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Key Oil Data

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</tr>
</thead>
<tbody>
<tr>
<td>Production (kb/d)</td>
<td>608.2</td>
<td>643.0</td>
<td>579.9</td>
<td>802.4</td>
<td>545.3</td>
<td>550.6</td>
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<td>Demand (kb/d)</td>
<td>638.6</td>
<td>737.9</td>
<td>810.9</td>
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<td>902.8</td>
<td>963.7</td>
<td>951.2</td>
<td>960.8</td>
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<tr>
<td>Motor gasoline</td>
<td>272.7</td>
<td>297.9</td>
<td>302.9</td>
<td>306.0</td>
<td>332.4</td>
<td>323.0</td>
<td>322.8</td>
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<td>Gas/diesel oil</td>
<td>147.5</td>
<td>175.3</td>
<td>199.0</td>
<td>229.3</td>
<td>291.3</td>
<td>327.5</td>
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<td>326.7</td>
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<td>Residual fuel oil</td>
<td>56.4</td>
<td>41.7</td>
<td>37.8</td>
<td>36.0</td>
<td>36.0</td>
<td>38.3</td>
<td>30.2</td>
<td>19.0</td>
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<tr>
<td>Others</td>
<td>162.0</td>
<td>223.0</td>
<td>271.2</td>
<td>298.6</td>
<td>273.1</td>
<td>274.8</td>
<td>272.2</td>
<td>282.5</td>
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<td>Net imports (kb/d)</td>
<td>30.4</td>
<td>94.9</td>
<td>231.0</td>
<td>70.0</td>
<td>387.5</td>
<td>413.1</td>
<td>397.8</td>
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<td>Import dependency</td>
<td>4.8%</td>
<td>12.9%</td>
<td>28.5%</td>
<td>8.0%</td>
<td>41.5%</td>
<td>42.9%</td>
<td>41.8%</td>
<td>46.5%</td>
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<td>Refining capacity (kb/d)</td>
<td>697</td>
<td>675</td>
<td>705</td>
<td>812</td>
<td>755</td>
<td>705</td>
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<tr>
<td>Oil in TPES</td>
<td>36.2%</td>
<td>36.2%</td>
<td>35.2%</td>
<td>31.6%</td>
<td>39.7%</td>
<td>30.4%</td>
<td>30.8%</td>
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End-Month Total Oil Stock Levels\(^1\) - Five Year Range

Key Natural Gas Data

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<tr>
<td>Production (mcm/yr)</td>
<td>13 101</td>
<td>26 475</td>
<td>29 260</td>
<td>32 819</td>
<td>40 764</td>
<td>44 740</td>
<td>46 818</td>
<td>45 116</td>
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<tr>
<td>Demand (mcm/yr)</td>
<td>13 101</td>
<td>17 684</td>
<td>20 096</td>
<td>22 507</td>
<td>28 559</td>
<td>31 128</td>
<td>31 350</td>
<td>26 408</td>
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<tr>
<td>Transformation</td>
<td>3 542</td>
<td>4 893</td>
<td>4 922</td>
<td>5 184</td>
<td>9 651</td>
<td>9 773</td>
<td>9 798</td>
<td>-</td>
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<tr>
<td>Industry</td>
<td>5 732</td>
<td>7 180</td>
<td>7 937</td>
<td>8 720</td>
<td>10 525</td>
<td>10 756</td>
<td>10 366</td>
<td>-</td>
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<tr>
<td>Residential</td>
<td>1 614</td>
<td>2 259</td>
<td>2 700</td>
<td>2 963</td>
<td>3 414</td>
<td>3 523</td>
<td>3 575</td>
<td>-</td>
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<tr>
<td>Others</td>
<td>2 213</td>
<td>3 352</td>
<td>4 537</td>
<td>5 670</td>
<td>4 959</td>
<td>7 076</td>
<td>7 614</td>
<td>-</td>
</tr>
<tr>
<td>Net imports (mcm/yr)</td>
<td>-</td>
<td>- 2 791</td>
<td>- 9 164</td>
<td>- 10 252</td>
<td>- 12 205</td>
<td>- 13 612</td>
<td>- 15 485</td>
<td>- 18 708</td>
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<tr>
<td>Import dependency</td>
<td>0.0%</td>
<td>- 19.8%</td>
<td>- 45.6%</td>
<td>- 45.4%</td>
<td>- 42.7%</td>
<td>- 43.7%</td>
<td>- 49.3%</td>
<td>- 70.8%</td>
</tr>
<tr>
<td>Natural Gas in TPES</td>
<td>15.4%</td>
<td>17.1%</td>
<td>18.1%</td>
<td>17.8%</td>
<td>19.3%</td>
<td>21.4%</td>
<td>21.6%</td>
<td>-</td>
</tr>
</tbody>
</table>

End-Month Natural Gas Stock Levels\(^2\) - Five Year Range

1 - Primary oil stocks on national territory; these exclude utility stocks and including pipeline and entrepot stocks where known.
2 - Stocks held on national territory, as reported to the IEA in monthly data submissions.
OVERVIEW

Oil and natural gas represented just over half of Australia’s total primary energy supply (TPES) in 2009. This is projected to rise to two-thirds of TPES over the coming two decades, with demand for oil and gas rising annually by 1.3% and 3.4% respectively. In the case of natural gas, domestic production will more than satisfy the country’s gas needs well beyond the projected period, and Australia’s gas export capacity will continue to rise apace. However this is not the case for oil, where a growing share of future oil demand will be met from imports of refined products.

