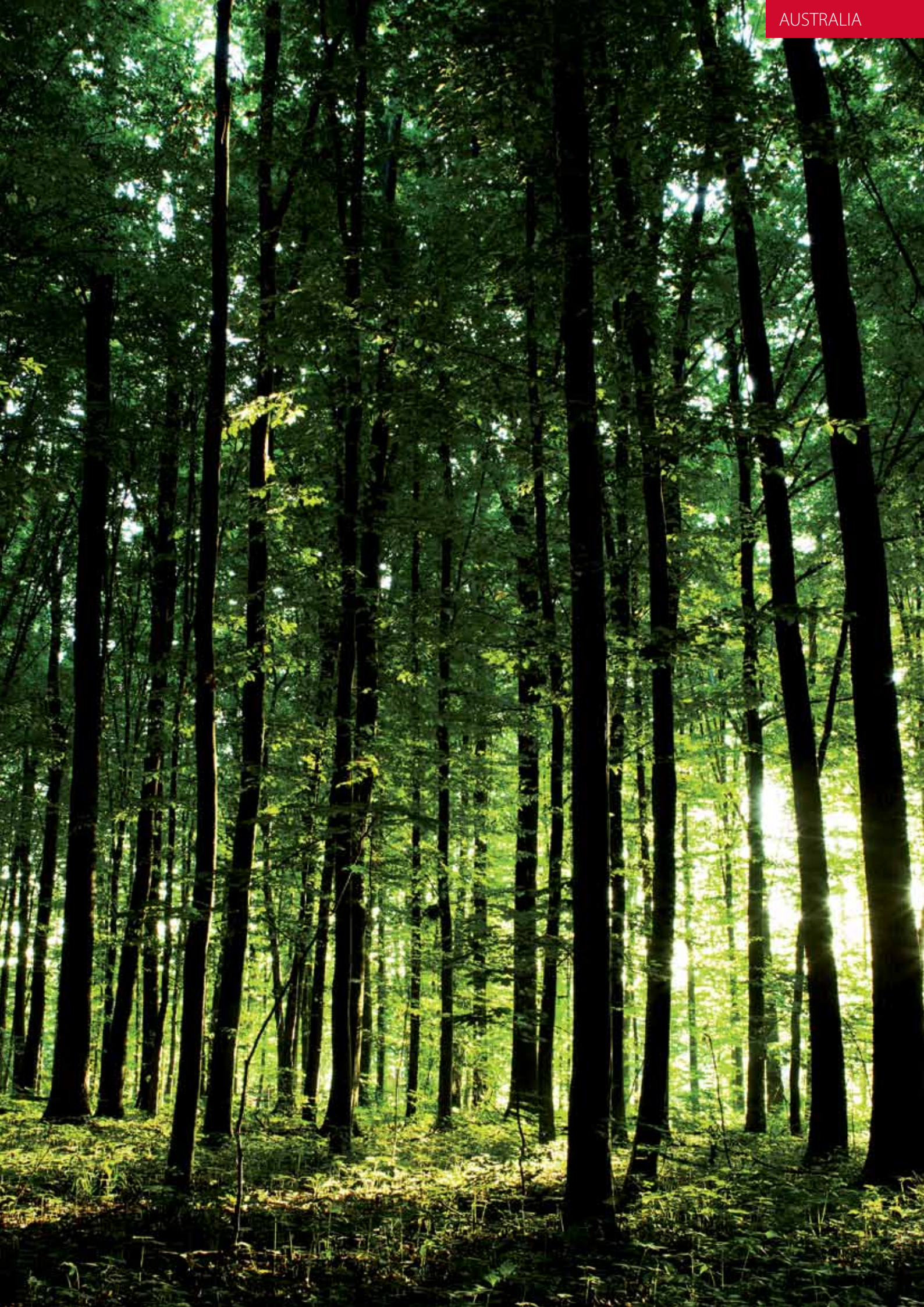
Petroleum Act 1984 (NT)

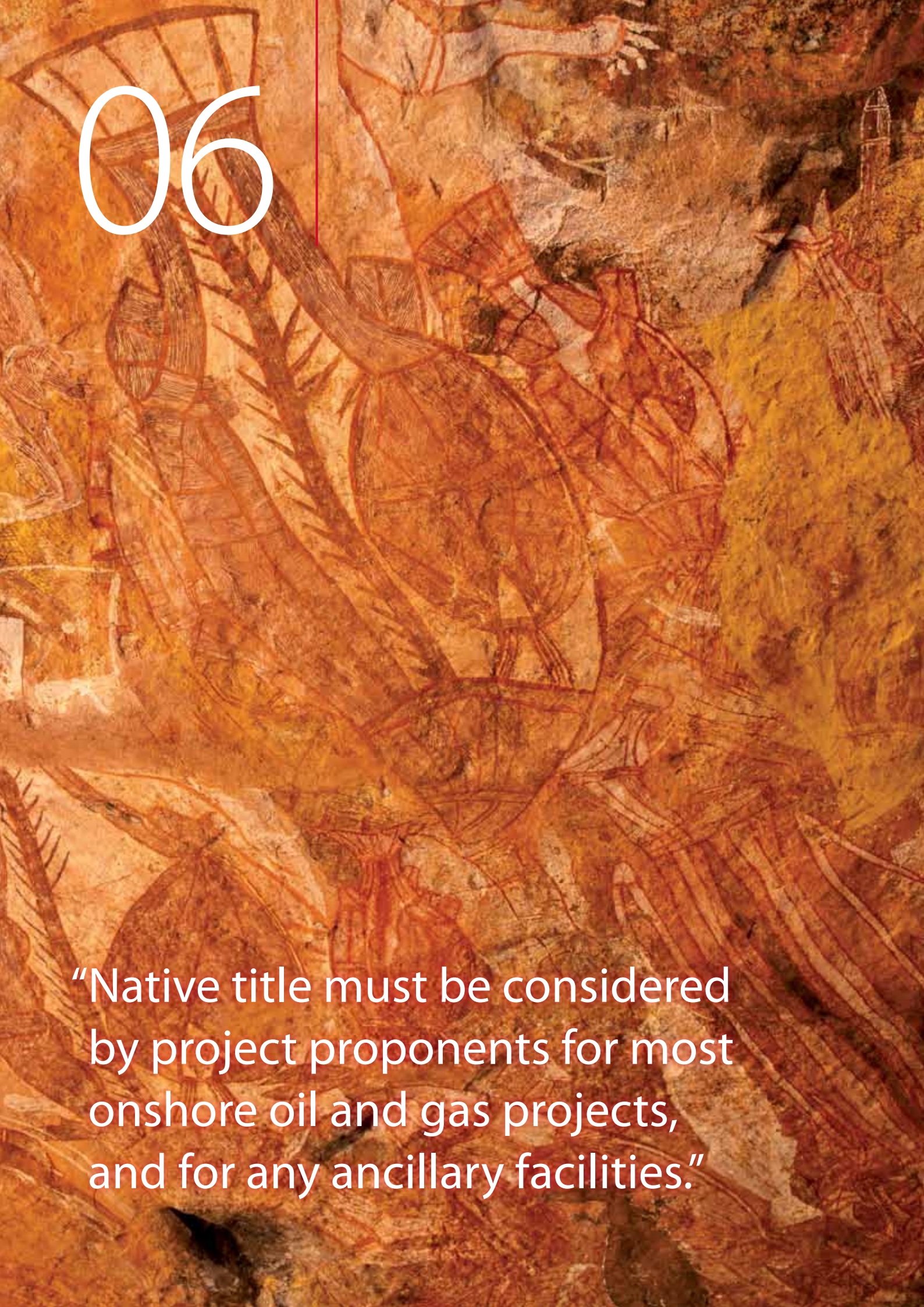
Territory Parks and Wildlife Conservation Act 1976 (NT)

Generally, approvals will be granted subject to a bond or security that can be drawn upon by the regulating authority where the project proponent does not comply with the approval conditions, including failing to rehabilitate and remediate a site.

4 APPROVAL IS LIKELY TO BE REQUIRED

Given the nature of oil and gas activities, at least one, if not multiple, environmental approvals will be required to carry out the project. Obtaining environmental approvals can be time consuming, and involve undertaking environmental studies, preparing reports, undergoing public consultation and preparing responses and negotiating conditions. Therefore, it is important that the environmental approvals that may be required for the project are identified upfront and then properly reflected in project schedules.





06

"Native title must be considered by project proponents for most onshore oil and gas projects, and for any ancillary facilities."

Native title and Aboriginal cultural heritage

1 NATIVE TITLE

Australian law recognises the native title rights of Aboriginal and Torres Strait Islander people in relation to land. Unless extinguished (for example, by the grant of freehold or some other right inconsistent with the exercise of native title), traditional owners of the land will have native title rights where and to the extent that they have maintained a traditional connection with the land. Accordingly, native title must be considered by project proponents for most onshore oil and gas projects, and for any ancillary facilities (eg, LNG terminals).

Where a person makes an application for an interest for the exploration or production of oil or gas onshore the state must notify the registered native title bodies corporate, the registered native title claimants and the representative Aboriginal/ Torres Strait Islander body for the area covered by the application. If there are no registered native title claimants or registered native title bodies corporate within four months after that notice, the state or territory is entitled to grant the petroleum interest without further reference to native title.

If there are interested parties, all parties (including the state or territory and the prospective grantee of the interest) must negotiate in good faith to obtain consent from the registered claimants or registered native title body corporate (called the Right to Negotiate process). If agreement has not been reached within six months of notification, any negotiating party may apply to the National Native Title Tribunal (**NNTT**) for a determination. The NNTT is required to make a determination that the tenement may be granted or not, or that it may be granted with conditions. To date, there have been only a few instances where the NNTT has determined outright that an act such as the grant of a tenement cannot be done, although there are many instances of determinations that an act can be done subject to conditions.

Some limited procedural requirements regarding native title may also apply for offshore oil and gas activities.

Negotiation of an indigenous land use agreement is an alternative way of satisfying native title requirements to obtain the grant of a petroleum interest.

2 ABORIGINAL CULTURAL HERITAGE

In addition to native title, Australian law recognises and protects items and sites of cultural significance to indigenous groups.

Unlike native title, Aboriginal cultural heritage (often referred to as artefacts and sacred sites) cannot be 'extinguished'. This is because the existence of Aboriginal cultural heritage is a physical attribute or otherwise arises by virtue of the significance of an area according to Aboriginal history or tradition.

The protection of Aboriginal cultural heritage is primarily governed by state and territory legislation. Although federal legislation is also in place, it is rarely used. There are a number of broad features apparent in many of the Australian jurisdictions, including those listed in Table 4 on page 34.

Project proponents will often manage their obligations regarding Aboriginal cultural heritage by entering into and complying with agreements (called 'cultural heritage management plans') with the relevant Aboriginal party. These agreements will usually outline the measures to be taken before, during and after an activity in order to manage and protect Aboriginal cultural heritage in the activity area.

