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U.S. Energy Information  
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# Country Analysis Brief: Australia

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Last Updated: March 7, 2017

## Overview

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*Australia, rich in hydrocarbons and uranium resources, was the world's largest coal exporter in 2015 and the second-largest liquefied natural gas (LNG) exporter in 2015.*

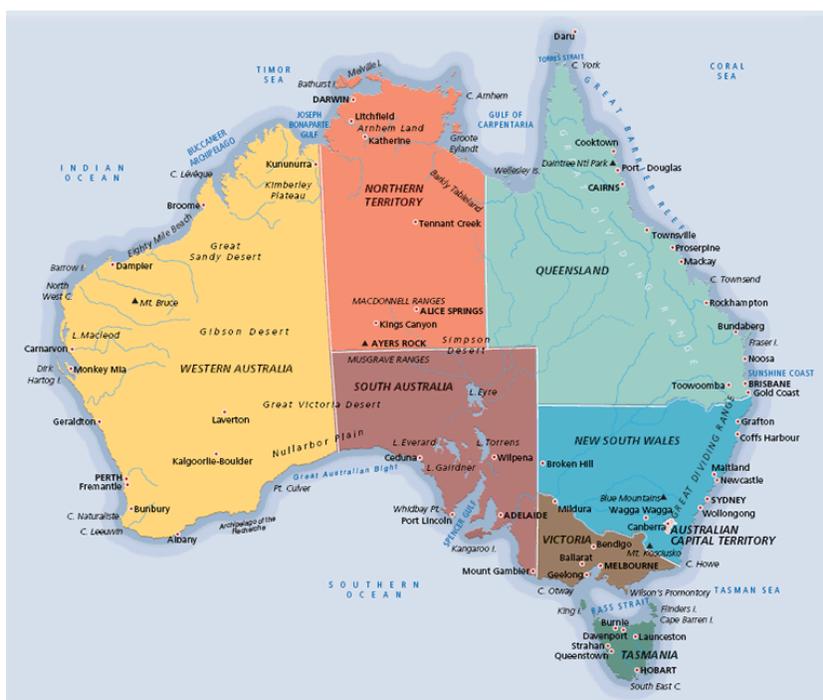
Australia is rich in commodities, including fossil fuel and uranium reserves, and is one of the few countries belonging to the Organization for Economic Cooperation and Development (OECD) that is a significant net energy exporter. Australia sent about 68% of its total energy production (includes uranium exports and excludes total energy imports) overseas in fiscal year 2015 (July 2014—June 2015), according to data from the Australian government.<sup>1</sup>

Except for crude oil and other liquids, Australia holds a surplus of all other energy commodities. In 2015, Australia was the world's largest coal exporter (based on both weight and energy content) and the second-largest exporter of liquefied natural gas (LNG). Energy exports accounted for 39% of Australia's total export revenues in fiscal year 2015.<sup>2</sup> The country holds the world's largest proved recoverable reserves of uranium (about 29%) and was the third-largest producer of uranium used for nuclear-powered electricity in 2015, according to the World Nuclear Association.<sup>3</sup> Although the country is rich in uranium, Australia has no nuclear-powered electricity generation capacity and exports all of its uranium production. Australia is a net importer of crude oil and refined petroleum products, although the country exports some petroleum liquids.

Australia's stable political environment, relatively transparent regulatory structure, substantial hydrocarbon reserves, and proximity to Asian markets make it an attractive place for foreign investment. The Australian government published an energy white paper in 2015 that outlines an energy policy that attempts to balance the need to secure domestic energy at affordable prices with increasing exports.<sup>4</sup>

This policy involves developing more resources and energy infrastructure, attracting foreign investment, fostering more competition, creating efficient and transparent energy markets and pricing mechanisms for consumers, streamlining regulations, enhancing energy technology innovation and skilled labor, and delivering cleaner and more sustainable energy to the domestic market. More recently, Australia's expanding energy industry has encountered escalating project costs and a shortage of labor. These factors, along with a bigger push for stricter environmental regulations in some states, low international commodity prices and their negative effect on revenues, and oversupplied regional markets pose challenges to investment in developing Australia's energy resources.

Figure 1. Australia's States and Territories



Source: University of Nebraska, Omaha

## Primary energy consumption

Australia has experienced limited energy demand growth because of lower levels of energy intensity compared with a few decades ago. Energy efficiency measures in many end-use sectors, technological advances, and a shift from heavy industries to a more service-sector oriented economy have resulted in a decrease in Australia's energy intensity.

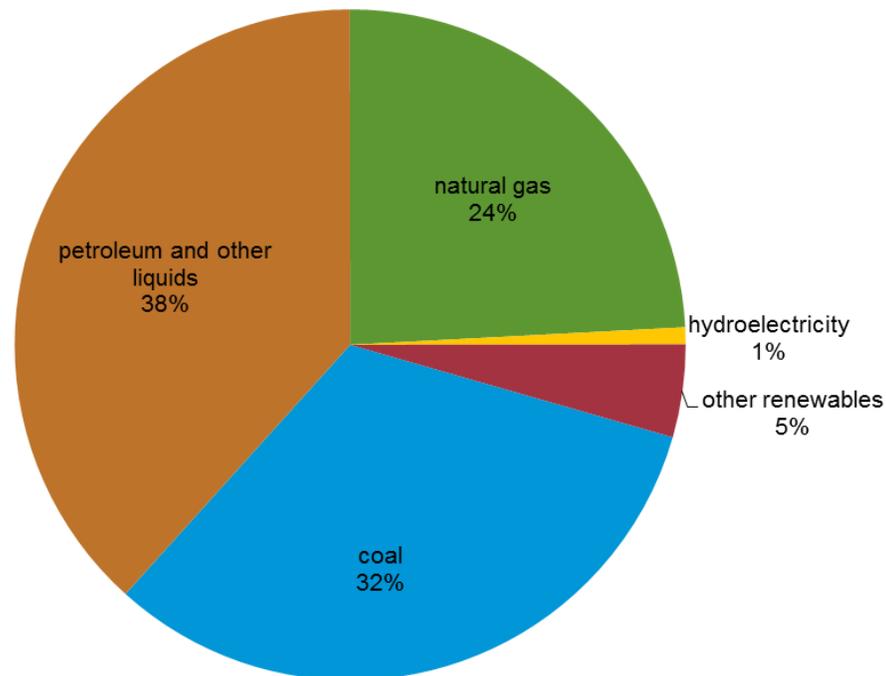
Australia is heavily dependent on fossil fuels for its primary energy consumption. In 2015, petroleum and other liquids accounted for an estimated 39% of the country's total energy consumption (Figure 2).<sup>5</sup> The share of oil consumption has risen in the past few years as it supports the country's commodity production growth, mining, and petrochemical industries as well as the transportation sector. The recent closing of some of the country's refineries and the high oil prices before 2015 caused a downturn in primary oil consumption relative to other fuels.

Coal and natural gas accounted for 33% and 24%, respectively, of the energy demand portfolio in 2015. The government promoted policies in recent years to reduce coal consumption, particularly in the power sector, in favor of cleaner fuels. The share of natural gas use has increased over the past decade, particularly in the electricity and mining sectors, and that fuel has replaced some coal and oil use. Renewable sources, including hydroelectricity, wind, solar, and biomass, accounted for slightly more than 5% of total consumption.

As part of the country's goal to reduce greenhouse gas (GHG) emissions by 2020, Australia implemented a fixed-price tax on carbon dioxide emissions to be paid by the top emitting companies in July 2012. This tax led to an increase in natural gas and renewable energy use, particularly in the electricity sector, and a replacement of coal-fired power. However, the carbon tax was repealed in July 2014 to remove the financial burden on industries that were required to pay for releasing emissions. The carbon tax put downward pressure on coal consumption during the two years of its existence, but the removal of this tax and low coal prices increased coal's fuel share in the energy balance. Australia's current energy policies may temper the expected pace of

growth in renewable energy use because these sources are currently more expensive to develop than fossil fuels. However, Australia announced a new GHG emissions reduction target of 26—28% from 2005 levels by 2030, which is likely to promote the use of cleaner fuels in the longer term.<sup>6</sup>

Figure 2. Australia's primary energy consumption, 2015



Note: Numbers may not add because of rounding.