Australia does not impose minimum stockholding requirements on oil companies, nor does it have public stocks; rather, it relies on the industry’s normal stockholding practices to meet the IEA requirement that stock levels equate to no less than 90 days of net imports. Until 2000, the year in which its domestic crude production peaked, Australia was either a net oil exporter or relied only marginally on oil imports to meet domestic demand. As such, Australia had little to no stockholding requirement towards the IEA. Since 2000, declining domestic oil production coupled with oil demand growth has resulted in a steady rise in net imports, and thus the amount of oil stocks necessary to meet Australia’s IEA obligation. Beginning in 2010, the level of oil stocks in Australia have failed to cover 90 days of net imports. A National Energy Security Assessment conducted by the Australian government in 2011 will evaluate the country’s current energy security situation and help inform Australia’s consideration of stockholding compliance options.

The Australian emergency policy is to rely on the domestic market to respond to supply shortfalls in the first instance, including consumer response to price signals. Short-term surge production capacity and fuel switching capacity in Australia is limited. In a declared state of emergency, the Australian government has legislative powers to control the storage, transfer, sale and production of liquid fuels. Initial light-handed demand restraint measures and a rationing scheme at the wholesaler level can quickly be escalated to invoke heavier-handed measures including retail rationing. Australia’s State and Territory Governments have constitutional powers for planning and coordinating emergency response within their territorial boundaries. In the case of a major oil crisis, affecting more than one jurisdiction, Ministers have agreed that the National Oil Supplies Emergency Committee (NOSEC), which includes the fuel industry, will advise on appropriate actions. In an IEA collective action, NOSEC would likely recommend initial participation with the use of demand restraint measures.

The management of temporary gas shortfalls is primarily undertaken by gas market participants and jurisdictional governments, depending on the nature and size of the event. In the case of a major gas crisis, affecting more than one jurisdiction, the National Gas Emergency Response Advisory Committee (NGERAC) will advise energy Ministers across jurisdictions, who in turn are able to enact emergency powers within their corresponding jurisdictions. These powers can include issuing directions for production, transmission, distribution and allocation of natural gas.
1. Energy Outlook

Oil and natural gas represented respectively 31% and 22% of the Australia’s total primary energy supply (TPES) in 2009. While the combined share of the two fuels in the supply mix has remained relatively stable over the past 3 decades, at around 50% of TPES, the share of natural gas has steadily risen. Coal has remained Australia’s single largest energy source, representing roughly 45% of TPES over the period.

Australia’s TPES, which equated to some 131 million tonnes of oil equivalent (Mtoe) in 2009, is projected to reach around 185 Mtoe by 2030, an increase of about 1.4 % per year.

Oil use is expected to grow at a rate of 1.3% per year, becoming Australia’s main source of energy in 2030 at just over 36% of TPES. Natural gas is projected to rise to 33% of TPES, with 3.4% annual demand growth driven primarily by gas used in electricity generation and amounts consumed in the production of LNG. The share of renewable energy is expected to rise to 8% of TPES by 2030, implying an annual growth rate of 3.5%, with strong growth expected for wind energy. Such growth expectations are underlined by Australia’s Renewable Energy Target (RET) which seeks to have 20% of the country’s electricity supply sourced from renewable energy by 2020 (compared to 7% in 2009). The share of coal in the fuel mix is projected to decline to 23% of TPES by 2030, representing 43% of electricity generation by 2030 compared to over 75% in 2009.
2. Oil

2.1 Market Features and Key Issues

Domestic oil production

Domestic oil production began in Australia in the 1960s following the discovery of giant fields located off the south-east coast of Australia. While there are over 300 producing fields in Australia, most production comes from seven major fields. The largest of the country’s petroleum producing basins are the Carnarvon Basin in the north-west of Australia and the Gippsland Basin in the south-eastern Bass Strait. Production from the Carnarvon Basin, which accounted for around 66% of total production in 2010, is mostly exported. Production from the Gippsland Basin has declined steadily since its peak in the mid-1980s and accounted for under 15% of total production in 2010. Production from this basin is predominantly used in domestic refining.

Most of Australia’s crude oils are of a high quality, light- sweet grade, as represented by its main crude streams (Gippsland, Bayu-Undan and Cossack). These are similar in quality to the condensates produced primarily in association with the country’s giant offshore gas fields. In addition to the crude oil and condensate production, Australia produces natural gas liquids (NGLs) in the form of naturally occurring liquid petroleum gas (LPG).

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 NGLs associated with undeveloped offshore gas fields. Crude oil reserves classified as economic demonstrated resources (EDR), which includes remaining proven and probable commercial reserves, were estimated at 1.07 billion barrels as of 1st January 2010, representing 27% of Australia’s total EDR of petroleum. This equated to approximately 10 years of remaining reserves based on the reserves to production ratio at the time of the estimate. Condensates represent more than half of the country’s total petroleum resources, with EDR estimated at some 2.16 billion barrels (roughly 45 years of production). Resources of naturally-occurring LPG are estimated at 1.04 billion barrels (42 years).

Australian crude and condensate production - outlook to 2015-16

Total crude oil and condensate production peaked in 2000 at some 687 kb/d. Production has since declined and averaged some 441 kb/d in 2010 (an additional 70 kb/d of LPG was also produced in 2010).
New projects will provide increases in production in 2012-13, and the Australian government’s 2010 projections expect total crude production to increase to some 521 kb/d in 2012-13. However, beyond this period production is expected to decline as older fields mature and slowly decline. By 2015, crude production is expected to average some 464 kb/d, with LPG likely adding an additional 70 kb/d to total indigenous production.

In the longer-term outlook, combined crude oil, condensate and LPG production is projected to fall gradually by 2% per year, to some 310 kb/d by 2030. Over the same period, total domestic oil demand is expected to grow annually, resulting in total net imports (including both crude and refined products) rising by 3.3% per year.

**Oil demand**

![Oil Consumption, by Product](source: Monthly Oil Statistics, IEA)

Oil product demand in Australia averaged 960 kb/d in 2010. Total oil use has grown at an annual average rate of 1% since 2000. The transport sector, which accounts for two-thirds of all oil used in Australia (see Oil Demand Restraint section below), has been the primary factor leading oil demand growth. At the same time the mining sector, where diesel is the primary fuel used, has continued to expand in Australia and contributed to growth in the fuel’s use. Demand for diesel grew by an average of 4.2% over the period, and in 2010 overtook gasoline as the largest component of the country’s overall oil demand.

