2 The upstream petroleum sector

Key points

- The upstream petroleum sector encompasses: (1) exploration and appraisal, (2) development and construction, and (3) production. For natural gas (including liquefied natural gas), the definition of upstream includes processing and delivery to export terminals or domestic gas transmission pipeline in-take.
- The Australian upstream petroleum sector is small by global standards.
- The upstream petroleum sector added $15.3 billion to Australian GDP, and contributed over $5.5 billion in taxes to governments in 2004-05.
- Australia's oil and gas reserves account for 0.1 per cent and 0.5 per cent of world totals respectively (excluding coal seam methane). Reserves are predominantly concentrated offshore in the Bonaparte, Browse, Carnarvon and Gippsland Basins.
- Australian natural gas production has increased steadily since 1970, while production of naturally occurring liquefied petroleum gas has remained stable. Crude oil production declined from 2000-01 to 2005-06, and increased in 2006-07.
- The Australian upstream petroleum sector has many international participants, with many engaged in joint ventures. Downstream customers are both domestic and international.

This chapter contains a discussion of the upstream petroleum sector in Australia, including the sector's economic significance, the quantity of Australian reserves, and the size and structure of the sector in a global context. It also contains a summary of the upstream elements of the oil and gas supply chain and an analysis of industry structure.

2.1 Oil and gas in Australia

The upstream petroleum sector represents a major component of the Australian economy. In terms of industry value added, oil and gas extraction contributed $15.3 billion to the Australian economy in 2004-05 (ABS 2008a). This represented approximately 2 per cent of GDP in 2004-05.

Australia is a net importer of crude oil. Indeed, crude oil has been Australia's largest import in dollar terms since 2006 (partly reflecting high global oil prices), accounting for $14.6 billion (6.2 per cent of total imports) in 2007 (DFAT 2008a). Australian crude oil exports also increased to $8.7 billion in 2007 (ABARE 2008a). Imports of crude oil are forecast to increase until 2027, with domestic consumption growth outstripping domestic production (Geoscience Australia 2008).

Australia is a significant net exporter of liquefied natural gas (LNG), with exports of $5.2 billion in 2006-07 (ABARE 2007b). No LNG is imported; however some natural gas from the Timor Sea brought onshore in Australia for processing is classified as imported. Liquefied petroleum gas (LPG) is also exported, accounting for $1 billion in 2006-07, more than 50 per cent higher in nominal terms than in 1999-2000 (ABARE 2001; 2007b).

Including company taxes, the upstream petroleum sector contributed over $6 billion in taxes to governments in 2006-07. Crude oil tax excise and royalty revenue to Australian governments was $3.3 billion in 2006-07, of which the Petroleum Resource Rent Tax contributed $1.7 billion (APPEA 2007a). A significant portion of petroleum royalties accrue to States and Territories. For example, the WA Government received around $737 million in petroleum royalties in 2007 (DoIR 2007b), reflecting that Western Australia accounts for 69 per cent and 67 per cent of Australian gas and oil production respectively (DoIR, sub. 18). Taxation of the sector is discussed further in chapter 5.

The upstream petroleum sector in Australia employs around 15 000 people (RET 2007) — less than 0.2 per cent of the total labour force at July 2008 (ABS 2008c). Wages and salaries in the sector totalled over $1.3 billion in 2006-07 (ABS 2008b).

Australia's oil and gas reserves

Oil and gas discoveries yet to be extracted are termed 'reserves'. However, prior to full extraction the size of oil and gas discoveries is always uncertain. The sector classifies reserves as 'proved' (greater than 90 per cent probability of existence), 'probable' (between 50 per cent and 90 per cent probability) or 'possible' (between 10 per cent and 50 per cent probability). The more general term 'resources' encompasses reserves, oil and gas that is yet to be discovered, and oil and gas that is uncommercial or technically infeasible to extract.

Australia has substantial reserves of gas, and was one of the world's top 20 gas-producing countries in 2006. It is currently ranked 24th in the world in terms of proved gas reserves. Nonetheless, proved reserves amounted to only 0.5 per cent

of the world total at 1 January 2008 (excluding coal seam methane), with worldwide reserves being concentrated in Russia, Iran and Qatar (PennWell 2008).

Australia's oil reserves are less extensive, comprising 0.1 per cent of the world total at 1 January 2008 (PennWell 2008). However, Australia has many under-explored sedimentary basins and may have considerable oil and gas resources yet to be discovered (Powell 2008).

Most of Australia's oil is light crude (box 2.1). Light crude is more valuable than heavy crude, as it is used for premium products such as gasolines. Most of the heavy crudes used for fuel oils, lubricating oils, and bitumen in Australia, are imported (Wilkinson 2006).