TABLE 4: SUMMARY OF ABORIGINAL CULTURAL HERITAGE PROTECTION REQUIREMENTS

	ACT	NSW	NT	Qld	SA	TAS	Vic	WA	Cth
a duty of care to avoid harm to Aboriginal cultural heritage				X					
protection of both sites and objects	X	X	X	X	X	X	X	X	X
establishment and maintenance of a register of sites	X	X	X	X	X		X	X	
protection of all Aboriginal cultural heritage, whether registered or not	X	X	X	X	X		X	X	
establishment of a permit system to permit disturbance to Aboriginal cultural heritage	X	X	X		X	X	X	X	
significant financial penalties for harm to Aboriginal cultural heritage	X	X	X	X	X	X	X	X	X
terms of imprisonment for harm to Aboriginal cultural heritage		X	X	X	X	X		X	
ability to grant injunctions, declarations or stop orders to prevent harm to Aboriginal cultural heritage	X	X		X			X		X

3 ABORIGINAL LAND

There are a number of Aboriginal land regimes throughout Australia. The most extensive legislative framework is in the Northern Territory – under the *Aboriginal Land Rights (Northern Territory) Act 1976* (Cth), which preceded the formal recognition of native title in Australia.

In the Northern Territory, the local Aboriginal peoples for an area of Aboriginal land have a right of veto in relation to whether an exploration tenement is granted. However, once the Aboriginal people have consented to the grant of an exploration tenement (and an agreement has been concluded), they are largely bound to negotiate a production agreement if the exploration tenement holder discovers and wishes to develop any viable reserves.

Not all jurisdictions grant such powers to the relevant Aboriginal peoples. The legal framework in each jurisdiction must be assessed to determine what rights apply and what procedures must be undertaken.

In the Northern Territory, South Australia, the Australian Capital Territory and Victoria, the future acts regime of the *Native Title Act 1993* (Cth) is excluded from operation in relation to Aboriginal land. This means that where there is Aboriginal land in those jurisdictions, there is no duplication of obligations on project proponents, and compliance with only the Aboriginal land regime is required.

4 TIMEFRAMES

Addressing native title and Aboriginal cultural heritage requirements can be time consuming and proper provision for these processes must be included in project schedules.

07

"A large refinery is estimated to emit between 600,000 and 800,000 tonnes of CO_2-e per annum."

Carbon policy and regulation

1 INTRODUCTION

The Federal Parliament passed the *Clean Energy Act 2011* (Cth) in November 2011 incorporating a Carbon Pricing Mechanism (**CPM**). The CPM and other measures took effect from 1 July 2012, with the first scheme year running from 1 July 2012 to 30 June 2013.

Shortly before this publication was finalised, the Liberal-National Coalition was elected to government. The new Coalition Government has pledged to abolish the 'carbon tax' and replace it with its 'Direct Action Plan'.

Like the Labor Government before it, the new Coalition Government is committed to reducing Australia's greenhouse gas emissions by 5% by 2020 (against 2000 levels).[14] The central component of the Direct Action Plan, as proposed by the Coalition back in 2010, is the establishment of an Emissions Reduction Fund (**ERF**) worth A$2.55 billion over four years.

The ERF would focus on:

- emissions reduction through bio-sequestration of CO_2 in soil (supporting up to 86 million tonnes per annum of CO_2 abatement); and
- reducing CO_2 in the electricity sector by providing incentives for the worst emitting power stations to reduce their emissions on a voluntary basis and supporting the development of Clean Energy Hubs in the La Trobe Valley, Hunter and Central Queensland regions.

The ERF would operate as a 'reverse auction', purchasing the lowest cost carbon abatement until targets and objectives are met. More specifically the ERF would:

- seek tenders and provide funding for projects that deliver the lowest cost abatement;
- provide financial benefits to entities that operate below historical emissions levels and penalise those entities that exceed historic emission levels; and
- provide funding for other activity to meet the emissions reduction target, such as forestry measures, waste coal mine gas, green building and energy efficiency, landfill, composting, recycling and transport fuels.

Now that it is in government, the Liberal-National Coalition is likely to take its first steps to implement the Direct Action Plan. In a speech in mid-2013, Greg Hunt (at that time the Shadow Minister for Climate Action, Environment and Heritage) announced the Coalition's commitment to:

- calling for submissions on the implementation of the ERF within 30 days of being elected;
- consulting between days 60 and 100; and
- releasing a White Paper and draft legislation by day 100 after taking office, seeking industry input on how the ERF reverse auction will work in practice.

However, the new Coalition Government does not (and will not in this Parliament) have a majority in the Senate and it is unclear what aspects of the Direct Action Plan will be implemented.

This chapter provides an overview of the climate change laws and policies relevant to the oil and gas sectors, with the focus on the Clean Energy Future Scheme (**CEF Scheme**), which is still law until such time as the Coalition Government is able to repeal the *Clean Energy Act 2011* (Cth) and implement the Direct Action Plan.

14 The Coalition's Direct Action Plan.

2 CLEAN ENERGY FUTURE SCHEME

The CEF Scheme has established a broad regulatory framework aimed at Australia's biggest carbon emitters. It is part of the Federal Government's overarching commitment to reduce greenhouse gas (**GHG**) emissions by at least 5% compared with 2000 levels by 2020 and 80% by 2050. In order to reach these stated levels, the CEF Scheme outlines a range of mechanisms and initiatives, including:

- the introduction of a CPM;
- assistance and relief packages for certain entities and industries that will be most affected by the CPM;
- promoting innovation and investment in renewable and sustainable energy through funding for research and development;
- energy efficiency initiatives; and
- creating opportunities in the land sector to reduce carbon emissions.

As at March 2013, 360 entities in Australia were listed in the 'Liable Entity Public Information Database' as emitters of more than 25,000 tonnes of carbon pollution equivalent per annum. The database includes upstream exploration and production entities (offshore and onshore), pipeline and LNG companies, and refining facilities.

2.1 Overview of the CPM

Since 2007, businesses that consume or produce energy or emit greenhouse gases above certain thresholds have had to report their energy and emissions under the National Greenhouse and Energy Reporting Scheme (NGERS). The information reported under NGERS provides the basis for assessing emissions liability under the CPM. The Coalition Government plans to retain the NGER Scheme. The CPM came into force on 1 July 2012.

The initial phase of the scheme is designed to operate using a fixed price for emissions: A$23/tonne of carbon dioxide equivalence (**CO_2-e**) for the 2012-13 financial year and rising to A$24.15 and A$25.40/tonne for the following two years. Up to 5% of a liable business' obligation during this period may be met by surrendering Australian Carbon Credit Units (**ACCUs**), which are generated under the Carbon Farming Initiative. Liquid fuels and fuel users are not directly subject to the CPM, although reductions to fuel tax rebates and excise remissions produce an effect equivalent to the carbon price.

From 1 July 2015, the CPM will transition into an emission trading scheme (**ETS**). The number of carbon units auctioned by the Federal Government (or, in certain cases, issued freely) will be restricted to correspond with the emissions cap imposed by the Federal Government and the price of the carbon units will be set by the market.

The floating price will be restricted during the first three years of the ETS by a ceiling price. The price ceiling will be set at A$20 above the expected international price in 2015-16 and will rise in real terms at 5% per annum. If the price of the carbon unit reaches the ceiling, then the restriction on carbon units issued will be eased.

The Federal Government announced in August 2012 that it would abolish a proposed floor price from 1 July 2015, the date of linkage with the European Union Emissions Trading Scheme.

If a liable entity fails to surrender enough carbon units to meet its obligation, it will be required to pay a 'unit shortfall charge'. During the fixed price period, this is set at 130% of the fixed price of carbon emissions for the corresponding year. Once the ETS is in effect, the unit shortfall charge will be up to 200% of the average auction price for the relevant period.

During the period of the ETS, liable entities will also be able to meet their obligations by surrendering ACCUs and, until 2020-2021, up to 50% of their liability using eligible international units (although eligible Kyoto units may only be used to meet up to 12.5% of an entity's total annual liability).

2.2 Scheme coverage and liability – general

The CPM is designed to impose liability on businesses for the direct emissions of carbon dioxide, methane, nitrous oxide and, in the case of aluminium smelting, perfluorocarbons. Liability will be imposed on the entity that has 'operational control' of a 'facility' that emits more than the 25,000 tonne of CO_2-e threshold per year.

The CPM regulates emissions across a range of industries, including mining (fugitive emissions), stationary energy (including electricity generation), non-legacy waste and industrial processes. Agriculture, forestry and fishery are not covered under the CPM. As mentioned earlier, a separate regime applies for certain liquid fuels to produce an effect equivalent to the carbon price.

2.3 Scheme coverage and liability – natural gas

The CPM incorporates separate rules for GHG emissions associated with natural gas. The CEF Scheme seeks to achieve 100% liability coverage for natural gas, so there are no minimum liability thresholds for suppliers of natural gas. Suppliers will generally be liable for emissions embodied in the natural gas that they supply to end users. However, any large gas consuming facilities that directly procure natural gas for their operation will have the carbon liability shifted to it under the CPM for emissions resulting from the combustion of that gas.

To help businesses manage their natural gas CPM liabilities, the CPM contains a mechanism that provides for 'obligation transfer numbers' (**OTNs**). OTNs facilitate the transfer of obligations between suppliers of natural gas and end-users. Quoting an OTN will relieve the gas supplier of liability under the CPM and liability will transfer to the recipient end-user of the natural gas.

There are provisions in the CPM designed to prevent double counting of emissions liability in relation to natural gas supplies.

Entities that purchase natural gas to use as feedstock or in the manufacture of LNG, CNG or LPG are also able to purchase the gas using an OTN and subsequently manage CPM liability for the use of the gas. Because the eventual emissions from the combustion of export LNG are not intended to be subject to the CPM, the OTN mechanism is designed to allow the purchaser to buy the gas at a carbon-exclusive price, without incurring any carbon liability for the natural gas not combusted in Australia.

2.4 Scheme coverage and liability – LNG

LNG projects are likely to fall within the operation of the CPM, although the effect of the CPM on LNG projects is yet to be fully determined.

The level of emissions generated by an LNG project will depend on a range of variables, including the size of the LNG facility, fugitive emissions from the entirety of the production, processing and transportation chain, the specification of the feed gas, the degree of flaring and the carbon efficiency of the compression and refrigerant system used. For CSG-sourced LNG projects, emissions from the operation of the gas fields through to the LNG plant have been stated to be approximately 0.905 tonnes of CO_2-e per tonne of LNG produced.[15] Industry sources have stated that off-shore operations with LNG plants located above the gas fields emit between approximately 0.33 and 0.46 tonnes of CO_2-e per tonne of LNG produced.[16]

15 WorleyParsons, Greenhouse Gas Emissions Study of Australian CSG to LNG, 2011.
16 Shell Development (Australia), Prelude Floating LNG Project, 2010.

Entities operating onshore LNG projects sourced from CSG potentially face additional carbon liability in the form of fugitive emissions from the process of extracting the CSG. The extent of fugitive emissions from CSG extraction is not clear.

The CEF Scheme's Jobs and Competitiveness Program is designed to support the LNG export industry and other emissions-intensive trade-exposed (EITE) industries. Under this program, the production of LNG is prescribed as a moderately emissions-intensive trade-exposed activity for which eligible entities are entitled to receive assistance (free carbon units) to cover 66% of industry average carbon costs in the 2012-2013 financial year. These assistance rates will reduce by 1.3% per year.

Assistance is available in relation to LNG production but does not apply to any upstream emissions from an LNG project. However, a supplementary allocation of free carbon units is potentially available to LNG projects. Any eligible entity that undertakes LNG production is entitled to an allocation of free carbon units to ensure an effective assistance rate of no less than 50% of the emissions from the entire LNG project (which includes upstream emissions). The Australian Productivity Commission will review the Jobs and Competitiveness Program in 2014-2015 and may recommend changes to the assistance available to the CSG and the LNG industry.