Total oil demand is expected to continue to grow in the coming years at an annual average rate of 1.3%. This rate would infer oil demand reaching just over 1 million barrels per day (mb/d) in 2015 and nearly 1.1 mb/d by 2020. The mining sector is expected to make the most significant contribution to oil demand growth, where the sector’s energy consumption is expected to grow at a rate of 3.3% annually to 2030. Air transport is also expected to drive oil demand growth, with a long term growth rate of 2.3% per year.

The breakdown by product of projected oil demand growth is likely to continue the

<table>
<thead>
<tr>
<th>Oil Demand (kb/d)</th>
<th>2000</th>
<th>2010</th>
<th>% change p.a.</th>
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<tr>
<td>LPG and Ethane</td>
<td>94.0</td>
<td>79.4</td>
<td>-1.7%</td>
</tr>
<tr>
<td>Naphtha</td>
<td>0.6</td>
<td>0.5</td>
<td>-1.7%</td>
</tr>
<tr>
<td>Gasoline</td>
<td>308.5</td>
<td>325.7</td>
<td>0.6%</td>
</tr>
<tr>
<td>Kerosene</td>
<td>92.5</td>
<td>118.8</td>
<td>2.5%</td>
</tr>
<tr>
<td>Diesel</td>
<td>218.3</td>
<td>330.9</td>
<td>4.2%</td>
</tr>
<tr>
<td>Heating/other Gas</td>
<td>11.1</td>
<td>0.1</td>
<td>-40.3%</td>
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<td>Residual Fuels</td>
<td>36.6</td>
<td>23.8</td>
<td>-4.2%</td>
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<tr>
<td>Other Products</td>
<td>111.7</td>
<td>80.5</td>
<td>-3.2%</td>
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<tr>
<td><strong>Total Products</strong></td>
<td>873</td>
<td>960</td>
<td>1.0%</td>
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*Source: Monthly Oil Statistics, IEA*
trends of the previous decade, with demand for diesel and jet kerosene growing at the greatest pace and demand for gasoline remaining flat or increasing at only a modest rate.

**Imports/exports and import dependency**

Until 2000, the year in which its domestic crude production peaked, Australia was either a net oil exporter or relied only marginally on oil imports to meet domestic demand. Since then, as domestic production has declined and domestic oil demand grown, Australia has become a growing net oil importer. In 2010, total oil net imports, including both crude and refined products, amounted to 393 kb/d.

<table>
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<th>Australian oil supply in 2010 (kb/d)</th>
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<td>Crude and condensate production</td>
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<tr>
<td>Exports</td>
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<tr>
<td>Imports</td>
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<tr>
<td>Other refinery feedstock, stock change, etc.*</td>
</tr>
<tr>
<td><strong>Total Input to Domestic Refineries</strong></td>
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<td>Domestic LPG production</td>
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<tr>
<td>Refined products - refinery output</td>
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<td>refinery own use, stock change, etc.*</td>
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<tr>
<td>Imports</td>
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<tr>
<td>Exports</td>
</tr>
<tr>
<td><strong>Total Product Supply</strong></td>
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</table>

* includes statistical difference

Source: Monthly Oil Statistics, IEA

A large portion of Australia’s domestic crude oil production is exported, as the oil’s quality and the geographic location of production (coming primarily from the north-west coast) makes it attractive for Asian refineries. In 2010, nearly 330 kb/d of domestic production was exported, primarily to Korea, Thailand and China. At the same time, the majority of domestic refinery capacity is located close to the major demand centres on the east coast, where refiners process primarily domestic crudes coming from the south-eastern fields and lower-quality imports from Southeast Asian producers. In 2010, total imports of crude oil amounted to some 480 kb/d, primarily sourced from Malaysia, Indonesia and Vietnam.

Imports of refined products have steadily increased in recent years, rising from just under 200 kb/d in 2004 to a high of over 330 kb/d in 2009. Total imports of refined products in 2010 were just under 300 kb/d, including 115 kb/d of middle-distillate imports from Singapore. At the same time, product exports averaged 56 kb/d.

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. In the shorter term, domestic production is expected to increase to 2012-13, with a significant proportion of this production growth concentrated in north-western Australia. As this production will likely be largely exported to Asian refineries, the ability of domestic production to meet domestic demand is likely to be lower than implied by the simple comparison of production and consumption.

At the same time, Australia’s refining capacity is not expected to expand significantly given increasing competitive pressures from larger refineries in India and South-East Asia in particular. In addition to the outlook for domestic production and consumption, the outlook for domestic refining capacity may result in lower crude oil imports and, simultaneously, higher imports of refined products. Reflecting this, the outlook for Australia’s net imports over the period to 2030 is for a 3.3% annual increase. By 2030, 76% of Australia’s oil demand is expected to be met by imports compared to some 40% in 2010.
Oil Company Operations

While there are many oil companies with upstream activities in Australia, four companies account for the vast majority of Australia’s domestic oil production; Woodside, ExxonMobil, BHP Billiton and Apache. Regarding downstream activities, there are four companies operating Australia’s 7 refineries; BP, Caltex, ExxonMobil and Shell.

There has been ongoing structural change in Australia’s oil retailing over the past few decades, with approximately 6,000 retail petroleum sites around Australia in 2010 compared to some 12,500 sites in the 1990s. The share of volume of retail sales by brand in 2009-10 were: Woolworths/Caltex (23%), Coles Express/Shell (23%), BP (17%), Caltex (17%), ExxonMobil (7%) and Shell (2%), with other smaller retail chains accounting for the remaining 11%.