Source: Australian Government, Department of Environment and Energy, *Australian Energy Update 2016*

## Petroleum and other liquids

*Australia's dependence on oil imports has increased to fill the growing gap between domestic consumption and production.*

Australia held more than 1.8 billion barrels of proved oil reserves at the end of 2016, according to the *Oil & Gas Journal (OGJ)*.<sup>7</sup> The Australian government reported economic reserves, which include proved and probable reserves, of nearly 5.4 billion barrels (22% crude oil, 52% condensates, and 26% liquid petroleum gas (LPG)). Most Australian crude oil is a light, sweet grade, typically low in sulfur and wax, and therefore higher in value than the heavier crudes. Most of reserves are located off the coasts of the states of Western Australia (Carnarvon and Browse basins), Victoria (Gippsland basin), and the Northern Territory (Bonaparte basin). Onshore basins, mostly found in the Cooper basin, account for only 10% of the country's oil resources.<sup>8</sup>

Although Australia is not producing oil shale (defined as sedimentary rock containing solid organic content, such as kerogen, and not equivalent to shale oil or tight oil) on a commercial

basis, the country has resources of about 14 billion barrels of demonstrated or potential reserves (defined as not economic or proved reserves), mostly located in Queensland.<sup>9</sup> The majority of these reserves face technical and environmental challenges for commercial production. In 2008, Queensland's government issued a 20-year moratorium on oil shale mining at the McFarlane deposit and suspended other oil shale projects until the state reviews various technologies and environmentally safe methods of production. Queensland lifted bans on all production projects outside of the McFarlane deposit, but the state still reviews each project, applying strict environmental standards. Australia also holds shale oil or tight oil reserves, estimated to be about 16 billion barrels of unproved technically recoverable reserves, located in various areas of Australia, according to a U.S. Energy Information Administration (EIA) study on world shale oil and natural gas resources.<sup>10</sup>

## Sector organization

Australia's management of oil and natural gas exploration and production is divided between the states and the federal (Commonwealth) governments. Australia's states manage the applications for onshore exploration and production projects, and the Commonwealth shares jurisdiction over Australia's offshore projects with the adjacent state or territory. The Department of the Environment and Energy (responsibility transferred from the Department of Industry, Innovation, and Science in July 2016) and the Council of Australian Governments Energy Council function as regulatory bodies over Australia's petroleum sector. The National Offshore Petroleum Safety and Environmental Management Authority (NOPSEMA) oversees safety and the environmental performance of all offshore petroleum facilities.

International oil companies actively investing in Australia's upstream hydrocarbon developments include Chevron, Shell, ExxonMobil, ConocoPhillips, Inpex (Japan), and Total (France). Australian companies BHP Billiton, Woodside Petroleum, and Santos also own and operate upstream oil and natural gas developments. Other smaller domestic players in both the upstream and downstream markets include Origin Energy and Beach Energy.

To secure investment from international oil companies to develop many offshore blocks, Australia holds regular licensing rounds to release acreage for exploration each year. The recent 2016 release offered 28 blocks spanning 5 basins offshore in northwestern Australian. This release consists of 3 rounds, with closing dates running through March 2017.<sup>11</sup>

## Exploration and production

*Australia's overall oil production has fallen since 2000, although additions through condensate production and smaller crude oil developments are expected to offset declines in mature fields over the next few years.*

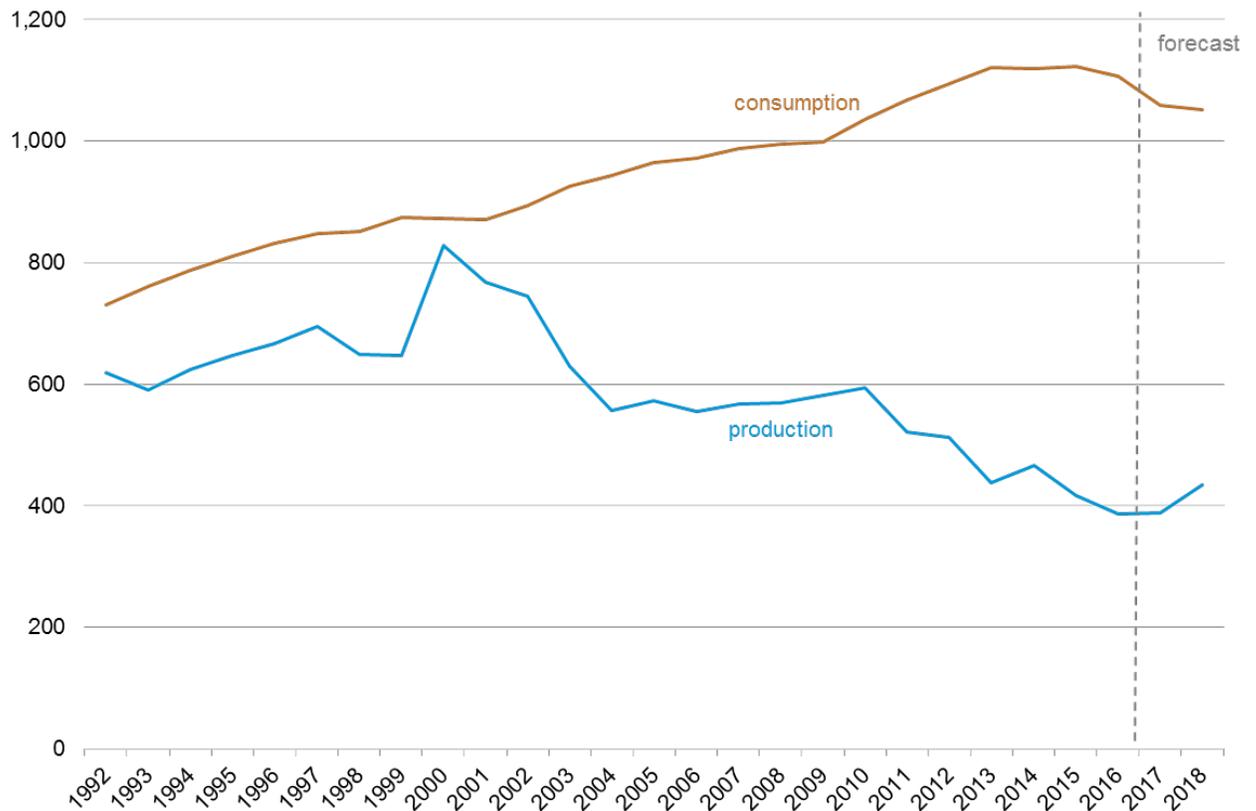
Australia's total liquids production peaked at 828,000 barrels per day (b/d) in 2000 and has declined overall since then (Figure 3). Petroleum and other liquids production has decreased from 467,000 b/d in 2014 to an estimated 387,000 b/d in 2016, of which about 43% consisted of crude oil, 32% lease condensates, and 16% natural gas liquids. The remaining 9% is from refinery gains and biofuels. The share of crude oil in the total oil stream has declined over the past decade and has been gradually replaced by condensates and liquids associated with natural gas production. Production from new, smaller offshore fields generally lasts less than 10 years and is not able to offset the production declines of larger, mature fields. New supply from upcoming condensate projects associated with natural gas developments is expected to boost overall output and offset some of the production declines during the next few years starting in 2017.

Unless Australia can materialize production in deepwater or tight oil plays, liquid fuels production is expected to fall in the long run. Since international crude oil prices plummeted in the second half of 2014, many E&P companies have reduced capital expenditures and drilling in certain areas, particularly offshore, because their revenue streams have declined considerably.

Exploration and drilling of wells in Australia's oil and natural gas basins, especially in the offshore areas, fell by half in 2015 over 2014.<sup>12</sup>

Figure 3. Australia's petroleum and other liquids production and consumption, 1992-2018

thousand barrels per day



Source: U.S. Energy Information Administration, *Short-Term Energy Outlook* March 2017

Australia's Carnarvon basin and the Bonaparte basin off the coast of northwestern Australia remain the busiest areas for overall oil drilling activity. Companies are also exploring in the frontier areas such as the deepwater zone of the Timor Sea. The Carnarvon and Perth basins offshore Western Australia accounted for 68% of crude oil and condensate production in fiscal year (FY) 2016 (July 2015–June 2016), according to Australia's government. The Bonaparte basin, located offshore in northern Australia, produced 7% of the country's crude oil and condensates. After a spike in drilling activity in the past decade, particularly in natural gas and oil condensate fields, several discoveries commenced production from these basins. Most of the oil production from Western and Northern Australia is exported.<sup>13</sup>

The area surrounding the Bass Strait, including the Gippsland basin (offshore southeastern Australia) is one of the oldest and most significant areas of oil production in the country, although production has declined substantially since the 1980s. This area produced only 42,000 b/d in FY 2016, down from nearly 70,000 b/d five years ago. Gippsland basin oil production, representing a 14% share of crude oil and condensate production in FY 2016, is predominantly refined for domestic use.<sup>14</sup> Onshore basins such as Cooper in the eastern half of the country have doubled production since 2010 and accounted for 11% of the oil production.

