

Chapter 3 Oil



3.1 Summary

KEY MESSAGES

- Oil is the most widely used primary source of energy globally. It plays a critical role as a transport fuel in most countries including Australia.
- Australia has about 0.3 per cent of world oil reserves. Australia has limited reserves of crude oil and most of Australia's known remaining oil resources are condensate and liquefied petroleum gas (LPG) associated with giant offshore gas fields.
- There is scope for growth in Australia's oil reserves in existing fields, and for new oil discoveries in both proven basins and in under-explored frontier basins which are prospective for petroleum.
- There is also potential to develop alternative transport fuels such as biofuels, coal-to-liquids (CTL), gas-to-liquids (GTL) and shale oil.
- Australia's oil consumption is projected to increase over the two next decades but the rate of growth is projected to be slower than in the past 20 years. Domestic crude oil production is projected to continue to decline.
- In the absence of major new discoveries and the development of alternatives, Australia's net imports of liquid fuels are projected to increase, rising to be three-quarters of consumption by 2029–30.

3.1.1 World oil resources and market

- Oil is an important energy source, accounting for around 34 per cent of world primary energy consumption in 2007. However, its importance has been declining steadily since the 1970s when its share of primary energy consumption was around 45 per cent.
- World proven oil reserves were estimated at some 1.4 trillion barrels (equivalent to 8.3 million PJ) at the end of 2008. This is equal to around 42 years supply at current production rates. This global reserves to production ratio has been maintained at around 40 years for the past decade. Australia accounted for around 0.3 per cent of these reserves.
- World oil production was around 30.5 billion barrels (174 012 PJ) in 2008. Major oil producers include Saudi Arabia, the Russian Federation, United States, Iran and China, with the Middle East accounting for 31 per cent of the world's production in 2008.
- The cost of oil production is expected to increase with the development of deeper water fields and the use of enhanced recovery technologies.
- World oil consumption has increased at an annual average rate of 1.6 per cent since 2000, to reach 31.6 billion barrels (Bbbl, 171 236 PJ) in 2008.
- The fastest growing oil consuming region is non-

OECD Asia, which includes China and India. At present more than half of world oil consumption is used in the transport sector.

- World oil demand is projected by the International Energy Agency (IEA) in its reference case to increase by around 1 per cent per year to reach 36.8 Bbbl (210 271 PJ) in 2030. Demand growth is expected to be concentrated in non-OECD economies.
- World oil supply is also projected to increase at an average annual rate of 1 per cent. OPEC's oil production is projected to grow as is supply from unconventional sources such as oil sands, gas-to-liquids, coal-to-liquids and oil shale.

3.1.2 Australia's oil resources

- In 2008, Australia's identified oil resources were estimated at 30 794 PJ made up of 16 170 PJ (2750 million barrels or mmbbl) of condensate, 8414 PJ (1431 mmbbl) of crude oil and 6210 PJ (1475 mmbbl) of LPG (liquefied petroleum gas).
- Australia has only limited domestic supplies of crude oil, and relies increasingly on imports to meet demand.
- Crude oil exploration in Australia has not repeated the early success of the 1960s when the first offshore exploration yielded giant field discoveries in the Gippsland Basin. Although Australia has over

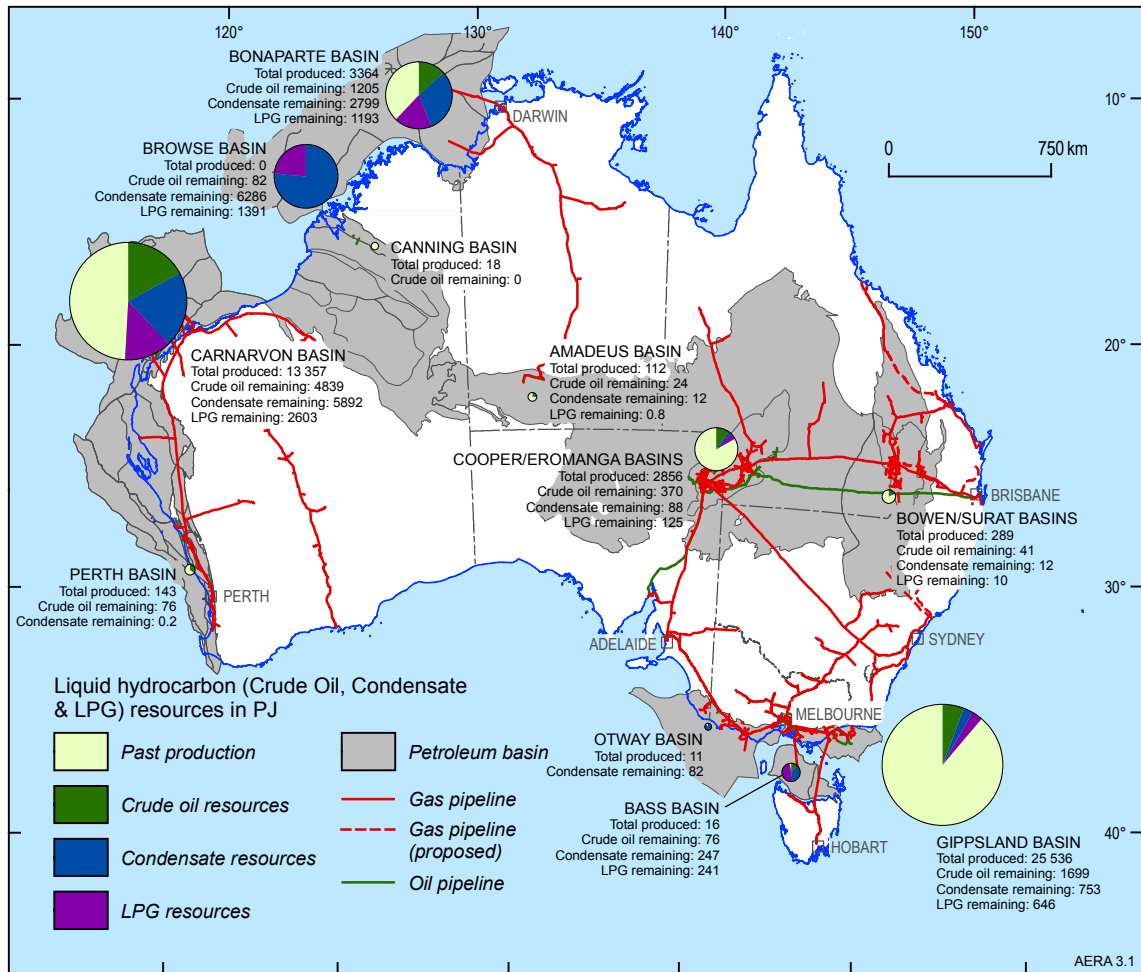


Figure 3.1 Australian crude oil, condensate and naturally-occurring LPG resources, infrastructure, past production and remaining resources

Source: Geoscience Australia

300 crude oil fields, most production has come from only seven major fields.

- Estimates of undiscovered crude oil in proven basins range from 9996 PJ (1700 mmbbl) to 29 588 PJ (5032 mmbbl) and undiscovered condensate from 4116 PJ (700 mmbbl) to 35 480 PJ (6035 mmbbl). Petroleum potential exists in deep water frontier basins but the oil resource remains unknown.
- Australia's largest remaining discovered liquid petroleum resource is now the condensate and LPG in the undeveloped Ichthys gas field in the offshore Browse Basin (figure 3.1).
- The scope for enhanced oil recovery (EOR) from identified fields was estimated at about 6468 PJ (1100 mmbbls) in 2005. Additions to resources from field growth were estimated at about 5880 PJ (1000 mmbbls) in 2004. In the intervening period some of this potential has been realised.
- In addition, Australia has a large unconventional and currently non-producing identified shale oil

resource of 131 600 PJ (22 390 mmbbl) which could potentially contribute to future oil supply if economic and environmental challenges can be overcome.

3.1.3 Australia's oil market

- Oil and oil products have the second largest share (1942 PJ or 34 per cent) of primary energy consumption in Australia, but domestic primary oil (crude oil, condensate and LPG) production accounts for only 6 per cent of total energy production. Australia's net imports of oil and oil products represented 45 per cent of consumption in 2007–08.
- Australian primary oil production (crude oil, condensate and LPG) peaked in 2000–01 at 1546 PJ (276 mmbbl). Since then primary oil production has been declining at an average rate of 5 per cent per year to 1059 PJ (187 mmbbl, 29.8 GL) in 2007–08.
- Australia is a net importer of oil and oil products. In 2007–08, Australia's net imports of primary oil were around 383 PJ (48 mmbbl, 7.7 GL), valued at \$5.5 billion.

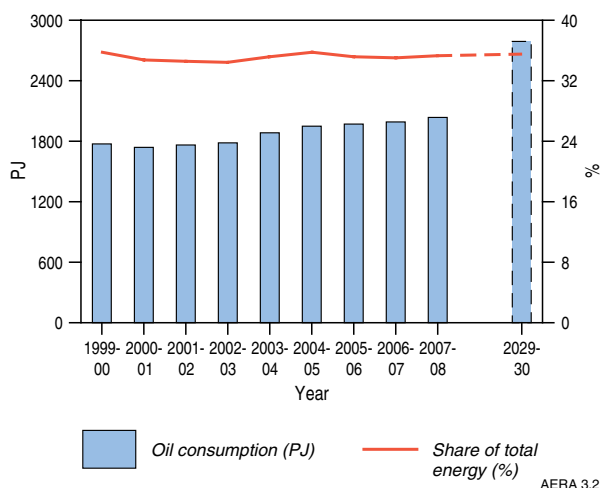


Figure 3.2 Australia's outlook for oil consumption

Source: ABARE 2009b; ABARE 2010

- Australian refineries produced 1557 PJ (269 mmbbl, 42.8 GL) of refined oil products in 2007–08.
- In the past, Australia was a net exporter of refined oil products. Since the closure of the Port Stanvac refinery in 2003, Australia has also become a net importer of these products. In 2007–08, Australia's net import of refined oil was around 430 PJ (94 mmbbl, 15 GL), valued at \$12 billion.
- The transport sector is the largest consumer of oil, accounting for around 70 per cent of Australia's total use of oil products.
- In ABARE's latest long term energy projections, which include the Renewable Energy Target, a 5 per cent emissions reduction target and other government policies, consumption of oil and oil products in Australia is projected to increase by 1.3 per cent per year to reach 2787 PJ (equivalent to about 473 mmbbl) in 2029–30. Its share of primary energy consumption is projected to remain around 36 per cent in 2029–30 (figure 3.2).
- Australian production of crude oil, condensate and LPG is projected to decline at an average rate of 2 per cent per year to 668 PJ by 2029–30.
- Net imports of oil and oil products are projected to account for 76 per cent of consumption in 2029–30.

3.2 Background information and world market

3.2.1 Definitions

The term oil encompasses the range of liquid hydrocarbons and includes crude oil and condensate. Liquefied petroleum gas (LPG) is considered along

with oil in this study. Oil that has been refined into other products is referred to as refined products, oil products or petroleum products.

Crude oil is a naturally-occurring liquid consisting mainly of hydrocarbons derived from the thermal and chemical alteration of organic matter buried in sedimentary basins. It is formed as organic-rich rocks are buried and heated over geological time. Crude oil varies widely in appearance, chemical composition and viscosity. Most Australian crude oils are classified as light oil. Light crude oils are liquids with low density and low viscosity that flow freely at standard conditions: they have high API gravity due to the presence of light hydrocarbons. Heavy oils, on the other hand, have higher density and viscosity, do not flow readily and have low API gravity (less than 20°) having lost the lighter hydrocarbons. Crude oil is found in deposits with or without associated gas; this gas may include natural gas liquids – condensate and liquefied petroleum gas (LPG). Crude oil can also be found in semi-solid form mixed with sand and water (oil or tar sands) or as an oil precursor, also in solid form, called oil shale. Oil from oil sands and oil shale is known as unconventional oil (box 3.1).

Condensate is a liquid mixture of pentane and heavier hydrocarbons found in oil fields with associated gas or in gas fields. It is a gas in the subsurface reservoir, but condenses to form a liquid when produced and brought to the surface (figure 3.3).

Liquefied petroleum gas (LPG) is a mixture of lighter hydrocarbons, such as propane and butane, and is normally a gas at the surface. It is usually stored and transported as a liquid under pressure. In addition to naturally-occurring LPG, it is also produced as a by-product of crude oil refining. LPG has lower energy

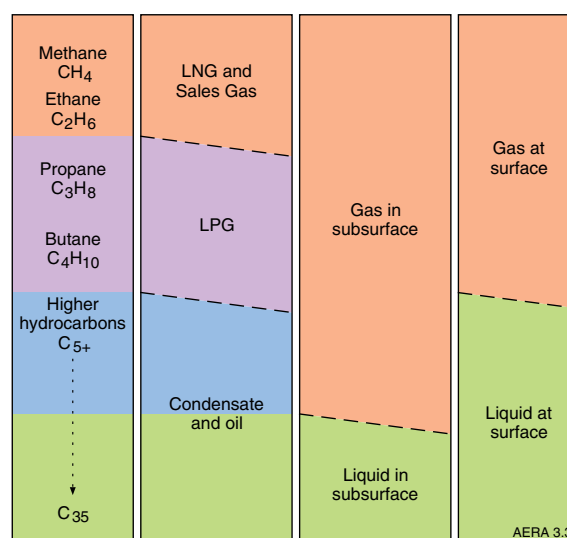


Figure 3.3 Petroleum resources nomenclature in terms of chemical composition, commercial product, physical state in the subsurface and physical state at the surface

Source: Geoscience Australia

content per volume than condensate and crude oil (Appendix E).

Refined products include petroleum products used as fuels (LPG, aviation gasoline, automotive gasoline, power kerosene, aviation turbine fuel, lighting kerosene, heating oil, automotive diesel oil, industrial diesel fuel, fuel oil, refinery fuel and naphtha) and refined products used in non-fuel applications (solvents, lubricants, bitumen, waxes, petroleum coke for anode production and specialised feedstocks).

Primary oil consumption includes all petroleum used directly as fuel – crude oil, condensate, LPG and petroleum products.

Primary oil production includes crude oil, condensate and naturally occurring LPG prior to use in refineries.

Oil shale is a fine-grained sedimentary rock containing large amounts of organic matter (kerogen), which can yield substantial quantities of hydrocarbons. Oil shale is essentially a very rich thermally immature source rock: it requires heating to high temperatures to convert the organic material within the shale to liquid hydrocarbons – shale oil. Shale oil is considered an alternative transport fuel, readily substitutable for high grade crude oil.

Oil sands, or tar sands, are sandstones impregnated with bitumen, the very viscous heavy hydrocarbons remaining after the more volatile components of crude oil have been lost. Mining and processing is required to recover the oil.

3.2.2 Oil supply chain

Figure 3.4 provides a representation of the oil industry in Australia. The oil industry undertakes the exploration, development and production of crude oil, condensate and LPG. More generally, the petroleum industry also includes downstream activities such as petroleum refining, and the transport and marketing of refined products, as well as non-energy products such as petrochemicals and plastics.

Resources and exploration

The supply of oil begins with undiscovered resources that must be identified through exploration. Geoscientists identify areas where hydrocarbons are liable to be trapped in the subsurface, that is in sedimentary basins of sufficient thickness to contain mature petroleum source rocks as well as suitable reservoir and seal rocks in trap configurations (box 3.1). The search narrows from broad regional geological studies through to determining an individual drilling target.

In the Australian context, governments have taken a key role in providing regional pre-competitive data to encourage investment in exploration by the private sector (figure 3.5). Company access to prospective exploration areas is by competitive bidding, usually on the basis of proposed work program (that is intended exploration effort) or by taking equity in ('farming-into') existing acreage holdings.

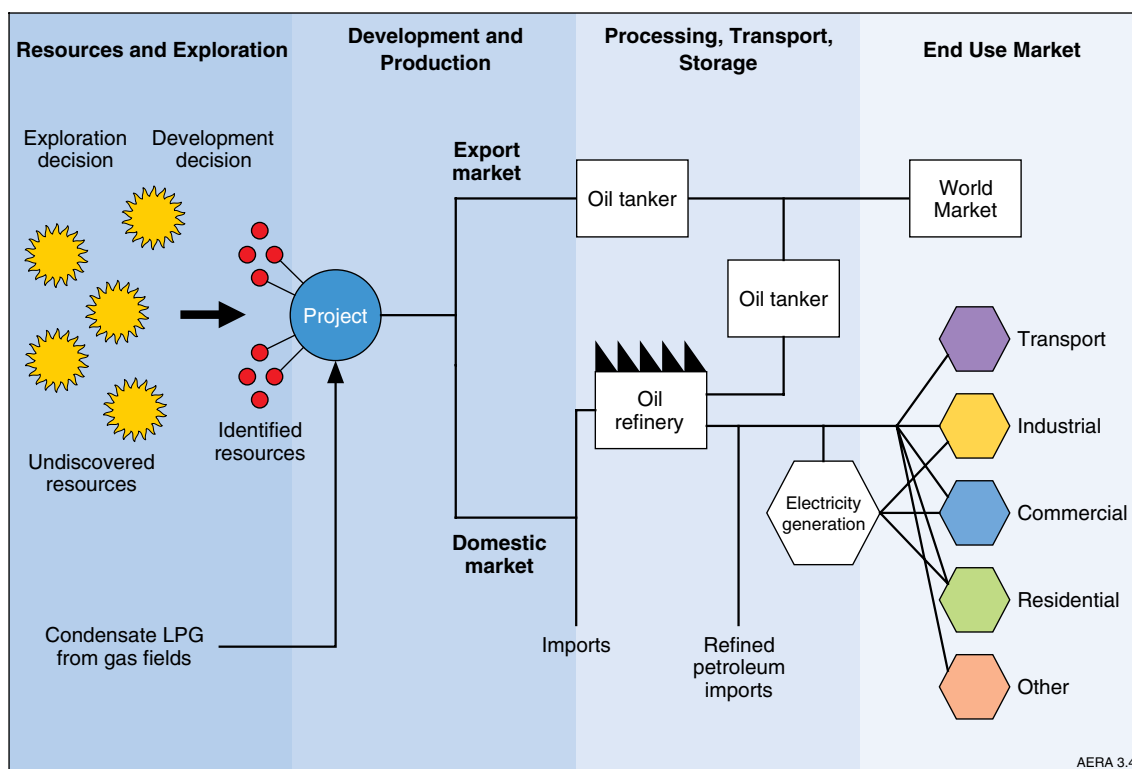


Figure 3.4 Australia's oil supply chain

Source: ABARE and Geoscience Australia

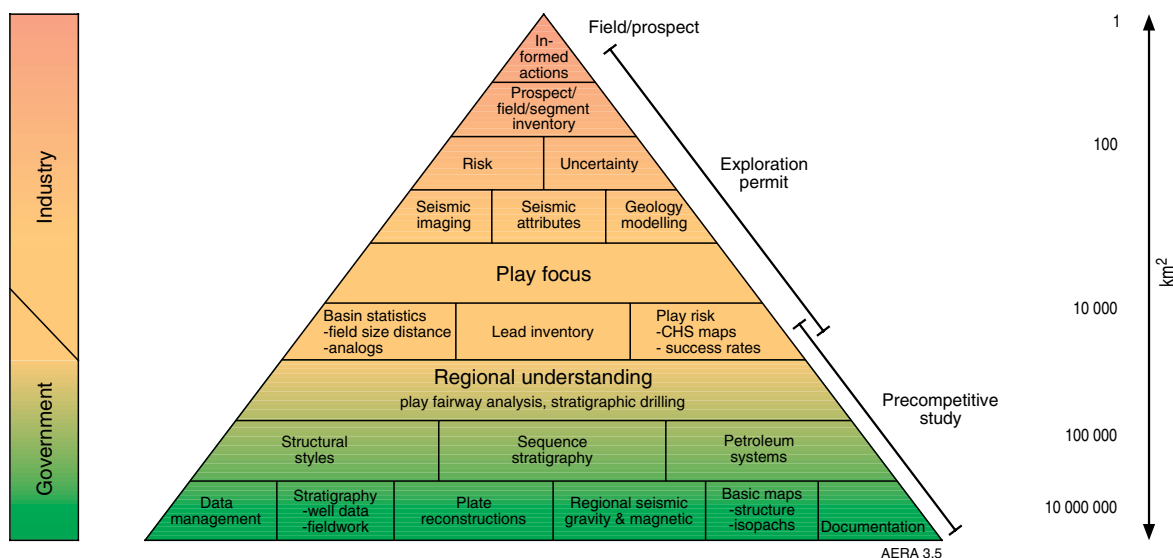


Figure 3.5 The resource discovery triangle

Source: Geoscience Australia (adapted from BP)

Reflection seismic is the primary technology used to identify likely hydrocarbon-bearing structures in the sub-surface. Drilling is then required to test whether the structure contains oil or gas, or both, or neither. The initial discovery well may be followed by appraisal drilling and/or the collection of further survey data (often 3D seismic) to help determine the extent of the accumulation.

Development and production

Once an economically recoverable resource has been identified, it is a matter of deciding whether to proceed to development based on project economics, market conditions (oil prices and cost of extraction technologies and facilities) and the availability of finance.

The development phase involves the construction of the infrastructure required for the production of the oil resource. Depending on the location, this infrastructure includes development wells, production facilities, a gathering system to connect individual wells to processing facilities, temporary storage and transport facilities.

In Australia, the options for offshore development include a floating production and storage offloading facility (FPSO) as, for example, the Enfield oil development in the Carnarvon Basin, or building a production platform and piping the oil ashore, as at

the Cliff Head field in the Perth Basin. Where the pipeline infrastructure is well established, new crude oil discoveries can be rapidly brought on stream as in the inshore Carnarvon Basin. Onshore, the options are to link into or extend the oil pipeline network or, in cases of small remote fields, as at Blina in the Canning Basin, to transport the oil by road.

The production phase includes extracting oil from the reservoir and separating impurities. At the initial stage of extraction, the natural pressure of the subsurface reservoir is generally sufficient for the oil to flow to the surface. If the reservoir pressure is insufficient, an advanced recovery method is used to increase reservoir pressure.

Condensate is a component of natural gas and is produced during gas or crude oil field development. In some cases the condensate is extracted and the gas is reinjected in a process called gas recycling.

Processing, transport, storage and trade

Crude oil and condensate is not generally used in its raw or unprocessed form, apart from some light-sweet crude oil with low sulphur content which can be used as a burner fuel for steam generation in industrial applications. The majority of crude oil is processed in a refinery to produce refined products, such as gasoline, diesel, aviation fuel, fuel oil,

BOX 3.1 PETROLEUM SYSTEMS AND RESOURCE PYRAMIDS

Oil accumulations are the products of a 'petroleum system' (Magoon and Dow 1994). The critical elements of a petroleum system are:

- source – an organic rich rock, such as an organic rich mudstone;
- reservoir – porous and permeable rock, such as sandstone;
- seal – an impermeable rock such as a shale or mudstone;
- trap – a sub-surface structure that contains the

- accumulation, such as a fault block or anticline;
- overburden – sediments overlying the source rock required for its thermal maturation; and
- migration pathways to link the mature source to the trap (figure 3.6).

In addition to these static elements, the actual processes involved – trap formation, hydrocarbon generation, expulsion, migration, accumulation and preservation – must occur, and in the correct order, for the petroleum system to successfully operate and for oil accumulations to be formed and preserved. It is essential that the source rock has been through (or is still within) the oil window, the zone in the subsurface where temperatures are sufficient for thermal alteration of the organic matter to oil. At higher temperatures, below the bottom of the oil window, oil starts to be broken down (cracked) to gas.

Unconventional oil accumulations reflect the failure or under-performance of the petroleum system. Oil shale is an example where a thermally immature source rock has not generated and expelled hydrocarbons. Oil or tar sands occur where conventional crude oil has failed to be trapped at depth and has migrated near to the surface and has become degraded by evaporation, biodegradation and water washing to produce a viscous heavy oil residue.