The retail fuel market is increasingly populated with independent operators, independently branded chains and supermarket chains. The refiner-marketers continue to reduce their involvement in retail operations. In May 2010, ExxonMobil signed an agreement for the sale of its retail fuels business, comprising 295 company-owned or leased service stations, primarily located in the metropolitan areas of eastern Australia, to 7-Eleven Australia.

2.2 Oil Supply Infrastructure

Refining

There are seven refineries in Australia, with a total crude distillation capacity of 762 kb/d. While mostly constructed in the 1950s and 1960s, these have undergone extensive upgrading, in particular in 2005-06. Australia’s refineries are relatively small by global standards, with the largest, the Kwinana refinery (south of Perth), at just over 142 kb/d, representing roughly 19% of the country’s total distillation capacity.

Australian refineries face considerable competition from mega-refineries in Asia, with Singapore product prices largely determining their profitability. In 2003, what was once Australia’s eighth refinery, Port Stanvac (75 kb/d) in Adelaide, was mothballed for economic reasons. Its owner, Mobil, decided to demolish the refinery and remediate the site in 2009. In April 2011, Shell announced plans to stop refining oil at its Clyde refinery (82 kb/d) near Sydney and turn the plant into a fuel import terminal. If carried out, this would reduce Australia’s total crude distillation capacity to 680 kb/d across 6 operating refineries.

Australian refineries use both domestic and imported crude, primarily from the country’s Bass Strait production in the south and from Southeast Asian producers. Total refinery intake of the country’s 7 refineries averaged 666 kb/d (605 kb/d of which was crude and condensates) in 2010. Over two-thirds of Australia’s refinery input requirements came from imports.
Refiners produce mostly gasoline and middle distillates, as well as smaller volumes of bitumen and LPG. In 2010, motor gasoline accounted for 43% of refinery output, diesel for 31% and kerosene for 14%.

In 2006, Australia enacted higher fuel quality standards that have required refineries to upgrade facilities. The fuel quality changes required automotive diesel oil (ADO) to contain 10 parts per million (ppm) sulphur by January 2009 (reduced in steps from 500 ppm and 50 ppm), all grades of gasoline to contain 150 ppm sulphur by January 2005 and premium gasoline to contain 50 ppm sulphur by January 2008 (reduced from 150 ppm).

**Bio-fuel Components in Transport Fuels**

Bio-fuels represented around 1% of Australia's gasoline and diesel supply in 2010. National fuel standards allow for up to 5% biodiesel and 10% ethanol, with labelling, however there is no national set requirement for the use of bio-components and Australian States may set their own fuel mandates.

There are three major fuel ethanol production facilities in Australia, with a combined capacity of just over 450 million litres a year (roughly equivalent to some 8 kb/d). These facilities produce ethanol primarily from wheat starch, grain sorghum and molasses. Around 67% of ethanol production capacity is located in New South Wales, at a single production facility in Manildra (300 km west of Sydney).

There are also three major biodiesel production facilities in Australia, with additional facilities producing small quantities. Total biodiesel operating capacity is 275 million litres a year (5 kb/d). The majority of Australia's biodiesel production occurs in Victoria. Biodiesel facilities in Australia use a range of vegetable oils, animal fats and waste oils as feedstocks, which are selected according to price and availability.

**Ports and Pipelines**

Australia has four main trunk lines for transporting oil and oil products by pipeline. The company Epic Energy operates a pipeline carrying crude oil and a mixture of NGLs 659 km (409 mile) from Moomba to Port Bonython. Santos operates a significant part of the oil pipeline network, including the Jackson to Brisbane line that spans nearly 797 km (500 miles), and the Mereenie to Alice Springs line that covers 270 km (168 miles). In addition, ExxonMobil operates the Longford to Long Island Point pipeline (southeast of Melbourne), which runs 190 km (118 miles).

Australian exports of crude oil and condensate are increasingly sourced from the west coast, while exports of refined product are largely sourced from the east coast. In addition to the 7 refineries which have port facilities for importing crude oil and exporting refined products, Australia has 64 refined product import terminals. Of these, there are 11 major deepwater ports which also have facilities to export petroleum liquids. The port at Fremantle in Western Australia, near Perth, is the country's largest oil exporting centre.
Storage capacity

All storage capacity in Australia is held commercially within the supply chain, with no capacity used for emergency reserves in the form of government held or obligated industry stocks.

<table>
<thead>
<tr>
<th>Storage site</th>
<th>Crude Oil</th>
<th>Gasoline</th>
<th>Distillates</th>
<th>Fuel oil</th>
<th>Total Refined Product</th>
<th>Total Oil (crude &amp; product)</th>
</tr>
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<tbody>
<tr>
<td>at refineries:</td>
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<td></td>
<td></td>
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<td></td>
<td></td>
</tr>
<tr>
<td>Sydney</td>
<td>3 157</td>
<td>1 346</td>
<td>881</td>
<td>509</td>
<td>2 969</td>
<td>6 126</td>
</tr>
<tr>
<td>Melbourne/Geelong</td>
<td>2 440</td>
<td>497</td>
<td>516</td>
<td>302</td>
<td>2 057</td>
<td>4 497</td>
</tr>
<tr>
<td>Brisbane</td>
<td>3 340</td>
<td>1 220</td>
<td>1 013</td>
<td>459</td>
<td>3 264</td>
<td>6 604</td>
</tr>
<tr>
<td>Perth</td>
<td>2 183</td>
<td>1 654</td>
<td>623</td>
<td>415</td>
<td>2 768</td>
<td>4 950</td>
</tr>
<tr>
<td>at terminals:</td>
<td></td>
<td>6 617</td>
<td>8 768</td>
<td>2 321</td>
<td>19 914</td>
<td>19 914</td>
</tr>
<tr>
<td>Total Australia</td>
<td>11 120</td>
<td>11 334</td>
<td>11 800</td>
<td>4 007</td>
<td>30 971</td>
<td>42 091</td>
</tr>
</tbody>
</table>

Source: Petroleum Import Infrastructure in Australia

Storage capacity at the main storage facilities across Australia was just over 42 mb (6.7 million cubic metres) in 2009, according to an independent study commissioned by Australian authorities. However, while this represents the latest available data it does not include all storage capacity in the country, as information from smaller industry participants and independent importers was not included in the study.