Condensate production, averaging about 130,000 b/d over the past decade, is expected to boost Australia's overall petroleum liquids production in the next few years. New LNG projects such as Gorgon, Wheatstone, and Ichthys are expected to support the country's natural gas exports and produce condensate as a by-product. Ichthys, a natural gas field heavy in condensates, could reach a peak production level of 100,000 b/d by 2020. Altogether, these new LNG projects are expected to add about 175,000 b/d by 2020.<sup>15</sup> The Northwest Shelf Project (NWS), one of the world's largest liquefied natural gas projects, is a significant source of Australia's light oil, LPG, and condensate production. Output at some of the fields is declining, and Woodside (the operator) is attempting to prolong the production life of the Northwest Shelf oil fields.<sup>16</sup>

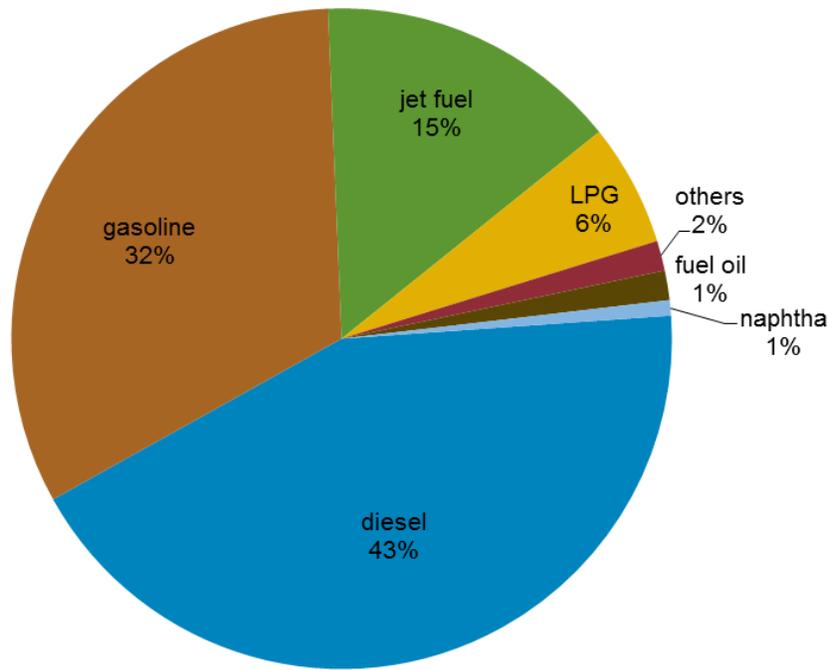
The only crude oil project under development is the Greater Enfield Project in Western Australia. Woodside approved the financial investment in June 2016 and plans to tie the production of the Laverda and Cimatti fields to the existing Vincent oil field. Additional output could be about 40,000 b/d and begin in mid-2019.<sup>17</sup>

## Consumption

Australia's consumption of petroleum and other liquids has exceeded domestic production for several decades. Australia's petroleum consumption has risen slightly at a rate of 1% per year since 2006, reaching an estimated 1.1 million b/d in 2015 and 2016. Oil demand has been relatively flat since 2013 because of higher vehicle energy efficiency, Australia's mature economy, and a slowdown in manufacturing and export-led industries. The transportation sector is the country's largest oil-consuming sector, accounting for the bulk of demand in 2016.<sup>18</sup> Other key consuming sectors are mining and agriculture. In the past few years, the country's focus on developing its vast hydrocarbon reserves and exporting energy commodities has boosted petroleum consumption required to operate remote mines and to extract resources.

Diesel fuel holds the largest market share of refined oil product consumption (43% in 2015) and is used mostly for transportation and for the country's sizeable mining industry (Figure 4).<sup>19</sup> Jet fuel consumption has also increased in the past several years as a result of rising air travel for commercial and tourism purposes.

Figure 4. Australia's petroleum demand by product, 2015



 Source: FACTS Global Energy

## Oil Trade

Australia is a net importer of both crude oil and oil products because its consumption of both energy sources exceeds overall production. In 2016, net crude oil imports were about 100,000 b/d, according to shipping data,<sup>20</sup> and net oil product imports were estimated at more than 480,000 b/d, according to FACTS Global Energy.<sup>21</sup> The country's northern and northwestern regions rely on oil product imports because they lack sufficient domestic refining capacity, while the eastern part of the country imports crude oil for their refineries and domestic markets. More than half of Australia's oil product imports are from Singapore and South Korea, with most of the remaining imports coming from refiners in Japan, China, and India.<sup>22</sup> Most of the country's crude oil imports (nearly 350,000 b/d in 2016) are from Southeast countries, making up about 66% of the total import volumes, according to tanker tracking data. Another 11% of crude oil imports in 2016 came from Africa, namely Congo and Gabon. The Middle East accounted for 14% of Australia's crude oil purchases, primarily from the United Arab Emirates.

Because the majority of Australia's oil production is located off its Northwest coast, away from its refineries in the East, Australia exports the bulk of its crude oil and condensates to other Asian refineries or to countries such as Japan or China that burn crude oil in electric power plants. In 2016, Australia exported 192,000 b/d of crude oil and condensates, most of which were shipped to Singapore, China, Thailand, Malaysia, and Indonesia.<sup>23</sup> Australia exports only small quantities of oil products, mainly LPG.

## Refining

After recent streamlining of the refining industry, Australia had four major refineries as of 2016, with a total crude oil refining capacity of 414,000 b/d operated by BP, ExxonMobil, Shell, and Caltex Australia.<sup>24</sup> Crude oil feedstock for these refineries comes from domestic oil produced in the Bass Strait offshore of southeastern Australia and from the country's crude oil imports. Refining output met less than 50% of domestic demand in 2015, down from 80% in 2005.<sup>25</sup> Diminishing refining capacity is prompting Australia to import even more petroleum products.

Australia's refining margins have tightened, and major refiners have incurred financial losses as a result of increasing refinery competition within Asia, Australia's high labor and operating costs, stricter environmental standards on transportation fuels, and previous higher prices of imported crude oil before mid-2014. Australia's refineries are small and outdated compared to the larger and more complex refineries being built within Asia. These unfavorable factors have pressured operators to close several facilities with more than 300,000 b/d of capacity and to convert some of them to oil product import terminals. Shell shut down the 85,000 b/d Clyde refinery, located near Sydney, in late 2012, which had contributed to Australia becoming Asia's top diesel importer. Recent closures include Caltex's 125,000 b/d-Kurnell refinery (located near Sydney) at the end of 2014 and BP's 95,000 b/d Bulwer Island facility in 2015. Shell sold its 105,000 b/d-Geelong refinery to oil trading company Vitol in 2014, leaving the fate of this refinery uncertain. Overall, these refinery closures, representing more than 40% of the operating capacity a few years ago, led to higher petroleum product imports, particularly for middle distillates such as diesel, gasoline, and jet fuel.

## Natural gas

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*Australian natural gas production has increased sharply over the past decade as a result of new projects.*

Australia produces enough natural gas to cover its consumption and to be considered a leading gas exporter. Several recent discoveries and growing regional demand for natural gas have spurred more investment activity in the country's reserves. Australia's natural gas reserves vary by industry source and the category of commercial viability. According to *OGJ*, Australia's proved natural gas reserves were more than 30 trillion cubic feet (Tcf) as of December 2015.<sup>26</sup> Geoscience Australia estimated total proved plus probable commercial reserves at 114 Tcf (62% conventional natural gas, 38% coal bed methane (CBM), and less than 1% tight gas) as of 2014. Almost all conventional gas resources (about 95%) are located in the North West Shelf (NWS) offshore in the Carnarvon, Browse, and Bonaparte basins and in the Gippsland basin in the southeastern region.<sup>27</sup>

CBM resources, equivalent to about 43 Tcf, are primarily located in the northeastern Queensland Province in the Bowen Basin and the Surat Basin. Geoscience Australia anticipates the resource distribution of natural gas will shift from the offshore traditional gas production to CBM or other sources in the next few decades because key CBM developers are aggressively exploring and drilling in several areas.<sup>28</sup>

In addition to CBM resources, Australia had an estimated 429 Tcf of unproved technically recoverable shale gas reserves in 2013, according to an [EIA study](#).<sup>29</sup> These resources are dispersed throughout the country in the inland Cooper Basin, the eastern Maryborough Basin, the offshore southwestern Perth Basin, and the northwestern Canning Basin.

## Sector organization

The Department of the Environment and Energy and the Council of Australian Governments Energy Council function as regulatory bodies over Australia's natural gas sector, similar to how the upstream petroleum industry is governed. Management of natural gas exploration and production is divided between the states and the federal governments, depending on the jurisdiction.

