‹ Countries

Australia

Last Updated: June 21, 2013 (Notes)

full report

Overview

Australia, rich in hydrocarbons and uranium, was the world's second largest coal exporter in 2011 and the third largest liquefied natural gas (LNG) exporter in 2012.

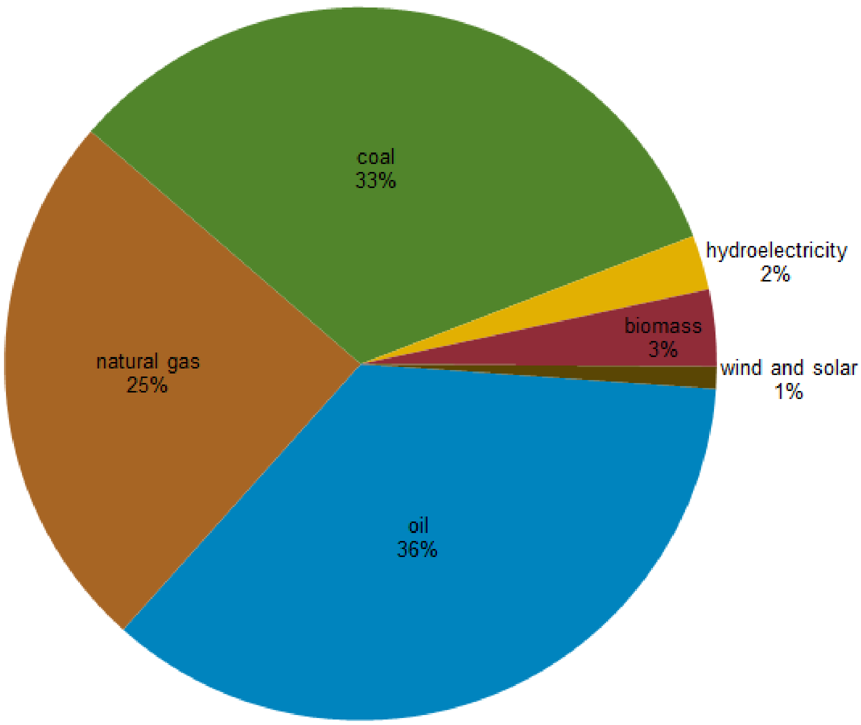
Australia is rich in commodities, including fossil fuel and uranium reserves, and is one of the few countries belonging to the Organization for Economic Cooperation and Development (OECD) that is a significant net hydrocarbon exporter, exporting over 70 percent of its total energy production according to government sources. Australia was the world's second largest coal exporter based on weight in 2011 and the third largest exporter of liquefied natural gas (LNG) in 2012.

Australia is a net importer of crude oil and refined petroleum products, although the country exports substantial amounts of petroleum liquids. Hydrocarbon exports accounted for 23 percent of total commodity export revenues in 2011. The country holds the world's largest recoverable reserves of uranium (about 31 percent) and is the third largest producer and exporter of uranium for nuclear-powered electricity, according to the World Nuclear Association.

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 government published an Energy White Paper in 2012 that outlines its energy policy including balancing its priority of maintaining energy security with increasing exports to help supply Asia's growing demand for fuel. Both of these paths involve developing more energy infrastructure, attracting greater investment, enhancing efficient energy markets and pricing mechanisms for consumers, and delivering cleaner and more sustainable energy. More recently, Australia's expanding energy industry has been fraught with escalating costs and a shortage of labor. These, coupled with a bigger push for clean energy and stricter environmental regulations, are some challenges that domestic and international companies face in developing Australia's energy resources.

Australia is heavily dependent on fossil fuels for its primary energy consumption. In 2011, oil accounted for 36 percent of the country's energy used. Coal and natural gas were at 33 percent and 25 percent of fuel used, respectively. Renewable sources, including hydroelectricity, wind, solar, and biomass that are consumed on a lesser scale, accounted for about 6 percent of the total consumption. Although the country is rich in uranium, Australia has no nuclear-powered electricity generation capacity. The new carbon dioxide emissions tax implemented in July 2012 may lead to an increase in natural gas and renewables demand to replace some coal or oil used in power generation and transportation. The Australian government projects that the natural gas share of primary energy consumption will increase to 35 percent by 2035.

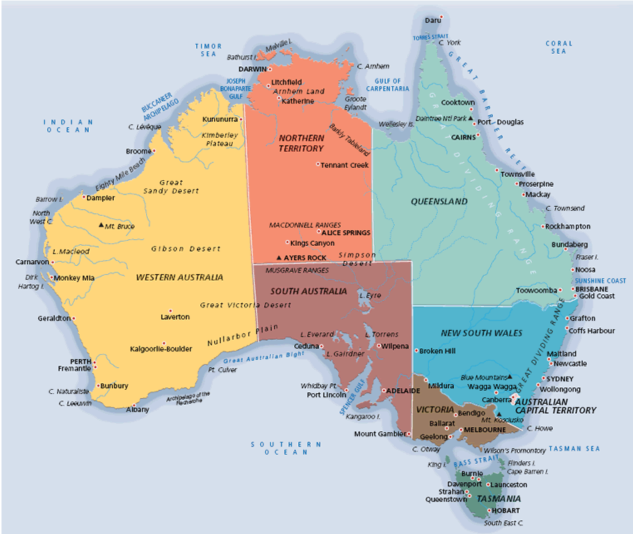
Australia's primary energy consumption, 2011



Source: EIA International Energy Statistics

Source: U.S. Department of State

Australia's States and Territories



Source: University of Nebraska, Omaha

Oil

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

According to *The Oil and Gas Journal (OGJ)*, Australia held over 1.4 billion barrels of proven oil reserves as of January 1, 2013. In 2011, Geoscience Australia reported economic reserves of 4 billion barrels, composed of 1 billion barrels crude oil, 2.1 billion barrels condensates, and 1 billion 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. The majority of reserves are located off the coasts of the states of Western Australia and Victoria and the Northern Territory. Onshore basins, mostly found in the Cooper basin, account for only 5 percent of the oil resources. Western Australia has 64 percent of the country's proven crude oil reserves, as well as 75 percent of its condensate and 58 percent of its LPG reserves. The two largest oil-producing basins are the Carnarvon Basin in the Northwest and the Gippsland Basin in southeastern Australia. While Carnarvon Basin production, accounting for 72 percent of total liquids production, is mostly exported, Gippsland Basin oil production, accounting for 24 percent, is predominantly used in domestic refining.