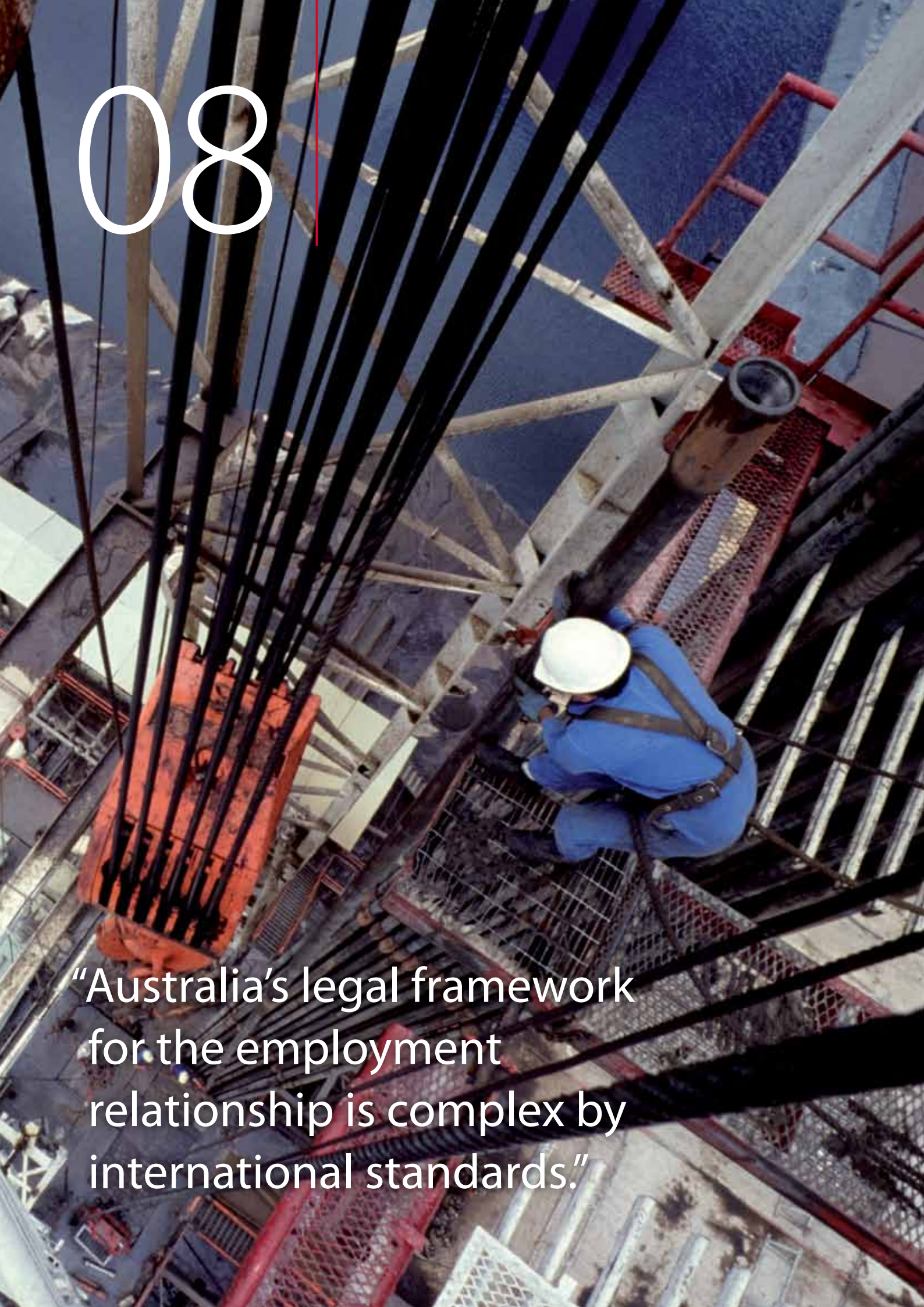
2.5 Scheme coverage and liability – oil and gas facility

Any significant oil or gas facility is likely to fall within the operation of the CPM and face carbon liability issues. Carbon emissions are generated at almost every step of an oil and gas facility's process – from exploration, extraction and processing of the resources to delivery of these resources to refineries and customers. This includes facilities located at production sites such as oil wells, gas wells and offshore oil and gas rigs, petroleum refineries, chemical plants and natural gas processing plants.

Emissions from offshore and onshore oil and gas facilities most commonly result from combustion of fuel, flaring and venting of gas and fugitive emissions. A large refinery, such as the BP Kwinana Refinery, is estimated to emit between 600,000 and 800,000 tonnes of CO_2-e per annum.[17] The ExxonMobil oil and gas platforms in the Bass Strait report emissions of approximately 400,000 tonnes of CO_2-e per annum.[18]

Petroleum refining may be entitled as an EITE activity to receive assistance from the Jobs and Competitiveness Program.

17 BP, Air Emissions BP Refinery Kwinana.
18 ExxonMobil, Offshore Bass Straight 2010 Environmental Report, 2010.



08

"Australia's legal framework for the employment relationship is complex by international standards."

Workforce issues

1 INDUSTRIAL RELATIONS

Australia's legal framework for the employment relationship is complex by international standards. Australian employees enjoy more rights and protections (including minimum conditions of employment, protection against unfair termination and discrimination) than employees in many other jurisdictions.

Federal and state employment laws are relevant, although responsibility for employment regulation has recently been substantially assumed by the Federal Government. The *Fair Work Act 2009* (Cth) (**FWA**) is the primary source of employment regulation in Australia. It sets out, in the National Employment Standards (**NES**), minimum terms and conditions that apply to all employees in Australia.

The NES provides minimum standards in relation to maximum weekly hours of employment (38 per week plus reasonable additional hours), leave entitlements (including parental leave, annual leave, personal/carer's leave, community service leave, long service leave and public holidays), notice of termination and redundancy pay, and the ability to request flexible working arrangements for parents in certain circumstances.

The FWA also provides additional minimum standards of employment for employees in particular occupations or industries. These are contained in Modern Awards. Managerial, professional and executive employees, for the most part, are excluded from the Modern Award system (although they are entitled to the NES minimum standards). Relevant Modern Awards for the oil and gas industry include the Oil Refining and Manufacturing Award 2010, the Gas Industry Award 2010 and the Hydrocarbons Industry (Upstream) Award 2010.

Modern Awards, where they apply, provide additional minimum standards in relation to overtime payments, penalty rates for weekend work, allowances, working arrangements (including standard hours of work) and a variety of other terms and conditions relevant to a particular type of employment. Consultation and dispute resolution provisions are also a feature of Modern Awards.

It is impossible to 'contract out' of the terms of a Modern Award, although employers and employees can vary and exclude the operation of a Modern Award by an enterprise agreement made through a process of collective bargaining. To be approved by the Fair Work Commission, an enterprise agreement must provide terms and conditions that ensure employees are better off overall than they would be if only the Modern Award terms and conditions applied to their employment.

2 INDUSTRIAL ACTION IN THE OIL AND GAS INDUSTRY

Some sectors of Australian industry have an unhappy reputation for industrial action. The oil and gas sector has not been particularly turbulent in recent times.

The dominant union in the oil and gas industry is the Australian Workers Union, although from time to time there have been competing claims from other unions, notably the Maritime Union of Australia and the Construction, Forestry, Mining and Energy Union. There are also trade unions which cover maintenance and electrical workers in this industry.

In recent years, Australian legislation provided strong remedies against 'unprotected' industrial action – both the Fair Work Commission (the

Federal Industrial Relations Tribunal) and the Federal Court have jurisdiction to issue orders preventing or stopping industrial action in most circumstances. Industrial action may be protected by law if certain requirements are satisfied. Specifically, protected industrial action is permitted within the enterprise bargaining framework, but only after procedural requirements have been met and the employees have bargained in good faith with their employer to try to reach an industrial settlement.

3 RECENT TRENDS AND DEVELOPMENTS

Other issues that are relevant to the employment relationship in Australia and that will need to be considered include anti-discrimination, privacy, superannuation, confidential information, restraints of trade, worker's compensation and employee protection based on trade union membership.

4 MIGRATION

Australia's visa system is regulated by the *Migration Act 1958* (Cth) and Migration Regulations 1994 and is administered by the Federal Department of Immigration and Citizenship (**DIAC**). Under Australia's immigration laws, all foreign nationals seeking to enter Australia for work or otherwise need a visa.

4.1 Subclass 457 – temporary work visas

Skills shortages in the Australian labour market and the need to hire staff for relatively short periods, often in remote areas, mean that many employers consider recruiting foreign workers for oil and gas projects. The subclass 457 visa is the most commonly used work visa for this purpose. It permits the employee (and family members) to remain in Australia for up to four years. If employment with that employer ceases, the visa holder has 90 days to return home, apply for another visa or find another employer to sponsor them.

Subclass 457 visa applications involve a three-stage process:

(a) Sponsorship application

The employer applies for approval as a business sponsor. Once granted, this approval is in place for three years (or 12 months for businesses that have been trading for less than 21 months) and enables the employer to sponsor an unlimited number of subclass 457 visa holders over that period. Overseas businesses can access the 457 program to establish a branch or subsidiary or fulfil contractual obligations in Australia.

(b) Nomination application

The employer applies for approval of the position to be filled by a particular foreign worker. As part of this application, the employer must show that:

(i) the occupation appears on the applicable government gazetted occupation list;

(ii) the employee has the skills and experience to undertake the role; and

(iii) the employee will be engaged on equivalent terms and conditions of employment that are at least as favourable as those applying to Australian workers in similar roles. This includes paying a 'market salary rate', which must be above a threshold amount currently set at A$53,900 per annum.

(c) Visa application

The employee and any accompanying family members apply for the visa. This includes meeting health, character and English language criteria (although for countries such as the UK, Canada and the USA testing is not required in order to meet that criteria).

DIAC advertises a processing time of up to three months for each of these three stages, but 'decision-ready' applications will usually be processed within a month of lodgement of the application.

4.2 Labour agreements, enterprise migration agreements and regional migration agreements

Where an employer wants to recruit foreign skilled workers in occupations not included on the gazetted occupation list for subclass 457 visas, it can enter into 'labour agreements' with DIAC. Although negotiations for these agreements can be protracted, labour agreements may relax some of the subclass 457 visa application criteria and enable employers to submit applications that would otherwise not meet the visa requirements.

In late 2011, the Federal Government introduced enterprise migration agreements. These are a form of labour agreement specifically designed for major resource projects with capital expenditure of more than A$2 billion and a peak workforce of more than 1,500.

The agreements are negotiated between the project owner or head contractor and DIAC and set the terms by which foreign workers are engaged on the project as well as how training commitments will be met. Sub-contractors are able to negotiate labour agreements and visa applications 'underneath' the main agreement and these are afforded expedited processing.

01

NEW ZEALAND

"New Zealand's largely unexplored petroleum resources represent one of the country's most significant economic opportunities."