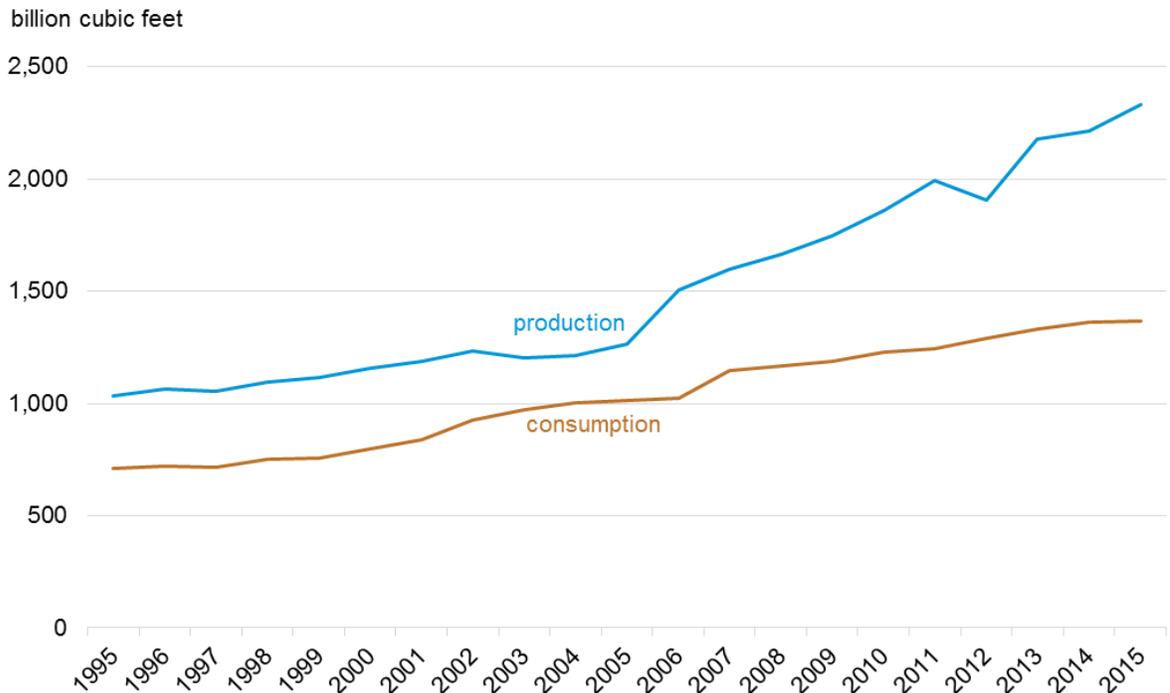
The Australian Energy Regulator oversees the natural gas pipeline networks in all states with the exception of Western Australia and Tasmania. The transmission and distribution network is largely privately-owned and operated, and several major pipelines are only partly regulated or not regulated depending on the level of pipeline competition.<sup>30</sup>

Major domestic and foreign companies operating in Australia include Santos, Woodside, Chevron, ConocoPhillips, ExxonMobil, Origin Energy, BG Group plc, Apache Corporation, INPEX Corporation, Total, Shell, and Statoil. The recent stream of CBM for LNG projects in Australia has also attracted Asian companies such as Sinopec, China National Offshore Oil Corporation (CNOOC), Tokyo Gas, and China National Petroleum Corporation (CNPC) that are interested in purchasing LNG for markets in China and Japan as well as the upstream assets slated to supply these projects.

## Exploration and production

Natural gas production in Australia climbed to nearly 2.3 Tcf in 2015 from less than 1.2 Tcf in 2000 as a result of several new developments and strong natural gas demand in the regional market (Figure 5). Conventional natural gas is largely produced in the Carnarvon Basin offshore northwestern Australia, the Cooper Basin in central Australia, the Gippsland Basin in the southeastern Victoria Province, and the Bonaparte Basin in northern Australia. The Western Australia offshore region produced the largest share of total natural gas (63%) in 2015. The Victorian state in the southeastern region comprised less than 15% of the total natural gas production. Queensland and New South Wales (NSW), Australia's main sources for coal bed methane, made up roughly 19% of total natural gas production.<sup>31</sup> The remaining share came from the inland Cooper and Amadeus basins or small offshore fields in the northern Bonaparte basin.

Figure 5. Australia's dry natural gas production and consumption, 1995-2015



Source: U.S. Energy Information Administration, International Energy Agency

Many of Australia's new natural gas field developments are tied to liquefaction projects that have several export contracts in place to support the strong natural gas demand in Asia. Several major new LNG projects, using conventional and coalbed methane, have become operational in the

past two years, and a few are under construction. Many international and domestic companies operating in Australia have reduced upstream capital expenditures over the past year, and international LNG prices, which loosely follow oil price trends, have plummeted. However, natural gas export obligations and strong domestic demand for natural gas are likely to bolster production over the next several years.

### *Conventional natural gas*

The Carnarvon Basin holds some of the country's most mature and prolific fields, which are the prime sources for the North West Shelf (NWS) LNG terminal. Many of the fields that have long supplied the NWS project have reached maturity and are declining in output. The project partners have made several discoveries and developed a few new fields that can sustain production for the project until 2020. As part of the North Rankin Redevelopment Project, the NWS Project developers installed a new production platform, North Rankin B, in 2013 to recover the remaining low-pressure natural gas from the North Rankin and Perseus natural gas fields through 2041. Also, the NWS project participants commissioned the first phase of the Greater Western Flank Project, with the second phase expected online in 2019.<sup>32</sup> The NWS joint venture plans to commission the Persephone field in 2018. These additional fields are expected to offset production declines at the NWS LNG project until about 2020. The Amerada Hess Equus project, which has an estimated 4 Tcf of gas reserves, could provide backup feedstock and sustain production levels for the NWS terminal after 2020. Negotiations for gas purchase from the Equus project are underway.<sup>33</sup>

The Greater Gorgon fields, located approximately 80 miles off the northwest coast of Australia in the North Carnarvon Basin near Barrow Island, are collectively the country's largest known natural gas resource, with total recoverable reserves (proven and probable) of 37 Tcf. The project is led by Chevron, and other upstream shareholders include Shell, ExxonMobil, BP, and several Japanese utility companies. The project includes development of the Gorgon and Jansz-lo natural gas fields, with connection by subsea pipelines to Barrow Island at the Gorgon LNG processing facilities. The first train of Gorgon LNG started operations in 2016, and the partners expect two more trains to come online in 2017. One of the project's key features is injecting the fields' carbon dioxide (CO<sub>2</sub>) into deep formations beneath Barrow Island to reduce overall greenhouse gas emissions. Other projects neighboring the Gorgon Project are Wheatstone LNG (coming online in 2018) and Pluto LNG, which is already operational.

The Browse Basin is another key area of natural gas discoveries in offshore northern Australia where two liquefaction projects are under construction and a third has been proposed. The largest field in the basin, Ichthys, holds 12.8 Tcf of gas and 530 million barrels of condensate reserves and has a high carbon content compared with other Australian fields, apart from Gorgon. A 552-mile undersea pipeline will connect the fields to a new export LNG terminal to be built near Darwin. When the project becomes operational in 2018, its production is expected to be 400 billion cubic feet per year (Bcf/y) of LNG, 100,000 b/d of condensate, and 32,000 b/d of LPG.<sup>34</sup> The Prelude field, which holds less than 3 Tcf of recoverable gas reserves, is the key supply source for the Prelude LNG project.<sup>35</sup> The partners developing the Crux field received a five-year retention lease in 2013 and continue to discuss gas processing options, such as constructing a designated stand-alone floating LNG terminal or supplying gas to other projects such as Shell's planned Prelude LNG floating terminal. The stalled Browse LNG project has also delayed the development of the three fields slated to supply the terminal.

The Bonaparte Basin in the Timor Sea straddles the waters of Australia and East Timor and holds some undeveloped natural gas resources. ConocoPhillips is currently drilling fields at the Bayu Undan natural gas and condensate field that supplies the Darwin LNG facility. The Greater Sunrise development is part of the Joint Petroleum Development Area that straddles Australia and East Timor. This area has been disputed for more than a decade, and East Timor insists that any production be sent to a new liquefaction plant onshore in East Timor. The Hague's Permanent Court of Arbitration began arbitrations over the dispute of the maritime border near the Greater Sunrise oil and gas fields, which contains more than 5 Tcf of gas and 226 million

barrels of condensates. Development of these fields is likely to be delayed at least until the dispute is settled (slated for late 2017) and project economics are favorable for investment.<sup>36</sup>

### *Coalbed methane and shale gas*

Australia has sizeable, untapped natural gas resources in the form of coalbed methane (CBM), known as coal seam gas in Australia, and shale gas. Commercial production from CBM, which began in 1996, rose to 424 Bcf in 2015, 50% higher than in 2014. This production increase corresponds with the commencement of the country's first CBM-to-LNG export terminals in Queensland over the past two years.<sup>37</sup>

Several CBM projects in the Surat and Bowen basins are under development to serve three new LNG projects in Queensland. CBM wells typically produce less gas than conventional wells and at slower rates, requiring upstream partners to develop more fields to fulfill LNG requirements. Investors face challenges with project delays based on greater public resistance to potential environmental impacts. Australia is attempting to balance its dual interests of increasing investment and exploitation of these resources as well as developing them in a sustainable and environmentally safe way. NSW, Queensland, and the federal government have established environmental regulations, particularly those related to water use and disposal and land rights in CBM and shale gas projects. Queensland established more austere water safety and management policies for CBM producers in 2010. In 2013, NSW enacted a natural gas plan that restricts CBM production near residential areas and small industries.<sup>38</sup>

Vast shale gas reserves in Australia could boost natural gas production once developed. As noted above, EIA estimates that Australia has 429 Tcf of technically recoverable reserves, ranking the country seventh highest in the world, behind Canada, the United States, Mexico, China, Argentina, and Algeria.<sup>39</sup> Most of the exploration activity has focused on the Cooper Basin in the interior of the country, where most of the country's onshore conventional gas reserves are located. The basin has attracted many international oil companies with the financing and technical capacities to develop the shale reserves as well as many mid-sized companies. Santos drilled the first successful commercial shale gas flow at its Moomba field in the Cooper basin at the end of 2012.<sup>40</sup> However, reduced capital expenditures resulting from the low oil price environment have significantly slowed the country's shale gas exploration and development since 2014. Furthermore, Victoria State and Northern Territory have announced bans on unconventional gas exploration, posing significant risks for Australia's shale gas development.<sup>41</sup>

## Consumption

Even though Australia has experienced a steady rise in domestic natural gas consumption over the past decade, the market for domestic consumption of natural gas in Australia is somewhat limited. However, the government is interested in reducing carbon dioxide emissions through the use of cleaner fuels such as natural gas and renewables. Australia consumed less than 1.4 Tcf of natural gas in 2015, steadily rising about 35% over the past decade.<sup>42</sup> Domestic markets consume most of Australia's natural gas supply, but since 2005, production and LNG sales began expanding. The gap between Australia's natural gas supply and demand is expected to widen as most of the production growth in the next few years is slated to meet LNG export agreements.