Although Australia is not producing oil shale on a commercial basis, the country has technically recoverable reserves of over 17 million barrels according to a recent EIA study on world shale oil resources. The majority of these reserves that are located in Queensland State face technical and environmental challenges for commercial production.

Sector organization

Australia's management of oil 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, while the Commonwealth shares jurisdiction over Australia's offshore projects with the adjacent state or territory. The Department of Resources, Energy and Tourism (RET) and the Ministerial Council on Energy (MCE) function as regulatory bodies over Australia's oil sector. As a result of the 2009 Montara field oil spill, Australia created a new offshore regulator to consolidate oversight for activity in this arena in 2011. This new body, the National Offshore Petroleum Safety and Environmental Management Authority (NOPSEMA) oversees safety and environmental performance of all offshore petroleum facilities.

International oil companies dominate the oil and natural gas exploration and development of the country. Chevron is the largest foreign oil producer supplying about 100,000 barrels per day (bbl/d). Other international oil companies actively investing in Australia's hydrocarbon developments include Shell, ExxonMobil, ConocoPhillips, Japex, Total, BHP Billiton, and Apache. There are Australian companies, the largest being Woodside Petroleum and Santos, and other smaller domestic players in both the upstream and downstream markets that include Origin Energy and Beach Energy.

Australia typically holds regular licensing rounds to release acreage for exploration each year. The 2011 and 2012 rounds are the largest releases in a decade. The 2012 release offered 27 offshore blocks across 9 basins of the states of Western Australia, Victoria, South Australia, Tasmania, and the Northern Territory. The Northwest Shelf near the city of Dampier off the northwest coast of Australia was a key area in this release. In addition, Western Australia held two separate licensing rounds in 2012 for 21 blocks including those in the Canning and North Carnarvon basins. The 2013 offshore petroleum exploration acreage release including 31 blocks on offer was issued in May 2013. These areas span six basins mostly in the offshore of Western Australia, the Northern Territory, and Victoria.

Exploration and production

Australia's oil production has declined overall since 2000. The country could stem production declines of mature basins in the short term through additions in condensate production and smaller crude oil developments.

Oil production totaled 484,000 barrels per day (bbl/d) in 2012, of which about 50 percent consisted of crude oil, over 28 percent lease condensates, and 13 percent liquids petroleum gas (LPG). The remaining production is from refining gains and biofuels. The share of crude 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. Total oil production in Australia peaked in 2000 at 828,000 bbl/d and has declined overall since then. According to the Australian Petroleum Production and Exploration Association (APPEA), liquid fuels production will continue to decline over the next decade unless more fields are discovered. Production from new fields has not been able to offset declines from mature basins.

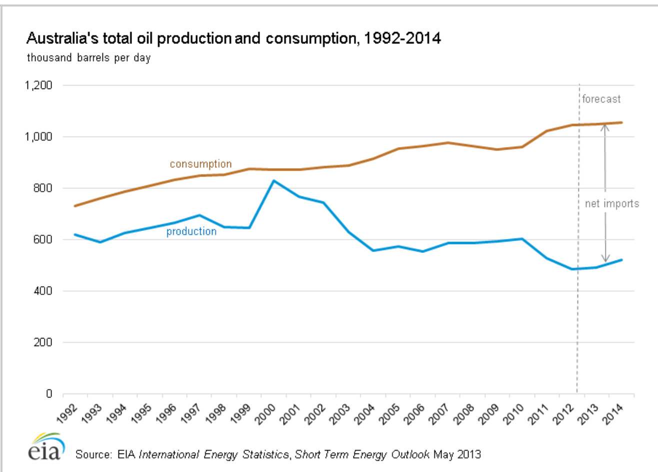
Australia's main frontier for oil exploration has moved in recent years to the deepwater area of the Timor Sea, although the nearby Carnarvon Basin off the coast of Western Australia remains the busiest area in terms of overall drilling activity. The offshore waters of Western Australia made up 77 percent of the total oil and condensate production in 2011. After a spike in drilling activity in the past decade, particularly in condensate fields, several significant discoveries are now in the process of being put into production.

Several oil fields, such as the Pyrenees, Van Gogh, Vincent, Enfield, and Stybarrow projects located offshore in Western Australia, were brought online between 2007 and 2010 and helped sustain crude oil production until 2011. The Pyrenees and Van Gogh projects have production capacities of 96,000 bbl/d and 63,000 bbl/d, respectively.

A number of smaller fields containing light and heavy sweet crude oil are under development and scheduled to come online by 2015. Following a large oil spill in 2009 at the Montara field, operator PTTEP (Thailand) is expected to restart production in 2013, and the field is slated to deliver 40,000 bbl/d. The Coniston and Novara fields have a production capacity of 22,000 bbl/d and are extensions of the larger Van Gogh field. The Balvanes, Fletcher, and Finucane fields in the Carnarvon basin will produce about 45,000 bbl/d in the next two years. The Kipper and Turum fields in the Gippsland Basin, southeastern Australia should start up by 2014 at 20,000 bbl/d. These additions to production will help to offset the declining output in other fields in the short term. However, some of these fields are expected to have short lives of less than 10 years.