Introduction to New Zealand's oil and gas sector

1 OVERVIEW

New Zealand's geological history has provided the country with rich petroleum resources, of which only a small proportion have been tapped. These largely unexplored petroleum resources represent one of the country's most significant economic opportunities. In addition, New Zealand has the fourth-largest 'Exclusive Economic Zone' in the world, which means there is vast potential for exploration.

The oil and gas sector has been the quiet achiever of New Zealand's economy. Oil is the country's fourth-largest export earner, with exports totalling more than NZ$2 billion, and gas is a vital input into New Zealand's domestic economy, providing fuel for electricity generation and industry.

The government recognises the sector's importance, and is committed to unlocking and maximising New Zealand's petroleum potential with a specific focus on exploration of offshore deepwater basins.

In November 2011, New Zealand elected a National-led coalition government for a second three-year term. Building 'a better and more productive economy' is a priority for the government and it has made it clear that the oil and gas sector has a significant role to play in achieving these goals. Estimates show that developing New Zealand's unexplored petroleum basins could increase export revenue for oil to NZ$30 billion per annum by 2025.

The sector is currently in a transition period, with the legislative and regulatory environment evolving and developing to adapt to this growing industry.

2 LIQUIDS: CRUDE OIL AND PETROLEUM

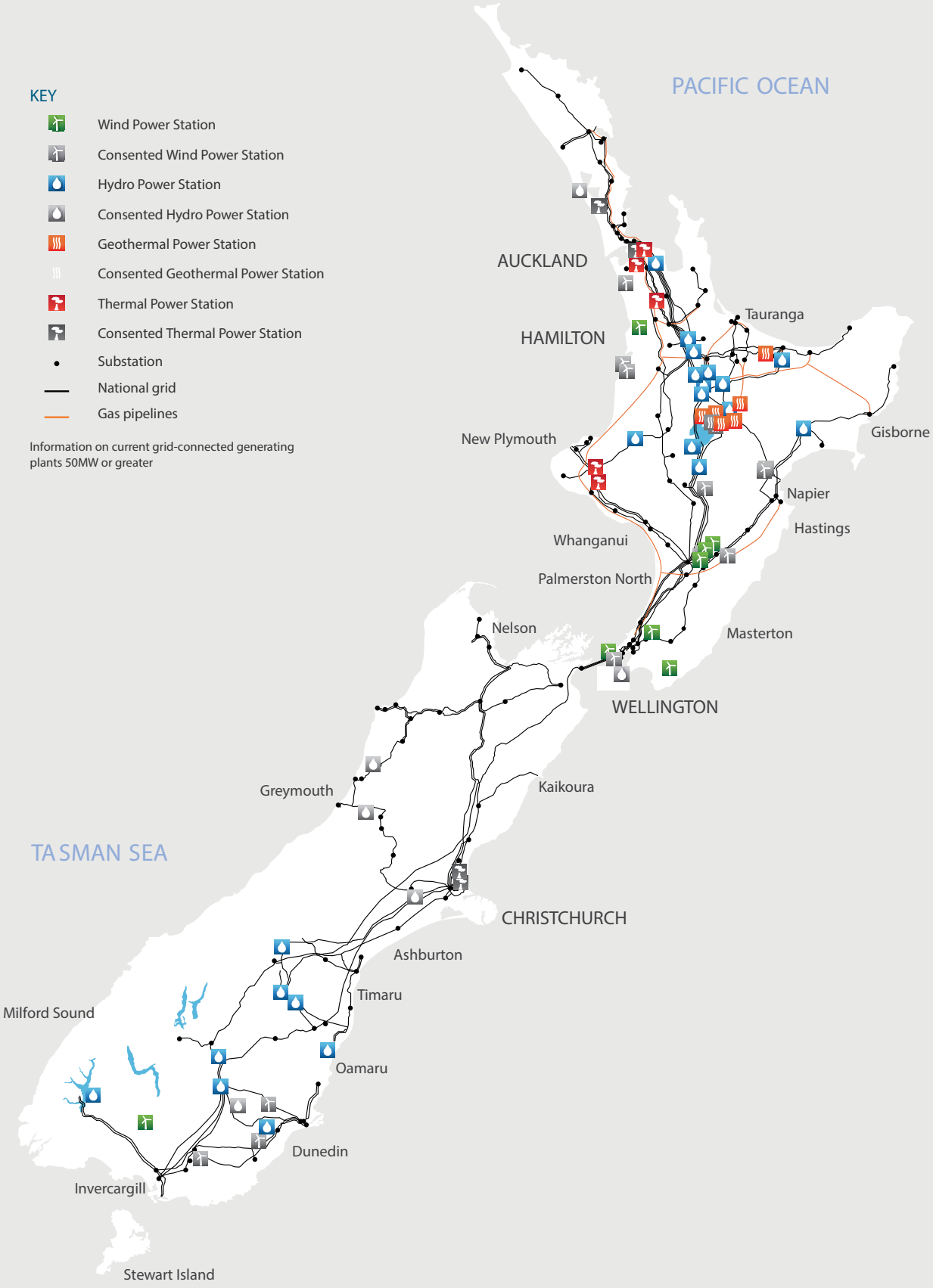
In 2011 New Zealand produced 17 million barrels of oil – enough to meet just under half of local demand (although New Zealand's locally produced oil is generally exported because of its high quality and therefore high value on the international market). Total oil production in 2011 was the lowest in the past four years, down almost 15% on 2010. This represented more than NZ$2 billion in export earnings, with almost NZ$1.4 billion of expenditure across the sector. The Crown's take from this was around NZ$400 million in royalties and levies.

Historically, New Zealand's oil has consisted mostly of condensate, with some crude oil and naptha. Recently, however, oil production has been mostly crude oil, making up some 52% of the total production, with condensate (46%) and naptha (2%) making up the balance.

New Zealand's oil is extracted from 19 fields in the Taranaki region (offshore and to the west of the North Island), which is home to all of New Zealand's current petroleum producing fields. Most of the mining permits (mining in New Zealand includes petroleum production) for these fields are owned jointly, with the bulk of investment coming from foreign companies.

Exploration and development activity remained high by New Zealand standards, with 52 oil and gas exploration wells drilled in 2011 – an increase from 45 wells drilled in 2010 and the highest number in the past 10 years. Wells were drilled in a number of basins in 2010, including onshore and offshore Taranaki, onshore East Coast Basin, Waikato Basin, West Coast Basin and Southland basins.

Gas pipelines and power stations in New Zealand



Source: National Infrastructure Unit.

New Zealand has developed an internationally competitive royalty regime. The regime stipulates that mining permit holders pay either an ad valorem royalty or an accounting profit royalty, whichever is greater in any given year. The royalty rates are either:

(a) 5% ad valorem – ie, 5% of the net revenue obtained from the sale of petroleum; or

(b) 20% of the accounting profit of petroleum production.

The overall value of the Crown's royalty for currently producing fields in the petroleum estate has been calculated, as at 30 June 2011, to be NZ$3.9 billion. Estimates show that if recent patterns of exploration and development continue, future royalty income could generate NZ$8.5 billion to New Zealand. If current exploration rates increased by 50% over the next 10 years, New Zealand could earn NZ$12.7 billion in royalties. Another estimate has Crown receipts increasing to more than NZ$10 billion per annum over the next 40 years on the back of NZ$30 billion per annum of export revenue.

3 GAS

New Zealand's natural gas is produced entirely in the Taranaki region. There were 17 gas producing fields in 2011 producing a total of 180 PJ, down from 198 PJ in 2010. This represents a decrease of net gas production of 9%, with most of the decrease due to declining output from the Maui field, which was 26% lower than the previous year. However, the Maui field, along with the Pohokura and Kupe fields, continues to dominate production. The three fields account for almost 75% of all natural gas produced in the country.

New Zealand does not currently export natural gas, and lacks LNG facilities, but natural gas is a vital input to the domestic energy market. Gas provided 19% of New Zealand's total primary energy supply in 2011. Although direct consumption of natural gas by consumers is low, with use by households accounting for just under 4% of total use, gas provides vital fuel for electricity generation and is the primary fuel for industry. In 2011, 46% of New Zealand's natural gas was used for electricity generation, 29% in the industrial sector and 16% in the petrochemical sector.

As at 1 January 2012, ultimate recoverable reserves (P50) from producing fields was estimated to be 7,698 PJ, whilst remaining reserves (P50) in non-producing reserves were estimated to be 1,999 PJ. This represents a decrease of 2% from the previous year and can be attributed to on-going gas production.

Natural gas is transmitted throughout the North Island through more than 3,500km of high pressure gas transmission pipelines, which connect to more 2,800km of intermediate, medium and low pressure gas distribution pipelines. These pipelines connect the oil fields of Taranaki with industry and consumers throughout the North Island.

02

"The New Zealand Government's Petroleum Action Plan is designed to maximise gains from responsible development of oil and gas resources."

Political system

1 CONSTITUTIONAL STRUCTURE

The New Zealand Government is formed from a democratically elected House of Representatives. The government advises the Governor-General (New Zealand's head of state). By convention, the Governor-General acts on the advice of the government in all but the most exceptional circumstances. This system is known as a constitutional monarchy.

Decision-making power is distributed across three branches of government: Parliament, the Executive, and the judiciary. Parliament makes the law, the Executive administers the law and the judiciary interprets the law through the courts.

New Zealand has no single written constitution or any form of law that is higher than the laws passed by the Parliament. The rules about how the system of government works are contained in a number of Acts of Parliament, documents issued under the authority of the Queen, relevant English and United Kingdom Acts of Parliament, decisions of the courts, and unwritten constitutional conventions.

2 REGIONAL AND LOCAL GOVERNMENT

Regional and local government decision making is an important consideration for investors in the oil and gas sector. New Zealand has 11 regional councils and 67 territorial authorities. Regional and local government make decisions and set the direction for promoting the social, cultural, environmental and economic well-being of their communities within the parameters set by the central government.

3 GOVERNMENT SUPPORTS THE OIL AND GAS SECTOR

In November 2009, during its first term, the government launched its Petroleum Action Plan (the **Plan**) to maximise New Zealand's gains from the responsible development of the country's oil and gas resources. The Plan comprised a number of core workstreams designed to ensure that New Zealand is a highly attractive global destination for petroleum exploration and production investment. These workstreams include:

(a) explicitly positioning the government as proactive and pro-development of petroleum resources;

(b) developing a co-ordinated investment strategy to improve knowledge of New Zealand's petroleum resources;

(c) conducting a short, focused review of the Crown's capability and resourcing to manage New Zealand's petroleum estate; and

(d) reviewing New Zealand's regulatory, royalty and taxation arrangements for petroleum.

In 2011, the government followed up the Plan by releasing *New Zealand Energy Strategy 2011-2021 – Developing our Energy Potential*, setting out how it intends to help develop New Zealand's petroleum resources by implementing the Plan, working to increase exploration activity and improving knowledge of New Zealand's petroleum basins.

Most recently, in late 2012, the government introduced the Crown Minerals (Permitting and Crown Land) Bill (the **Bill**) to Parliament. The Bill has three stated objectives:

(a) to encourage the development of Crown-owned minerals so that they contribute to New Zealand's economic development;

(b) to streamline and simplify the permitting regime where appropriate, making it better able to deal with future development; and

(c) to ensure that better co-ordination of regulatory agencies can contribute to stringent health, safety and environmental standards in exploration and production activities.