Storage capacity is likely to have expanded substantially since the 2009 study. The study itself noted that investments were underway at that time which would expand Australia’s total

storage capacity by 1.7 mb (270 ML), with independent terminal operators accounting for 64% of this capacity expansion. In early 2011, Australia’s major oil companies were reportedly expanding their storage capacity by a total of 1 mb (including capacity either recently brought into service or under construction) and projects for an additional 1.6 mb of storage capacity expansion were under consideration.

**2.3 Decision-making Structure for Oil Emergencies**

The Minister for Resources and Energy is responsible for co-ordinating emergency response in the event of an oil supply disruption. Within the Ministry, the Australian Government Department of Resources, Energy and Tourism (RET), functions as the permanent core of the NESO body. In a disruption, this would expand to include the National Oil Supplies Emergency Committee (NOSEC), which is composed of representatives from Australian state and territory governments (which have constitutional authority for energy emergencies within their jurisdictions), as well as from industry and the Australian Institute of Petroleum. The NOSEC manages the National Liquid Fuel Emergency Response Plan (NLFERP) which details how Australian governments would respond to a fuel disruption with national implications.

In the event of a disruption, the minister would initially consult with NOSEC to assess potential implications and appropriate response measures. The minister would also consult other relevant Commonwealth Government agencies including the Department of Prime Minister and Cabinet, the Department of Foreign Affairs and Trade, the Treasury, and the Office of National Assessments.

The Governor-General may, when circumstances require, declare a national liquid fuel emergency under the Australian government’s Liquid Fuel Emergency Act of 1984 (LFE Act). Such a declaration must be made by way of proclamation by the Governor-General of Australia, upon the recommendation of the minister. A national emergency can only be declared if the Governor-General is satisfied that the situation meets the following criteria: the use of emergency powers is in the public interest; there is no real prospect of averting the shortage through voluntary augmentation of supplies by oil companies; and the minister has provided the opportunity for prior consultation with the relevant ministers for energy in all Australian states and territories.

**2.4 Stocks**

**Stockholding Structure**

Australia does not have public stocks, nor is there a minimum stockholding requirement imposed on oil companies operating in the country. The Australian Government relies on the normal stockholding practices of the domestic oil industry to meet its 90-day net import stockholding obligation as a member of the IEA.

The Australian Government does have statutory powers over industry stocks in a declared state of emergency under the LFE Act. The Act also empowers the Minister for Resources and Energy to impose specific reporting and establish stockholding requirements on industry, including in the planning stages prior to a declared state of emergency.
Crude or Products

Total oil stocks held by industry in Australia at end-2010 totalled 38.1 million barrels (mb), nearly 45% of which in the form of unrefined oil. The level of industry stockholding fluctuates monthly, ranging between 35 mb and 45 mb over the previous 5 years.

Location and Availability

Australia has a bilateral agreement with New Zealand, where Australian oil companies may tender and hold stocks on behalf of the New Zealand Government with a guarantee that Australia will not impede the release of these stocks to New Zealand. No stocks were held under the Australia-New Zealand bilateral agreement in 2011.

Monitoring and Non-compliance

Companies report stock levels to the Australian government on a monthly basis through the Australian Petroleum Statistics collection. If necessary, more frequent reporting of stock levels could be implemented to monitor compliance with a direction issued under the LFE Act. The Act also sets out penalties for failure to comply with reporting directives.

In 2000, Australia was a net oil exporter according to the IEA methodology for establishing a country’s 90-day stockholding obligation. Therefore, Australia had no stockholding obligation towards the IEA. Beginning in 2001, and until 2006, the level of net oil imports was marginal relative to the size of industry stockholding in Australia, with stocks in terms of days of net imports measuring well in excess of 90 days. As imports have been increasingly necessary to meet Australia’s domestic oil demand, there has been a steady rise in the amount of oil stocks necessary to meet Australia’s 90-day IEA stockholding obligation.

Since 2010, the level of oil stocks in Australia have equated to less than 90 days of net imports. A National Energy Security Assessment conducted by the Australian government in 2011 will look at potential structural solutions for complying with the IEA stockholding obligation.

Stock Drawdown and Timeframe

Australia’s major industry suppliers of petroleum products are represented on NOSEC by their national supply managers. Thus, decisions by the Australian NESO in response to a supply disruption would include their close consultation. The role of stocks in the country’s overall response would be through their participation with NESO, and any stockdraw would be through the normal supply and distribution system.

Financing and Fees

All stockholding costs are recouped by oil companies through their normal operations – i.e. are passed on to consumers through retail prices.
3. Other Measures

3.1 Demand Restraint

At the first sign of an oil disruption, the Australian government’s policy is to allow market price mechanism to operate in order to reduce demand, i.e. to allow oil price increases to flow through to consumers. The government would monitor the effect of natural price increases that flow from the supply disruption on patterns of demand without intervening in the market.

If price increases do not lead to an adequate decline in consumption, the Australian government would pursue a voluntary, industry-based bulk rationing strategy. This would involve seeking the co-operation of industry to voluntarily place its large consumers and retailers on allocation systems, e.g. fuel purchasers would be able to purchase a set percentage of their normal fuel purchases. Allocation usually commence at 100% of allocation by removing spot sales (which account for 5%) from the market. This approach considers that the use of voluntary, industry-based measures to influence bulk sales is an efficient and effective response tool that would reinforce the normal operations of the market and minimise government intervention.