Proved and probable reserves of oil and gas are highly concentrated in a few areas off the coast of Australia (figure 2.1). In particular, most reserves are located in the

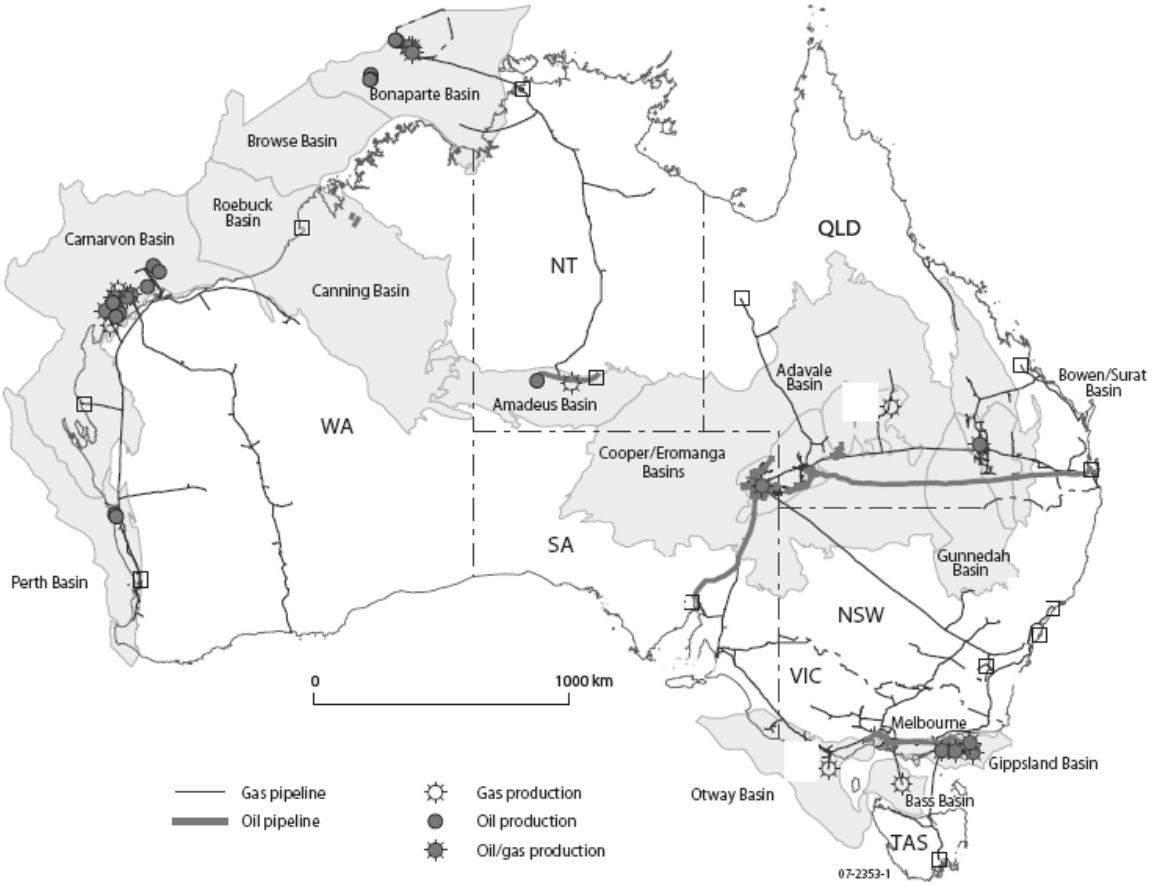
Box 2.1 **Types of oil and gas product**

The types of oil and gas products depend partly on the natural structure of the hydrocarbons, and partly on the post-extraction production processes.

- *Crude oil* — comes in three types depending on its chemical structure, which also determines its density:
  - *Paraffin-based crudes* — are mostly composed of paraffin molecules. These tend to have a low density, and are generally referred to as *light crudes*.
  - *Asphalt-based crudes* — are mostly composed of napthene molecules. These tend to have a high density, and are generally referred to as *heavy crudes*.
  - *Mixed-base crudes* — contain paraffins, napthenes and aromatic hydrocarbons. These are heavier than paraffin-based, but lighter than asphalt-based crudes.
- *Condensates* — are hydrocarbons that are gaseous in reservoirs, due to the high temperatures. At surface temperatures and atmospheric pressure they condense into a light oil. The term 'crude oil' is often applied to both crude oil and condensate.
- *Natural gas* — is mainly methane. It is treated before sale to remove the propane, butane, other liquid hydrocarbons and impurities it often contains in its crude form.
- *Liquefied natural gas (LNG)* — is natural gas cooled to below -160 degrees Celsius, thereby rendering it a liquid. This reduces its volume by over 600 times, making storage and transportation viable.
- *Liquefied petroleum gas (LPG)* — consists of propane and butane. It is found in gas and oil reservoirs, and is also a refinery by-product. LPG liquefies under slight cooling and compression, and is used as motor, domestic and industrial fuel.

Sources: Gary et al. (2007); Wilkinson (2006).

Figure 2.1 **Identified Australian oil and gas reserves, 2007**



Source: Geoscience Australia (pers. comm., 27 October 2008).

Bonaparte, Browse, Carnarvon and Gippsland Basins (table 2.1). The Bass Basin contains Australia's fifth largest reserves of LPG. Smaller reserves of oil have been found in the Perth Basin; and the Otway Basin contains small reserves of gas. By comparison, onshore Australian reserves make up 4 per cent of total oil reserves and 17 per cent of total gas reserves (RET 2007). The most substantial onshore petroleum reserves are located in the Cooper and Eromanga Basins.

Over time, the location of known Australian reserves has changed. Production of early oil and gas discoveries in the Cooper, Eromanga and Gippsland Basins have reduced the significance of the reserves in these basins. By contrast, newer discoveries in the Bonaparte, Browse and Carnarvon Basins that are yet to be fully exploited have increased the importance of these basins to Australian revenues.

Most of Australia's oil and gas reserves (78 per cent of crude oil and 92 per cent of natural gas) are located off the coast of Western Australia, in the Bonaparte, Browse, Carnarvon and Perth Basins (table 2.1).