If passed into law, the Bill will amend the *Crown Minerals Act 1991* (**CMA**) and make related amendments to the *Conservation Act 1987*, the *Continental Shelf Act 1964* (**CSA**), the *Reserves Act 1977* and the *Wildlife Act 1953*. We discuss the Bill in more detail below.

4 FOREIGN INVESTMENT

The New Zealand Government regulates foreign investment though the *Overseas Investment Act 2005* (**OIA**). Under the OIA, an overseas person must obtain consent for a transaction that will result in overseas investment in 'significant business assets' or 'sensitive land.'

An overseas investment in significant business assets is defined as:[1]

(a) acquiring 25% or more of rights or interests in securities if the consideration, or the value of the securities or the New Zealand assets of the target and its 25% or more subsidiaries, exceeds NZ$100 million; or

(b) establishing a business or acquiring property used to carry on a business if the consideration exceeds NZ$100 million.

An overseas investment in sensitive land may include an investment involving farmland, certain types of reserves and conservation land, and land adjoining the foreshore, if this land exceeds the area prescribed in the OIA.[2] A permit under the CMA or a licence under the CSA is not considered an interest in land for the purpose of the OIA.

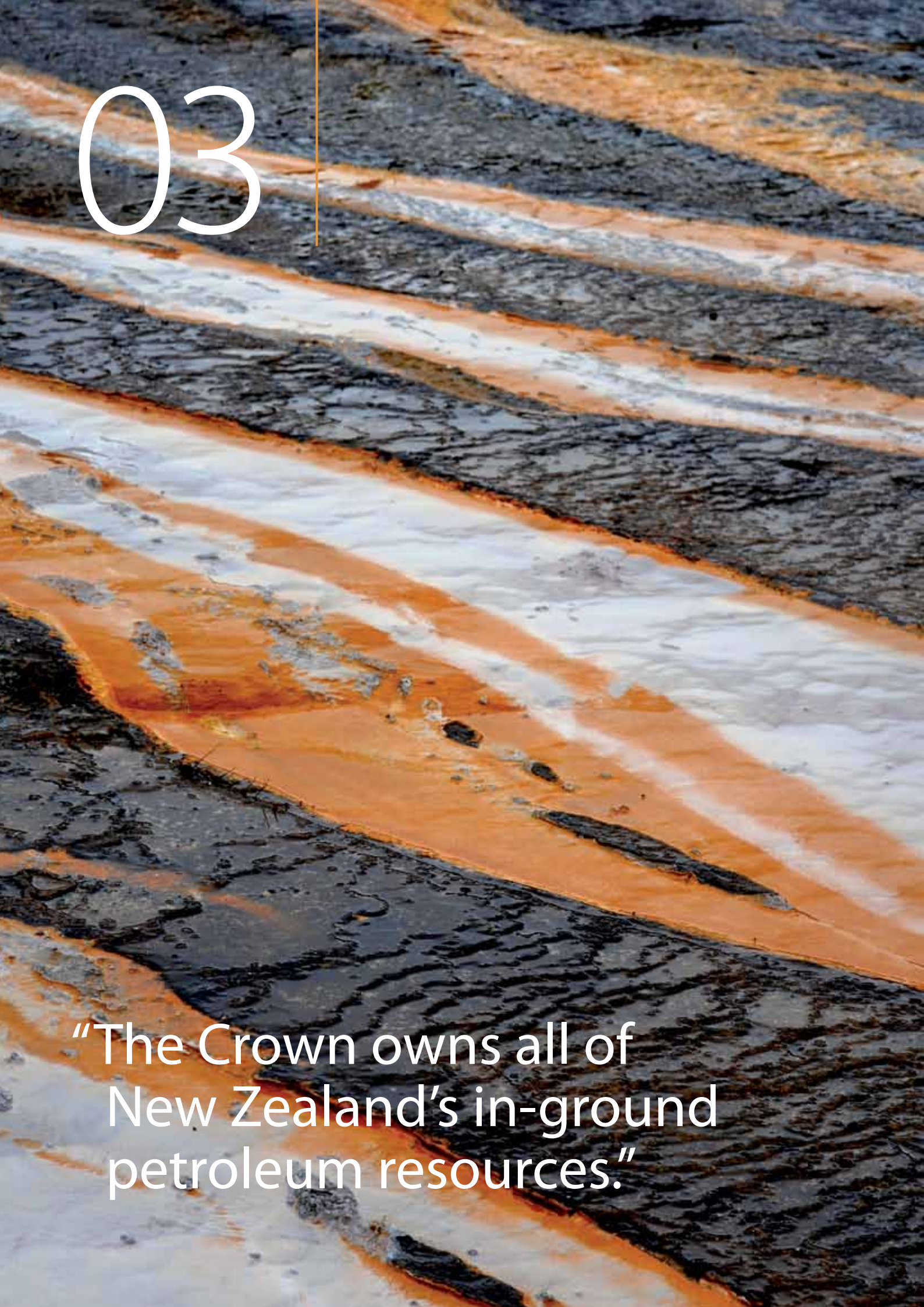
Generally, consent will be granted to an overseas investment where the overseas person can demonstrate that they have the business experience, acumen and financial commitment to make the investment successful and that the investment will, or is likely to, benefit New Zealand.

5 COMPETITION

Entrants into the New Zealand mining market should also consider whether their investment will trigger any requirements under the *Commerce Act 1986*. This Act prohibits acquisitions that would have the effect, or likely effect, of substantially lessening competition in a market.[3]

1 Section 13, *Overseas Investment Act 2005*.
2 Section 12 and Schedule 1, *Overseas Investment Act 2005*.
3 Sections 27-29, *Commerce Act 1986*.

03



"The Crown owns all of New Zealand's in-ground petroleum resources."

Policy and legislative framework

1 PRINCIPAL UPSTREAM PERMITS

1.1 Overview

New Zealand's oil and gas sector is governed by the CMA, which sets the broad legislative policy for prospecting, exploration and mining of minerals. In New Zealand this includes petroleum. The CMA is administered by NZ Petroleum & Minerals (**NZPAM**), which is a division of the Ministry of Business, Innovation and Employment.

The CMA is supplemented by other important pieces of subordinate legislation, including:

- **Minerals Programme for Petroleum 2005,** which establishes the policies, procedures and provisions relating to petroleum that are to be applied under the CMA. This includes details of the permitting and royalty regimes. The CMA requires functions and powers exercised under the CMA to be carried out in a manner that is consistent with the policies, procedures and provisions of any relevant minerals program;
- **Crown Minerals (Petroleum) Regulations 2007,** which specify information permit and licence holders must supply and includes forms for applying for, transferring and surrendering permits; and
- **Crown Minerals (Petroleum Fees) Regulations 2006,** which outline the fees payable under the CMA for petroleum permits among other matters.

The CMA provides that the Crown owns all of New Zealand's in-ground petroleum resources and any company wanting to prospect, explore or mine petroleum in New Zealand must obtain a permit under the CMA. The CSA extends the application of the CMA with respect to petroleum to include the seabed and subsoil of the continental shelf. This includes the seabed and subsoil of those submarine areas that extend beyond the territorial limits of New Zealand.

The CMA separates mining operations into three stages: prospecting, exploration, and mining. A permit under the CMA is required for each of these stages.

1.2 Prospecting and exploration

The purpose of the prospecting phase is to conduct reconnaissance and general investigations of an area to obtain enough information to enable a commercially justifiable decision to be made regarding ongoing exploration investment in the area. Prospecting work is typically low impact and may involve desk top studies, air-borne and ship-borne surveys, and historical literature searches.

A prospecting permit will generally be granted over a relatively large area for a period of no more than one year and it is unlikely an extension of duration will be granted.[4] The permit is not always granted exclusively, especially if there is a lot of interest in a particular area.

Petroleum prospecting permits are granted on the condition that the holder will have no subsequent right to obtain an exploration or mining permit[5] and on the condition that the holder carries out work with the objective of adding to the existing knowledge about the

4 Clause 5.3.4, Minerals Programme for Petroleum.
5 Clause 5.3.6, Minerals Programme for Petroleum.

petroleum potential of the area.[6] If previous prospecting has been undertaken in an area, it may be more appropriate to apply for an exploration permit.

The purpose of the exploration phase is to identify petroleum deposits and evaluate the feasibility of mining any discoveries made. Exploration activities include geological, geochemical and geophysical surveying, exploration and appraisal drilling and the testing of petrochemical discoveries.

Exploration permits are now allocated exclusively by public tender, as the government removed the 'Priority in Time' application process from the Plan in early 2012. Interested parties submit competitive bids for block areas advertised by the Minister of Energy in a Petrol Exploration Permit Block Offer.

The competitive allocation method is designed to ensure petroleum rights are allocated efficiently and are obtained by the person who is most likely to prospect, explore and develop the petroleum resource.

Applications for an exploration permit will be evaluated on the appropriateness of the proposed work plan and the likelihood of the exploration operations resulting in increased knowledge of New Zealand's petroleum resources and petroleum potential. The Minister is not obliged to accept the highest offer or any offer.

Any exploration permit granted will be subject to the conditions that were advertised in the Block Offer Notice or agreed upon by the Crown and the person seeking the permit. For example, these conditions can include the requirement to drill an exploration well within a certain timeframe.

An exploration permit can be granted for a first term of up to five years.[7] A further five-year renewal is also available, with at least half of the area of the permit to be relinquished at the completion of the first term.[8] The total duration of an exploration permit can generally be no longer than 10 years from its commencement date. In certain circumstances, an appraisal extension of up to four years can be granted to allow for the appraisal of a petroleum discovery.

Exploration permits come with exclusive exploration rights over the block area and include a subsequent right to apply for a mining permit.

1.3 Production

Mining permits are granted to enable the development of a petroleum field to extract and produce petroleum. The holder of an exploration permit is entitled to exchange the permit for a mining permit provided that they can satisfy the Minister that they have discovered a petroleum field.[9] A mining permit can be granted for up to 40 years.[10]

1.4 Access to land

To be granted a prospecting, exploration, or mining permit an applicant must demonstrate that they have the financial and technical capability to carry out the proposed work. The government also refers all permit applications to the relevant iwi (local Māori group) for comment. This is consistent with the Crown's consultation obligations under the Treaty of Waitangi. There is currently no requirement for CMA permit applications to be notified to the public.

A permit under the CMA does not give the permit holder any rights to access the land to which the permit relates.[11] The permit holder must enter into an access arrangement with the land owner before it can commence prospecting, exploration or mining.[12] There is an exception to this rule for minimum impact activities. Subject to conditions, these may be carried out without an access arrangement provided that written notice is provided to the land owner and occupier.[13]

Access to minerals on Crown-owned land has special challenges, particularly where the land is administered by the Department of Conservation

6 Clause 5.3.8, Minerals Programme for Petroleum.
7 Section 35(1), *Crown Minerals Act 1991*.
8 Section 37(1), *Crown Minerals Act 1991*.
9 Section 32(3), *Crown Minerals Act 1991*.
10 Section 35(1), *Crown Minerals Act 1991*.
11 Section 47, *Crown Minerals Act 1991*.
12 Section 54, *Crown Minerals Act 1991*.
13 Section 49, *Crown Minerals Act 1991*.

(**DOC**). The CMA provides that an access arrangement in respect of Crown land can be entered into by the land-holding Minister, which in most cases is the Minister of Conservation. An access arrangement cannot be granted in respect of any land listed in Schedule 4 of the CMA, except in very limited circumstances.[14] Schedule 4 protects land that has been given a high conservation status and includes most National Parks and Marine Reserves.