The petroleum resource pyramid (McCabe 1998) describes how a smaller volume of easily extracted conventional gas and oil is underpinned by larger volumes of more difficult and more costly to extract

unconventional gas and oil (figure 3.7). For the unconventional hydrocarbon resources, additional technology, energy and capital has to be applied to extract the gas or oil, replacing the natural action of the geological processes of the petroleum system. Technological developments and rises in price can make the lower parts of the resource pyramid accessible and economic to produce. The recent development of oil sands in Canada and of shale gas in the United States are examples where rising energy prices and technological development has facilitated the exploitation of unconventional hydrocarbon resources lower in the pyramid.

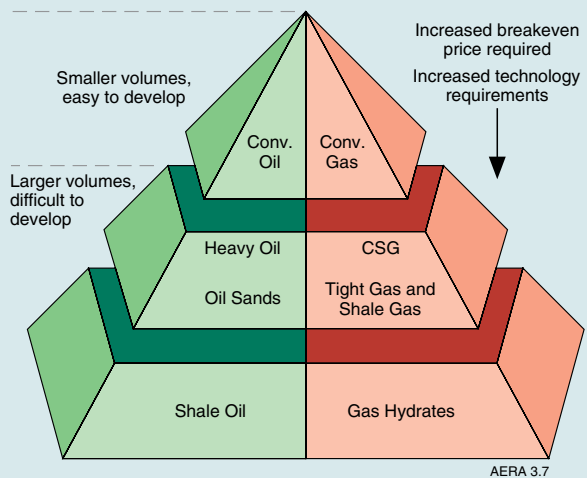


Figure 3.7 Petroleum Resource Pyramid

Source: Geoscience Australia (adapted from McCabe 1998 and Branran 2008)

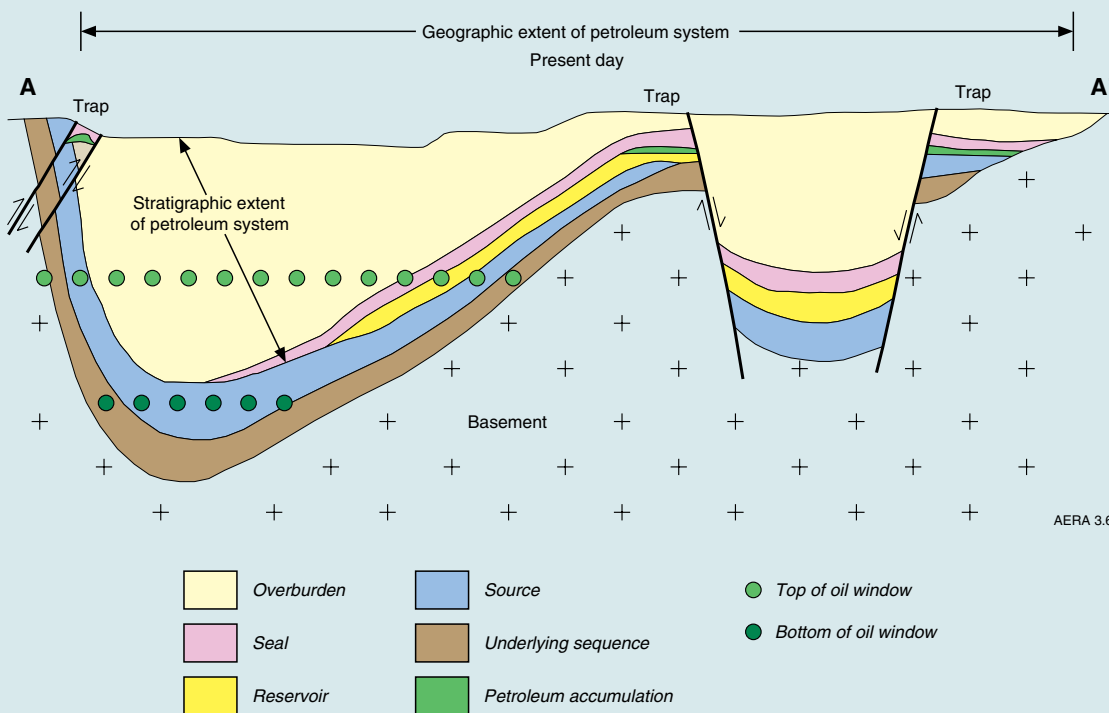


Figure 3.6 Petroleum system elements

Source: Magoon and Dow 1994 (modified)

kerosene and LPG. Some crude oil and condensate can also be converted into non-energy products and used as a feedstock in the petrochemical industry.

Once refined, end-use products can be stored and transported to the demand centre via road, rail, sea or pipeline.

Around 70 per cent of Australia's crude oil and condensate production occurs off the north-west coast. Around 60 per cent of this production is exported, reflecting the proximity to refineries in south-east Asia. In 2008–09, approximately 63 per cent of Australia's refinery input requirements were imported. This partly reflects the insufficient crude oil and condensate production in eastern Australia, particularly within reasonable distance of refineries in Sydney and Brisbane.

In 2008–09, around 40 per cent of Australia's refined petroleum products were imported, primarily reflecting increasing dependence on overseas

refineries to meet incremental domestic refined product demand. Some 8 per cent of Australia's refinery production was exported, mainly in the form of transport fuels for international carriers.

End use market

The major end-use market for refined products is the transport sector. Refined petroleum products are transported to local distribution points, from where they are delivered either directly to end users or to retail outlets, predominately as petrol, diesel and LPG.

3.2.3 World oil market

Table 3.1 provides a snapshot of the Australian oil market within a global context. Australia's reserves account for only a small share of global reserves, and Australia is a relatively small producer and consumer.

Oil reserves and production

World proven oil reserves were estimated to be around 1.4 trillion barrels (equivalent to around 8.3 million PJ), at the end of 2008 (table 3.1). This

Table 3.1 Key oil statistics, 2008

	unit	Australia 2007–08	Australia 2008	World 2008
Reserves	PJ	-	24 284	8 257 028
	Bbbl	-	4.2	1408
Share of world	%	-	0.3	100
Production of crude oil, condensate and LPG	PJ	1059	-	174 012
	mmbbl	187	194	30 471
Share of world	%	-	0.6	100
Average annual growth from 2000	%	-4.3		1.3
Oil refining capacity	kb/d	-	734	88 627
Share of world	%	-	0.8	100
Consumption of crude oil, condensate and LPG	PJ	1417	-	-
Average annual growth from 2000	%	-2.4	-	-
Consumption of oil and oil products	PJ	1942	-	171 236 ^a
	mmbbl	-	342	31 586 ^a
Share of world	%	-	1.1	100
Share of primary energy consumption	%	33.6	-	34.0
Average annual growth from 2000	%	1.3	-	1.6
Imports of crude oil and other refinery feedstocks	PJ	1019	-	98 392 ^a
Average annual growth from 2000	%	-0.3	-	1.8
Imports of oil and oil products	PJ	1678	-	139 109 ^a
	kb/d	762	771	67 277 ^a
	mmbbl	278	282	24 556 ^a
Share of world	%	-	1.1	100
Average annual growth from 2000	%	4.2	-	2.6
Exports of crude oil, condensate and LPG	PJ	661	-	92 842 ^a
Average annual growth from 2000	%	-3.0	-	-
Exports of oil and oil products	PJ	807.7	-	135 742 ^a
Average annual growth from 2000	%	-2.6	-	-

Note: Bbbl – billion barrels, mmbbl – million barrels, kb/d – thousand barrels a day
a 2007 data

Source: ABARE 2009b; BP 2009a; IEA 2009a, b

amount could be increased in the future if unproved oil reserves and resources can be upgraded to proven reserves (oil considered to be recoverable with reasonable certainty under current economic and operating conditions). At current rates of world production, the estimated proven oil reserves are enough to last for around 42 years. Since the mid-1980s the global reserves to production ratio has been steady at around 40 years or more (BP 2009a) as production is balanced as new discoveries are made and new reserves are developed each year.

About two-thirds of total world reserves are located in the Middle East. Four of the five countries with the world's largest reserves – Saudi Arabia, Iran, Iraq and Kuwait – are in this region (figure 3.8). Saudi Arabia alone accounted for 19 per cent (1 552 320 PJ, 264 Bbbl) of world reserves. Canada has the second largest share of world oil reserves, though oil sands totalling some 887 880 PJ (151 Bbbl) account for around 80 per cent of these reserves. The Asia Pacific region accounted for 3 per cent of world oil reserves. The largest oil reserves in this region are located in China.

Australia is ranked twenty-seventh in the world in terms of proven oil reserves, accounting for around 0.3 per cent of global reserves.

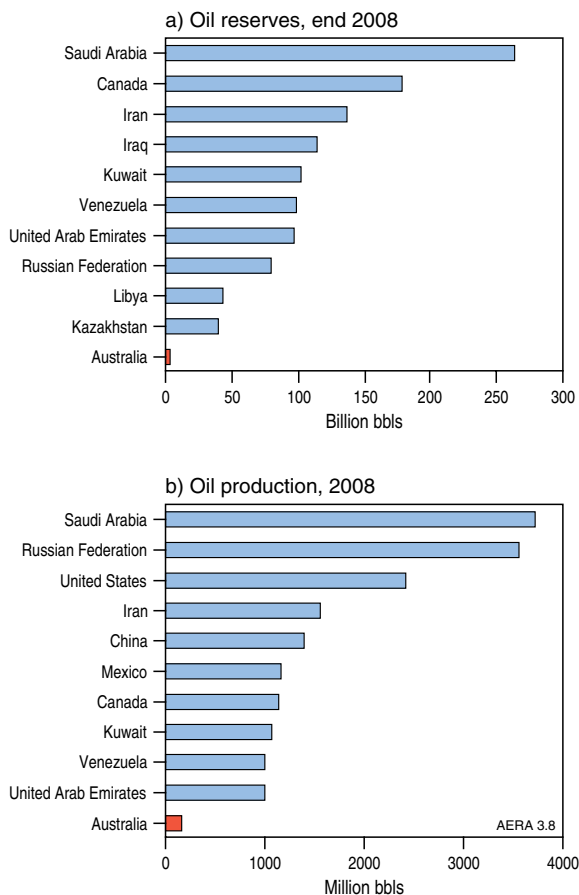


Figure 3.8 World oil reserves and production, major countries, 2008

Source: BP 2009a; IEA 2009a

World total oil production in 2008 was some 30.5 Bbbl (equivalent to around 174 012 PJ). Production of crude oil represents more than 90 per cent of total oil production, which includes crude oil, condensate, LPG and unconventional oil. The major oil producers are located in the Middle East, with a 31 per cent share of world production. Saudi Arabia is the largest single producer, accounting for around 13 per cent of world production (figure 3.8). The Russian Federation is also a major producer (12 per cent). Other Former Soviet Union countries (particularly Azerbaijan, Kazakhstan and Turkmenistan) and Africa (particularly Angola and Sudan) are also becoming important oil producing regions. Over the period 2000 to 2008, production from these two regions grew at an average annual rate of around 7 per cent and 5 per cent respectively.

Australia is only a small oil producer, accounting for 0.6 per cent of total oil production in 2008.

Petroleum refining

Because virtually all oil, conventional and unconventional, needs to be processed before end use, refinery capacity and throughput are significant

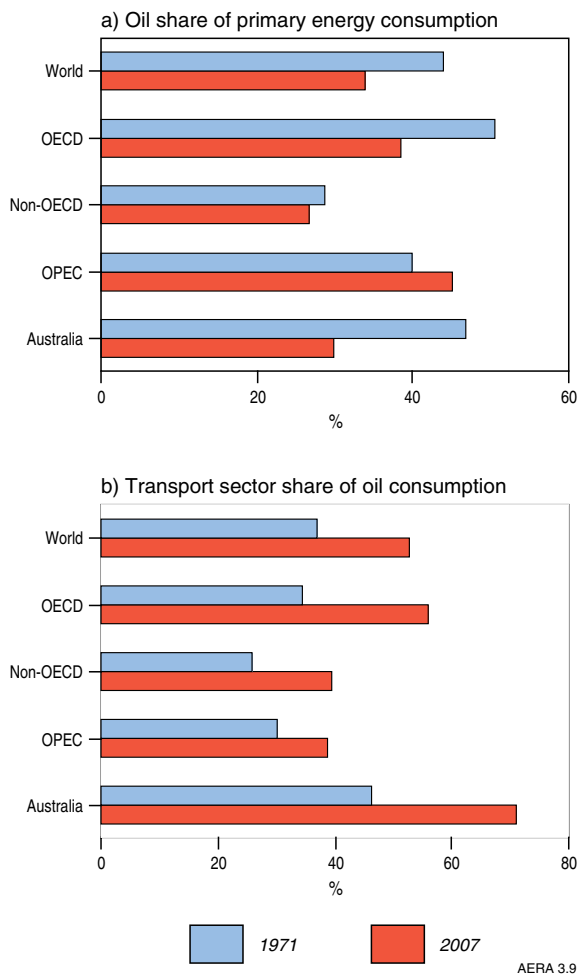


Figure 3.9 Oil share of total energy consumption and transport sector usage

Source: IEA 2009a; 2009b

Table 3.2 World refinery capacities and petroleum production, 2008

	Refinery capacities (kb/d)	Share of world capacity (%)	Refinery output (kb/d)	Share of world production (%)
Asia Pacific	25 098	28.3	22 653	28.0
North America	21 035	23.7	21 567	26.7
Europe	17 007	19.2	16 071	19.9
Former Soviet Union	8079	9.1	6172	7.6
Middle East	7592	8.6	6493	8.0
Latin America	6588	7.4	5434	6.7
Africa	3228	3.6	2466	3.0
World	88 627	100.0	80 856	100.0
Australia	734	0.8	684	0.8

Note: Includes capacity and production from unconventional oil

Source: BP 2009a; IEA 2009a

indicators of supply of end use products. Table 3.2 summarises world refining capacity and production, by region.

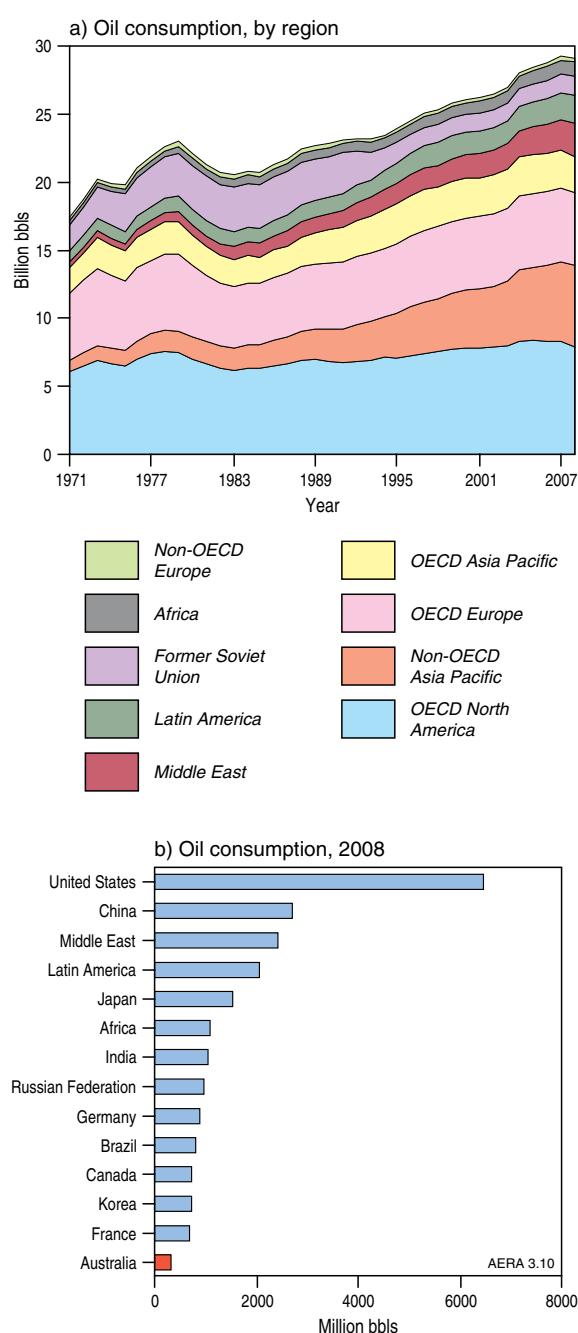
The largest share, accounting for around 28 per cent of world refinery capacity and output, is in the Asia Pacific region. China, Japan, India and the Republic of Korea are the major producers of refined products in the region, although Japan and the Republic of Korea rely almost entirely on imported crude oil. The largest single producer is the United States, accounting for more than 20 per cent of world production of oil products. Australia accounted for less than 1 per cent of world refining capacity and production.

Consumption

Oil is an important energy source, currently accounting for around 34 per cent of world primary energy requirements. However, its share of primary energy has been declining steadily since the 1970s from around 45 per cent (figure 3.9). World oil consumption grew at a moderate rate of around 1.5 per cent per year between 1971 and 2008 whereas primary energy consumption grew at 2.2 per cent per year over the same period.

More than 50 per cent of world oil consumption is currently used in the transport sector, compared with less than 40 per cent in the early 1970s (figure 3.9). In contrast, the global shares of oil consumption in the industry and electricity generation sectors have been steadily declining over the past twenty years. In 2007, the industry and electricity generation sectors accounted for 8 per cent and 7 per cent respectively of total oil consumption. Around 14 per cent of world oil consumption is used as non-energy feedstock.

Figure 3.10 shows world oil consumption by region. North America and the Asia Pacific are the major consuming regions, responsible for nearly 60 per cent of world oil consumption in 2008. Oil consumption in non-OECD countries has grown more rapidly than the world average, at an average rate of 3 per cent per year between 1971 and 2008. The fastest growing oil consuming region is non-OECD Asia, growing at an

**Figure 3.10** World oil consumption

Source: IEA 2009a

Table 3.3 World oil trade by region, 2008

Shares %	To							
	Asia Pacific	North America	Europe	Latin America	Africa	Australasia	unknown	World exports
From								
Middle East	63	18	19	8	60	12	11	37
Africa	8	19	22	27	7	1	0	15
Former Soviet Union	4	4	47	4	1	1	40	15
North America	1	31	5	42	2	2	6	11
Asia Pacific	19	1	1	12	4	80	8	10
Latin America	3	17	4	0	2	0	0	7
Europe	1	8	0	7	24	0	34	4
Australasia	1	0	0	0	0	0	0	1
Unknown	0	2	2	0	0	4	0	1
World imports	40	26	25	3	3	2	1	100

Source: BP 2009a

average rate of more than 5 per cent per year over the same period.

Australia is ranked twenty-second in the world in terms of oil consumption, accounting for around 1 per cent of the world total. Almost 70 per cent is consumed in the transport sector, while 8 per cent is used as non-energy feedstock.

Trade

Given the significant separation of major producing and major consuming countries, there is a substantial level of trade in oil. Over the past twenty years oil trade has increased as oil production reserves in the Asia Pacific region and North America failed to keep pace with growth in demand. In the mid-1980s, around 40 per cent of world oil consumption was supplied through international trade. This increased to around 65 per cent in 2008.

World oil trade in 2008 was 67.3 million barrels per day (IEA 2009a). The largest export region was the Middle East, which accounted for around 37 per cent of world oil exports (table 3.3). Africa and the Former Soviet Union countries together accounted for 30 per cent of world oil exports. The largest importer of oil, the Asia Pacific region, accounted for around 40 per cent of world oil trade in 2008. North America and Europe together accounted for about half of world trade.

In 2008, around 63 per cent of Asia Pacific oil imports were sourced from the Middle East and regional trade within the Asia Pacific accounted for a further 19 per cent. In North America, 31 per cent of imports are sourced from within the region, specifically oil exports from Canada and Mexico to the United States. Significant quantities of oil are imported into North America from Latin America, the Middle East and Africa. The majority of the Europe's imports are sourced from the Former Soviet Union, Africa and the Middle East.

Australia is a net importer of crude oil and condensate and of refined oil products, but is a net exporter of LPG. Since the mid-1990s, Australia's imports of crude oil from the Middle East have been gradually declining and have been increasingly sourced from South-East Asia, mainly from Vietnam.

World oil market outlook

In its reference scenario, the IEA projects world demand for primary oil – and the supply to meet that demand – to both grow by 1 per cent per year, from 29 645 mmbbl (169 297 PJ) in 2008 to 36 820 mmbbl (210 271 PJ) in 2030 (table 3.4).

Oil demand in non-OECD economies is expected to grow at a faster rate than in OECD economies. By 2030, non-OECD economies are expected to represent more than half of world oil demand, up from 41 per cent in 2008.

The majority of the increase is expected to be supplied by OPEC countries, where significant proven reserves of conventional crude oil exist. OPEC's share of world oil supply could increase from around 44 per cent in 2008 to 52 per cent in 2030.

Some 52 per cent of the oil was used in the transport sector in 2008. This share is expected to rise further to 57 per cent in 2030. Viable alternatives for transport fuels are expected to remain relatively limited throughout the outlook period, while the share of oil use in other sectors, including industry and electricity generation, is expected to decline further.

Production of conventional oil, including crude oil and condensate, is expected to slow towards the end of the outlook period. To meet oil demand, increased production is expected to come from unconventional sources, mainly oil sands, extra-heavy oil, gas-to-liquids and coal-to-liquids. As a result, the share of unconventional oil is expected to rise from 2 per cent in 2008 to 7 per cent in 2030.

Table 3.4 World oil outlook from IEA reference case^a

	unit	2008	2030
World oil supply	PJ	169 097	210 271
	mmbbl	29 610	36 820
Share of OPEC supply	%	43.7	52.2
Share of supply from unconventional oil	%	2.1	7.0
Annual growth 2008–30	%		1.0
World primary oil demand	PJ	169 297	210 271
	mmbbl	29 645	36 820
Share of non-OECD demand	%	41.3	53.4
Share of transport sector demand	%	52.0	57.0
Annual growth 2008–30	%		1.0

^a Data are converted from million barrels per day to million barrels by multiplying with 350, factor that is consistent with BP (2009a).
Source: IEA 2009c

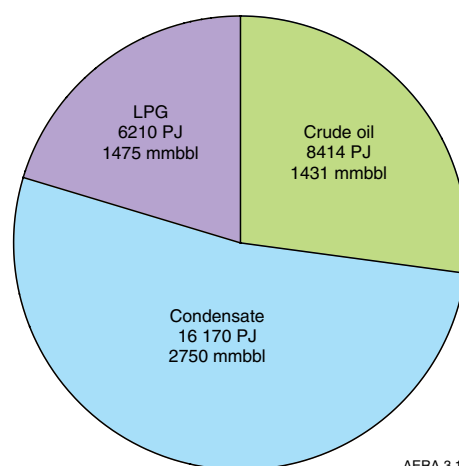
The IEA projects world demand for energy to grow more slowly under its 450 scenario in which countries take coordinated action to restrict the rise in global temperatures to 2°C and stabilise the greenhouse gases in the Earth’s atmosphere to around 450 parts per million carbon dioxide-equivalent (IEA 2009c). Under this scenario the IEA projects oil demand to grow at an average rate of 0.2 per cent per year to reach 31 240 mmbbl in 2030 (down 15 per cent on the reference case). In the IEA’s 450 scenario demand growth is driven primarily by China (averaging 2.7 per cent per year) and to a lesser extent other developing countries while demand reduces in the United States and other OECD countries. In this scenario the IEA predicts savings in transport fuel consumption through efficiencies and greater use of electric and hybrid vehicles and a greater contribution from second-generation biofuels after 2020 (IEA 2009c).

3.3 Australia’s oil resources and market

3.3.1 Crude oil resources

Australia’s crude oil resources were estimated at 8414 PJ (1431 mmbbl) as at 1 January 2009. Crude oil represents 27 per cent of liquid petroleum resources with the remainder being made up of condensate (16 170 PJ, 53 per cent) and naturally-occurring LPG (6210 PJ, 20 per cent) (figure 3.11).

As shown in table 3.5, most of Australia’s identified crude oil resource is in the economic demonstrated resource (EDR) category and only a small volume is considered sub-economic given current relatively high oil prices.



AERA 3.11

Figure 3.11 Australia’s liquid petroleum resources by energy content and volume as at 1 January 2009**Source:** Geoscience Australia 2009a

Resource classification is more fully discussed in Appendix D, but note that EDR are resources with the highest levels of geological and economic certainty and include remaining proved plus probable commercial reserves of petroleum. Sub-economic Demonstrated Resources (SDR) are resources for which profitable extraction has not yet been established. Inferred Resources are those with a lower level of confidence that have been inferred from more limited geological evidence and assumed but not verified.