Table 2.1 **Estimated oil and gas reserves, 1 January 2006[a]**

Basin	*Location*	*Crude oil*	*Condensate*	*LPG*	*Natural gas*[b]
		GL	GL	GL	bm^3
Adavale	Onshore	–	–	–	0.36
Amadeus	Onshore	0.73	0.18	0.03	6.79
Bass	Offshore	2.11	6.88	9.31	14.78
Bonaparte[c]	Offshore	21.32	100.44	58.14	792.61
Bowen	Onshore	1.26	0.38	0.45	11.15
Browse	Offshore	2.16	100.00	69.67	831.88
Canning	Onshore	0.02	–	–	0.18
Carnarvon	Offshore and onshore	180.56	168.22	121.95	2 315.86
Cooper	Onshore	2.03	2.61	4.50	38.77
Eromanga	Onshore	8.11	0.08	0.07	0.74
Gippsland	Offshore and onshore	44.24	20.82	27.80	208.10
Gunnedah	Onshore	–	–	–	0.30
Otway	Offshore and onshore	–	2.67	–	54.25
Perth	Offshore and onshore	6.35	1.79	–	39.13
Surat	Onshore	0.03	0.01	0.01	0.90
Total[d]		**268.93**	**404.05**	**291.93**	**4 315.80**
Total in PJ[e]		**8 914**	**14 130**	**8 012**	**160 816**

a Includes estimates of proved and probable reserves both from fields that are commercially viable and fields that have not yet been declared commercially viable. **b** Sales quality natural gas (refined to the specification of sales contracts). **c** Estimates for Bonaparte Basin include total reserves in the Joint Petroleum Development Area. **d** Totals may not add due to rounding. **e** Estimates based on conversion factors of 37 MJ/L for crude oil and condensate, 26.5 MJ/L for liquefied petroleum gas and 40.5 MJ/L for natural gas (1 m^3 natural gas is equal to 1000 L) (ABARE, pers. comm., 17 October 2008). – Nil or rounded to zero.

Sources: ABARE (2008a); Geoscience Australia (2006, 2008); Commission estimates.

Basins often cross more than one jurisdiction, particularly where they extend more than three nautical miles offshore. Moreover, the Bonaparte Basin straddles both Western Australia and the Northern Territory, as well as Commonwealth waters and the Joint Petroleum Development Area with East Timor. (Definitions reflecting Australia's maritime boundaries are presented in chapter 4.) Similarly, some onshore basins (such as the Cooper Basin) also straddle more than one jurisdiction.

Petroleum is a non-renewable resource. As Australian petroleum resources decline, the economic contribution of oil and gas production could also decline. However, to the extent that this occurs in conjunction with a decline in global resources, higher prices will increase the economic significance of oil and gas consumption and remaining Australian production. Higher prices are also likely to stimulate exploration and the discovery of new reserves.

As Tina Hunter observed:

> Once Australia exploits its petroleum resources, it liquidates the petroleum asset and will no longer have the revenue from these resources. That is because like any other asset, once the petroleum is extracted and sold, it is permanently lost. This creates an enormous challenge for the Australian government: to create a regulatory framework that generates appropriate and adequate revenue, whilst at the same time establishing appropriate incentives so oil companies are attracted to the petroleum province to develop the resources. (sub. DR28, pp. 3–4)

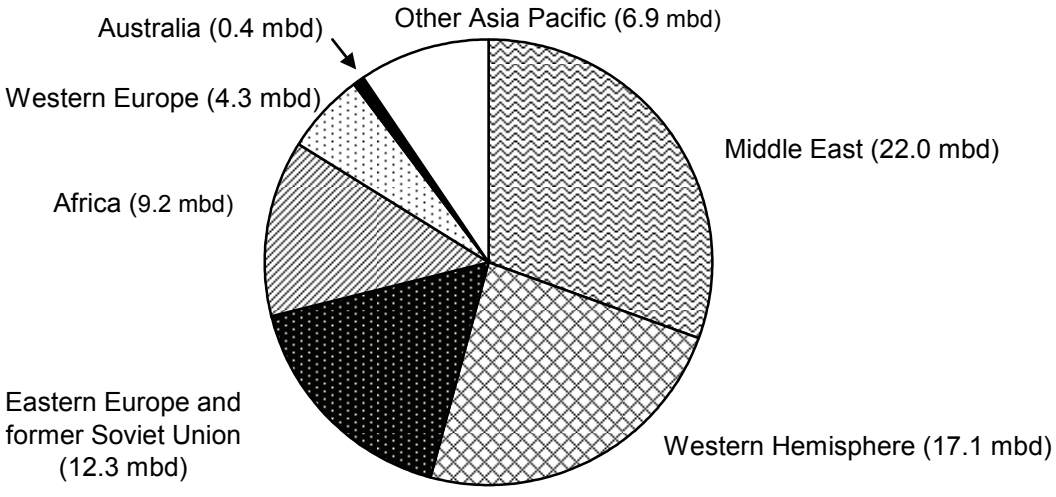
2.2 Structure and size of the sector in a global context

Australian oil and gas production represents a very small proportion of world production, with Australian reserves also small by global standards. Australian crude oil production (445 000 barrels per day) represented less than 1 per cent of worldwide production in 2007 (figure 2.2).

The Australian oil and gas market is also small by global standards. Specifically, ABARE (2008b) noted:

> … the domestic market for natural gas in Australia is presently characterised by a small number of producers, a small number of large consumers and limited depth in consumption. (ABARE 2008b, p. 32)

Figure 2.2 **Estimated world oil production, 2007[a]**



a Production expressed in million barrels of oil per day (mbd).