The National Oil Emergency Demand Restraint Strategy (NOEDRS) establishes the purpose and principles of Australia’s demand restraint strategy. It provides a range of light-handed demand restraint measures, supported by policies and procedures, to compliment industry initiatives and build on incentives created by price pass through. The NOEDRS extends options available to Australia by introducing a list of actions which can be utilised to complement market based mechanisms, including the promotion of eco-driving, corporate information campaigns, carpooling campaigns and public transport campaigns.

Where a further government response to a fuel supply shortage is required, measures would focus on regulatory controls which could be placed on either bulk or retail sales of petroleum products and further demand side management responses with the objective of reserving supplies for essential users and ensuring other users have petroleum supply for as long as possible.

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Oil Consumption by Sector\(^2\)

<table>
<thead>
<tr>
<th>Year</th>
<th>Transformation/Energy</th>
<th>Residential</th>
<th>Commercial/Agriculture/Other</th>
<th>Industry</th>
<th>Transport</th>
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<td>1973</td>
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<td>2009</td>
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</table>

Source: Oil Information, IEA

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\(^2\) Total Consumption (including refinery consumption), does not include international marine bunkers.
3.2 Fuel Switching

The Australian potential for reducing oil use through fuel-switching - from oil to coal or natural gas - in the power and heating plants is limited. Oil is only a minor input fuel for electricity generation in Australia, accounting for less than 1% of total electricity generation.

3.3 Others

Short-term surge production capacity in Australia is considered inconsequential. Around 94% of Australia’s crude oil production (including condensate) is from offshore production facilities. While it may be technically possible to achieve small increases in production from some of these offshore facilities within a 30-day period, it would not be possible to achieve an increase that would alleviate a short-term production crisis in a meaningful way.
4. Natural Gas

4.1 Market Features and Key Issues

Gas production and reserves

Australia has significant volumes of natural gas reserves that are increasingly being developed for domestic use and for LNG exports. Around 90% of estimated recoverable reserves of conventional gas are located in the Carnarvon, Browse and Bonaparte basins off the north-west coast. In addition to conventional gas resources, there is growing commercial utilisation of Australia’s resources of coal seam gas (CSG). Most of these resources are located in the black coal deposits of Queensland and New South Wales. Tight gas accumulations are located onshore Western Australia, Queensland and South Australia, while potential shale gas resources are located in the Northern Territory, Queensland, South Australia and Western Australia.

Australia’s large and growing gas resources are sufficient to enable significant expansion in domestic consumption and export production capacity. Identified conventional gas resources have increased threefold over the past 20 years while identified CSG resources have grown substantially in recent years. Combined, these identified resources are on the order of 10 trillion cubic metres (393 000 PJ) as of 1st January 2009, the equivalent to roughly 180 years of gas at production rates at the time of the estimate. Potential undiscovered resources and inferred CSG (resources that can be expected to exist based on geological formations but requiring further appraisal) are substantial and could add significantly to total identified reserves in the future.

Total natural gas production was some 50.4 billion cubic metres (bcm) in 2010 (1 954 PJ). Australia also imports gas by pipeline from the area of overlapping maritime claims with Timor-Leste, which totalled around 4.5 bcm in 2010. Roughly two-thirds of domestic production came from Western Australia, primarily linked to LNG projects sourced from the Carnarvon Basin. Gas production in Western Australia has grown substantially in recent years. In 2009–10, the region’s gas production was 33 bcm, representing an increase of 11% over the previous year and an average annual rate of 5% over the previous five years.

Production of CSG has increased significantly in recent years, with its share of total Australian gas production increasing from 3% in 2003–04 to 10% in 2009–10. Most CSG production is sourced from Queensland, which accounted for approximately 97% of total CSG production in 2009–10. The Sydney Basin in New South Wales supplied the remaining 3%. Production of CSG is expected to continue to grow, with a number of projects planned in both states and a number of companies planning to export CSG in the form of LNG from Queensland from 2014 onwards.

Over the medium term, the production of gas is expected to continue to rise as developments now under construction or in the advanced stages of planning are
completed. Total production may exceed 75 bcm (3 028 PJ) by 2015. The Australian government’s long-term outlook is for gas production to reach nearly 220 bcm (8 505 PJ) by 2030, a 6.7% annual rate of increase. The majority of future conventional gas production is likely to be sourced from offshore basins in north, northwest and south-east Australia. Western Australia is projected to account for nearly two thirds of this increase.

Gas demand

Domestic gas consumption in Australia totalled some 32.8 bcm in 2010, compared to 31.4 bcm in 2009, the latest year for which data on consumption by sector is available. In that year, 33% of total gas use was consumed in the industry sector, which includes metal product industries (mainly smelting and refining activities), the chemical industry (fertilisers and plastics), and the cement industry. The transformation sector was the second largest gas user, representing 31%. Some 19% of gas was consumed in the energy sector, which includes amounts consumed in the production of LNG. The residential sector, characterised by a large number of small scale consumers where uses of gas include water heating, space heating and cooking, accounted for 11% of total gas consumption.

Natural gas demand is projected to grow at a rate of 3.4% annual over the coming two decades, reaching over 65 bcm (2 575 PJ) by 2030. This growth in demand is driven primarily by the electricity generation sector and the mining sector.

Gas fired electricity generation has been the largest factor driving gas consumption over the last decade, which grew annually by 4%. The share of gas-fired electricity has increased in recent years, accounting for an estimated 14% of electricity generation in 2009, compared to 8% in 2000.

Gas-fired electricity generation and its share in total electricity generation are projected to increase considerably over the period to 2030. Electricity generation from natural gas is projected to grow at an average rate of 5% per year, rising to 135 terawatt-hours (TWh) in 2029–30, from 36 TWh in 2009. The share of gas in total electricity generation is projected to grow from 14% in 2010 to 37% in 2029–30. In 2010, there were four natural gas-fired power stations with a combined capacity of around 800 MW under construction and a 630 MW coal seam gas fuelled gas-fired power station was commissioned.
Gas import dependency

Australia is a net exporter of natural gas. Until 1989, Australia consumed all of the natural gas that was produced domestically. Following the development of the North West Shelf, located in the Carnarvon Basin (off the northwest coast of Western Australia), Australia began exporting LNG to overseas markets. Since 2006, LNG has also been exported from Darwin in the Northern Territory. In 2009–10 Australia’s annual LNG export capacity was nearly 26.7 bcm (19.6 million tonnes).