An additional but uncertain resource is represented by the volumes of crude oil that could be produced from existing fields by the application of enhanced oil recovery (EOR) technologies such as miscible gas flooding (e.g. using nitrogen or carbon dioxide). These methods can increase the oil recovery factor significantly beyond the 30–50 per cent typically recovered using combined primary and second recovery methods. However, EOR depends heavily on the availability and cost of miscible gases (Wright et al. 1990) and is not currently undertaken at any Australian oil field. Reserves growth (Geoscience Australia, 2001, 2004, 2005) in existing fields is another potential source of additional crude oil resources.

Table 3.5 Australian crude oil resources represented as McKelvey classification estimates as at 1 January 2009

Crude Oil Resources	PJ	mmbbl
Economic Demonstrated Resources	6950	1182
Sub-economic Demonstrated Resources	1464	249
Total	8414	1431

Source: Geoscience Australia 2009a

Most (72 per cent) of the remaining identified crude oil resource is located in the Carnarvon (4839 PJ) and Bonaparte (1205 PJ) basins. Despite its 40 years of production, the Gippsland Basin remains a significant resource (1700 PJ) with smaller volumes in a number of onshore (Cooper-Eromanga, Bowen-Surat and Amadeus) and offshore (Browse, Perth and Bass) basins (figure 3.12).

While crude oil resources are identified across nine basins and through much of the stratigraphic column the significant volumes are restricted to the offshore Mesozoic basins on the northwest margin and in Bass Strait. The onshore basins contribute only about 5 per cent of the total crude oil resources.

Australia's remaining identified crude oil resources are dwarfed by past production which has come mainly from a few super-giant fields in the Gippsland Basin and the Barrow Island field in the Carnarvon Basin, all discovered in the 1960s (figure 3.13). Many such smaller oil fields have been found since, mostly in the Carnarvon and Bonaparte basins. The impact of these initial discoveries on crude oil resources and the reserves to production ratio is illustrated in figures 3.14 and 3.15.

The reserves to production (R/P) ratio has been relatively steady at around 7 to 10 years since the

1980s. However, it must be recognised that both production volumes and reserves have declined markedly in recent years. To date, around 80 per cent of the crude oil reserves discovered in Australia have been produced.

3.3.2 Condensate resources

Condensate exists as a hydrocarbon gas in the sub-surface reservoir that condenses to a light oil at the surface when a gas (or a gas and oil) accumulation is produced. Condensate now represents more than half of Australia's remaining liquid hydrocarbon resources. In 2008 the demonstrated condensate resource totalled 16 170 PJ (2750 mmbbls) most of which was assessed as EDR (table 3.6).

Table 3.6 Australian condensate resources represented as McKelvey classification estimates as at 1 January 2009

Condensate Resources	PJ	mmbbl
Economic Demonstrated Resources	12 560	2136
Sub-economic Demonstrated Resources	3610	614
Total	16 170	2750

Source: Geoscience Australia 2009a

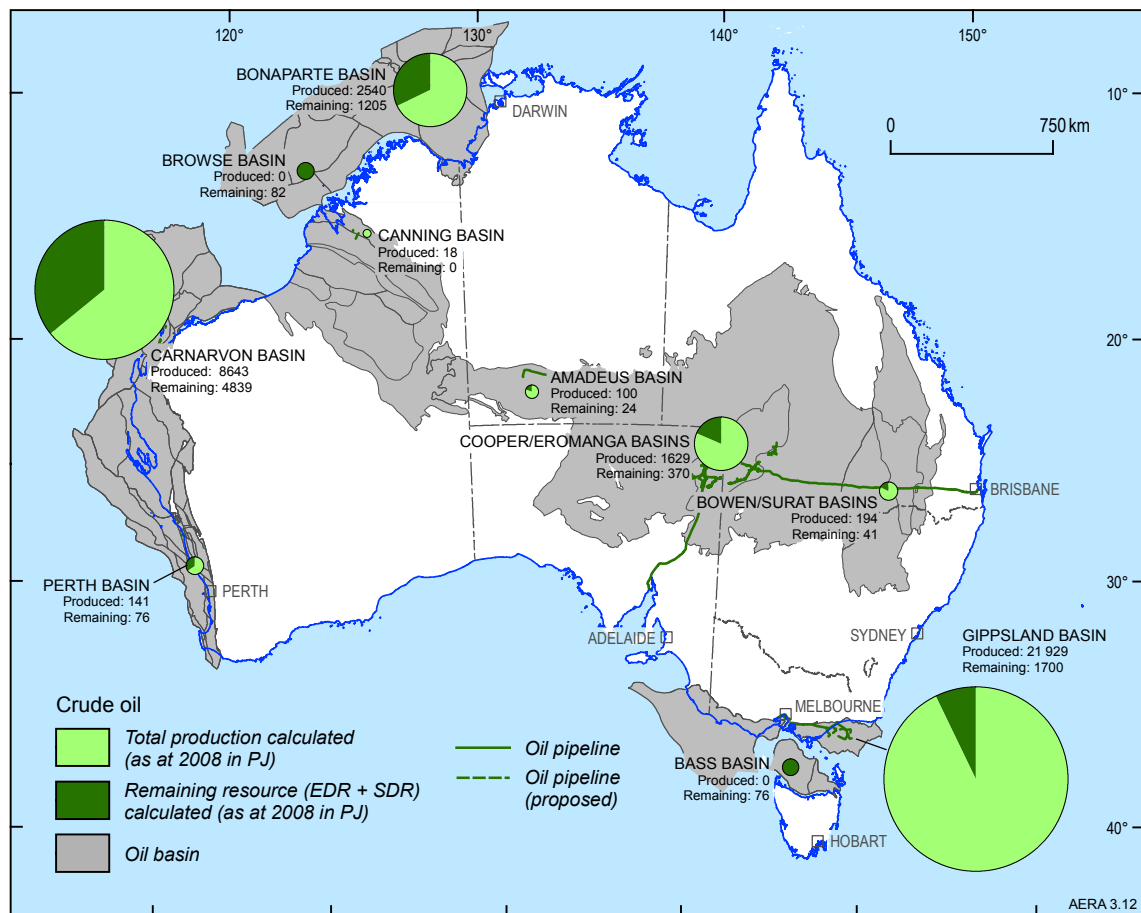


Figure 3.12 Australia's known crude oil resources, by basin and oil pipelines

Source: Geoscience Australia

As most Australian crude oils are light, sweet crudes and are very similar to the condensate produced from gas fields, both are considered to have equivalent energy value per volume (5.88 PJ/mmbbl) in this report.

Condensate resources are located across ten basins, but the offshore basins along the North West Shelf – Bonaparte, Browse and Carnarvon – contain 92 per cent of the resource (figure 3.16). Similarly, the bulk of this resource is contained in a small number of giant ‘wet’ gas fields. The undeveloped Ichthys gas resource in the Browse Basin, for example, is estimated to contain 3099 PJ (527 mmbbls) or 19 per cent of Australia’s condensate resources; and is

the largest liquid hydrocarbon resource found since the Bass Strait oil fields in the Gippsland Basin in the 1960s.

Proportionally the Carnarvon Basin gas fields tend to be leaner in condensate than those in the Browse and Bonaparte basins due to the dominance of the super-giant dry gas accumulations of Ito-Ito and Scarborough.

The identified condensate resource has an energy content that is less than 10 per cent that of the associated gas resource, but has strategic importance as it constitutes more than half of

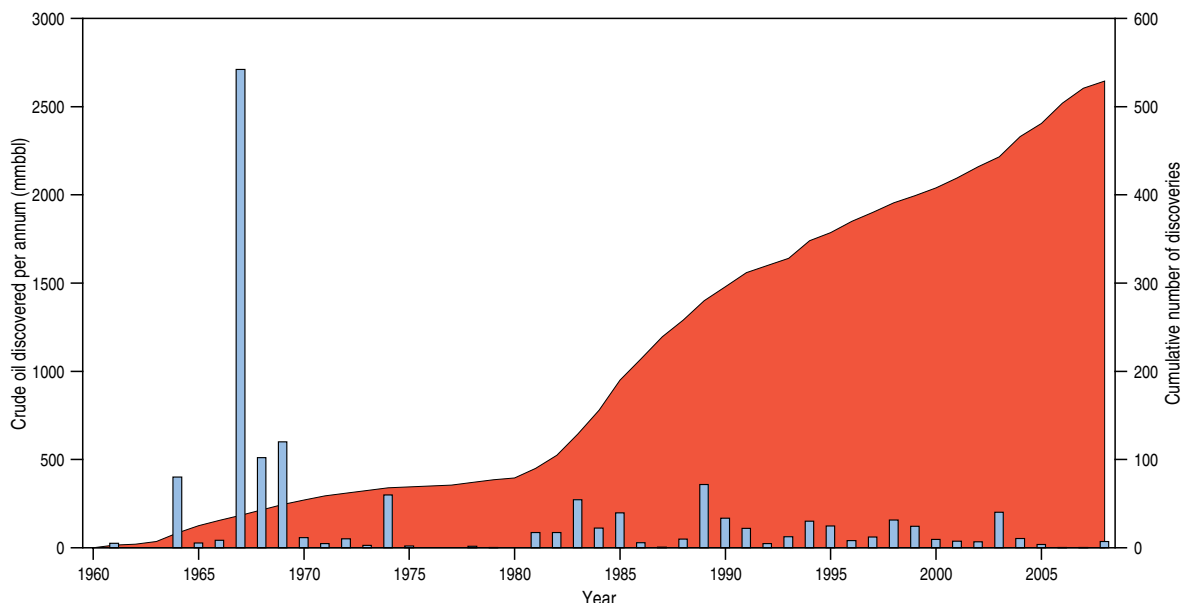


Figure 3.13 Australia’s crude oil discoveries, annual discovered volume (blue columns) and cumulative number of discoveries, 1960–2008

Source: Geoscience Australia

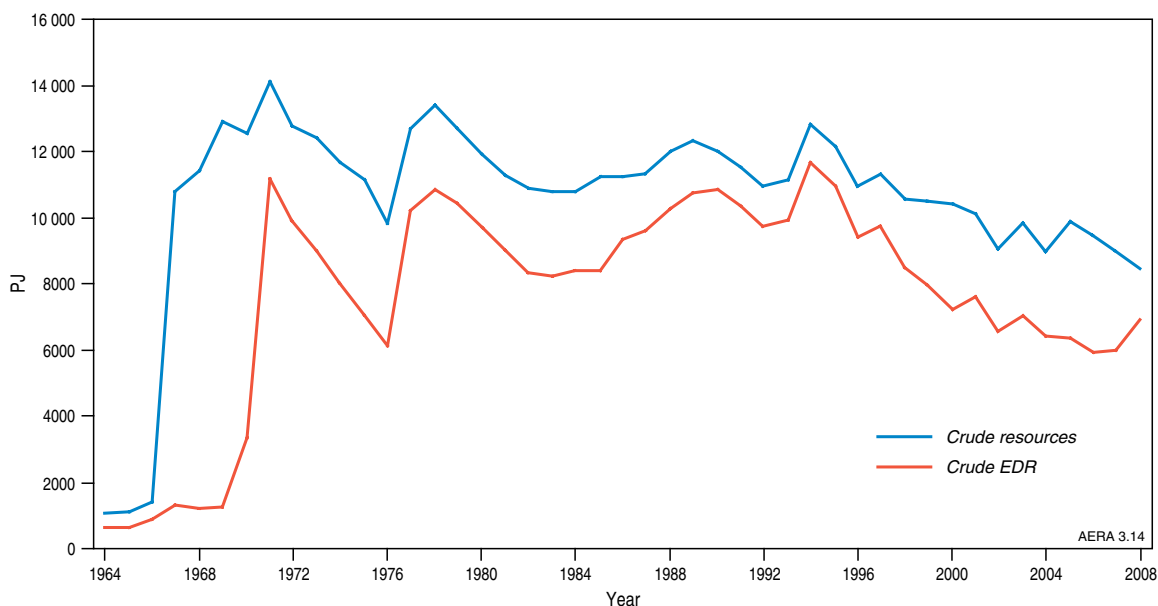


Figure 3.14 Australian crude oil resources and economic demonstrated resources (EDR), 1964–2008

Source: Geoscience Australia

Australia's liquid fuel resource. Access to this resource requires development of the giant wet gas fields which in several cases also contain considerable volumes of carbon dioxide (CO₂).

Australia's condensate resources have grown substantially since the discovery of the super-giant and giant gas fields along the North West Shelf in the early 1970s (North Rankin in the Carnarvon Basin,

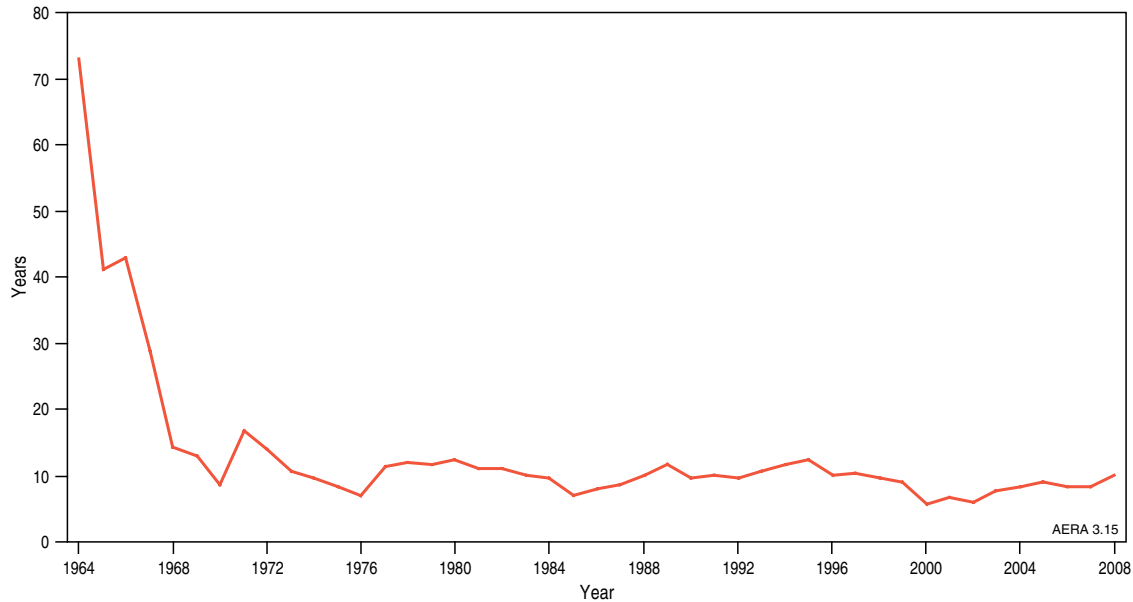


Figure 3.15 Australian crude oil reserves to production ratio in years of remaining production, 1964–2008

Source: Geoscience Australia

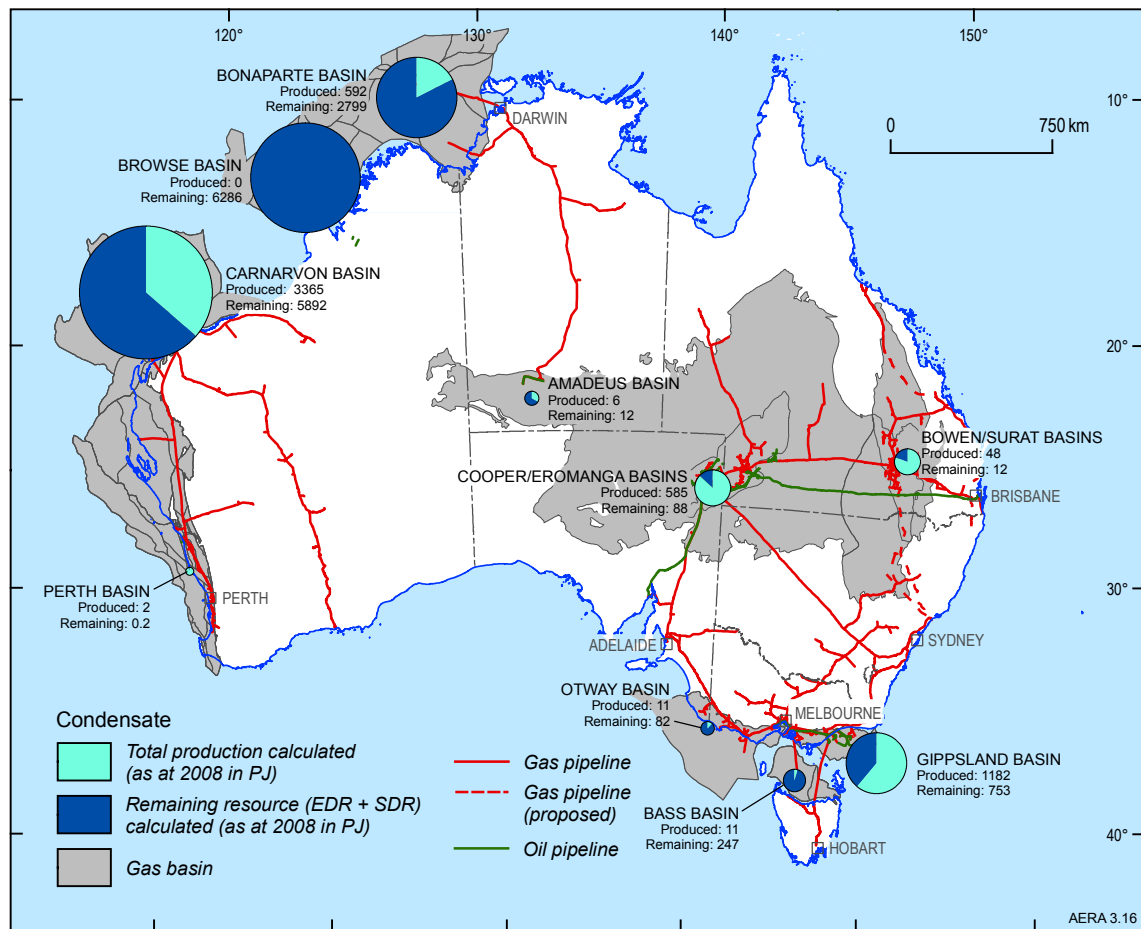


Figure 3.16 Australia's known condensate resources by basin, and gas and oil pipelines

Source: Geoscience Australia

Scott Reef (Torosa) in the Browse Basin, Sunrise in the Bonaparte Basin). The big step in the condensate EDR in 2008 (figure 3.17) is largely due to the promotion of Ichthys into this category.

The EDR to production ratio of condensate since 1980 has mostly been between 20 and 50 years, apart from a peak in the early 1980s (figure 3.18). In 2008 at current levels of production Australia had about 30 years of condensate reserves remaining.

3.3.3 LPG resources

The identified resource of naturally-occurring liquid petroleum gas (LPG) in 2008 was estimated at 6210 PJ (1475 mmbbls), most of which was

assessed as EDR (table 3.7). LPG represents 20 per cent of Australia’s liquid hydrocarbon resource in energy content terms. LPG is less energy dense than crude oil and condensate. Hence, though Australia’s naturally-occurring LPG now volumetrically exceeds the crude oil resource, the crude oil has a higher energy content (8414 PJ in 1431 mmbbls of crude oil, compared with 6210 PJ in 1475 mmbbls of LPG).

LPG is a mixture of light hydrocarbons that is normally a gas in subsurface reservoirs and at the surface. However, LPG is stored and transported as a liquid under pressure and forms part of Australia’s liquid fuel supply. In addition to the LPG occurring naturally in gas and oil fields, LPG is also produced during the refining of crude oil.

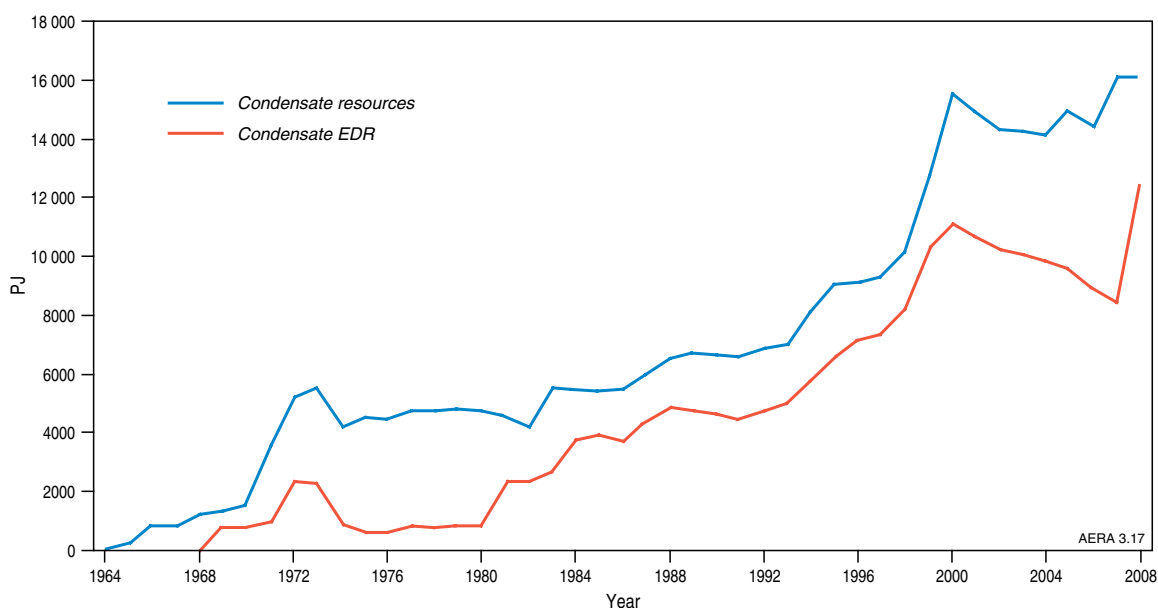


Figure 3.17 Australia’s identified condensate resources

Source: Geoscience Australia

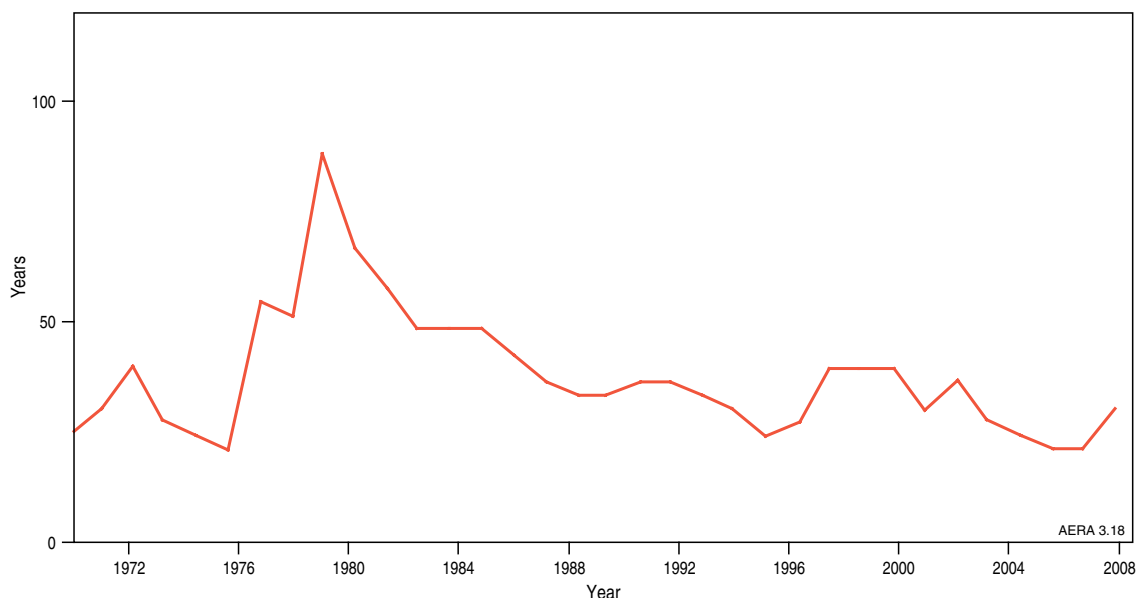


Figure 3.18 Condensate EDR to production ratio in years of remaining production

Source: Geoscience Australia

Table 3.7 Australian naturally-occurring LPG resources represented as McKelvey classification estimates as at 1 January 2009

LPG Resources	PJ	mmbbl
Economic Demonstrated Resources	4613	1096
Sub-economic Demonstrated Resources	1597	379
Total	6210	1475

Source: Geoscience Australia 2009a

Naturally-occurring LPG resources are identified in eight basins (figure 3.19). The distribution of LPG is similar to that of condensate with the Carnarvon, Browse and Bonaparte basins again dominating (85 per cent of the remaining resource). The resource in the Gippsland Basin remains significant (10 per cent of the total) even though this represents only about a quarter of the initial resource.