Source: PennWell (2008).

Over 100 companies (excluding wholly-owned subsidiaries) and individuals across Australia hold interests in oil and gas production permits. However, the industry is

dominated by a few large businesses, including BHP Billiton, Chevron, ExxonMobil, Santos and Woodside, which together accounted for approximately 58 per cent of oil production in 2006 (EnergyQuest 2007). As the upstream petroleum sector in Australia is open to competition from domestic and foreign businesses, it attracts investment from other large international businesses, including Apache, BP, ConocoPhillips, ENI, Inpex and Shell.

The exploration sector comprises over 270 companies and individuals holding interests in exploration permits (Commission estimates based on ENCOM 2008). This reflects the lower cost of the exploration phase compared with the production phase, with lower barriers to entry existing for the participation of smaller businesses. For example, Bow focuses on exploration activities such as data collection, and retains a small interest in any discoveries. The bulk of their interests is passed to larger businesses — with better access to capital — for exploration drilling and field development (Bow 2007).

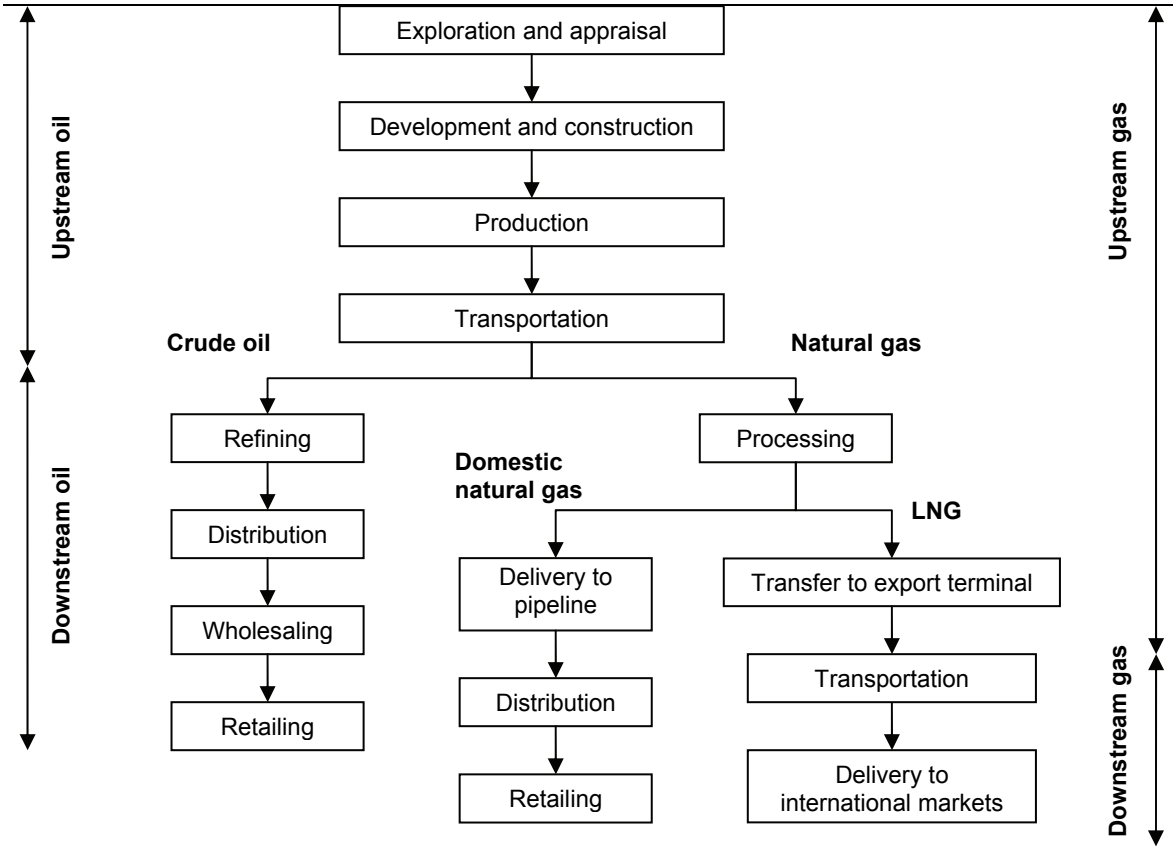
The number of industry participants has decreased slightly in recent years, with 163 companies ceasing exploration activities in Australia between 1993 and 2002, while 154 companies commenced or recommenced exploration during that period (Powell 2008).

Overall, the Australian upstream petroleum sector has shown after-tax returns on assets ranging between 5.1 per cent and 12.6 per cent in the 20-year period 1987-88 to 2006-07, with an average return of 8.6 per cent over the same period. (Commission estimates based on APPEA 2007a). These returns are below the 11.7 per cent average return on assets obtained by the top 200 American-owned upstream and downstream oil and gas companies in 2006 (PennWell 2008).

2.3 Exploration, development and production

The oil and gas supply chains contain a number of distinct stages. The upstream petroleum sector encompasses three of these stages: (1) exploration and appraisal; (2) development and construction; and (3) production. The downstream activities usually include refining, distribution, wholesaling and retailing. For natural gas (including LNG), the definition of upstream includes processing and delivery to export terminals or to domestic gas transmission pipeline in-take (figure 2.3).