Electric power is the major consumer of Australia's natural gas, with a 38% market share in 2014, according to government data. The second-largest consumer is the industrial sector, accounting for 31%. The mining sector accounted for 14%, and the residential sector's share was 11%. Commercial, agriculture, and other sectors account for the remaining shares.<sup>43</sup> The repeal of Australia's carbon tax in 2014 weakened growth in demand for natural gas, especially in the power sector. Inexpensive coal prices encouraged industries and power generators to shift to more coal-fired generation.

Natural gas prices in the domestic market have been low compared to international rates. However, rising LNG exports have created various supply-side cost pressures, especially in the eastern states of Queensland and Victoria. As natural gas contracts expire, suppliers are raising

prices to reflect the netback of global LNG markets and shortening the contract period. Since the Queensland CBM-to-LNG liquefaction plants entered service in 2014, price volatility in eastern and southern Australia increased significantly, concerning the industries in these states. Both the private sector and the government are taking steps to mitigate the risks and reduce domestic market uncertainties. These measures include expanding natural gas transmission pipeline capacity, building more pipeline interconnections and storage facilities, linking the Northern Territory to the eastern markets to enhance gas supply sources, developing more upstream gas fields, and improving gas supply hubs and transparency on spot trading markets.<sup>44</sup>

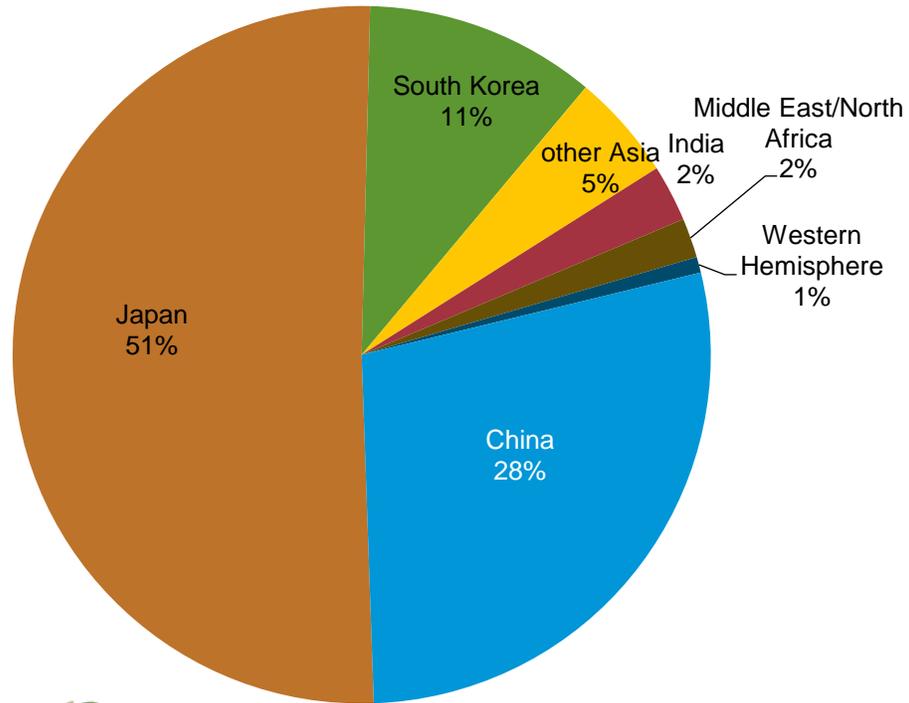
## LNG exports

*Australia has become a leading LNG exporter in the Asia-Pacific region in the past decade. Greater expected natural gas production and new LNG capacity in the next few years is likely to boost natural gas exports even higher.*

As a result of its abundant natural gas resources and its geographic proximity to consumer markets, Australia has become a leader of LNG supply for the Pacific basin. Over the past decade, Australian LNG exports have increased nearly three times, and they are expected to rise substantially in the medium term as developers usher in new upstream and liquefaction capacity. Australia became the second-largest LNG exporter in the world behind Qatar, surpassing Malaysia for the first time in 2015. Australia is poised to overtake Qatar as the world's largest LNG exporter by 2020 as capacity of its liquefaction terminals builds.<sup>45</sup> Exports rose to 2.1 Tcf in 2016, up from about 1.4 Tcf in 2015.<sup>46</sup>

Australia exports natural gas almost exclusively to Asian markets, with Japan purchasing about 51% of Australia's exports in 2016, mostly through long-term contracts (Figure 6). Australia became the largest source of LNG for Japan in 2012. Japan's demand for LNG rose in 2011 when natural gas-fired generation was substituted for the lost nuclear capacity following the Fukushima nuclear power plant accident. Other key consumers include China, South Korea, and Taiwan.<sup>47</sup> Chinese national oil companies (NOCs) own some stakes in several Australian liquefaction projects and plan to increase natural gas supply for the growing market in China. Australia also began supplying some of the new LNG demand markets in Southeast and South Asia and the Middle East. The Asian LNG market is currently oversupplied as regional demand has slowed. However, Australia is set to expand its LNG exports through long-term contracts and stronger LNG demand growth in Asia's emerging markets.

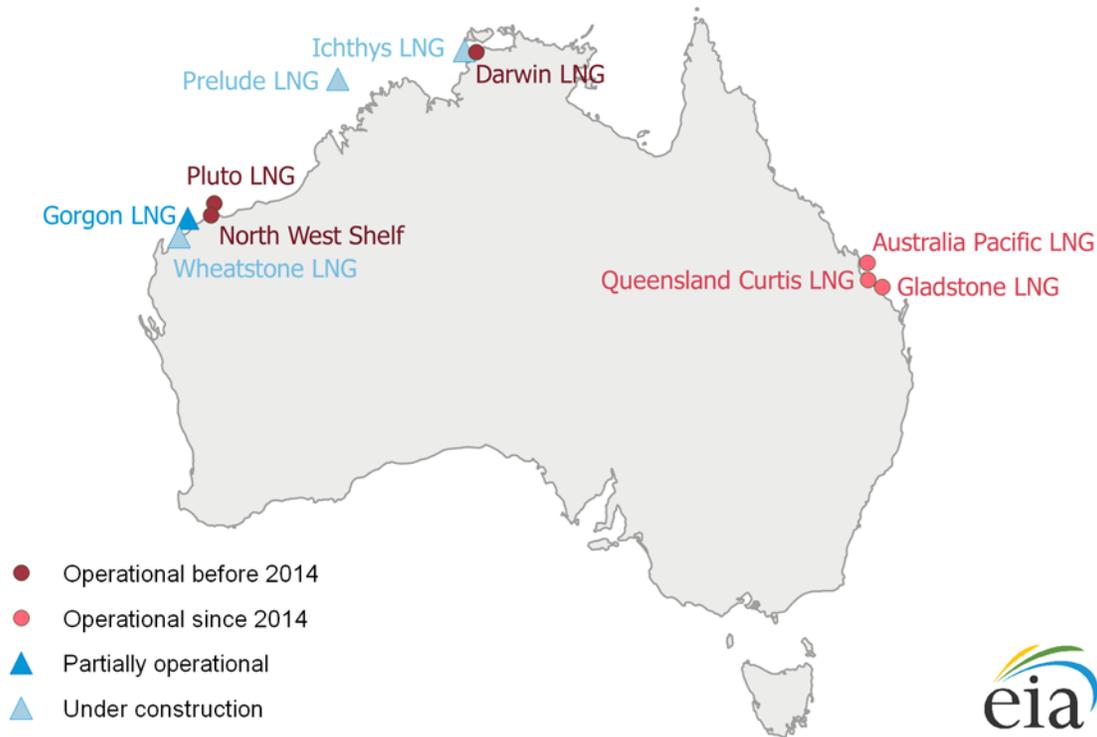
Figure 6. Australia's LNG exports, 2016



 Source: IHS Energy, Global LNG Trade Data

At the beginning of 2017, Australia had seven existing LNG export facilities with a total capacity of almost 2.9 Tcf/y (Figure 7 and Table 1). The largest and oldest LNG facility is North West Shelf LNG, owned and operated by a consortium of Australian and international oil companies. The facility, which became operational in 1985, has five offshore LNG trains with a total capacity of 808 Bcf/y. It relies on natural gas supplied from nearby fields in the country's prolific North West Shelf (NWS). In 2006, Australia commissioned Darwin LNG, located on Australia's northern coast. Natural gas from the Bayu-Undan field in the Timor Sea supplies the terminal. Pluto LNG, located in the country's northwestern offshore, came online in 2012. Project owners had discussed plans to increase capacity at both of these terminals, but difficulties procuring additional natural gas reserves and rising project costs posed challenges to future expansions.