In 2008 at current levels of production, Australia had 20 years of naturally-occurring LPG remaining.

3.3.4 Shale oil resources

Australia has significant potential unconventional oil resources contained in oil shale deposits in several basins. Oil shale is essentially a petroleum source rock which has not undergone the complete thermal maturation required to convert organic matter to

oil. In addition, the further geological processes of expulsion, migration and accumulation which produce conventional crude oil resources trapped in subsurface reservoirs have not occurred. The unconventional shale oil resource can be transformed into liquid hydrocarbons by mining, crushing, heating, processing and refining, or by *in situ* heating, oil extraction and refining (box 3.2).

Australia's total identified energy resource contained in oil shale was estimated at 131 600 PJ (22 390 mmbbl) in 2009 (table 3.8). However, all of this was classified as either recoverable contingent (84 600 PJ, 14 387 mmbbl) or inferred (47 000 PJ, 8003 mmbbl) resources. This is a large unconventional oil resource.

Table 3.8 Australian shale oil resources represented as McKelvey classification estimates as at 1 January 2009

Shale Oil Resources	PJ	mmbbl
Sub-economic Demonstrated Resources	84 600	14 387
Inferred Resources*	47 000	8 003
Total	131 600	22 390

* The total inferred resource does not include a 'total potential' low grade shale oil resource of the Toolebuc Formation, Queensland estimated to be about 9 061 100 PJ (equivalent to 1 541 000 mmbbls, 245 000 GL) by BMR and CSIRO in 1983.

Source: Geoscience Australia 2009b

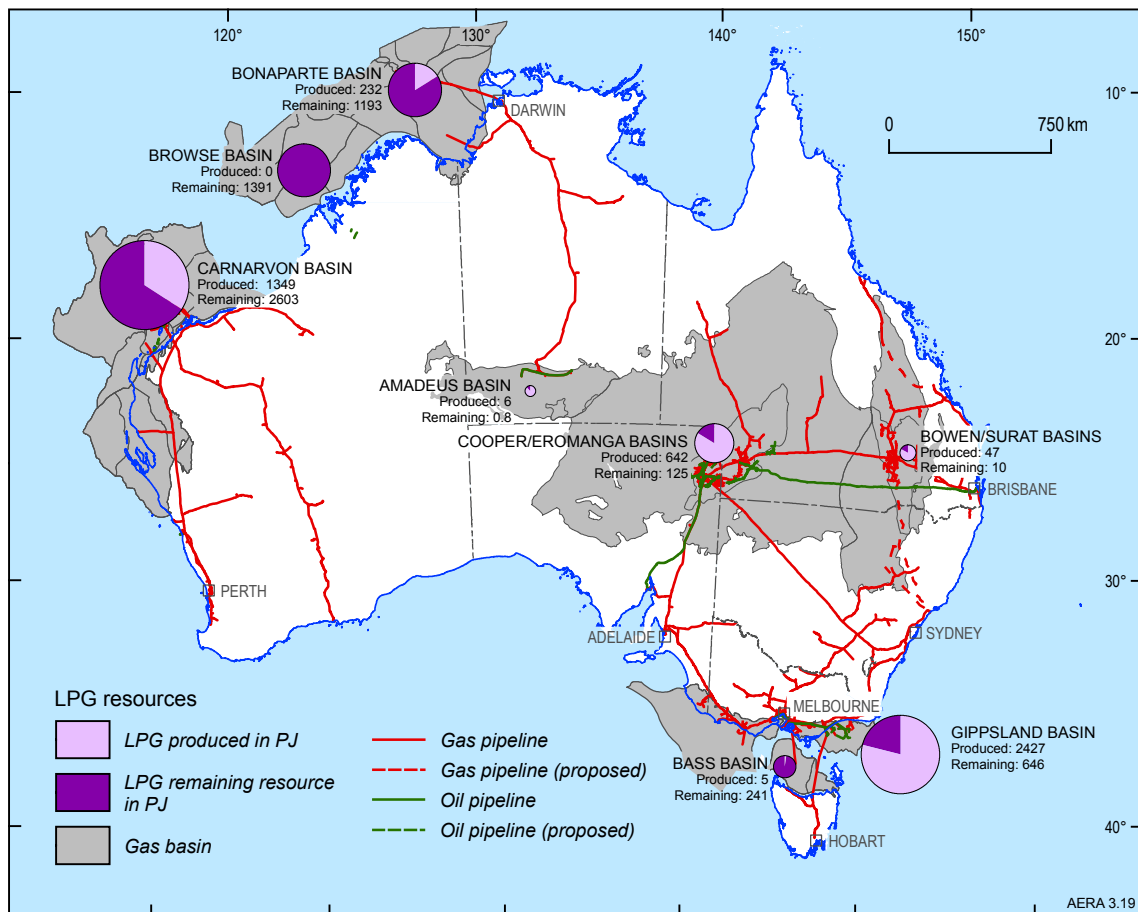


Figure 3.19 Australia's LPG resources by basin

Source: Geoscience Australia

BOX 3.2 SHALE OIL*Resources*

Oil shale is a significant but largely unutilised source of hydrocarbons (shale oil). Total world in-situ shale oil resources were estimated in 2005 (the last year for which world oil shale market data are available) to be around 16.62 million PJ (2826 billion bbl) in 27 countries (WEC 2007). Most of the resource is located in the Green River oil shale deposit in the United States. The USGS estimates the Green River oil shale to contain 1525 billion barrels of oil in-place in some seventeen oil shale zones (Johnson et al. 2009). Other countries with significant shale oil resources are the Russian Federation, the Democratic Republic of Congo, Brazil, Italy, Morocco, Jordan, Australia and Estonia. The total recoverable shale oil resource was estimated at about 6.27 million PJ (1067 Bbbl). Australia is estimated to have about 1.3 per cent of world recoverable shale oil resources.

Production

Small scale production of hydrocarbons (kerosene, lamp oil, fuel oil, and other products) from oil shale began in several countries in the late 1800s including Australia with production from the torbanite deposits at Joadja Creek near Lithgow and at Glen Davis (both in New South Wales) from 1865. This production continued through World War II until 1952. There was also production in the period 1910–34 from the Mersey River tasmanite deposits in Tasmania. Production in most western countries ceased after World War II because of the availability of cheaper supplies of conventional crude oil. However, production continued in Estonia, the then USSR, China and Brazil, peaking at 46 Mt of oil shale per year in 1980 (WEC 2007). Total recorded shale oil production in 2005 was about 5.014 mmbbl, comprising 2.529 mmbbl from Estonia, 1.319 mmbbl from China and 1.165 mmbbl from Brazil. In 2008 production of shale oil was limited to Estonia, China, and Brazil with several countries, including Israel, Morocco, Thailand and the United States, investigating the potential production of shale oil or use of oil shale in electricity generation (WEC 2009).

Geology and extraction

Oil shale deposits range in age from Cambrian to Cenozoic and were formed in a wide range of depositional environments ranging from freshwater and saline ponds and lakes commonly associated with coastal swamps (including peat swamps) to broad marine basins. Oil shales have a wide range of organic and mineral compositions and are classified according to their depositional environment, either terrestrial, lacustrine or marine. Terrestrial oil shales are composed mostly of resins and other lipid-rich (naturally-occurring molecules that include fats, waxes and sterols) organic matter and plant material. Lacustrine oil shales (known as lamosite

and torbanite) contain lipid-rich material derived from algae, whereas marine shales (tasmanite and marinite) are composed of lipid-rich derived from marine algae and other marine micro-organisms.

The organic matter in oil shale (which contains small amounts of sulphur and nitrogen in addition to carbon, hydrogen and oxygen) is insoluble in common organic solvents and is mixed with variable amounts of mineral matter, mostly silicate and carbonate minerals. There are currently two main methods for recovering oil from oil shale. The first involves mining (commonly by open-cut means) and crushing the shale, and then retorting (heating) it, typically in the absence of oxygen, to about 500°C. A large number of oil shale retorting technologies have been proposed but only a limited number are in commercial use. A second, more recent approach involves in-situ extraction of shale oil by gradually heating the rocks over a period of years to convert the kerogen. Both approaches rely on the chemical process of pyrolysis which converts the kerogen in the oil shale to shale oil (synthetic crude oil), gas and a solid residue. Conversion begins at lower temperatures but proceeds faster and more completely at higher temperatures.

Renewed interest in shale oil in recent years has prompted ongoing research into extraction technologies. A large number of technologies have been proposed and many trialled to produce shale oil. A report by the United States Department of Energy summarises those currently being investigated to produce shale oil (USDOE 2007). In-situ methods include injecting hot fluids (steam or hot gasses) into the shale formation via drill holes or heating using elements or pipes drilled into the shale with the heat conducted beyond the walls. Other approaches rely on heating volumes of shale using radio waves or electric currents. In-situ extraction has been reported to require less processing of the resultant fuels before refining but the process uses substantial amounts of energy. Both methods use substantial amounts of water and typically produce more greenhouse gases than does extraction of conventional crude oil. Currently over 30 companies in the United States are investing in the development of commercial-scale surface and in-situ processing technologies with several companies testing in-situ technologies to extract shale oil at more than 300 m depth (USDOE 2007).

Australia

There is no oil being extracted from oil shale in Australia. From 2000 to 2004, the Stage 1 demonstration-scale processing plant at the Stuart deposit near Gladstone in central Queensland produced more than 1.5 mmbbl of oil using a horizontal rotating kiln process (Alberta Taciuk

Process). No oil has been produced since 2004. The demonstration plant achieved stable production capacity of 6000 t of shale per day and oil yield totalling 4500 bbls per stream day while maintaining product quality and adhering to Environment Protection Authority emissions limits. The demonstration plant produced Ultra Low Sulphur Naphtha (ULSN), accounting for about 55 to 60 per cent of the output and Light Fuel Oil, about 40 to 45 per cent of output. The ULSN, which can be used to make petrol, diesel and jet fuel, had a very low sulphur content of less than 1 part per million.

Since acquiring the Stuart oil shale project, Queensland Energy Resources has undertaken a detailed testing program of processing of the

Queensland oil shale at a pilot plant in Colorado, United States and successfully demonstrated the use of the Paraho II vertical kiln technology to extract shale oil (WEC 2009). The company is currently examining a proposal for the construction of a small-scale technology demonstration plant at the Stuart site using the Paraho technology (www.qer.com).

In 2008, the Queensland Government prohibited shale oil mining at the McFarlane (formerly Condor) deposit near Proserpine for 20 years. The Queensland Government is currently undertaking a two-year review on whether the oil shale industry should be developed in the state. Other Australian oil shale industry developments are summarised elsewhere (Geoscience Australia 2009b).

The majority of Australian shale oil resources of commercial interest are located in Queensland, in the vicinity of Gladstone and Mackay (figure 3.20). Thick Cenozoic lacustrine oil shale deposits (lamosite) of commercial interest are predominantly in a series of narrow and deep extensional basins near Gladstone and Mackay. From 1999 to 2003, oil was produced at a demonstration-scale processing plant (referred to as the Stuart Oil Shale Project) at the Stuart deposit

in the Narrows Basin, near Gladstone. The oil shales are graded from about 60 litres per tonne at zero per cent moisture (LTOM) to over 200 LTOM, comfortably above the 50 LTOM cut-off generally regarded as the minimum required for profitable operation.

Oil shale deposits of varying quality also occur in New South Wales, Tasmania, and Western Australia in sedimentary sequences of Permian, Cretaceous

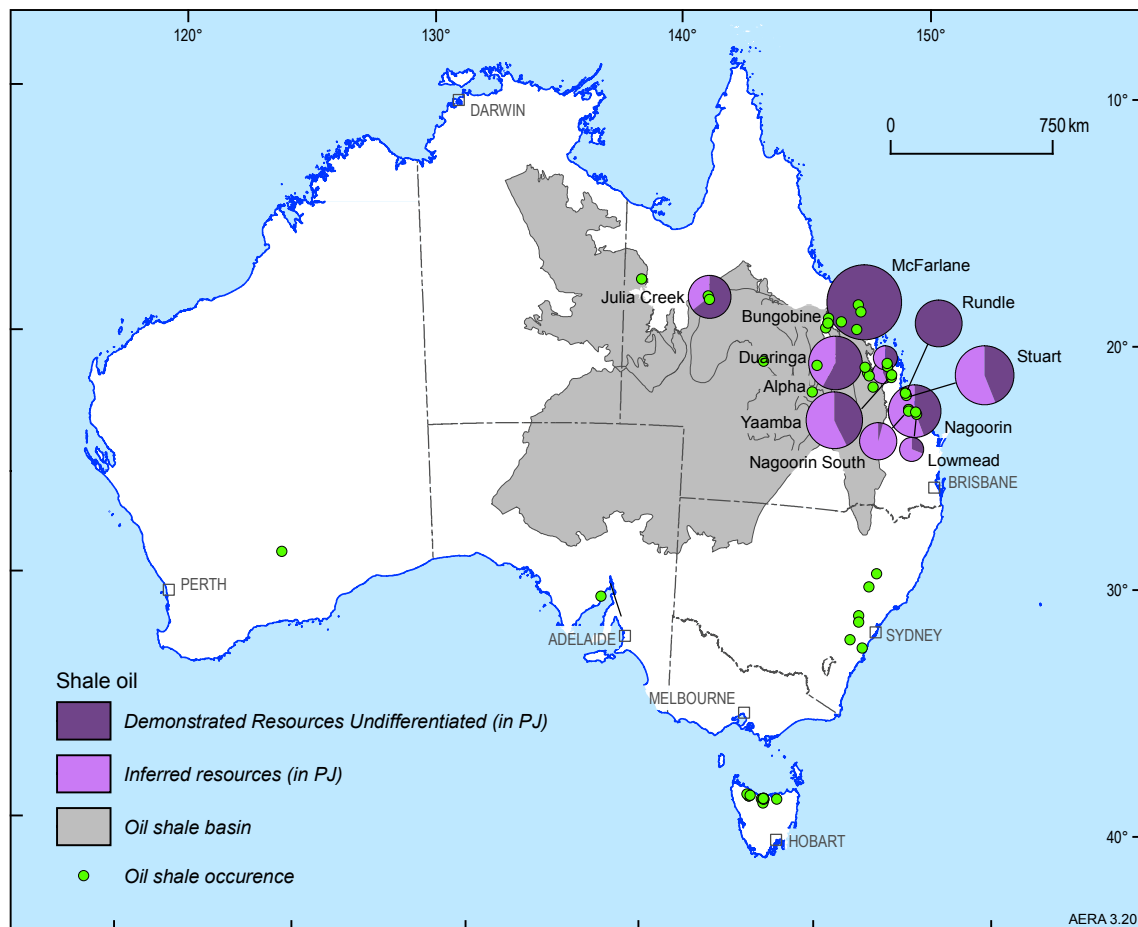


Figure 3.20 Distribution of Australian indicated shale oil resources

Source: Geoscience Australia

and Cenozoic age. There was some modest scale production from two of these deposits for periods up to the 1950s.

A potential shale oil resource of approximately 1 541 000 million barrels (9 061 086 PJ) was estimated for the Toolebuc Formation in north-western Queensland by the then Bureau of Mineral Resources (now Geoscience Australia) and the CSIRO (Ozimic and Saxby 1983). The Toolebuc Formation is very widespread but, at an average 37 LTOM, the resource is considered very low grade. It is not counted among the resources in table 3.8.

3.3.5 Total oil resources

Australia's oil resources are predominantly made up of conventional liquid hydrocarbons. Crude oil reserves are in decline, but there is a substantial remaining resource of condensate and naturally-occurring LPG associated with undeveloped offshore gas fields. Oil shale deposits contain a large, unconventional resource which does not currently add to Australia's liquid fuel supplies. Apart from

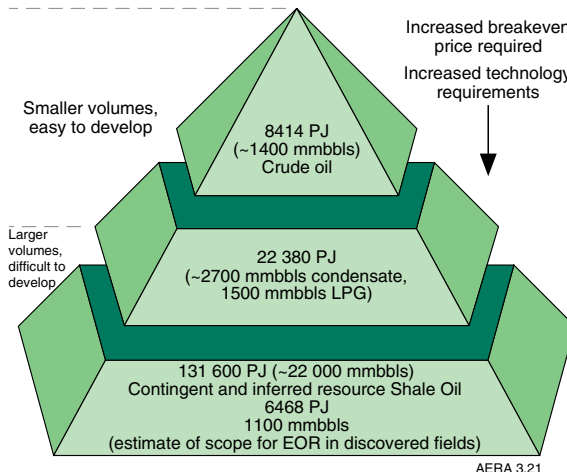


Figure 3.21 Australian oil resource pyramid

Source: Geoscience Australia (adapted from McCabe 1998 and Branran 2008)

enhanced oil recovery (EOR), options for future liquid fuel supply also include gas-to-liquids (GTL), coal-to-liquids (CTL) and biofuels which are discussed in other chapters in this assessment.

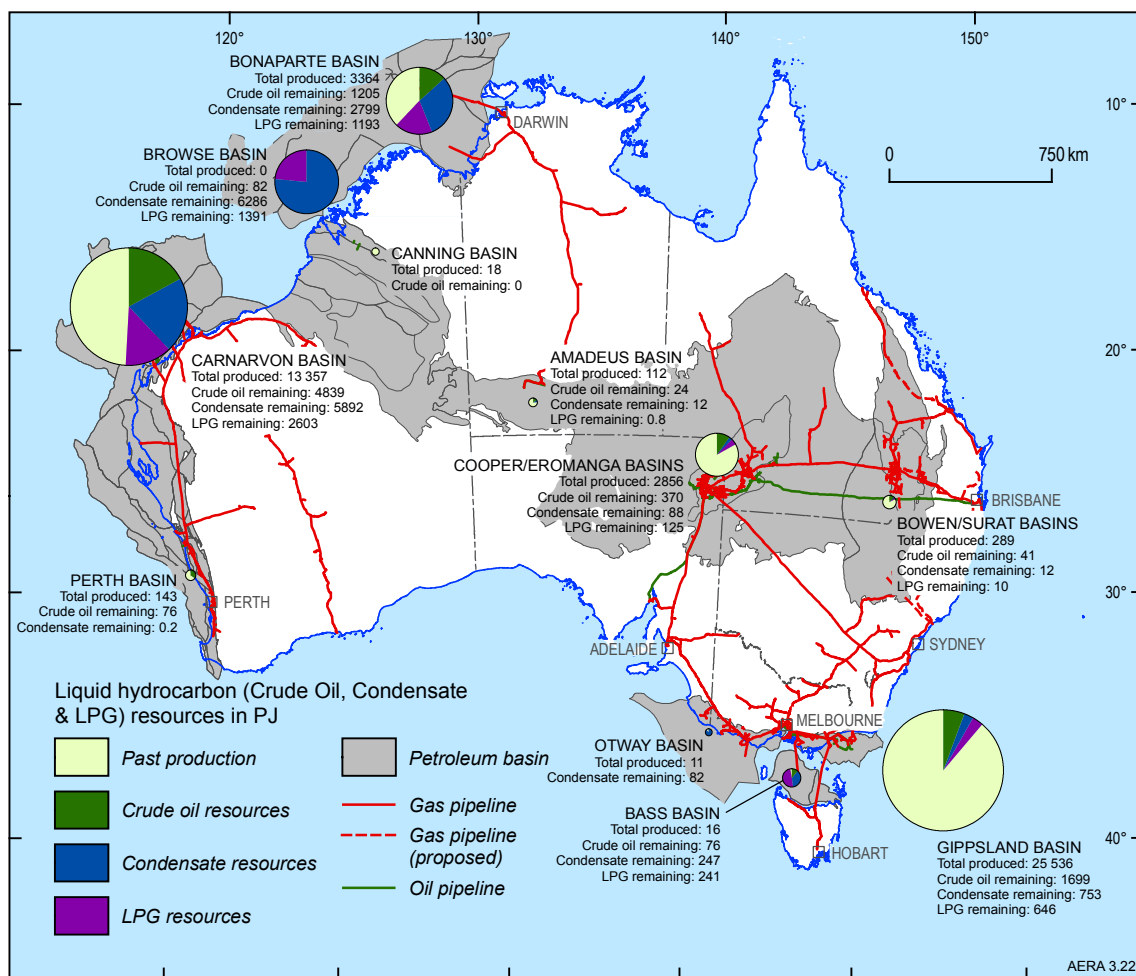


Figure 3.22 Australian crude oil, condensate and naturally-occurring LPG resources, infrastructure, past production and remaining resources

Source: Geoscience Australia

Table 3.9 Crude oil, condensate and LPG McKelvey classification estimates by basin as at 1 January 2009

McKelvey Class.	Basin	Total energy	Crude Oil		Condensate		LPG	
		PJ	PJ	mmbbl	PJ	mmbbl	PJ	mmbbl
EDR	Carnarvon	12 464	4405	749	5457	928	2602	618
EDR	Browse	3957	0	0	3957	673	0	0
EDR	Bonaparte	4131	676	115	2264	385	1191	283
EDR	Gippsland	2626	1353	230	629	107	644	153
EDR	Other	945	516	88	253	43	176	42
Total EDR		24 123	6950	1182	12 560	2136	4613	1096
SDR	Carnarvon	868	434	74	434	74	0	0
SDR	Browse	3797	82	14	2327	396	1389	330
SDR	Bonaparte	1063	529	90	534	91	0	0
SDR	Gippsland	470	348	59	122	21	0	0
SDR	Other	473	71	12	193	32	209	49
Total SDR		6671	1464	249	3610	614	1597	379
Total EDR + SDR		30 794	8414	1431	16 170	2750	6210	1475

Source: Geoscience Australia 2009a

The resource pyramid (figure 3.21) highlights how a smaller volume of more readily accessible, high quality resources are underpinned by larger but less accessible resources. However, these unconventional oil resources come with development costs and risks. Technology, price and their own environmental impacts can influence access to them.

Conventional hydrocarbon liquid resources are located across ten basins but most remaining resources are in the Carnarvon, Browse and Bonaparte basins (table 3.9). The initial liquid resources of the Carnarvon Basin were nearly equivalent to those of the crude oil-rich Gippsland Basin (figures 3.22 and 3.12).

3.3.6 Oil market

Oil production

Most of Australia's current crude oil production is from the mature oil provinces – the Carnarvon and Gippsland basins – which in 2007–08 accounted for 62 per cent and 18 per cent respectively of crude oil production. The Gippsland Basin also accounts for almost half of Australia's naturally-occurring LPG production, although this has been declining steadily since production peaked in the mid-1980s (figure 3.23).

Australia's annual crude oil production progressively declined between 1985–86 and 1998–99 from 1102 PJ to 738 PJ (187.4 to 125.2 mmbbl, 29 794 to 19 905 ML). However, following the start-up of a number of new oil fields, including the Laminaria/Corallina, Elang/Kakatua and Cossack/Wanaea fields (all offshore north-western Australia), oil production increased rapidly, peaking at 1209 PJ (205.7 mmbbl, 32 704 ML) in 2000–01. Since then, crude oil production has declined at a rate of 7 per cent per year, to 697 PJ (117 mmbbl, 18 602 ML) in 2007–08.

Domestic production of condensate increased from around 36 PJ (6.1 mmbbl, 1096 ML) in the first year of production in 1982–83 to 257 PJ (43.7 mmbbl, 6949 ML) in 2007–08, with production reaching 316 PJ (53.7 mmbbl, 8544 ML) in 2002–03. Naturally-occurring LPG production in Australia also increased from around 80 PJ (19 mmbbl, 3021 ML) in 1979–80 to 125 PJ (29.7 mmbbl, 4721 ML) in 2005–06, mainly from the Carnarvon Basin in Western Australia. In 2007–08, LPG production declined to 105 PJ (25.6 mmbbl, 4072 ML).