LNG exports are expected to grow steadily from around 24.5 bcm as of 2009-10 to 82 bcm by 2015; LNG exports could exceed well over 140 bcm by 2030. In 2010 there were four LNG export projects representing 48 bcm under construction; one of which (Pluto) will start in 2011 and the three others (Gorgon, Gladstone LNG and Queensland Curtis) expected to start over 2014-2016. Two of these projects (Gladstone LNG and Queensland Curtis) are CSG-based projects located near Gladstone, in central coastal Queensland. Three of the four projects took Final Investment Decisions (FID) in 2009-2010. The FID of the Wheatstone project was taken in September 2011, and a few other projects (Australia-Pacific LNG, Shell Australia LNG, and Ichthys) could take FID in 2011-2012. Australia-Pacific LNG and Shell Australia LNG are also located near Gladstone.

Gas Company Operations

The Australian natural gas industry is largely privatised, with a handful of State/Territory governments fully or partly owning interests in gas retail companies. Certain aspects of the wholesale, transmission, distribution and retail industries are, however, regulated by both Australian and State and Territory Governments. Government regulation varies depending on the issues at hand, such as safety, competition and taxation. There is no local, state or Australian Government ownership or shareholdings in upstream gas projects.

Six major companies accounted for 72% of the domestic market in 2008-09. Santos and BHP Billiton each supplied 17%, ExxonMobil 12%, Woodside 12%, Origin Energy 9% and Apache Energy 5%.

In terms of gas retailers, South Australia, Victoria, Queensland and Western Australia have privatised their state owned retailers. While the New South Wales Government owns Ausgrid and Essential Energy, the gas retail sector is mainly in private hands.

In the 1990s, vertically integrated gas utilities were disaggregated and most government owned transmission pipelines were privatised. If transmission pipelines are determined to be anti-competitive, they are regulated under the National Gas Law and National Gas Rules. Major transmission pipeline companies include APA Group, Jemena and Epic Energy.

The major gas distribution systems in Australia are privately owned, but regulated by government to ensure gas can be transported on reasonable terms by third parties. There is some duplication between companies owning transmission and distribution networks, including Jemena and APA Group.
4.2 Natural gas supply infrastructure

Ports and Pipelines

The Australian domestic gas market consists of three distinct regional markets: the Eastern market (Queensland, New South Wales, Australian Capital Territory, Victoria, South Australia and Tasmania); the Western market (Western Australia) and the Northern market (Northern Territory). These markets are geographically isolated from one another, making transmission and distribution of gas between markets generally uneconomic and as a result gas production is either consumed within each market or exported as LNG. Australia’s gas production statistics exclude production from the Joint Petroleum Development Area with East Timor.

The Eastern domestic gas market is Australia’s largest consumer of natural gas, accounting for 64% of the country’s total domestic gas consumption. It also accounts for around 35% of the country’s total gas production (including for export as LNG), all of which is consumed within the region where electricity generation and the residential sectors make up the largest consumers of gas.

The Western gas market accounts for around 63% of Australia’s total gas production (including for export as LNG). The region is also a large consumer of gas, accounting for around 35% of...
Australia’s total domestic gas consumption. The electricity generation and manufacturing sectors account for the majority of gas consumption in the Western gas market. From 1989–90, the Western gas market produced significantly more gas than it consumed following the development of the North West Shelf Venture and the establishment of long term export LNG contracts.

The Northern gas market is the smallest producer and consumer of gas in Australia, accounting for 1.5% and under 1% of Australia’s gas production and consumption in 2010. Production began in the Northern gas market in the early 1980s through the development of the onshore Amadeus Basin. In 2005–06, production in the region increased significantly with the development of the Bayu–Undan field in the offshore Joint Petroleum Development Area with East Timor (most of the gas produced from Bayu-Udan is apportioned to East Timor but is processed into LNG in Darwin). Electricity generation and mining account for the majority of gas use in the Northern gas market. Until 2005–06, all of the gas produced in the region was consumed locally.

**Storage**

There are 4 underground natural gas storage facilities in Australia with a total capacity of 1.3 bcm of working gas. The Dandenong LNG Storage Facility in Victoria provides peak shaving and security of supply services for the Victorian transmission system as well as supporting wholesale trade in LNG used as fuel for transport vehicles.

<table>
<thead>
<tr>
<th>Storage site</th>
<th>Type</th>
<th>Working Capacity (bcm)</th>
<th>Peak Output (mcm/day)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mondarra, Perth Basin (WA)</td>
<td>Depleted gas field</td>
<td>127</td>
<td>5.0</td>
</tr>
<tr>
<td>Moomba, Cooper Basin (SA)</td>
<td>Depleted gas field</td>
<td>623</td>
<td>4.0</td>
</tr>
<tr>
<td>Newstead, Surat Basin (Qld)</td>
<td>Depleted gas field</td>
<td>234</td>
<td>-</td>
</tr>
<tr>
<td>Iona Field, Otway Basin (Vic)</td>
<td>Depleted gas field</td>
<td>308</td>
<td>5.2</td>
</tr>
<tr>
<td>Dandenong (Vic)</td>
<td>LNG peak shaving unit</td>
<td>17</td>
<td>6.0</td>
</tr>
<tr>
<td><strong>Total Australia</strong></td>
<td></td>
<td><strong>1,309</strong></td>
<td><strong>20.2</strong></td>
</tr>
</tbody>
</table>

1 Working gas capacity = total gas storage minus cushion gas
2 Peak output = the maximum rate at which gas can be withdrawn from storage

*Source: IEA Annual Gas Statistics*

There were proposals in 2011 for additional natural gas storage facilities in Australia, including plans to expand Mondarra, to develop additional underground gas storage in the east, and to develop an LNG storage facility in Newcastle.