Condensate production, averaging about 140,000 bbl/d over the last several years, is likely to boost Australia's overall oil production at least in the next five years. FACTS Global Energy projects that condensate production will rise to 300,000 bbl/d by 2018, over twice the current production rates of almost 140,000 bbl/d, once several onshore and offshore projects come online to support the LNG export endeavors. In the near term, the Crux field in the eastern section of the Browse basin will add about 38,000 bbl/d of liquids and process natural gas for upcoming liquefaction facilities. Other fields expected to augment condensate production by 2017 are Pluto, Gorgon, Wheatstone, Ichthys, and Prelude. Ichthys, a field heavy in condensates, could peak at 80,000 bbl/d.

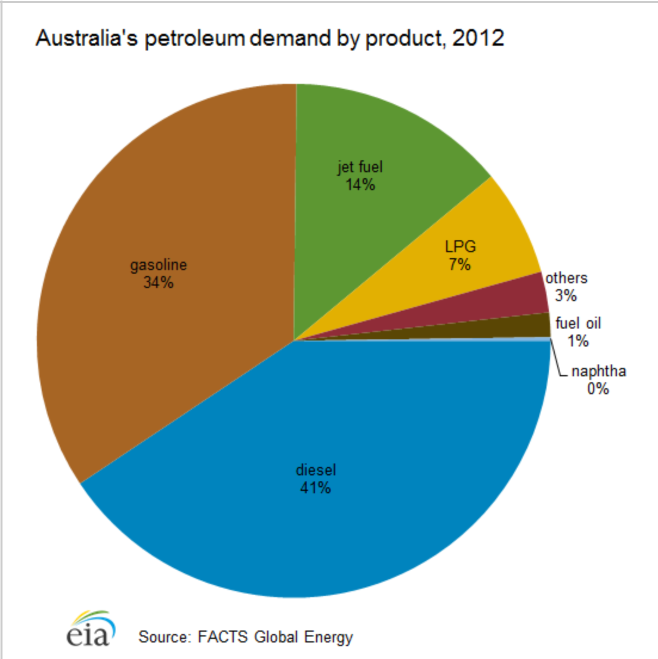
The Northwest Shelf Redevelopment Project intends to prolong the production life of the Okha (formerly known as Cossack), Wanaea, Lambert, and Hermes oil fields to 2020 and develop the remaining 88.2 million barrels of proven and probable reserves through the replacement of infrastructure. Production from Okha resumed in 2011 and rose to 60,000 bbl/d by 2012 after a new floating production, storage, and offloading facility was installed.



Consumption

As Australia's economy has grown due to increases in domestic consumption and exports to Asia, the country's petroleum consumption has risen steadily in the past decade by about 20 percent to over 1 million bbl/d in 2012. Petroleum consumption has been higher than petroleum production for several decades. Transportation is the country's primary oil consumer, with a 74-percent market share in 2010. Other key consuming sectors are mining, petroleum refining, and petrochemicals, which contributed to most of the growth in petroleum use in the past few years. Agriculture boosted its oil consumption in 2012 as a result of favorable weather patterns.

Diesel fuel holds the largest market share of refined oil product consumption (40 percent) and is used mostly in the industrial sector. Jet fuel consumption has also increased in the past several years due to rising air travel and tourism.



Pipelines

Australia has a well-developed domestic oil pipeline network, which is privately owned and operated. Epic Energy operates a 400-mile pipeline carrying crude and natural gas liquids from Moomba to Stony Point. Santos operates two major domestic pipelines that are used for carrying oil and oil products, which include the Jackson to Brisbane line that spans 500 miles, and the Mereenie to Alice Springs line that covers 167 miles. Esso Australia Ltd. operates the 115-mile Longford to Long Island Point pipeline.

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 2012, net crude imports were 234,000 bbl/d, and net product imports were 294,000 bbl/d, according to FACTS Global Energy. The country's north and northwest regions rely on oil product imports resulting from the lack of sufficient regional refining capacity, while the eastern side imports crude oil for its refineries and major domestic markets. Singapore supplies about 60 percent of Australia's oil product imports. Most crude oil imports come from Malaysia, Nigeria, United Arab Emirates, and Indonesia, altogether providing about 55 percent of the total imports in 2012. Another 22 percent comes from West Africa, as Nigeria, Congo, and Gabon have increasingly supplied crude to Australia over recent years.

Because the majority of Australia's oil production is located off its Northwest coast, Australia exports the bulk of its crude oil and condensates to other Asian refineries or to countries using direct crude burning in electric power plants such as Japan. According to the Australian Bureau of Statistics, in 2012, Australia exported 280,000 bbl/d of crude oil and condensates, which were sent to Singapore, South Korea, China, Japan, Thailand, and Malaysia.

Refining

According to *OGJ*, Australia has six major refineries as of 2013, with a total crude oil refining capacity of 675,648 bbl/d operated by BP, ExxonMobil, Shell, and Caltex. Crude oil feedstock for these refineries comes from domestic oil produced in the Bass Strait offshore of southeastern Australia in addition to increasing imports. Currently, only 17 percent of the feedstock comes from domestic crude oil, down from 37 percent a decade ago. Refining throughput meets an estimated 65 percent of domestic demand, and as refining capacity diminishes in Australia, this share will also decline.

Australia's refining margins have tightened as a result of increasing refinery competition within Asia, the country's escalating labor and operating costs, stricter environmental standards on fuels, and high prices of imported crude oil. Australia's refineries are small compared to the larger and more complex refineries being built within the region. These unfavorable economics have pressured operators to close certain facilities and convert them to oil product import terminals. ExxonMobil closed its Adelaide refinery in 2004. Also, Shell shut down the 85,000 bbl/d Clyde refinery, located near Sydney, in late 2012, which contributed to Australia becoming Asia's top diesel importer. Planned closures include Caltex's 135,000 bbl/d-Kurnell refinery by mid-2014 and potentially Shell's 120,000 bbl/d-Geelong refinery by the end of 2014. Shell is auctioning Geelong, and if a buyer is not found, it plans to close the refinery. These closures are likely to result in increases in petroleum product imports, particularly gasoline.