Over the past four years, a number of oil projects have been developed, with six fields in the Carnarvon Basin and one each in the Perth and Bonaparte basins. The eight fields have a production capacity in excess of 350 thousands of barrels per day (kbpd, table 3.10).

The Cliff Head development represents the first – and currently the only – offshore producing oil field in the Perth Basin. The Cliff Head field is modest in size (around 10 mmbbls), the accumulation's size having been revised downwards following further appraisal drilling. The decision to develop the field occurred during a period of rising oil prices that helped offset the impact of this appraisal drilling. The Enfield, Stybarrow and Vincent fields, all located in the deeper waters of the offshore Exmouth Sub-basin, Carnarvon Basin (figure 3.24), signal the addition of a significant new oil producing area for Australia: recoverable crude oil volumes across a dozen fields total around half a billion barrels.

In contrast to the nearly 6 billion barrels of conventional oil produced in Australia since the 1960s, only a few million barrels have been produced from oil shale. There was intermittent and small scale production from 1865 to 1952 when there was no indigenous conventional crude oil production. Another

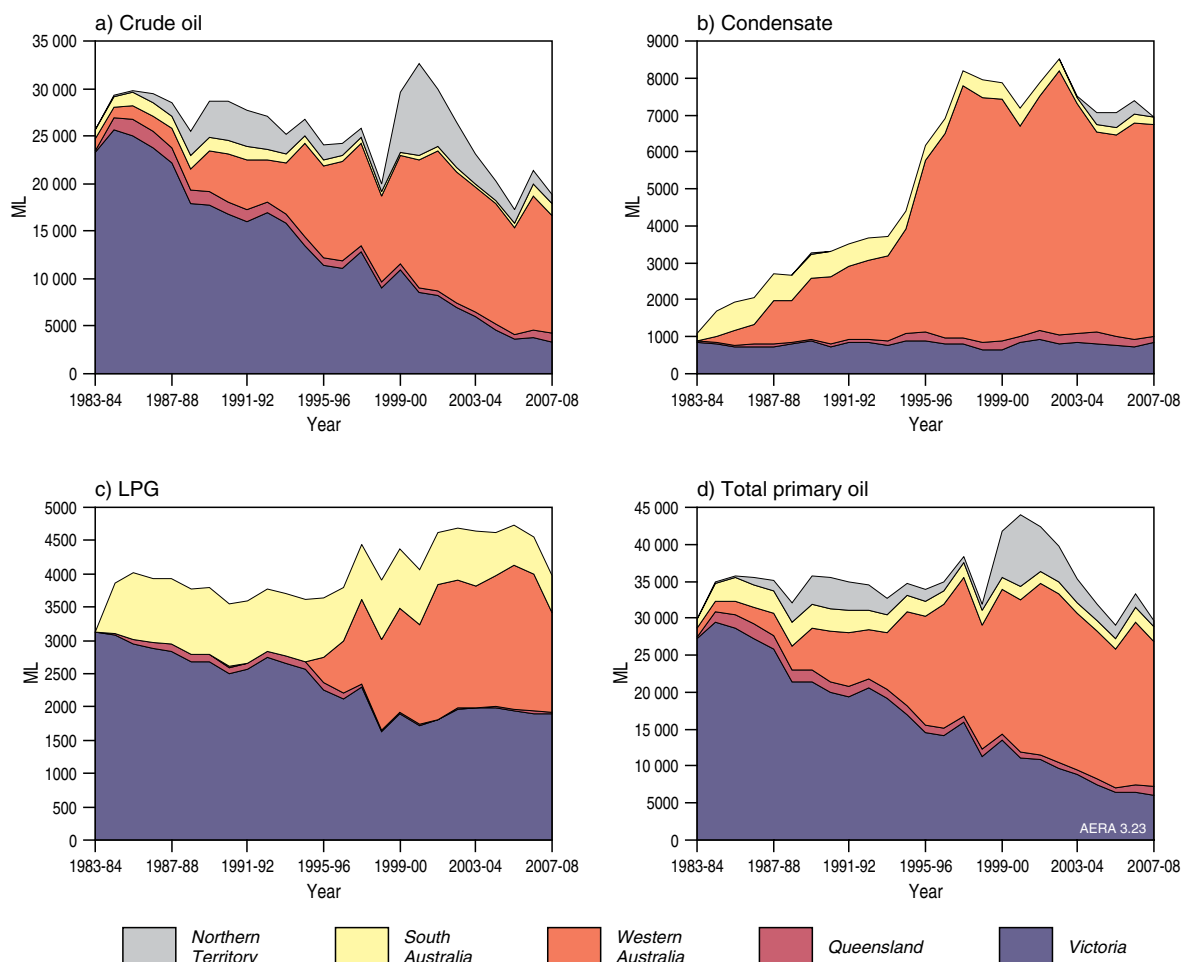


Figure 3.23 Australian oil production

Source: ABARE 2008

Table 3.10 Crude oil and condensate projects recently completed, as at October 2009

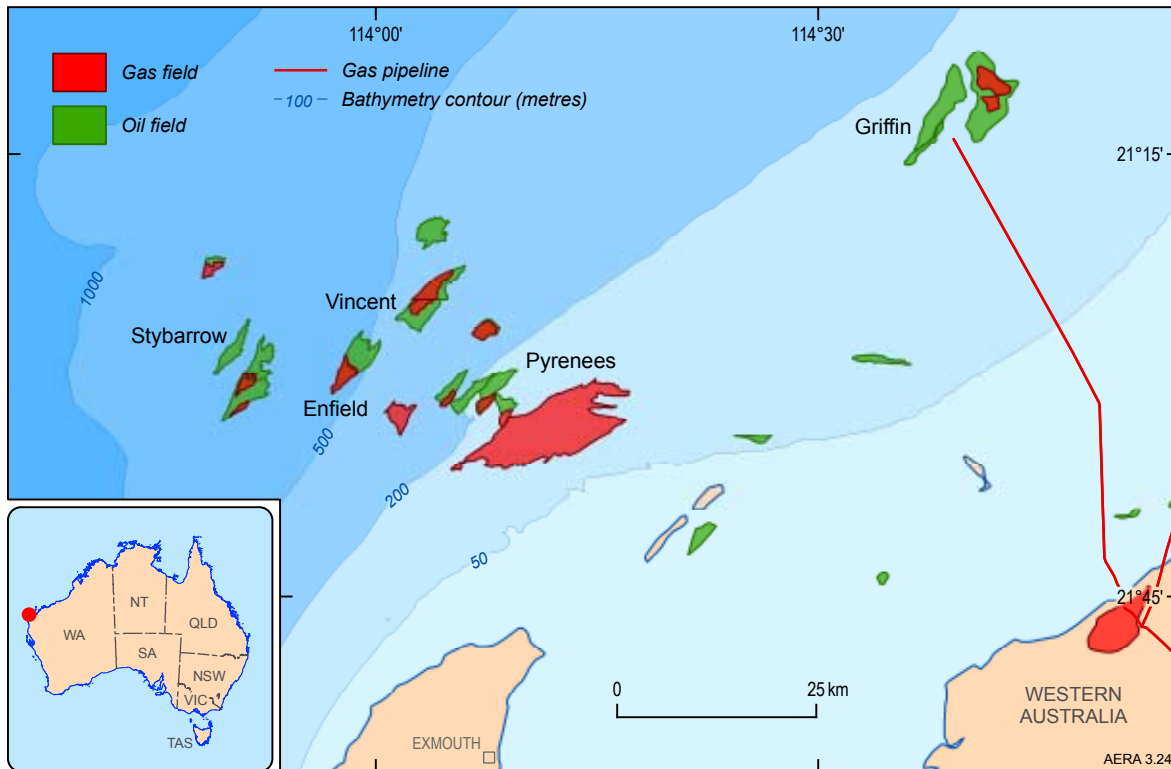
Project	Company	Basin	Start up	Capacity	Capital Expenditure (\$m)
Cliff Head oil field	ROC Oil	Perth	2006	20 kbpd	285
Enfield oil field	Woodside Energy/Mitsui	Carnarvon	2006	100 kbpd	1480
Puffin oil field	AED Oil/Sinopec	Bonaparte	2007	30 kbpd	150
Woollybutt oil field South Lobe	Tap Oil	Carnarvon	2008	6–8 kbpd	143
Perseus-over-Goodwyn project	Woodside Energy	Carnarvon	2008	na	800
Stybarrow oil field	BHP Billiton/Woodside Energy	Carnarvon	2008	80 kbpd	874
Vincent oil field (stage 1)	Woodside Energy/Mitsui	Carnarvon	2008	100 kbpd	1000
Angel gas and condensate field	Woodside/BHP Billiton/BP/Chevron Texaco/Shell/Japan Australia LNG	Carnarvon	2008	310 PJ pa gas, 50 kbpd condensate	1400

Source: ABARE; Geoscience Australia

unconventional oil resource, tar sands in the onshore Gippsland Basin, was exploited during World War II and in the post-war period (Bradshaw et al. 1999).

The high quality oil shale deposits in the Narrows Basin, near Gladstone, have been the subject of pre-

development studies for several decades (McFarland 2001). The Stuart Oil Shale Project achieved production from a demonstration-scale processing plant in the period 1999 to 2004, producing more than 1.5 million barrels of oil using a horizontal rotary kiln retort (box 3.2).



Field outline information is provided by GP Info, an Encom Petroleum Information Pty Ltd product.

Figure 3.24 Oil and gas fields and bathymetry, Exmouth Sub-basin, Carnarvon Basin

Source: Geoscience Australia

Petroleum refining

The petroleum refining industry in Australia produces a wide range of oil products, such as gasoline, diesel, aviation fuel and LPG, from crude oil and condensate feedstock. In 2007–08, Australian refineries consumed 1333 PJ (226.7 mmbbl, 36 043 ML) of crude oil and condensate, of which imports accounted for around 68 per cent (figure 3.25). Most of the imports are used in the domestic petroleum refining industry in Eastern Australia, to offset the declining production from the Gippsland Basin.

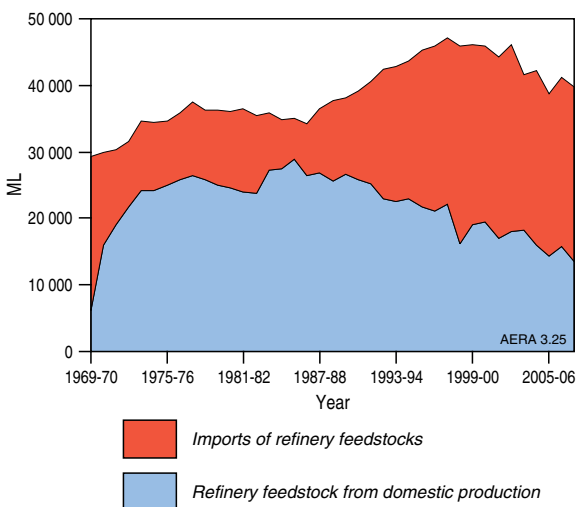


Figure 3.25 Sources of Australian refinery inputs

Source: ABARE 2009b

There are seven major petroleum refineries currently operating in Australia, managed by four companies — BP, Caltex, Mobil and Shell (table 3.11). These seven refineries have a combined capacity of around 42.7 billion litres a year. The largest of these are BP's Kwinana refinery in Western Australia and Caltex's Kurnell refinery in New South Wales. A refinery at Port Stanvac in South Australia ceased production in

Table 3.11 Australian refinery capacity

	Operator	Year commissioned	Capacity MLpa
New South Wales			
Clyde	Shell	1928	4930
Kurnell	Caltex	1956	7320
Queensland			
Bulwer Island	BP	1965	5110
Lytton	Caltex	1965	6270
South Australia			
Port Stanvac ^a	Mobil	1963	(4520)
Victoria			
Altona	Mobil	1949	4530
Geelong	Shell	1954	6380
Western Australia			
Kwinana	BP	1955	7960
Total^b			42 500

Notes: a The Port Stanvac refinery ceased production in July 2003; b Total of currently operating refineries; MLpa million litres per annum
Source: Australian Institute of Petroleum 2007

2003 and is currently under a care and maintenance regime. Its closure is one of the reasons behind a decline in total refinery output, which has led to increased imports of refined petroleum products.

Consumption

Oil is second only to coal, in terms of shares in Australian primary energy consumption. However, its share has been declining steadily, from a high of almost 50 per cent of primary energy use in the late 1970s to around 34 per cent in 2007–08. Prior to 1979, Australia's primary oil consumption had grown strongly at a rate of around 5 per cent per year. However, since then, consumption has been growing at a moderate rate of around 1 per cent per year to reach 1942 PJ (347 mmbbls, 55 168 ML) in 2007–08 (ABARE 2009b).

The transport sector is the largest consumer of oil products in Australia, currently accounting for around 70 per cent of total use, compared with 50 per cent in the 1970s (figure 3.26). The increased share has offset the decline in the industrial sector's share, down from about 40 per cent in the 1970s to about 20 per cent in 2007–08.

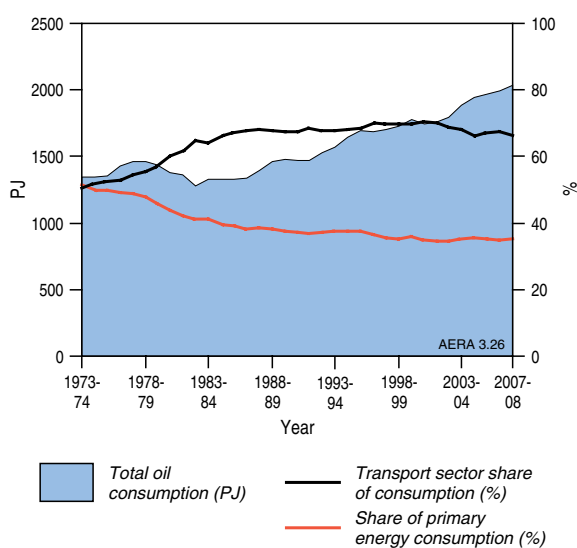


Figure 3.26 Australian oil consumption, share of total energy consumption and transport sector consumption

Source: ABARE 2009b

Trade

Australia is a net importer of crude oil and oil products but a net exporter of LPG. More than 60 per cent of domestic crude oil and condensate production (18.6 billion litres, 688 PJ, 117 mmbbl) was exported in 2007–08, predominantly from the Carnarvon Basin in Western Australia to Asian refineries. This reflects their relative proximity to the major producing fields compared with the refineries on Australia's east coast. Australia also imported 26 billion litres (962 PJ, 163.5 mmbbl) of combined crude oil and condensate to meet its domestic refineries'

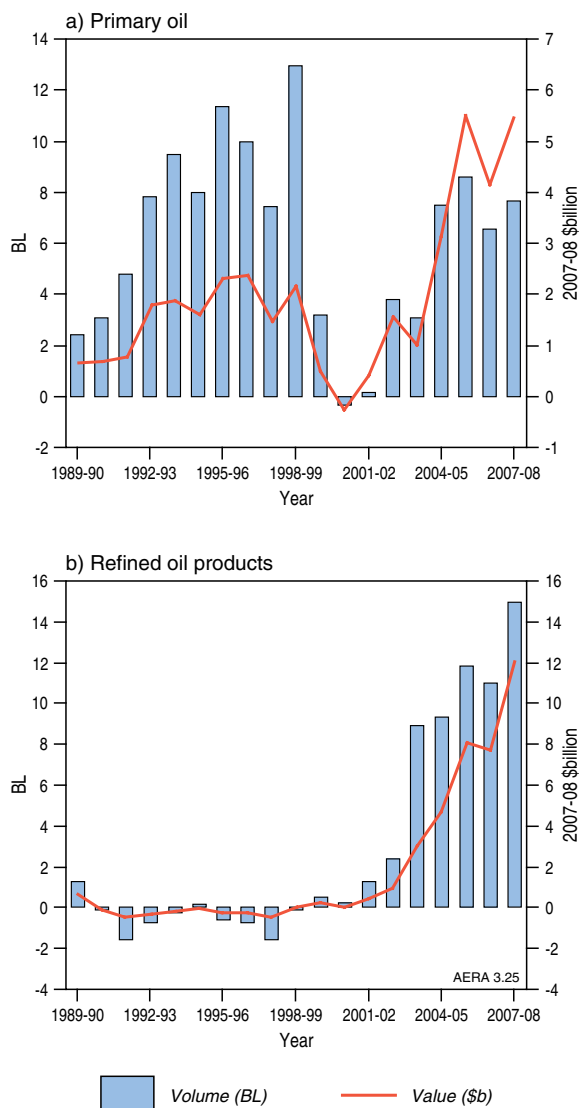


Figure 3.27 Australia's net oil imports – volume and value

Source: ABARE 2008 and 2009c

requirements. In 2007–08, Australia's net imports of primary oil (crude oil, condensate and LPG) were around 7.7 billion litres (383 PJ, 48.4 mmbbl), valued at \$5.5 billion.

For most of the 1990s Australia was a net exporter of refined oil products. Strong growth in consumption resulted in net imports from around 1999–2000 (figure 3.27). However, imports increased significantly following the closure of the Port Stanvac refinery in 2003 and amounted to around 15 billion litres (555 PJ, 94 mmbbl) in 2007–08. These imports were valued at around \$12 billion.

Oil supply–demand balance

Figure 3.28 provides a supply–demand balance for primary oil – production from oil fields and consumption in domestic refineries (refinery feedstock). Except for a brief period in the mid-

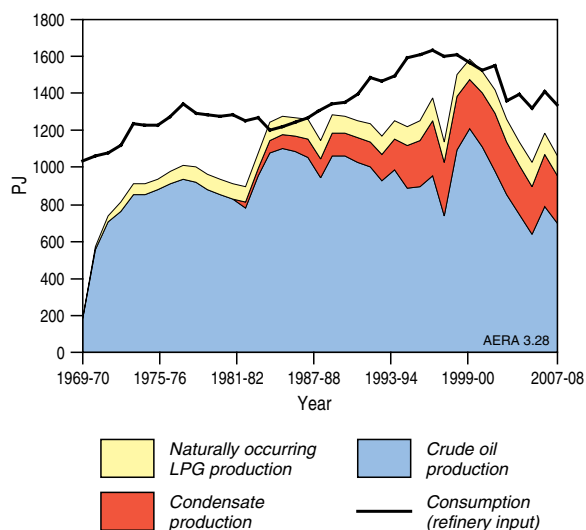


Figure 3.28 Australian primary oil supply–demand balance

Source: ABARE 2009b

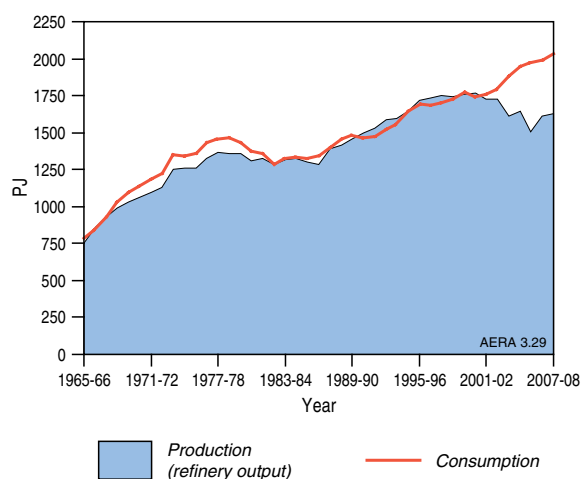


Figure 3.29 Australian refined oil products supply–demand balance

Source: ABARE 2009b

1980s, Australia has relied on net imports to meet domestic refineries' needs. In 2007–08, refineries in Australia used 1462 PJ of feedstock with around 25 per cent of this input met from imports.

Figure 3.29 provides a supply–demand balance for refined oil products, that is, oil products produced from domestic refineries to meet domestic demand for liquid fuels. In contrast to primary oil, Australia was generally self sufficient in terms of refined oil products for substantial periods during the 1980s and 1990s, because Australia had enough refinery capacity to meet domestic demand for oil products. Since the closure of the Port Stanvac refinery in 2002–03, however, net imports of oil products have risen steadily, and in 2007–08 net imports accounted for around 30 per cent of total consumption.

3.4 Outlook to 2030 for Australia's resources and market

3.4.1 Key factors influencing the outlook

For the purposes of this assessment, a key assumption is that demand for oil will continue to grow and will be met from a variety of sources including imports, domestic conventional crude oil and condensate production, and unconventional sources. Given the rapid changes in the past decade where Australia moved from net exporter to importer of oil, further significant change is expected in the outlook period to 2030. There will be continued production from known fields, and the dominance of the basins offshore north-western Australia will be entrenched as production comes on stream from condensate-rich gas fields such as Ichthys in the Browse Basin, and as the newly developed Exmouth Sub-basin of the Carnarvon Basin reaches peak production. The major uncertainties in indigenous oil supply are whether exploration efforts in frontier basins will be successful in finding a new oil province; whether discovered resources are commercialised; and the role of unconventional oil sources (gas-to-liquids, coal-to-liquids, enhanced oil recovery and shale oil) as well as alternative transport fuels such as biofuels.

This outlook is affected by various factors, including the geological characteristics of the resource (such as location, depth, quality), economic characteristics of the resource (such as cost), developments in technology, infrastructure issues, fiscal and regulatory regime, and environmental considerations. The market price of oil is perhaps the most important factor of all in determining the incentives for oil exploration and development, especially for unconventional oil resources.

Oil prices

Australia is a producer, exporter and importer of crude oil and refined products. Since deregulation of the oil sector in the late 1980s, Australia's oil market has been open, competitive and fully exposed to global market conditions.

Global oil prices are subject to both short-term price movements and longer-term price trends. Short-term oil price movements relate to influences on demand and supply of oil in the marketplace. These include cyclical/seasonal oil demand, the impact of supply disruptions such as hurricanes, accidents or sabotage, risk premiums associated with geopolitical tensions, and extraneous shocks to the economy such as the global financial crisis. In domestic market terms, significant exchange rate variations and market speculation can also affect short-term oil price movements.

In the longer term, an important driver of oil prices will be the underlying marginal cost of oil production,

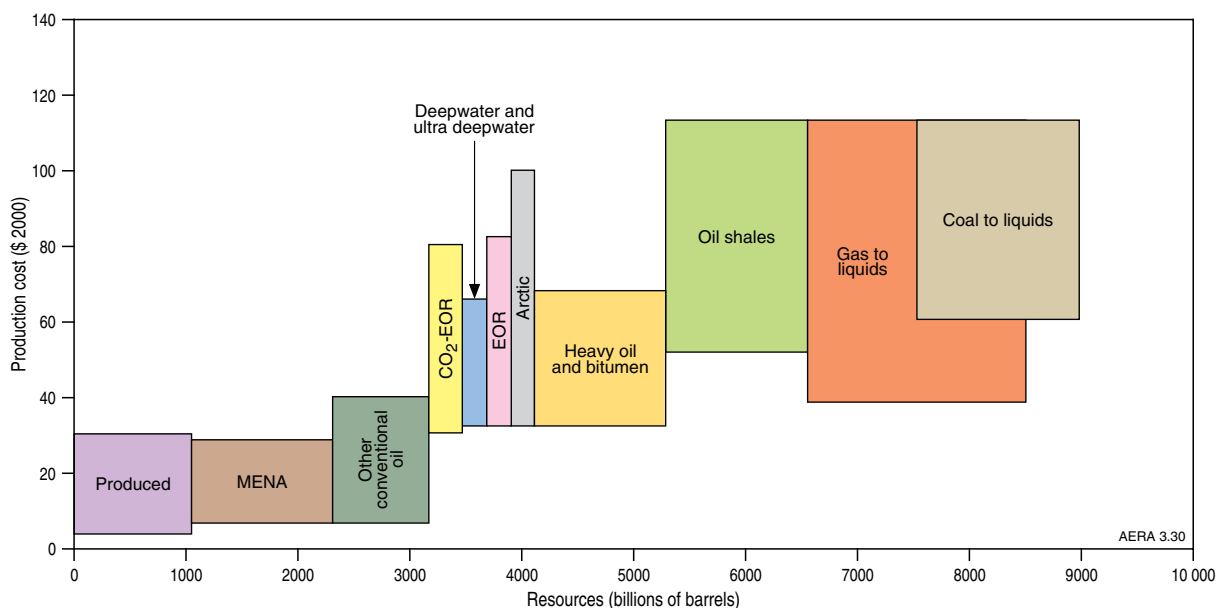


Figure 3.30 Long term oil supply cost curve

Note: MENA – Middle East and North Africa

Source: IEA 2008

which will have implications for oil supply, and a combination of long term economic growth and demand side efficiency improvements, which will have implications for oil demand.