Figure 2.3 **Stylised supply chain for oil and natural gas**



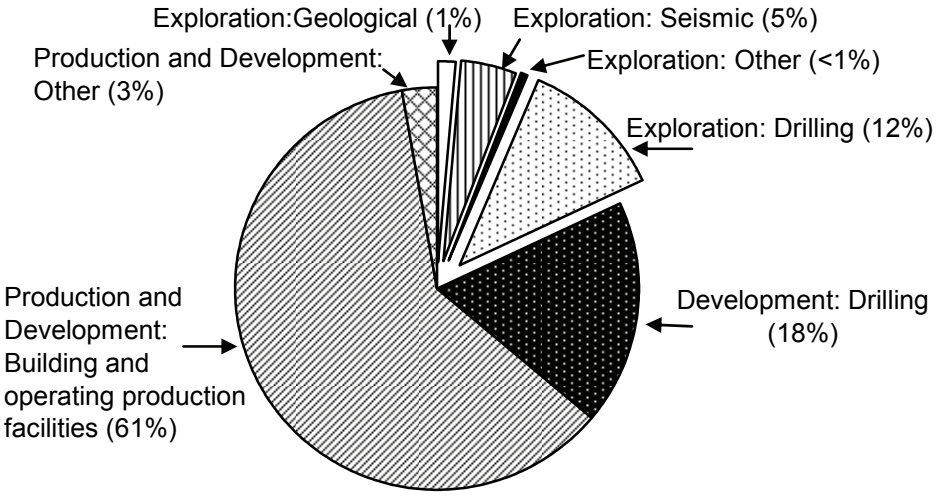
Total upstream project expenditure is dependent on a variety of factors at each stage of the supply chain (figure 2.4). The costs incurred at each stage also depend on the activities conducted in prior stages.

Exploration and appraisal

The primary focus of the exploration and appraisal stage is information gathering. This stage involves the use of a number of scientific techniques as well as drilling activities. Exploration expenditure tends to be lumpy, and occurs long before development. Consequently, it varies substantially from year to year as a proportion of total expenditure. In 2005, it comprised approximately 17 per cent of total expenditure, however, overall exploration accounted for about 28 per cent of total expenditure by the upstream petroleum sector in Australia over the period 1980–2005 (Geoscience Australia 2008).

A scientific approach is applied to select an appropriate area of the chosen sedimentary basin in which to explore. This includes a variety of non-seismic techniques, such as satellite imagery; gravity, magnetic and geochemical surveys; radiometric surveys and controlled electro-magnetic surveys (Wilkinson 2006).

Figure 2.4 **Breakdown of total upstream petroleum expenditure, 2005**



Source: Geoscience Australia (2008).

More detailed techniques are then applied in order to pinpoint a location in which to place a 'wildcat' well (that is, a search well placed in a previously undrilled area). Seismic surveys are the principal method used for obtaining data on subsurface geological structures. This entails sending sound waves through the earth, and collecting data from the reflections of those sound waves in order to compile a cross-sectional image of the subsurface geology. Surveys can be two- or three-dimensional. Three-dimensional surveys provide more detailed imagery, but are more costly and time consuming (Wilkinson 2006).

Collecting, processing and analysing the exploration data obtained from these procedures accounts for only a small proportion of the upstream sector's total annual expenditure. Exploration expenditure is high-risk and will not generate any revenues if oil and gas are not found. Even the discovery of oil or gas does not guarantee a return, as the resources may be marginal or non-commercial.

If geological information suggests a reasonable likelihood of oil or gas discovery, then a wildcat well is drilled to determine whether an oil or gas deposit exists (Wilkinson 2006). The number of wildcat wells drilled in Australia has fluctuated over time, ranging from 48 wells in 2002 to 124 wells in 1998 (table 2.2). In 2005, 85 wildcat wells were drilled, around the annual average for the preceding 10 years. The proportion of wildcat wells that have been successful in locating an oil or gas deposit varies across years, from around one quarter in 2003 to over one half in 2004 (Geoscience Australia 2008).

Table 2.2 **Exploration activities**

Year	Wildcat wells[a]	Extension/ appraisal wells[b]	Seismic surveys		Wildcat success rate[d]
			2-dimensional[c]	3-dimensional[c]	
	number	number	line km	sq km	%
1995	88	58	161 174	na	34
1996	95	50	389 163	na	37
1997	110	69	529 529	na	43
1998	124	39	1 062 810	na	36
1999	69	27	523 410	na	34
2000	72	28	135 828	15 178	39
2001	94	37	65 024	21 779	44
2002	48	41	15 442	15 653	46
2003	66	33	15 837	7 305	26
2004	86	36	43 215[e]	14 778[e]	52
2005	85	60	44 119	24 606	35

[a] A 'wildcat' well is a search well placed in a previously undrilled area. [b] An 'appraisal' well is typically drilled as part of the process to determine the size of a discovery. Similarly, an 'extension' well is used to determine if a discovery extends beyond the known area. [c] Measures of 3 dimensional seismic surveys conducted prior to 2000 were converted to line km and included in the 2 dimensional seismic survey figure by Geoscience Australia. [d] Wildcat success rate is based on the number of wildcat wells and the number of new field discoveries (irrespective of commerciality). [e] Figures may include reprocessed data. **na** Not available.

Sources: Geoscience Australia (2006, 2008).

Should oil or gas be found, the extent of the discovery is appraised for commercial viability by drilling appraisal wells. Combined with seismic mapping, appraisal wells are used to determine the nature and size of the discovery (Wilkinson 2006).