Where the land in question is administered by the DOC, an application for an access arrangement must be made to the relevant conservancy office. The DOC is required to take the view of iwi into account in deciding whether or not to grant access but the application will not be publicly notified. A range of information must be submitted with the application, including an assessment of the environmental effects of the activity. In practice, the DOC will not grant an access arrangement until a permit under the CMA and all necessary consents under the *Resource Management Act 1991* (**RMA**) have been obtained.

Once an access arrangement has been agreed, an authority to enter and operate must be obtained before prospecting, exploration or mining can commence. Further information, including current insurance details, will need to be provided to the DOC before authority to enter and operate will be granted. An authority to enter and operate can be granted for up to 12 months at a time, after which it will need to be renewed.

1.5 Main authorisations

As discussed earlier, the main authorisations required to undertake petroleum activities in New Zealand are:

(a) a permit under the CMA;

(b) the required resource consents under the RMA; and

(c) if necessary, an access arrangement with the land owner and occupier.

Any person, including an overseas entity, can obtain these authorisations provided that the relevant statutory requirements are met.

14 Section 61, *Crown Minerals Act 1991*.

In the case of obtaining a permit under the CMA, the applicant will be required to demonstrate that it can give proper effect to the permit. The factors that the Minister will consider include:[15]

(a) the applicant's financial ability to carry out the proposed work program and to pay monies owed to the Crown;

(b) the applicant's technical ability to carry out the proposed work, including evidence of access to technical experts;

(c) other prospecting, exploration or mining activities, both in New Zealand and internationally, that the applicant (or any related company) has been involved with.

Many international players also enter into the New Zealand mining market by investing in existing mining operations. Investments of this nature are generally subject to section 41 of the CMA, which requires obtaining the consent of the Minister of Energy and Resources.

Section 41 of the CMA is drafted widely and applies to any agreement that transfers a permit, creates an interest in or affects a permit, deals directly or indirectly with a permit, or imposes any obligation on the permit holder relating to production under the permit.[16] Any agreement that is captured by section 41 must be stated to be subject to obtaining the consent of the Minister and will not have any effect unless consent is obtained.[17]

An application for Ministerial consent under section 41 must contain a description of the dealings and state why the Minister should consent to the dealings, including any effects on the financial and technical ability of the permit holder to carry out the work under the permit and to pay the required royalties and fees to the Crown. The Minister may also require other information relating to the agreement, including detailed financial information.[18]

15 Clause 5.6.21, Minerals Programme for Petroleum.
16 Section 41(2), *Crown Minerals Act 1991*.
17 Sections 41(2)-(4), *Crown Minerals Act 1991*.
18 Section 41(3), *Crown Minerals Act 1991*.

2 ENVIRONMENTAL REQUIREMENTS

2.1 Resource Management Act 1991

Most mining operations located onshore or within New Zealand's 12 nautical mile territorial limit will require a resource consent under the RMA in addition to a permit under the CMA.

The RMA is the principal environmental and development statute in New Zealand. Its purpose is "to promote the sustainable management of natural and physical resources".[19] The definition of sustainable management specifically excludes minerals from the requirement to sustain the potential of natural and physical resources to meet the needs of future generations.[20]

The RMA sets out the roles and responsibilities of central government (via the Minister of Conservation and the Minister for the Environment), the Environment Court (a specialist court with jurisdiction established under the RMA), and local authorities (district and regional councils).

The RMA also introduces the following hierarchy of governing documents:

(a) National Policy Statements;

(b) National Environmental Standards;

(c) Regional Policy Statements;

(d) Regional Plans (promulgated by regional councils and which include rules about the coastal marine area, water, discharges, air, and land); and

(e) District Plans (promulgated by district councils and which include rules about land use and subdivision).

These documents contain rules that determine whether a resource consent is required for a particular activity as well as the policies against which applications for resource consents must be assessed. In general, the greater the adverse effects of the proposed activity on the environment, the greater the complexity of processing and determining an application for resource consent.

19 Section 5(1), *Resource Management Act 1991*.
20 Section 5(2), *Resource Management Act 1991*.

One of the key features of the RMA is the extent to which it devolves responsibility for resource management to local authorities. Local authorities are largely responsible for the enforcement of environmental rules under regional and district plans and under the RMA.

District and regional councils can grant a resource consent to allow the consent holder to undertake an activity that is otherwise restricted by the rules of the relevant district or regional plan. There are five types of resource consent:[21]

- land use consent;
- subdivision consent;
- coastal permit;
- water permit;
- discharge permit.

Onshore mining operations are likely to require a land use permit for the activity, as well as discharge permits for any discharge to land, air, or water, and a water permit if the activity involves taking, using, damming or diverting water. Mining activities in the coastal marine area are likely to require a coastal permit.[22] Depending on the activity in question, consent may be required from more than one district or regional council or from both a district and regional council.

A resource consent application must be accompanied by an assessment of effects on the environment in such detail as corresponds with the scale and significance of the effects that the activity may have on the environment.[23] In the case of mining activities, a number of expert reports may need to be commissioned to satisfy this requirement.

The government has identified the RMA as a reform priority and the first phase of reforms were enacted in July 2009. These reforms introduced new processes to streamline the resource consent process, particularly for major projects. The reforms also aim to improve the timeliness of local authority decision making by requiring local authorities to refund a percentage of the applicant's fees if the statutory timeframes for processing a resource consent application are exceeded.

The standard route for obtaining resource consent is by application to the relevant local authority. Depending on the effects of the activity, the local authority may publicly notify the application, in which case the public will have the opportunity to make submissions on the application and a local authority hearing is likely to follow.

21 Section 87, *Resource Management Act 1991*.

22 The seaward boundary of the coastal marine area is the 12 nautical mile territorial limit and the landward boundary is the line of mean high water springs (essentially the high tide mark).

The local authority will then decide whether to grant the application, decline the application, or grant the application subject to conditions. The decision of the local authority can be appealed to the Environment Court, with further appeals available to the High Court on points of law.

An alternative route, introduced by the recent RMA reforms, is to request direct referral of the application to the Environment Court. This makes the Environment Court the primary decision maker and avoids the need for a local authority hearing. This route is likely to have advantages for large projects, or projects where any decision of the local authority is likely to be appealed. The decision of the Environment Court can be appealed to the High Court on points of law.

The reforms have also amended the process for determining resource consent applications for nationally significant projects. Resource consent applications for such projects have always been able to be "called in" by the Minister for the Environment and decided at a national level, but these provisions were rarely used. The amended process for nationally significant projects enables an applicant to lodge its application directly with the newly-created Environment Protection Authority (**EPA**).[24] The EPA will then refer the application to a Board of Inquiry or to the Environment Court. A major advantage of this route is that the Board of Inquiry is required to make its decision within nine months and appeal opportunities are limited.

The government is currently working on a number of workstreams that will feed into a second phase of RMA reforms. These include infrastructure reforms, water management reforms, and further reforms to improve the operation of the RMA and its alignment with other legislation.

2.2 Marine and Coastal Area (Takutai Moana) Act 2011

The marine and coastal area (also known as the foreshore and seabed) is the area extending from the line of mean high water springs (essentially the high tide mark) to the 12 nautical mile territorial limit. This area is governed by the *Marine and Coastal Area (Takutai Moana) Act 2011* (the **MCAA**).

The MCAA establishes a common marine and coastal area (the **CMCA**) and allows for the interests and rights of all New Zealanders in the marine and coastal area to be recognised in law. The CMCA is a public space that is not capable of freehold ownership – neither the Crown, nor any other person, can own the CMCA. The MCAA guarantees public access to the CMCA free of charge and protects navigation and fishing rights.

The MCAA provides for recognition of customary interests in the CMCA. In general terms, customary interests are interests that were held by Māori prior to the signing of the Treaty of Waitangi and Crown sovereignty in 1840 and that have been exercised ever since. Customary interests may be territorial (also known as customary title) or they may be activities, uses, or practices that are not territorial in nature (also known as customary rights).

The recognition of customary interests includes the right to go to the High Court (or negotiate an out-of-court settlement with the Crown) to seek customary title for areas with which groups, such as iwi, have a longstanding and exclusive history of use and occupation. Customary title does not include a right to alienate or otherwise dispose of the area or exclude members of the public, but confers on the customary title group a set of rights to influence the management of, and activities in, the area.

23 Section 88(2)(b), *Resource Management Act 1991*.
24 The Environmental Protection Authority is a newly-established entity that sits within the Ministry for the Environment. Its principal function is to administer resource. consent applications for nationally significant projects, although this role is likely to be expanded as part of phase two of the RMA reforms.

These rights include the RMA permission right, which allows the customary title group to give or decline permission for an activity that is to be carried out under a resource consent within the customary title area. The rights also include ownership of all non-nationalised minerals in the foreshore and seabed. Nationalised minerals (gold, silver, petroleum, and uranium) remain the property of the Crown. As access for mining is not 'as of right', this may have significant implications for the mining sector as it will be necessary to negotiate with iwi to obtain access to a customary titled area.

2.3 Emissions trading scheme

New Zealand ratified the Kyoto Protocol (**Protocol**) on 19 December 2002. The Protocol is intended to address global climate change by setting the global target of reducing worldwide greenhouse gas (**GHG**) emissions to 5% of the 1990 level. To do this, targets were set for individual countries during the first commitment period of the Protocol (2008-2012).

New Zealand is committed to reducing its GHG emissions to 1990 levels (on average over five-year periods). If this domestic target is not achieved, New Zealand will have to take responsibility for the excess emissions by purchasing emission units on the international market or using forest sink credits to do so.

To address New Zealand's obligations under the Protocol, the government passed legislation to establish an Emissions Trading Scheme (**ETS**). The detail of the ETS is contained in the *Climate Change Response Act 2002* and numerous regulations made under the Act.

Under the ETS, persons who undertake specified activities that emit GHGs must register as participants in the ETS and pay for all their GHG emissions. In addition, the ETS specifies certain activities that remove GHGs from the atmosphere. Persons undertaking those activities may register as a voluntary participant in the ETS and be entitled to earn New Zealand Units (**NZU**) for the removal of GHGs.

The ETS is designed to have a small number of mandatory participants. This is achieved by targeting those high up the production chain, including oil and gas producers. The ETS covers all fuels used in electricity generation and in the direct production of industrial heat. It does not include energy used for transport, emissions from industrial processes, or heating in commercial

or residential facilities. For example, persons who import or mine natural gas above specified thresholds and persons refining petroleum are required to register as participants. Other mining operators will be indirectly affected by the ETS, for example by an increase in electricity and fuel costs as mandatory participants pass on the cost of compliance.

Participants will be required to surrender one NZU per tonne of GHG emitted. The NZU is the 'currency' of the ETS and is equivalent to one Kyoto unit.

There is also provision for purchasers of large volumes of natural gas to voluntarily become participants in the ETS and to be responsible for surrendering NZUs for emissions from the gas purchased. Where this occurs, the relevant vendor will not have any liabilities under the ETS in relation to the gas for which the purchaser has assumed responsibility.

Although the ETS provides for free allocation of NZUs to some sectors for an initial period, the oil and gas sector will not receive an allocation of NZUs because they will be able to pass the costs of their ETS obligations on to their customers.