The IEA's representation of the availability of oil resources and associated production costs is shown in figure 3.30. It shows that just over 1 trillion barrels of oil have already been produced at a cost of below US\$30 per barrel. There are potentially around 2 trillion barrels of oil remaining that can be produced at a cost below US\$40 per barrel, around three-quarters of them in OPEC member countries in the Middle East and North Africa (MENA). Reflecting its large, low cost reserves, OPEC's share of production is projected to increase from 44 per cent in 2008 to 52 per cent by 2030 (IEA 2009c). OPEC's decisions on oil field development will become progressively more important for the world oil market.

The importance of OPEC's investment decisions will be underpinned by the increasing cost of non-OPEC production. The majority of new non-OPEC investment is likely to be in offshore oil fields, increasingly in deeper water, further below the seabed and a greater distance from shore (including fields within the Arctic circle). The cost of oil production from deepwater sources and those needing advanced techniques such as EOR is estimated to be between US\$35 and US\$80 a barrel, similar to the cost of production from oil sands. The cost of producing oil from the Arctic could reach US\$100 a barrel because the large cost associated with developing infrastructure in an environmentally challenging area (IEA 2008).

The increase in oil prices over the past five years has encouraged exploration activity in frontier regions

such as the Campos Basin off the coast of Brazil and in deeper water in the Gulf of Mexico. The Brazilian Tupi field, for example, one of the most significant oil discoveries in the past 20 years, is 5 km below the surface of the Atlantic Ocean and below a salt layer up to 2 km thick. In September 2009, BP announced the discovery of the Tiber oil field in the Gulf of Mexico. The oil field is 10 700 m below the ocean floor and in water that is around 1200 m deep, making it one of the deepest drilled in the industry (BP 2009b). The continued development and application of deep water drilling and field development will eventually lead to lower production costs and the expansion of frontier areas where new oil fields can be developed in deeper water and further below the seabed, but the process at present is costly.

Synthetic oil production, such as shale oil, CTL and GTL, has the highest production costs, estimated by the IEA at up to US\$110 per barrel. This makes no allowance for any costs associated with the abatement of greenhouse gas emissions that are by-products of the process. At present there are very few commercial CTL and GTL projects, reflecting large capital and production costs and technically challenging production processes.

The future expansion of GTL capacity will depend on competing uses for gas such as for electricity generation, transport or export by pipeline or as LNG. One of the challenges for CTL is managing the high CO₂ output. Each barrel of oil produced from this technology releases between 0.5 and 0.7 tonnes of CO₂, compared with around 0.2 tonnes of CO₂ from a barrel of oil from the GTL process (IEA 2008).

GTL plants are operating in Qatar, South Africa and Malaysia and there has been output from an experimental (500 bbls per day) plant in Japan. There is one CTL plant in South Africa.

In comparison to GTL and CTL, production from oil shale is the more uncertain, given its energy and carbon intensity. There is some oil production from oil shale in Brazil, China and Estonia. The introduction of a price for carbon would further increase the cost of shale oil extraction.

Recent high oil prices have encouraged investment in technology to improve extraction of oil from oil sands and research to commercialise oil production from coal and gas. If the R&D is successful, it should enable production of increased quantities of oil from unconventional sources. However, despite the recent R&D effort, production costs for these unconventional sources have all increased, associated with higher capital and operating costs.

Further information on the long term outlook for oil prices is contained in Chapter 2.

Oil demand

The two factors expected to influence oil demand over the next two decades are the continued decrease in oil intensity in OECD economies and the increased oil consumption in non-OECD economies associated with strong economic growth.

In the OECD, oil intensity (the amount of oil consumed per unit of GDP) has been decreasing since the oil shocks of the 1970s (figure 3.31). One of the drivers of this trend has been the move away from oil-fired electricity generation capacity, to coal, gas or nuclear power. The increase in prices during 2007 and the first half of 2008 is likely to reinforce this trend and will encourage analogous responses in other areas of demand such as the transport sector. Improved fuel efficiency, increased uptake of alternative transport fuels and development of alternative transport modes are all possible impacts. The continued decrease in oil intensity also complements broader environmental and energy security policy goals.

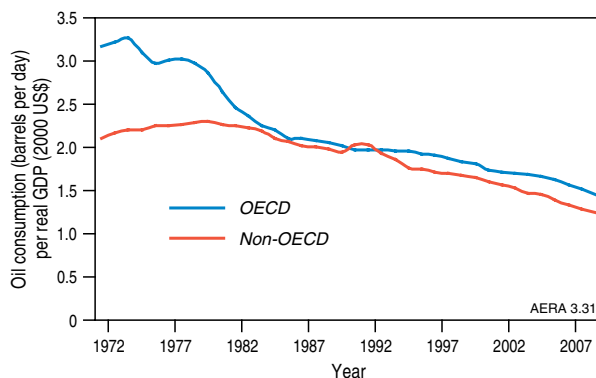


Figure 3.31 Oil intensity of GDP

Source: ABARE estimates from IEA 2009b data

Non-OECD economies, including China and India, are projected to grow strongly over the outlook period. Historically, there has been a strong correlation between economic growth and oil consumption, driven by higher personal incomes and increased demand for personal transport and vehicle ownership. The IEA projects that, by 2030, non-OECD economies will account for around 53 per cent of world oil consumption, compared with 41 per cent in 2008 (IEA 2009c).

Resource characteristics

In Australia, the initial depositional environments and subsequent maturation history after burial that are required to produce and preserve crude oil accumulations (Box 3.1) have occurred less frequently than the geological conditions that have resulted in natural gas accumulations. Australia's identified conventional petroleum resources are dominated by widely distributed natural gas. In contrast, the major known accumulations of crude oil are restricted to the Gippsland Basin and five 'oily' sub-basins (Longley et al. 2002) along the north-west margin. This distribution is controlled by the occurrence of deep, narrow troughs containing mature oil source rocks which were formed around the continent's margins as it broke apart from Gondwana. The Gippsland Basin is a world class oil province with a number of giant fields: it is exceptional in the Australian context, having the greatest thickness of young (Cenozoic) sediments. Most of Australia's crude oil has come from this one small basin being sourced from an oil kitchen (the Central Deep) only about 50 km wide (figure 3.32).

Similarly, the crude oil in the Exmouth, Barrow and Dampier sub-basins of the Carnarvon Basin, and in the Vulcan Sub-basin and the Laminaria High – Flamingo Syncline of the Bonaparte Basin is derived from narrow Late Jurassic troughs filled with oil-prone source rocks. Some crude oil accumulations have been preserved in the older (Paleozoic) largely onshore basins but the major discovered resources and the greatest potential for future finds are offshore.

The condensate and LPG resources are also predominantly located in offshore basins, especially in giant gas fields on the North West Shelf. Gas liquids are not present in the large coal seam gas (CSG) resources identified in onshore eastern Australia.

Australian shale oil resources are variable in organic richness and moisture content. Those in Cenozoic basins of eastern Queensland are thick and relatively shallow deposits with viable oil yields, and have a low carbonate content which does have advantages in processing, including less CO₂ release.

Technology developments

The development of conventional oil resources in the past has benefited from significant technological

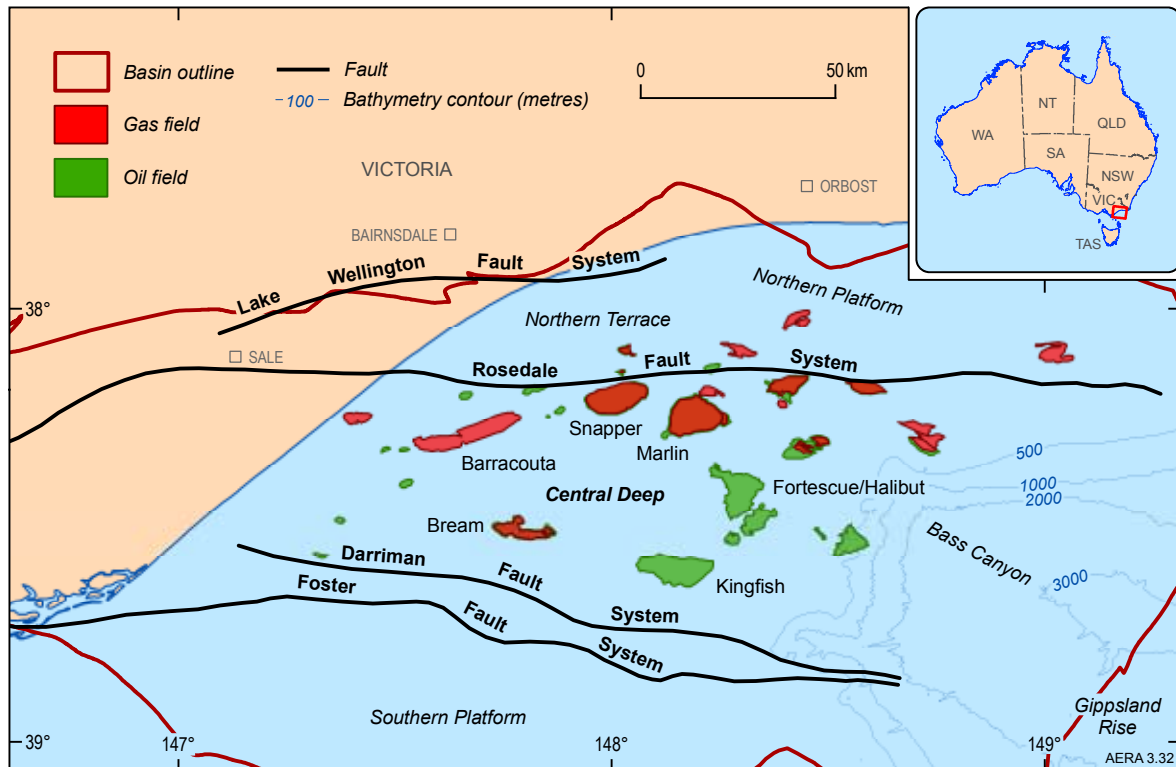


Figure 3.32 Gippsland Basin showing oil and gas fields and structural elements

Source: Geoscience Australia, from data provided by GeoScience Victoria

change over a sustained period of time, leading to increased access to reservoirs, increased recovery of reserves, reduced costs of exploration and production, and reduced technical and economic risks to the development of oil projects. There are similar technological advances – and needs – in developing unconventional resources. Both are discussed in more detail below.

Development of exploration technology

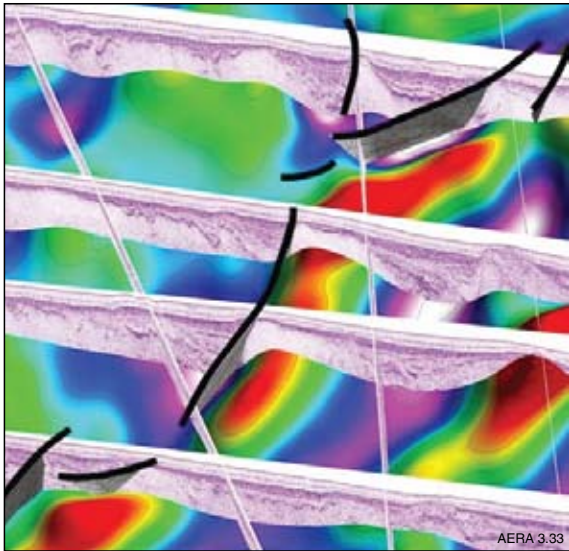
Exploration involves a number of geophysical and drilling activities to determine the location, size, type (oil or gas) and quality of a petroleum resource. Prior to area selection, initial regional studies (figure 3.33) may use non-seismic survey techniques (gravity, magnetic and geochemical surveys, satellite imagery and sea-bed sampling) to define sedimentary basins and to determine if there are any indications of natural hydrocarbons seepage. Recent technological developments, such as accurate global positioning systems, improved computing power, and algorithms for reprocessing existing seismic data and advanced visualisation techniques used to combine different data sets (Wilkinson 2006), have enhanced the value of this phase of the exploration process, especially in offshore frontier basins. In Australia, with its largely under-explored vast on- and offshore jurisdiction, government has taken an active role in providing this regional scale pre-competitive information to stimulate exploration.

Hashimoto et al. (2008) demonstrate how a variety of geophysical and other datasets can be integrated to assess the structure and petroleum potential of the remote frontier Capel and Faust basins offshore from eastern Australia. Figure 3.33 is a 3D view across the undrilled Capel and Faust basins showing seismic lines integrated with gravity imagery. These datasets have assisted in the identification of potentially prospective thick sedimentary depocentres, bounding faults and structural highs underlain by shallow basement within this vast frontier area.

Once the prospective area is located, more detailed seismic survey techniques are used to determine subsurface geological structures. Advances in 3D seismic imaging can now display the subsurface structure in greater detail (Wilkinson 2006) and amplitude analysis can reveal potential petroleum-bearing reservoirs, contributing to recent high drilling success rates in the Carnarvon Basin (Williamson and Kroh 2007). Developments in exploration drilling now allow prospective structures identified on seismic to be tested in water depths beyond two and half kilometres.

Development of production technology

For onshore fields, development proceeds in step with the appraisal drilling. In offshore fields, however, the optimal number and location of development wells must be identified prior to proceeding with the development.



— Fault

Figure 3.33 Integrated seismic and gravity data showing the location of major faults, sedimentary depocentres (gravity lows denoted in blue tones) and areas of shallow basement (gravity highs denoted in red tones) from the remote Capel and Faust basins

Source: Geoscience Australia

Oil production requires the establishment of production wells and facilities. At the initial stage of production, the natural pressure of the sub-surface oil reservoir forces oil to flow to the wellhead. This primary recovery commonly accounts for 25 to 30 per cent of total oil in the reservoir (CEM 2004), though some offshore Australian reservoirs have recovery rates of 70 or 80 per cent supported by a natural strong water drive, as in the case of the Gippsland Basin. More commonly, advanced recovery techniques are employed to extract additional oil from the reservoir, including injecting water or gas into the reservoir to maintain the reservoir's pressure. Pumps can also be used to extract oil. These conventional techniques can increase the additional amount of recoverable oil by around 15 per cent.

Enhanced oil recovery (EOR) is a more advanced technique that has been developed to extract additional oil from the reservoir. This technique alters the oil properties, making it flow more easily, by injecting various fluids and gases, such as complex polymers, CO₂ and nitrogen, to enable more oil to be produced. This technique could increase oil recovery by an additional 40 per cent, but is costly to implement (IEA 2007). Currently, there are 11 countries, including Australia, participating in the IEA's EOR Implementing Agreement, which encourages international collaboration on the development of new oil recovery technologies, including less costly EOR technology. While these techniques have been employed in the past, currently there is no EOR in Australia.

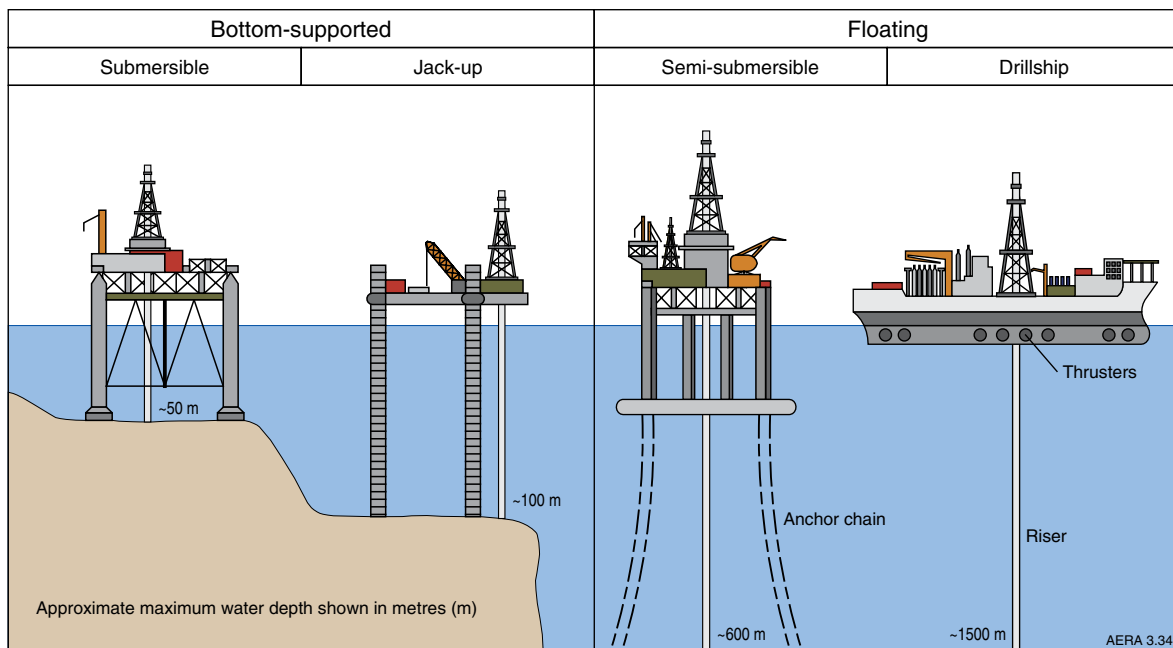


Figure 3.34 Types of offshore drilling vessels

Source: Wilkinson 2006

Reflecting the large number of oil resources located offshore, most R&D has been directed toward offshore technologies. There are several possible development options for offshore oil projects, based on bottom-supported and floating production facilities. The development of these options is dependent on several factors including resource type, reservoir size, water depth and distance from shore. Bottom-supported platform developments are suitable for relatively shallow water depth (figure 3.34).

Access to deep water fields has become technologically feasible with the recent development of floating facilities and tension leg platforms (Wilkinson 2006). The maximum water depth at which oil projects can be developed increased from 6 m in 1947 to 312 m in 1978 and 1027 m in 1995 (Hogan et al. 1996). More recently, maximum water depths for petroleum production have increased further to beyond 2300 m with the Cheyenne field (Anadarko 2007) and the Perdido development (Shell 2009) in the United States' Gulf of Mexico.

There have also been technological developments in shale oil production particularly in the United States where several companies are testing in situ technologies to extract shale oil at more than 300m depth (USDOE 2007). In comparison Australia's oil shales are relatively shallow deposits and the focus has been on surface extraction technologies (Geoscience Australia 2009b).

Oil supply economics

The process of supplying oil is complex, involving steps such as exploration, development, production, processing/refining and transport (section 3.3.2). Upstream oil costs (exploration, project development and production) are a major component of total costs within the oil and refined products industry.

Over the past five years, there has been a considerable increase in exploration, project development and production costs. This increase in costs largely relates to increased competition for inputs (drilling rigs, production equipment, labour) as oil fields were developed in response to higher prices. In Australia, costs have increased as a result of global demand for inputs, but also because of the nature of resources. Australia's remaining undeveloped oil resources are generally located in fields that are further offshore, in deeper water and further below the ocean floor. These factors increase the technical and economic challenges associated with exploration, development and production of Australia's oil resources.

Exploration

Oil exploration is fundamentally concerned with the management of risks (Jones 1988). The expected location, size and quality of oil reservoirs are crucial in decision making because large oil deposits

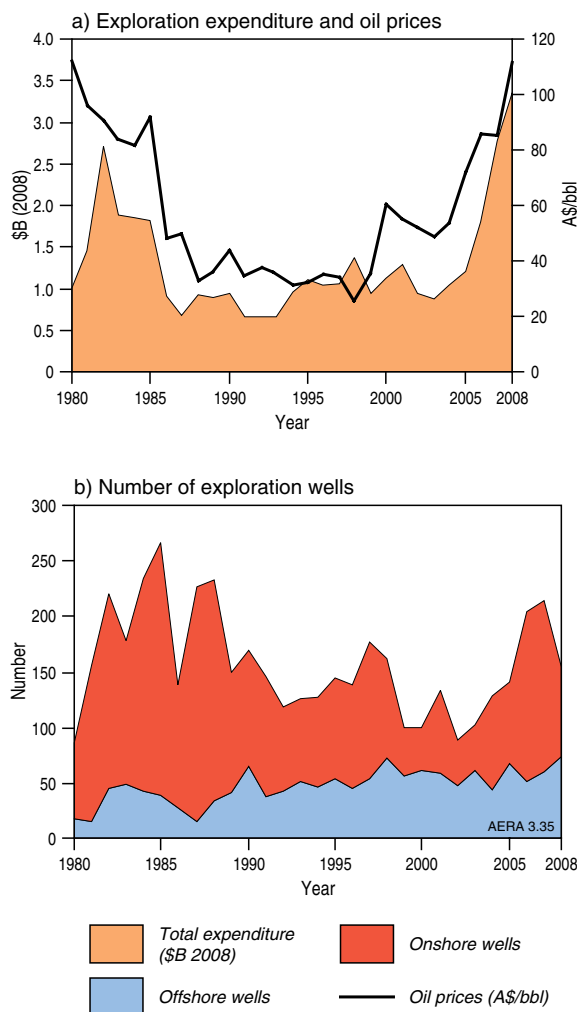


Figure 3.35 Exploration for Australia's petroleum resources

Source: Geoscience Australia, Australian Bureau of Statistics 2009

generally mean large payoffs. When an exploration well is drilled, there is a risk that no oil will be found and therefore no revenue generated. Even if oil is found, there is still a risk that it will not be available in commercially exploitable quantities or that the costs of development and production are sufficiently high to render the new discoveries non-viable. Because of this risk, a large exploration expenditure is generally required, and only a small portion of this expenditure will actually lead to the discovery of resources that are economically viable to extract.

Figure 3.35 provides key indicators of exploration expenditure and activity, in terms of the number of exploration wells drilled, for Australia's petroleum resources, both oil and gas. Between 2002 and 2007 there was a significant increase in the number of exploration wells drilled. Higher oil prices encouraged companies to explore because of the increased potential returns associated with a discovery. In 2008, the number of exploration wells

decreased significantly even though the level of exploration expenditure continued to rise. The number of onshore exploration wells drilled declined steeply from more than 150 in 2006 and 2007 to 80 wells in 2008 whereas the number of offshore exploration wells increased slightly, reaching an all time high of 74 wells in 2008. The cost associated with drilling each well increased dramatically in the first half of 2008 associated with a worldwide shortage of drilling equipment and labour. The oil price fell dramatically in the second half of 2008 but recovered in 2009 to levels well below the highs reached the previous year (Chapter 2). The fall in oil price may have discouraged discretionary onshore exploration as some companies sought to reduce expenditure as global capital markets dried up. Oil price fluctuations tend to have a less immediate impact on offshore exploration. Permit drilling commitments and rig contracts delay response to oil price signals and many offshore exploration wells target gas rather than oil.

Since 1980, more exploration wells have been drilled onshore in Australia than offshore. This reflects the relatively lower cost of onshore oil exploration. In 2005, the average cost of surveying and drilling an onshore exploration well in Australia was around

A\$3 million, while that for offshore was around A\$12 million (ABARE and Geoscience Australia). Hence, smaller companies are generally involved in onshore exploration, while offshore exploration is mostly undertaken by larger companies.

Since 2005 exploration expenditure has exceeded a billion dollars annually and steeply risen to an expenditure totalling \$3.36 billion in 2008 (Australian Bureau of Statistics 2009), mirroring the rise in oil prices and exceeding the previous peak in exploration in the early 1980s. However, in an environment of increased drilling costs this large rise in exploration investment has not translated into more wells drilled.