Natural gas

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

Australia produces enough natural gas to cover its consumption and be a leading gas exporter. Several recent discoveries and growing regional demand for gas have spurred greater 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 had over 43 trillion cubic feet (Tcf) of proven natural gas reserves in January 2013, rising 15 Tcf from 2012. In 2011, Geoscience Australia estimated total economic reserves at 136 Tcf (103 Tcf traditional natural gas and 33 Tcf of coal bed methane-CBM). Most of the traditional gas resources (about 92 percent) are located in the North West Shelf (NWS) offshore in the Carnarvon, Browse, and Bonaparte basins. Also, most of the traditional gas resources are from 10 super-giant fields even though there are nearly 500 fields included in the resource count.

CBM economic resources, located in the Northeast in the Bowen and Surat Basins, have doubled in the past 3 years to 33 Tcf in 2012. Geoscience Australia anticipates the resource distribution of gas will shift away from the offshore traditional gas production to the CBM or other sources in the next 2 decades.

Australia also had an estimated 437 Tcf of technically recoverable shale gas reserves in 2012, according to an EIA study Technically Recoverable Shale Oil and Shale Gas Resources. These resources are dispersed throughout the country: the inland Cooper Basin, eastern Maryborough Basin, the offshore southwestern Perth Basin, and the northwestern Canning Basin.

Sector organization

The domestic oil and natural gas industry is part of the private sector. The industry is regulated by the Department of Resources, Energy, and Tourism (RET) and the Ministerial Council of Energy (MCE). The MCE was created in 2001 to foster policy coordination between the Commonwealth and the state governments. The MCE functions as the national policy and governance body for the Australian energy market and comprises of ministers with responsibility for energy from the Australian government and all states and territories.

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. Chevron holds the largest amount of gas resources in Australia, and the company has made 21 discoveries in the prolific Carnarvon Basin since mid-2009, adding 10 Tcf to proven gas resources. The recent stream of CBM and shale gas and 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 not only gas for markets in China and Japan but also upstream assets slated to supply these projects.

Exploration and production

Natural gas production in Australia reached 1.6 Tcf in 2011, according to the International Energy Agency (IEA) and has increased overall from nearly 1.2 Tcf in 2000 as a result of new developments. Traditional natural gas is largely produced from the Carnarvon Basin offshore Northwestern Australia, the Cooper/Eromanga basin in central Australia, the Gippsland in the Victoria province, and the Bonaparte Basin in the joint production area shared between Australia and East Timor. The Western Australian offshore produced the largest share of total natural gas (56 percent) in 2011, while the Gippsland basin made up 17 percent according to APPEA. The Carnarvon basin supplies about a third of the domestic gas market and nearly all of the export market according to the Australian government. Queensland and New South Wales (NSW), Australia's main sources for coal bed methane, make up roughly a tenth of gas production and are discussed in greater detail below.

Much of Australia's new gas field developments are tied to liquefaction projects that will facilitate a greater export potential. Several major new LNG projects are under construction or in advanced planning stages to support Asia's increasing appetite for natural gas.

The North West Shelf of Australia in the Carnarvon Basin holds some of the country's most mature and prolific fields that are the prime sources for the North West Shelf LNG terminal. As part of the North Rankin Redevelopment Project, the NWS Project developers are investing about $4.8 billion to recover remaining low-pressure gas from the North Rankin and Perseus gas fields. Also, a new production platform, North Rankin B, will be installed in 2013 to support production of smaller fields and extend their development until 2040. Also, the NWS project participants approved the first-phase development of the Greater Western Flank Project containing up to 3 Tcf of gas and 100 million barrels of recoverable condensate. The project is expected to start in 2016.

The Greater Gorgon fields, located around 100 miles off the northwest coast in the North Carnarvon Basin, are collectively the country's largest known gas resource, and the Gorgon Project could encompass total reserves of 40 Tcf. The project, led by Chevron (50 percent), with Shell and ExxonMobil (25 percent each), is under construction and is on track to be completed in 2014. The project includes development of the Gorgon and Jansz-Io gas fields, with connection by subsea pipelines to Barrow Island, where gas processing facilities will have production capacity of 720 MMcf/y. Also planned are LNG shipping facilities to transport products to international markets, and greenhouse gas management via injection of carbon dioxide into deep formations beneath Barrow Island. The project is expected to annually produce 390 Bcf of LNG and 19 million bbl of LPG, as well as 100,000 bbl/d of condensate when completed. Another major project close to the Gorgon Project under development is the Wheatstone Project that began construction in late 2011. When complete in 2016, the first two trains of its LNG export plant are expected to export 430 Bcf/y.

The first stage of the Pluto Project near Karratha offshore Western Australia came online in March 2012, with estimated LNG capacity of 200 Bcf/y. Woodside Energy owns 90 percent of the venture supported by 15-year sales contracts with Kansai Electric and Tokyo Gas, which have 5-percent equity each. The Pluto project includes an offshore platform connecting 5 subsea wells and a 112-mile pipeline to an onshore LNG facility on the Burrup Peninsula. Plans for a second train are on hold as additional gas supplies are sought.

The Browse Basin Development Program is another key area of gas discoveries in offshore northern Australia. The largest field in the basin, Ichthys, holds 12.8 Tcf of gas and 527 million bbl of condensate reserves. Construction on this field began in 2012. The project is led by Japan's INPEX (66 percent) and Total (30 percent). 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 2017, its production is expected to be 380 Bcf of LNG and 12 million barrels of LPG per year, as well as 100,000 bbl/d of condensate. Other smaller fields under development in Browse are Crux and Prelude. The partners developing Crux received a 5-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 Prelude LNG.