The cost of extraction and the marketability of both oil and gas in part depend on their chemical make-up. This is determined through testing prior to development and production.

The nature of an oil or gas deposit, as well as the subsurface geology, also determines recovery estimates. Not all of the hydrocarbons in a reservoir are extractable. Production of an oilfield usually extracts between 10 and 40 per cent of estimated resources, but up to 80 per cent in some circumstances. Between 75 and 90 per cent of estimated resources can usually be extracted from gas fields (Favennec 2004).

Development and construction

Infrastructure to support production is established in the development and construction stage. In addition to drilling production wells, this includes

constructing field infrastructure, on-site production and processing facilities, and transmission facilities to connect the field with downstream refineries and distribution systems.

The capital expenditure incurred in the development and construction phase forms a large proportion of the total costs of a project, with the development drilling component alone accounting for 18 per cent of total upstream petroleum expenditure in 2005 (figure 2.4). Development costs are influenced by the information gathered during the exploration and appraisal phase. Insufficient or inadequate information may lead to a poorly designed production system, which can increase overall project costs.

Development costs include drilling and constructing a gathering network, well testing facilities, on-site processing plants and pipelines. In addition, offshore plants may require an offshore processing platform. Much of this equipment is imported from the United States, the United Kingdom, Germany, Denmark, Sweden and Japan. Supplies from Asia, including China and India, are increasing (US Commercial Service 2008).

Development of LNG and domestic gas plants account for a large proportion of total project expenditure. For example, the construction of the North West Shelf Venture's fifth LNG train and production facility cost $2.6 billion (ASX 2008).

Delays in bringing proven reserves to commercial production are inevitably costly, due to significant sunk costs of exploration. At the development and construction stage delays are even more costly, due to the direct costs of placing construction on hold and the opportunity cost of idle capital equipment already in place.

Development drilling

Development drilling establishes the production wells. Drilling is generally a step-by-step process (particularly for onshore fields), thereby allowing the developer to revise the development plan based on the outcome of each well drilled. Successful onshore exploration wells may also be used as production wells (Wilkinson 2006).

The step-by-step process is often not possible for offshore fields, because economic design of production facilities requires the location of all wells to be known prior to development commencing. In this case, the optimal number and location of wells must be determined prior to drilling (Wilkinson 2006).

Development wells tend to be drilled more quickly than exploration wells and the costs are easier to control. This is because drilling in the area becomes a repetitive

process, with drill times and costs declining with the number of wells. However, development drilling forms a significant proportion of total expenditure (figure 2.4).

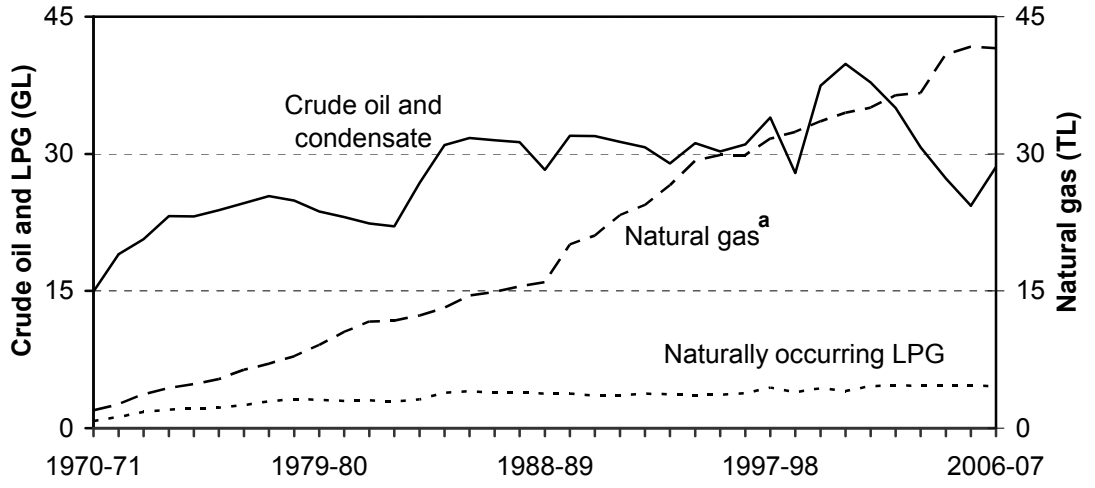
Production

The production stage commences after a field has been developed. Production activities commence with the recovery of petroleum from the reservoir using primary, secondary and tertiary methods. The recovered hydrocarbons are then processed, and finally transported to refineries and distribution systems.

The production stage involves higher operating expenditure and lower ongoing capital expenditure. Two thirds of on-site operating cash costs (excluding those related to LNG or domestic gas treatment facilities) are incurred in the areas of general support, well and surface operations, maintenance and logistics. Personnel costs form a substantial proportion of the costs in these areas (Favennec 2004).

Australian natural gas production has increased steadily since 1970, while production of naturally occurring LPG has remained more stable. Crude oil and condensate production increased from 15 GL in 1970-71, and peaked at 40 GL in 2000-01, before declining to 24 GL in 2005-06 (figure 2.5).

Figure 2.5 **Australian annual production, 1970-71 to 2006-07**



a 1 TL natural gas = 1 billion m^3. Litres refer to gas volume, and are not equivalent to liquefied natural gas (LNG) volume. Natural gas includes gas that is later converted to LNG, but excludes liquefied petroleum gas.

Source: ABARE (2008c).