Development

Figure 3.36 shows the flow of activities from exploration to production of an oil field. During exploration and appraisal, the oil field is discovered and the reserves estimated for potential development. The development of an oil field includes the planning and construction processes. Planning involves a preliminary design (or feasibility study) followed by a front-end engineering and design (FEED) study. The FEED provides definitive costs and technical details to enable a final investment decision (FID). After a FID has been made, construction

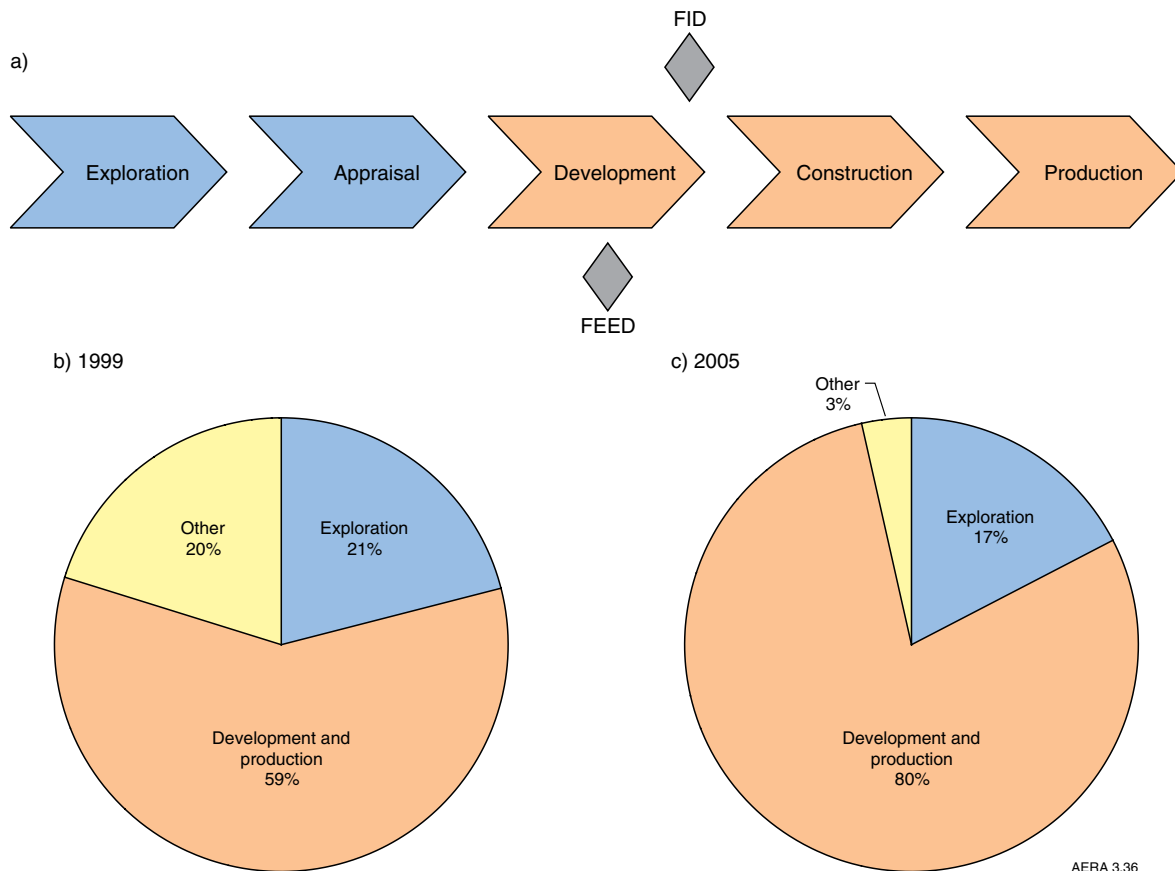


Figure 3.36 Components of upstream petroleum expenditure, a) steps in development process, b) expenditure by activity in 1999, c) expenditure by activity in 2005

Note: FEED – front-end engineering and design, FID – final investment decision

Source: Geoscience Australia 2008

can commence. The average time from discovery to production for Australian new field crude oil discoveries is about five years (Powell 2004).

The development and production of oil is technically complex which results in large capital expenditure. In Australia, the majority of oil production occurs below the seabed, often in water that is hundreds of metres deep. This requires specialised equipment that can withstand the pressure and temperatures of deep water and deep within the sedimentary section.

Project development costs have increased significantly over the past six years, both in Australia (figure 3.37) and globally. This increase in expenditure is twofold. Firstly, the increase in oil prices has encouraged the development of new capacity which has placed upward pressure on prices for inputs such as labour and equipment globally. Secondly, newly developed oil fields in Australia tend to be in deeper water and further offshore (table 3.12), which increases the technical complexity of the project and hence cost. Extensions to existing

projects, such as Laminaria Phase 2 (table 3.12), can achieve additions to capacity at lower cost than entire new developments.

Production

Each oil field has a unique production profile, depending on the natural characteristics of the reservoirs including locations, depth and size of the reservoirs and the nature of production from an oilfield including commercial and policy decisions. However, a typical production profile of an oilfield looks similar to a bell-shaped curve that skews to the left and can be divided into three phases. These include a build-up phase where production rises as new wells are developed, a plateau phase where production from new wells offsets a natural decline from old wells, and a decline phase where the resource from an oilfield begins to deplete.

A typical oil production profile for various types of oilfields is shown in figure 3.38, by plotting annual and cumulative production from the sample of oilfields with respect to their reserves. In general, the build-up to peak production is longer for a larger oilfield, whereas smaller fields reach their peak sooner and decline more rapidly than large fields. Figure 3.38 shows that, for an average onshore oilfield, around 20 per cent of reserves from a small field are produced during the build-up phase, compared with just over 10 per cent for a larger field.

For some large fields, such as the Zakum field in the United Arab Emirates where production started in the late 1960s, the build-up period took more than several decades before it reached peak production in 2002. In contrast, the smaller Hassi Berkine Sud field in Algeria where production started in 1998 has already passed its peak production (IEA 2008).

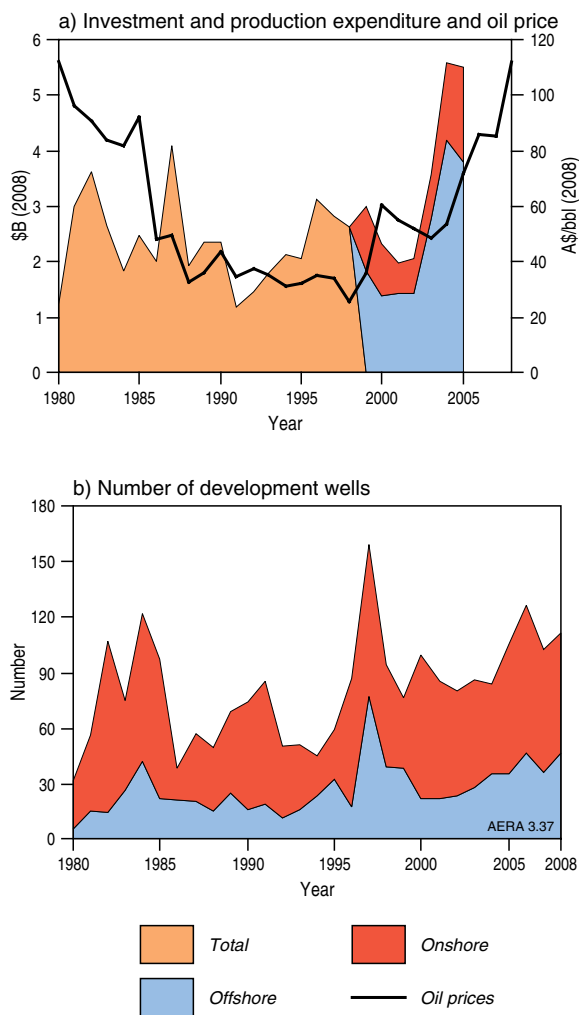


Figure 3.37 Development and production of Australia's petroleum resources
Source: Geoscience Australia

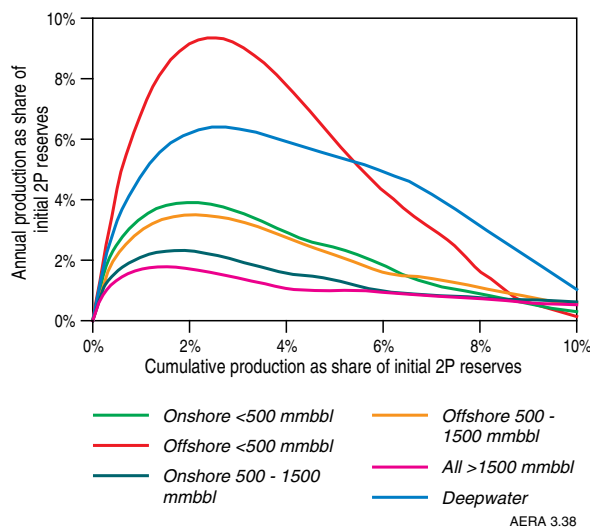


Figure 3.38 Typical oil production profiles
Source: IEA 2008

Table 3.12 Australian oil projects, capital costs, unit costs

Project	State	Year completed	Capital cost A\$m	Additional capacity (kbpd)	A\$/bpd	Water depth (m)
Roller/Skate	WA	1994	170	-	-	10
Elang/Kakatua	WA	1998	42	40	1050	-
Stag	WA	1998	180	50	3600	49
Cossack/Wanaea	WA	1999	190	25	7600	80
Laminaria/Corallina	WA	1999	1370	155	8839	-
Buffalo	WA	2000	145	40	3625	-
Lambert/Hermes	WA	2000	120	16	7500	126
Legendre	WA	2001	110	40	2750	52
Laminaria Phase 2	WA	2002	130	65	2000	-
Mutineer-Exeter	WA	2005	440	90	4889	168
Basker and Manta	Vic	2005	260	20	13 000	-
Enfield	WA	2006	1480	74	20 000	544
Cliff Head	WA	2006	285	12.5	22 800	-
Puffin	NT	2007	100	25	4000	-
Vincent (stage 1)	WA	2008	1000	100	10 000	-
Stybarrow	WA	2008	874	80	10 925	800
Woollybutt	WA	2008	143	7	20 429	100

Note: kbpd – thousands of barrels per day, \$A/bpd – cost in Australian dollars per additional barrel per day production capacity

Source: ABARE

In addition, oilfields that are located offshore generally reach peak production in a shorter time than reserves that are located onshore. For oilfields that contain reserves of less than 500 mmbbl, around 25 per cent of reserves from an offshore oil field are produced by the time production reaches its peak (figure 3.38). This compares with cumulative production of around 20 per cent for fields of the same size that are located onshore. The production profile of offshore fields reflect their higher development costs relative to onshore fields, which generally trigger the project developer to recover oil more quickly in order to keep the cashflows for further development. Deeper offshore oil fields tend to reach peak production early.

In Australia, total conventional oil production (including crude oil, condensate and LPG) is increasingly from offshore oilfields with deeper oil accumulations (table 3.12) and fields that contain smaller reserves compared with those developed in the past. Given the typical production profile of these types of reserves, increased exploration activity is required and more oil wells need to be drilled if the current production level is to be maintained.

Infrastructure issues

Australian oil infrastructure is generally well developed, from upstream oil developments to processing at refineries. There have not been any recent significant increases in Australia's oil refinery capacity, however substantial capital is spent on existing refineries to ensure continued and reliable

production of clean fuels. Australia's liquid fuel supply has also been enhanced by imports from refineries in the Asia Pacific region. The increased interdependency between refineries (with the move to cleaner fuels), and little spare refining capacity has the potential for a refinery disruption to impact on supply (ACILTasman 2008).

Given the likely increased levels of imports of refined product, investment in import/export infrastructure, including the possibility of greater storage capacity to mitigate supply disruption will be of growing importance. Resolution of policy issues impacting on markets, including national and international decisions on emission reductions targets, and methods to achieve them, such as levels of support for alternative transport fuels, will help enhance investment decision-making.

Environmental considerations

The Australian State/Territory governments require petroleum companies to conduct their activities in a manner that meets a high standard of environmental protection. This applies to the exploration, development, production, transport and use of Australia's oil and other hydrocarbon resources. Onshore and within three nautical miles of the coastline the relevant state/ territory government has the main environmental management authority although the Australian Government has some responsibilities regarding environmental protection, especially under the *Environmental Protection and Biodiversity Conservation (EPBC) Act 1999*.

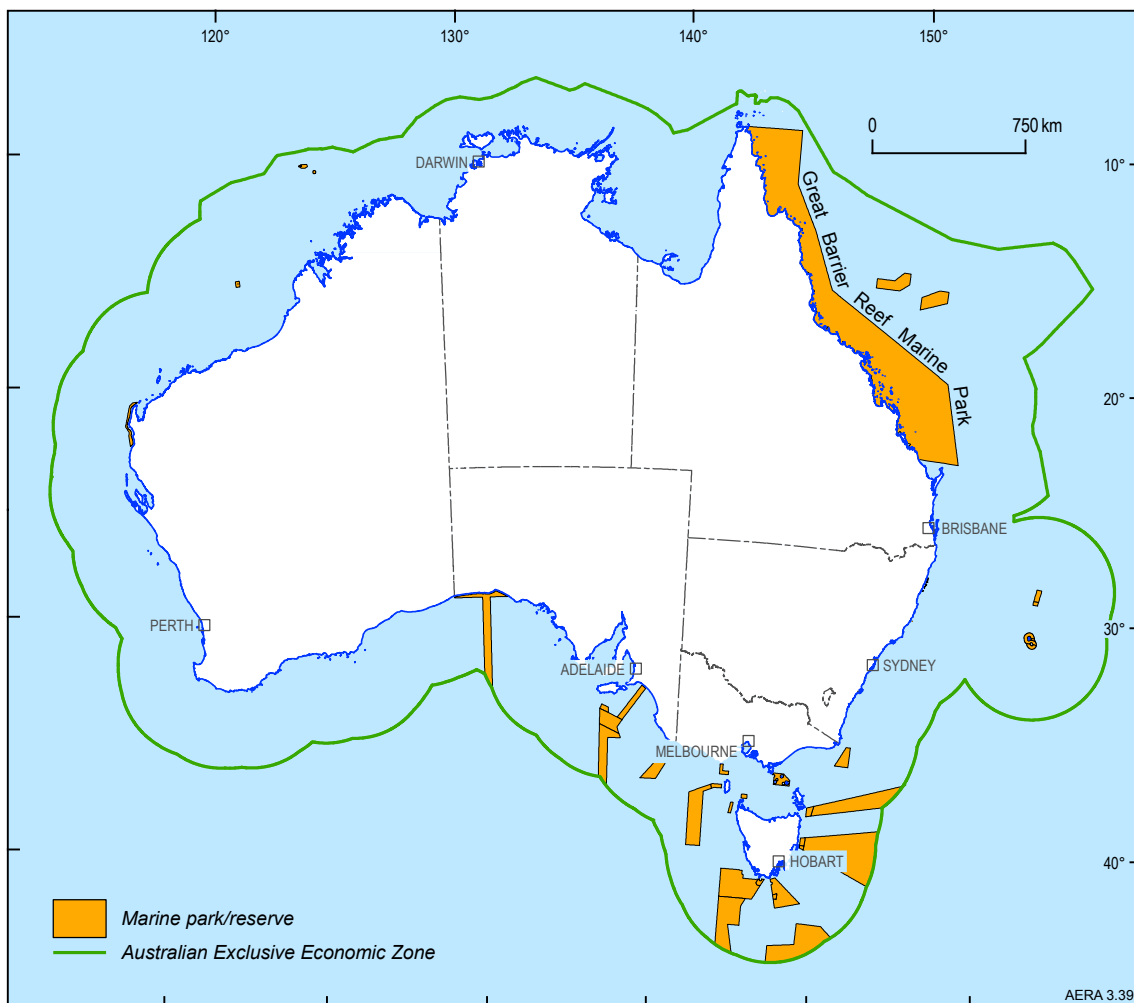


Figure 3.39 Current marine protected areas of Australia

Source: DEWHA 2008

In the offshore areas beyond coastal waters the Australian Government has jurisdiction for the regulation of petroleum activities. The objective-based Petroleum (Submerged Lands) (Management Environment) Regulations 1999 provide companies with the flexibility to meet environmental protection requirements. Petroleum exploration and development is prohibited in some marine protected areas offshore (such as the Great Barrier Reef Marine Park) and tightly controlled in others where multiple marine uses have been sanctioned (figure 3.39). Environmental Impact Assessments (EIA) required as pre-conditions to infrastructure development applications – especially of larger projects – may require environmental monitoring over a period of time as a condition to the approval before the development can commence. In some cases regional-scale pre-competitive baseline environmental information is available from government in the form of regional syntheses containing contextual information that already characterises the environmental conditions in the area of the proposed

development. In the offshore area typical data sets that are required for marine EIA in EPBC Act referrals include: bathymetry, substrate type, seabed stability, ocean currents and processes, benthic habitats and biodiversity patterns.

Oil spills are a potential environmental risk that requires careful management during exploration and production phases. Safeguards are in place through the Australian Marine Safety Authority (AMSA 2009). There are also well established processes for mitigating other environmental concerns including the impact of seismic surveying on cetaceans.

The mining, processing and refining of shale oil involves a somewhat different range of environmental issues, including disposal of spent shale, impacts on air and water quality, and greenhouse gas emissions. Heating oil shale, whether above or below ground, requires energy inputs and entails emissions. The composition of Australian oil shales is low in carbonates, making carbonate decomposition to CO₂ less of a problem in Australia than it is in some other deposits.

3.4.2 Outlook for oil resources

For **conventional liquid petroleum** resources additions will come from several potential sources:

- Field growth – extensions to identified fields and revisions to recovery factor estimates;
- Enhanced oil recovery (EOR) from existing fields;
- Discovery of new commercial fields in established hydrocarbon basins; and
- Discovery of new fields in frontier basins that become commercial by 2030.

Field growth

Growth in reserves in existing fields can add significantly to total reserves, for example by 40 per cent for sandstone reservoirs in the North Sea (Klett and Gautier 2003). These increases are based on new information gathered about the extent and nature of the initial oil pool intersected by the discovery well during the development and production phases. Factors which can contribute to field growth were listed by Powell (2004) as including:

- Increases in the known volume of discovered pools from drilling and geophysical data;
- New pool discoveries often by development wells;
- Improved development technology allowing a greater proportion of the oil-in-place to be produced; and
- Revised assessment of reservoir and fluid properties leading to higher recovery factors than those originally calculated, with real world reservoir performance data substituting for initial generic assumptions.

Geoscience Australia estimated that there was scope for an additional 5880 PJ (1000 mmbbl) of liquid petroleum resource (crude oil and condensate) from field growth in identified fields. Some of this potential may have already been realised as these estimates were made several years ago (Geoscience Australia 2004, 2005).

Enhanced Oil Recovery

Geoscience Australia estimated in 2005 that there was scope for about an additional 6468 PJ (11.00 mmbbs) of crude oil from EOR. However, currently there is no EOR production in Australia, and none in offshore fields anywhere in the world.

Application of EOR depends on the availability (supply) and cost of miscible gases such as CO₂ or nitrogen (Wright et al. 1990), oil price, technology advances and the geology of the reservoir. Because of initial recoveries of up to 60 per cent or more of the oil in place, it is considered unlikely that EOR from Australia's major oil reserves in offshore basins will contribute significantly to liquid fuel supply in the outlook period. Field growth through improved reservoir performance also reduces the target

volume of oil in place for EOR. There may be some minor EOR production from onshore basins where enhanced recovery is coupled with CO₂ storage as in the proposed Moomba Carbon Storage project in the Cooper Basin (Santos 2009).

Discovery of new fields in established hydrocarbon basins

Successful exploration in hydrocarbon producing basins is a major potential contributor to Australia's conventional oil resources. The volume of new reserves added is dependent on the number of exploration wells drilled, the size of the prospects tested and the success rate for oil discoveries that can be commercially developed. Perceptions of prospectivity and the economic, regulatory and fiscal environment influence the number of exploration wells drilled (Bradshaw et al. 1999); while geological factors, as outlined in box 3.1, determine the field size distribution and the chance for oil. As a basin is explored the size of prospects tested generally decreases, as the largest structures are usually those first drilled. However, application of new geological concepts and new technology can reverse this trend.

The number of exploration wells drilled in Australia has varied through time but prior to the recent peak there has been a long term decline in onshore drilling (figure 3.35). The historical success rates are around 20 per cent for petroleum exploration in Australian basins, but lower when crude oil only is considered.

A number of assessments of the undiscovered oil potential of Australia's major hydrocarbon producing basins have been undertaken using different methods, including those used by the USGS and the more conservative approach employed by Geoscience Australia (box 3.3). As noted by Powell (2001), undiscovered resource assessments have multiple inbuilt uncertainties and only have validity in the context of the method used and the purpose for which they were undertaken. Estimates in established hydrocarbon basins can be based on the known discovery history trends and field

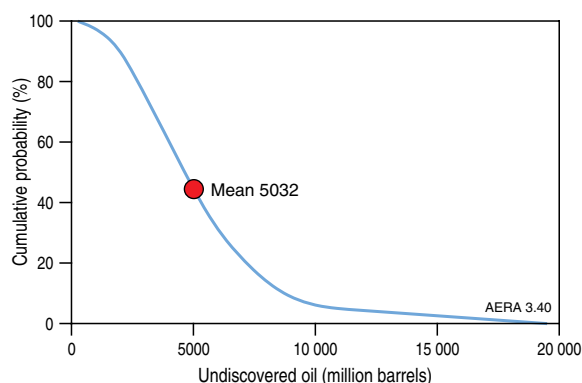


Figure 3.40 Australia's undiscovered oil resources

Source: USGS 2000

BOX 3.3 RESOURCE ASSESSMENT METHODOLOGIES

USGS World Petroleum Assessment (USGS 2000) – estimation of the long-term geological potential of the total petroleum system in a basin. It is limited to conventional potential resources that could be added to reserves in a 30 year time frame and based on the demonstrated existence of generative (mature) source rocks and geological models of petroleum occurrence. The geological opinion of a panel of experts is used to establish probabilities for the chance of occurrence, number and size of fields, and proportions of oil, gas and condensate. Probability distributions are then computed for undiscovered resources.

Geoscience Australia assessments – discovery

forecasts for a limited time horizon (typically 5 to 15 years) and an emphasis on discovery modelling using known exploration trends (Powell 2001). The assessment unit is a single migration fairway comprising a system of traps that is contained with a sequence of source, reservoir, and cap rocks and is separated from adjacent systems by geological barriers to tertiary migration of hydrocarbons. The approach uses log linear models of drilling or discovery to estimate the size of potential future discoveries, and takes into account existence risk, exploration success rate, the proportion of oil and gas, and the smallest size to be included as a resource (Powell 2001).

Table 3.13 Estimates of undiscovered potential in Australian basins

Basin	Crude Oil						Condensate					
	95%		Mean		5%		95%		Mean		5%	
	PJ	mmbbl	PJ	mmbbl	PJ	mmbbl	PJ	mmbbl	PJ	mmbbl	PJ	mmbbl
Bonaparte	2252	383	7562	1286	15 317	2605	1564	266	6345	1079	14 124	2402
Browse	1347	229	6203	1055	15 323	2606	1241	211	5492	934	12 965	2205
Carnarvon	5069	862	14 000	2381	23 826	4052	7138	1214	21 650	3682	38 408	6532
Gippsland	606	103	1823	310	3428	583	423	72	1993	339	4398	748
Total	9273	1577	29 588	5032	57 894	9846	10 366	1762	35 480	6035	69 896	11 887

Note: 95%, Mean and 5% denote the probability of the resources exceeding the stated value

Source: USGS 2000

size distributions, and a substantial geological dataset which has sampled the natural variability in the basin. They are also dynamic and change as knowledge improves and uncertainties are resolved, assessments of frontier basins are more uncertain as there is no local history of exploration outcomes on which to base the estimates. The results of undiscovered resource assessments are best considered as probability distributions rather than as a raw number. Figure 3.40 is a cumulative probability plot of Australia's undiscovered oil resources in the major offshore producing basins as generated by the USGS (2000). Each point of the curve shows the probability of discovering at least the amount of oil shown on the horizontal axis.