**Figure 7. Australia liquefaction facilities (beginning 2017)**



As new LNG facilities and expansions of existing facilities have come online within the past few years, Australia's LNG export capacity has expanded substantially. The country commissioned about 1.7 Tcf/y of new capacity since 2014 from three coalbed methane projects in northeastern Australia and the Gorgon LNG project in northwestern Australia. CBM-to-LNG projects have become feasible with the sizeable amount of natural gas reserves associated with Australia's coal production. Queensland Curtis LNG became the world's first LNG project of this kind, followed by Gladstone LNG and Australia Pacific LNG. Although many companies are leveraging the vast CBM resources in Queensland to convert the fuel to LNG, CBM projects pose unique challenges to production. There are typically more hurdles for environmental approval of upstream production. Also, CBM wells produce much less than traditional natural gas wells, ramp up to peak production over a longer period, and have steeper decline rates once they reach their maximum output.

Australia has about US \$80 billion worth of LNG projects still under construction, and natural gas companies have already spent approximately \$130 billion on new LNG terminals commissioned since 2012.<sup>48</sup> As of the beginning of 2017, three new projects and one expansion project under construction in northwestern Australia are expected to begin production by 2019. Some projects, such as Ichthys LNG, are designed to produce associated petroleum condensates and LPG. Several proposed projects are waiting on regulatory approvals or final investment decisions. However, project owners have suspended or cancelled any projects not under construction until regional LNG market conditions become more favorable for investors.

Australia's burgeoning LNG industry has faced acute capital cost escalation, requiring much larger investments for new greenfield projects. High development costs, coupled with a low global oil and gas price environment during the past two years, competition for limited upstream natural gas supply, and an overcapacity of global liquefaction supply, have dampened the investment climate and prompted project owners to delay or cancel many proposed projects. Cost increases are attributed to a number of factors, such as: labor shortages and resultant high wages, high material costs, exchange rate appreciation of the Australian dollar between 2009 and 2013, more stringent environmental regulations, land rights issues, and the remote locations of some

projects. The following projects that recently came online or are currently under development have experienced notable cost inflation after their final investment decisions were announced: Pluto, Ichthys, Gorgon, Wheatstone, Gladstone, Queensland Curtis, and APLNG. Ichthys LNG, sanctioned in 2012, is currently the world’s most expensive liquefaction project on a per unit basis. Also, Chevron’s Gorgon LNG project, one of the most expensive LNG projects in the world, cited cost increases of 46% in U.S. dollar terms, escalating from \$37 billion at the time of the project’s final investment decision to \$54 billion.<sup>49</sup>

Australia is now facing LNG supply competition in an oversupplied global market. New liquefaction projects are coming online in Russia, the United States, and Africa, and weak global gas demand is creating excess gas supply and driving down international gas prices. Australia’s high-cost environment has prompted international companies to focus investments in more advanced export projects and has delayed, downsized, or cancelled projects that encountered greater regulatory challenges, lack of sufficient upstream reserves, or inertia from project partners.

Some of Australia’s LNG projects in the same vicinity face competition with each other for contracted natural gas supply and limited gas resources. In 2015, Shell cancelled the Arrow LNG project that competed with the other three CBM-to-LNG projects. Woodside Petroleum and their project partners indefinitely suspended development of a floating LNG terminal in the Browse basin off the northwest coast in March 2016 as a result of low gas prices and market oversupply.<sup>50</sup> Engie (formerly GDF Suez) and Santos revived the Bonaparte LNG project in 2015 after cancelling it in 2014. The partners revised the offshore floating LNG project to a less expensive design of a smaller, near-shore floating terminal as a result of the project’s rising costs and small gas resource base. The project is stalled because of the oversupplied LNG market.<sup>51</sup> ExxonMobil’s Scarborough LNG project is on hold because project partners have not agreed whether to move forward with a large floating terminal or to sell the upstream volumes to nearby LNG terminals. Woodside Petroleum purchased about half of BHP Billiton’s upstream assets slated for Scarborough LNG in 2016. Exxon holds a lease retention on the fields until 2020, when it plans to make a final investment decision on the project.<sup>52</sup>

**Table 1. Australia’s Existing and Planned Export Liquefaction Terminals**

Project name	Companies	Peak output (Bcf/y)	Status	Capital cost
<b>Existing LNG terminals</b>				
Northwest Shelf LNG	Woodside, Shell, BHP Billiton, BP, Chevron, Mitsubishi & Mitsui—16.7% each	808; 5 trains <sup>1</sup>	Operational	\$11.5 billion for T1-3; \$3.5 billion for T4; \$6.5 billion for T5
Darwin LNG	ConocoPhillips 57.2%, Santos 11.4%, Inpex 11.3%, Eni 11%, Tepco 6%, Tokyo Gas 3%	179; 1 train	Operational	\$3.84 billion

Pluto LNG	Woodside 90%, Kansai Electric 5%, Tokyo Gas 5%	214; 1 train	Operational	\$14 billion
Queensland Curtis LNG (CBM)	T1: BG 50%, CNOOC 50%; T2: BG 97.5%, Tokyo Gas 2.5%	411; 2 trains	Operational	\$20.4 billion
Gladstone LNG (CBM)	Santos 30%, Petronas 27.5%, Total 27.5%, Kogas 15%	377; 2 trains	Operational	\$18.5 billion
Australia Pacific LNG (CBM)	Origin Energy 37.5%, ConocoPhillips 37.5%, Sinopec 25%	435; 2 trains	Operational	\$25.5 billion
Gorgon LNG	Chevron 47.33%, ExxonMobil 25%, Shell 25%, Japanese gas & electric utilities 2.667%	503; 2 trains	Trains 1-2: Operational; Train 3 (251 Bcf/y): 2017	\$54 billion
<b>Projects under construction</b>				
Wheatstone LNG	Chevron 64.14%, Woodside 13%, KUFPEC (Kuwait) 13.4%, Japanese gas and electric utilities 9.455%	431; 2 trains	Q3 2017 - 2018	\$33 billion
Ichthys LNG	INPEX 63.45%, Total 30%, CPC 2.63%, Japanese gas and electric utilities 3.94%	431; 2 trains	Q3 2017 - 2018	\$37.4 billion
Prelude LNG	Shell 67.5%, Inpex 17.5%, Kogas 10%, CPC 5%	174; 1 floating terminal <sup>2</sup>	2018	\$11 billion
<b>Proposed projects</b>				
Browse FLNG	Woodside 31.23%, Shell 26.63%, BP 17.21%, PetroChina 10.23%, Mitsui 7.35%, Mitsubishi 7.35%	218; 3 floating terminals	FEED completed; Project suspended in March 2016	\$36 billion
Bonaparte FLNG	ENGIE 60%; Santos 40%	97; 1 floating terminal	Project revived in May 2015; modified for a nearshore barge design	\$5 billion

Abbot Point LNG	Energy World Corporation (100%)	49; 2 trains	Post 2020	N/A
Scarborough LNG	BHP Billiton 50%, ExxonMobil 50% (operator); Woodside acquired 50% of BHP Billiton's upstream assets related to this project in 2016. <sup>53</sup>	315; 1 floating terminal	Post 2020	N/A

1 A train is an independent unit for liquefaction and purification.

2 A floating terminal is one above an offshore gas field that produces, liquefies, stores, and transfers natural gas.

Sources: IHS Energy Liquefaction Projects Database and LNG Value Chain and Markets Service, FACTS Global Energy, International Energy Agency, company websites

## Pipelines

Australia's natural gas transmission pipeline network is well developed and transports gas from the key production centers to main economic hubs in the east. Significant investments since 2000 have expanded the gas network. The pipeline system interconnects all states except Western Australia and the Northern Territory because of their remote locations. Some pipelines transport gas from the country's inland fields to Darwin, Sydney, and the southeastern coast. In Western Australia, three major pipelines transport natural gas from northwestern gas fields to the southwestern region.

Rising natural gas prices in Australia, natural gas shortages (particularly in markets in the eastern region), and developments of various basins in other parts of Australia, are compelling the country to further connect its gas pipeline network. Jemena, a joint venture of China's State Grid Corporation and Singapore Power, is constructing the first pipeline to link the Northern Territory to markets in Queensland. The Northeast Gas Interconnector is scheduled to begin transporting gas in 2018.<sup>54</sup> Natural gas developments in offshore basins such as the Bonaparte basin in the Northern Territory and a completely integrated system would optimize natural gas transit to meet domestic demand and LNG export obligations in the eastern markets.