Recovery

Primary recovery refers to the initial extraction of petroleum, using the natural pressure in the reservoir. This natural pressure forces the oil and gas to the top of the wellhead. Generally, 25 to 30 per cent of oil, or 80 per cent of gas can be recovered using this method (Favennec 2004).

Secondary recovery extends natural flow through artificial methods, such as injecting water or gas into the reservoir. This maintains the pressure in the reservoir and flushes the oil into the production well. Alternatively, pumps can be used to extract the oil. Tertiary (or enhanced) recovery alters the chemical properties of the remaining oil, to make it flow into the well. Techniques include injecting various fluids and gases, such as complex polymers and carbon dioxide (Wilkinson 2006).

Processing and transportation

Preliminary processing occurs on-site in conjunction with recovery. Processing involves dividing the hydrocarbon mix into separate streams of oil, water and gas. Both oil and gas are further treated to remove any remaining water.

Treated crude oils and condensates are transported by pipelines, tankers or trucks to refineries, where they are converted into commercial products. Refining represents the first stage of the downstream petroleum sector.

Natural gas also requires additional processing prior to its distribution. Therefore gas is transported (usually by pipeline) to gas processing plants. There, inert gases, liquid hydrocarbons, and sulphur and other impurities are removed from the gas, leaving a commercial form of gas that is mostly methane. This is then sold to retailers or large end users.

In order to make natural gas easier to transport and store, gas can be converted to LNG. The gas from the production field is transported to an LNG processing plant (train), generally located near port facilities. There it is processed, purified and cooled to below -160 degrees Celsius to convert it to liquid form. The LNG is then loaded onto a special LNG shipping tanker, and exported.

LPG is classified as either naturally occurring, as is 77 per cent of Australian LPG production (RET 2008d), or artificial. Naturally occurring LPG is sourced from gas fields and oilfields, while the artificial variety is a by-product from refineries.

Naturally produced LPG is separated from natural gas and condensate at the LNG or gas processing plant. It is then compressed, and transported in pressurised tanks to domestic or export markets.

2.4 Industry structure

The upstream petroleum sector is characterised by a number of international oil businesses, many of which participate in joint venture agreements. Petroleum products are then sold to downstream customers, such as oil refineries, gas retailers, and overseas markets.

Ownership structure

Many of the key businesses in the Australian upstream petroleum sector are subsidiaries of multinationals. For example, Apache, ConocoPhillips, Chevron and ExxonMobil have US parent companies, while BP, ENI, OMV and Shell have parent companies in Europe.

Some large Australian businesses are now engaged in overseas exploration and production. Woodside represents the largest independent Australian upstream petroleum company in terms of both market capitalisation and proved plus probable reserves, reflecting the large scale of some of Woodside's projects (table 2.3). Beach Petroleum, Origin and Santos have equity holdings in a large number of oil, gas and coal seam methane production permits in Australia.

The industry structure is complicated by the prevalence of joint ventures. Most onshore and offshore production licences are issued to multiple parties, with a single business designated as the 'operator'. For example, the North West Shelf project involves a joint venture between Woodside, BHP Billiton, BP, Chevron, Japan Australia LNG and Shell. Santos has joint interests with over 40 other producers, including Beach Petroleum, BHP Billiton, Chevron, ExxonMobil and Origin. A substantial proportion of exploration permits is also issued to joint ventures.

Joint ventures are important in the petroleum industry, as they facilitate risk sharing, and allow businesses to specialise and still accomplish the maximum development of a given field. Joint ventures also allow smaller businesses to be involved in production without raising the large quantities of capital required to develop a field alone.

Table 2.3 **Major Australian-listed oil producers**

Company	*ASX code*	*Market capitalisation at 1 January 2008*	*Reserves*		*Production permits in Australia 2008*
			Proved	*Proved plus probable*	
		A$ billion	mboe[a]	mboe[a]	number[b]
Arc Energy	ARQ	0.4	5.7	17	16
Australian Worldwide Exploration	AWE	1.6	na	39	3
Beach Petroleum	BPT	1.4	na	4.3	308
BHP Billiton	BHP	128.3	275	551	43
Cue energy Resources	CUE	0.1	5.1	47	–
Oil Search	OSH	5.2	132	1 193	–
Origin (upstream and downstream)	ORG	7.6	na	378	316
Petsec Energy	PSA	0.2	na	5.7	–
ROC Oil	ROC	0.9	13.0	17	2
Santos	STO	8.4	348	643	413
Tap Oil	TAP	0.3	na	19	9
Woodside	WPL	35.2	951	1 294	27

a Million barrels of oil equivalent. **b** Includes permits issued to wholly-owned subsidiaries. – Nil. **na** Not available.

Source: ABARE (2008a); Commission estimates based on ENCOM (2008).

Downstream customers

Once treated, crude oil, natural gas (including LNG) and LPG are either sold to domestic customers, or exported. The proportion of domestic production that is exported has increased significantly since the early 1990s (figure 2.6).