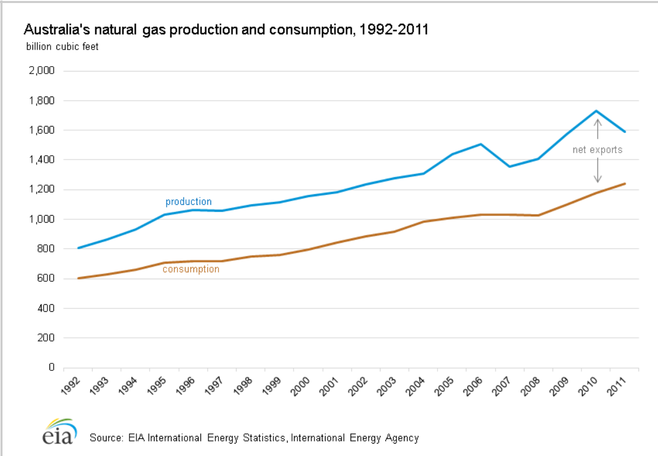
The Bonaparte Basin in the Timor Sea straddles the waters of Australia and East Timor and holds some undeveloped gas resources. ConocoPhillips is currently drilling fields at the Bayu Undan gas and condensate field. The Greater Sunrise field is a new development that has estimated resources of over 5 Tcf of gas and 230 million barrels of condensates.

Coal bed methane and shale gas

Australia has sizeable, untapped gas resources in the form of coal bed methane (CBM), known as coal seam gas in Australia, and shale gas. Australian officials estimate that economically recoverable CBM reserves in 2011 were 33 Tcf, mostly contained in the Surat and Bowen basins in Queensland. The only significant commercial production is from CBM, accounting for about 230 Bcf in 2011, or almost 12 percent of total natural gas production. The IEA predicts that production from these sources in Australia will expand to over 2,100 Bcf by 2020 and account for more than 50 percent of total gas production.

Many CBM projects are still under exploration, and production is not targeted for another few years. 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 increased 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 2012, NSW replaced the moratorium it imposed in 2011 on hydraulic fracturing with a Strategic Regional Land Use Policy that restricts CBM production near residential areas and small industries. South Australia, which houses part of the Cooper Basin, was the first province to publish extensive guidelines for gas development. The guidelines intend to encourage investment and development of these projects while outlining environmentally safe extraction practices.

Shale gas reserves in Australia are vast and could boost gas production once exploited. As noted above, EIA estimates that Australia has 437 Tcf of technically recoverable reserves, ranking the country sixth highest in the world. Most of the exploration activity has focused on the Cooper basin in the interior of the country where the majority of the country's onshore traditional gas reserves are located. The basin has attracted many international oil companies with the financing and technical capacities to develop the shale reserves. Firms such as Chevron, ConocoPhillips, Statoil, Total, BG Group, and Hess procured farm-in agreements and have invested over $1.55 billion in Australia's shale gas industry. Santos drilled the first successful commercial shale gas flow at its Moomba field in the Cooper basin at the end of 2012. In 2013, the South Australian regional government created regulatory guidelines of field development in order to provide transparency and recommendations for the industry to tap into the shale gas reserves.



Consumption

Even though Australia has experienced a steady rise in domestic natural gas consumption over the previous decade, the market for domestic consumption of 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 973 Bcf of gas in 2011, rising about 47 percent over the past decade. On average, domestic consumption has been around 70 percent of total production, although this share has dropped in the past few years as LNG sales expand. The country's industries are the major consumers of gas, with a 32 percent market share in 2010, according to Geoscience Australia. The second largest consumer is the power sector at 29 percent. The mining industry's share was 23 percent, and the residential sector's share was 10 percent. Australia implemented a carbon tax in July 2012 that is likely to shift more electricity generation from the coal-fired to gas-fired facilities.

LNG exports

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

As a result of its abundant gas resources and 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, the third largest LNG exporter in the world behind Qatar and Malaysia, exported about 990 Bcf of LNG in 2012, up from about 900 Bcf in 2011, according to FACTS Global Energy. Australia exports gas almost exclusively to the Asian market. Japan is the primary destination, taking over three-quarters of Australia's exports in 2012. Most of this supply to Japan is covered in long-term contracts. Other key consumers include China, South Korea, and Taiwan. Japan's demand for LNG rose in 2011 when natural gas-fired generation was substituted for the lost nuclear capacity following the Fukushima power plant accident. Australia became the largest source of LNG for Japan by 2012. All three main Chinese national oil companies (NOCs) have teamed with international oil companies (IOCs) on several Australian liquefaction projects and signed gas purchase agreements to lock in supply for the growing market in China.

Australia has three LNG export facilities with a total capacity of almost 1,200 Bcf per year (Bcf/y). The largest is North West Shelf LNG, owned and operated by a consortium of Woodside, Shell, BP, Chevron, Japan Australia LNG, and BHP Billiton. The facility has five offshore LNG trains with a total capacity of 780 Bcf/y, and it relies on natural gas supplied from nearby fields in the North West Shelf (NWS). The majority of LNG produced by the consortium is exported to Japan by long-term contracts. Darwin LNG, operated by the consortium of ConocoPhillips, Santos, Eni, INPEX, Tokyo Gas, and Tokyo Electric (TEPCO) is Australia's second facility. It has one production train with capacity of 170 Bcf/y and exports LNG under contracts to Tokyo Gas Corp. and Tokyo Electric. Darwin is located on Australia's northern coast and is supplied with natural gas from the Bayu-Undan field in the Timor Sea. Pluto LNG is Australia's most recent terminal to come online in 2012. The terminal is located in the Northwest region and has a capacity of over 200 Bcf/y. Woodside is discussing expansion plans for Pluto LNG, but difficulties procuring additional gas reserves nearby and rising project costs pose challenges to the expansion moving forward.

As new LNG facilities and expansions of existing facilities come online within the next decade, Australia's LNG export capacity is set to expand substantially. Most of the liquefaction projects are located in the coastal or offshore Northwest or North Australia and in the northeastern Queensland region. Some projects such as Ichthys are designed to produce associated condensates and LPG. Currently, there are seven projects under construction, three in Queensland and four in the basins of the Northwest coast and offshore. Total current capacity under construction is 3 Tcf/y which should enter operations by 2017. There are other projects waiting on regulatory approval or final investment decisions, although these projects are facing competition because of escalating costs and potential overcapacity. Australia currently has nearly $200 billion worth of LNG projects under construction, and the country is on target to overtake Qatar as the world's largest LNG exporter by 2020 according to industry sources.