2.4 The Exclusive Economic Zone

The *Exclusive Economic Zone and Continental Shelf (Environmental Effects) Act 2012* (EEZCSA) is scheduled to come into force in July 2014, at the latest. It creates a regime comparable to the RMA for New Zealand's Exclusive Economic Zone and Continental Shelf. The purpose of the Act is to promote the sustainable management of natural resources in these areas.

The Act introduces a regulatory framework, similar to the RMA, allowing for the classification of activities or effects as permitted, discretionary or prohibited. The classification depends on the degree of harm or potential harm from an activity. Operators in the Exclusive Economic Zone seeking to carry out discretionary activities must submit impact statements to the EPA, which may allow the activity to go ahead.

Interim measures apply until the Act comes into force. As some petroleum exploration is already permitted or due to start, the government has established voluntary measures – developed in consultation with the industry – to manage the risks in the interim. During this interim period, the industry will prepare environmental impact assessments and provide them to the EPA for review.

3 POLICY DEVELOPMENTS

Following initial consultation in 2010, the government is currently undertaking a review of the entire Crown-minerals management regime. The review is looking at the *Crown Minerals Act 1991* and associated minerals programs and regulations as a single package and is intended to streamline permitting processes and make it easier for miners to explore and then extract minerals.

3.1 Crown Mineral (Permitting and Crown Land) Bill

This Bill contains wide ranging and significant reforms, principally to the CMA, that will impact the oil and gas sector in New Zealand. The more significant proposed changes include:

(a) introduction of a new two-tiered system for permit management:

  (i) Tier 1 permits apply to all petroleum operations and complex, high-return mineral operations; and

  (ii) Tier 2 permits apply to all other mining permits (ie, smaller and lower-return mining operations). Tier 2 permits are intended to be simpler and more streamlined.

(b) substantial extension to the maximum duration of prospecting and exploration permits:

  (i) prospecting permits are extended from two to four years with no further extension possible;

(ii) exploration permits are extended from five to fifteen years with further extensions possible only for appraisal activities.

(c) limitation of the scope of section 41 of CMA. Section 41 currently requires Ministerial consent for transfers of permits or the creation of interests or obligations in relation to permits. The Bill restricts this to agreements that are 12 months or longer, or if the agreement was not entered into at "arms-length".

(d) ability to apply for permits for different strata in the same area of land.

(e) increase in the period of confidentiality for speculative petroleum prospectors, from five to fifteen years.

(f) requirement of a high-level, preliminary assessment by all Tier 1 operators to demonstrate that they are capable of meeting health, safety and environmental standards. This is in addition to existing assessment requirements for these standards.

(g) requirement that Tier 1 permit holders provide annual reports to the Minister of their engagement with local iwi.

(h) easier revocation of permits by the Minister. Permits can be revoked if payments to the Crown under the permit are overdue or if there is a lack of compliance with the permit, legislation or regulation. The Bill also increases the minimum time for an application for a change or extension to a permit.

(i) increase in penalties and the creation of 'enforcement officers' to ensure compliance with relevant legislation and regulation.

(j) extended ability of the Minister to require relinquishment of areas over which a permit has been granted.

(k) extension of the CMA regime to cover non-petroleum mineral activities in the Continental Shelf and Exclusive Economic Zone (which currently only covers petroleum mineral activities).

The Bill passed its first reading in Parliament on 27 September 2012 and has been referred to the Commerce Select Committee for further consideration. This Committee reported back to Parliament in March 2013 and the government has indicated it is aiming to have the Bill passed in 2013.

3.2 Consultation on Draft Minerals Programme

As noted earlier, the Minerals Programme for Petroleum 2005 establishes the policies, procedures and provisions relating to petroleum that are to be applied under the CMA. In the face of the reforms proposed by the Bill, NZPAM is currently engaged in public consultation regarding a revised minerals programme that sets out how the Minister, the Chief Executive of the Ministry of Business, Innovation and Employment, and NZPAM would apply CMA, if amended as proposed by the Bill.

The consultation process is ongoing and the revised programme is unlikely to be finalised until the Bill is passed into law.

3.3 Resource Management Reform Phase II

Phase II of the Resource Management Reform includes the recently-introduced Resource Management Amendment Bill. This Bill makes a number of reforms, including:

(a) a faster consent application process from local councils for 'medium sized projects' – a term not defined in the Bill;

(b) an emphasis on the economic effects and opportunity costs when assessing proposed plans or policy statements;

(c) additional information requirements in resource consent applications;

(d) some amendments to the process for referring resource consent applications directly from the council to the Environment Court, including a threshold above which councils cannot refuse a request for direct referral;

(e) a streamlined public consultation process for Auckland Council, with limited rights to appeal to the Environment Court.

The Resource Management Amendment Bill is the first of two stages of RMA reforms in this electoral cycle. More substantial and more controversial amendments are likely to follow in 2013.

The explanatory note to the Bill suggests that aspects of the new process for Auckland planning may be rolled out nation-wide. Reforms to the governing principles of the RMA, the government's proposal to require each council to have a single resource management plan, and fresh water governance are also likely in 2013.

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ANNEXURES

About Minter Ellison

Minter Ellison is a leading international law firm with a strong Asia Pacific footprint. Consistently ranked by The American Lawyer amongst its Global 100 – the world's top law firms – our client base includes blue-chip public and private companies, leading multinationals operating in our region, global financial institutions, government organisations and state-owned entities.

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Our Oil & Gas team has been independently recognised for its track record of achievement and service excellence:

- **Australia's Best Lawyers® 2013** named as leading lawyers: Mark Carkeet, Neil Gordon, Kent Grey, Michael Harrison, Sam MacGibbon, Andrew Thompson, Ewan Vickery, Allison Warburton, Paul Wentworth (Oil & Gas); Mitzi Gilligan, Allison Warburton (Climate Change); Ewan Vickery (Native Title)
- **Chambers Asia Pacific 2013** named as leading lawyers: Mark Carkeet, Mitzi Gilligan, Michael Harrison (Energy & Natural Resources: Utilities – Australia); Denis Gately (Senior Statesman), Jordan Phillips (Energy & Natural Resources: Oil and Gas); Sarah Sinclair (Energy & Natural Resources – New Zealand), Rachel Devine (Environment & Resource Management – New Zealand)
- **Legal 500: Asia Pacific 2013** named as leading lawyers: Michael Harrison, Andrew Thompson (Energy & Resources – Australia), Sam Farrands (Projects & Energy – Hong Kong)
- **2013 Guide to the World's Leading Experts in Energy Law** (Expert Guides) named as leading lawyers in Australia: Mark Carkeet, Denis Gately, Mitzi Gilligan, Michael Harrison, Allison Warburton

Minter Ellison's oil and gas team

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Mark leads our national energy and resources industry group and also heads our practice in Brisbane. He has worked in commercial law since 1983, and focused almost exclusively on energy since 1992. He has advised in major gas and electricity projects throughout Australia and South East Asia; power purchase agreements; technology transfers and trade practices issues. Mark has worked closely with Queensland government officials throughout this period. He is the editor of the firm's publication 'Energy in Australia'.

Mark has nearly 20 years experience assisting clients with commercial and legal advice arising in relation to the energy sector. His expertise includes advising on M&A transactions, tolling arrangements, gas price reviews, gas transportation arrangements, long-term purchase arrangements, preparation of steam supply, electricity supply and share services agreements, mining approvals and project developments.

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Allison is a partner in our Energy and Resources team and co-head of the firms' climate change practice. She has over 15 years experience advising in the energy and resources sectors. Allison regularly advises petroleum sector participants on tenement issues, farm-ins, joint operating agreements, overlapping tenements, project approvals and infrastructure development, as well as transportation and sales.

She has experience in natural gas, coal seam gas and LNG projects and with on-shore, offshore and international project development (both upstream and downstream). Allison has also assisted in developing regulatory regimes to manage competing land uses in such areas as petroleum production, coal mining, and carbon storage.

Allison also has extensive experience in climate change projects and advises energy and resource clients on carbon tax, emissions trading, renewables and greenhouse compliance issues and projects.

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Brendan advises on commercial arrangements, mergers and acquisitions, and regulatory matters in the petroleum, energy, mining, and water sectors in Australia and internationally.

His petroleum sector experience includes advising on farm-in transactions, joint venture and joint operating agreements, overlapping tenure and competing land use issues, drilling contracts and other service and procurement contracting, pipeline corridor development, sale and transportation arrangements, and associated water regulation.

He also advises clients in Australia on liability and cost pass-through issues arising in relation to the Federal Government's Clean Energy Scheme and on AFS licensing requirements.

Brendan is recognised by Best Lawyers® International as a leading Australian lawyer in the Energy, Natural Resources and Water categories.

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Simon has many years' experience advising the energy sector. His expertise spans oil and gas sales and supply contracts, exploration, development, production, transportation and procurement.

Simon has advised on international oil and gas production sharing agreements, gas and CSG joint operating agreements and farm-ins, coal and gas co-development arrangements, tolling agreements, as well as coal and water access, and supply and transportation arrangements for power stations.

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One of Australia's most experienced and respected energy and resources lawyers, Denis Gately is a Brisbane-based consultant with Minter Ellison with more than 30 years' industry practice.

A pre-eminent figure in international oil and gas, Denis has advised on offshore and onshore exploration and production projects for natural gas, crude oil and coal seam methane in Australia, South East Asia and China, as well as more broadly in other jurisdictions.

His work has involved joint operating agreements, drilling services contracts and project development approvals. Denis has also advised on the development and operation of significant trunk pipelines across on and offshore Australia, South East Asia and China, including related access and regulatory regimes.

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Richard heads our Energy and Resource group in Perth. He brings to the table over 15 years of expertise as a leading lawyer in energy and resources and infrastructure projects. Richard advises on a broad range of energy and resource infrastructure projects, from negotiating the purchase of long lead items for large scale iron ore mining, to EPC contracts for offshore LNG production, and negotiating terms for rail corridor construction. Richards expertise extends further, providing tailored advice in the renewable energy sector and has advised on some of the most significant renewable energy deals in Europe, including the largest waste-fired power station in Western Europe where he led the team.

Adam Handley
Partner & Co-Chair China Interest Group

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Adam is a senior partner specialising in North Asian (particularly Chinese) mergers and Acquisitions and Project Development in the Energy & Resources sector. He has b widely regarded as one of the leading legal advisers to major Chinese State Owned Enterprises and private Chinese enterprises investing in the Australian resources and infrastructure sectors.

Adam has significant experience in the China market, working with Chinese SOEs and private companies, and specialises in energy and resources, infrastructure, mergers and acquisitions and capital markets. He is the Co-Chair of the Minter Ellison China Business Group and has advised on the landmark investments by Chinese SOEs in the Western Australia market, many of these investments have involved negotiation of arrangements for large scale infrastructure projects to support the expanded growth in the North of Western Australia.

Andrew Thompson
Partner, Perth

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Andrew is a senior Partner in the Energy and Resource group in Perth. He practices law in relation to major projects and transactions with an emphasis on energy (electricity, LNG, oil and gas) transactions, pipelines/ infrastructure and sales contracts and other resource arrangements.

Andrew worked for five years with the Burmah Oil Group of Companies in London and Perth. He was Legal Manager for Woodside Petroleum for stage one of the A$12 billion North West Shelf Gas (LNG export and Domestic Gas) Project, offshore WA.