Geoscience Australia estimates that risked mean undiscovered resources in currently producing basins are around 9996 PJ (1700 mmbbl) of crude oil and 4116 PJ (700 mmbbl) of condensate. The USGS assessment at the 50 per cent probability (P50) of 29 588 PJ (5032 mmbbl) of crude oil and 35 480 PJ (6035 mmbbl) of condensate (table 3.13) is substantially more optimistic than the conservative shorter-time horizon Geoscience Australia assessment. The USGS assessment represents an indicative estimate of the ultimate resource potential for these basins (Powell 2001) whereas the

Geoscience Australia estimate may better reflect the potential oil resources discovered in producing basins by 2030 given current exploration drilling rates. The Carnarvon Basin is considered the most prospective of the basins assessed to contain large undiscovered resources of crude oil and condensate (table 3.13).

The USGS assessment focussed only on the most prospective of Australia's established hydrocarbon basins and did not include the Cooper/Eromanga, Bowen/Surat, Perth, Otway and Bass basins, all of which have had oil discoveries in the past decade, although of only modest size (10 mmbbl, 59 PJ or considerably less).

There is still crude oil to be found in the established basins, especially in the less explored zones, such as the deep water extensions of the proven areas, but giant oil field discoveries are considered unlikely in the context of current play concepts and technology. The analysis of Powell (2004) showed that most established basins demonstrated 'a very strong creaming effect', implying that the large oil fields had already been found in these basins. The exceptions were the Carnarvon and the Perth basins. In the Carnarvon Basin the successful exploration of the deep water Exmouth Sub-basin has provided the largest additions to crude oil reserves (around 500

mmbbls, 2940 PJ), but in the Perth Basin the early promise of the offshore Cliff Head discovery has not been followed up with more substantial finds in the surrounding area. However, most of the deepwater offshore Perth Basin remains untested and it is the focus of new pre-competitive data acquisition by Geoscience Australia.

In comparison, the North West Shelf is more fully explored and Longley et al. (2002) reviewed the chances of finding a new oil province, similar in size and significance to the Exmouth Sub-basin, on the shelf and concluded that it was unlikely. Since this prediction a number of the less explored sub-basins have been drilled, including deepwater tests at Maginnis-1 in the Seringapatam Sub-basin, Browse Basin; Huntsman-1 in the Rowley Sub-basin, offshore Canning Basin; Wigmore-1 in the Beagle sub-basin and Herdsman-1 in the southern Exmouth Sub-basin, Carnarvon Basin (Walker 2007). However, none of these were successful in finding a new oil trend and the pattern of known oil occurrence on the North West Shelf remains confined within the proven parts of the Bonaparte, Browse and Carnarvon basins. Successful exploration has proceeded in these basins but with the focus on gas, and giant gas fields continue to be found.

Crude oil discoveries tend to be developed relatively quickly with most coming into production within five years of discovery (Powell 2004) and sometimes

within months if they are close to infrastructure (e.g. inshore fields in the Carnarvon Basin). Development of gas liquid (condensate and LPG) accumulations which now account for most of Australia's oil resources, on the other hand, can be delayed, sometimes for decades. Powell's 2004 analysis shows that most gas fields take 11 to 15 years from discovery to development. A high liquids content can accelerate development, although Ichthys with over 500 mmbbls of condensate and Australia's largest remaining oil field was discovered by the Brewster well in 1980 and is only now being assessed for development. Hence the oil resource outlook to 2030 is in part dependent on the rate of development of liquids-rich gas fields. Factors that may influence development timetables include market demand, environmental approvals, the challenge of any associated CO₂ and technological developments such as floating LNG facilities, discussed in Chapter 4.

Discovery of new fields in non-producing and frontier basins

Frontier basins have a low level of exploration activity compared to established hydrocarbon basins. There are rank frontiers that have had no exploration drilling (for example, the Bremer Sub-basin) and other frontier areas where there has been only handful of wells drilled and major trends remain untested (for example, the Ceduna Sub-basin where only one well has been drilled in the main depocentre with others drilled on the margin, figure 3.41). In Australia's

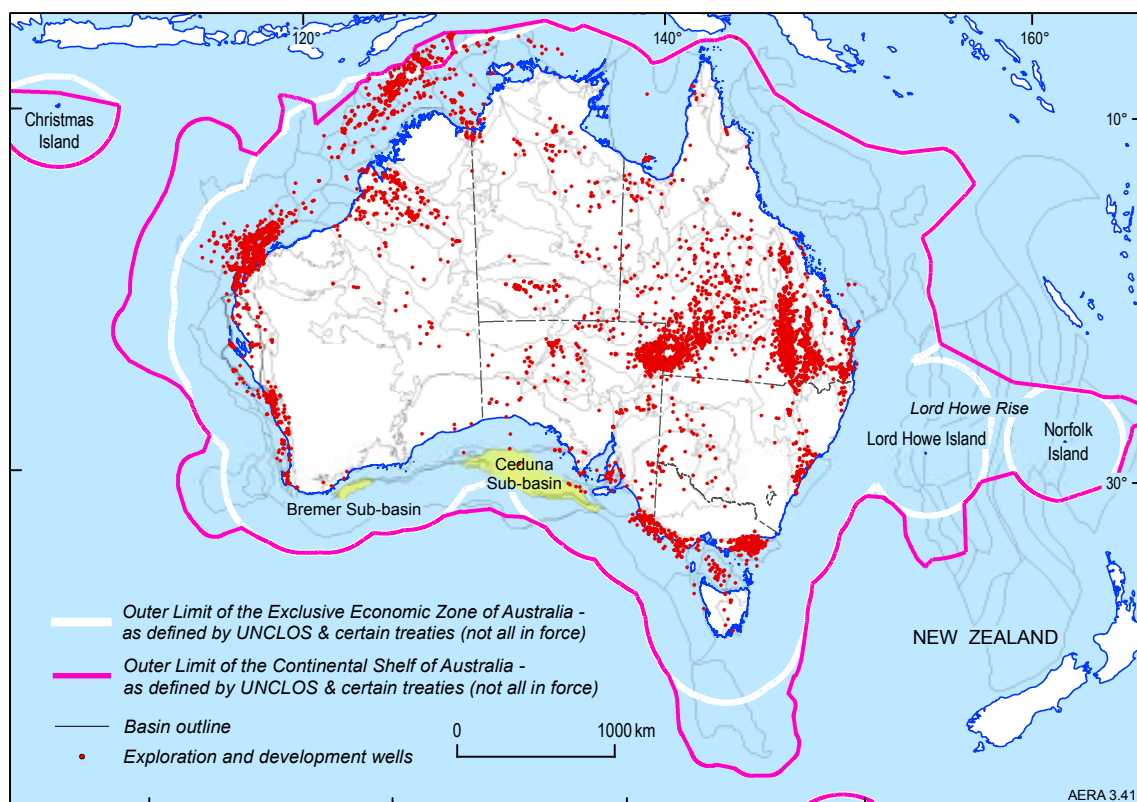


Figure 3.41 Sedimentary basins and petroleum exploration wells

Source: Geoscience Australia

poorly explored frontier basins many of the largest structures remain untested, and vast areas of sedimentary basins especially off the south-western, southern and eastern margins, have not been drilled. These offshore areas offer the greatest potential for major new oil discoveries. The deepwater Ceduna Sub-basin in the Great Australian Bight is considered to represent the highest probability for finding a new oil province (Totterdell et al. 2008) given the presence of an oil-prone source rock within a thick Cretaceous delta sequence.

Geoscience Australia is currently undertaking a program of pre-competitive data acquisition and interpretation to assess the petroleum potential of selected frontier basins. New seismic, potential field data and seabed samples have been collected from a number of offshore basins (Bight, Mentelle, Perth, Offshore Canning, Arafura, Otway and Sorell) to better understand the geological history and hydrocarbon resource potential of these areas. These studies have underpinned subsequent acreage release with uptake of exploration acreage in previously neglected areas (Bremer Sub-basin, Bight Basin; Vlaming Sub-basin, Perth Basin; Offshore Canning Basin and the Arafura Basin). Industry work in these new exploration permits is at an early stage; 2D and 3D seismic data have been acquired but exploration wells are yet to be drilled.

Geoscience Australia is also completing pre-competitive studies of two of the four basins in the remote deepwater frontier of the Lord Howe Rise. Early results have identified a number of depocentres that have sedimentary thickness (up to 7 km) and volume (100 km long and 30 km wide) sufficient to have potentially generated significant hydrocarbons if source rocks are present at depth (figure 3.31). While these structural results from new seismic acquisition are encouraging, no petroleum source rocks are known because the area has not been drilled for hydrocarbons. Pre-competitive data acquisition programs in the onshore frontier Amadeus, Georgina, Darling and Canning basins are being undertaken by Geoscience Australia in cooperation with relevant State Geological Surveys. The current programs are limited compared with the large size of these basins: both the Amadeus and Canning basins are proven oil producers and oil source rocks known from the Georgina Basin.

The size, number and geological diversity of Australia's frontier basins are consistent with major undiscovered petroleum resources being present. The petroleum resources likely to be discovered in the years to 2030 depend on the amount of exploration activity, the success rate, and the size of prospects. Current frontier exploration rates are low, averaging in the past decade less than 2 wells per year in the offshore and around 10 per year onshore (APPEA 2009) and are liable to remain so

without the stimulus supplied by access to regional pre-competitive data. Success rates in frontier basins can be as low as 10 per cent but can be improved with new information and new technologies and, as discussed above, prospect sizes can be large as the largest structures are yet to be drilled. Current low frontier drilling rates and low success rates make it unlikely that a frontier oil discovery will be made in any particular year. The only new oil province discovered last decade was the Abrolhos Sub-basin in the offshore Perth Basin, where the Cliff Head field was found in 2001 as an offshore example of a proven trend onshore. The offshore Exmouth Sub-basin, which has materially added to Australia's oil production, was already established as a proven hydrocarbon province with oil discoveries in the 1980s and 1990s.

A number of estimates of undiscovered hydrocarbon potential derived from a variety of methods are available for individual frontier basins and for Australia as a whole (Bradshaw et al. 1998; Longley et al. 2001). The publicly available assessments have not integrated the results from the current rounds of pre-competitive data acquisition. Even in deepwater frontier basins, oil discoveries can be expected to be developed within a few years using FPSOs, if they are of commercial size.

Outlook for unconventional oils

Oil shale contains a large unconventional oil resource for Australia. However there is currently no production. Some of the challenges for the oil shale industry include technical issues associated with achieving large scale commercial production in the face of uncertainty and volatility of future crude oil prices. There are also environmental challenges, including reducing CO₂ emissions and water usage, and issues associated with disposal of spent shale. These challenges need to be overcome and oil prices remain high for shale oil to contribute significantly to resources in the outlook period.

Other unconventional sources of liquid fuels include GTL and CTL technologies. While Australia has abundant gas and coal resources, it is not anticipated that these technologies will significantly add to liquid fuel supplies in the outlook period. Biofuels make a small contribution to current oil supply in Australia and even with expanded production are not expected to impact significantly on Australian oil production until second generation biofuels become available. Biofuels are discussed in more detail in Chapter 12.

Total resource outlook

Figure 3.42 plots Australia's potential total oil resources, including known and undiscovered. The following section details the potential demands on these resources over the next twenty years.

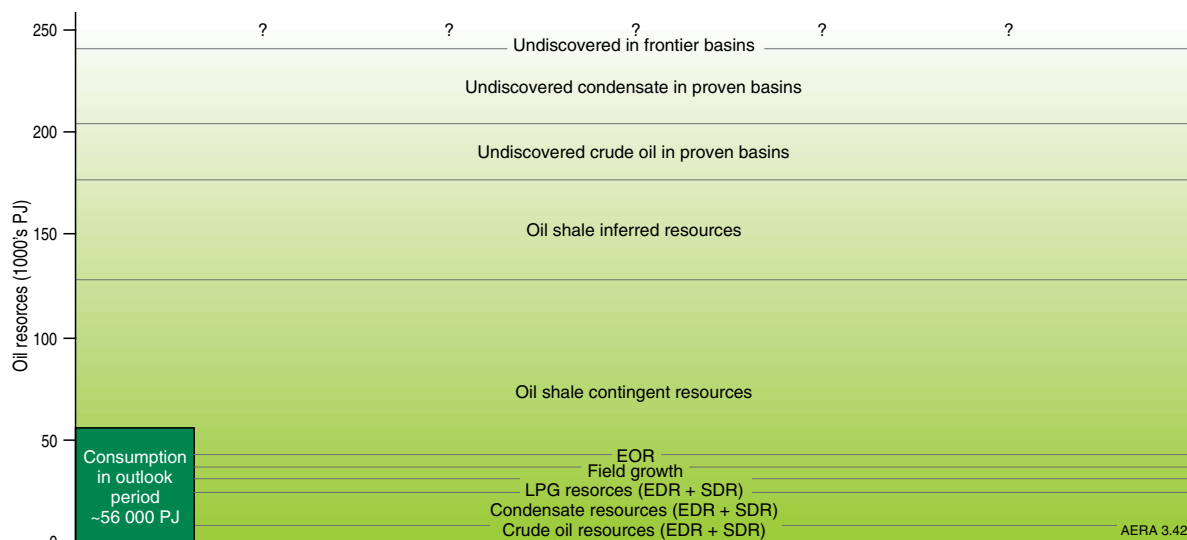


Figure 3.42 Total oil resources (identified and potential) and estimated cumulative consumption

Source: Geoscience Australia

There is no currently publicly available resource assessment of Australia’s undiscovered oil resources that adequately reflects the new knowledge gained in recent years during the active programs of government pre-competitive data acquisition and increased company exploration during the recent resource boom. The knowledge base for unconventional oil is at a low level.

3.4.3 Outlook for oil market

Without a major discovery, Australian oil production is expected to continue to decline over the next twenty years. In contrast, domestic oil consumption is projected to increase moderately over the same period, increasing the reliance on imports. ABARE’s latest long term projections for Australian energy production, consumption and trade include the impacts of the Renewable Energy Target (RET), a 5 per cent emissions reduction target and other existing government policies (ABARE 2010). These results are discussed in more detail below.

Production

In the next few years, the production of oil in Australia is expected to rise as developments now under construction or in the advanced stages of planning are completed. However, beyond the medium term as far as 2029–30, combined crude oil and condensate production are expected to fall as older oil fields mature and slowly deplete. As with current production, the majority of future production is likely to be sourced from offshore basins in north-western Australia. Combined crude oil, condensate and LPG production is projected to fall gradually by 2.0 per cent per year to 668 PJ by 2029–30.

More detailed production forecasts by Geoscience Australia show that condensate is expected to outstrip crude oil production by about 2015 and new discoveries within the established basins could add to production in the later half of the outlook period (figure 3.43). Major new oil discoveries could reverse this trend, just as the discovery and development of new oil fields in the Carnarvon and Bonaparte basins replaced the declining production from the Gippsland

Table 3.14 Outlook for Australia’s oil market to 2029–30

	unit	2029–30	Average annual growth, 2007–08 to 2029–30 %
Production of crude oil, condensate and LPG	PJ	668	-2.0
Consumption of crude oil, condensate and LPG	PJ	2443	1.8
Consumption of crude oil, condensate, LPG and oil products	PJ	2787	1.3
Share of primary energy consumption	%	36	
Net imports of crude oil and LPG	PJ	1775	5.0
Net imports of crude oil, LPG and petroleum products	PJ	2119	3.3

Source: ABARE 2010

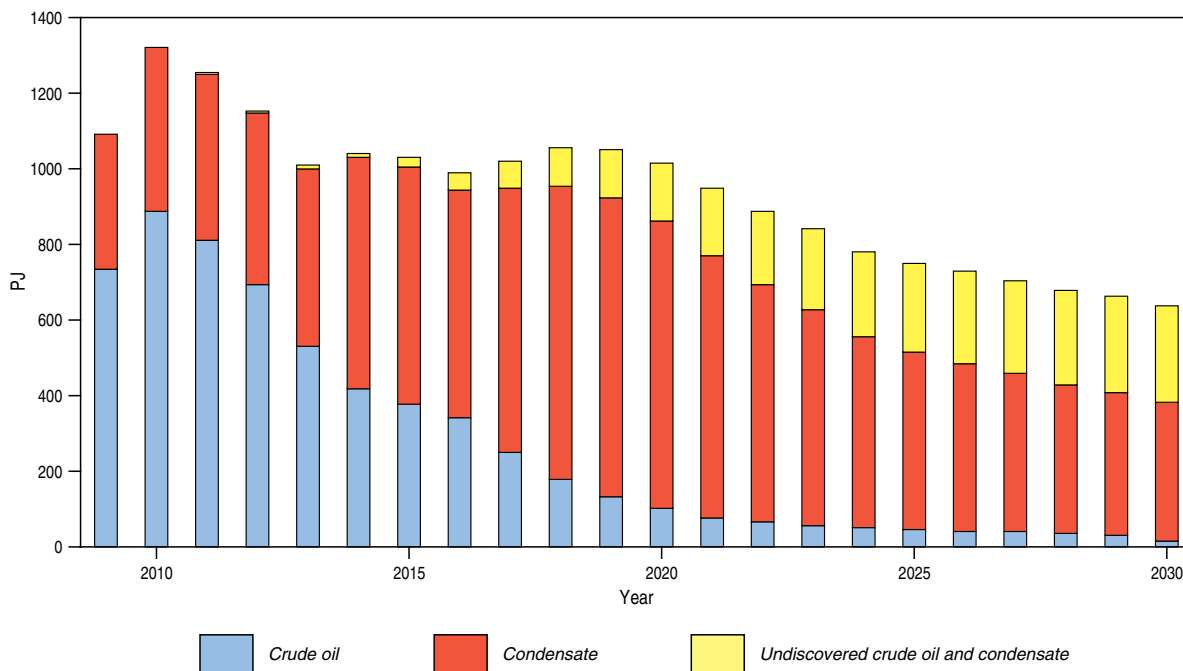


Figure 3.43 Australian oil production outlook from proven hydrocarbon basins

Note: the production forecast is based on data from an industry survey of producing fields and Geoscience Australia’s assessment of undiscovered resources in proven basins

Source: Geoscience Australia

Basin in the late 1980s (Powell 2001). Frontier basins, such as the deep water Ceduna Sub-basin in the Great Australian Bight, are seen as offering the best chance for finding a major new oil province; increased frontier drilling rates would improve the likelihood of this outcome in the outlook period.

Consumption

Australia’s primary oil consumption is projected to grow faster than production. Total consumption of oil and oil products is projected to rise by 1.3 per cent per year to reach 2787 PJ in 2029–30, with a share in total primary energy consumption of 36 per cent in 2029–30 (figure 3.44, table 3.14).

In the short term, the global financial crisis and its adverse impact on economic growth is a contributor to the below-trend growth in consumption. The introduction of significant policy measures, namely the RET and a proposed emissions reduction target, are expected to lead to an increase in energy prices, and an associated dampening effect on demand. Partly offsetting this trend, economic growth in Australia is assumed to return to its long term potential as world economic performance improves. The decline in the growth rate for oil consumption in the final decade of the outlook period reflects primarily increasing carbon prices under the emission reduction target and lower economic growth assumptions.

The transport sector is expected to continue to rely heavily on oil over the next twenty years.

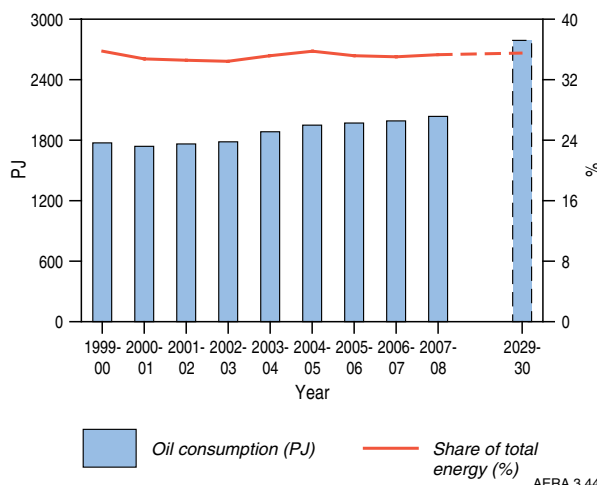


Figure 3.44 Australia’s outlook for oil consumption

Source: ABARE 2009b; ABARE 2010

Consumption of oil and petroleum products in the transport sector is expected to grow steadily over the projection period at an average rate of 1.2 per cent per year driven largely by economic growth.

Trade

Continued growth in domestic oil demand and declining domestic oil production are expected to result in an increase in Australia’s oil imports over the next twenty years (figure 3.45).

Exacerbating this gap between supply and demand is the fact that a significant proportion of the growth

in domestic production of crude oil, condensate and naturally occurring LPG will be concentrated in the Carnarvon and Browse basins, in north western Australia. As a result, it is reasonable to assume that this supply of crude oil, condensate and naturally occurring LPG will largely be exported to Asia for processing, as opposed to supplied to the domestic market. As a result, the ability of domestic production to meet domestic demand is likely to be lower than implied by the simple comparison of production and consumption.

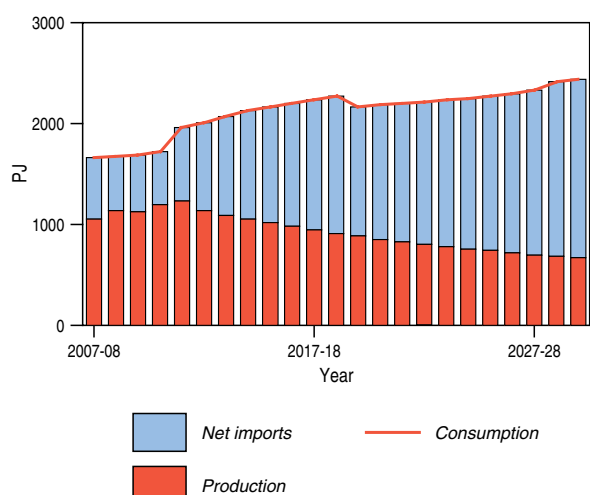


Figure 3.45 Australia's oil supply–demand balance outlook

Source: ABARE 2010

The demand for petroleum product imports is not only determined by domestic oil production and end-use consumption of petroleum products, but also by domestic petroleum refining capacity. Australia's refining capacity is not expected to expand significantly given increasing competitive pressures from larger refineries in south-east Asia in particular. For a given domestic production and consumption outlook, petroleum refining capacity constraints may result in lower crude oil imports and, simultaneously, higher imports of refined products.

Reflecting this, Australia's net trade position for liquid fuels is expected to worsen over the outlook period, with net imports increasing by 3.3 per cent per year over the period to 2029–30.

Major project developments

However, new oil fields continue to be brought on stream and at the end of October 2009, there were three offshore oil projects under construction (table 3.15). Two projects are located in the Carnarvon Basin and one project in the Bonaparte Basin in north-western Australia. These three projects have a combined peak oil production capacity of around 170 000 barrels a day at an estimated capital cost of around \$3.5 billion.

There are also three oil projects with a combined peak production capacity of up to 78 000 barrels a day at a less advanced stage of development (table 3.16). Two of these projects are located in offshore north-western Australia, and another project in the Gippsland Basin offshore Victoria.

Table 3.15 Oil projects at an advanced stage of development, as at October 2009

Project	Company	Basin	Status	Start up	Capacity	Capital Expenditure (\$m)
Montara/Skua oilfield	PTTEP	Bonaparte	under construction	na	38 kbpd	US\$700 m (A\$843 m)
Van Gogh	Apache Energy/ Inpex	Carnarvon	under construction	2010	38 kbpd	US\$546 m (\$658 m)
Pyrenees	BHP Billiton/ Apache Energy	Carnarvon	under construction	2010	96 kbpd, 23 PJ pa gas	US\$1.68 b (A\$2 b)

Source: ABARE 2009d

Table 3.16 Oil projects at a less advanced stage of development, as at October 2009

Project	Company	Basin	Status	Start up	Capacity	Capital Expenditure (\$m)
Basker, Manta and Gummy oil development	Roc Oil/Beach Petroleum	Gippsland	Expansion	na	10 kbpd	na
Crux liquids project	Nexus Energy/ Osaka gas	Browse	FEED study completed	na	38 kbpd condensate	US\$650 m (A\$783 m)
Talbot oil field	AED Oil	Bonaparte	Feasibility study under way	na	10–20 kbpd	na

Source: ABARE 2009d

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