CBM-to-LNG projects have become feasible with the sizeable amount of gas reserves associated with the coal production. Queensland Curtis LNG could become the world's first LNG project of this kind, with two neighboring projects under construction and two others waiting on final investment decisions. Even though 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. Also, CBM wells produce much less than traditional gas wells and ramp up to peak production over a much longer period.

Australia's burgeoning LNG industry faces acute capital cost escalation requiring much larger investments for new greenfield projects and puts some newer proposed projects at risk of delay or cancellation. The cost increases are attributed to a number of factors: labor shortages and resultant high wages, appreciation of the Australian dollar to the U.S. dollar since 2009, greater environmental hurdles due to more strict regulations recently, and the remote locations of some projects. The following projects have experienced cost overruns of between 12 and 32 percent: Ichthys, Gorgon, Wheatstone, Gladstone, and Queensland Curtis. Pluto LNG also incurred budget overruns by 30 percent from its original financial investment decision (FID) in 2007. Ichthys LNG, sanctioned in 2012, currently is the world's most expensive liquefaction project on a per unit basis, and Chevron's Gorgon LNG project cited cost increases of over 40 percent in U.S. dollar terms, from US$37 billion to US$52 billion.

Some of the economic and resource constraints have caused several equity partners to prioritize their project portfolio stakes and exit some projects. Also, some neighboring projects face competition from each other for contracted gas supply. In a high-cost environment, companies are beginning to target their investments towards projects in more advanced stages and could shift more focus to expansion of facilities versus planning new ones. The floating liquefied natural gas (FLNG) terminal design is less expensive than the cost of an onshore plant in Australia's high-cost environment, and companies have proposed several facilities. Prelude LNG, located in the Browse basin off the Northwest coast, is slated to become the world's first FLNG terminal using a new technology developed by Shell. As less expensive gas from Russia and the United States is brought online and exported, Australia potentially faces LNG competition on a more global scale in the longer term.

Australia existing and planned liquefaction terminals

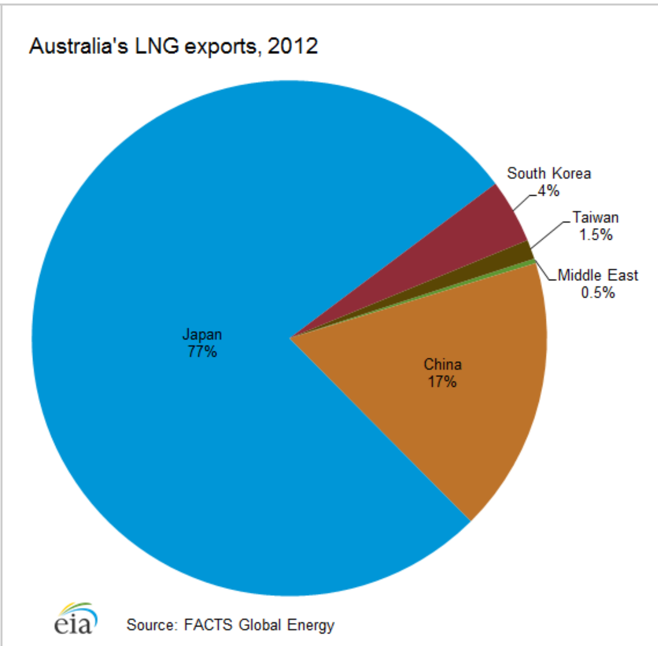
Liquefaction terminal	Equity partners	Status / online date	Capacity (Bcf/y)	Consumer markets	Capital cost
Existing facilities					
Northwest Shelf LNG	Woodside, Shell, BHP Billiton, BP, Chevron, Mitsubishi & Mitsui - 16.7% each	Existing	780; 5 trains[1]	Japan, China spot market	$11.5 billion for T1-3; $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%	Existing	170; 1 train	Japan and spot market	$3.84 billion
Pluto LNG	Woodside 90%, Kansai Electric 5%, Tokyo Gas 5%	Existing / Expansion plans are being discussed	205; 1 train	Japan, Malaysia	$15 billion
Planned LNG projects using traditional gas					
Gorgon LNG	Chevron, 47.33% ExxonMobil 25%, Shell 25%, Japanese gas & electric utilities 2.667%	Under construction; Q1 2015; T4 planned with construction to begin in 2014	720; 3 trains	Long-term contracts with Japan, Korea China, India, Mexico. Spot market	$52 billion
Ichthys LNG	INPEX 66.07%, Total 30%, Japanese gas & electric utilities 2.74%	Under construction; 2017	400; 2 trains	Japan, Taiwan	$34 billion
Wheatstone LNG	Chevron 64.14%, Apache 13%, KUFPEC (Kuwait) 7%, Shell 6.4%, Japanese gas & electric utilities 9.455%	Under construction; 2016	430; 2 trains	Japanese utilities	$29 billion
Prelude LNG	Shell 67.5%, Inpex 17.5%, Kogas 10%, CPC 5%	Under construction; 2017	175; 1 floating terminal[2]	Japan and Asian markets	$11.4 billion
Cash Maple LNG	PTTEP (Thailand) 100%	2017	100; 1 floating terminal	Potentially Thailand	N/A
Browse LNG	Woodside 31.23%, Shell 26.63%, BP 17.21%, PetroChina 10.23%, Mitsui 7.35%, Mitsubishi 7.35%	2020; Cancelled financial investment decision (FID) for onshore facility in 2013, potential floating terminal proposed.	576; 3 trains	Japan, Taiwan, other Asia	$48 billion
Bonaparte LNG	GDF Suez 60%, Santos 40%	2018; FID expected 2014	100-150; 1 floating terminal	N/A	$8 billion
Scarborough LNG	BHP Billiton 50%, ExxonMobil 50% (operator)	2020/21; FID anticipated 2014/15	300; 1 floating terminal	N/A	N/A
Sunrise LNG (Joint Development Area- Australia and Timor-Leste)	Woodside 33.44%, ConocoPhillips 30%, Shell 26.56%, Osaka Gas 10%	2017	525; 1 floating terminal	N/A	$5 billion
Planned CBM to LNG projects					
Queensland Curtis LNG	T1: BG 50%, CNOOC 50%; T2: BG 97.5%, Tokyo Gas 2.5%	Under construction; 2014	400; 2 trains	Chile, Singapore, China, India	$20.4 billion
Australia Pacific LNG	Origin Energy 37.5%, ConocoPhillips 37.5%, Sinopec 25%	Under construction; mid-2015; Proposed expansion	430; 2 trains	China and Japan (Kansai Electric)	$25.3 billion
Gladstone LNG	Santos 30%, Petronas 27.5%.	Under construction; 2015	375; 2 trains	Malaysia and Korea	$18.5 billion