Sydney

Sam MacGibbon
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Sam is a transactional and projects lawyer with deep and broad international experience. He has specialised in the oil and gas sector for more than 20 years, both in Australia and abroad. His experience includes long-term gas sale and purchase arrangements (and related disputes and renegotiations). His experience also includes the acquisition, development, divestment and funding of oil and gas projects (onshore and offshore E&P), LNG, natural gas pipelines, gas processing and fractionation, oil refining and petrochemicals.

Paul Wentworth
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Paul deals widely in corporate and commercial transactions in the oil and gas sector spanning mergers and acquisitions, due diligence, joint ventures as well as diverse contractual arrangements. He advises on the acquisition and development of gas pipelines through construction to commissioning, drawing upon an intimate knowledge of easement acquisition, registration of plans and vesting of easements under the Pipelines Act. Also well versed in regulatory matters, Paul has a keen understanding of interplay between industry regulation and contract requirements, advising both supply and demand-side clients on supply and transportation agreements.

Michael Harrison
Partner, Sydney

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Michael advises clients across a range of industries, including energy, mining and resources, oil and gas (including LNG), steel, transport, water and waste industries, and on economic and social infrastructure development. He has a market leading reputation in these industry sectors. His broad multi-disciplinary advisory focus includes finance (debt and equity), corporate (including joint ventures and acquisitions), commercial, construction and engineering, project development and financing (advising on all aspects of project development, including environmental and planning) and regulated markets.

Melbourne

Mitzi Gilligan Partner, Melbourne

Competition and Market Regulation, Government, Climate Change

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Mitzi has been a specialist adviser to the energy industry since the mid nineties – acting as team leader on many acquisitions and sales in the sector, including privatisations in Victoria, South Australia and NSW. She has a detailed understanding of the regulatory frameworks for electricity and gas retail and wholesale markets, as well as the access and pricing regimes applying to electricity and gas distribution and transmission.

Mitzi drafts and negotiates the full range of energy industry contracts. She also advises on dealings with regulators and on price determinations, merits review and dispute resolution processes under the National Electricity Rules and National Gas Rules. In the area of climate change, Mitzi advises on renewable energy projects, emissions trading, energy efficiency and greenhouse and energy reporting.

Mark Green Managing Partner International, Melbourne

Tax, Energy, Mergers and Acquisitions

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Mark has extensive involvement in the energy and infrastructure sectors, based on a strong background advising corporate and government entities on Australian State and Federal tax laws, including restructuring and finance advice. He has also worked extensively with international organisations, particularly those looking to invest in Australia's mining, energy and resources industries.

Adelaide

Neil Gordon
Partner, Adelaide

Commercial Contracting, Mergers and Acquisitions, Pipelines, Regulatory and Access

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Neil has a wealth of experience in the marketing, sale and transport of natural gas, and the connection, operation and maintenance of significant natural gas infrastructure. Neil's first work in this area was acting for the South Australian Government when they sold the state's transmission pipeline assets to the private sector in the mid 1990s – a project that involved unbundling existing haulage arrangements and negotiating complex new long-term arrangements. Since that time Neil has continued to be a key adviser to many organisations in this important industry.

Kent Grey Partner, Adelaide

Corporate Governance, Infrastructure, Native Title, Privacy Law

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With a strong understanding of the relevant Federal and State-based regulation and licensing, Kent advises mining and petroleum clients on all aspects of exploration, drilling and production operations. He advises on joint ventures, farm-ins/farm-outs, unitisations, coordination arrangements and relationship management. He also advises on operations management and project delivery, offtakes, export, marketing and product commercialisation arrangements.

Ewan Vickery
Consultant, Adelaide

Acquisitions and Disposals, Corporate and Capital Raisings, Native Title

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Throughout his more than 30 year career, Ewan has consistently practiced in the energy and resources sector, particularly in relation to mining and minerals processing, and oil, petroleum and gas exploration and development. He has a strong understanding of the principals of international and Australian resources legislation and is familiar with related issues of land access and infrastructure contracts. He re-wrote the AS 2124 standard construction contract for specific petroleum client use and provided strategic advice to the Northern Territory Government on petroleum legislation and its application.

International

Paul Foley
Partner, New Zealand

Corporate and Commercial, Funds Management, Corporate Governance, Equity Capital Markets

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Paul is a senior corporate and commercial lawyer with extensive experience in the energy and resources sector, advising clients on a range of sector related issues. The companies he acts for include oil exploration companies, energy retailers, coal miners, electricity regulators and financial service and product providers.

Paul has an excellent understanding of the energy sector and the regulatory environment in which it operates. He has also advised on major infrastructure and supply-chain contracts for companies in the mineral sector, and has advised oil & gas companies on debt and equity capital raisings and also farm-ins, drilling contracts, and gas sales agreements. Paul's experience as a director of companies in the above sectors gives him insights into governance which can translate across many projects.

Sarah Sinclair
Partner, New Zealand

Climate Change, Joint Ventures, Sales and Hedging Markets, Corporate and Commercial

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Sarah is a transactional, contracting and projects lawyer with expertise in corporate and commercial law, including periods as an in-house corporate advisor. She has considerable experience in advising on energy and resources and construction and development projects, and drafting and negotiating complex engineering and infrastructure arrangements.

Sarah has particular expertise as a transactional and projects lawyer in energy work including upstream oil and gas, joint venture and consortium arrangements, power generation (thermal and renewable), fuel contracting and transmission arrangements, sales and hedging, regulatory issues, and access to infrastructure. Sarah also advises clients on construction and development projects, acting for owners, contractors and funders, advising on a range of contracting structures, procurement models and risk sharing arrangements.

Rachel Devine
Partner, New Zealand

Environment, Climate Change, Corporate, Infrastructure

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Rachel is a specialist environmental, planning and climate change lawyer. Rachel advises oil and gas industry participants about meeting current and proposed legislative and planning requirements and ensuring that environmental effects arising from oil and gas exploration, development or production are managed appropriately. Recent work includes advising Maui Development about how to protect its gas pipeline asset with reference to various types of legislation. sharing arrangements.

Sam Farrands
Partner, Hong Kong

LNG, Major Projects, PPP, Infrastructure

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Sam is Head of the firm's Major Projects practice in Asia. Recognised as one of Hong Kong's leading projects lawyers, Sam advises developers, contractors, financiers and governments on major projects and privatisations throughout Asia. These projects have been primarily in the energy, petroleum, gas, LNG, water and wastewater sectors. Sam has played a leading role in securing numerous major energy projects across the wider Asian region, acting for both private and state-owned companies. He led Australia's largest-ever single income export deal to supply LNG to Guangdong, as well as major development and procurement deals for PetroChina and Sinopec.

Elisabeth Ellis
Partner, Mongolia

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One of Asia's pre-eminent energy and natural resources lawyers, Lis has worked with mining and energy companies on the full lifecycle of their projects. She has advised on mining projects in Australia, Indonesia and now Mongolia, power and water projects throughout Asia, and significant LNG and gas projects in China. She has also assisted a number of mining service companies to establish their businesses in Mongolia. Her clients include Peabody Energy, Noble Energy, Rio (Oyu Tolgoi and South Gobi Sands), and Xanadu Mines amongst others.

Michael Wallin
Partner, London

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Combined with top tier international experience, Michael Wallin draws on substantial expertise in corporate finance, private equity, mergers and acquisitions and outsourcing.

He advises on wide range of corporate matters, focusing on cross border mergers, acquisitions and disposals, private equity investments, joint ventures and venture capital work. Michael is also experienced in advising clients in connection with significant outsourcing transactions.

Michael is a Registered Foreign Lawyer in England and Wales.

ACRONYMS, ABBREVIATIONS AND TERMINOLOGY

ACCC	Australian Competition and Consumer Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CMA	*Crown Minerals Act 1991* (New Zealand)
CMCA	common marine and coastal area
CO_2-e	carbon dioxide equivalence
CPM	Carbon Pricing Mechanism
CSA	*Continental Shelf Act 1964* (New Zealand)
CSG	coal seam gas
DIAC	Department of Immigration and Citizenship (Australia)
DOC	Department of Conservation (New Zealand)
EEZCSA	*Exclusive Economic Zone and Continental Shelf (Environmental Effects) Act 2012* (New Zealand)
EIS	environmental impact statement
EITE	emissions-intensive trade-exposed
EPA	Environment Protection Authority (New Zealand)
EPBC Act	*Environment Protection and Biodiversity Conservation Act 1999* (Cth) (Australia)
ETS	Emissions Trading Scheme
FDP	field development plan
FIRB	Foreign Investment Review Board (Australia)
FPSO	Floating production, storage and offloading vessel
FWA	*Fair Work Act 2009* (Cth) (Australia)
GHG	greenhouse gas
LNG	liquefied natural gas (principally methane)
LPG	liquefied petroleum gas
MCAA	*Marine and Coastal Area (Takutai Moana) Act 2011* (New Zealand)
Mt	million tones
NCC	National Competition Council (Australia)
NES	National Employment Standards
NGL	National Gas Law (Australia)
NGR	National Gas Rules (Australia)
NNTT	National Native Title Tribunal (Australia)
NOPTA	National Offshore Petroleum Titles Administrator (Australia)
NOPSEMA	National Offshore Petroleum Safety and Environment Management Authority (Australia)
NZPAM	NZ Petroleum & Minerals (New Zealand)
NZU	New Zealand Unit
OIA	*Overseas Investment Act 2005* (New Zealand)
OTN	obligation transfer number
PJ	petajoules
PL	production licence
PRRT	Petroleum Resource Rent Tax (Australia)
RMA	*Resource Management Act 1991* (New Zealand)
STTM	Short-Term Trading Market
VWGM	Victorian Wholesale Gas Market (Australia)

MEASUREMENTS AND CONVERSIONS

Natural Gas/Energy/Volume Equivalents

Joules	Million Standard Cubic Feet (MMCF)	Million Standard Cubic Meters (MMCM)	Billion BTUs
1 GJ	= 0.000943	= 0.0000267	= 0.000943
1 TJ	= 0.943	= 0.0267	= 0.943
1 PJ	= 943	= 26.7	= 943

1 PJ	= 10^3TJ	=10^6GJ	=0^9MJ	=10^{12}KJ	1015J

Natural Gas Conversions

Metric to Imperial				
10^6m^3	x	35.31073	=	MMCF
TJ	x	0.9430	=	BillionBtu
GJ	x	0.000943	=	BillionBtu
Mt (LNG)	x	46369	=	MMCF (LNG)
MJ/m^3	x	26.715110	=	Btu/cf
$/GJ	x	0.000943	=	$/BillionBtu
$/$10^6m^3$	x	35.3107	=	$/MMCF

Imperial to Metric				
MMCF	x	x 0.02832	=	10^6m^3
BillionBtu	x	1.06	=	TJ
BillionBtu	x	1060	=	GJ
MMCF(LNG)	x	0.00002157	=	Mt (LNG)
Btu/cf	x	0.037432	=	MJ/m^3
$/BillionBtu	x	1060.445	=	$/GJ
$/MMCF	x	0.02832	=	10^6m^3

10^6m^3 = million cubic metersMMCF = million standard cubic feetMt (LNG) = million tonnes LNG

A$ dollar (Australian)NZ$ dollar (New Zealand)US$ dollar (United States)

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