Storage facility contracts and terms of access are worked out on a confidential bilateral basis between storage providers and customers. No public storage is held by the Australian Government.

**4.3 Emergency Policy for Natural Gas**

The management of temporary gas shortfalls is primarily undertaken by gas market participants and jurisdictional governments, depending on the nature and size of the event. For larger issues, each state and territory has legislation which confers emergency powers which may be exercised in natural gas emergency situations affecting only one jurisdiction.

In the case of a major gas crisis affecting more than one jurisdiction, the National Gas Emergency Response Advisory Committee (NGERAC) will advise energy Ministers across jurisdictions. The NGERAC is chaired by the Commonwealth, and includes government representatives from each jurisdiction as well as industry representatives. This includes producers, transmission system owners and operators, retailers, wholesale market operators, distribution network owners and operators, and major gas users.
Standing Committee on Energy and Resources (SCER) concluded in 2005 a Memorandum of Understanding setting out a National Gas Emergency Response Protocol which seeks to provide for more efficient and effective management of major natural gas supply shortages. The protocol provides guidance to gas suppliers, gas retailers, the natural gas market operator, and state and territory jurisdictions on their roles and responsibilities during natural gas supply shortages.

The legal framework for natural gas is the National Gas Law 2008. Additionally, the National Gas Rules governs access to natural gas pipeline services and elements of broader natural gas markets. The Rules have the force of law and are made under the National Gas Law.

**Strategic Gas Stocks and Drawdown**

There are no strategic stocks of natural gas in Australia, as there are neither government stocks nor requirements placed on grid owners, system operators and other industry participants to hold minimum reserves of natural gas.

**Demand Restraint**

In a gas crisis, system operators and market participants provide information on gas supply and demand, allowing NGERAC to assess the optimum allocation of gas to meet demand. NGERAC provides advice to jurisdictional Ministers, who are able to enact emergency powers within their corresponding jurisdictions. These powers can include issuing directions for production, transmission, distribution and allocation of natural gas.

NGERAC has rarely been convened, as the management of temporary gas shortfalls to date have been undertaken by market participants, natural gas system operators and State and Territory governments, depending on the nature and size of the event. For larger disruptions affecting only one jurisdiction, each State and Territory has legislation which confers emergency powers which may be exercised in a natural gas emergency. For emergency situations affecting more than one jurisdiction, NGERAC (or a sub-committee of the NGERAC) would be convened to consider the situation and provide advice to the SCER Energy Ministers.

**Fuel Switching**

There are no policies in Australia to promote fuel switching away from natural gas in an emergency. However during a gas crisis, power plants and large industrial customers can use a number of strategies, including fuel switching.

This was the case in June 2008 when a pipeline explosion at the Varanus Island processing terminal removed some 30% of Western Australia’s gas supply. While supplies were partially restored within a couple of months, complete restoration of supplies took some 12 months. During this time, mothballed coal-fired electricity plants were brought online and the use of diesel fuel generators helped moderate the rise in natural gas prices.
Other measures

The Council of Australian Governments, through the SCER Energy Ministers, has introduced a series of reforms to promote the on-going development of Australia’s gas industry. These reforms include:

• The National Gas Market Bulletin Board, which commenced in July 2008, is a website that publishes daily supply and demand data for transmission pipelines in the eastern states with the aim of facilitating trade in gas and pipeline capacity.

• The Gas Statement of Opportunities (GSOO) is an annual publication that provides 20 year forecasts of gas reserves, demand, production and transmission capacity for Australia’s eastern and south eastern gas markets. The GSOO will assist existing industry participants and potential new investors in making commercial decisions about entering into contracts and investing in infrastructure.

• The Short Term Trading Market (STTM) is a market-based wholesale gas balancing mechanism at defined gas hubs. This market uses bids, offers and forecasts to determine schedules for deliveries through the hub of gas between shippers and users. The STTM commenced at Adelaide and Sydney hubs in September 2010 with additional hubs to follow at other major demand centres, for example the Brisbane hub will be added on 1 December 2011. These STTM hubs are expected to increase price transparency in these markets by setting a daily price for gas.
The International Energy Agency (IEA), an autonomous agency, was established in November 1974. Its primary mandate was – and is – two-fold: to promote energy security amongst its member countries through collective response to physical disruptions in oil supply, and provide authoritative research and analysis on ways to ensure reliable, affordable and clean energy for its 28 member countries and beyond. The IEA carries out a comprehensive programme of energy co-operation among its member countries, each of which is obliged to hold oil stocks equivalent to 90 days of its net imports. The Agency’s aims include the following objectives:

- Secure member countries’ access to reliable and ample supplies of all forms of energy; in particular, through maintaining effective emergency response capabilities in case of oil supply disruptions.
- Promote sustainable energy policies that spur economic growth and environmental protection in a global context – particularly in terms of reducing greenhouse-gas emissions that contribute to climate change.
- Improve transparency of international markets through collection and analysis of energy data.
- Support global collaboration on energy technology to secure future energy supplies and mitigate their environmental impact, including through improved energy efficiency and development and deployment of low-carbon technologies.
- Find solutions to global energy challenges through engagement and dialogue with non-member countries, industry, international organisations and other stakeholders.

IEA member countries:

- Australia
- Austria
- Belgium
- Canada
- Czech Republic
- Denmark
- Finland
- France
- Germany
- Greece
- Hungary
- Ireland
- Italy
- Japan
- Korea (Republic of)
- Luxembourg
- Netherlands
- New Zealand
- Norway
- Poland
- Portugal
- Slovak Republic
- Spain
- Sweden
- Switzerland
- Turkey
- United Kingdom
- United States

The European Commission also participates in the work of the IEA.