	Total 27.5%, Kogas 15%				
Fisherman's Landing	LNG Ltd 81.11%, CNPC subsidiary 19.89%	2016; FID expected 2H2013	144; 2 trains	Potentially CNPC	$1.1 billion
Arrow LNG	Shell 50%, PetroChina 50%	2018; EIS plan submitted; FID expected end-2013	384; 2 trains in Phase I	China	$24.2 billion

1 *An independent unit for liquefaction and purification*

2 *Terminal above an offshore gas field that produces, liquefies, stores, and transfers natural gas*

Sources: IHS Global Insight, FACTS Global Energy, LNG company websites



Pipelines

Australia's domestic gas transmission pipeline network, covering 15,000 miles, is well-developed and transports gas from the key production centers to main economic hubs in the east. Significant investments of nearly $4 billion 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, there are three major pipelines that transport gas from northwestern gas fields to the southwestern region.

The Australian Energy Regulator oversees the gas pipeline networks in all states apart from Western Australia, which is regulated by the Economic Regulation Authority. However, the transmission and distribution network is largely privately-owned and operated, and several major pipelines are only partly regulated or not regulated.

The APA Group (APA) is Australia's largest pipeline operator, with interests in 8,400 miles of pipeline. APA transports about half of the country's gas use. In 2012, APA acquired Hastings Diversified Utilities Fund (owner of Epic Energy) making the operator the country's majority stakeholder of transmission capacity. Other key pipeline owners include Jemena, Prime Infrastructure, and Australian Gas Light.

Coal

Australia is the world's fourth largest coal producer and second largest exporter on a weight-basis. It holds the fourth largest reserves. Coal ranks as the second largest export commodity for Australia in terms of revenues.

Australia is one of the key sources of coal in the world, and the commodity plays a significant role in the country's economy. In 2008, Australia held 84 billion short tons (Bst) of recoverable coal reserves, the fourth largest in the world according to the World Energy Council. Australia is the world's fourth largest coal producer, after China, the United States, and India. For 25 years Australia was the largest coal exporter, but in 2011 Indonesia surpassed Australia in terms of coal exports on a weight-basis. Black coal, primarily bituminous or anthracite coal, is Australia's second largest export commodity, behind iron ore, in terms of revenues, and accrued over $62 billion in 2012.

The states of Queensland and NSW together account for 97 percent of Australia's black coal production, while Victoria accounts for 96 percent of brown coal reserves. Brown coal, or lignite, is used largely for domestic electricity generation. Australian coal is chiefly bituminous or sub-bituminous (black coal) in rank.

Sector organization

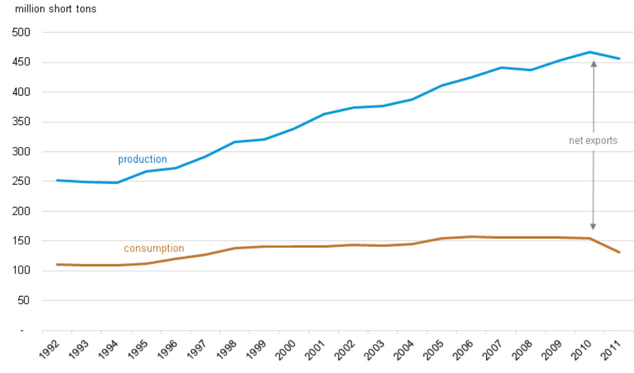
Australia has around 107 privately-owned coal mines located throughout the country. About 74 percent of Australia's coal production comes from open pit operations, with the remainder coming from underground mines. International companies such as BHP Billiton, Anglo American (UK), Rio Tinto (Australia-UK), and Xstrata (Switzerland) play a significant role in Australia's coal industry.

Production and consumption

In 2011, Australia produced 457 million short tons (MMst) of coal, down from 467 MMst in 2010. This decline is primarily a result of the flooding in Queensland that occurred in early 2011 and lowered production in that state by 30 percent. According to EIA estimates, over the last two decades, coal production in Australia has grown by 80 percent, with new projects continuing to come online every year. This growth has been supported by strong global and regional demand and by continued investment in new mining and export capacity. The Australia Coal Association reports that Australia has $25.6 billion in advanced coal mining and infrastructure projects to add over 80 MMst to production by 2014.

Coal plays a major role in meeting domestic energy needs, accounting for about 69 percent of Australian electricity generation according to the Bureau of Resources and Energy Economics. However, the country is seeking to replace some coal-fired generation with natural gas-fired generation or renewables and focus on coal production for exports.