## Coal

*Australia is the world's largest coal exporter on a weight and energy content basis, and coal ranks as the second-largest export commodity for Australia in terms of revenue.*

Australia is one of the key sources of coal in the world, and the commodity plays a significant role in the country's economy. Australia was the largest coal exporter for more than two decades until Indonesia surpassed Australia in terms of coal exports on a weight-basis between 2011 and 2014. Australia recaptured the top position of highest global exporter in 2015. Metallurgical coal, used mostly for iron and steel production, is Australia's second-largest export commodity, behind iron ore, in terms of revenues. Australia exported about US \$28 billion worth of coal (both metallurgical and thermal coal used for power generation and other industries) in FY 2015, according to the Australian Bureau of Statistics.<sup>55</sup> Revenues have declined overall as a result of the weak global coal prices over the past few years.

In 2014, Australia held 117 billion short tons (Bst) of recoverable coal reserves, the fourth-largest in the world behind the United States, Russia, and China.<sup>56</sup> The Australian government estimates recoverable proved and probable reserves to be 138 Bst at the end of 2014, with about half from black coal and half from brown coal.<sup>57</sup> Black coal, which has a higher energy content, can produce more energy than the same volume of brown coal.

Australian coal is typically high quality with low ash content. Most of the country's coal is located in the eastern regions. Together, the states of Queensland and NSW (Sydney and Bowen basins) accounted for virtually all of Australia's black coal production in 2015, and Victoria (Gippsland basin) in the southeastern region accounted for 96% of brown coal production.<sup>58</sup> Black coal, which accounts for a vast majority of Australia's coal production, is typically exported, and brown coal, or lignite, is used largely for domestic electricity generation.

## Sector organization

A majority of Australia's coal production comes from open pit operations, and the remainder comes from underground mines, which allows Australia's coal mining to be more cost-efficient than many countries. International companies such as Glencore (UK-Switzerland), BHP Billiton, Anglo American (UK), Peabody (U.S.), and Rio Tinto (Australia-UK) play a significant role in Australia's coal industry. These top producers made up over 50% of the country's coal output in 2015.<sup>59</sup>

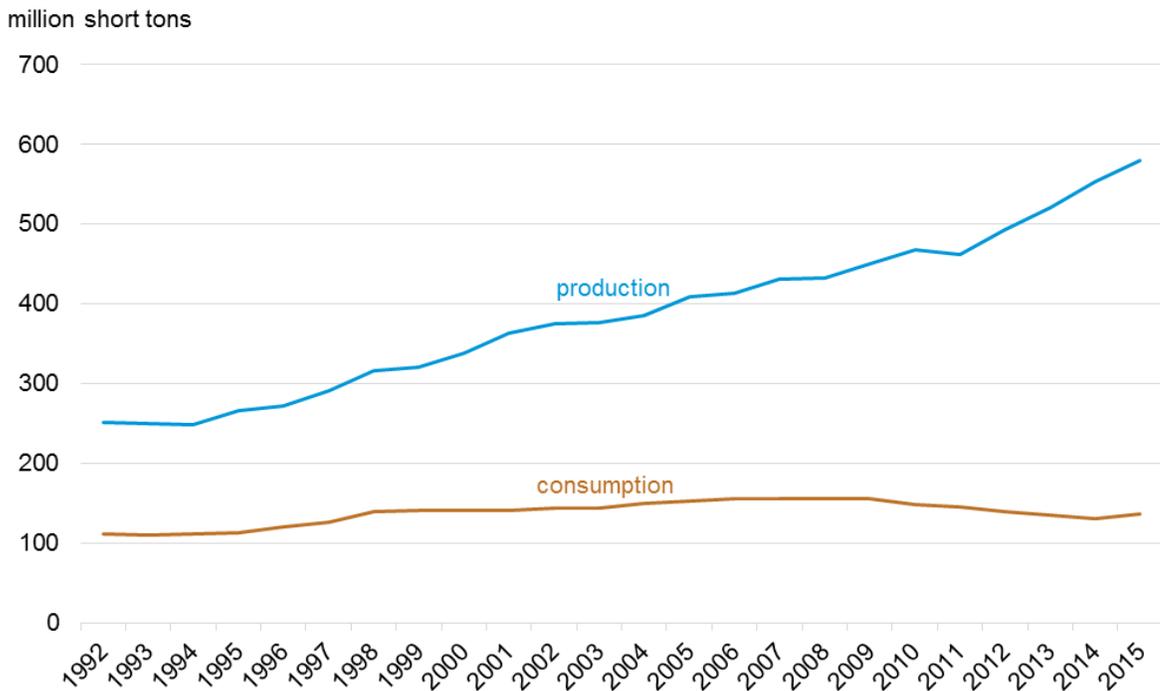
## Production and consumption

During the past decade, coal production in Australia has grown by 42%. Production has been supported by strong regional demand and investment in new mining and export capacity. In 2015, Australia produced an estimated 580 million short tons (MMst) of coal, up from more than 550 MMst in 2014 (Figure 8).<sup>60</sup> Most of Australia's coal is exported, and domestic demand accounted for less than one-quarter of total production. Coal output continued to expand in 2015 despite a dip in China's coal imports and the downward effects of low international coal prices in recent years. Since late 2014, several mine projects have been commissioned or brought back online, with new projects adding roughly 14 MMst. Other new projects, expected online in the next several years, could add another 32 MMst of capacity.<sup>61</sup> The depreciation of the Australian dollar since 2013 helped offset some of the high costs facing mining companies as a result of the steep drop in coal prices.

However, plummeting coal prices over the past five years have discouraged investments, and exploration expenditures fell 37% in 2015 from the prior year.<sup>62</sup> Mine suspensions and closures have continued through the first half of 2016, which is dampening coal production growth. Although, some mines have become more efficient in reducing their operational costs and have been able to sustain the same level of output.<sup>63</sup> The amount of exploration investments and regional coal market conditions could affect production levels over the longer term.

Coal plays a major role in meeting domestic energy needs, accounting for approximately 63% of Australian electricity generation in 2015, according to government statistics.<sup>64</sup> In the past several years, Australia has focused on substituting some coal-fired generation with natural gas and renewable power, resulting in a drop in coal consumption since 2009. Following the carbon tax repeal in 2014, coal consumption edged up slightly in 2015. Coal remains a baseload source for power generation because of the country's abundant resources and sophisticated infrastructure. The future of coal in the country's power generation will depend on environmental policies and on the cost competitiveness of coal relative to other sources of electricity generation.

Figure 8. Australia's coal production and consumption, 1992-2015



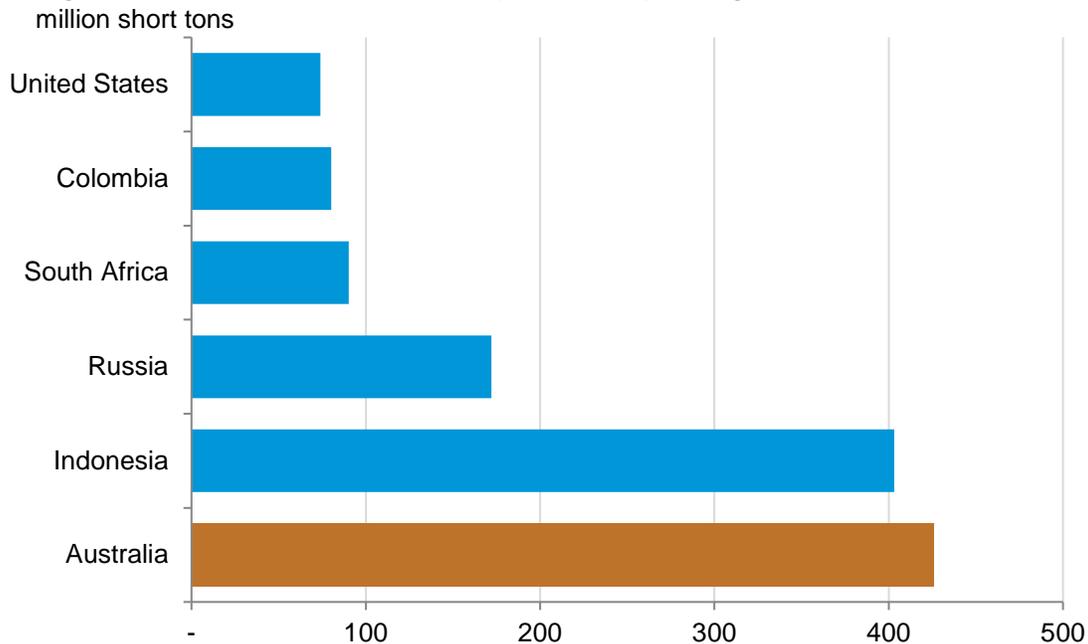
Source: U.S. Energy Information Administration, *Australian Energy Update 2016* (Australian Government, Department of Energy, Innovation, and Science)

## Exports

Australia is focused on increasing exports to satisfy higher energy demands throughout Asia, particularly in key growth markets such as China, India, and Southeast Asia. Australia reclaimed its long-term status of the world's highest coal exporter on a weight basis in 2015 after falling second to Indonesia between 2011 and 2014 (Figure 9).<sup>65</sup> Total coal exports, which amounted to almost 427 MMst in 2016, remained relatively flat from the level in 2015. Japan purchased almost one-third of Australia's coal exports in 2016. China, Australia's second-largest market for exported coal, accounted for 19%. Other key markets included South Korea (13%), India (12%), and Taiwan (9%).<sup>66</sup> Coal imports from China dropped sharply in 2015 when that country's economic growth slowed, their government imposed greater environmental restrictions, and there was a policy push for greater use of renewables and cleaner fuels. However, China's tightening of its own coal production prompted their industries to import more Australian coal in 2016. Australia shipped more coal to Japan and South Korea in 2015. However, overall electricity demand in Japan and South Korea declined and some nuclear power generation returned to service, reversing some of their higher coal import shipments from Australia in 2016. Most exports are from the Queensland and NSW states, although Western Australia began exporting small amounts of coal in 2007.