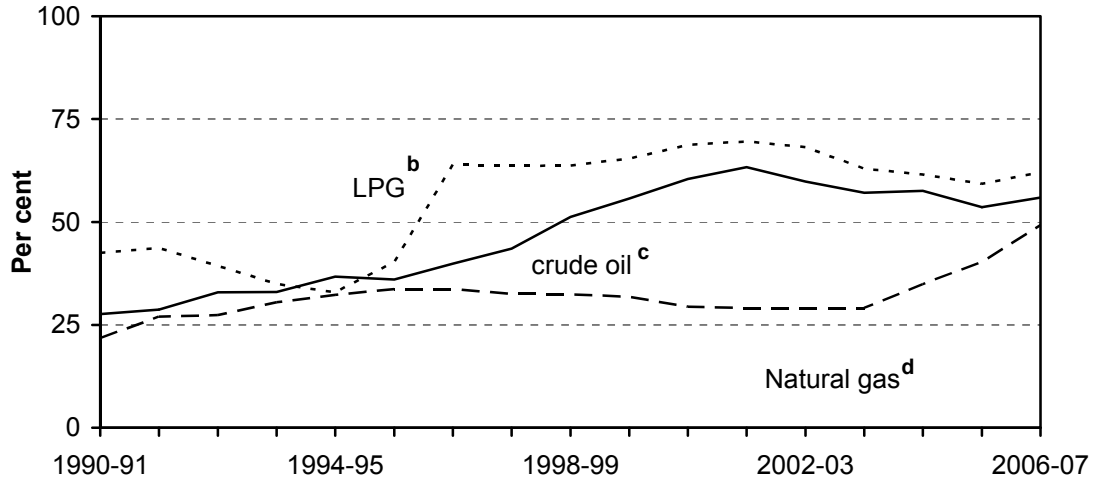
Tina Hunter noted:

> The export of petroleum was the second largest [export] income earner in 2006, behind coal. Importantly, LNG exports are increasing rapidly, from $5 billion in 2006 to an estimated $8.5 billion by 2011. As a source of import expenditure, crude oil is Australia's largest import in dollar terms, approximately 6.2% in 2006. (sub. DR22, p. 2)

Crude oil and condensate

Treated crude oil is not in a form that can be used as fuel — it must be refined. Consequently, the main customers of upstream crude oil producers are refineries, although intermediaries may also purchase crude oil and then sell it to the refineries. Australia has seven refineries, operated by BP, Caltex, ExxonMobil and Shell (PennWell 2008).

Figure 2.6 **Exports as a percentage of oil and gas production, 1990-91 to 2006-07[a]**



a Original measurements of production and exports are in PJ. **b** Liquefied petroleum gas (LPG) is equal to total LPG exports as a percentage of naturally occurring LPG produced. Production data for artificial LPG are not available. **c** Crude oil is equal to exported 'crude oil and other refinery feedstock' divided by produced 'crude oil and condensate'. **d** Natural gas includes LNG.

Sources: ABARE (2008b, 2008c); Commission estimates.

Although Australia is a net importer of crude oil, approximately 56 per cent of Australian-produced crude oil and condensate was exported in 2006-07, following a peak of 63 per cent in 2001-02 (Commission estimates based on ABARE 2008c). This partly reflects the fact that production from north-western Australia is mostly exported, whereas local refineries import crude oil in order to supplement declining production in south-eastern Australia (ABARE 2008a).

Over 68 per cent of Australia's crude oil exports went to the Asian region in 2005-06 (IEA 2008). The largest export markets for crude oil in 2007 were the Republic of Korea, Japan, Singapore, Thailand and Papua New Guinea (DFAT 2008a).

Natural gas and LNG

Once extracted, natural gas is transferred (usually by pipeline) to a gas processing plant. A number of domestic gas processing plants exist in Australia, most of which are located in southern Queensland, the Northern Territory, coastal Victoria and in the Carnarvon and Perth Basins in Western Australia (ABARE 2008b).

Processed natural gas can be sold directly to the end user, which is common with large users. However, natural gas is usually sold to a retailer, who generally has third party access to the transmission and distribution pipelines used to deliver the

gas to customers, including households. Major Australian gas retailers include AGL, AlintaGas, Allgas, Country Energy, Origin, TXU and Wesfarmers (PC 2004d).

Natural gas in its standard form is not exported, as its large volume makes transportation uneconomical. However, a substantial proportion — 49 per cent in 2006-07 (figure 2.6) — of Australia's natural gas is exported after being converted to LNG. This currently occurs in two LNG processing facilities, located in the Pilbara and in Darwin, and operated by Woodside and ConocoPhillips respectively. The majority of exported Australian LNG is purchased by Japan, Republic of Korea, China and Taiwan (Roarty 2008).

Although domestic natural gas consumption is forecast to increase by 86 per cent over the 25 years to 2029-30, production is forecast to grow at a faster rate, resulting in strong growth in LNG exports (ABARE 2007a).

LPG

Naturally occurring LPG must be separated from natural gas streams in an LPG extraction plant. A number of LPG extraction plants exist in Australia, including two in Western Australia, operated by the North West Shelf Joint Venture and Wesfarmers.

Around 60 per cent of Australian production of naturally occurring LPG is exported, primarily from Western Australia (figure 2.6). The largest export markets are Japan, the Republic of Korea and China (RET 2008d). Exports are forecast to increase until at least 2029-30 (ABARE 2007a).

Although Australia is a net exporter of LPG, eastern Australian States import LPG, amounting to 18 per cent of Australian consumption (RET 2008d). This reflects demand for particular gas mixes. While exports of LPG contain a mixture of propane and butane, demand in the eastern States is primarily for propane.

Domestic LPG consumption totalled 4038 ML in 2006-07, more than half of which was for automotive use (RET 2008e). Domestic consumption of LPG is forecast to increase by over 44 per cent between 2006-07 and 2029-30. However, production is forecast to increase by a greater amount, resulting in an increase in exports (ABARE 2008b).