Australia's coal production and consumption, 1992-2011

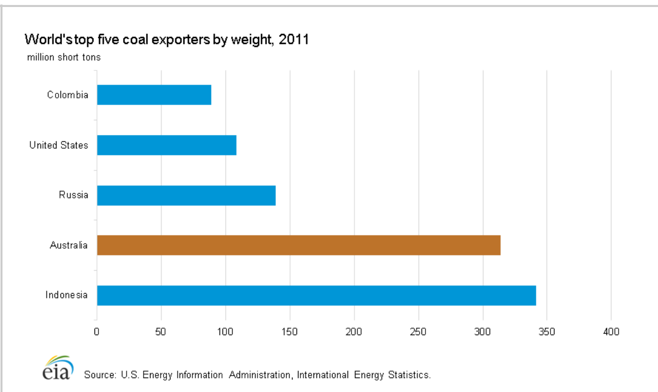


Source: U.S. Energy Information Administration, *International Energy Statistics*

Exports

Australia exported about 70 percent of its coal production (about 314 MMst) in 2011. The country was the world's largest coal exporter for over two decades, and fell behind Indonesia on a weight-basis this year. According to the Australian Coal Association, Japan was the destination for nearly 40 percent of Australia's black coal exports in 2010. China, Australia's second largest market for export coal, held a 14-percent share and doubled its export levels from the year earlier. Other top markets included South Korea (14 percent), India (11 percent), and Taiwan (9 percent). Most exports are from the Queensland and NSW states, although Western Australia began exporting coal in 2007.

Coal exports are serviced by nine major coal ports and export terminals located in Queensland and NSW. In 2009, these terminals had a combined handling capacity of 400 MMst. Several new port infrastructure projects are in various stages of development and are expected to add about 126 MMst to annual coal loading capacity by 2014. These include Wiggins Island, the Newcastle Coal Infrastructure Group's capacity expansion at the Port of Newcastle, and the expansion at Abbot Point in Queensland.



Electricity

Although about 90 percent of Australia's electric generation in 2011 was from fossil fuels (dominated by coal), there is a push for cleaner and more renewable power.

Australia's electricity generation has steadily risen over the past two decades as a result of a well-developed economy and growing mining sector. Between 2000 and 2011, electric generation rose 14 percent from about 100 Terawatt hours (Twh) to 225 Twh. However, generation has been stagnant since 2007 with consumption being held in check by higher electricity costs, weaker economic growth, and gains in energy efficiency.

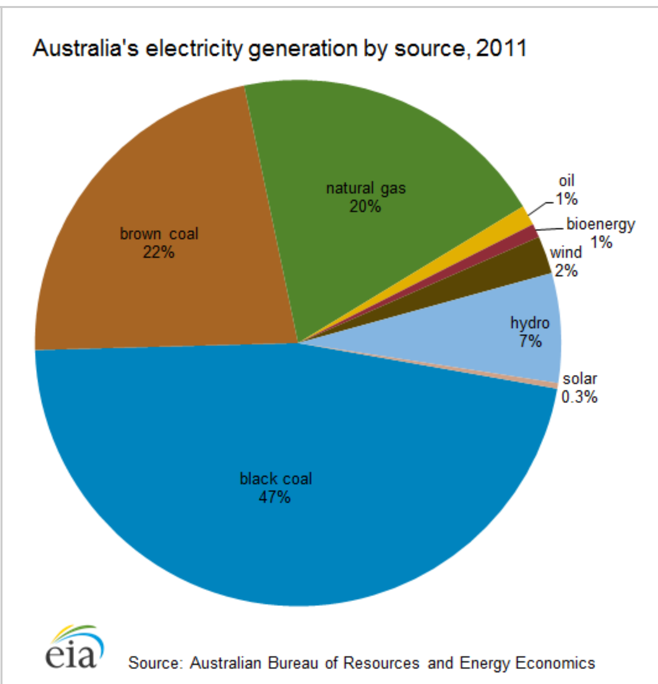
Australia's generation is mostly from fossil fuels, with brown and black coal making up 69 percent of electric power generation in 2011 according to Australia's Bureau of Resources and Energy Economics (BREE). The use of coal-fired generation rose until 2009 and has yielded some share to natural gas, hydroelectric, and other renewable energy in the last two years. Gas-powered generation is mostly used for intermediate and peaking demand and supplies 20 percent of total generation. BREE projects that natural gas will gain further market share and account for 36 percent of electric generation by 2035. Gas-fired generation capacity is highest in Queensland, and over the past decade, investment has increased 54 percent in gas-fired capacity in the country.

Hydroelectricity, accounting for nearly 7 percent of total generation, occurs in the states of Tasmania, Victoria, and NSW. Hydroelectricity is Australia's major source of renewable energy, although it has limited growth potential because of water availability constraints. Also, the country's hydropower market is mature apart from opportunities for small projects.

Other renewable sources, such as wind, bioenergy, and solar, supplied nearly 4 percent of electricity in 2011 and have been the fastest growing sources since 2000 with over 700 percent expansion. Wind energy has seen substantial growth since 2007 and accounted for almost 60 percent of other renewable sources in 2011. Biomass and waste made up a bulk of the remaining shares. Although accounting for a small portion of the renewable energy sources, solar power experienced the most growth in the past year as a result of the government's small-scale renewable energy projects. As part of Australia's Renewable Energy Target, the goal is to achieve a 20 percent share from renewable energy sources in power generation by 2020.

Australia's electricity grid is well established in the eastern and southern states under the National Electricity Market (NEM), a wholesale market. About 75 percent of capacity in the NEM is entirely or partly owned by state-level governments. Western Australia and the Northern Territory have separate transmission networks from the other states.

Electricity prices in Australia are typically low compared to most developed countries. However, between 2008 and 2011, retail prices rose 40 percent. This increase has been necessary to finance infrastructure upgrades and investment in system reliability as well as support renewable energy tariff programs.



Notes

- Data presented in the text are the most recent available as of June 21, 2013.
- Data are EIA estimates unless otherwise noted.

Sources

- AAP Newsfeed
- APA Group (APA)
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- Australian Bureau of Agriculture and Resource Economics (ABARE)
- Australian Bureau of Resources and Energy Economics (BREE)
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- Chevron
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