Coal exports are serviced by nine major coal ports and export terminals located in Queensland and NSW. In 2015, these terminals had a combined handling capacity of 587 MMst. New port infrastructure projects, including the Wiggins Island Coal Terminal and an expansion of the Hay Point Coal Terminal, added 42 MMst to annual coal loading capacity in 2015.<sup>67</sup> Several proposed project expansions are on the table, but development will depend on the investment climate and future coal demand.

Figure 9. World's top coal exporters by weight, 2015



Source: U.S. Energy Information Administration and United Nations, Comtrade,

## Electricity

*Although fossil fuels, chiefly coal, supplied about 84% of Australia's electric generation in 2015, a push for cleaner and more renewable power has occurred in the last few years.*

Australia's demand for electricity has gradually risen over the past two decades as a result of a well-developed economy and a robust mining sector. However, electricity consumption has weakened since 2011 as a result of higher electricity costs, a slowdown in manufacturing growth, and energy efficiency gains in the demand centers of Eastern Australia. Mining demand and off-grid expansions in Western and Northern Australia and the startup of new liquefaction projects offset some of the electricity demand reductions. Electricity generation increased from about 225 terawatt-hours (TWh) to 252 TWh between 2002 and 2015, according to Australia's government data.<sup>68</sup>

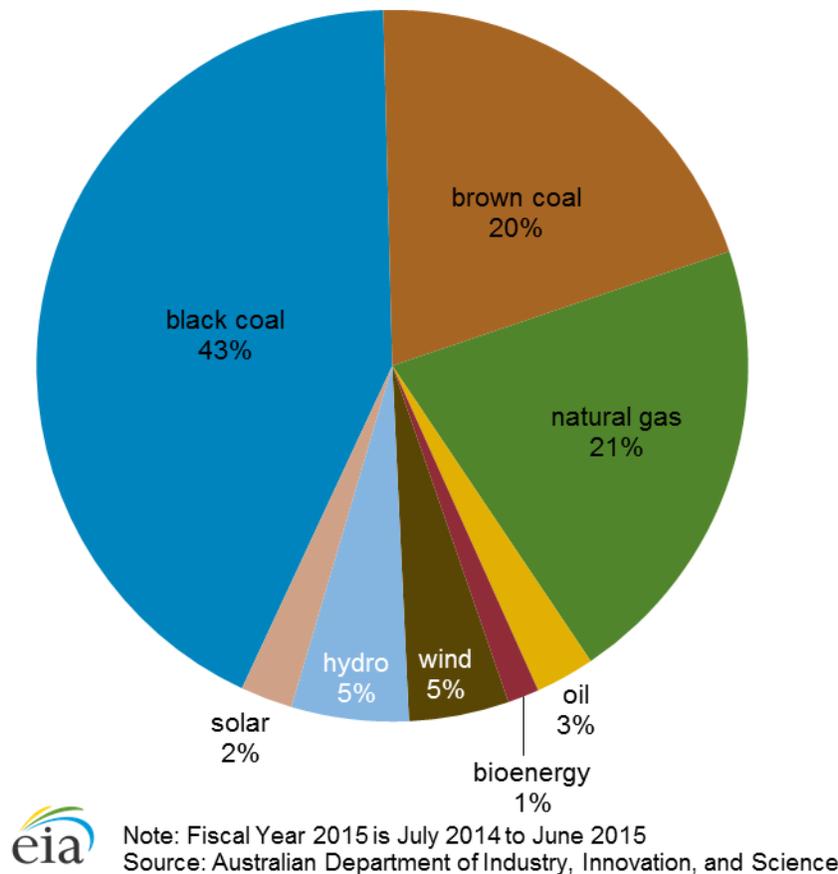
Australia's electricity generation is mostly from fossil fuels, with coal making up 63% of total electric power generation in 2015 (Figure 10). The use of coal-fired generation rose until 2009 and since then has yielded some share to natural gas, hydroelectric, and other renewable energy in the past few years. Natural gas-powered generation is mostly used during intermediate and peak demand times and supplied 21% of total electricity generation. Natural gas-fired generation capacity is highest in Queensland where natural gas is used in the LNG and other industries. Over the past decade, investment in natural gas-fired plants has increased overall, but use of natural gas fell in 2015 because of domestic coal prices were lower.<sup>69</sup>

Hydroelectricity, accounting for 5% of total electricity generation in 2015, occurs in the states of Tasmania, Victoria, and NSW.<sup>70</sup> Hydroelectricity is Australia's largest source of renewable

energy, although it has limited growth potential because of water availability constraints. The country's hydropower market is fairly extensive, and development opportunities exist only for smaller projects. In 2015, hydroelectricity use dipped because of drought conditions in southern Australia.

Other renewable sources, such as wind, bioenergy, and solar, have rapidly grown from less than 1% of the electricity generation portfolio in 2000 to more than 8% in 2015.<sup>71</sup> Wind energy, the second-largest renewable source for electricity, has grown substantially in the past decade and accounted for 5% of total power generation in 2015. Solar power also experienced substantial growth over the past few years as a result of the government's promotion of small-scale renewable energy projects and off-grid residential solar use. Australia's Renewable Energy Target introduced in 2009 aims to help the government achieve the goal of meeting 20% of the country's electricity production with renewable energy sources by 2020, up from almost 14% in 2015.<sup>72</sup>

Figure 10. Australia's electricity generation by source, 2015



Australia's electricity grid is well established in the eastern and southern states under the National Electricity Market (NEM), a wholesale market that connects five Australian states and the Australian Capital Territory. The NEM infrastructure is owned by a mixture of state-level governments and the private sector. Western Australia and the Northern Territory each have separate transmission networks. In addition, Australia has expanded its off-grid electricity generation (accounting for 17% of electricity supply in 2015) for use in the remote mining areas and rooftop solar installations in the residential sector.<sup>73</sup>

Retail electricity prices in Australia roughly doubled between 2007 and 2013 as part of an effort to finance infrastructure upgrades and investment in system reliability as well as to support renewable energy tariff programs. The carbon tax in effect between 2012 and 2014 also resulted in higher electricity generation costs. According to the Australian Energy Regulator, electricity prices have dropped considerably in 2015 for most states, apart from tariffs in Queensland, as a result of the carbon tax repeal and lower overall electricity demand.<sup>74</sup>

## Notes

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- Data presented in the text are the most recent available as of March 7, 2017.
- Data are EIA estimates unless otherwise noted.

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<sup>3</sup> World Nuclear Association, [Supply of Uranium](#) (updated December 2016) and [Australia's Uranium](#) (updated December 2016).

<sup>4</sup> Australia's Department of Industry, Innovation, and Science, [The Energy White Paper](#), April 8, 2015.

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<sup>10</sup> U.S. Energy Information Administration, [World Shale Resource Assessments](#), updated September 24, 2015.

<sup>11</sup> Australian Government, Department of Industry, Innovation and Science, [Offshore Petroleum Exploration Acreage Release](#)

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<sup>17</sup> Woodside Petroleum, [Australia Developments](#) (accessed January 2017); FACTS Global Energy, [Databook 1: Supply, Demand, & Prices](#), Spring 2016, page 101.

<sup>18</sup> FACTS Global Energy, [Asia Pacific Databook 1: Supply, Demand and Prices](#), Fall 2016, page 22.

<sup>19</sup> Australian Government, Department of Industry, Innovation and Science, [Energy in Australia 2015](#), page 102; FACTS Global Energy, [Asia Pacific Databook 1: Supply, Demand and Prices](#), Fall 2016, page 37.

<sup>20</sup> Lloyd's List, [APEX trade data](#) (accessed January 2017).

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<sup>56</sup> U.S. Energy Information Administration

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<sup>61</sup> International Energy Agency, Medium-Term Coal Market Report 2015, pages 124-125 and Medium-Term Coal Market Report 2016, pages 107-108; Australia’s Department of Industry, Innovation, and Science, Office of the Chief Economist, [Resources and Energy Quarterly](#), June 2016, page 40.

<sup>62</sup> Australia’s Department of Industry, Innovation, and Science, Office of the Chief Economist, [Resources and Energy Quarterly](#), March 2016, pages 67.

<sup>63</sup> Australia’s Department of Industry, Innovation, and Science, Office of the Chief Economist, [Resources and Energy Quarterly](#), June 2016, pages 39-40, 47-48 and September 2016, pages 41-42, 49-50.

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<sup>68</sup> Australian Government, Department of Industry, Innovation and Science, [Australian Energy Update 2016, Table O](#).

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